CIGRE Green Books

International Council on Large Electric Systems (CIGRE)
Study Committee B2: Overhead Lines

Overhead Lines

Springer Reference

CIGRE Green Books

Series editor

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Konstantin O. Papailiou
Editor

Overhead Lines

With 868 Figures and 175 Tables

Springer Reference

Editor
Konstantin O. Papailiou
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Message from the President

Dear Members of Cigré, dear reader,

Since its creation in 1921, Cigré follows the mission to be a platform for exchange and elaboration of knowledge in the electric power system. Being a global and nonprofit organization throughout the decades Cigré has been a key factor for gaining unbiased knowledge and understanding of the principles of the electric network in all aspects e.g. for material, equipment, control- and system questions. Most important are the biannual sessions in Paris and many smaller events on national and international level every year. Also numerous Cigré Working Groups generated and synthesized knowledge throughout the decades. At this time, 230 groups are active involving more than 3500 experts spread over the globe. Their product is mainly the so-called Technical Brochures which are invaluable publications as they contain the collective experience and expertise of most prominent experts in the field on an international basis. The information made available is used in many ways, such as textbooks for students and/or information for specialists in the various topics. Quite often Cigré Technical Brochures are used as a reference when standards are not available. Frequently they are the basis for IEC standardization. Major strategic directions of Cigré's activities are; best practice issues, as well as future aspects of the power system and ecological topics.

Today Cigré's publications are available in hard copy and in electronic form back to the year 1968 to be searched in "e-cigre". An invaluable amount of information has been published in conference reports and more comprehensive working group documents. However, it turns out that there is still a gap as a regular review of the State of the Art in the various fields is missing, that would be useful for education and/or as reference books for experts.

For that reason Cigré made the strategic decision to develop a series of reference books for the various fields, the so-called CigréGreenBooks. The goal would be to compile state of the art knowledge in the field in a comprehensive and well-rounded manner. The books should be updated periodically by the Study Committee responsible for the topic.

For the time being two Cigré Green Books are available. The first one elaborated by SC B2 with the title "Overhead Lines" (in hand) and a second one titled "Accessories for HV Underground Cables" by SC B1. Both books compile a unique state of the art review. Basic principles as well as important data for experts can be found easily as the books are well structured. History, material, technology and system aspects are well covered. The books are an essential enrichment of the Cigré publication portfolio. More books in other fields will follow.

The authors and contributors of the two books ("Overhead Lines" in hand) have to be congratulated for this first successful edition and their extreme efforts are sincerely appreciated. The Technical Committee also has to be acknowledged as it took patronage.

In particular I like to express my sincerest thanks to Konstantin Papailiou, Chairman of Study Committee B2 (Overhead Lines) and to Pierre Argaut, Chairman of Study Committee B1 (Insulated Cables) for their unflagging efforts to make both books a success and having finished them in time for the Paris Session 2014. Konstantin deserves particular credits as he was the one who offered the idea for a Reference Book in the first place to the Technical Committee.

Klaus Fröhlich
President of Cigré

Klaus Fröhlich received a Ph.D. in Technical Sciences from the University of Technology in Vienna, Austria. For more than 11 years he worked for ABB Switzerland and USA in development of high voltage equipment. From 1990 till 1997 he was employed as a full Professor for Switchgear and High Voltage Technology at the University of Technology in Vienna, Austria followed by a full Professorship for High Voltage Technology at the Swiss Federal Institute of Technology (ETH) in Zurich, Switzerland. Klaus Fröhlich has a Fellow Membership in Electrosuisse and IEEE. He also is a member of the Swiss Academy of Engineering Sciences. In Cigré his latest positions were Chairman of Study Committee A3 and chairman of the Cigré Technical Committee. Currently Klaus Fröhlich is the president of Cigré.

Message from the Chairman of the Technical Committee

Efficient use of electric energy is at the very heart of a sustainable future for us all and for almost 100 years now, Cigré has provided a worldwide platform for achieving such an ambitious target.

Initially, as integrated, high voltage, electric power networks were developed and became established in various parts of the world, Cigré was very much focussed on the technical aspects of transmission of electric energy. As the electric power industry evolved it was vital that Cigré also evolved. Over time, greater focus was placed on aspects such as markets, regulation, system planning, sustainability and information systems but this was certainly not at the expense of the more fundamental technical aspects.

Today, as the distinctions between transmission and distribution and between end user and electricity provider are eroded and as the entire electric power system becomes more interactive and reliant upon intelligent systems, Cigré's focus has, of course, widened to address the entire electric power system. Generation, transmission, distribution and end-use of electric energy are all addressed across the entire spectrum from 1200 kV transmission grids to local micro-grids, employing AC or DC.

The present day activities of Cigré can be divided into three key themes namely: "*Developing the power system of the future*", "*Making best use of existing power systems*" and "*Environment and sustainability*". Within this framework Cigré strives to bring together the widest possible range of experts from across the world to share and exchange knowledge and to use this combined knowledge and experience to develop and publish pre-eminent technical information and state of the art guidance.

Our aim is to prepare documents and communications that are clear, readily accessible, unambiguous and appropriate to the intended audience, and which also promote the value and importance of electrical engineering and the electric power industry within technical, political, business and academic arenas. This has been achieved very successfully over many years and Cigré's ever growing library of Technical Brochures, conference papers, tutorials and articles is a unique and unparalleled resource in the electric power industry. Nevertheless, recognising that dissemination of high quality, unbiased information is Cigré's singular focus, finding new ways to make our work visible is always a priority, which brings us to the Cigré Green Book initiative.

Cigré Green Books are a way of consolidating, enhancing and disseminating Cigré's accumulated knowledge in specific fields. Addressing all aspects of Cigré's key themes, prepared and edited by world recognised experts, and building upon Cigré's established library of world class publications, the Green Books provide a single, invaluable reference source within their specific field of application. They also provide a unique resource for those wishing to develop themselves, for those wanting to make their contribution to the power system of the future, and to the vision of access to reliable, affordable and sustainable electric energy.

The Technical Committee is committed to the continuing development of Cigré's technical leadership in the electric power industry and the future expansion of the Green Book series is a key part of this commitment.

Mark Waldron
Chairman of Technical
Committee of Cigré

Mark Waldron graduated in Electrical Engineering in 1988, joined the Research Division of the Central Electricity Generating Board and then, following privatisation, National Grid in the UK by whom he is still employed. He has been involved in all aspects of lifetime management of switchgear & substation equipment from research & development, specification, assessment, maintenance & monitoring, condition assessment & end of life management. He presently holds the position of Switchgear Technical Leader in addition to his role as the Technical Committee Chairman of Cigré. His involvement in Cigré spans in excess of 20 years during which he has been a participant in several Working Groups, Working Group Convenor and Study Committee Chairman of Study Committee A3 and has led the Technical Committee project on Ultra High Voltage Transmission.

Message from the Secretary General

While these lines are being written, Cigré counts more than 7700 individual members and 1100 collective members from 90 countries. All the members have access to the publications produced by the Cigré Working Groups in the form of "Technical Brochures" when their work is completed.

Between 40 and 50 new Technical Brochures are published yearly. The brochures are announced in Electra, Cigré's magazine, and are available for downloading from e-cigre, the online library of Cigré (www.e-cigre.org).

Over 6800 references of publications, from 1968, can be accessed from this library, one of the most comprehensive accessible databases of relevant technical work on power engineering.

From 1931 to 1974 the technical reports of Working Groups were published only in Electra. As some brochures were becoming voluminous it was decided to publish them separately, as Technical Brochures.

The first Technical Brochures were published in around 1974, and until 2000 Electra or separate Technical Brochures could be used to deliver the work of the Working Groups, depending on the size of the document, 6 pages being the limit for a publication in Electra.

In 2000, Electra was redesigned, and as a result, no longer published the final reports of Working Groups. Today only summaries of Technical Brochures are provided in Electra, in both English and French.

From 2002 to 2014 some Study Committees have produced many Technical Brochures: up to 75 for one of them, the average being 30 per Study Committee.

Therefore it is a good idea to organize over twenty years of accumulated knowledge into comprehensive books.

Cigré Green Books are a new collection of publications, in a new format, a good method to compile a large amount of knowledge, and the additional efforts of the experts of the Study Committees involved in such projects should be recognized. I am sure that the work involved will be appreciated by all the Cigré community.

Welcome to this new collection which I wish every success!

Philippe Adam
Secretary General of Cigré

Graduate of the Ecole Centrale de Paris, **Philippe Adam** started his career in EDF in 1980 as a research engineer in the field of HVDC and was involved in the studies and tests of outstanding projects like the Cross Channel 2000 MW link and the first multiterminal DC link between Sardinia, Corsica and Italy. After this pioneering period he managed the team of engineers in charge of HVDC and FACTS studies of the R&D division of EDF. In this period, his Cigré membership as a working group expert and then as a working group convener in Study Committee 14, was a genuine support to his professional activities. Then he held several management positions in EDF Generation and Transmission division in the fields of substation engineering, network planning, transmission asset management and international consulting until 2000. When RTE, the French TSO was created in 2000, he was appointed manager of the financial and management control department, in order to install this corporate function and the necessary tools. In 2004 he contributed to the creation of RTE international activities as project director first and then deputy Head of the International relations department. From 2011 to 2014 he has been the Strategy Director of Infrastructures and Technologies of the Medgrid industrial initiative. In the meantime, between 2002 and 2012 he have served Cigré as the Technical Committee Secretary and as the Secretary and Treasurer of the French National Committee from 2009 till 2014. He was appointed Secretary General of Cigré in March 2014.

Preface

Exactly at the date this book is being presented for the first time during the 45th Cigré Session, i.e. on August 24th 2014, in Paris, the first high voltage AC transmission in the world took place. It was actually on August 24th 1891 when one of the main players of this memorable event shouted from the top of a wooden pole in the line: “The current is now in Frankfurt!”. And indeed, for the first time in world history, electric power from the picturesque small town of Lauffen in Southern Germany travelled more than 185 km to provide light to 3000 incandescent bulbs and an artificial waterfall at the then electro-technical exhibition in Frankfurt/Main. This was the beginning of -also in the physical sense- “a long” success story. From the single 15 kV, and later 25 kV-AC line supported on wooden poles and with 4 mm diameter Copper conductors (the losses were in the range of 25%!), there are nowadays in Europe alone more than 100,000 km of 380 kV AC lines, fully interconnected! Electric power lines are thus most probably the longest and most complex artifact mankind has ever conceived and created. Cigré, the Council on Large Electric Systems (Conseil International des Grands Réseaux Electriques), was founded 30 years later in 1921 in Paris, and by its unique structure has been and is the supreme reference for electric power networks. The Cigré Study Committee on Overhead Lines, one of the oldest in Cigré, combines through its presently 25 Working Groups (WG) and some 300 experts from more than 40 countries, a massive –and impressive- expertise in this field. This guarantees valuable exchange and dissemination of unbiased information for technical and increasingly for nontechnical audiences, like the public, journalists and politicians.

To be frank, overhead lines, despite a practically worldwide constant demand for new lines and the refurbishment of old lines, and despite all the interesting engineering but also management tasks related to them, have been considered by some as becoming old-fashioned. What a misconception! Through the “Energiewende”, i.e. the massive integration of renewables in the network, on one side and the huge demand for electric power in the developing countries, China, India and Brazil are good examples, on the other, overhead lines have recently become focus items for utilities, investors, researchers, media and the public, for the last not always with a positive attitude.

In this sense the idea of writing a reference book on Overhead Lines was born in order to present to all interested parties the bundled knowledge and experience of Cigré SC B2 in this exciting field. It was also considered as a unique opportunity to pass on valuable information and experience to the next generation of transmission line engineers, as many of the contributors to this volume have been active for innumerable years in Cigré in this field and have accumulated a wealth of knowledge which has to be preserved.

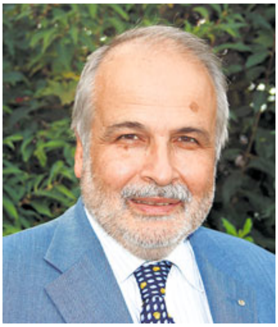
Preparing a book, and in particular such a big and complex one with many coauthors, is like coaching a world class soccer team for the editor, a parallel to the World Cup 2014 that has just finished, i.e. it is not an easy task. The basic book structure has to be defined, the content but also the focus agreed upon, overlaps to be avoided. And many technical issues to be solved: the size of the book, the picture on the cover, the fonts to be used, one- or two-columns, the style of the tables, the numbering of the figures, etc., etc.

And it is like building a house: everything looks half-finished until the very last minute. And you never believe that it will be completed on time. But it is extremely rewarding. In particular when the book is nearing completion, the "happy-end", this is evident by the fact that the Editor starts preparing his Preface, as is the case now. Because at that stage the hard work of so many people involved becomes visible. I know it is a daring comparison, but when the first trial print is ready, it feels like holding your baby in your hands for the first time.

But to continue in this tune, a book has its own life. And it is never finished. Fortunately with the advances in electronic printing, oversights, omissions, suggestions can be relatively easily incorporated in future editions, which I am confident, will come. So please feel free to send your comments to konstantin@papailiou.ch and to editions@cigre.org and they will be given thoughtful consideration.

But enough said, or better written: It is now time dear reader that you start enjoying!

Athens/Greece, July 2014 Konstantin O. Papailiou



Konstantin O. Papailiou studied electrical engineering at the Braunschweig University of Technology and civil engineering at the University of Stuttgart. He received his doctorate degree from the Swiss Federal Institute of Technology (ETH) Zurich and his post doctoral qualification as lecturer (Dr.-Ing. habil.) from the Technical University of Dresden. Until his retirement at the end of 2011 he was CEO of the Pfisterer Group in Winterbach (Germany), a company he has served for more than 25 years. He has held various honorary positions in Technical Bodies and Standard Associations, being presently Chairman of the Cigré Study Committee "Overhead Lines" (SC B2). He has published numerous papers in professional journals as well as co-authored two reference books, the EPRI Transmission Line Reference Book – "Wind -Induced Conductor Motion" and "Silicone Composite Insulators". He is also active in power engineering education, teaching Master's level courses on "High Voltage Transmission Lines" at the University of Stuttgart and the Technical University of Dresden.

Preface of the Republished Edition

What a great coincidence! The very days the new CIGRE Green Book “Overhead Lines” is to be presented during the bi-annual CIGRE session in the last week of August, our industry – and I mean not only lines but the whole power system – will celebrate the 125th anniversary of the first high voltage (15 kV to be precise) AC transmission, which took place in the southern part of Germany in August 1891.

In 2014 I had the pleasure to write a few lines (lines again!) on the new series of Reference Books CIGRE had started, the Overhead Lines Green Book and the HV Cable Accessories Green Book. This has been an important step for CIGRE to make available to the interested public valuable information collected over many years of hard work in CIGRE working groups by a huge number of internationally-renowned experts. The success of these books – hundreds have been sold since their introduction – proved that there is a demand for such information, which, because of its plurality, is accurate and unbiased.

What better reason could there be to continue the series with subjects covered by other CIGRE Study Committees, such as High Voltage Equipment, Insulated Cables, Substations, HVDC and Power Electronics, Protection and Automation and Distribution Systems and Dispersed Generation? And what better concept than for CIGRE to liaise with a renowned international publisher like Springer for the GREEN Book Series, which will be published by Springer as part of their so-called Major Reference Works, a brand recognized worldwide for high quality content and layout and enjoying high visibility in a large number of libraries, book fairs, and internet platforms?

Another big advantage of this concept is that the Green Books will be available not only in print but also as#2003(eBook)s, with all their advantages, such as availability on mobile devices, easily searchable, fully linked content. At the same time Springer will establish a so-called living book platform for each Green Book, where updates, corrections, digital media material, etc. can be readily uploaded and will become immediately available to the public.

The first book which will be published under this collaboration is this Overhead Lines Green Book. Within my editorials duties I had the opportunity during proof reading to go through it again two years later and make some corrections, additions and updates here and there. And I have to confess that, although I thought I knew a few things about Overhead Lines (a wonder after 40 years – since 1976 – of being active in CIGRE, another anniversary!), I have been more or less struck by the wealth of information this book contains and also the way this information is presented: clear and to the point; I dare say educational, so that also non-experts on the subject will profit by reading it.

This gives me before closing the opportunity to thank once more all authors for their valuable contributions, the CIGRE officials for their continuing support and the Springer team for its great expertise and happily cheer:

Happy Birthday Overhead Lines, welcome new Green Book!

Malters/Switzerland
July 2016

Konstantin O. Papailiou
Editor

Acknowledgements

A reference book like this one is always a big collective effort; and a hard piece of work. Many individuals have been involved to accomplish it. First of all the chapter lead authors and the chapter authors as indicated in the individual chapters, but also the respective reviewers, all of them internationally recognized experts in their fields. I would like to thank them all.

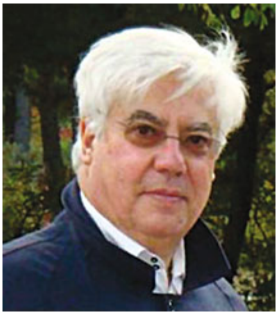
Luckily enough I could rely upon a competent team of book advisors, who made valuable suggestions and have been always at my disposal every time need arose. They are Bernard Dalle, former SC B2 Chairman, Normand Bell, former SC B2 Secretary and David Havard, former SC B2 WG11 (predecessor to TAG B2 06) Convenor. In addition the last two offered their invaluable services by reviewing the content of the whole book for consistency and overlaps and by performing a language check. All three of them deserve my gratitude and thanks.

This is also the time and the place to offer my thanks and gratitude to the President of Cigré, my good friend Prof. Klaus Fröhlich, who was immediately enthused by the idea of a Green Book series (green evidently because of the Cigré-logo green color) when first presented to him. Thanks and cheers also for my two dear colleagues, Mark Waldron, the Chairman of the Technical Committee of Cigré, and Philippe Adam, the Secretary General of Cigré, as well as the other TC Chairmen. All of them supported the idea and were always helpful in making it happen.

Because of extraordinary circumstances, this book (and its companion book on "Accessories for HV Extruded Cables") would not have been published on time for the Cigré session 2014, if my beloved wife Margarita has not put all her energy and skills to support me in the layout and production process. She and her publishing team have done a great job which is herewith thankfully acknowledged.

Konstantin O. Papailiou
Editor

Normand Bell received his B.Sc.A. Degree in civil engineering from Sherbrooke University (Québec) in 1974. He joined Hydro-Québec in 1974. He has 40 years experiences in the design, construction and managing of overhead transmission lines and underground lines. For the last 5 years, he has been providing consultancy services to electrical utilities, consultancy firms and developer for OHL projects. In Study Committee B2 (overhead lines), he has been a member and secretary of working group, special reporter, advisory group convener and was secretary of SCB2 from 2004–2010. He has published over 30 papers and been involved in the preparation of Cigré TB 147, 265, 274 and 320.



Bernard Dalle is a Consultant on Overhead Lines and a witness Expert at the Paris Court of Appeal. He has been Chairman of Cigré Study Committee B2 Overhead Lines for 6 years (2004–2010). He has worked as a Senior Executive Consultant within RTE – Power Transmission Infrastructures and as Director of Infrastructure Grid R&D Programme within EDF/R&D. He has also been Chairman of UF11, the Standardization Committe on Overhead lines within UTE, the French Organization for Standardization for electric and electronic products. He is a honorary member of Cigré and a member of SEE.

Dr. David (Dave) Havard, Ph.D., P.Eng. President of Havard Engineering Inc., has over 50 years experience solving the mechanical and civil engineering problems of power delivery systems. His work involves analysis of problems and finding solutions, particularly those problems involving vibration, wear and fatigue. As a Senior Research Engineer in the Mechanical Research Department of Ontario Hydro, he coordinated Ontario Hydro's assessment of older transmission lines for the province-wide refurbishment and upgrading, and has worked closely with design and maintenance staff to solve problems on vibration and galloping of overhead lines. Since establishing his own company in 1992, Dr. Havard continues to provide engineering services to utilities on control of vibration and galloping and testing and analysis of components of transmission systems. David has been conducting open and in-house training courses in these topics and degradation and upgrading of transmission lines for utility staff. David is a long time active member of IEEE, CEA and particularly Cigré. He served from 1987 to 1999 first as Secretary of the Task Force on Galloping, then Secretary and later Convenor of Cigré Study Committee B2, "Overhead

Lines", Working Group 11 "Mechanical Behaviour of Conductors and Fittings", and continues to be an active contributor. Under his leadership the working group produced a number of technologically significant reports, ELECTRA papers and technical brochures on overhead conductor vibration topics. Dr. Havard has authored over 200 published papers and reports and is a Registered Professional Engineer in the Province of Ontario.

Contents

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1 Introduction

Konstantin O. Papailiou

Overhead Lines look back to a long history from the first AC transmission in 1891 with 15 kV, Figure 1.1, to the 1000 and 1200 kV AC lines of today, Figure 1.2. This unique and this exciting development has been tracked and supported by Cigré in general and the Study Committee for Overhead Lines in particular. Chapter 2 "History of Overhead Lines in Cigré" describes in detail this successful "partnership". From its very beginning in autumn 1921 Cigré aimed to provide a forum for technical studies on the generation, transmission and distribution of electric energy. In this sense Cigré brought together, on one hand, equipment manufacturers and operators of power plants and transmission lines and electric energy producers, consultant engineers and engineers of major public administration bodies on the other. In addition 1931, coincidentally the year the Study Committee of Overhead Lines was established, Cigré put in place a monthly journal named "Electra", which is still the printed (today also the electronic) voice of the association. It is at the least remarkable, that in 1946, Cigré was the first technical organization in the world which organized an international conference and brought together worldwide experts who had the enormous task to rebuild electrical infrastructure after the perils of the second world war. In 2000 as another landmark and as a key element in the new approach to communication, the "Conference des Grands Réseaux Électriques à haute tension" became the "Conseil International des Grands Réseaux Électriques", that it changed from a "Conference" to a "Council" and its scope was extended also to lower voltages. At the same time the areas covered by Cigré's field of action were redefined. Cigré now covers not only conventional technical expertise but also economic and environmental aspects.

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K.O. Papailiou (✉)
Malters, Switzerland
e-mail: konstantin@papailiou.ch

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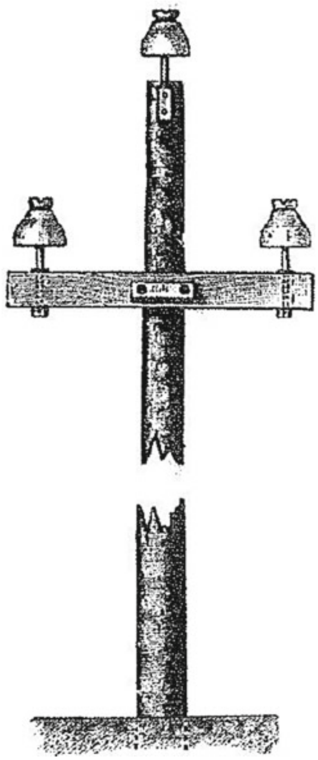


Figure 1.1 Wood pole of the first 15 kV AC line between Lauffen/Neckar to Frankfurt/Main (1891).

An Overhead Transmission Line is a very complex structure often spanning thousands of kilometers, crossing different weather zones and being subject to huge electrical, mechanical and environmental stresses. Because of this it is very important that in the management of a transmission line from conception to decommissioning to realize the nature of the line as a device (or system) and to ensure management structures do not compromise any aspect of the life cycle. Chapter 3 "Planning and Management Processes" covers the various management concepts that should be employed as well as the processes for line design, construction and maintenance.

The following Chapters of the book cover many of these processes in detail. For instance Chapter 4 on "Electrical Design" contains all the basic information needed for the electrical design of a transmission line. Subjects covered include such diverse topics such as Surge Impedance and Surge Impedance Loading, Insulation Coordination, Electric and Magnetic Fields and also Electric Parameters of DC Lines which show the breadth of knowledge required for the proper design of a line. Specific emphasis is given to the importance of the natural power as a key design factor. Especially nowadays with the advent of HTLS (High Temperature Low Sag) conductors it is worth to remember that their higher thermal capacity cannot be utilized except for relative short lines, Figure 1.3. Also the aspects of proper grounding of transmission line towers, eminently important for personal safety, as well as the issues of insulation coordination and Corona are given the place they deserve. Finally the increasing use of DC-lines for long distance transmission is adequately and in detail addressed.

Figure 1.2 1200 kV AC line at Bina test station in India (Photo: Alberto Pigini).

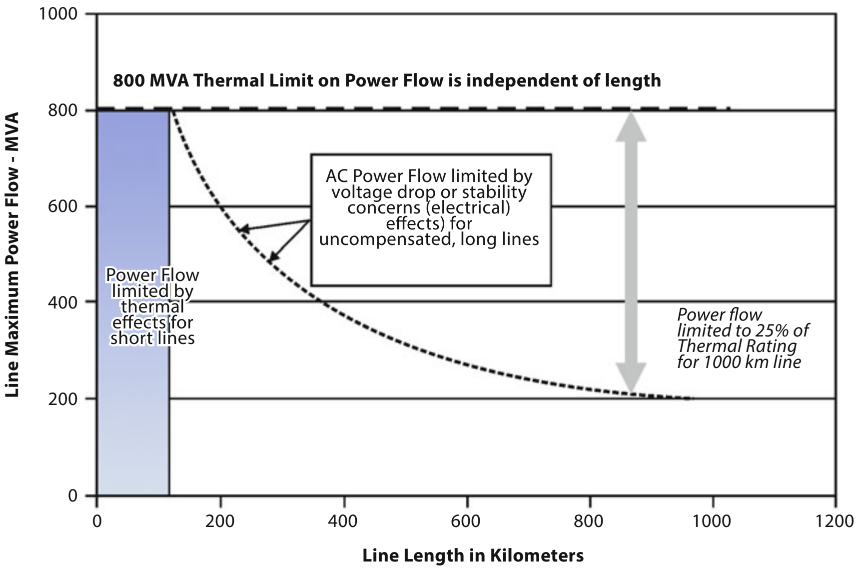


Figure 1.3 300-400 kV Transmisison Line max Power Flow dependence on length.

Overhead Transmission Lines are insofar unique, as they encompass mechanical design issues of equal importance, and research interest, as the electrical issues above. “Structural and Mechanical Design” is thus the focus of Chapter 5. This Chapter is an excellent example on the pursuing of new venues by Cigré and also on the cooperation between Cigré and other leading international organizations, in this case IEC, a strategy successfully pursued up to these days. The subject is reliability based design (RBD), an issue started in Cigré more than 40 years ago under the auspices of Study Committee 22, the predecessor of SC B2. Further technical development was pioneered by a joint effort between Cigré and IEC leading to a milestone in 1991 when IEC 8261 entitled “Loading and Strength of Overhead Lines” was published, introducing reliability and probabilistic concepts for calculation of loading and strength requirements for overhead line components Figure 1.4, a major improvement compared to deterministic methods and nowadays widely used worldwide. A good part of Chapter 5 deals extensively with the calculation of meteorological loads on line structures notably wind and ice loads, followed by an explicit calculation or tower top and mid-span clearances, demonstrating nicely the already mentioned multidisciplinary nature of a line, as the clearances are significant for the proper electrical functioning of the line. The Chapter concludes with quite a specific subject, i.e. the design and use of load control devices for containing possible cascade failures and explains the influence of line parameters on line security.

Chapter 6 “Environmental Issues” is, in addition to providing very valuable information on this nowadays very central subject, a good example of the interdisciplinary way Cigré works, as it encompasses important input from other Study Committees, notably SC C3 (System Environmental Performance). Overhead Lines and environmental issues and their interaction have been under consideration within Cigré for many years. In this sense the issues covered in this chapter range from permit

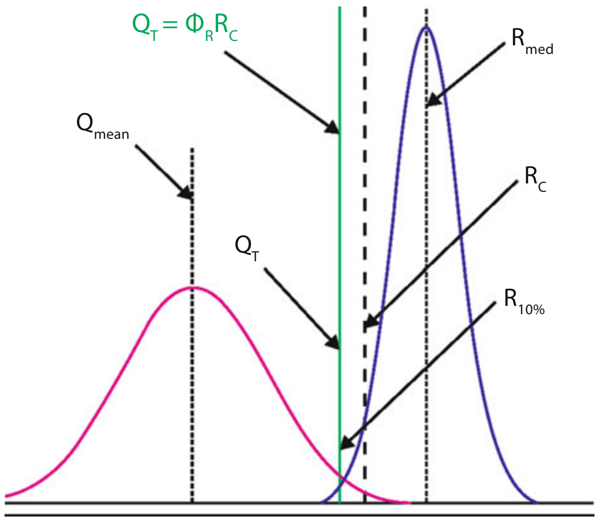


Figure 1.4 IEC 60826 reliability based design philosophy.

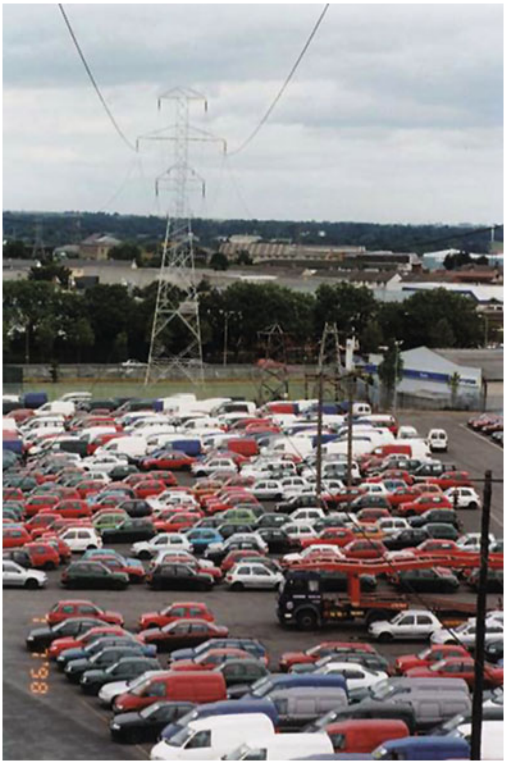


Figure 1.5 A double circuit 110 kV line corridor used as a car park in an industrial area (Ireland).

procedures, environmental impact assessments and consultation methodologies for Overhead Line projects to mitigation of environmental impacts be they visual, ecological, on land use or of construction and maintenance. Extensive space is given to the development of reduced visual impact designs and aesthetic designs, a subject further expanded in Chapter 12 "Supports" and to multiple use of Overhead Line corridors, Figure 1.5. Last but not least all issues associated with field effects inclusive of the debates on EMF and mitigation measures are presented including Corona, Radio and Television Interferences and ion current phenomena associated with DC.

For a better assessment of the meteorological loads acting on a transmission line and presented in Chapter 4, it is important to understand the weather and its interaction with a line. This is exactly the subject of Chapter 7 "Overhead Lines and Weather". Therein not only the basic mechanisms of the different weather phenomena, as for example the creation of a cyclone, a thunderstorm or the different icing procedures, which can have detrimental effects on a line, Figure 1.6, are well explained, but also the ever increasing, and worrying, influences to the weather due to changes in global climate are adequately covered. The chapter further includes information on the application of numerical weather prediction models, a subject of increasing interest thanks to the recent advances in information and data managing techniques.

Figure 1.6 Rime icing on a 420 kV line in Norway, 1400 m above sea level.

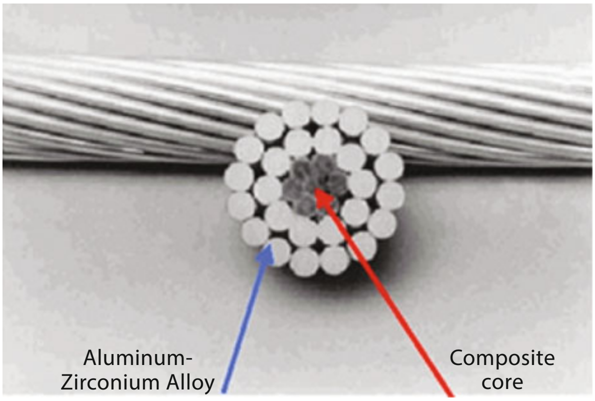


Figure 1.7 ACCR conductor showing the stranded metal composite core.

Conductors are the only active component of a line, i.e. the one component involved in the transmission of electric power and their costs, including the associated fittings, can reach up to 50% of the total line investment costs. Because inadvertently they generate Ohmic losses, their properties influence significantly also the operating costs of a line. It is thus no wonder that many Cigré Working Groups have over the years investigated them. The summary of their findings is given in Chapter 8 "Conductors". This chapter focusses on the following three areas:

- Calculation of AC resistance
- Sag-tension calculations
- Conductors for operation at high temperature

Regarding the latter, it has been astonishing to follow, how many innovative conductor concepts have been created in the last years, Figures 1.7 and 1.8, following the need to increase the power transfer capacity of a line with minimal changes of the structure of the line.

Figure 1.8 ACCC conductor showing its carbon fiber thermoset resin core.

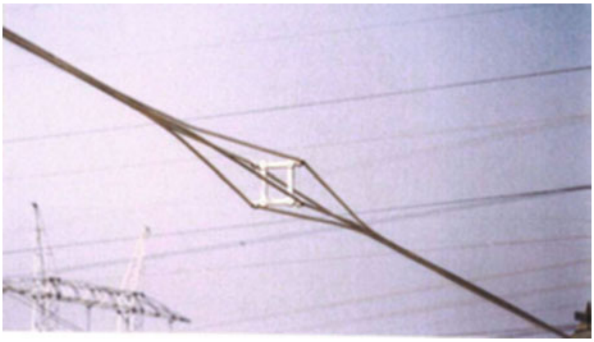


Figure 1.9 Short circuit test of spacer damper.

Line components to anchor, clamp, connect (join), damp and repair the conductor are collectively known as "Fittings". They are extensively covered in Chapter 9. The chapter starts with a detailed section on the various manufacturing and finishing processes of such fittings to continue with the electrical stresses they have often to endure, such as Corona, short circuits, Figure 1.9, and contact deterioration. The latter are of increasing interest due to the elevated conductor temperatures applicable nowadays. Another important issue is the test methodology developed within Study Committee B2 for testing "old" fittings, i.e. fittings which have been for long time in service, in order to decide on their usability. This goes hand in hand with the extensive coverage of repair methods and the related hardware, also covered in this chapter.

Conductor vibrations have plagued transmission line engineers since the early days of overhead line transmission. In particular when the copper conductors originally used started being replaced in the twenties, because of economic considerations, by ACSR (Aluminium Conductors Steel Reinforced), vibration damages have been so heavy, that the use of the latter has been seriously questioned. The

Figure 1.10 Wear and failure of conductor strands due to spacer clamp loosening.

understanding of the vibration phenomenon and its detrimental effects on line conductors, Figure 1.10, has been thus for innumerable years a focus area of studies within Cigré and it is not exaggerated to state, that quite a number of seminal papers and state of the art Technical Brochures have been produced by Cigré experts and published for the first time by Cigré. It is thus no wonder that Chapter 10 "Conductor Motions" turned out to be the lengthiest of this book. The following examples might illustrate Cigré's legacy in this field: a) the concept of the lifetime estimation of conductors undergoing Aeolian vibrations, Figure 1.11, b) the EDS principle followed by the safe design tension method, Figure 1.12, and c) the energy balance principle (EBP) for the calculation of the vibration activity. This chapter evidently includes also details on other types of wind-induced motions such as sub-span oscillations and galloping, valuable information on conductor self-damping and external damping devices (e.g. Stockbridge dampers and spacer dampers) as well as a section dedicated to mechanical effects of short circuit loads on conductors and line hardware, a phenomenon occurring mainly at the physical interface of lines and outdoor substations.

The following Chapter 11 "Insulators" is equivalent to Chapter 10 as far as originality and value of published information by Cigré is concerned. As for conductor vibrations, also in the field of insulators, Cigré has played a pioneering role over the years. And doubtlessly, the fact that Composite Insulators, a relative new, for Overhead Line time frames, technology has advanced tremendously in the last decades is due largely to the work of Cigré. This Chapter covers surveys (a very powerful and frequently used Cigré tool which takes advantage of the unique international character of the organization) on many topics, on screening tests on aged porcelain and glass insulations, service experience of composite insulators), standardization issues (where Cigré Working Groups have prepared the basis for many IEC Standards) and design recommendations (for instance for the proper Corona and power arc protection of insulator strings), Figures 1.13 and 1.14.

For many years "Supports", the subject of Chapter 12, were more or less equivalent to steel lattice towers and Cigré Working Groups have delivered important contributions on their proper design philosophy, static and dynamic loads, structural modeling and analysis, calculations and dimensioning, including advanced tools and techniques, materials and standards but also detailing, fabrication and prototype testin, g not to mention types and causes of defects and industry repair practices. The last years though, increased awareness to transmission line structures and

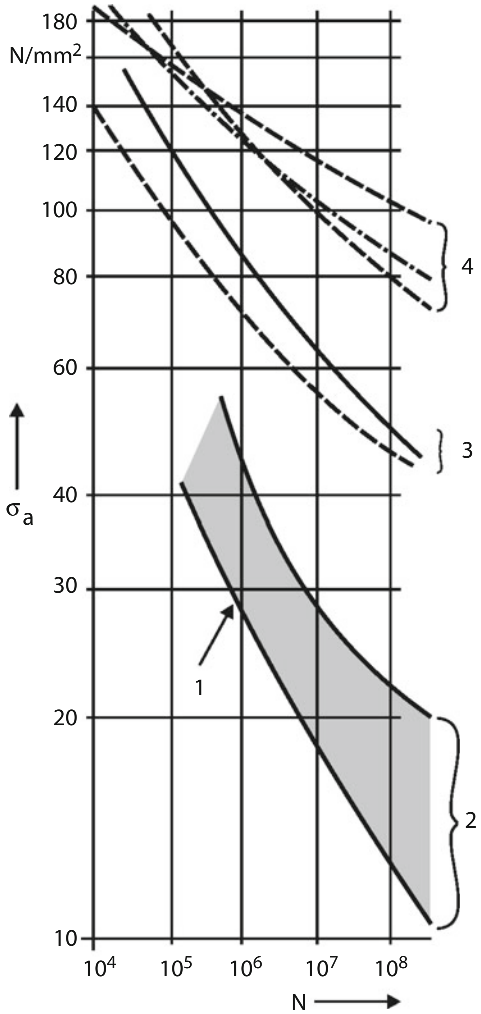


Figure 1.11 S-N curves (Woehler curves) for individual wires and for stranded conductors. 1. Safe border line 2. Aluminium based conductors 3. Pure aluminium individual wires 4. Aluminium alloy individual wires

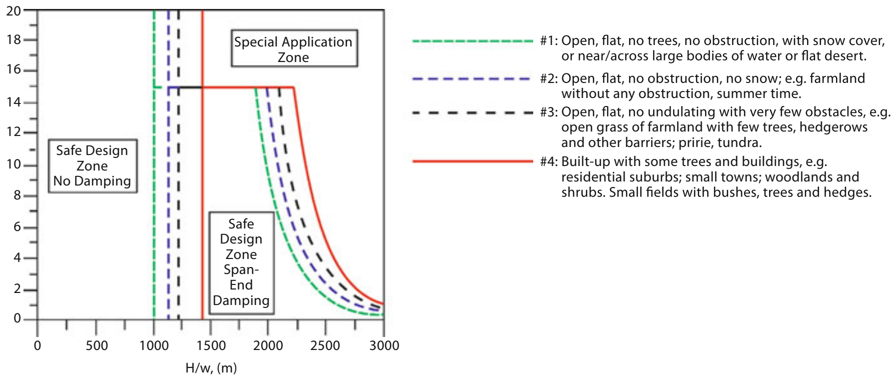


Figure 1.12 Recommended safe design tension for single aluminium based conductors.

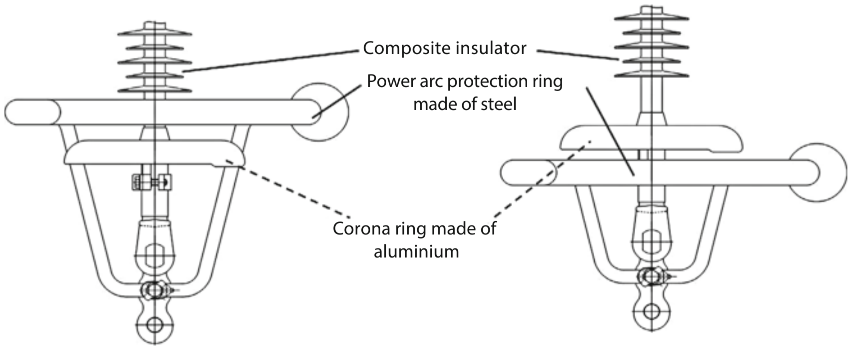


Figure 1.13 Coordination between Corona and power arc protection: correct (left), incorrect (right).

Figure 1.14 Scale comparison between a porcelain longrod, a cap and pin and a composite insulator.

environmental concerns by the public, have propelled the development of so called landscape or aesthetic towers, some of them very unique, Figure 1.15. For these innovative solutions Cigré has collected worldwide examples and presented them in a very informative Technical Brochure (TB 416, "Innovative Solutions for Overhead Line Supports") in 2010. The chapter concludes with information on steel monopoles, often used for compact lines, Figure 1.16, concrete poles and wood poles, while work on supports with high-tech materials like composites is just starting.

Another "classic" component of a line is "Foundations", presented comprehensively in Chapter 13. Foundations are evidently –and in every sense of the word- very "basic" for the reliability and the structural integrity of a line and thus they are addressed with great care. Quite unique is the fact that for foundations, because of the variable soil conditions, from rocks to swamps and to undisturbed mother soil, over the length of a line, site investigations during the design phase of a line project are absolutely necessary. This is also one of the three pillars of this chapter, the other two being foundation design (basic theory, static and dynamic loadings, foundation types, Figure 1.17, and their interaction with the surrounding ground) and the post-mortem examination of failures with related risk assessment, Figure 1.18.

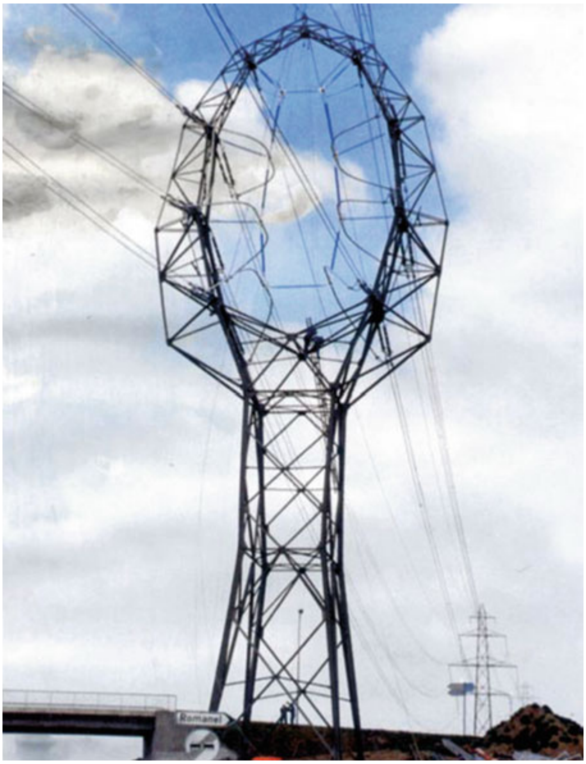


Figure 1.15 Pylone Raquette in west Switzerland.

Figure 1.16 Visual comparison of 420 kV conventional and compact lines side by side carrying the same power in Dubai/UAE.

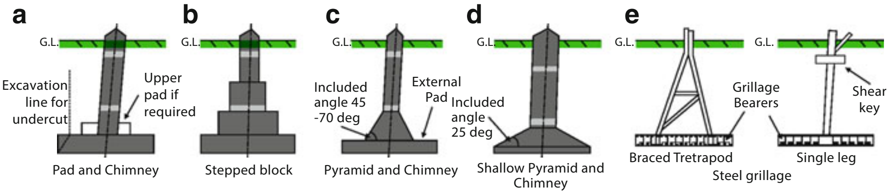


Figure 1.17 Spread Footings Foundations.

Figure 1.18 Failure of a 500 kV suspension tower drilled shaft foundation.

Probably for the first time in transmission line literature the concept of "Overall Line Design", part of ongoing Cigré work, is given such a prominent place as in Chapter 14. Therein one can find the complex, sometimes unexpected interactions and interdependencies of the decisions taken during the design phase of a line. For instance while phase spacing increase (as for example in compact lines) is beneficial for the SIL (surge impedance loading) of a line and the mechanical loads of the line supports and foundations, it has negative effects on Corona and AN/RIV, as both increase, Figure 1.19. While this is understandable form basic physical principles, other interdependencies are not so obvious. For example by lowering the knee-point temperature of an ACSR conductor (this is the temperature at which the slope of the sag-temperature curve changes), the longer the sag relationship will follow the steel core, resulting in a higher temperature and lower sag condition. This is possible for conductors with annealed aluminium wires and also with so-called Gap-conductors, both costing more than

	SIL	Corona	Mechanical loading	Thermal rating
Phase spacing decrease				
Large Al area/cond (less conductors)				
Diameter bundle increase				
High steel content				

Figure 1.19 Relationship between actions taken in line design and effect on SIL, Corona, Mechanical loading and thermal rating.

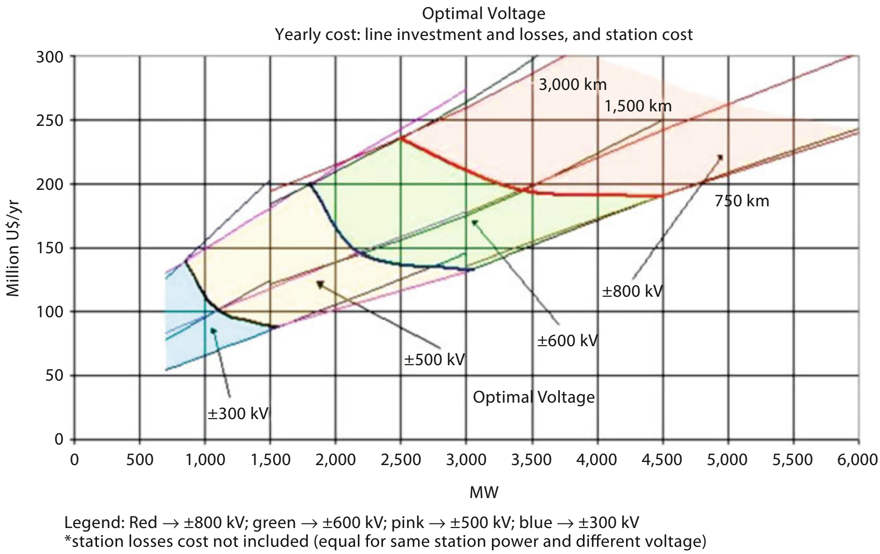


Figure 1.20 Optimal voltage as a function of converter station power and line length.

conventional conductors. This leads to the second part of this chapter, where a methodology for line optimization is given by introducing a suitable composite indicator for comparison of the different design options including cost aspects. The methodology can be also applied to HVDC lines in continuation of previous Cigré work, Figure 1.20).

Traditionally Cigré has dealt more with design and field experience issues than with the construction of a line. This short-coming is thankfully rectified with Chapter 15 "Construction". Therein practical aspects of line construction are addressed providing an concise picture of the most common construction activities and installation techniques used in installation of an overhead transmission line. Special attention is being paid to construction activities requiring

Figure 1.21 Trailer mounted payoffs and a truck mounted bullwheel for tension stringing.

either high degree of accuracy or those posing high safety risks to construction crews. Items covered include line survey, Right-Of-Way (ROW) clearing and site access, assembly and setting of foundations, structure assembly and erection including insulators, hardware and fittings, conductor stringing and as-built inspection, Figure 1.21.

On the other hand "Maintenance", as presented in Chapter 16, has attracted over the years the interest for quite a few Cigré Working Groups, such as the joint (with SC B3, "Substations") Working Group on "Live work - a Management Perspective" and the recently created Working Group on "The Use of Robotics in Assessment and Maintenance of OHL", an exciting new option in overhead line maintenance. Proper and efficient maintenance starts with the formulation of a maintenance strategy. This should include the prioritizing of the transmission lines in the network, carrying out periodic inspections, setting-up a data base storage and retrieval systems (otherwise sooner or later the results of the inspections would be lost) and the -management- decision, whether maintenance work should be done in-house or outsourced and done on live or de-energized lines. The core of maintenance work is the condition assessment of line components. The Chapter continues with valuable information on such assessment for the line conductors including joints and fittings, the insulators, the supports and the foundations. Special attention is then given to the use of carts for in-span work, Figure 1.22, such as the repair or replacement of spacers, dampers, aircraft warning markers, followed by a detailed description of the costs and benefits of live line work versus de-energized methods with interesting examples of typical live work operations. The chapter closes with the use of Robotics based on input from an ongoing Cigré working group, Figure 1.23.

With the advent of liberalization of the electricity markets in the last years, a holistic view of overhead lines as an asset has become a reality and a necessity.

Figure 1.22 Cart used on a horizontal twin bundle.

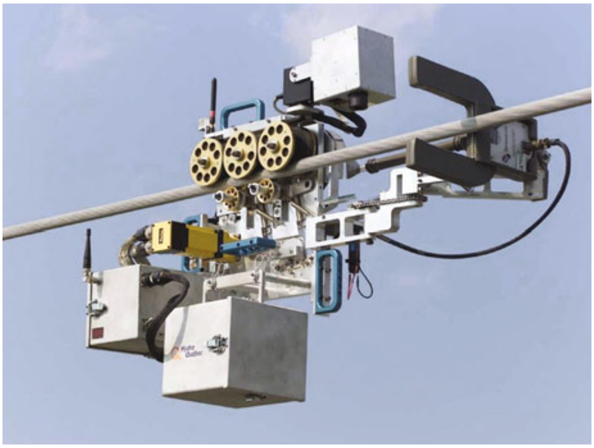


Figure 1.23 Photo of the LineROVer robot inspecting a transmission line.

The importance of "Asset Management" for electric utilities and network operators is well demonstrated in Chapter 17. In the past decisions on the management of existing overhead transmission lines were frequently based on the qualitative judgment of experienced individuals. This chapter quantifies such decisions using risk management techniques and presents methodologies for estimating costs and risks associated with various actions required for proper management of an overhead transmission line asset such as adequate inspections, analysis of a database of the conditions of the transmission line components, cost factors, safety and regulatory and environmental considerations. Management actions to be considered include risk reduction, risk acceptance and risk increase also well described in Cigré TB 175. The chapter concludes with important information for establishing and updating of databases, as this will lead to an improvement of transmission line availability and reliability and give the owner a better insight as to the remaining life expectancy and future operating costs of their transmission assets.

Liberalization and the opening of the markets has also led, together with the tremendous increase in renewables in the last years, and in combination with serious objections by the public to new transmission corridors, to the development of a new field in overhead line techniques, the "Uprating and Upgrading" of Chapter 18. The purpose of this chapter is to provide a general overview of the economic and technical considerations in order to facilitate decisions for uprating and upgrading of overhead lines. Upgrading will increase the original structural strength and thus decrease the probability of failure of a line. Uprating on the other hand will improve the electrical characteristics and thus also increase the power transmitted over the line. The latter is nowadays of particular importance and is basically accomplished by increasing the thermal rating and/or the voltage rating of the line in question. Of specific interest is the information provided for the world's first AC/DC hybrid line, which is going to be presented during this Cigré session (Paris 2014), Figure 1.24.

For the same reasons, i.e. increased demand for power transfer and at the same time public resentments against new line corridors, has favored in recent years the combination of "Overhead Lines and Underground Cables" in particular for higher voltage levels. This is the theme of the concluding Chapter of this book. Its scope is to give an overview and comparison between Overhead Lines (OHL) and

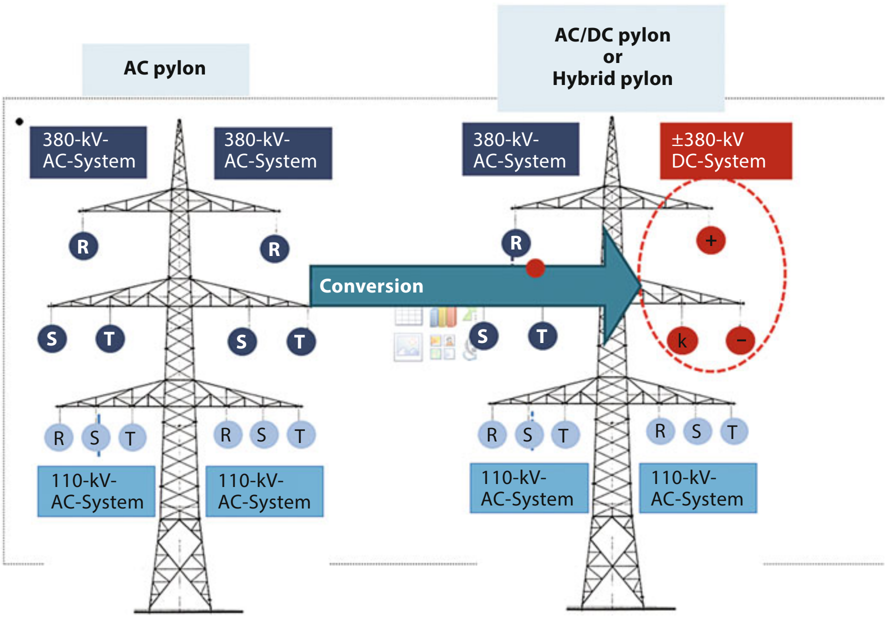


Figure 1.24 Conversion of a double circuit of a 380 kV AC line to a hybrid 380 kV AC/±400 kV DC line.

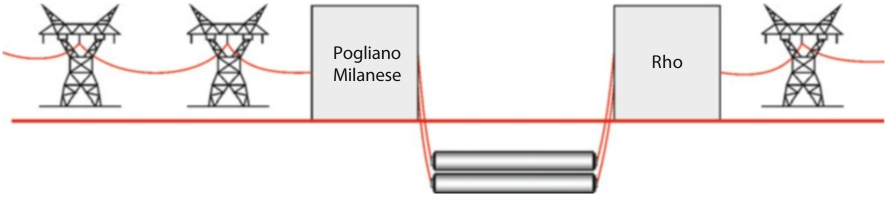
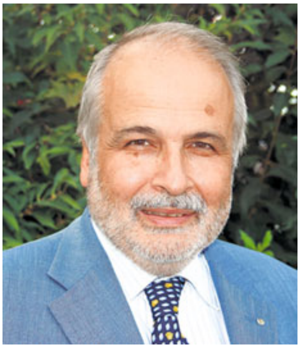


Figure 1.25 Example of a partial undergrounded line route (Italy).

Underground Cables (UGC) regarding techniques, costs, failure rates, operating issues and life expectancy with the objective to provide a sound technical base for discussions (which are unfortunately often controversial) and to present the newest developments and outlooks for both technologies, Figure 1.25. It is a very happy coincidence, that the other book of the Cigré Green Book Series, is the book prepared by Study Committee B1 "Underground Cables" on "Accessories for HV Extruded Cables". In this way the coexistence of both important transmission technologies for bulk power transfer is very visibly documented, as well as the excellent cooperation between the two related Study Committees.



Konstantin O. Papailiou studied electrical engineering at the Braunschweig University of Technology and civil engineering at the University of Stuttgart. He received his doctorate degree from the Swiss Federal Institute of Technology (ETH) Zurich and his post doctoral qualification as lecturer (Dr.-Ing. habil.) from the Technical University of Dresden. Until his retirement at the end of 2011 he was CEO of the Pfisterer Group in Winterbach (Germany), a company he has served for more than 25 years. He has held various honorary positions in Technical Bodies and Standard Associations, being presently Chairman of the Cigré Study Committee "Overhead Lines" (SC B2). He has published numerous papers in professional journals as well as coauthored two reference books, the EPRI Transmission Line Reference Book - "Wind -Induced Conductor Motion" and "Silicone Composite Insulators". He is also active in power engineering education, teaching Master's level courses on "High Voltage Transmission Lines" at the University of Stuttgart and the Technical University of Dresden.

History of Overhead Lines in Cigré

2

Bernard Dalle

Contents

2.1 OHL Major Item of Discussion: 1880–1920

After the electric-telegraph and the first arc lamp lighting systems, electric technology entered a new historical phase of outstanding acceleration in the last quarter of the 19th century.

At the Vienna International Electric Exhibition in 1873, Hyppolyte Fontaine (France) realized the possibilities offered by long distance transmission of electricity. First industrial-scale transmission of electrical power was developed on a long distance transmission between Vizille and Grenoble in 1883 by Marcel Deprez for railways. However, until 1883, despite all the efforts of Marcel Deprez, the efficiencies remained too low for commercial purposes. The use of transformers gave alternating current an essential advantage.

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B. Dalle (✉)
Paris, France
e-mail: bernard.dalle@cegetel.net

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The first experimental three phase AC transmission between Lauffen (near Heilbronn) and Frankfurt in 1891 was made by two Swiss companies AEG and Oerlikon Maschinen Fabrik Oerlikon (MFO). This project had a crucial impact on the following history of electricity (a good result of this project was that Lord Kelvin, as a chairman of Commission of the Niagara Power station 2 project, suggested AC as solution for transmission of power from the Niagara Power Generation Station– at the time the largest project in the world – 5000 HP).

The father of the Transmission project for the Frankfurt Fair was Oskar van Miller from Munich, who later established the excellent Deutsches Museum in there. The designer of the first AC 3-phase generator and oil transformer (550 V to 15 kV) was Charles L. Brown, who in the same year, 1891, co-established with Walter Boveri the Brown-Bovery Company (BBC), which merged in 1987 with Asea (to become ABB). The designer of the overhead line as well as of the electrical pump (100 HP) was Mihael Dolivo – Dobrowolski, from AEG. The line powered 1000 incandescent bulbs and an artificial water fall at the Frankfurt fair site. OHL was a 15 kV, later 25 kV, 40 Hz system, on 3200 wooden poles with copper conductors $3 \times 12{,}6\ \mathrm{mm}^2$, for a distance of 175 km. The operating voltage was 15 kV, later 25 kV, and the efficiency of transmission was 72.5 %, which is equivalent to 22.5 % losses! The protagonists of this historical event can be seen in the nostalgic picture of Figure 2.1.

The voltage problem was very important in the history of OHL's. Growth and of voltages depends of the history of insulators. The first suspension insulators were invented in 1907 enabled, in 1908, the first OHL with voltage over 100 kV. The invention of cap-and-pin insulator in 1910 opened the possibility for higher voltage overhead lines.

Figure 2.1 shows the development of voltage level in the world.

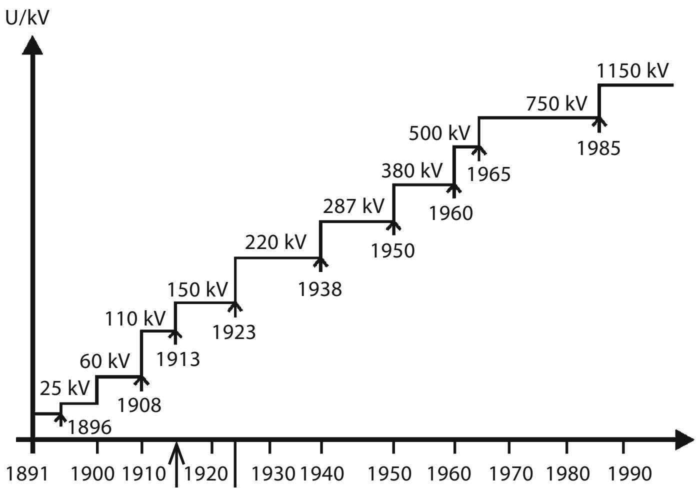

Figure 2.1 Development of the OHL voltages.

In this spectacular process of the expansion of electric energy in industrial civilization, one must stress the decisive role of the International Exhibitions. In 1881, the International Electric Exhibition had an enormous success and the Scientific Congress organized in parallel brought together the greatest scientists of the time, who adopted the first international system of electrical units. The impacts of the Paris events were the impetus for the constitution of a new professional community, and marked the foundations of the Societé Internationale des Electriciens.

Hence these large scale events opened the way for creation of specific International bodies, and particularly with the creation of the Internatioanl Electrotechnical Commission (IEC) in 1906 and later the foundations of Cigré (Conférence Internationale des Grands Réseaux Electriques in 1921, the World Energy Conference (WEC) in 1924 and the International Union of Producers and Distributors of Electricity (UNIPEDE) in 1925.

2.2 The Creation of Cigré and its Development from 1921 to 1940 and the Role of OHL

From 1911 to 1920, C.O. Mailloux, President of IEC and Charles Le Maistre, its Secretary General recommended the formation of a specialized body of a technical, scientific and applied technology character.

The contacts established in various countries confirmed these aims and led to the organization of the first International Conference on Large Electric Systems (Cigré) in PARIS in the autumn 1921. This meeting was considered as the first inaugural meeting of the new international engineering organization.

Cigré aimed to provide an international setting for the discussion and the study of technical questions concerning the generation, transmission and distribution of electric energy.

Therefore, when it was founded, Cigré brought together, on one hand, manufacturers of electrical machines and equipment and operators of power plants and transmission lines and on the other hand, electric energy producers, consultant engineers and engineers of major public administration bodies.

In 1931 Cigré put in place an ambitious journal "Electra", a monthly journal devoted to the study of the generation, transmission and transformation of electric energy.

The rapid organization and rapid growth of Cigré's Study Committees started in 1925: the first Study Committee was the Statistics Study Committee which lasted only a short while having been transferred to UNIPEDE, founded in 1925. The Insulators Committee was created in 1929, the Overhead Lines Committee in 1931 and the Towers and Foundations Committee in 1935.

The main subjects dealt within the reports during the inter-war period were:

- Parallel operations of power plants and oscillation between machines,
- Problems in construction of large generators and transformers,
- Laws and electrical calculation of energy transmission, voltage adjustment and reactive power,

- Reliability of cables for high voltage,
- Insulation of lines, the nature and properties of insulators, and dielectric strength of insulation,
- Earth connection of the neutral and extinction coils, and interference caused in telecommunication circuits.

2.3 Reactivation of Cigré in 1948 and the Place of OHL in the Evolution of Cigré Organisation: 1948–1966

During the Second World war, Cigré activities stopped naturally just after the publication of the main conclusions of the 1939 Session.

In 1946, Cigré was the first technical organization in the world which organized an International Conference and brought together worldwide electrical experts to rebuild electrical infrastructure after World War 2, and start with intensive electrification.

In 1956, the fields corresponding to the preferential subjects devoted to overhead lines were divided among no less than 4 Study Committees for the general design dimensioning of lines: SC 22 for towers and foundations blocks, SC 23–24 for conductors, SC 25 for insulators, SC 40–42 for very high voltage lines (above 220 kV) and 3 "electrical" study committees: SC 33 for overvoltage and lightning, SC 35 for telephone and radio interference and SC 41 for "Insulation Coordination".

Regarding these Study Committees scopes, a key technical achievement was realized in 1962 by the Volgograd-Donbass (USSR) DC Transmission line +/– 400 kV. Around the same time, AC transmission lines were put in operation in the late 60s – 735 kV in Canada, 750 kV in the USSR and 765 kV in the USA. Until 1970, groups 22, 23, 24, 25 and 33 alternated with groups 35, 41 and 40–42 and, as a result, the different fields related with overhead lines were discussed only every four years. The preferential subjects were then very specific to each of the components: insulators, foundations, conductor bundles,… At the 1960 Session, this very specific nature was very clearly visible through the subjects developed: insulators' thermal shock tests, withstand tests in a polluted atmosphere, heaving and corrosion of foundations,… Yet, in 1964, the subjects became more general. People studied the lifetime of structures in relation to the effects of vibrations, weathering and the associated safety coefficient, conductor creep,… Lastly, at the 1966 Session, the reduction in the costs of towers was one of the priority subjects.

In the late 1950s and early 1960s, Cigré's main priorities for study were the increase in the transmission capacities, mainly by a voltage increase, and the stability of power systems which were becoming more and more interconnected. A recurrent topic was Corona radio interference, which made it necessary to oversize the conductors in relation to the size required for an economic utilization of their thermal capacities.

2.4 OHL and Preferential Subjects from 1966 to the Present

The reorganization of Study Committees in 1966 led to a new configuration of the field of overhead lines, with Study Committee 22, officially named "Overhead Lines", Study Committee 33 for insulation coordination, and for 36 for interference. This new configuration made it possible to combine within a single Study Committee, all the issues concerning design dimensioning of structures: foundations, towers, multiple conductors in bundles and insulators.

From the early 1960s to the early 1980s, overhead transmission lines at 735, 750 and 765 kV were mastered in Canada, USSR, USA andBrazil. Thermal and electrodynamic problems also arose after the increase in levels of transmitted power (effects of nominal, exceptional current intensities and of short-circuit currents).

For the first time, in 1974, consideration of the environment in the design of overhead lines, and therefore their acceptability, was chosen as a preferential subject. In the 1990s, the aesthetic of towers design was a major area of the Cigré community's work. Tubular towers, architectural towers and compact towers were the subject of very interesting presentations and discussions.

In the late 1970s, the development of information technology resources became a vital tool in the development of power systems: programs for optimization of structures (optimization of towers and optimization of conductors) also appeared, and they gave rise to regular discussions. The development of personal computers led to the development of very efficient software applications, which are now new standards in their respective fields.

In 1981 Cigré organize the first Symposium in Stockholm which was "Overhead lines impacts on environment and vice versa". From that time began a discussion on how to improve the aesthetic view of OHL in landscapes, impacts of lines on EMC, how to made new standards to mitigate impacts of nature on lines, etc.

Probabilistic approaches were discussed in 1988: probabilities of maximum currents, of maximum ambient temperatures, and low wind speeds,…

At the same time, optic fibers also appeared as one of the preferential subjects. This was somewhat the starting point of the rapid development in the incorporation of these new telecommunication links in the networks, in spite of the additional constraints they induce on the design and the operation of the lines.

In 1990, since the oldest EHV lines had been in operation for 60 years, the lifetime of structures started to be a concern for operators. It remained one of the recurring subjects of the Sessions, with significant feedback on operation and maintenance methods, considering the strategic stakes attached to these topics. In 1994, for the first time, live line work aimed to improve the availability of structures, was tackled.

In 2000, as a key element in the new approach to communication, the "Conference des grands Réseaux électriques à haute tension" became the "Conseil International des Grands Réseaux Electriques", that it changed from a "Conference" to a "Council". The area covered by Cigré's field of action was redefined in 2000. It now covered not only conventional technical expertise but also economic, environmental aspects and the impact of aspects related to organization and to regulations.

In 2002, a new organization was set up and SC 22 became SC B2. In 2003, a new reference model for Study Committees was ratified by the Cigré's governing bodies and gradually applied. This reference model stressed the need for the proactive character of the Study Committees, which had to absolutely avoid gradually becoming artificially expanded and self-sustaining techno structures with organization and running costs far exceeding their technical output.

In the 2000s, studies and discussions in the area of overhead lines focused on the increase in transmission capacities and on the ageing of structures: increases in voltage, taking into account in real-time weather conditions, development of new types of conductors (composite conductors with metal or composite fiber core). The storms observed around year 2000 throughout the world led to renewed discussions on the dimensioning of structures based on methods combining static and dynamic loads in a probabilistic approach.

The considerable progression, in terms of general innovation, and of Geographic Information Systems (GIS) was acknowledge in 2006. It was confirmed that they were applied to all phases of the life cycle of a line: planning, design, construction, operation, management and control of vegetation, forest fires, inspection, maintenance, rehabilitation and dismantling.

To increase the transmission capacities, different solutions were discussed: real-time management of certain structures became possible as a result of the development of sensors indication the real sag at the most sensitive point and notable gains in transit capacities could then be envisaged, but this required specific organization of the control actions. In some configurations, the transformation of alternating current overhead lines into direct current overhead lines could increase transit capacities by more than 100 %, but with costly conversion stations.

Lifetime assessment and lifetime extension, precise knowledge on the equipment condition, diagnostic methods, environmental and societal acceptability of overhead lines were other topics in recent group meeting.

In 2016, Study Committee B2 "Overhead Lines", counted 22 working groups with 371 experts from 43 countries.

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Bernard Dalle is a Consultant on Overhead Lines and a witness expert at the Paris Court of Appeal. He has been Chairman of Cigré Study Committee B2 Overhead Lines for 6 years (2004–2010). He has worked as a Senior Executive Consultant within RTE – Power Transmission Infrastructures and as Director of Infrastructure Grid R&D Programme within EDF /R&D. He has also been Chairman of UF_{11}, the Standardization Committe on Overhead lines within UTE, the French Organization for Standardization for electric and electronic products. He is a honorary member of Cigré and a member of SEE.

Planning and Management Concepts

3

Rob Stephen

Contents

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R. Stephen (✉)
Durban, South Africa
e-mail: stepherg@eskom.co.za

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3.1 Introduction

In the management of a Transmission line from conception to decommissioning it is important to realise the nature of the line as a device (or system) and to ensure management structures do not compromise any aspect of the life cycle.

This chapter covers the various management concepts that should be employed as well as the process for line design, construction and maintenance with role clarity provided.

The organograms or management structures (hierarchy) have deliberately been excluded as the concepts may be met in many different ways depending on the utility structure and the insourcing or outsourcing of resources.

3.2 Management Concepts up to Commissioning

A Transmission line, as defined in Chapter 14, is a device that transmits power over long distances. It should be seen as a single device (or system) with electrical properties that contribute to power transmission within the supply grid. Chapter 14 outlined how a line can be "tailor made" to meet the system planner's requirements within the grid.

A line can also be regarded as a large mechanical structure (system) spanning many kilometres over many terrain types that must endure varying adverse weather conditions. It is therefore a device requiring mechanical, civil, environmental, geotechnical and electrical consideratons in the design of the line.

This section deals with the different possible management concepts for the line from planning to commissioning.

3.2.1 Management Concepts for Preliminary Design and Optimisation Studies

3.2.1.1 Series Model

It is often the case that the tower designs are done separately from the conductor selection and the electrical parameters which are normally determined up front often from standard configurations. This is either outsourced or performed in house by a separate division. The tower design is determined from the phase configuration and bundle configuration supplied and is considered fixed. Likewise the foundation design is then determined based on the loadings provided by the tower designers and is also considered fixed.

In this model the tower designers do not consider or question the reasoning behind the conductor bundle and phase configuration but convert the requirements into loads for a tower to withstand. Likewise the electrical engineers who determine the conductor bundle and phase spacing maybe ignorant as to the effect their requirements have on the mechanical aspects of the line.

The series model and distance between the disciplines is often further exacerbated with outsourcing of tower and foundation designs. This often requires a specific scope and specification which has little flexibility.

The series model will result in sub optimal designs in most cases. It is a more simple model to manage than the iterative model described in the next section.

3.2.1.2 Iterative Model

In order to optimise the design, either for a specific line or to develop new or revise standard designs, the electrical, mechanical and civil engineers need to work as a team to ensure iteration of the design components. This is because each aspect affects the other. For example an electrical engineer may specify a 6 bundle Zebra conductor with a certain phase spacing for a 765 kV line. The tower designer will design accordingly without comment in the series model. However, if the iterative model is applied, it may be found that a quad bundle with a lower steel content conductor with slightly wider phase spacing could be used at a reduced cost due to the lower mechanical forces (wind load and guy wire for example).

If the line is to be optimised as proposed in Chapter 14, then the design of the line cannot be performed in series with the planner determining the conductor type and the tower being designed based on the conductor specified followed by foundation design.

The iterative model is more difficult to implement from a management viewpoint as it involves engineers from different disciplines working together and understanding each other's field with regard to transmission lines. This can be achieved in a number of ways:

- In house design (insource): a line design department is established with different disciplines under one manager. The aim is to create a group of line design engineers with in depth knowledge in one of the disciplines. Tower detailing and detailed foundation design can still be outsourced after the tower outline is optimised and conductor bundle and type chosen.
- In house management (outsource): in this case the company employs one or two experienced line designers who manage an outsourced team of engineers of different disciplines. The contracting of the engineers may be done on a time basis and not on an output based using a defined scope.

3.2.2 Management Concepts for Route Selection and Property Acquisition

The route selection and acquisition may form a separate project as the time duration is normally far longer than the construction period. However, a project management approach with designer involvement is recommended. This team may include a variety of environmental, legal, negotiators and technical experts some of which may be outsourced.

It is important that the negotiator understands the line design as well as the implications of certain concessions made with the land owner. An additional strain tower to avoid a certain point in the land or to follow the border of the property can increase the line cost overall.

It is important that the line designers are part of the team to advise on technical matters as well as to be aware of the agreements reached. For example in certain areas of the line route, guyed structures maybe prohibited or existing servitudes (right of ways) used requiring narrow servitude multicircuit multi voltage pole structures.

In addition to all the permits required for a line to be built, it is also important that the team include wildlife experts for flora and fauna as well as bird experts to ensure flight paths and nesting grounds are catered for.

The project team for the route selection and property acquisition is often the largest and most diverse of teams required to realise a final constructed line. It is also the longest serving. For this reason the handover to different Project Managers needs to be well managed with decisions clearly documented.

3.2.3 Management Concepts for Construction

The construction phase consists of construction activities and handover for operation.

This phase is best managed by a team under a project manager using matrix management whereby the team members are seconded to the team from management. The Project Manager decides on the timelines and outputs and informs the team members. There may be a sub structure in the team for environmental, design, construction elements.

The team can be outsourced or insourced to varying degrees depending on the company. If the team is totally outsourced from various suppliers it is important not to duplicate the structure with in house staff. This could result in an in house project manager managing the outsourced project manager with duplication of work, conflicting instructions to contractors etc. If the project manager is outsourced the in house resources need to manage the outputs and milestones by exception and not interfere with the team below the Project Manager.

It is also important that the project manager be appointed as early in the project life cycle as possible so that he understands the reasons for the design chosen, issues with line route and stakeholders. It is also desirable that one project manager be accountable from the start to the end of the project to avoid handover points with possible misinformation arising. It is also necessary to have one person accountable for time, cost and quality to avoid blaming later in the project.

3.3 Responsibilities

In any management structure it is important that roles and accountabilities are clearly defined. The three main role players in the establishment of a line are the Network Planner, Project Engineer and Project Manager. These may work for different companies and be contracted separately. They do need to fulfil the responsibilities as listed below.

The following roles are responsible for the design and construction of overhead lines-

- Network planner
  - Responsible to ensure the line requirements (R,X,B, loading for AC lines) are correct.

  - Responsible to ensure the project is released for preliminary design timely.
  - To ensure correct targeted in service dates are communicated.
- Project Engineer
  - To assist in the route selection process
  - To ensure the consultative process is followed relating to the design options and selection of the optimum design.
  - To ensure full understanding of all aspects of the line design as well as how to implement this on site.
  - To assist the Project Manager in the construction phase of the project.
- Project Manager
  - To ensure milestones are set and resources are arranged so that target dates are met.
  - The project manager is to understand the nature of lines and the types of problems and issues that may result from the line design and construction process.
  - To take charge of the programme (target dates, milestones), from the pre-engineering stage to final commissioning.
  - The project manager is to authorise all costs to the line. This is to include over-heads which are normally accrued without the project manager being aware of them.

3.4 Life Cycle Process up to Commissioning

The life cycle of a transmission line commences with the system planner and is completed when the line is decommissioned. This section deals with the planning, design and construction aspects.

3.4.1 Planning Requirements

As mentioned in Chapter 14 the planner is to provide information on the electrical requirements of the line. This can be submitted in the form of a table as indicated below. Note that even if standard designs are used, it is useful to have the requirement specification from the planner to check whether the proposed standard design will meet the requirements.

The planner should provide the information to the line designers as indicated in Table 3.1. A few fields may need explanation.

- *The* ***profile of the proposed line load on a yearly and daily basis*** *is essential for the designer to determine the templating temperature of the line. If the load profile shows a morning peak and a winter peak it may be possible to use a smaller conductor as the temperature reached under peak load may be relatively low. If the daily load profile is very peaky, it may be possible to use small conductors with a higher templating temperature. If the load profile is flat it may be necessary to use larger conductors with a lower templating temperature.*

Table 3.1 Information required to be supplied by Network Planner.

Project Name	Project name and number of line to be built.																							
Start Sub	Substation at which the line starts.																							
Finish Sub	Substation at which the line terminates																							
NDP ref.	(Name and reference of Network development plan)																							
Planner	(enter name of planner responsible)																							
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20				
Load MVA																								
Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Profile																								
Month	1	2	3	4	5	6	7	8	9	10	11	12												
Profile																								
Imped.	R		X		B		R (Z)		X (Z)		B (Z)													
Max																								
Min																								
Cost/km																								
Environ	(Include possible environmental constraints)																							
Time	(Include cost to utility for every Month delayed from preferred due date)																							
Voltage	Preferred	Second option																						
kV																								

- *The **load growth** is necessary to determine the optimum aluminium area of conductors.*
- *The **impedance** is necessary to determine the optimum bundle and phase configuration (AC lines). The designer needs two values, a minimum and maximum value to ensure the optimum impedance to the network.*
- *The **voltage** of the line is often fixed and cannot be altered, however, in certain cases the costs can be such that the lower voltage option provides a major cost saving. For example a 10MVA load required to be transferred at 132 kV may prove far more effective at 66 kV (sub transmission)*
- *The **time** the line is required is often exaggerated by the planner who expects a certain load growth, however, there are times when the utility can lose substantial amounts of revenue should the line be delayed. In these cases it is often cost effective to utilise more than one contractor and fast track the project.*

In addition to the above the maximum voltage level and fault level needs to be specified. The reliability level also needs to be specified by the system planner. Line ratings (normal, emergency) also need to be known (these may be a minimum and the line designer must ensure these are met).

3.4.2 Route Selection and Property Acquisition

The selection of a line route is often a very time consuming task that could take many years (in some cases over 20). In the management of the line route acquisition it is important that the route of "least objection" is not always obtained. It is often required that the route chosen is along the border between properties or along a road. In this case there is normally a large amount of bends and angle structures required which results in an increase of the overall line cost. Management needs to be cognisant of these issues when appointing consultants to obtain route or when using in house resources.

In contracts for negotiators, if they are outsourced and in house resources are not utilised, the payment method should include the cost of the line as a result of the route chosen. This could include for example a ratio of tangent (suspension) to angle or strain towers. If the contract is time based the negotiation process may be extended, if the contract is a turnkey for the servitude/easement to be signed up it may result in a large number of bends.

A project management approach is also recommended for this process as it covers many years, different resources and involves many public forums which require knowledgeable presenters. The project team may include environmentalists, negotiators, surveyors, marketers, design engineers and even health professionals if the electromagnetic field issues are raised.

As the process is a long one, the decisions and concessions taken need to be clearly documented and stored in an organised manner to ensure that no concession is overlooked in the design and construction phase. Concessions may be made to land owners in the early stages of the route acquisition. However, the nature of the concession may be overlooked in the design and construction stage resulting in rework or lengthy delays.

Chapter 6 and Cigré TB 147 cover the requirements for property route selection, consultation models and property acquisition.

3.4.3 Management Process for Preliminary Design and Optisation Studies

As proposed in Chapter 14, the purpose of this stage is to determine a group of design options (ten options provide a wide range that will ensure possible optimisation) and, via the use of optimisation tools, to select the final group options for further analysis. The number in the final group may be around 3 or 4 depending on whether an option is obviously superior.

The project engineering team is to be formed under a knowledgeable line design expert. The team should include members knowledgeable in conductor, tower and foundation issues. This encompasses electrical, mechanical and civil disciplines. As mentioned in section 3.2.1, these team members can be from the same or different companies.

Possible routes can be determined from the digital terrain map or from the Environmental Impact Analysis. If this is not possible the design team should select a profile similar in nature to that expected in the line that they are designing.

The line route can seriously affect the overall cost of the line. It is imperative that the line design leader approves the line design route prior to final negotiations and servitude acquisition.

The possible conductor and bundle options are then considered.

The tower family can then be determined from the selected terrain (either the actual terrain or a sample selected from terrain that is similar in nature) using the conductor families selected and the available tower families.

The planners are then to be consulted again to ensure that the proposed set of line design options is in line with the planner's requirements.

The Appropriate Technology Indicator (ATI) (covered in Chapter 14) is then to be determined for the options. The best (approximately four) options are to be taken to the next stage. This can be achieved by using the programme (spreadsheet) that determines the scores for each option.

The ATI takes into account the initial cost, cost of losses, MVA thermal rating and MVA surge impedance loading.

The motivation for project finance (may be made in the preliminary design phase) is to be completed. This is to include the following:-

- A design document which should contain the following information:
  - Reason for the line including extract from the planning proposal documentation. This normally includes the Net present value cost benefit analysis.
  - Information from planners on line requirements including time and cost constraints.

  - Possible routes with cost options if possible.
  - Environmental Impact Assessment (EIA) details (extract from the EIA produced if possible. This may vary from country to country).
  - Options selected for analysis.
  - Appropriate Technology Indicator (ATI) analysis and results.
  - Design options to be analysed further.
- A cost estimate of the following
  - Labour cost to complete the detailed design stage.
  - Cost of the geo tech survey
  - Cost of tower development (if required).

The cost estimate is to be added to the project costs for approval via the relevant governance procedures.

Note that the geo tech survey is often overlooked. It is a critical aspect of the detailed design stage. It determines the suite of foundation options that should be used on the line. It assists in determining the numbers to specify in the enquiry document or for construction. It also highlights the type of foundations that need to be designed or developed.

3.4.4 Management Process for the Detailed Design Phase

The detailed design phase precedes the execution phase. The output of this phase is a detailed design and costing which is then presented to management for execution approval.

In some cases the utility may decide to go to market to obtain actual tendered prices for submission to management. In other cases estimates may be made from previous projects. In the former case the risk of error in costing is lower.

Approval is normally required from management for the detailed design phase to commence. The output of the design phase is a detailed cost of the line (90 % or higher) accurate. This can only be achieved if the following are known:

- The line route and line profile.
- The tower positions and types per position.
- The detailed bill of materials including conductor, towers, insulators and fittings.
- The contract prices for the erection phase as well as material costs.

It should be noted that the construction and material costs can be very volatile and depends on the exchange rate, the availability of materials and labour. It can vary from line to line even if they are in the same geographical area.

The line route and actual line profile (as accurate as possible) needs to be used to determine the optimum tower, conductor and foundation combination.

The options short listed from the ATI analysis are to be used to determine the optimum combination. These are to be used using the actual line profile and line route chosen. Tower spotting packages should be used to determine the best option in relation to the ATI. This will mean that network planners have to be consulted once again to determine the best option including the R, X, B values as well as the cost of losses.

Note that the best design combination is to be determined together with Maintenance staff. Preferably there should be a technical governance structure which will assess the proposed design option. This committee should consist of maintenance and operation staff as well as line designers and system planners. These may be from different companies. If new towers are to be designed, it is necessary that the maintenance and construction staff are to be involved. This could mean engaging with contractors who are likely to be involved in the construction of the line.

Once the best combination is determined, it is necessary to optimise the tower selection for each tower position using a tower spotting programme. This is best performed by a "peg walk" of the route. A "peg walk" or "tower staking" is a walk down the line by the line designers to determine if the proposed tower selection in the proposed tower sites are optimal. This also includes accessibility, constructability and proximity to roads, drains or even unmarked graves that may not have been known about when the line was profiled.

In order to determine the type of foundation to use at each site, it is necessary to perform a detailed geotechnical survey at each tower site. This can only be performed after the tower, foundation and conductor combination has been chosen and the first selection of tower types per site is completed.

The peg walk can be conducted at the same time as the geo tech survey. The peg walk will determine if any tower position changes are required or if a different tower needs to be placed at a specific location. In addition access roads can be planned as well as farm gate positions and types of gate (e.g. game gates).

The information gained from the peg walk and geo tech survey can be used in the finalisation of the Environmental Management programme which is essential for each project.

The information available at this point is the full tower schedule, the detailed bill of materials, the line profile with tower types, the access road locations and gate locations and types.

This information may then be compiled into an enquiry document. The document is then sent to prospective contractors for tender.

Once the tenders are received it is necessary to analyse the tender in detail. The services of a quantity surveyor should be used at this stage.

Once the appropriate tender has been selected the price and motivation needs to be submitted for approval (this will depend on the utility governance requirements), it may be permitted to proceed if the tendered prices are within a certain percentage of the estimate.

The design document should now be updated to include:

- Planning information
  - Reason for the line including extract from the planning proposal documentation.
  - Information from planners on line requirements including time and cost constraints.
- Survey and Environmental
  - Possible routes with cost options if possible.
  - EIA details (extract from the EIA produced if possible).
  - Route and profile
- Initial tower, conductor, foundation combinations
  - Options selected for analysis.
  - ATI analysis and results.
  - Design options to be analysed further
- Towers
  - Tower design chosen with reasons
  - Tower schedule summary
- Conductor and earthwire
  - Final conductor or conductor bundle chosen with reasons.
  - Final earthwire chosen with reasons.

Note the earthwire selection is dependent on the fault level as well as the fault dissipation in the towers and ground. This analysis is to be performed as part of the earthwire selection. In addition the interference criteria for telecommunication lines are to be taken into account and described here.

- Foundations
  - Geotechnical survey results
  - Foundation designs for each soil category and tower type
  - Schedule summary of foundation types
- Hardware
  - Outline of suspension and strain assemblies
  - Damping system used
  - Clamps and fittings
- Insulators
  - Analysis of pollution and other requirements
  - Insulator options that could be used
  - Final insulator selection and reasons
- Performance assessment
  - Performance analysis of other lines in the vicinity
  - Lightning performance studies
  - Environmental impact studies such as bird pollution/interaction with the line, veld or cane fires

- Contracts (tenders received)
  - Summary of tenders received with technical analysis as to their suitability.

Once the overall project is approved by management, the contractor responsible for construction may be appointed.

3.4.5 Project Execution (Construction)

An overhead power line is unlike a substation in that there are many factors that **cannot** be taken into account before construction begins. Items such as access to site, soil types and tower erection methods may necessitate that the tower type, foundation type, equipment used or tower location be changed on site subsequent to the design being approved. This includes right of way clearing requirements and stringing specifications (location of equipment, drums).

3.4.5.1 Pre Construction Planning

The Project Manager responsible for the project is to set up a pre-construction meeting to plan the construction activities with the contractor, clerk of works and Project Engineer (who may include design staff). The following items should be discussed:

- Material arrival and storage

Note that the control of material on site is critical to the success of the project. Nuts and bolts as well as spacer dampers, and insulators should be kept in a clean environment preferably off the ground. Composite insulators should be handled in accordance with the Cigré composite insulator handling guide (Cigré TB184 2001) ***(TB 184). There must also be a system whereby the material issue is controlled and the stock levels are known. A person should be placed in charge of the store which should be fenced off.***

- Project plan for construction including possible dates for line and road crossings.

Note that line and road crossings need detailed up front planning. In the case of line crossings the permission to take the line out needs to be obtained from the Operations authority. The detailed bill of material, tools, and procedure needs to be drawn up and agreed to well in advance. Special items such as cranes, helicopters etc may also be required. This activity occurs after the permission has been obtained from the relevant authorities relating to the crossing.

- Environmental Management Plan (EMP) issues and plans as to how the EMP will be met. The EMP is a plan to meet the environmental requirements of the line. It includes the rehabilitation of the environment.

Note that this will include the formation of access roads, the clearing of the servitude and whether tyre or track vehicles are to be used.

- Foundation design issues and tools to construct the foundations.

Note that it may be possible that certain foundation designs will need to be done or modified. There may, for example be a large rock area and rock piles may not have been designed. Or the contractor may not have the drill bits for the type of rock foundation required. This needs to be taken into account and resolved up front.

- Safety

Note that this is a standard item on all site meetings. It includes the safety procedures and equipment required and available to staff.

3.4.5.2 Foundation Nominations

The foundation types are to be nominated by an experienced person other than the contractor. This is due to the fact that the contractor is likely to err on the conservative side or on the side of higher financial returns.

The foundation types need to be documented per tower installation.

3.4.5.3 Backup Technical Support

Issues may arise on a daily basis that require urgent solutions. An example could be a drain or grave that is found to be in the foundation location. In these cases where a tower needs to be moved or a plan made on other matters, it is essential that competent backup available for assistance. The Project Engineer is to ensure that this back up is available.

3.4.5.4 Change Control Process

The resulting solution from the back up support may result in a tower move or other modification from the original design. These changes must be controlled in the following manner:

- The Project Engineer is to examine the proposal and agree to the change if applicable.

- The Project Engineer is to ensure the design document as well as line profiles or other drawings as appropriate are updated (once approved and executed).
- The cost of the change is to be determined by the Project Engineer.
- The reason for the change as well as the cost is to be submitted to the project manager for approval.
- The Project Manager needs to sign off the proposal and update the project costs and, where applicable, the projections (both cost and time).

Note that in order for the Project Engineer to understand the issues relating to problems on site he is to visit site regularly and have a very good understanding of the requirements of the project and the final design option chosen.

3.4.5.5 Clerk of Works

Clerk of Works need to have the skills and knowledge to oversee the following activities:

Note that Clerk of Works (COWS) are key to the success of the construction stage. The COW are the "eyes and ears" of the customer on site. They need to have knowledge of what is required to be done on site to ensure that the contractor is executing the work correctly.

- Excavations and foundation confirmation/selection
- Foundation cementing including testing (slump and cube test) as well as the correct method to vibrate the concrete.
- Assembly and erection of structures.
- Stringing of conductors including running out, regulating and clipping in.

In some cases it may be necessary to have more than one COW on site at one time and certain COW's may be specialised different areas such as foundations, tower erection and stringing.

3.4.5.6 Tests Required During Construction

There are a number of tests that are required during the construction process on site. Examples of these include:

Foundations: Cube and slump tests for concrete
Pull out tests for guy anchours

Tests may also be required in the laboratory such as tensile tests for compression fittings and Guy anchor assembly tensile tests.

Tower footing resistances need to be measured per tower and documented.

Impedance measurements should be conducted on the completed line to compare them with the designed values as well as to update the planning and fault level parameters with exact values thereby enabling a more robust planning database to be created.

3.4.5.7 Inspection Prior to Commissioning

A walkdown to each structure should be performed by the COW, Site Manager, the Project Manager and the asset owner representative. A list of defects need to be created which needs to resolved within a specified time.

3.4.5.8 Site Access Control

The design staff should be permitted to visit site at any time. However, they must inform the Project Manager who needs to make arrangements. The design staff must not communicate directly with the Contractor unless the Project Engineer or a representative of the Project Manager is present.

3.5 Forms and Records (Including Accreditation)

The following staff that are involved in the following activities need to be accredited to perform these functions:

- Design document – It is assumed that the design team would have sufficient knowledge to conduct the design process. The Design document needs to have each section signed by the designer and a person who is checking the section. The latter needs to be a registered professional (Professional or certificated engineer depending on the country).
- Tender evaluation – The technical evaluation of tenders needs to be performed with the presence of at least one expert in the field of line design. This needs to be a Professional engineer or registered professional.
- Foundation nomination – A technician approved by the foundation designer or member of the design team assigned to foundations (must be a registered professional) should carry out nominations.
- Clerk of Works – the clerk of works needs to have had training and experience in each of the fields mentioned before he may oversee the work in these areas.
- Records of site visits by the design engineer as well as the findings must be recorded on site together with the required actions.

3.6 Summary of Process

The process comprises the following steps:

1. Planning proposal (concept) release of project and pre-engineering funding is obtained to conduct the concept design. The output is the conductor, tower and possible foundation combinations.

2. Obtaining of servitude and Environmental approval. In some cases this may take up to 20 years. In cases where it is likely to take longer than 3-5 years a separate project may be commenced. Often, however, the negotiations may require a final tower design to be presented. In this case the concept design will need to be conducted.
3. Perform pre-engineering design and determine a short list of options that could be investigated further.
4. Submit the project for detailed design stage approval and funds for detailed design.
5. Obtain route and line profile.
6. Determine the optimum conductor, tower, foundation combination.
7. Determine tower positions and types per position.
8. Conduct geotechnical survey, peg walk to determine gate positions, foundation types and access road.
9. Complete Environmental Management Plan.
10. Complete and issue enquiry documents based on results of optimisation and geotech survey.
11. Evaluate tenders (using line design experts and quantity surveyor)
12. Compile and submit request for permission to construct line to Investment committee or management structure
13. Conduct pre-construction meeting
14. Construct line.
15. Process for inspection and commissioning.

Note that in some cases the steps 10 and 11 take place after the step 12. This is due to the time required for step 12. This is not ideal, however, as the cost of construction submitted by contractors is difficult to determine upfront and depends on workload, competition and cash requirements of contractors.

It is critical, that the step 5 is obtained before steps 6–12. The temptation is to begin construction or issue the tender before the route or line profile has been completed. As the line is useless until completed, by commencing the line too early may result in a weaker case for obtaining the route (right of way or servitude) or standing time claims from contractors. In cases of extremely long lines it may be prudent to commence construction on a section if the line route on the remaining sections can be altered if need be.

It is a fallacy that the quicker the tender is issued the quicker the line is completed. It is preferable to have all permissions approved prior to commencement of construction.

3.7 Management of Maintenance

3.7.1 Involvement at Design Stage

It is critical that the maintenance staff are involved in the design of the line irrespective of whether the towers and conductors are standard or not. This is to ensure access to towers is mutually agreed prior to construction as well as maintenance methods.

In the case of Live line maintenance the maintenance staff must be involved in determining the live line maintenance methods prior to design finalisation. Special tools may need to be developed or insulated cranes or personnel lifts purchased. In cases of new tower designs it is necessary to determine the adequate spacing by using dummy objects with full scale electrical impulse tests. This will determine whether the spacing proposed is adequate.

3.7.2 Information Required and Handover (Submission)

It is critical that the asset owner and maintenance staff be involved as early as possible in the construction of the line. his will allow for all issues to be resolved prior to handover from the construction company. A detailed handover check sheet needs to be established and agreed to prior to the commencement of construction. This should include checks per tower.

Maintenance of the constructed asset may be contracted out to a number of external suppliers. It is important for the asset owner to ensure that, prior to taken over the line, all information is available on the line that has been constructed or refurbished. This includes:

- Line as built profiles
- Map of line route with landowner details
- Tower type per tower position
- Conductor details (supplier, type, contract, numbers etc)
- Earthwire and OPGW details (supplier, type, contract numbers etc)
- Hardware details (supplier, type, contract numbers etc)
- Drawings of towers and assemblies.
- Foundation types per tower leg (this is particularly important with large tower footing areas such as the cross rope suspension)
- Results of concrete slump and test cube (compression) tests.
- Tower footing resistance per tower.
- Earthing used especially if additional earthing has been applied.
- Accessories such as aerial warning spheres, bird guards.
- Insulator types per tower if different (composite and glass may be used on one line for example), information to include creepage, material, insulator profile.
- Location of conductor joints as well as the compression tool number to perform the joint (if such joints were installed).

3.7.3 Information for Maintenance during Operation

In addition to the above it is important that the maintenance required is also provided. This includes the type of inspections to be conducted and the time interval. Items such as retensioning guy wires should also be included.

Regular line inspections should be conducted with focus on the following:

- Tension in guy wires
- Evaluation of the earthing system at the towers
- Structure condition
- Vibration and spacer damper – condition and orientation
- Aircraft warning spheres, condition
- Condition of guy anchors
- Insulator damage
- Servitude condition and access to towers – poor maintenance of servitudes could inhibit effective restoration of lines as well as affect line performance depending on the vegetation below the line.
- Thermal imaging of the line for potential electrical hot spots
- Periodic assessment of the conductor – especially in corrosive environments – this may entail taking physical conductor samples and testing them in a laboratory
- Records should be maintained with the fault information for each line so that analysis and performance improvement projects can be undertaken if necessary.

3.8 Conclusion

The current utility structure often differs from vertically integrated to fully outsourced with many different companies involved in the life of the asset. This chapter highlights the concepts for management of the line in the different stages. The organogram or management structure can vary between utilities and companies and still comply with the proposed concepts. As a result the management structures have not been discussed.

The aim is to make the utility aware of the management concepts to be applied and to apply these in the best manner that befits the company structure and insourcing or outsourcing policy.

3.9 Highlights

The management of the line life cycle is consistent irrespective of the structure of the company or companies involved with different stages of the life cycle.

It is important for the asset owner and operator to be aware of the management concepts and process to ensure all stages are well catered for even if they fall outside the domain of the company.

The concepts highlighted in this chapter have been proven over many years and, although they may vary from country to country in detail (for example it may not be practice for the planners to provide the information as suggested and only state a conductor type), each stage must be covered to some extent.

3.10 Outlook

It is likely that the planning, design, construction, maintenance and operation of overhead power lines will be conducted by different companies with different goals, make up and skills compared to the past. In this case it is important that the process through the life cycle of the line is not compromised. This can be achieved by the role players being aware of the process as described in this chapter.

The risk exists that the more independent the role players are the less the overall planning and management concepts will be understood and executed. it is possible that each stage is seen in isolation to the detriment of the overall line design, operation and maintenance. This risk is likely to increase in future as the role players become more segregated.

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Rob Stephen has MSc, MBA degrees and recently received his PhD degree in line optimisation from the University of Cape Town South Africa. He is employed in Eskom, the South African utility where he holds the position of Master Specialist. He has been involved in all aspects of line design as well as network planning, electrification and project management. In study committee B2 (overhead lines) he has held position of working group convener, special reporter, advisory group convener and was chairman of SC B2 from 2000–2004. He has published over 100 papers and been involved in technical brochures on aspects of thermal rating, real time monitoring and overall line design since 1988. He is an horonary member of Cigré and a fellow of the South African Institute of Electrical engineers.

Electrical Design

4

Joao Felix Nolasco, José Antonio Jardini,
and Elilson Ribeiro

Contents

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J.F. Nolasco (✉) • J.A. Jardini • E. Ribeiro
Florianópolis, Brazil
e-mail: nolascojf@gmail.com

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4.1 Electrical Characteristics

4.1.1 Introduction

Electrical parameters of transmission lines or otherwise refered to as line constants, resistance, inductance and capacitance (R,L,C) are used to evaluate the electrical behavior of the power system. Depending on the phenomena to be studied a different set of parameters is required. For load flow and electromechanical transients the parameters used are the positive sequence. In the short-circuit calculation the positive/negative/zero sequence paremementers and for electromagnetic transients the phase parameters and its frequency-dependent parameters.

For the former case, normally, the line is considered full transposed and there are simple equations to determine the parameters. For others cases digital programs are used like the ATP. The various procedures of calculation are discussed here-in-after, starting with straight forward calculation for positive sequence model and completing with a general calculation.

4.1.2 Resistance

The resistance of conductors R is found in the manufacturers catalog. The values of resistance in Ω/km for dc current at 20 °C and sometimes for ac (50 or 60 Hz) are given as function of the conductor cross section.

R -the resistance of the bundle- is then the one sub-conductor resistance divided by the number of them in a bundle.

It should be noted that manufacturers' catalog indicate, normally, conductor resistance (R_{20}) for dc at 20 °C. For other temperature (R_t) a correction shall be applied:

$$R_t = R_{20}\left[1 + \beta\left(t - 20\right)\right] \tag{4.1}$$

where t is the conductor temperature and β the resistance temperature coefficient equal to 0.00403 for Aluminum and 0.00393 for copper. Aluminum Association provides specific values of β for every conductor section in the ranges 25-50 °C and 50-75 °C.

Example: for the conductor ACSR 954 MCM (45/7), extracting the individual resistances from a Catalogue (Aluminum Association Handbook) and making the calculation of β coefficients, Table 4.1 is obtained:

4.1.3 Inductance

The inductive reactance of the transmission line is calculated by (Stevenson 1962):

$$X_l = 2w10^{-4}\ln\left(\frac{GMD}{GMR}\right) \quad \left(\Omega / km\right) / \ phase \tag{4.2}$$

Table 4.1 Examples of coefficients of resistance variation according to temperatures

ACSR 954 MCM (Rail)			
		t(°C)	
Unit	25	50	75
Ω/Mi	0.099	0.109	0.118
Ω/km	0.061778	0.067744	0.073337
$\beta_{(25\text{-}50)}$	0.003863		
$\beta_{(50\text{-}75)}$	0.003303		

$$w = 2\pi f \tag{4.3}$$

f is the frequency.

GMD and GMR are the geometric mean distance and geometric mean radius.

For a single circuit fully transposed:

$$GMD = \sqrt[3]{d_{ab} d_{ac} d_{bc}} \tag{4.4}$$

d_{ab} d_{ac} d_{bc} are the phase distances.

For bundle of n sub-conductors located in a circle of radius R and being a the equal spacing between adjacent sub-conductors the equivalent radius of the bundle or the GMR is:

$$GMR = R \sqrt[n]{\frac{nrk}{R}} \tag{4.5}$$

r is the sub conductor radius

$$R = \frac{a}{2 \sin(\pi / n)} \tag{4.6}$$

k is a correction factor

4.1.4 Capacitance

The capacitance of a full transposed three phase line is calculated by:

$$C = \frac{0.05556}{\ln\left(k_1 \dfrac{GMD}{GMR_c}\right)} \quad \mu F / km \tag{4.7}$$

$$GMR_c = R \sqrt[n]{\frac{nr}{R}} \tag{4.8}$$

k_1 depends on distances between conductors and conductors to images in the soil (equal to *0.95-1.0* for 138 kV and *0.85-0.9* for 400 kV and higher voltages).

4.1.5 Negative and Zero Sequence Parameters

Negative sequence parameters are equal to the positive parameters for transmission lines.

There are straight forward equations also for the calculation of the zero sequence parameters, however it is recommended to use the procedures described in (Stevenson 1962; Happoldt and Oeding 1978; Kiessling et al. 2003).

4.1.6 Representation of Lines

In this section formulae will be presented for calculating voltage, current and power at any point of a transmission line, provided such values are known at one point. Loads are usually specified by their voltage, power and power factor, for which current can be calculated for use in the equations.

Normally transmission lines are operated with balanced three-phase loads. Even if they are not spaced equilaterally and may not be transposed, the resulting dissymmetry is slight, and the phases are considered to be balanced.

The equivalent circuit of a short line is represented by a series reactance only, which are concentrated or lumped parameters not uniformly distributed along the line. As the shunt admittance is neglected for short lines, it makes no difference, as far as measurements at the ends of the line are concerned, whether the parameters are lumped or uniformly distributed.

The shunt admittance, generally pure capacitance, is included in the calculations for a line of medium length. The nominal Π circuit, shown in Figure 4.1 below, is often used to represent medium-length lines.

In this circuit, the total shunt admittance is divided into two equal parts placed at the sending and receiving ends of the line.

The voltage and current relationships used in electrical calculations under this approach are:

$$V_S = \left(\frac{ZY}{2} + 1\right) V_R + Z I_R \tag{4.9}$$

$$I_S = Y\left(\frac{ZY}{4} + 1\right) V_R + \left(\frac{ZY}{2} + 1\right) I_R \tag{4.10}$$

Neglecting the capacitance for short lines, the above equations become the well-known simple relationships:

$$V_S = V_R + Z I_R \tag{4.11}$$

$$I_S = I_R \tag{4.12}$$

The magnitude of the voltage regulation (%Reg) for the case of medium lines is:

$$\%Reg = 100 \frac{|V_S| - |V_R|}{|V_R|} \tag{4.13}$$

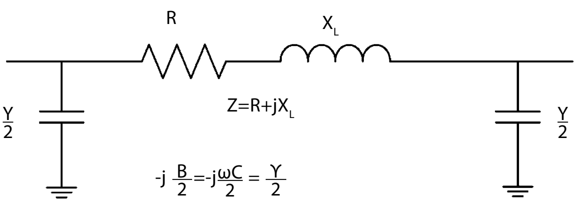


Figure 4.1 Nominal Π circuit of a line.

4.1.6.1 Long Transmission Lines

As impedance and admittance are uniformly distributed along the line, the exact solution of any transmission line is required for a high degree of accuracy in calculating long lines (for instance longer than 100 km); distributed parameters should be used in this case.

The following nomenclature is used:

- z = series impedance per unit length, per phase
- y = shunt admittance per unit length, per phase to neutral
- l = line length
- $Z = zl$ = total series impedance per phase
- $Y = yl$ = total shunt admittance per phase to neutral

The following equations can be deduced:

$$V = \frac{V_R + I_R Z_C}{2} e^{\gamma x} + \frac{V_R - I_R Z_C}{2} e^{-\gamma x} \tag{4.14}$$

$$I = \frac{V_R + I_R Z_C}{2Z_C} e^{\gamma x} + \frac{V_R - I_R Z_C}{2Z_C} e^{-\gamma x} \tag{4.15}$$

$$Z_C = \sqrt{\frac{z}{y}} \tag{4.16}$$

and the propagation constant is:

$$\gamma = \sqrt{z\,y} \tag{4.17}$$

Both γ and Z_C are complex quantities. The real part of the propagation constant γ is called the attenuation constant α, while the quadrature part is called phase constant β.

Thus: $\gamma = \alpha + j\beta$. The above equations for voltage and current for defining V and I turn out into:

$$V = \frac{V_R + I_R Z_C}{2} e^{\alpha x} e^{j\beta x} + \frac{V_R - I_R Z_C}{2} e^{-\alpha x} e^{-j\beta x} \tag{4.18}$$

$$I = \frac{V_R + I_R Z_C}{2Z_C} e^{\gamma x} + \frac{V_R - I_R Z_C}{2Z_C} e^{-\gamma x} \tag{4.19}$$

A deep analysis, beyond the scope of these highlights, will prove that the first terms of the above equations are the incident voltage (or current), while the second term is the reflected voltage (or current). Observe that a line terminated in its characteristic impedance Z_C has $V_R = I_R Z_C$ and therefore has no reflected wave.

Such a line is called flat line or infinite line, the latter designation arising from the fact that a line of infinite length cannot have a reflected wave. Usually power

Table 4.2 Typical line parameters and line constants for a 500 kV Line

4 × ACAR 1300 MCM (30/7)			Ling length → 365 km		$\beta^{(b)}$
Parameter	R(Ω/km)	X_L(Ω/km)	X_C(Ω*km)	B(μS/km))	0,001276
Z_1unit	0.013172	0.220388	135411	7,385	γ
Z_0unit	0.15317	1.00965	326807	B_0(μS/km))	0,001277
Eq. LT	R(Ω)	X_L(Ω)	B/2(μS)	3,060	λ(km)
"Π"nomZ_1	4.808	80.442	1347.7	Z_C(Ω)	4923
"Π"equiv	4.466	77.576	1372.64	172,9	
"Π"nomZ_0	55.906	368.521	558.43	α	v(km/s)
E/E_0	0.785	SIL(MW)	1447	3,81 E-05	295373

Notes: a) *1 MCM = 0.5067 mm²* ***b)*** *This column refers to line constants*

Line data used for the calculation above:

- voltage → 500 kV Tower type → Guyed cross rope
- phase bundle conductor → 4 × ACAR 1300 MCM (~4 × 653 mm²).
- diameter → 3.325 cm Stranding: 30/7
- sub-conductor spacing → 120,0 cm (Expanded bundle)
- phase spacing → 6.41 m
- conductor height at tower → 28.3 (average) m
- minimum distance conductor to ground → 12.0 m
- conductor sag → 22.5 m
- shield wires EHS → 3/8" and OPGW 14.4 mm S. wires spacing → 28.1 m
- shield wire height at tower → 38.0 m shield wire sag 16.5 m
- soil resistivity → 1000 Ω m

lines are not terminated in their characteristic impedance, but communication lines are frequently so terminated in order to eliminate the reflected wave. A typical value of Z_C is 400 Ω for a single conductor line. For conductor bundles between 2 and 6, see typical values in Table 4.2. The phase angle of Z_C is usually between 0 and −15°. Z_C is also called surge impedance in power lines.

Surge impedance loading (SIL) of a line is the power delivered by a line to a purely resistive load equal to its surge impedance.

4.1.6.2 Lumped Representation of Lines

The exact representation of a transmission line is usually made through the use of hyperbolic functions that can treat the line with distributed electric parameters of resistance, inductance and capacitance.

Such functions are equated in terms of the incident and reflected waves of voltage and current, being summarized as follows:

$$V_S = V_R \cosh \gamma l + I_R Z_C \sinh \gamma l \tag{4.20}$$

$$I_S = I_R \cosh \gamma l + \frac{V_R}{Z_C} \sinh \gamma l \tag{4.21}$$

$$V_R = V_S \cosh \gamma l - I_S Z_C \sinh \gamma l \tag{4.22}$$

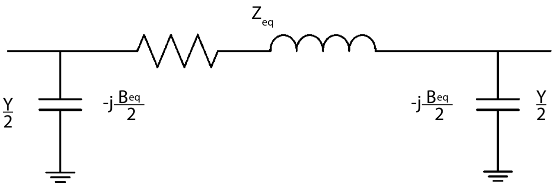


Figure 4.2 Equivalent circuit of a long line (Equivalent Π).

$$I_R = I_S \cosh \gamma l - \frac{V_S}{Z_C} \sinh \gamma l \tag{4.23}$$

However for the case of short or medium-length lines, equivalent circuits of transmission lines have been simplified by calculating equivalent series resistance and reactance, which are shown as concentrated or lumped parameters and not distributed along the line. The distributed capacitances are also represented by one or two lumped parameters.

This simple circuit having the shape of the Greek letter Π is named as nominal Π. The nominal Π does not represent a transmission line exactly because it does not account for the parameters of the line being uniformly distributed.

The discrepancy between the nominal Π and the actual line becomes larger as the length of the line increases. It is possible, however, to find the equivalent circuit of a long transmission line composed of lumped parameters so that voltage and current relations at both ends are accurate. In view of that, the true line representation that is really a hyperbolic function can be replaced by a simplified Line Representation having the shape of the so called Equivalent Π as shown in Figure 4.2. The values of the equivalent parameters, R_{eq}, X_{eq} and B_{eq} are determined so that the voltages and currents are the same at the sending-end and receiving-end terminals. The calculation formulas state below.

$$Z_C \sin \gamma l = z \frac{\sinh \gamma l}{\gamma l} \tag{4.24}$$

$$\frac{B_{eq}}{2} = \frac{1}{Z_C} \frac{\tanh \gamma l}{2} = \frac{B}{2} \frac{\tanh\ (\gamma l / 2)}{\gamma l} \tag{4.25}$$

Therefore, starting from the nominal Π parameters and using the circuit constants, it is possible to calculate the equivalent Π values.

$$Z_{eq} = R_{eq} + jX_{eq} \tag{4.26}$$

For short lines and low voltage lines, capacitance C is neglected and a simplified model neglecting the capacitance can be used instead. Such simplification could be applied to lines below 72.5 kV and for lengths below 30 to 40 km.

An example of calculation of the main parameters and line constant is shown in Table 4.2 for a 500 kV overhead line.

Line data used for the calculation above:

- voltage = 500 kV Tower type = Guyed cross rope
- phase bundle conductor = 4 × ACAR 1300 MCM (~4 × 653 mm^2).
- diameter = 3.325 cm Stranding: 30/7
- sub-conductor spacing = 120.0 cm (Expanded bundle)
- phase spacing = 6.41 m
- conductor height at tower = 28.3 (average) m
- minimum distance conductor to ground = 12.0 m
- conductor sag = 22.5 m
- shield wires EHS = 3/8" and OPGW 14.4 mm s. wires spacing = 28.1 m
- shield wire height at tower = 38.0 m shield wire sag 16.5 m
- soil resistivity = 1000 Ω m.

4.1.7 General Overhead Transmission Line Models

Overhead transmission lines are modeled by electric circuit based on their parameters (resistance, inductance and capacitance) and length.

The relation between voltage to ground (V), incremental length voltage drop along the line ($\Delta V/\Delta x$), and current (I) or charge (Q) are (Dommel 1986):

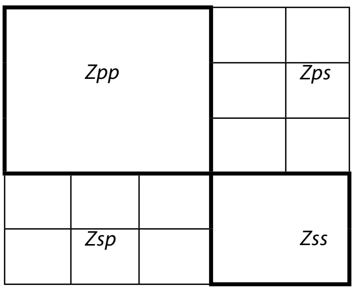
- Electromagnetic phenomena

$$[\Delta V / \Delta x] = [Z][I] \tag{4.27}$$

- Electrostatic phenomena

$$[V] = [H][Q] \tag{4.28}$$

For AC system, matrixes Z and H have one line and one column for each conductor and shield wire. For instance, for an AC line with three phases (sub index p) and two shield wires (sub index s) they look like:



For bipolar DC systems the matrixes are similar however with p = 2.

4.1.7.1 Electromagnetic and Electrostatic Line Equations

The terms of the impedance matrix Z in (Ω/km) are:

$$Z_{ii} = \left(R_{ii} + \Delta R_{ii}\right) + j\left(X_{ii} + \Delta X_{ii}\right) \tag{4.29}$$

$$\mathrm{Z}_{\mathrm{ij}} = \left(\Delta \mathrm{R}_{\mathrm{ij}}\right) + \mathrm{j}\left(\mathrm{X}_{\mathrm{ij}} + \Delta \mathrm{X}_{\mathrm{ij}}\right) \tag{4.30}$$

R_{ii} is the AC resistance of the bundle (one subconductor resistance divided by the number of them in a bundle)

$$X_{ii} = 2w10^{-4} \ln\left(\frac{1}{R_{eqz_{ii}}}\right) \tag{4.31}$$

$$X_{ij} = 2w10^{-4} \ln\left(\frac{1}{d_{ij}}\right) \tag{4.32}$$

ΔR_{ii}, ΔR_{ij}, ΔX_{ii}, ΔX_{ij}, are additional parcels (Carlson correction) for which resistance and reactance initial term of the series are:

$$\Delta R_{ij} = 4w10^{-4} \left[\frac{1.5708}{4} - \frac{0.0026492\left(h_i + h_j\right)\sqrt{f/\rho}}{4} + \cdots\right] \tag{4.33}$$

$$\Delta X_{ij} = 4w10^{-4} \left[\frac{2}{4}\ln\left(\frac{658.8}{\sqrt{f/\rho}}\right) + \frac{0.0026492\left(h_i + h_j\right)\sqrt{f/\rho}}{4} + \cdots\right] \tag{4.34}$$

for ii terms use h_i in place of h_j

For bundle of n sub-conductors located in a circle of radius R and being a the spacing between adjacent sub-conductors the equivalent radius of the bundle is:

$$R_{eqz_{ii}} = R\sqrt[n]{\frac{nrk}{R}} \tag{4.35}$$

r is the sub conductor radius

$$R = \frac{a}{2\sin\left(\pi/n\right)} \tag{4.36}$$

k = correction factor
d_{ij} = distance between the center of the bundles i and j
h_i = average conductor i height (height at mid span plus 1/3 of the sag)
f = frequency
ρ = soil resistivity in Ω m
The terms of the potential matrix H in (km/μF) are:

$$H_{ii} = 17.976 \ln\left(\frac{D_{ii}}{R_{eqc_{ii}}}\right) \tag{4.37}$$

$$H_{ij} = 17.976 \ln\left(\frac{D_{ij}}{d_{ij}}\right) \tag{4.38}$$

$$R_{eqc_{ii}} = R\sqrt[n]{\frac{nr}{R}} \tag{4.39}$$

D_{ij} = distance from bundle i to the image of bundle j.

The inverse H_{-1} is the bus admittance matrix Y divided by w and includes the line capacitances.

Therefore for the line parameters calculation the tower geometry has to be known.

Notes:

- Shield wire may be grounded ($\Delta Vs = 0$), and their rows and columns can then be eliminated (Gauss's elimination) as shown by the equation below, and hence their effects are included in the others lines and rows.

$$Z_{ij}^{new} = Z_{ij} - \frac{Z_{ik} Z_{kj}}{Z_{kk}} \tag{4.40}$$

- for $k = 4{,}5$ and $i{,}j = 1{,}2{,}3$ in the example above.
- For isolated shield wire ($Is = 0$) their lines and columns are deleted.
- For asymmetrical bundle every sub-conductor has one line and one column in the matrix Z for instance. As the sub-conductors in the same bundle have the same voltage drop the lines and columns of one is maintained, and the others lines and columns are substituted by the difference of their values and the corresponding of the remained lines and columns. Now for the modified sub-conductors $\Delta V = 0$, It = Σ Ic, and can be eliminated like the shield wires, and their effect is kept in the remaining one (Dommel 1986).
- If the line has phase transpositions the terms of the matrixes Z, H can be averaged by its section length.
- Finally matrices Z, H remain with the number of lines/columns equal to the number of phases.
- For DC line the same applies being the remaining lines/columns equal to the number of poles.
- The Electromagnetic Transients Programs that are available have routines to perform the necessary calculations.

4.1.7.2 Line Models

The equations indicated before, for a short line of length L are:

$$[\Delta V] = [Z_u][I] = [Z][I] \tag{4.41}$$

$$\left[I\right] = jw\left[H\right]^{-1}\left[V\right] \tag{4.42}$$

- Symmetrical components (AC lines)

Z and *Y* matrixes terms are all non zeros, and ΔV, V, I are phase quantities. To simplify the calculation the equations above may be transformed for instance, *Z*, into symmetrical components (positive, negative and zero sequences, or 1, 2, 0) by:

$$\left[\Delta V_{012}\right] = \left[T\right]^{-1}\left[Z\right]\left[T\right]\left[I_{012}\right] \tag{4.43}$$

Hence the symmetrical component impedance matrix is:

$$\left[Z_{012}\right] = \left[T\right]^{-1}\left[Z\right]\left[T\right] \tag{4.44}$$

If the line has a complete transposition of phases in equal sections then the symmetrical component matrix Z_{012} has only the diagonal terms (the sequential impedances, Z_o, Z_1, Z_2)

Now for the calculation, given one set of phase values, they are transformed into symmetrical components, and the calculation is carried using the equation above. After that, the calculated sequence components values have to be changed back to phase components. The transformation matrix *T* is:

$$T = \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \tag{4.45}$$

With $a = e^{j120}$.

Note that the phase components are:

$$Z = \begin{bmatrix} Z_{aa} & Z_{ab} & Z_{ac} \\ Z_{ba} & Z_{bb} & Z_{bc} \\ Z_{ca} & Z_{cb} & z_{cc} \end{bmatrix} \tag{4.46}$$

The matrix *Z* is symmetric (Ex.: $Z_{ab} = Z_{ba}$). Also, if the phases have the same configuration and they have complete phase transposition, then:

$$Z = \begin{bmatrix} Z_s & Z_m & Z_m \\ Z_m & Z_s & Z_m \\ Z_m & Z_m & Z_s \end{bmatrix} \tag{4.47}$$

$$Z_{aa} = Z_{bb} = Z_{cc} = Z_s \tag{4.48}$$

$$Z_{ab} = Z_{ac} = Z_{bc} = Z_m \tag{4.49}$$

And

$$Z_1 = Z_2 = Z_s - Z_m \tag{4.50}$$

$$Z_0 = Z_s + 2Z_m \tag{4.51}$$

Note: If the line is a double circuit (w,y) then Z matrix can be partitioned into four 3×3 sub-matrices Z_{ww}; Z_{yy}; Z_{wy} and the same equations can be applicable, provided there is a complete transposition, obtaining the sequence self parameters of circuit w, y and the mutual wy.

Therefore for two circuits w and y close together considering complete transposition the matrix has the following type.

Zws	*Zwm*	*Zwm*	*Zwys*	*Zwym*	*Zwym*
	Zws	*Zwm*	*Zwym*	*ZwyS*	*Zwym*
		Zws	*Zwym*	*Zwym*	*Zwys*
			Zys	*Zym*	*Zym*
				Zys	*Zym*
					Zys

And the self impedances of circuit *w* are:

$$\begin{aligned} Z_{w1} &= Z_{w2} = Z_{ws} - Z_{wm} \\ Z_{w0} &= Z_{ws} + 2Z_{wm} \end{aligned} \tag{4.52}$$

The mutual impedances of circuit *w* and *y* are:

$$\begin{aligned} Z_{wy1} &= Z_{wy2} = Z_{wys} - Z_{wym} \\ Z_{wy0} &= Z_{wys} + 2Z_{wym} \end{aligned} \tag{4.53}$$

Similar considerations apply to the second equation and *Y* matrix. As example, for single circuit being:

$$C_1 = \frac{1}{H_s - H_m} \tag{4.54}$$

$$C_0 = \frac{1}{H_s + 2H_m} \tag{4.55}$$

Once obtained the sequence impedances the line/cable can be modeled using lumped circuits, –π sections like in Figure 4.3.

For short lines (≤50 km) the above impedances are obtained by multiplying the unit impedance with the line length. For long lines a factor < 1 shall be included as indicated before.

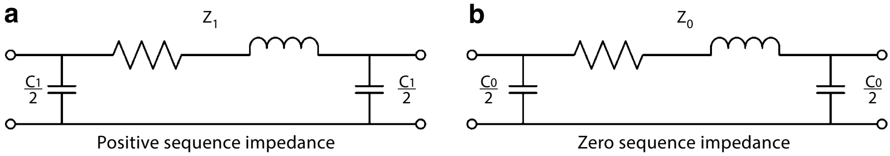


Figure 4.3 AC line model, single phase π for positive/negative sequences a) and zero sequence b).

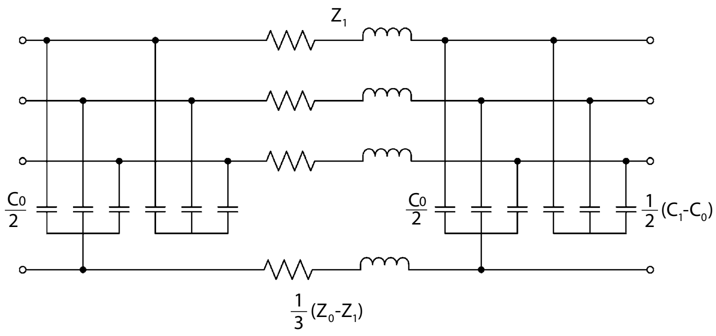


Figure 4.4 Three phase, π-model.

A three phase model can also be established and was useful for TNA calculation (Figure 4.4).

For DC lines, similarly to the symmetrical component transformation, the matrix T is:

$$T = \frac{1}{\sqrt{2}}\begin{bmatrix} 1 & 1 \\ 1 & -1 \end{bmatrix} \tag{4.56}$$

That leads to two modes: ground and aerial or metallic modes (0 and 1 respectively).

Similarly for the AC equations, it results:

$$Z_1 = Z_{11} - Z_{12} \tag{4.57}$$

$$Z_0 = Z_{11} + Z_{12} \tag{4.58}$$

$$C_1 = \frac{1}{H_s - H_m} \tag{4.59}$$

$$C_1 = \frac{1}{H_s + H_m} \tag{4.60}$$

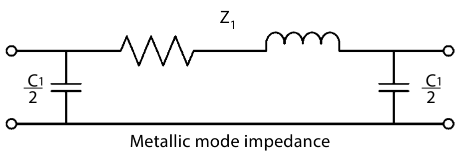
The corresponding π circuit for aerial mode is (Figure 4.5):

The two poles model is that of Figure 4.6.

- For electromagnetic calculations the following equations applies

$$[\partial V / \partial x] = [Z][I] \tag{4.61}$$

Figure 4.5 Aerial/ Metallic mode circuit; for ground mode change Z_1, C_1 by Z_0, C_0.



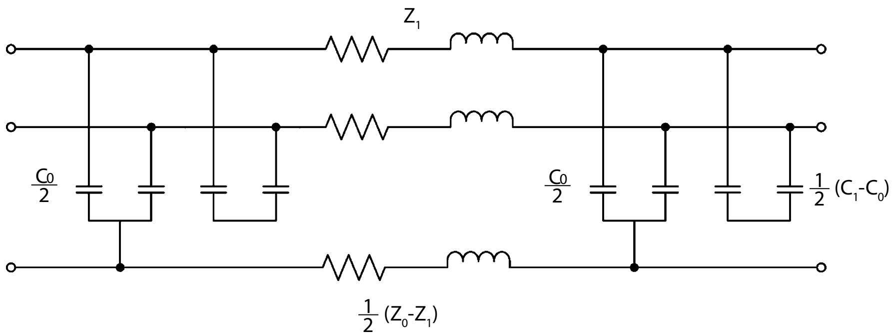


Figure 4.6 Two poles circuit.

$$[\partial I/\partial x] = j\omega[H]^{-1}[V] = [Y][V] \tag{4.62}$$

and

$$[\partial^2 V/\partial x^2] = [Z][Y][V] \tag{4.63}$$

Now it is necessary to transform into diagonal matrix the product $[Z][Y]$. This is obtained by searching for the eigenvalues and eigenvector of it (modal analysis) (Dommel 1986).

4.1.7.3 Electrical Studies and Their Line Models

The following studies are applicable for AC and DC systems.

- Steady-state (load flow and short circuit)
- Electromechanical transients (stability, power frequency overvoltage due to load rejection, and line/cable energization/reclosing)
- Electromagnetic transient (transient part of short-circuits, switching surge overvoltages, DC converters commutation failure).
- Harmonic performance
- Relay protection and control coordination.

The overhead transmission line models may vary depending on the study.

- Steady state.
  For load-flow calculation, the overhead AC lines and cables are represented by -π sections based on positive sequence parameters. Overhead DC lines are represented by their resistance only.
  For short circuit calculations transposed symmetrical components parameters should be used for AC lines. For DC lines this type of calculation is not completely valid unless the converter station control action is simulated.
- Electromechanical transients

AC and DC lines are represented using the same above mentioned modelling for load flow analysis. However, for power-frequency over-voltages (rated frequency ± 10%) the variation of the parameters (reactance: ωL and $1/\omega C$) with the frequency shall be simulated (note that this does not refer to line frequency dependence of parameters).

- Electromagnetic transients
  AC and DC lines are represented by distributed parameter or a cascade of -π sections. Now, overhead DC lines model considers frequency dependant parameters. Modal decomposition analysis is normally used in the calculation together with non transposed Z, $H-1$, matrixes. This line model applies when calculating the initial transient of a short circuit in DC and AC lines.
- Harmonic performance
  AC and DC overhead lines are represented as -π sections using transposed parameters at the specific harmonic frequency taking into account the parameters as a function of frequency.
- Relay protection and control
  The same modeling used for electromagnetic studies applies in this case when the transient part of the overcurrent/overvoltage phenomena is important.

4.1.7.4 Examples of Calculation DC Line

Calculations were done using ATP/EMTP-RV for the line on Figure 4.7 and are reported below. The data for the example (arbitrarily chosen (Cigré 2009)).

- voltage = ± 500 kV
- pole conductor = 3 × 1590 MCM (~806 mm^2)
- economic conductor for 1300 MW bipole
- diameter = 3.822 cm
- pole spacing = 13 m
- sub-conductor spacing = 45 cm
- minimum distance conductor to ground = 12.5 m
- conductor sag = 20.5 m (conductor height at tower 33 m)
- shield wires = EHS 3/8”
- shied wires spacing = 11 m
- shield wire sag = 20.5 m
- shield wire height at tower = 41 m
- soil resistivity = 500 Ω m.

The results using EMTP-RV are shown below (Figures 4.8, and 4.9):

After bundling (left) and elimination of the shield wires (right) the matrixes are (Figures 4.10, 4.11, and 4.12):

or

$I_+ = \omega\ 1.12\text{E-}08\ V_+ + \omega\ (-1.69\text{E-}09)\ V_-$

$\omega = 2\pi\ f = 1$ as $f = 1/2\pi$

$C_0 = 1.12\text{E-}08 - 1.69\text{E-}09 \Rightarrow 9.51\ \mu F$

$C_1 = 1.12\text{E-}08 + 1.69\text{E-}09 \Rightarrow 12.89\ \mu F$

Therefore

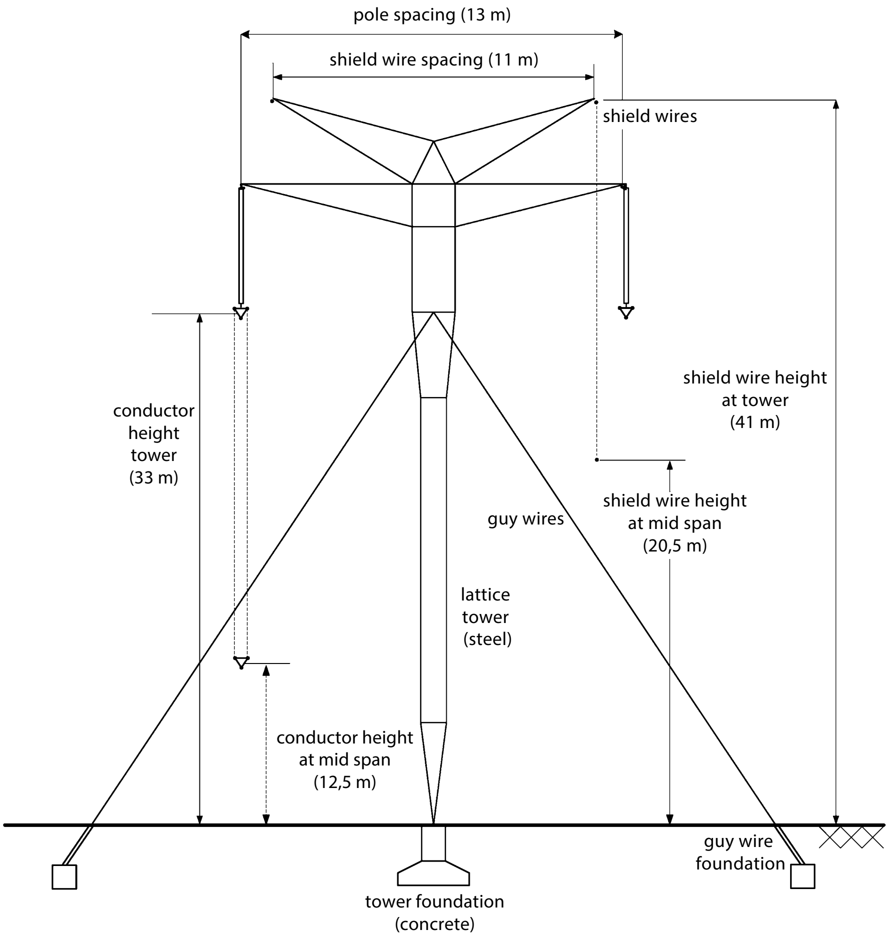


Figure 4.7 Line geometry.

$Z_0 = (1.21\ \text{E-02} + 1.58\ \text{E-04}) + j\ (2.49\ \text{E-03} + 1.59\ \text{E-03}) = 0.0122 + j\ 0.00408\ \Omega$ ($\omega = 1$ rad/s)

$Z_1 = (1.21\ \text{E-02} - 1.58\ \text{E-04}) + j\ (2.49\ \text{E-03} - 1.59\ \text{E-03}) = 0.0120 + j\ 0.0009\ \Omega$ ($\omega = 1$ rad/s).

AC Line

Calculations were done using ATP/EMTP-RV for the line on Figure 4.13 and are reported below. The data for the example are.

- voltage = 500 kV
- phase bundle conductor = 4 × 954 MCM (~483 mm^2)
- diameter = 2.961 cm
- sub-conductor spacing = 45.7 cm.

```
INPUT DATA                 (skin)      (resistance)         (group) (rep.)   (rep.)  (model)      (outer diameter)  ( X )   (Ytower)   (Ymin)
Line conductor card.   3.750E-01  3.596E-02      4  |  10.3750.035959|4            3.822  6.7285 33.1319 12.6319 ┐
Line conductor card.   3.750E-01  3.596E-02      4  |  10.3750.035959|4            3.822  6.2715 33.1319 12.6319 │ POLE 1
Line conductor card.   3.750E-01  3.596E-02      4  |  10.3750.035959|4            3.822     6.5 32.7362 12.2362 ┘
Line conductor card.   3.750E-01  3.596E-02      4  |  20.3750.035959|4            3.822 -6.7285 33.1319 12.6319 ┐
Line conductor card.   3.750E-01  3.596E-02      4  |  20.3750.035959|4            3.822 -6.2715 33.1319 12.6319 │ POLE 2
Line conductor card.   3.750E-01  3.596E-02      4  |  20.3750.035959|4            3.822    -6.5 32.7362 12.2362 ┘
Line conductor card.   5.000E-01  3.282E+00      4  |  3   0.5| 3.28153|4         0.953     5.5     41.      20.5 ┐ SHIELD WIRES
Line conductor card.   5.000E-01  3.282E+00      4  |  4   0.5| 3.28153|4         0.953    -5.5     41.      20.5 ┘
Blank card terminating conductor cards.             |BLANK CARD ENDING CONDUCTOR CARDS
Frequency card.  5.000E+02  1.592E-01  1.000E+00    |    500.0.15915494           000110 110000 0       1.               44

INPUT PRINTOUT

Line conductor table after sorting and initial processing.
 Table    Phase    Skin effect     Resistance    Reactance data specification     Diameter    Horizontal     Avg height
   Row   Number         R-type   R (ohm/km)    X-type      X(ohm/km) or GMR     (  cm  )     X (mtrs)      Y (mtrs)          Name
     1        1         .37500       .03596         4               .000000      3.82200        6.728        19.465
     2        2         .37500       .03596         4               .000000      3.82200       -6.728        19.465
     3        1         .37500       .03596         4               .000000      3.82200        6.271        19.465
     4        1         .37500       .03596         4               .000000      3.82200        6.500        19.070
     5        2         .37500       .03596         4               .000000      3.82200       -6.271        19.465
     6        2         .37500       .03596         4               .000000      3.82200       -6.500        19.070
     7        0         .50000      3.28153         4               .000000       .95300        5.500        27.333
     8        0         .50000      3.28153         4               .000000       .95300       -5.500        27.333

Matrices are for earth resistivity = 5.00000000E+02  ohm-meters  and frequency 1.59154940E-01  Hz.   Correction factor =
1.00000000E-06
```

Figure 4.8 Input data of line geometry.

$$
\begin{bmatrix}
1{,}29E\text{-}02 & & & & & & & \\
-1{,}58E\text{-}04 & 1{,}29E\text{-}02 & & & & & & \\
-4{,}59E\text{-}03 & -1{,}86E\text{-}04 & 1{,}29E\text{-}02 & & & & & \\
-4{,}60E\text{-}03 & -1{,}70E\text{-}04 & -4{,}59E\text{-}03 & 1{,}29E\text{-}02 & & & & \\
-1{,}86E\text{-}04 & -4{,}59E\text{-}03 & -2{,}22E\text{-}04 & -2{,}03E\text{-}04 & 1{,}29E\text{-}02 & & & \\
-1{,}70E\text{-}04 & -4{,}60E\text{-}03 & -2{,}03E\text{-}04 & -1{,}89E\text{-}04 & -4{,}59E\text{-}03 & 1{,}29E\text{-}02 & & \\
-6{,}16E\text{-}04 & -2{,}69E\text{-}04 & -6{,}16E\text{-}04 & -5{,}14E\text{-}04 & -3{,}00E\text{-}04 & -2{,}58E\text{-}04 & 6{,}52E\text{-}03 & \\
-2{,}69E\text{-}04 & -6{,}16E\text{-}04 & -3{,}00E\text{-}04 & -2{,}58E\text{-}04 & -6{,}16E\text{-}04 & -5{,}14E\text{-}04 & -7{,}51E\text{-}04 & 6{,}52E\text{-}03
\end{bmatrix}
$$

Figure 4.9 Susceptance matrix, in units of [mhos/km] for the system of physical conductors. Rows and columns proceed in the same order as the sorted input.

$$
\begin{bmatrix}
1{,}12E\text{-}08 & & & \\
-1{,}69E\text{-}09 & 1{,}12E\text{-}08 & & \\
-1{,}75E\text{-}09 & -8{,}27E\text{-}10 & 6{,}52E\text{-}09 & \\
-8{,}27E\text{-}10 & -1{,}75E\text{-}09 & -7{,}51E\text{-}10 & 6{,}52E\text{-}09
\end{bmatrix}
\qquad
\begin{bmatrix}
1{,}12E\text{-}08 & \\
-1{,}69E\text{-}09 & 1{,}12E\text{-}08
\end{bmatrix}
$$

Figure 4.10 Susceptance matrix, in units of [mhos/km] for the system of equivalent phase conductors. Rows and columns proceed in the same order as the sorted input.

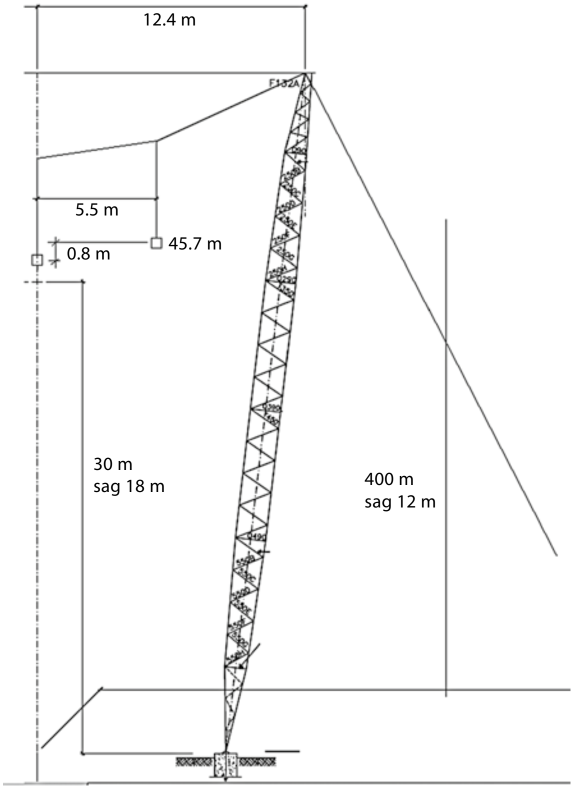
$$
\begin{bmatrix}
3{,}61E\text{-}02 & & & & & & & \\
2{,}94E\text{-}03 & & & & & & & \\
1{,}57E\text{-}04 & 3{,}61E\text{-}02 & & & & & & \\
1{,}58E\text{-}03 & 2{,}94E\text{-}03 & & & & & & \\
1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 3{,}61E\text{-}02 & & & & & \\
2{,}26E\text{-}03 & 1{,}59E\text{-}03 & 2{,}94E\text{-}03 & & & & & \\
1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 3{,}61E\text{-}02 & & & & \\
2{,}26E\text{-}03 & 1{,}59E\text{-}03 & 2{,}26E\text{-}03 & 2{,}94E\text{-}03 & & & & \\
1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 3{,}61E\text{-}02 & & & \\
1{,}59E\text{-}03 & 2{,}26E\text{-}03 & 1{,}60E\text{-}03 & 1{,}59E\text{-}03 & 2{,}94E\text{-}03 & & & \\
1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 3{,}61E\text{-}02 & & \\
1{,}59E\text{-}03 & 2{,}26E\text{-}03 & 1{,}59E\text{-}03 & 1{,}59E\text{-}03 & 2{,}26E\text{-}03 & 2{,}94E\text{-}03 & & \\
1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 3{,}28E{+}00 & \\
1{,}69E\text{-}03 & 1{,}57E\text{-}03 & 1{,}69E\text{-}03 & 1{,}68E\text{-}03 & 1{,}57E\text{-}03 & 1{,}57E\text{-}03 & 3{,}22E\text{-}03 & \\
1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 1{,}57E\text{-}04 & 3{,}28E{+}00 \\
1{,}57E\text{-}03 & 1{,}69E\text{-}03 & 1{,}57E\text{-}03 & 1{,}57E\text{-}03 & 1{,}69E\text{-}03 & 1{,}68E\text{-}03 & 1{,}62E\text{-}03 & 3{,}22E\text{-}03
\end{bmatrix}
$$

Figure 4.11 Impedance matrix, in units of [Ω/km] for the system of physical conductors. Rows and columns proceed in the same order as the sorted input.

$$\begin{bmatrix} 1{,}21\text{E-}02 & & & \\ 2{,}49\text{E-}03 & & & \\ & & & \\ 1{,}57\text{E-}04 & 1{,}21\text{E-}02 & & \\ 1{,}59\text{E-}03 & 2{,}49\text{E-}03 & & \\ & & & \\ 1{,}57\text{E-}04 & 1{,}57\text{E-}04 & 3{,}28\text{E+}00 & \\ 1{,}69\text{E-}03 & 1{,}57\text{E-}03 & 3{,}22\text{E-}03 & \\ & & & \\ 1{,}57\text{E-}04 & 1{,}57\text{E-}04 & 1{,}57\text{E-}04 & 3{,}28\text{E+}00 \\ 1{,}57\text{E-}03 & 1{,}69\text{E-}03 & 1{,}62\text{E-}03 & 3{,}22\text{E-}03 \end{bmatrix} \qquad \begin{bmatrix} 1{,}21\text{E-}02 & \\ 2{,}49\text{E-}03 & \\ & \\ 1{,}58\text{E-}04 & 1{,}21\text{E-}02 \\ 1{,}59\text{E-}03 & 2{,}49\text{E-}03 \end{bmatrix}$$

Figure 4.12 Impedance matrix, in units of [Ω/km] for the system of equivalent phase conductors. Rows and columns proceed in the same order as the sorted input.

Figure 4.13 AC 500 kV line.



- phase spacing = 11 m
- conductor height at tower = 30.0 and 30.8 m
- minimum distance conductor to ground = 12.0 m
- conductor sag = 18.0 m
- shield wires EHS = 3/8".

- shied wires spacing = 24.8 m
- shield wire height at tower = 40.0 m shield wire sag 12.0 m
- soil resistivity = 500 Ω m.

```
INPUT DATA                  (skin)       (resistance)          (group) (rep.)  (rep.) (model)  (outer diameter)   (x)    (Ytower)  (Ymin)   (Ytower)  (Ymin)

Line conductor card.  5.000E-01  6.000E-02     4  | 1  0.5     0.06 4         2.961     -5.5    30.8    12.8    45.7    45.       4
Line conductor card.  5.000E-01  6.000E-02     4  | 2  0.5     0.06 4         2.961      0.0    30.     12.     45.7    45.       4
Line conductor card.  5.000E-01  6.000E-02     4  | 3  0.5     0.06 4         2.961      5.5    30.8    12.8    45.7    45.       4
Line conductor card.  5.000E-01  3.282E+00     4  | 0  0.5 3.28153 4         0.9525|  -12.4    40.     28.      0.0    0.0       1
Line conductor card.  5.000E-01  3.282E+00     4  | 0  0.5 3.28153 4         0.9525    12.4    40.     28.      0.0    0.0       1
Blank card terminating conductor cards.           |BLANK CARD ENDING CONDUCTOR CARDS
Frequency card.   5.000E+02  6.000E+01  1.000E+00 |    500.         60.       000111 111000 0      1.              44

INPUT PRINTOUT

Line conductor table after sorting and initial processing.
 Table   Phase   Skin effect   Resistance   Reactance data specification    Diameter   Horizontal   Avg height
  Row   Number       R-type    R (ohm/km)   X-type      X(ohm/km) or GMR    (  cm  )    X (mtrs)     Y (mtrs)        Name
   1       1        .50000       .06000        4               .000000      2.96100      -5.271      18.572
   2       2        .50000       .06000        4               .000000      2.96100       0.229      17.772
   3       3        .50000       .06000        4               .000000      2.96100       5.729      18.572
   4       1        .50000       .06000        4               .000000      2.96100      -5.729      18.572
   5       1        .50000       .06000        4               .000000      2.96100      -5.729      19.029
   6       1        .50000       .06000        4               .000000      2.96100      -5.271      19.029
   7       2        .50000       .06000        4               .000000      2.96100      -0.228      17.772
   8       2        .50000       .06000        4               .000000      2.96100      -0.229      18.229
   9       2        .50000       .06000        4               .000000      2.96100       0.228      18.229
  10       3        .50000       .06000        4               .000000      2.96100       5.271      18.572
  11       3        .50000       .06000        4               .000000      2.96100       5.271      19.029
  12       3        .50000       .06000        4               .000000      2.96100       5.729      19.029
  13       0        .50000      3.28153        4               .000000       .95250     -12.400      32.000
  14       0        .50000      3.28153        4               .000000       .95250      12.400      32.000

Matrices are for earth resistivity = 5.00000000E+02  ohm-meters  and frequency 6.00000000E+01  Hz.   Correction factor =
1.00000000E-06


Capacitance matrix,  in units of  [farads/kmeter ]  for the system of equivalent phase conductors.
Rows and columns proceed in the same order as the sorted input.

  1  1.287220E-08

  2 -3.933361E-09  1.396611E-08

  3 -1.420180E-09 -3.933361E-09  1.287220E-08

Capacitance matrix,  in units of  [farads/kmeter ]  for symmetrical components of the equivalent phase conductor
Rows proceed in the sequence  (0, 1, 2),  (0, 1, 2),  etc.;  columns proceed in the sequence  (0, 2, 1),  (0, 2, 1),  etc.

           0              2              1
  0  7.045569E-09
     0.000000E+00

  1  2.365456E-10 -1.020045E-09
    -4.097090E-10 -1.766769E-09

  2  2.365456E-10  1.633247E-08 -1.020045E-09
     4.097090E-10  9.996965E-26  1.766769E-09


Impedance matrix,  in units of  [ohms/kmeter ]  for the system of equivalent phase conductors.
Rows and columns proceed in the same order as the sorted input.

  1  1.273080E-01
     6.474170E-01

  2  1.113489E-01  1.265447E-01
     3.965905E-01  6.477023E-01

  3  1.115025E-01  1.113489E-01  1.273080E-01
     3.451484E-01  3.965905E-01  6.474170E-01
  Both  "R"  and  "X"  are in  [ohms];   "C"  are in  [microFarads].

Impedance matrix,  in units of  [ohms/kmeter ]  for symmetrical components of the equivalent phase conductor
Rows proceed in the sequence  (0, 1, 2),  (0, 1, 2),  etc.;  columns proceed in the sequence  (0, 2, 1),  (0, 2, 1),  etc.

           0              2              1
  0  3.498538E-01
     1.406398E+00

  1 -1.477963E-02 -2.954170E-02
    -8.885908E-03  1.723152E-02

  2  1.508524E-02  1.565342E-02  2.969378E-02
    -8.356583E-03  2.680689E-01  1.696810E-02


Sequence        Surge impedance         Attenuation    velocity     Wavelength    Resistance    Reactance    Susceptance
           magnitude(ohm) angle(degr.)     db/km        km/sec          km          ohm/km        ohm/km       mho/km
  Zero :  7.38668E+02 -6.98464E+00  2.07232E-03  1.93584E+05  3.22640E+03  3.49854E-01  1.40640E+00  2.65612E-06
Positive:  2.08834E+02 -1.67095E+00  3.25669E-04  2.93313E+05  4.88855E+03  1.56534E-02  2.68069E-01  6.15720E-06

Calculated steady state benchmark data for line/cable model
Frequency [Hz]:   6.00000000000000E+0001
Line-voltage [kV]:   5.00000000000000E+0002
Positive and zero- sequence data:
            R0 [ohm]   X0 [ohm]   Rp [ohm]   Xp [ohm]   Q0 [MVA]   Qp [MVA]
cir. 1:      0.3501      1.404     0.01594     0.2635     0.664      1.539
```

4.2 Surge Impedance and Surge Impedance Loading (Natural Power)

The energy stored in the electric field of an overhead line can be represented as

$$E_e = \frac{1}{2}CV^2 \tag{4.64}$$

At a similar way, the energy stored in the magnetic field is:

$$E_m = \frac{1}{2}LI^2 \tag{4.65}$$

At the threshold condition of having electric energy equal to the magnetic energy stored in both fields, that is as if $E_e = E_m$, it results from the equations above (neglecting resistance):

$$\frac{V}{I} = \sqrt{\frac{L}{C}} = Z_0 \tag{4.66}$$

The ratio above has dimensions of an impedance and is called surge impedance of the line. It can further be deduced

$$Z_0 = \sqrt{\frac{L}{C}} = \sqrt{X_L X_C} \tag{4.67}$$

The surge impedance of a transmission line is also called the characteristic impedance with resistance set equal to zero (i.e., R is assumed small compared with the inductive reactance

The power which flows in a lossless transmission line terminated in a resistive load equal to line's surge impedance is denoted as the surge impedance loading (SIL) of the line, being also called natural power.

Under these conditions, the sending end voltage E_S leads the receiving end voltage E_R by an angle δ corresponding to the travel time of the line.

For a three-phase line:

$$SIL = \frac{V_{\varphi\varphi}^2}{Z_c} \tag{4.68}$$

Where $V_{\varphi\varphi}$ is the phase-to-phase voltage and Z_c is the surge impedance of the line.

Since Z_c has no reactive component, there is no reactive power in the line,

$Q_l + Q_c = 0$. This indicates that for SIL the reactive losses in the line inductance are exactly offset by the reactive power supplied by the shunt capacitance, or

$$I^2\omega L = V^2\omega C \tag{4.69}$$

SIL is a useful measure of transmission line capability even for practical lines with resistance, as it indicates a loading when the line reactive requirements are small. For power transfer significantly above SIL, shunt capacitors may be needed to minimize voltage drop along the line, while for transfer significantly below SIL, shunt reactors may be needed.

Table 4.3 Surge Impedance Loading of Typical Overhead Lines (MW)

N° of Conductors per phase bundle	Z_0 (Ω)	Operating voltages (kV)					
kV		**69**	**138**	**230**	**345**	**500**	**765**
1	**400**	12	48	132	298		
2	**320**		60	165	372	781	
3	**280**					893	
4	**240**					1042	2438
6	**162**					1550	3613

4.2.1 Methods for Increasing SIL of Overhead Lines

An effort that has been made by electric industry nowadays has been directed toward the goal of increasing the SIL of the overhead lines, especially considering the growing difficulties to acquire rights of way for new lines. For increasing the Surge Impedance Loading of an overhead line, the following ways are possible

- Voltage increase
- Reduction of Z_0 through one of the measures:
  - Reducing phase spacing (compaction)
  - Increasing number of conductors per phase bundle
  - Increasing conductor diameter
  - Increasing bundle radius
  - Introducing bundle expansion along the span but keeping the conventional bundle spacing inside and near the tower.

Table 4.3 shows the surge impedance loading of typical overhead lines.

Table 4.3 is only illustrative of loading limits and is useful as an estimating tool. Long lines tend to be stability-limited and give a lower loading limit than shorter lines which tend to be voltage-drop or thermally (conductor ampacity)-limited.

4.2.2 Compact Lines

When compacted a Transmission line, the surge impedance loading can be increased. Compaction, in this case, consists of arranging the tower top geometry so that the phases are as close as possible together. As defined by equations below, the SIL reflects the interaction between line parameters, as follows:

$$SIL = \frac{V^2}{Z_1} \tag{4.70}$$

$$Z_1 = Z_s - Z_m \tag{4.71}$$

where:

SIL = Surge Impedance Loading (MW)

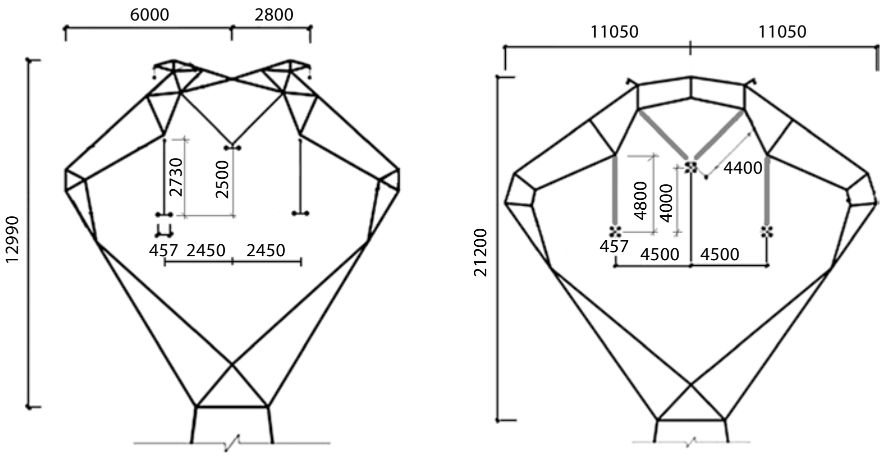


Figure 4.14 Compact Racket Tower 230 kV (left) and Compact Racket Tower 500 kV (right).

V = Operation voltage (kV)
Z_1 = Positive sequence impedance (Ω)
Z_s = Self impedance (Ω)
Z_m = Mutual impedance (Ω).

The use of compact lines is one of the most effective methods for obtaining lines with higher surge impedance loading or natural power figures. Reference (Fernandes et al. 2008) shows interesting examples of 500 kV and 230 kV lines adopted by a Utility in Brazil for having their first conventional self-supporting flat-configuration towers which generated High SIL ratings. It was designed in the beginning of the 1980's, but later a more recent development of compact lines was introduced into their system. The big aim of the engineering team consisted in reducing the required series compensation, by means of a high SIL of the lines. This represented a valuable new tool for optimizing the new planned transmission systems

As a first real gain, the use of the compaction technology, associated with the installation of series capacitor banks, could preclude for the transmission of 5000 MW the construction of two additional 500 kV – 800 km long each one – transmission circuits; the adequate use of this technology could simultaneously increase the energy transmission rate through the same corridor (MW/m^2) and improve the effectiveness of the costs associated thereof (MW/US$).

Consequently, the compaction results in an increase of the coupling between phase conductors, so increasing the mutual impedance Z_m and reducing the positive sequence impedance Z_1, causing a net increase in the SIL of the line. Such technology can provide a maximum increase of around 20 to 25% in SIL, as a function of some limiting factors as: minimum viable phase spacing able to guarantee adequate insulation coordination, asynchronous swing angles between phase conductors, appropriate limitation of conductor surface gradient. Figure 4.14 shows a compact racket tower for 230 and 500 kV and Figure 4.15 shows a compact cross-rope tower.

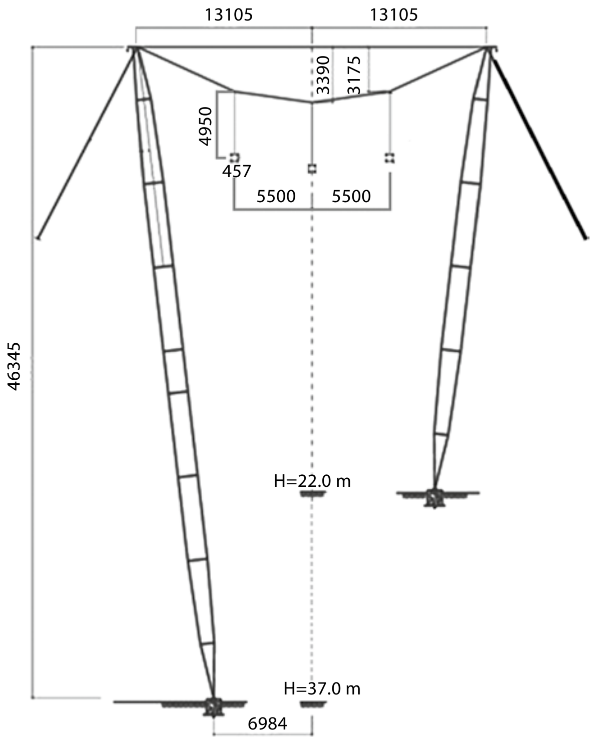


Figure 4.15 Compact Cross-rope Tower 500 kV.

4.2.3 Bundle Expansion

This technique consists in designing the bundle radius R with higher value than normal use. With that, the self impedance Z_p is reduced therefore decreasing Z_1 and increasing the SIL. Similar effect is obtained by increasing the number of subconductors in the bundle, for the same total phase aluminum area.

4.3 Stability

A power system made up of interconnected dynamic elements may be said to have stability if it will remain in stable operation following a system disturbance.

- Steady-state stability is associated with small perturbations such as slow variation on loads or generation. It depends fundamentally on the state of the system, and on the operating conditions at the instant of the perturbation.
- Transient stability is associated with great perturbations (periodic disturbances), such as line faults, loss of a generating unit, sudden application of a big load, fault in equipment.

It strongly depends on the magnitude and size of the perturbation and less on the initial state of the system.

The stability limit is defined as:

$$P = \frac{V_1 V_2}{X_L} \sin \delta \tag{4.72}$$

Where P is the power in MW, V_1 and V_2 are the voltages at sending end and receiving end terminals respectively; δ is the power angle of stability (between V_1 and V_2).

As far as dynamic stability is concerned the power angle δ is limited to the range 30-45°, depending on the system, for the case of a generator connected to an infinite bus, instead of a theoretical higher value near 90°, to allow stability to be kept following power oscillations resulting from perturbations.

The reduction of the series reactance X_L is therefore considered by planning engineers as a convenient alternative to increase the power transmitted by the line.

4.4 Thermal Limit and Voltage Drop

- As the conductor temperature increases, the following effects take place:
  - The ohmic resistance and therefore the losses increase.
  - The sags increase, reducing conductor-to-ground clearances or, conversely, requiring higher towers.
  - As there is an increase in rating with the increase in conductor temperature, a convenient and economic templating temperature should be chosen for every line.
  - As the conductor temperature reaches values higher than 90 °C (except for HTLS conductor), there is a loss of its mechanical strength. The mechanical strength reduction is cumulative with time and can cause sag increase and the consequent reduction of conductor to ground clearances; due to safety reasons a maximum value of 10% reduction in conductor UTS is usually accepted along the line life.

Design temperature of a conductor is defined as the highest steady-state temperature it can undergo under the worst (from a cooling viewpoint) meteorological conditions (temperature, wind, solar radiation) and current. Regarding to the determination of weather parameters for use in the case of deterministic ratings, see (Cigré TB 299).

It is usually a deterministic value. However, the determination of probabilistic ratings is becoming more and more usual, as often significant savings can be achieved. For more details, see (Stephen 1996) and also Chapter 7.

The actual recommended highest conductor (non HTLS) temperatures for line design and spotting are 75 to 85 °C for steady-state operation and 100 to 150 °C (HTLS conductors excluded) for emergency operation. The line should be spotted considering such temperatures and the relevant clearances to prevent the occurrence of safety problems.

It should be observed that new conductors (HTLS) recently developed or under development stage can be operated continuously at temperatures until 150 °C to 200 °C or even more.

Table 4.4 Example of Maximum Current Ratings (A) of Some ACSR Conductors and Bundles used in Overhead Lines

Conditions		Steady – State				Emergency
Conductor		Winter		Summer		Summer
N × Section (mm^2)	Code	Day	Night	Day	Night	Day
170/28	Linnet	505	570	400	495	660
242/40	Hawk	625	715	490	620	825
322/52	Grosbeak	803	892	644	775	1055
403/29	Tern	840	965	647	840	1100
564/40	Bluejay	1030	1200	780	1045	1370
2 × 403/29	Tern	1680	1930	1290	1680	2200
483/34	Rail	957	1100	737	959	1275
2 × 483/34	Rail	1910	2200	1470	1915	2550
3 × 483/34	Rail	2870	3300	2210	2975	3825
4 × 483/34	Rail	3820	4400	2940	3830	5100
3 × 564/40	Bluejay	3090	3600	2340	3130	4100

Parameters adopted in Table above:
• Ambient temperature: winter: 20 °C
summer: 30 °C
• Wind speed: 1,0 m/s
• Latitude: 20°
• Solar radiation: winter: Day → 800 W/m^2 Night → 0 W/m^2
summer: Day → 1000 W/m^2 Night → 0 W/m^2 Conductor temperature: steady-state: 60 °C (current indicated above) emergency: 100 °C (emergency current above)

Table 4.4 shows an example of thermal limits adopted by some utilities, for steady-state and emergency conditions in lines using ACSR conductors of more widespread use.

Parameters adopted in table above:

- Ambient temperature: winter: 25 °C
  summer: 30 °C
- Wind speed: 0.61 m/s
- Latitude: 20 °C
- Solar radiation: winter: 800 W/m^2
  summer: 1000 W/m^2
- Conductor temperature: steady-state: 60 °C
  emergency: 100 °C

- Voltage drop: Radial lines, especially medium and long lines, up-to 138 kV have often their maximum transmitted powers limited by voltage drop or regulation.
  The highest limit practically recommended for the line voltage regulation is around 10% for medium voltage lines and around 5% for EHV lines (230 kV and above). Shunt reactive compensation (capacitors or reactors depending on the SIL) are frequently required to reduce the voltage drop in certain cases.

4.5 Capability of a Line

It is the degree of power that can be transmitted by a line as a function of its length, considering the limitations imposed by voltage drop, stability and conductor temperature, as well as limitations inherent to substation terminal equipment, such as circuit-breakers, current transformers etc.

The main factors determining the line capability in EHV lines are shown on Table 4.5.

4.6 Reactive Power Compensation

There are two basic types of compensation required by an electric system as a consequence of the reactive power requirements, namely:

- Series Compensation, made up of capacitor banks connected in series with the line, offsetting part of the inductive reactance (reduction of electrical length). This compensation may be of fixed or variable value. Its main advantages are following:
  - It improves the steady-state and transient stability
  - It allows a more economical power loading
  - It reduces the voltage drop
  - If a variable type of compensation is used it can be utilized to improve the load distribution between circuits.

When using series compensation, especial attention should be given to other factors affecting technically and economically the system such as, capacitor protection, line protection and sub-synchronous resonance.

- Shunt compensation

The main shunt compensation schemes used in electric systems are:
  - Reactors, for long EHV lines for compensating line capacitive powers in hours of light load (Ferranti Effect)
  - line connected reactors for line energization
  - Capacitors, for voltage control and power factor correction during hours of higher demand load
  - Synchronous condensers (rarely used nowadays) that can perform the both functions of reactors or of capacitors, depending on the instantaneous system needs.
  - Static compensators that perform the same function of the above synchronous condensers, but have no moving parts.

Table 4.5 Determinant factors on EHV line capability

Line Length (km)	Governing condition
0-80	Thermal limit
80-320	Voltage drop
> 320	Stability

4.7 Electromagnetic Unbalance - Transposition

Transpositions are made for the purpose of reducing the electrostatic and electromagnetic unbalance among the phases which can result in unequal phase voltages for long lines.

Untransposed lines can cause/increase in the following undesirable effects:

- Inductive interference with paralleling wire communication lines.
- Negative sequence currents that heat generator rotors.
- Zero sequence currents that can cause erroneous operation of protection relays.

For carrying out physically the phase transposition of the conductors, some alternatives can be used such as making them in intermediate substations or near dead-end towers through especial conductor and insulator string arrangements or through the utilization of special structures that allow changing phase positions by keeping the necessary clearances to the towers and to earth.

Instead of performing phase transpositions, it is possible to adopt alternatives that preclude them, such as:

- Use of delta or triangular phase configurations
- In rare cases.

4.8 Losses

The following types of losses have to be considered in overhead transmission lines.

4.8.1 Losses by Joule Heating Effect (RI^2) in the Conductors

Those are the main losses that occur in the overhead conductors and their correct selection and design are decisive for obtaining an economical line. Losses should be seen as wastefull as they represent consumption of fuels or lowering of water reservoirs without the corresponding generation of useful work.

The power RI^2 spent in the conductors and joints reduce the efficiency of the electric system and its ability to supply new loads while the heat $RI^2\Delta t$ represents burnt fuel or loss of useful water.

4.8.2 Dielectric Losses: Corona Losses, Insulator and Hardware Losses

By careful design and specifications of single or bundle conductors and accessories, maximum conductor gradients may be limited so as to generate minimum Corona losses under fair and foul weather conditions. Similarly a careful design of accessories and insulators can reduce to negligible values the amount of leakage currents and the resulting losses.

4.8.3 Losses by Induced Currents

The shield wires of the line are metallic conductors subjected to induced currents by the line conductors and therefore producing losses. There are usually three alternatives for reducing the shield wire losses, consisting basically in insulating them from the towers so that only negligible currents can circulate through them:

- By insulating sections of the shield wires in the towers and just earthing an intermediate point
- By totally Insulating the shield wires in the towers, i.e. not grounding them in any point.

Certain utilities have shown that the shield wire insulation has sometimes caused flashovers along the respective insulator, this is usually an insulator with a low flashover capability as it must offer a free conductive path for lightning stroke currents. The current continues to flow in the shield wire until line is opened.

So, in the case the Utility decides to evaluate the economic feasibility of insulating the shield wires for reducing line losses, a compromise must be found between the savings in losses and the additional cost of insulating and maintaining the shield wires and insulators.

4.9 Reliability and Availability

Consideration of the two important aspects of continuity and quality of supply, together with other relevant elements in the planning, design, control, operation and maintenance of an electric power system network, is usually designated as reliability assessment.

Generally the past performance of a system is calculated according to some performance indices.

SAIFI-System Average Interruption Frequency Index; SAIDI-System Average Interruption Duration Index.

For the transmission lines, the unavailability is measured in terms of hours per year or percent of time while the lines have been out.

Two considerations are more usual, namely:

- Mechanical Unavailability of the weakest component (towers), equal to the inverse of twice the Return Period of the Design Wind Velocity, as per Reference (Nolasco et al. 2002). The unavailability of all other components together usually doesn't exceed 25% of the one for the towers.
- Electrical Unavailability, considered equal to the unsuccessful reclosing operation when a lightning flashover occurs. Generally 65 to 70% of the reclosing operations are successful. Such faults are usually caused by lightning strokes that reach the conductors, towers or shield wires. An index that is generally used for measuring an overhead line. Bush firing may create a similar problem.

- Performance in the last case is the number of outages/100 km/year. The time used for line maintenance (not live) is also part of the index.
- Additionally adverse weather conditions can add about for instance 0.3 events per year with an average duration below 10 hours in general.

4.10 Overvoltages

The AC system overvoltages stresses are the input of the insulation coordination study for the design of clearances and of the insulator string of transmission line.

The overvoltages can be classified as:

- Sustained voltages: continued power frequency voltages originated from system operation under normal conditions; and temporary sustained overvoltages originating from switching operations such as load rejection, energization and resonance conditions.
- Slow front overvoltages (switching surges): due to faults and switching operations
- Fast front overvoltages: originated mainly from lightning strikes or certain types of switching
- Very fast front overvoltages: mainly related with gas insulated substation equipment switching.

4.10.1 Fast-front Overvoltages (Lightning Overvoltages)

An important aspect to be considered in overhead transmission lines is their lightning performance.

Usually, the lightning performance criterion to be considered in the project of a line or in the performance evaluation of an existing line is the maximum number of flashovers, due to lightning, that can occur in the line per 100 km per year.

As the transmission line nominal voltage increases, the overvoltages generated by lightning becomes less important to the specification of its insulation. This is due to the increase in importance of other overvoltages such as switching surges.

Examples of lightning performance of real lines are shown on the Table 4.6. As expected, the flashover rate caused by lightning is greater for lines with the lower nominal voltages.

Lightning strokes to ground near a line or directly on it (on its conductors, towers or ground wires) can generate high over-voltages that cause flashover in their insulation and, consequently, the outage of the line.

Even though it is not the objective of the present item the detailed discussion of lightning phenomenon and the results of studies and researches developed to understand its various aspects (that can be found in Cigré TB 549, 2013), a summary of its most important parameters to the design of an overhead transmission line is presented.

To evaluate the lightning performance of transmission lines it is necessary to considerer many additional aspects, primarily those related to the attachment

Table 4.6 Examples of transmission line lightning performance (Anderson, 1975)

Nominal Voltage (kV)	Lightning performance (Flashovers/100 km-Year)
11-22	20.3
42	21.9
88	11.9
132	5.0
275	1.9
400	0.6
500	0.5
765	0.3

process of lightning channel to them, the electromagnetic surges generated in the line when impulse currents are injected on them and the overvoltages withstand by their insulation.

4.10.1.1 Lightning Discharge Parameters

The primary lightning parameters are described, in Cigré TB 549, and is summarized here to emphasize the primary aspects relevant to a usual transmission line design (Cigré TB 549).

Lightning can be defined as a transient, high-current (typically tens of kA) electric discharge in air whose length is measured in kilometers. The lightning discharge in its entirety, whether it strikes ground or not, is usually termed a "lightning flash" or just a "flash." A lightning discharge that involves an object on ground or in the atmosphere is sometimes referred to as a "lightning strike". The terms "stroke" or "component stroke" apply only to components of cloud-to-ground discharges. Most lightning flashes are composed of multiple strokes. All strokes other than the "first" are referred to as "subsequent" strokes.

Each lightning stroke is composed of a downward-moving process, termed a "leader", and an upward-moving process, termed a "return stroke". The leader creates a conducting path between the cloud charge source region and ground and distributes electric charge from the cloud source along this path, and the return stroke traverses that path moving from ground toward the cloud charge source and neutralizes the leader charge. Thus, both leader and return stroke processes serve to effectively transport electric charge of the same polarity (positive or negative) from the cloud to ground.

The kA-scale impulsive component of the current in a return stroke is often followed by a "continuing current" which has a magnitude of tens to hundreds of amperes and a duration up to hundreds of milliseconds. Continuing currents with duration in excess of 40 ms are traditionally termed "long continuing currents". These usually occur in subsequent strokes.

The global lightning flash rate is some tens to a hundred flashes per second or so. The majority of lightning flashes, about three-quarters, do not involve ground. These are termed cloud flashes (discharges) and sometimes are referred to as ICs. Cloud discharges include intra cloud, inter cloud, and cloud-to-air discharges.

Lightning discharges between cloud and earth are termed cloud-to-ground discharges and sometimes referred to as CGs. The latter constitute about 25% of global lightning activity.

From the observed polarity of the charge lowered to ground and the direction of propagation of the initial leader, four different types of lightning discharges between cloud and earth have been identified: (a) downward negative lightning (b) upward negative lightning (c) downward positive lightning, and (d) upward positive lightning. Downward flashes exhibit downward branching, while upward flashes are branched upward.

It is believed that downward negative lightning flashes (type a) account for about 90% or more of global cloud-to-ground lightning, and that 10% or less of cloud-to-ground discharges are downward positive lightning flashes (type c). Upward lightning discharges (types b and d) are thought to occur only from tall objects (higher than 100 m or so) or from objects of moderate height located on mountain tops.

As noted above, positive lightning discharges are relatively rare (less than 10% of global cloud-to-ground lightning activity). Positive lightning is typically more energetic and potentially more destructive than negative lightning.

Sometimes both positive and negative charges are transferred to ground during the same flash. Such flashes are referred to as bipolar. Bipolar lightning discharges are usually initiated from tall objects (are of-upward type). It appears that positive and negative charge sources in the cloud are tapped by different upward branches of the lightning channel. Downward bipolar lightning discharges do exist, but appear to be rare.

The ground flash density N_g(flashes/km^2/yr) is often viewed as the primary descriptor of lightning incidence. Ground flash density has been estimated from records of lightning flash counters (LFCs) and lightning locating systems (LLSs) and can potentially be estimated from records of satellite-based optical or radio-frequency radiation detectors. It is worth noting that satellite detectors cannot distinguish between cloud and ground discharges and, hence, in order to obtain N_g maps from satellite observations, a spatial distribution of the fraction of discharges to ground relative to the total number of lightning discharges is needed. IEEE Std 1410-2010 recommends, in the absence of ground-based measurements of N_g, to assume that N_g is equal to one-third of the total flash density (including both cloud and ground discharges) based on satellite observations (IEEE Standard 1410-2010).

If no measurements of the ground flash density N_g for the area in question are available, this parameter can be roughly estimated from the annual number of thunderstorm days T_d, also called the keraunic level. Apparently the most reliable expression relating N_g and T_d is the one proposed by (Anderson et al. 1984):

$$N_g = 0.04 T_d^{1.25} \tag{4.73}$$

Another characteristic of lightning activity that can be used for the estimation of N_g is the annual number of thunderstorm hours T_H. The relation between N_g and T_H proposed by (MacGorman et al. 1984) is:

$$N_g = 0.054 T_h^{1.1} \tag{4.74}$$

A typical negative cloud-to-ground flash is composed of 3 to 5 strokes (leader/return stroke sequences), with the geometric mean inter-stroke interval being about 60 ms. Occasionally, two leader/return stroke sequences occur in the same lightning channel with a time interval between them as short as 1 ms or less.

The observed percentage of single-stroke flashes, based on accurate-stroke-count studies is about 20% or less, which is considerably lower than 45% presently recommended by Cigré.

First-stroke current peaks are typically a factor of 2 to 3 larger than subsequent-stroke current peaks. However, about one third of cloud-to-ground flashes contain at least one subsequent stroke with electric field peak, and, by theory, current peak, greater than the first-stroke peak.

Traditional lightning parameters needed in engineering applications include lightning peak current, maximum current derivative, average current rate of rise, current rise time, current duration, charge transfer, and action integral (specific energy), all derivable from direct current measurements.

Essentially all national and international lightning protection standards (IEEE Standard 1410; IEEE Std 1243; IEC 62305), include a statistical distribution of peak currents for first strokes in negative lightning flashes (including single-stroke flashes). This distribution, which is one of the cornerstones of most lightning protection studies, is largely based on direct lightning current measurements conducted in Switzerland from 1963 to 1971 (Anderson and Eriksson 1980). The cumulative statistical distributions of lightning peak currents for negative first strokes, negative subsequent strokes and positive first strokes are presented in Figures 4.16, 4.17, and 4.18.

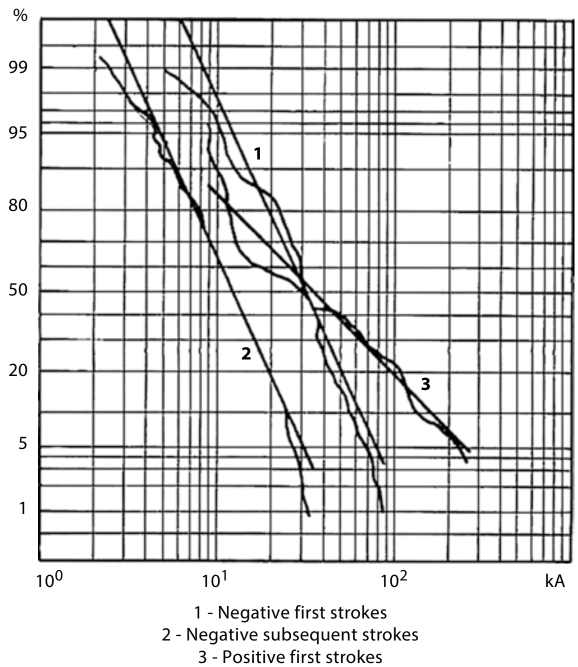


Figure 4.16 Cumulative statistical distributions of lightning peak currents, giving percent of cases exceeding abscissa value, from direct measurements in Switzerland.

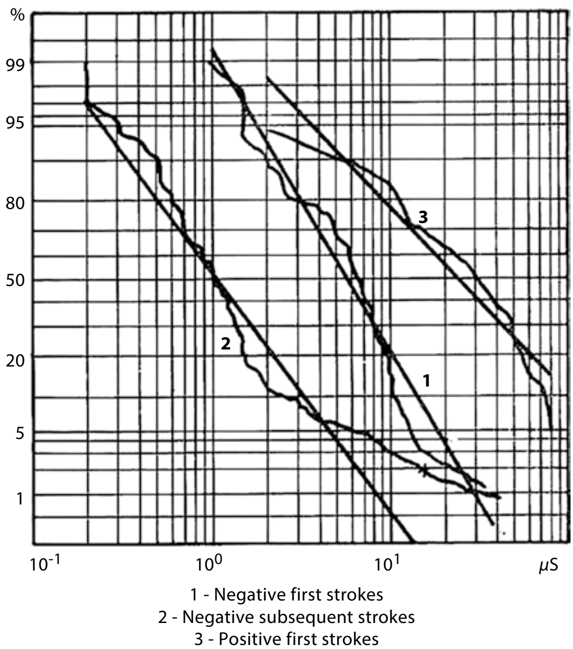


Figure 4.17 Cumulative statistical distributions of crest time, giving percent of cases exceeding abscissa value, from direct measurements in Switzerland.

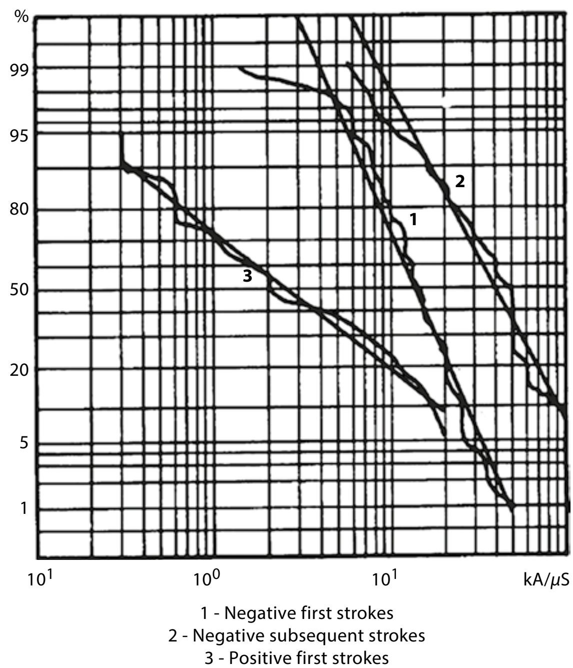


Figure 4.18 Cumulative statistical distributions of current rate of rise, giving percent of cases exceeding abscissa value, from direct measurements in Switzerland (Berger et al. 1975).

The distributions are assumed to be log-normal and give percent of cases exceeding abscissa value.

The log-normal probability density function for peak current I is given by:

$$f(I) = \frac{1}{\sqrt{2\pi}\beta\,\mathrm{I}} e^{-\left(z^2/2\right)} \tag{4.75}$$

Where:

$$z = \frac{\ln I - Mean(\ln I)}{\beta} \tag{4.76}$$

and $ln\ I$ is the natural logarithm of I, $Mean\ (ln\ I)$ is the mean value of $ln\ I$, and $\beta = \sigma_{lnI}$ is the standard deviation of $ln\ I$.

A log-normal distribution is completely described by two parameters, the median and logarithmic standard deviation of the variable. Logarithmic standard deviations of lightning peak currents are often given for base 10.

$$P(I) = \int_I^\infty \frac{1}{\sqrt{2\pi}\ \beta\lambda} e^{-\left(z^2/2\right)} d\lambda \tag{4.77}$$

Only a few percent of negative first strokes exceed 100 kA, while about 20% of positive strokes have been observed to do so. About 95% of negative first strokes are expected to exceed 14 kA, 50% exceed 30 kA, and 5% exceed 80 kA. The corresponding values for negative subsequent strokes are 4.6, 12, and 30 kA, and 4.6, 35, and 250 kA for positive strokes. Subsequent strokes are typically less severe in terms of peak current and therefore often neglected in lightning protection studies. Slightly more than 5% of lightning peak currents exceed 100 kA, when positive and negative first strokes are combined.

Berger's peak current distribution for negative first strokes shown in Figure 4.18 is based on about 100 direct current measurements. The minimum peak current value included in Berger's distributions is 2 kA.

In lightning protection standards, in order to increase the sample size, Berger's data are often supplemented by limited direct current measurements in South Africa and by less accurate indirect lightning current measurements obtained (in different countries) using magnetic links. There are two main distributions of lightning peak currents for negative first strokes adopted by lightning protection standards: the IEEE distribution (IEEE Standard 1410; IEEE Std 1243; Cigré WG 33-04). Both these "global distributions" are presented in Figure 4.19.

For the Cigré distribution, 98% of peak currents exceed 4 kA, 80% exceed 20 kA, and 5% exceed 90 kA.

For the IEEE distribution, the "probability to exceed" values are given by the following equation:

$$P(I) = \frac{1}{1 + \left(\frac{I}{31}\right)^{2.6}} \tag{4.78}$$

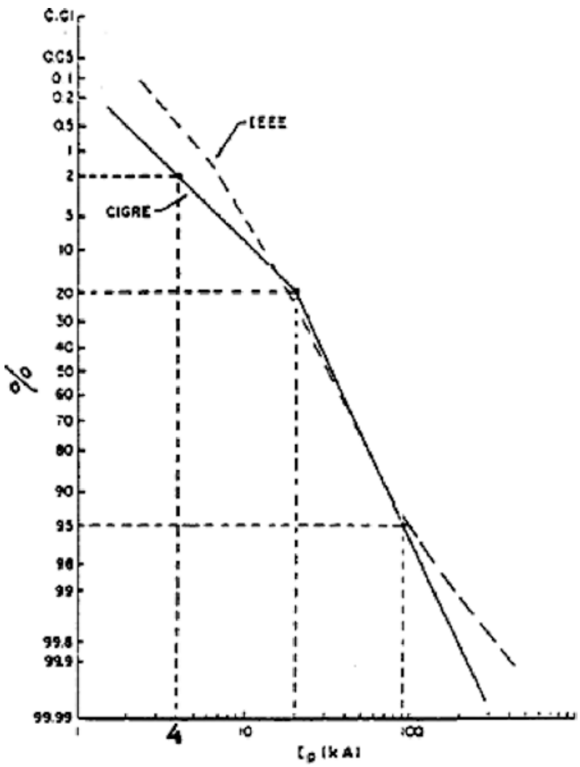


Figure 4.19 Cumulative statistical distributions of peak currents (percent values on the vertical axis should be subtracted from 100% to obtain the probability to exceed.

Table 4.7 Peak current distributions adopted by IEEE

Peak current, I, kA		5	10	20	40	60	80	100	200
Percentage exceeding tabulated value, P(t) 100%	First strokes	99	95	76	34	15	7.8	4.5	0.78
	Subsequent strokes	91	62	20	3.7	1.3	0.59	0.33	0.050

where *P(I)* is in per unit and *I* is in kA. This equation, usually assumed to be applicable to negative first strokes, is based on data for 624 strokes analyzed by (Popolansky 1972), whose sample included both positive and negative strokes, as well as strokes in the upward direction. This equation applies to values of *I* up to 200 kA. Values of *P(I)* for *I* varying from 5 to 200 kA, computed using the previous equation are given in Table 4.7. The median (50%) peak current value is equal to 31 kA.

In the range of 10 to 100 kA that is well supported by experimental data, the IEEE and Cigré distributions are very close to each other (IEEE Standard 1410).

The peak-current distribution for subsequent strokes adopted is given by:

$$P(I) = \frac{1}{1 + \left(\frac{I}{12}\right)^{2.7}} \tag{4.79}$$

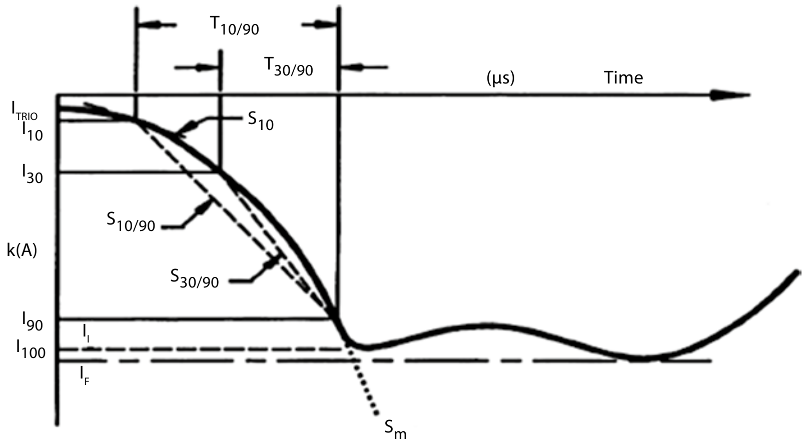


Figure 4.20 Description of lightning current waveform parameters. The waveform corresponds to the typical negative first return stroke. Adapted from Cigré TB 63 and IEEE Std 1410-2010.

Cigré recommends for negative subsequent stroke peak currents a log-normal distribution with the median of 12.3 kA and $\beta = 0.53$ (Cigré WG 33-04), which is also included in IEEE Std 1410–2010.

In Cigré TB 549, it is discussed what it called "global" distribution of peak current found in most lightning protection standards. Concern is expressed about using imprecise or not homogeneous data (lumped or not in a single sample with data considered more reliable). In this document, recent distributions of lightning peak currents obtained from many individual studies are presented and compared.

A representative double-peaked current waveform of negative first strokes is presented in Figure 4.20, with the definition of its front parameters.

Table 4.8 are lists the values of the lightning current parameters of Figure 4.20 recommended by Cigré and IEEE.

4.10.1.2 Equivalent Impedance of the Lightning Channel

Lightning-channel impedance is an important parameter that can influence the current injected into the object subjected to a strike.

Direct-strike Effects

Lightning is approximated by a Norton equivalent circuit. This representation includes an ideal current source equal to the lightning current that would be injected into the ground if that ground were perfectly conducting (a short-circuit current, I_{sc}) in parallel with a lightning-channel impedance Z_{ch} assumed to be constant. In the case when the strike object can be represented by lumped grounding impedance, Z_{gr}, this impedance is a load connected in parallel with the lightning Norton equivalent (Figure 4.21). Thus, the "short-circuit" lightning current Isc effectively splits between Z_{gr} and Z_{ch} so that the current flowing from the lightning-channel base into the

Table 4.8 Lightning current parameters (based on Berger's data) recommended by Cigré and IEEE

Parameter	Description
I_{10}	10% intercept along the stroke current waveshape
I_{30}	30% intercept along the stroke current waveshape
I_{90}	90% intercept along the stroke current waveshape
$I_{100}=I_I$	Initial peak of current
I_F	Final (global) peak of current (same as peak current without an adjective)
$T_{10/90}$	Time between I_{10} and I_{90} intercepts on the wavefront
$T_{30/90}$	Time between I_{30} and I_{90} intercepts on the wavefront
S_{10}	Instantaneous rate-of-rise of current at I_{10}
$S_{10/90}$	Average steepness (through I_{10} and I_{90} intercepts)
$S_{30/90}$	Average steepness (through I_{30} and I_{90} intercepts)
S_m	Maximum rate-of-rise of current along wavefront, typically at I_{90}
$t_{d\ 10/90}$	Equivalent linear wavefront duration derived from $I_F/S_{10/90}$
$t_{d\ 30/90}$	Equivalent linear wavefront duration derived from $I_F/S_{30/90}$
T_m	Equivalent linear waveform duration derived from I_F/S_m
Q_I	Impulse charge (time integral of current)

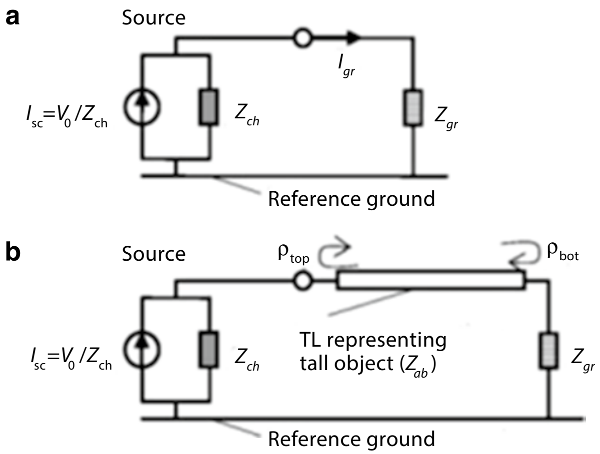


Figure 4.21 Engineering models of lightning strikes (**a**) to lumped grounding impedance and (**b**) to a tall grounded object.

ground is found as $I_{gr}=I_{sc}\,Z_{ch}/(Z_{ch}+Z_{gr})$. Both source characteristics, I_{sc} and Z_{ch}, vary from stroke to stroke, and Z_{ch} is a function of channel current, the latter nonlinearity being in violation of the linearity requirement necessary for obtaining the Norton equivalent circuit. Nevertheless, Z_{ch}, which is usually referred to as equivalent impedance of the lightning channel, is assumed to be constant.

Lightning-Induced Effects

In studying lightning-induced effects, the distribution of current along the lightning channel is needed for computing electric and magnetic fields (Baba and Rakov).

Equivalent Impedance

The limited estimates of the equivalent impedance of lightning channel from experimental data suggest values ranging from several hundred Ω to a few kΩ.

4.10.1.3 Protection of Power Transmission Lines - Concepts

Lightning strokes can cause insulation flashover when they strike the conductors, ground wires or even the soil nearby the transmission lines.

- Flashover caused by Induced surges.

Lightning striking to soil nearby a transmission line can induce surge overvoltages on it. Most measurements of induced voltage have been less than 300 kV.

This level of overvoltage can cause flashover in medium voltage lines, but usually is not a concern to high voltage transmission line.

- Flashover caused by direct strokes to conductors.

When a lightning strikes a conductor of a transmission line, a high impulse overvoltage is developed between the conductor and tower (in the insulator strings or air gaps), the conductor and other phase conductors or the conductor and ground. These impulse overvoltages can cause flashover in the line. As the insulation strings are, usually, the elements with the lowest impulse insulation level, they are the element with the greatest probability of occurrence of flashover.

The peak of the impulse overvoltage generated by a direct stroke in a conductor with a surge impedance Z can be estimated, approximately, by:

$$V_{surge} \cong \frac{Z\,I_{peak}}{2} \tag{4.80}$$

where I_{peak} is the peak current of stroke.

Considering a surge impedance Z of 400 Ω, it is easy to see that even a low discharge current of 10 kA can generate very high overvoltages in the conductor (2 MV).

So, when a line with high performance is desired, it is necessary to provide some protection to reduce the probability of direct strokes to the conductors that exceed the insulation level of the line.

- Flashover caused by direct strokes to shield wire or tower.

Even installing ground wires in a line, they cannot eliminate the probability of flashover in the line caused by lightning.

High impulse overvoltage can still be generated, especially in the presence of a large peak current.

Related to the lightning stroke hitting the ground wires, as the impulse impedance seen from the point of incidence of the stroke is not low (it is depends on the surge impedance of various elements: ground wires, tower, grounding system, length of span, etc.), the ground wires voltage can reach very high values. The tower top voltage rises too.

Then, consequently, the insulation of the line is stressed by the large voltage generated between the tower or ground wires and the conductors. If this voltage is high enough, a flashover can occur. This flashover is called back flashover, as it tends to occur from the grounded elements (tower or ground wire) to the energized phase conductors.

Induced Surges

Induced surge by nearby lightning discharge is not a concern to high voltage transmission lines.

In medium voltage lines, some measures can be implemented to improve the performance of the line in respect to flashover caused by nearby strokes.

Direct Strokes to Conductors

Lightning strokes, with relatively high peak currents, directly to phase conductors can generate very high overvoltages on them, which can cause a line outage in case of flashover.

To reduce the probability of occurrence of such high overvoltages, the most common measure is to install shield wires on the lines. Other measure is the installation of surge arresters. In respect to the installation of shield wires, in a specific line, it is necessary to make a shielding analysis to determine the number and the position relative to the phase conductors.

In both (Cigré WG 33-04) and (IEEE Std 1243), the so-called electro-geometric model (EGM) is employed.

The basic concepts involved in this model will be explained using Figure 4.22.

Several researchers have contributed to the electro geometric model (EGM). As the downward leader approaches the earth, a point of discrimination is reached for a final leader step. The EGM portrays this concept with the use of striking distances.

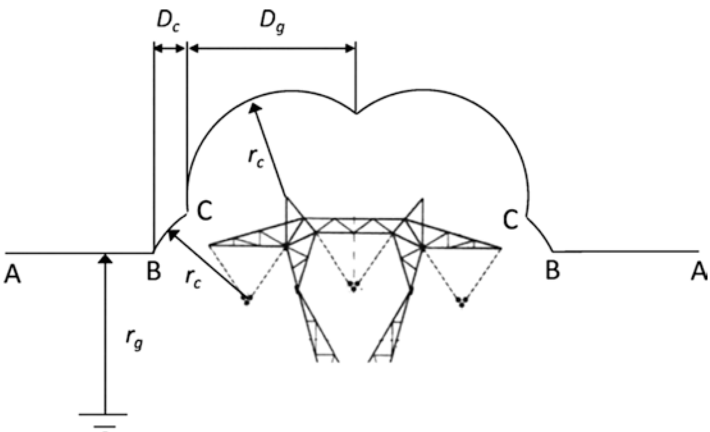


Figure 4.22 Electrogeometric model representation of conductors and ground wires.

The striking distance is of the form

$$r_{c,g} = AI^b \tag{4.81}$$

Where A and b are constants that depend on the object and I is the stroke current.

Local electric field gradients around conductors are somewhat higher than at ground level, so r_c is usually considered to be greater than r_g (the striking distance to ground), resulting in $r_c \geq r_g$. Arcs of circles with the radii r_c are drawn centered at the phase conductor and OHGW. A horizontal line is then drawn at a distance r_g from earth.

If a downward leader, having a prospective current I, for which the arcs were drawn, touches the arcs between B and C (Figure 4.22), the leader will strike the phase conductor. If the leader touches the arcs between B's, it will strike the shield wire. If all leaders are considered vertical, the exposure distance for a shielding failure is D_c.

Since the final jump length in the EGM depends on current, the statistics of the stroke-current distribution will be needed to compute the number of lightning strokes to phase conductors (that depend on D_c).

At present, the following striking distance equations are recommended by IEEE (IEEE Std 1243):

$$r_c = 10I^{0.65} \tag{4.82}$$

$$r_g = \begin{cases} \left[3.6 + 1.7\ln\left(43 - y_c\right)\right] I^{0.65} & y_c < 40m \\ 5.5I^{0.65} & y_c \geq 40m \end{cases} \tag{4.83}$$

where I is the stroke current (in kA) and y_c is the average conductor height, given by the height at the tower minus two-thirds of the sag.

Some researchers of EGM assume all striking distances are equal, while others consider different striking distances to phase conductors, shield wires, and earth. In addition, some researchers do not use a striking distance to earth. Estimates of striking distance sometimes differ by a factor of two. However, this uncertainty has not prevented the design and operation of lines with low lightning outage rates. In particular, when an engineering judgment is made to accept a low but non-zero shielding failure flashover rate (*SFFOR*), most models suggest similar shielding angles.

Figure 4.22 indicates an apparent possibility of perfect shielding: the possibility to install ground wires in a position that makes D_c null for lightning stroke currents greater than a minimal current necessary to cause flashover when it strikes directly the phase conductors (called critical current I_c).

Strokes to Shield Wire or Towers

High impulse overvoltage can be generated in a transmission line when high intensity lightning strikes its ground wires or towers. If the overvoltage stressing the insulation of the line is greater than the voltage that it can withstand, a flashover occurs (in this case, called back-flashover).

To reduce the probability of occurrence of back flashover to an acceptable level, in the design of a transmission line, one important aspect to be considered is the appropriate design of structure grounding systems. It should be considered the necessary value of resistance to achieve the desired lightning performance of the line, but also the fact that the transient response of grounding system cannot be expressed only by its resistance to low frequency and low amplitude currents. For example, a long counterpoise cable can have relatively low resistance to industrial frequency currents, but high impulse impedance (as will be discussed latter. Usually, a number of parallel cables is better than a long counterpoise.

In areas of large flash density and high electrical resistivity of soil, sometimes it is necessary to reduce the resistance to a level that is not possible technically or economically. In these cases, one of the most efficient measures is the installation of surge arresters in the line.

To identify which measures needed to be implemented, it is necessary to evaluate the lightning performance of the line with and without those measures, even if some approximation should be done. The evaluation of lightning performance of transmission lines is then discussed.

4.10.1.4 Evaluating the Lightning Performance of a Power Transmission Line

To estimate the lightning performance of OHTL the following primary aspects should be considered (information also in 4.10.1.1):

- Ground flash density along the line
- Lightning current parameters (primarily its peak distribution)
- Lightning stroke to the transmission line and to its individual components
- Estimate of insulation stress when lightning strikes the line
- Flashover strength of insulation to the over-voltage
- Estimate the rate of insulation flashover due to lightning striking directly the conductors (shielding flashover) or due to backflashover phenomenon (lighting strokes to ground wires or towers).

In terms of calculation, the fourth aspect in the above list is the most complex, because it involves the estimation of the transient response of relative complex elements that are interconnected: conductors and ground wires (depending on the current front of wave), towers and grounding systems. Usually, many simplifications are done to reduce the complexity of calculation and enable the use of simple computational routines in the lightning performance calculation.

Knowing the current that can reach a component of the line, the comparison of the results of overvoltage stress with the flashover strength of insulation will indicate if the flashover will occur.

In the final the lightning performance of an overhead transmission line can be calculated. Basically, knowing the currents that can reach the line and cause a flashover and its probability of occurrence, it should be determined:

- the shielding failure flashover rate (relative to the lightning strokes directly to conductors);
- the back flashover rate (relative to the lightning strokes on the ground wires or towers);
- overall flashover rate (the sum of the two previous rates).

These rates usually are expressed as number of flashovers per 100 km of line per year.

Two proposed specific procedures for estimating the lighting performance of transmission lines are described in the documents (IEEE Std 1243; Cigré WG 33-04). In the following items the primary aspects involved in the estimation procedures of lightning performance of transmission lines, as recommended by IEEE and Cigré, are characterized, keeping in mind the practical design objective.

Ground Flash Density

The ground flash density N_g can be roughly estimated from the annual number of thunderstorm days T_D, by the equations shown in 4.10.1.1.

Lightning Current Parameter Considered

Anderson and Eriksson (1980) noted that the two sub-distributions (below and above 20 kA) can be viewed as corresponding to the shielding failure and back-flashover regimes, respectively. A single distribution, also shown in Figure 4.19, was adopted by IEEE guidelines consider a triangular (2 μs/50 μs) implemented in the software "Flash".

For the IEEE distribution, the "probability to exceed" value of peak currents from 2 kA to 200 kA are given by the following equation:

$$P(I) = \frac{1}{1 + \left(\frac{I}{31}\right)^{2.6}} \tag{4.84}$$

where *P(I)* is in per unit and *I* is in kA.

Cigré guidelines consider a concave front current as shown in Figure 4.20, with parameters listed in Tables 4.8 and 4.9.

The log-normal probability density function for peak current I is given by:

$$f(I) = \frac{1}{\sqrt{2\pi}\,\beta I} e^{-\left(z^2/2\right)} \tag{4.85}$$

The probability for peak current to exceed a specified value I is given by:

$$P(I) = \int_T^{\infty} \frac{1}{\sqrt{2\pi}\,\beta\lambda} e^{-\left(z^2/2\right)} \, d\lambda \tag{4.86}$$

Table 4.9 Lightning current parameters (based on Berger's data) recommended by Cigré and IEEE

Parameter	First stroke		Subsequent stroke	
	M, Median	β, logarithmic (base e) standard deviation	*M*, Median	β, logarithmic (base e) standard deviation
	Front time (μs)			
$t_{d10/90}=t_{10/90}/0.8$	5.63	0.576	0.75	0.921
$t_{d30/90}=t_{30/90}/0.6$	3.83	0.553	0.67	1.013
$t_m=I_F/S_m$	1.28	0.611	0.308	0.708
	Steepnes (kA/μs)			
S_m, Maximum	24.3	0.599	39.9	0.852
S_{10}, at 10%	2.6	0.921	18.9	1.404
$S_{10/90}$, 10-90%	5.0	0.645	15.4	0.944
	Peak (Crest) current (A)			
I_I, initial	27.7	0.461	11.8	0.530
I_F, final	31.1	0.484	12.3	0.530
Ratio, I_I/I_F	0.9	0.230	0.9	0.207
Other relevant parameters				
Tail time to half value t_h (μs)	77.5	0.577	30.2	0.933
Number of strokes per flash	1	0	2.4	0.96 based on median
				$N_{total}=3.4$
Stroke charge, Q_I (Coulomb)	4.65	0.882	0.938	0.882
$\int I^2 dt\left[(\text{kA})^2\,\text{s}\right]$	0.057	1.373	0.0055	1.366
Interstroke interval (ms)	–	–	35	1.066

Lightning to the Transmission Line

Number of Lightning Strokes that Hit the Line

IEEE guidelines use the same expression as Cigré to evaluate the number of lightning strokes the hits a transmission line:

$$N_l = \frac{N_g}{10}\left(28h^{0.6} + b\right) \tag{4.87}$$

where N_g is the ground flash density (flashes/km²/yr), h is the tower height (m) and b is the ground wires separation distance between (m).

Lightning Strokes that Hit the Phase Conductors

In IEEE and Cigré procedures, for a line with ground wires, the number of lightning strokes that hit directly the phase conductors are expressed as shielding failure rate (*SFFOR*), calculated by:

$$SFFOR = 2N_g L \int_{3}^{I_{max}} D_c(I)\ f(I)dI \tag{4.88}$$

where:

L = length of the line (km)
$Dc(I)$ = exposure length (m) relative to phase conductor, calculated in function of I
$f(I)$ = statistical distribution of I
I_{max} = maximum current (kA) that can hit the phase conductor (current that makes null the distance $Dc(I)$).

The lower limit, 3 kA, recognizes that there is a lower limit to the stroke current.

Strength of Insulation

To identify if a flashover will occur on an insulator string stressed by an overvoltage generated by a lightning stroke that hits a line, IEEE evaluate the voltage necessary to cause a flashover in an insulator string with the following equations:

$$V_D = \left(400 + \frac{710}{t^{0.75}}\right) l \quad \left(0.5\mu s \le t \le 16\mu s\right) \tag{4.89}$$

where V_D is the impulse flashover voltage in kV, t is the time to flashover in μs and l is the insulator string length in m.

For t greater than 16 μs, IEEE recommends the use of 490 kV/m as CFO of insulator strings.

Among other methods that could be used to evaluate the voltage necessary to cause a flashover in an insulator string (Cigré WG 33-04), Cigré recommends the use of a leader propagation model, where the leader propagation velocity is calculated by:

$$v(t) = K_L u(t)\left(\frac{u(t)}{d_g - l_l} - E_o\right) \tag{4.90}$$

where:

$v(t)$ = leader velocity (in m/s)
$u(t)$ = voltage applied to the insulator string (in kV)
E_o = electric field needed to begin the leader considered (kV/m)
d_g = length (in m) of insulator strings orair (at instance t = 0)
l_l = leader length (in m) at an instance t
K_L = constant.

For positive surges in air gaps or insulator strings, Cigré recommends the use of $E_o$as 600 kV/m and K_L as 0.8×10^{-6}. For negative surges, it is recommended E_o as 670 kV/m and K_L as 1×10^{-6}.

When voltage/time curve for standard 1.2/50 μs lightning impulse is known, the best fitting constants may also be determined by numerical calculations for selected combinations of flashover and time to breakdown.

Estimate the Rate of Insulation Flashover

SHIELDING FAILURE FLASHOVER RATE

Shielding failure occurs when a lightning stroke hits directly a phase conductor of a transmission line that has shield wires. When such failure results in flashover, ininsulator strings or in air gaps between conductor and metallic grounded components, it is said that a shielding failure flashover occurred.

According to IEEE, the minimal or critical current *Ic* required to cause a flashover can be calculated as follows:

$$I_c = \frac{2 \cdot CFO}{Z_{surge}} \tag{4.91}$$

$$Z_{surge} = 60\sqrt{\ln(2h/r)\ln(2h/R_c)} \tag{4.92}$$

where

Z_{surge} = conductor surge impedance under Corona (Ohms)
h = average conductor height (m)
r = conductor radius (m)
R_C = Corona radius of the conductor under a gradient of 1500 kV/m (m)
CFO = critical flashover voltage (kV), negative polarity, as defined in Item.

According to Cigré procedure, I_c can be calculated by a similar procedure or by one that considers a more precise transient response of the line (using a electromagnetic transients program, like EMTP-Electromagnetic Transients Program) and the same or other processes of line critical flashover voltage estimation, such as:

- insulation voltage/time curve;
- integration method;
- physical models representing the Corona phase, the streamer propagation
- phase and leader phases along the line insulation.

IEEE and Cigré estimate the shielding failure rate (number of lightning strokes directly to the phase conductors that cause flashover) as:

$$SFFOR = 2N_g \; L \int_{I_c}^{I_{\max}} D_c(I) \; f(I) \; dI \tag{4.93}$$

where

$SFFOR$ = shielding failure flashover rate (flashovers/100 km/yr)
L = length of the line (km)
$D_c(I)$ = exposure length (m) relative to phase conductor, calculated in function of I
$f(I)$ = statistical distribution of I
I_{max} = maximum current (kA) that can hit the phase conductor (current that makes null the distance $D_c(I)$

The probability that an individual subsequent stroke current I_s will exceed I_c is given approximately by:

$$P\left(I_c > I_s\right) = \frac{1}{1+\left(\frac{I_c}{I_{subs}}\right)^{2.7}} \tag{4.94}$$

where

I_{subs} is taken as 12 kA;
I_c is also taken in kA.

The following equation gives P_S, the probability of flashover on any subsequent stroke, given that no flashover occurs on the previous strokes:

$$P_s = \sum_{n=2}^{n=\infty} P_n\left(1-\left[P\left(I_s > I_c\right)\right]^{n-1}\right) \tag{4.95}$$

where P_n is the probability that there are n strokes/flash, from data in (Tompson 1980).

The total *SFFOR* will be the sum of the first stroke failure rate *SFFOR* and the added rate $SFFOR_S$ obtained from:

$$SFFOR_s = 2N_g \; LP_s \int_0^{I_c} D_c\left(I\right) \; f_1\left(I\right) \; dI \tag{4.96}$$

If the critical current I_c is low, most shielding failures will lead to flashover, either from the small first stroke or from the 60-70% chance that there will be a subsequent stroke that exceeds I_c. If the critical current is higher, P_S from will be lower ($P_S = 0.4$ for space I_c of 16 kA).

The extra contribution of subsequent stroke effects to total *SFFOR* ensures that perfect shielding (*SFFOR* = 0) will rarely be achieved. See next item.

As cited in the previous item, the estimation of shielding failure rate considering only the lighting first strokes (number of lighting first strokes directly to the phase conductors that cause flashover) as:

$$SFFOR = 2N_g \; L \int_{I_c}^{I_{\max}} D_c\left(I\right) \; f\left(I\right) \; dI \tag{4.97}$$

It indicates an apparent possibility of perfect shielding: a shielding angle that makes $I_{max} = I_c$ (maximum stroke current that can be injected directly to a phase conductor equal to the current necessary to generate an overvoltage in the phase conductor equal to the insulator withstand), but this can be rarely achieved as it can have a contribution of subsequent stroke effects to total *SFFOR*.

Considering only lightning first strokes, Cigré procedure presents the following equation to evaluate the shielding angle where $I_{max} = I_c$:

$$\alpha_p = 0.5\left[\sin^{-1}\left(\frac{r_g - h}{r_c}\right) + \sin^{-1}\left(\frac{r_g - y}{r_c}\right)\right] \tag{4.98}$$

where

r_g, r_c = calculated for the current Ic (m)
h = average height of ground wire (m)
y = average height of phase conductor (m)

An attempt to achieve a perfect shielding angle may severely handicap an economical design of lines in areas of low flash density ($N_g < 2$ flashes/km^2/yr). It is suggested to the designer evaluating the most economical configuration based on the *SFFOR* required. For example, serving a critical load, a design *SFFOR* value of 0.05 flashover/100 km/yr may be suitable, while values of 0.1-0.2 flashover/100 km/yr are recommended for general practice.

Rate of Insulation Flashover due to Backflashover

When a lightning strikes the tower or the overhead ground wire, the current in the tower and ground impedances cause the rise of the tower voltage. A considerable fraction of the tower and shield wire voltage is coupled by mutual surge impedance to the phase conductors. The tower and shield wire voltages are much larger than the phase conductor voltages. If a voltage difference from phase to tower exceeds a critical value, a flashover occurs, called "backflash" or "backflashover". The corresponding minimum lightning current that produces such a flashover is called "critical current".

The calculation of the critical current for back-flashover depends, in general order of sensitivity, on the following parameters:

- Amplitude of the lightning current (generally the peak value of the first return stroke);
- Flashover criteria for the insulation and air gaps;
- Presence of surge arresters across some or all insulators;
- Surge impedance coupling among phases and ground wires, evaluated using transmission line models and considering the additional coupling from arrester-protected insulators;
- Steepness (di/dt) at the peak of the current wave, which is generally assumed to be the maximum di/dt;
- Waveshape, including both time to peak and time to half-peak value
- Footing impedance, influenced by high frequency and soil ionization effects;
- Tower inductance or surge impedance model;
- Representation of nearby towers and grounding systems;
- Representation of nearby power system components (e.g. transformers).

Sometimes, the induction effects of the electromagnetic field of the lightning channel are additionally taken into account for the estimation of the insulator voltage. Induction effects related to current flow in the tower past the phase conductors have been observed and modeled in several ways.

The procedure adopted by Cigré for the calculation of the line backflashover rate (*BFR*), the same as described by (Aileman 1999), is specifically aimed at calculating the critical current and the resultant *BFR* value. In particular, the Cigré procedure analytically estimates the backflashover critical current by making reference to the representation of the travelling wave phenomena that take place for both cases of a lightning strike to a tower or to an overhead ground wire.

The *BFR* is given by the probability of exceeding the critical current multiplied by the number of flashes to the shield wires (N_L), taking into account that the crest voltage and the flashover voltage are both functions of the time-to-crest (t_f) of the lightning current. Therefore, the *BRF* considering all the possible time-to-crest values is:

$$BFR = 0.6\ N_l \int_0^{\infty} \int_{I_c(t_f)}^{\infty} f\left(\frac{1}{t_f}\right) f\left(t_f\right) dI\ \ dt_f \qquad (4.99)$$
$$\left(\text{flashovers}/100\,\text{km}/\text{yr}\right)$$

where $f(I/t_f)$ is the conditional probability density function of the stroke current given the time-to-crest and $f(t_f)$ is the probability function of the time-to-crest value. Note that, in order to obtain the *BFR* for strokes to the tower and for stroke to the spans, the *BFR* obtained for strokes to the tower is multiplied by a coefficient, equal to 0.6.

Another, more simplified procedure for the calculation of the *BFR*, is also presented in Cigré procedure as the *BFR* resulting from the application of previous equation using of an equivalent time-to-crest value *Te*. Such a value is approximately the median value of time to crest for the specific critical current. With such a value, since a single equivalent front is used, the *BFR* is reduced to:

$$BFR = 0.6 N_l \int_{I_c}^{\infty} f\left(I\right) dI = 0.6\ \ N_l\ \ P\left(I > I_c\right) \qquad (4.100)$$

In these equations, I_c is the minimum current that leads to insulator backflash in the phase conductor. To consider the system voltage at the striking time, this current can be calculated considering that such voltage is approximated 80% of the nominal voltage.

The approach adopted by the IEEE is based on the estimation of the voltage across the line insulation at two specific time instants namely: a first evaluation of the full impulse-voltage waveshape peak (at 2 μs) considering only the stricken tower, and a second evaluation on the tail (at 6 μs) considering relevant adjacent towers. In order to estimate the backflash critical current, these values are compared with an estimation of the volt-time curve of the line insulation.

The backflashover rate is computed according to the equation:

$$BFR = N_l \sum_{Nc}^{Nc} \left(t_1\ \ P_i\right) \qquad (4.101)$$

where N_C is the number of phase conductors and *ti* is the period of time in which each phase is dominant. This concept is related to the system voltage at the different phases when lightning strikes, as well as the different coupling factors between each phase and the shield wire. *Pi* is the probability of the lightning current exceeding a backflashover critical value. This is evaluated with respect to each phase, taking into account the phase shift between the sinusoidal voltages and the different coupling factors between each phase and the ground wire.

Note that the procedures to calculate both rates, *SFFOR* and *BFR*, are based on using the local ground flash density N_g to determine the number of strikes to the line.

To calculate the I_c, the minimum current that leads to insulator backflash in the phase conductor, it is necessary to calculate the overvoltage in the insulation of the line and compare with the withstand voltage. In the next items, the most important aspects involved in this calculation are discussed.

The Cigré and IEEE procedures are compared in (Nucci 2010). The main differences, when present, lie in the fact that some approaches/methods proposed so far within Cigré can be considered to be more general than those proposed within IEEE, in that they take into account more variables of the problem. Within the IEEE – thanks in part to the inherently simpler approach – a computer code, called FLASH, has been made available, which can serve either as a professional tool capable of providing an approximate, yet very useful, answer on the lightning performance of typical overhead transmission lines or as a reference for beginner researchers when simple cases are dealt with.

4.10.1.5 Estimate of Insulation Stress Generated by Lightning Strokes in the Line

To estimate the overvoltages generated in the insulation of a transmission line by lightning striking on its conductors, ground wires or towers, it is necessary to model the primary components that are responsible for the transient response of the line.

In the following items the primary aspects involved in such modeling are discussed. The presentation of all the equations involved in the calculation is beyond the scope of the present text.

Tower Surge Response Model

In the evaluation of voltages generated at the top of tower during a lightning discharge, it is necessary to consider the response of the tower to electromagnetic transients. Usually, the tower is modeled with distributed parameters, characterized by a surge impedance associated with an electromagnetic wave travel time. In Table 4.10 are listed equations that enable the evaluation of theses parameters for some self-supporting towers.

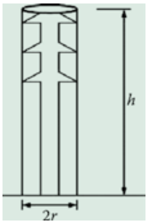
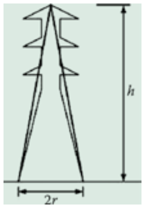
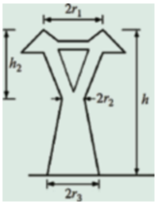
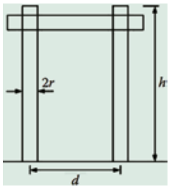
Common experience with practical structures yields typical values for tower surge impedances in the range 150-250 Ω.

For tower with guy wires, Cigré presents a simplified approach where the mutual coupling of guy-wires is not taken into account.

Basically, the process is:

- Evaluate the guy-wire surge impedance and travel time;
- Evaluate the equivalent inductance of all guy-wires;
- Evaluate the inductance parallel of guy-wires inductance with the tower inductance;
- Evaluate the equivalent surge impedance and travel time.

Table 4.10 Tower model (impedance and travel time) (IEEE Std 1243-1997)

Cylindrical	**Conical**
	
$Z = 60\left[\ln\left(\sqrt{2}\,\frac{2h}{r}\right) - 1\right]$ $\tau = \frac{h}{0.85c}$	$Z = 60\ \ln\left(\sqrt{2}\sqrt{\frac{h^2 + r^2}{r^2}}\right)$ $\tau = \frac{h}{0.85c}$
Waist	**H-Frame**
	
$Z = \sqrt{\frac{\pi}{4}}60\left[\ln\left(\cot\frac{tan^{-1}(r/h)}{2}\right) - \ln\sqrt{2}\right]$ $r = \frac{r_1 h_2 + r_2 h + r_3 (h - h_2)}{h}$ $\tau = \frac{h}{0.85c}$	$Z_1 = 60\left(\ln\left(2\sqrt{2}\,\frac{h}{r}\right) - 1\right)$ $Z_2 = \frac{60\ d\ \ln\left(2\frac{h}{r}\right) + h\ Z_1}{h + d}$ $Z = \frac{Z_1 Z_2}{Z_1 + Z_2}$ $\tau = \frac{1}{cZ}\,\frac{hZ_1 (d + h) Z_2}{hZ_1 + (d + h) Z_3}$

Note (1): For tower of conical type, IEEE uses h/(0.85.c) as travel time instead of h/c indicated by Cigré Document 63 (1991).

To evaluate the parameters cited the following equations can be used:

$$Z_{guy} = 60\left[\ln\left(2h/r\right)-1\right] \tag{4.102}$$

$$\tau_{guy} = l_{guy}/c \tag{4.103}$$

$$L_{guy} = L_{guy}\ \tau_{guy} \tag{4.104}$$

$$L_{equiv\_guy\_wires} = L_{guy}/n \tag{4.105}$$

where:

h = guy-wire height (m)
r = guy-wire radius (m)
l_{guy} = guy-wire length (m)
c = light velocity
n = number of parallel guy-wires
L_{guy} = inductance of a guy-wire (H)
$L_{equiv\_guy\text{-}wires}$ = inductance of n guy-wires (H).

Finally, for item (d), the following equations can be used:

$$L_{tower} = Z_{tower}\ \tau_{tower} \tag{4.106}$$

$$L_{equiv\_tower+guy\_wires} = \frac{L_{equiv\_guy\_wires}\ L_{tower}}{L_{equiv\_guy\_wires}+L_{tower}} \tag{4.107}$$

$$Z_{equiv\_tower+guy\_wires} = \frac{cL_{equiv\_tower+guy\_wires}}{H_T} \tag{4.108}$$

$$\tau_{equiv\_tower+guy\_wires} = H_T/c \tag{4.109}$$

where:

Z_{tower} = surge impedance of tower only (Ω)
τ_{tower} = travel time in the tower only (s)
L_{tower} = inductance of tower only (H)
H_T = tower height (m)
$L_{equiv\_tower+guy\text{-}wires}$ = inductance of the tower and guy wires (H).

It is important to note that several approaches have been presented in the recent literature addressing tower models.

Tower Footing Resistance

In the IEEE and Cigré procedures the tower grounding system behavior is characterized by a lumped resistance (the tower footing resistance).

In IEEE procedure this resistance is constant. In Cigré procedure, the effect of soil ionization is taken into account, using the following equation when the lightning current amplitude exceeds the critical value I_g:

$$R_i = \frac{R_0}{\sqrt{1 + \frac{I}{I_g}}} \tag{4.110}$$

where:

R_0 = is the low frequency non-ionized soil resistance;

I_g = is the critical value of the lightning current.

I_g = is estimated considering the soil ionization threshold field E_g, using the equation:

$$I_g = \frac{E_g\ \rho}{2\pi\ R_0^2} \tag{4.111}$$

Where:

ρ = is the electrical resistivity of the soil (Ω m)

E_g = is the soil ionization threshold field, considered to be, approximately, 400 kV/m for most common soils (Cigré TB 63, 1991).

In both evaluation procedures, of IEEE and Cigré, except the soil ionization, no reference is made explicit to the transient response of structure grounding systems or to the fact that the soil parameters vary with frequency.

Relative to these aspects, many researchers have been done. For example, the main factors that influence the grounding behavior have been analyzed in (Visacro and Alípio 2012), the current-dependent response of electrodes is addressed in (Sekioka et al. 2005) and the effect of the frequency-dependent soil parameters on this response is addressed in (Visacro and Alípio 2012).

Transmission Line Modeling

In both procedures, of IEEE and Cigré, the effects of occurrence of Corona in ground wires are considered.

The surge impedance of each conductor or ground wire and the mutual impedance between them are calculated considering as infinite the electrical conductivity of soil and the cables in their mean height.

In IEEE procedure the wave travel time in the phase conductors and ground wires is calculated considering an electromagnetic traveling wave velocity as 90% of velocity of light.

To evaluate the voltage on the top of a tower where a lightning strikes, usually it is not necessary to model more than three spans and towers on each side of the tower.

4.10.1.6 Improving Lightning Performance

As discussed in more details in IEEE Std 1243-1997, the following special methods, among others, can improve lightning performance of a line:

- Installation of additional ground wires under conductors:
  Basically used to increase the common-mode coupling of voltage surges on the ground wires to the phase conductors, and cause a reduction on the insulator voltage at the tower.
- Installation of guy wire on the towers:
  Fitting new or additional guy wires from tower to rock or soil anchors can reduce the tower surge impedance and the grounding resistance (the latter because new guy anchor will behave as an additional ground electrode).
- Ground wires in separated structures:
  OHGWs may be supported by separate outboard towers or poles instead of being assembled on the same structure that supports the phase conductors. This arrangement may give extreme negative shielding angles,which minimize induction losses and provide excellent security from shielding failures.
  Tower height and wind loading may also be reduced. While an expensive option, OHGWs on separate structures may result inexcellent lightning performance. Connections can be made from the OHGWs to towers, if required for ac fault-current management, should be designed to have a high impedance to lightning through long interconnection length to minimize risk of backflash over.
- Installation of surge arresters:
  With the installation of surge arresters in parallel to the insulator strings the overvoltage on them will be reduced to acceptable levels.
  The number of surge arresters can be optimized, i.e., it is not necessary to install them in all towers and in all phases.
  The use of surge arresters is covered by Cigré TB 440 (Cigré TB 440).

4.10.1.7 Grounding

Grounding systems are installed in the structures of a transmission line with the following primary objectives:

- to provide a preferential path to earth for currents generated by faults in the line;
- to provide a grounding system with a resistance low enough to enable the overcurrent protection to detect a ground fault in the line.
- to provide a preferential path to earth to lightning discharge currents;
- in urban areas, to control the step and touch voltages generated during ground faults in the line;
- to reduce the structure ground potential rise during a lightning discharge and, consequently, reduce the probability of occurrence of backflashover on the line.

In the following items, the primary practical aspects involved in the design of the grounding system of the transmission line structures are discussed.

Measuring the Electrical Resistivity of Soil

To design a grounding system it is necessary to measure the electrical resistivity of the soil where it will be installed.

As the soil resistivity may vary considerably over the surface and depth, it is necessary to perform measurements at various locations throughout the area occupied by the grounding system using a process that enables the identification of the variation of the resistivity with depth.

To design the grounding systems of transmission lines structures, measurements should be done with electrodes driven along an axis coincident or near the axis of the line and centered at the installation point of each structure. In addition to this axis, some companies specify measurements on axes near the edges of the right-of-way of the line. In this case, measurements made on three axes: one in the center of the right-of-way and the other two near their limits. The final resistivity considered for each distance "*a*" (between measuring probes) is the mean value of all the measurements done with that distance, except that ones those have great discrepancies from the mean value, which are neglected.

One of the most widely used methods of measuring electrical resistivity of soil is the *Wenner four-pin method* (Dawalibi and Barbeito 1991).

Soil Stratification

Usually, modeling the soil with a model of stratified horizontal layers, where each layer has a specific resistivity and thickness, is used in grounding system design. This can be done as most of the real soils are not homogeneous, but composed of several layers of different electrical resistivity and thickness. These layers, due to the geological formation, in general, are fairly horizontal and parallel to the ground surface.

From the results of resistivity measurement, it is possible to find the parameters of the model (of a soil stratified in two or more horizontal layers).

Considering a two-layer soil model (Figure 4.23), its structure can be characterized by:

- a first layer with resistivity ρ_1 and thickness d_1
- a second layer with resistivity ρ_2 and infinite thickness.

The stratification of the soil can be carried out by a curve fitting process, where ρ_1, ρ_2 and d_1 are determined.

As an example, it will be shown the results of a stratification process done with a specific set of measured resistivity values obtained with the Wenner four-pin method, that are presented in Table 4.11.

The two-layer soil parameters are shown Table 4.11. In Figure 4.24 are shown the measured values and the curve ρ over *a* generated with the values of ρ_1, ρ_2 and d_1 shown on Table 4.11.

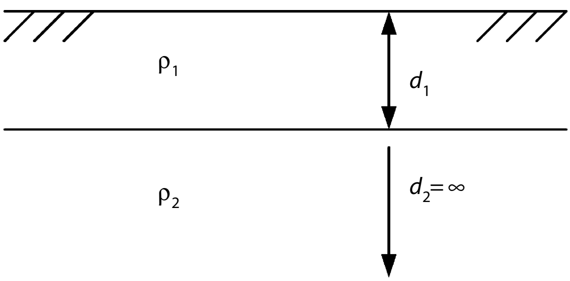


Figure 4.23 Structure of a soil stratified in two-layer of different resistivities.

Table 4.11 Measured value of apparent resistivity of soil obtained with the Wenner four-pin method

Resistivity in Ω m for distance *a* between electrodes					
a	2 m	4 m	8 m	16 m	32 m
ρ_a	1405	1173	743	553	549
Two-layer soil stratification					
		ρ_1 (Ω m)	ρ_2 (Ω m)	d1 (m)	
		1515	525	3.2	

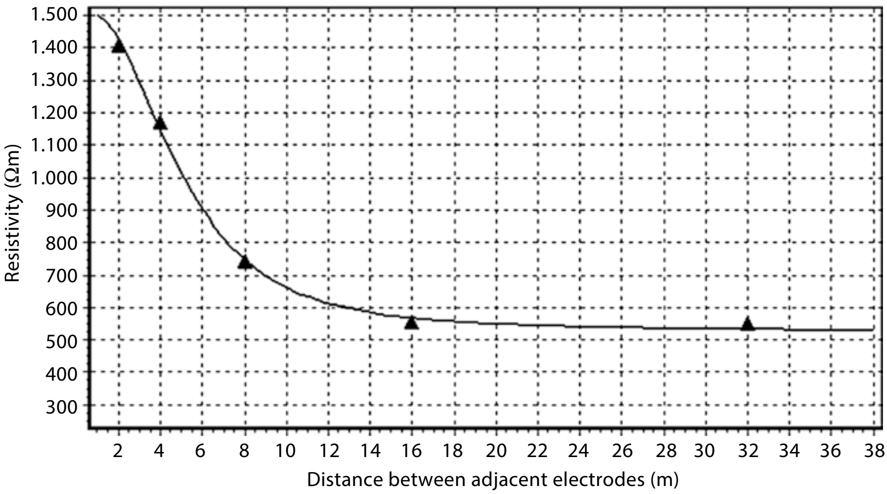


Figure 4.24 Measured resistivity for distance ***a*** and curve calculated with the parameters of the two-layer soil structure obtained in the stratification process.

In this example, the deviations between measured and calculated values of resistivity are small, indicating that the real soil can effectively be approximated by a two-layer soil model.

In many practical situations, the soils cannot be perfectly stratified in two layers as the one shown here. In such cases, conservative approximations should be done or multi-layer layer soil model should be used.

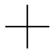
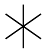
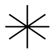
Resistance Calculation

The resistance of a grounding system can be estimated knowing its geometry and the resistivity of the soil where it will be installed (Table 4.12).

Usually, simplified equations are used to calculate the resistance of single electrodes or simple grounding systems. In most case, they consider uniform soil with a resistivity called the apparent resistivity. Such apparent resistivity can be evaluated, approximately, from the stratification of the soil and the dimensions of the grounding system.

Reference (Heppe 1979) presents the equations necessary to calculate the induction coefficients and the potential generated in each point of the soil by the currents

Table 4.12 Examples of simplified equations that can be used to calculate the resistance of electrodes installed in a uniform soil of resistivity ρ (IEEE Std 142)

Electrode		Grounding Resistance
	Vertical ground rod	$R=\frac{\rho}{2\ \pi\ L}\left(\ln\frac{4L}{a}-1\right)$
	Single counterpoise	$R=\frac{\rho}{\pi L}\left(\ln\frac{2L}{\sqrt{2ad}}-1\right)$
	Three point star	$R=\frac{\rho}{6\pi L}\left(\ln\frac{2L}{a}+\ln\frac{2L}{s}+1.071-0.209\frac{s}{L}+0.238\frac{s^2}{L^2}-0.054\frac{s^4}{L^4}\ldots\right)$
	Four point star	$R=\frac{\rho}{8\pi L}\left(\ln\frac{2L}{a}+\ln\frac{2L}{s}+2.912-1.071\frac{s}{L}+0.645\frac{s^2}{L^2}-0.145\frac{s^4}{L^4}\ldots\right)$
	Six point star	$R=\frac{\rho}{126\pi L}\left(\ln\frac{2L}{a}+\ln\frac{2L}{s}+6.851-3.128\frac{s}{L}+1.758\frac{s^2}{L^2}-0.490\frac{s^4}{L^4}\ldots\right)$
	Eight point star	$R=\frac{\rho}{16\pi L}\left(\ln\frac{2L}{a}+\ln\frac{2L}{s}+10.98-5.51\frac{s}{L}+3.26\frac{s^2}{L^2}-1.17\frac{s^4}{L^4}\ldots\right)$

Dimensions: Rod or wire radius → a ; Length → L ; Depth → d = s/2

injected through the segments of conductors in which the grounding system was subdivided. Theses equations were derived considering a two-layer soil.

To calculate the grounding system resistance, it is assumed that all segments of conductor are metallically interconnected and the calculations done at power frequency. Then, it can be assumed that all the segments are at the same potential $V_{\rm m}$. For an arbitrary value of $V_{\rm m}$, for example 1.0 V, the current injected in earth by each segment of conductor can be calculated. Then, the grounding resistance can be calculated as:

$$R_{grounding}=\frac{V_m}{\sum_{i=1} I_i} \tag{4.112}$$

To calculate the potentials generated in the soil during the occurrence of ground fault in the transmission line, it is necessary to estimate the ground potential rise of the grounding system $V_{\rm m}$, in the desired situation, and with it to calculate the real currents that will be injected into the soil.

Resistance and Impedance

For low frequency currents, the behavior of typical grounding systems that are installed in structures of transmission lines can be characterized by a resistance.

For greater frequencies, especially the frequencies that are present in lightning currents (ranging from 100 Hz to 4 MHz), the capacitance and inductance of grounding systems are significant in their behavior (Visacro et al. 2011).

For such high frequencies, the relation between voltage (ground potential rise) and current injected in the grounding system cannot be characterized by a constant (the resistance). To be more precise, this relation should be described as an impedance that varies with frequency:

$$Z(\omega) = \frac{V(\omega)}{I(\omega)} \tag{4.113}$$

The variation of the soil resistivity and permittivity with frequency is another important aspect to be considered when high precision is required, especially for grounding systems installed in high resistivity soils.

In the literature, some expressions are presented to describe the variation of resistivity and permittivity with frequency. They are curve-fitting expressions that are based on experimental results.

The following expressions were proposed in (Visacro and Alípio 2012):

$$\rho = \rho_0 / \left\{1 + 1.2E^{-6}\rho_0^{0.73}\left(f - 100\right)^{0.65}\right\} \tag{4.114}$$

$$\varepsilon_r = 7.6E^3 f^{-0.4} + 1.3 \tag{4.115}$$

where ρ_o is the soil resistivity at 100 Hz, ρ (in Ω,m) and ε_r are the soil resistivity and relative permittivity at frequency f (in Hz), respectively. The equation of ρ is valid for frequencies between 100 Hz and 4 MHz, while the equation of ε_r is valid for frequencies between 10 kHz and 4 MHz (below 10 kHz, it is suggested to use the value of relative permittivity calculated at 10 kHz).

In Figure 4.25, the impedance *Z(ω)* is shown for a counterpoise of 50 m in length, buried in 2500 Ω m soil. It considers the frequency variation of the soil parameters. As can be seen, immediately after power frequency, *Z(ω)* reduces with increasing frequencies. For even greater frequencies, it increases again, until exceeding the low frequency resistance value.

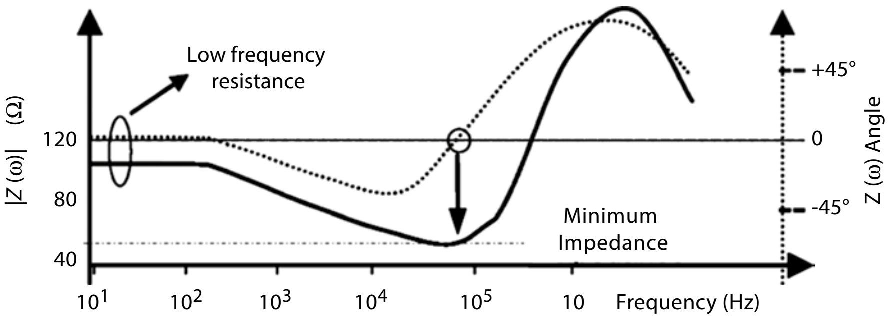


Figure 4.25 Impedance of a counterpoise of 50 m buried in a 2500 Ωm soil. Continuous line: modulus of impedance. Dotted line: impedance angles.

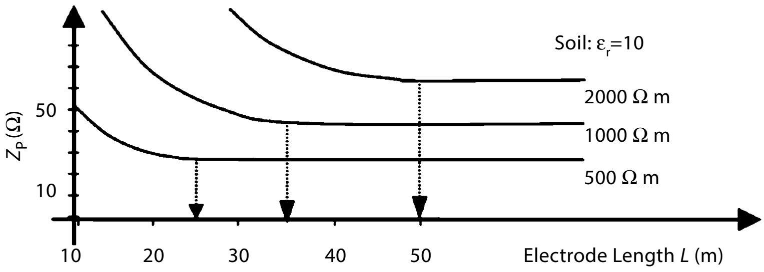


Figure 4.26 Calculated Impedance of a counterpoise buried in a uniform soil. For each soil the effective length is indicated.

Table 4.13 Effective counterpoise length L_{eff} (Visacro 2007)

Resistivity of Soil (Ω m)	L_{eff} (m) for fast current waves 1.2/50 μs
100	14
500	23
1000	34
2000	50

For impulse waves, primarily in lightning analysis, the behavior of a grounding system is, usually, described by its impulse grounding impedance Z_p, defined as the ratio between the voltage and current peaks developed at the current injection point:

$$Z_p = \frac{V_p}{I_p} \tag{4.116}$$

For a specific grounding system, the impulse grounding impedance Z_p is a function of resistivity of soil and the current waveform, primarily its front-time parameter.

Figure 4.26 shows calculated curves Z_p over L, where Z_p is the impulse impedance of a counterpoise of length L installed in a uniform soil. In this same figure is indicated the effective length of counterpoise, defined as that length beyond it Z_p no longer reduces which the increase of L. These curves were calculated considering the soil parameters constant with frequency.

Table 4.13 shows values of effective counterpoise length for current waves of 1.2/50 μs (Visacro 2007). For current waves of 4.5/60 μs, the effective length for these same cases are, approximately, 40% greater than for 1.2/50 μs.

The results of Figure 4.26 and Table 4.13 were obtained considering constant the soil parameters ρ and ε; Soil ionization were not considered. In recent works, it was identified lower values of Z_p and greater values of effective length, primarily for high soil resistivity (as 3000 Ω m) and for impulse current waves representative to lightning first strokes wave.

Even though the precision of the values of effective length can be an object of discussion it clearly shows that too long counterpoises should not be used with the objective of reducing its impulse impedance. Using a continuous counterpoise, for example, is clearly a mistake.

As a design criterion, it is suggested not to install counterpoise with length much greater than the effective length calculated with the 4.5/60 μs current wave form.

One interesting parameter that can be used to analyze the impulse behavior of a grounding system is the impulse coefficient, defined as the relation between the impulse impedance Z_p and the low frequency resistance *RLF* of the grounding system, usually called *Ic*.

Soil ionization occurs primarily when high current is discharged into concentrated electrodes. Usually the ionization process starts when the electric field in the soil reaches a critical value (approximately 300 kV/m for typical soils (Mousa 1994)), and tends to reduce the ground system resistance.

In large grounding systems, as the ones used in a high voltage transmission line constructed in high resistivity soil, which can be composed by long counterpoises, reduction in their resistance by soil ionization occurs only for very high lightning currents injected on them.

Although some studies have been done and simplified methodologies have been proposed to consider the soil ionization in grounding system analyses (Mousa 1994), in practical power transmission line grounding system design, usually, the soil ionization has not been considered explicitly.

Measuring the Structure Grounding Resistance

After the installation of the grounding system in a structure of a transmission line, it is recommended to measure its resistance. In the following paragraphs, a basic procedure that is widely used to do this measurement is described.

Some utilities have specification for this procedure.

In rural areas, usually, horizontal counterpoise wires, radially disposed from the structures, with or without ground rods, are used as tower grounding system.

Usual variations done in the grounding system geometries are:

- installation of additional small wire or cables from tower (to reduce the grounding system surge impedance)
- installation of a wire or cable in a form of rectangular ring around the tower base or around guy-wires foundation
- preclusion of the cables that interconnect the guy-wires to the central mast, in guyed tower
- installation of ground rods with or without the counterpoise cables
- installation of continuous counterpoise cables, i.e., interconnecting the counterpoises of adjacent towers (this procedure is not recommended as reported before)
- installation of deep grounding well
- use of low resistivity materials in substitution of some portion of the local soil: use of bentonite, for example.

Grounding systems with greater number of counterpoises or ground rods in parallel from the points of connection to tower have lower impulse impedances.

Determining the Ground System to Install in each Tower

As mentioned before, the geometry of the grounding system to install in a structure depends on the value and distribution of the soil resistivity, the desired maximum resistance to be obtained and the extension of the area available to install it.

When the transmission line has a large number of structures, it is common to define basic geometries of grounding systems to be used. Usually, they are called grounding stages as one geometry can be viewed as an extension of the previous one. Then, the grounding stage to be installed in a specific structure is identified by calculations or measurements.

In regions with soil of high resistivity where, even with the last stage of grounding system it may occur that the desired maximum resistance is not reached. In this case, the installation of special grounding system should be considered.

Depending on the soil resistivity, it can be considered the installation of a larger number of horizontal radial counterpoises, ground rods, deep grounding well and the use of low resistivity materials, like bentonite, for example.

In Figure 4.27 an example is shown of special grounding system geometry designed to be used in very high resistivity soils, with the objective of reduction of the tower grounding impulse impedance.

In urban areas, the structures can be in regions with high traffic of people. In this case, to guarantee the public safety, it may be necessary to design specific grounding systems to control the touch and step voltage generated, primarily, during faults on the transmission line.

Touch and Step Voltage Limits

As discussed in (IEEE Std 80-2000), the touch and step voltages generated at the grounding system should not exceed the limits calculated with the following equations:

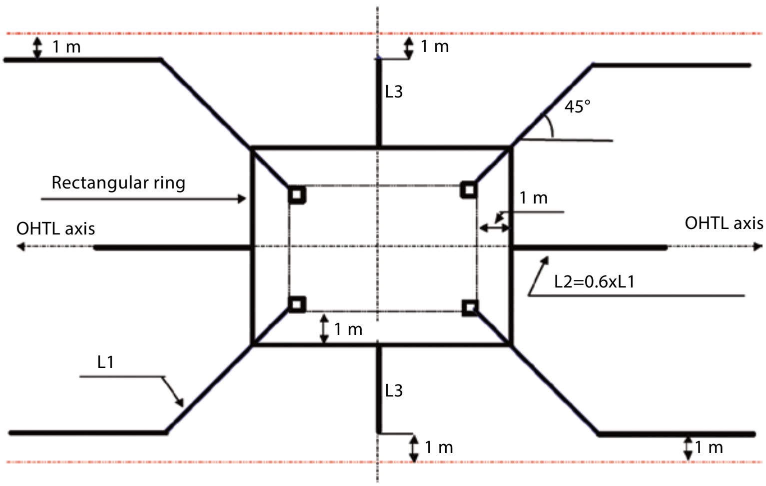


Figure 4.27 Example of grounding system designed to reduce the grounding impulse impedance of a tower.

$$V_{\max\_step} = \left(R_{ch} + R_{2Fs}\right) I_{ch} \tag{4.117}$$

$$V_{\max\_touch} = \left(R_{ch} + R_{2Fp}\right) I_{ch} \tag{4.118}$$

where:

R_{ch} = human body resistance (of order of 1000 Ω);
R_{2Fs} = resistance of the two human feet in series;
R_{2Fp} = resistance of the two human feet in parallel;
I_{ch} = maximum allowable current in the human body.

The current I_{ch} can be estimated as (for 50 kg person):

$$I_{ch} = \frac{0.116}{\sqrt{t}} [A] \tag{4.119}$$

where t is the exposition time to the current.

The resistances R_{2Fs} and R_{2Fp} can be estimated by the = following equations:

$$R_{2Fs} = 6C_s \ \rho_s \tag{4.120}$$

$$R_{2Fp} = 1.5C_s \ \rho_s \tag{4.121}$$

where ρ_s is the soil surface resistivity and C_s is a function of ρ_s, its thickness h_s and the resistivity of the soil immediately below ρs. In a natural soil ρs is equal to ρ_1 and C_s is equal to 1. If the natural soil is covered with a high resistivity material, as a layer of gravel, asphalt or stones, ρ_s will be the resistivity of this material and C_s can be calculated as:

$$C_s = 1 - \frac{0.09\left(1 - \frac{\rho_1}{\rho_s}\right)}{2h_s + 0.09} \tag{4.122}$$

With the installation of a layer of high resistivity material the step and touch voltage generated by the grounding system can be greater, lowering its complexity and cost or providing a greater safety margin. Another advantage is that it gives some protection to the grounding system against thieves and vandalism.

As an example, in Table 4.14 the step and touch voltage limits are shown for a natural soil with resistivity 500 Ω m, with or without a thin layer of high resistivity material: granite stones or asphalt (the installation of gravel is not recommended as it is easy to be stolen). The time of exposure t to the current was considered equal to 1.0 s.

The step and touch voltages generated at the grounding system of a structure will depend on the characteristics of the electrical system (basically its short-circuit current and fault clearing time), the characteristics of the transmission line, the electrical resistivity of soil and the geometry of the grounding system. In case of proximity of the structure with a substation, the influence of its grounding mat should be considered.

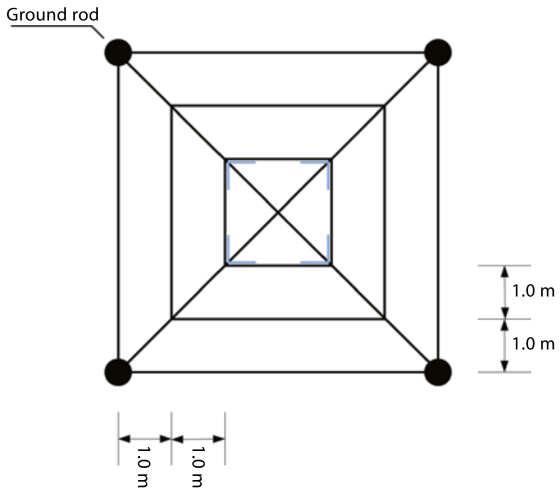
Typical geometries of grounding systems installed in urban areas are shown in Figure 4.28. Basically, they are composed by ground rods and cables installed as

Table 4.14 Step and touch voltage limits

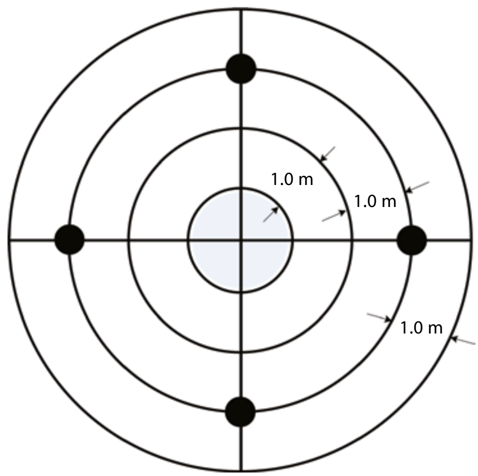
Short duration step and touch voltage limits (V)					
Natural soil (500 Ω m)		Thin layer of granite stones (ρs : 5000 Ω m; thickness: 10 cm)		Thin layer of asphalt (ρs : 10000 Ω m; thickness: 10 cm)	
V_{touch}	V_{step}	V_{touch}	V_{step}	V_{touch}	V_{step}
203	464	742	2621	1073	3944

Note: Except for natural soil, all the other resistivities are for wet materials.

Figure 4.28 Typical grounding system geometry for structures in areas where it is necessary to control the step and touch voltages.



Four ground rods and three wires/cables installed as rectangular rings around the base of a metallic structure at a depth of 0.5 m.



Four ground rods and wires/cables installed as circular rings around the base of a concrete structure, at a depth of 0.5 m, except the last ring, that is at 1.0 m.

rectangular or circular rings, around the feet of the structure, with 1 m apart. The installation depth of the outer ring may be greater in order to control the step voltage in the border of the grounding rings.

In addition to the grounding system itself, usually it is necessary to install a thin layer of high electrical resistivity material over the natural soil to increase the maximum allowable step and touch voltages and also to protect the grounding system. Examples are parallelepipeds of granite with sides, at least, 10 cm in length or a layer of asphalt, with a thickness of 5 cm.

Example of Design

As an example, in this item it is presented the results of the design of a grounding system installed to control the step and touch voltages in a structure located in an urban area. This is the grounding system of the 40th structure of a 138 kV transmission line.

- Transmission line data:
  - Nominal voltage = 138 kV
  - Length = 60 km
  - Typical span = 400 m
  - Number of structures = 149
  - Conductor = ACSR 176.9 MCM - Linnet
  - Ground wire = ACSR 101.8 MCM - Petrel
  - Typical tower = see the following figure
  - Average grounding resistance of structures = 15 Ω
  - Base of structure 40 = 5 m × 5 m
  - Distance between structure 40 and the substation at the beginning of line = 16 km.
- Electrical system data:
  - Symmetrical ground fault current in both substations of the line = 15 kA
  - Total ground fault clearing time = 1 s
  - Resistance of the substation ground mats = 1 Ω
- Soil stratification in structure n° 40:
  - $\rho_1 = 500\ \Omega\text{m}$
  - $\rho_2 = 1000\ \Omega\text{m}$
  - $d_1 = 3$ m.

The designed grounding system is shown in Figure 4.29. Its grounding resistance was estimated in 29.3 Ω (Figure 4.30).

Also, it was recommended to cover the natural soil around the tower with granite stones (parallelepiped) with sides, at least, 10 cm in length.

In the design process of tower 40 grounding system, it was necessary to calculate the current distribution in the ground wire and towers of the line, for a ground fault in tower 40 (Figure 4.31). The ground potential rise of tower 40 was estimated in 6.03 kV. The current distribution calculation was made with a software developed

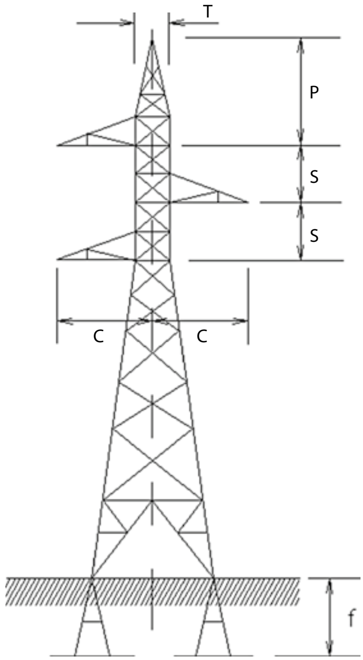


Figure 4.29 Typical tower of the line.

Dimensions (mm)				
T	P	C	S	f
800	3030	2900	1860	2350

specifically for this purpose (the ATP – Alternative Transients Program could also be used). The resistance of the grounding system in design was considered in the results shown here.

In points inside the covered area, the limits of step and touch voltages were estimated considering:

- $\rho_s = 5000\ \Omega m$ (wet granite stones)
- $h_s = 0.1$ m
- $\rho_1 = 500\ \Omega m$

With these parameters, C_s is equal to 0.72.

Then:

$$R_{2Fs} = 6.0 \cdot 0.72 \cdot 5000 = 21600\ \Omega$$
$$R_{2Fp} = 1.5 \cdot 0.72 \cdot 5000 = 5400\ \Omega$$

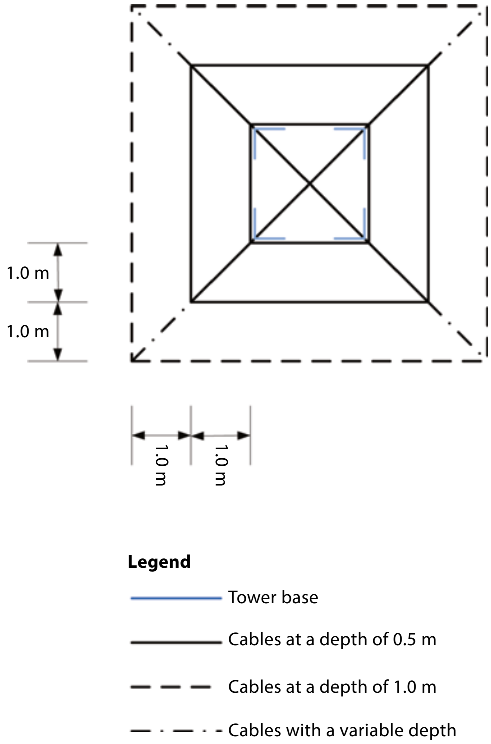


Figure 4.30 Grounding system of tower 40.

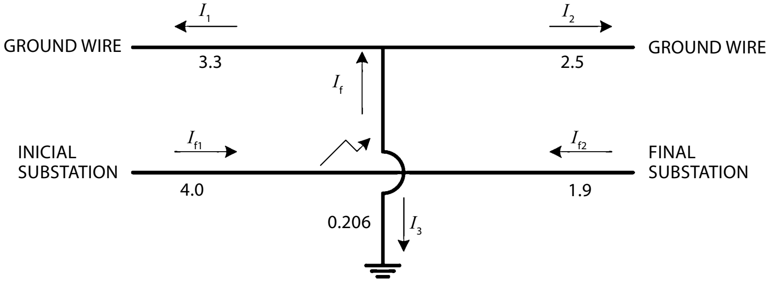


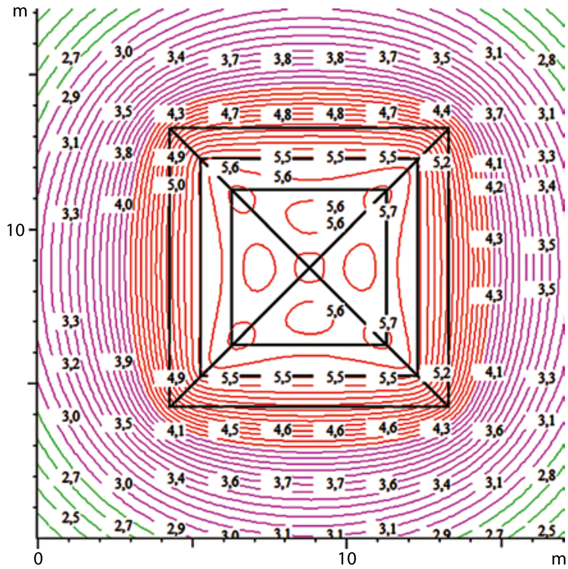
Figure 4.31 Current distribution near tower 40, in kA, for a ground fault on it.

and the limits are:

$$V_{\max\_step} = (1000 + 21600)\frac{0{,}116}{\sqrt{l}} = 2621 \text{ V}$$

$$V_{\max\_touch} = (1000 + 5400)\frac{0{,}116}{\sqrt{l}} = 742 \text{ V}$$

Figure 4.32 Equipotential curves on the surface of the soil near the structure n° 40. Values in kV.



In a point outside the covered area, the limits are:

$$V_{\max\_step\_adm} = (1000 + 6x500)\frac{0{,}116}{\sqrt{l}} = 464 \ \text{V}$$

$$V_{\max\_touch\_adm} = (1000 + 1{,}5x500)\frac{0{,}116}{\sqrt{l}} = 203 \ \text{V}$$

Figure 4.32 shows an equipotential map near tower 40.

The curve in red indicates the points where the generated touch voltage is equal to the allowable limit for this voltage. Points inside this curve have generated touch voltage less than the limit.

Figure 4.33 shows graphs of the calculated step voltages.

Table 4.15 lists the maximum values of the generated step and touch voltages with the respective limit. As it can be seen, the step and touch voltages are controlled.

4.10.2 Temporary (Sustained) Overvoltage

They are of sinusoidal type and defined by its magnitude and duration. They affect the insulation withstand of the clearances (gaps) and other insulation and are defined by test with an amplitude with duration of one minute. They are also important for examining the surge arrester behavior and its energy absorption. The surge arrester rating is chosen not to conduct significant current during these overvoltages.

The origins of temporary overvoltages are: earth faults; load rejection; line/equipment switching; resonances (IEC 71-2).

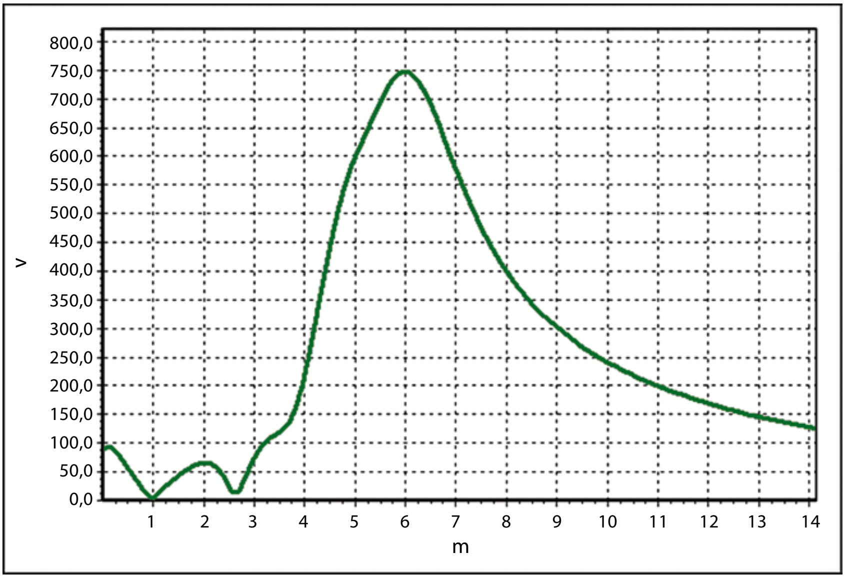


Figure 4.33 Generated step voltage at 45 degree direction.

Table 4.15 Comparison between limits and the generated step and touch voltages (for tower n°40)

Soil with thin layer of granite stones				Natural soil	
Limits (V)		Generated voltages (V)		Step voltage limit (V)	Step voltage generated (V)
V_{touch}	V_{step}	V_{touch}	V_{step}		
742	2621	513	748	464	428

4.10.2.1 Earth Faults

These overvoltages are related to phase-to-ground faults location and the system neutral earthing. For ungrounded earthing system the phase-to-ground overvoltage may reach values close to the phase-to-phase voltage. For grounded neutral impedance or solidly grounded system these overvoltages are much smaller.

4.10.2.2 Load Rejection

For long line systems, after load rejection overvoltages appear due to Ferranti effect, they are bigger in the line opened end.

Shunt reactors connected to the lines reduce these overvoltages.

The condition may become worse if load rejection is combined with pre existing, or post occurring phase-to-ground faults.

4.10.2.3 Line/Equipment Switching

Energization/reclosing of lines lead to temporary overvoltages due to Ferranti effect. Shunt reactors reduce the overvoltage.

Capacitor switching in is also a cause of temporary overvoltages.

4.10.2.4 Resonances

Temporary overvoltages may be originated by resonances, and may be mitigated by detuning the system circuit.

Transformer energization and ferro-resonance should be of concern.

An example of sustained transient overvoltage due to load rejection is shown in Figure 4.34.

4.10.3 Slow-Front Overvoltages (Switching Surges)

Slow front overvoltages are of oscillatory nature fast damped. They are represented in laboratory test by a wave with time-to-peak of 250 μs and time to half-value in the tail 2500 μs (Figure 4.35).

The switching surge overvoltages arise from:

- line energization
- line reclosing (re-energization)

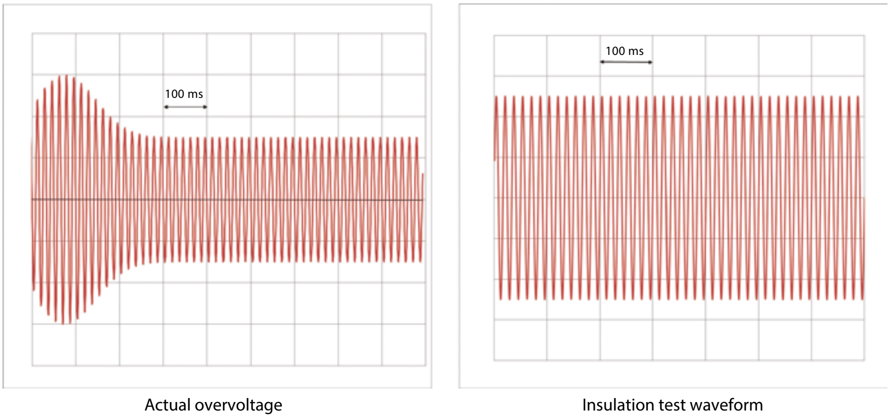


Figure 4.34 Sustained overvoltage – load rejection.

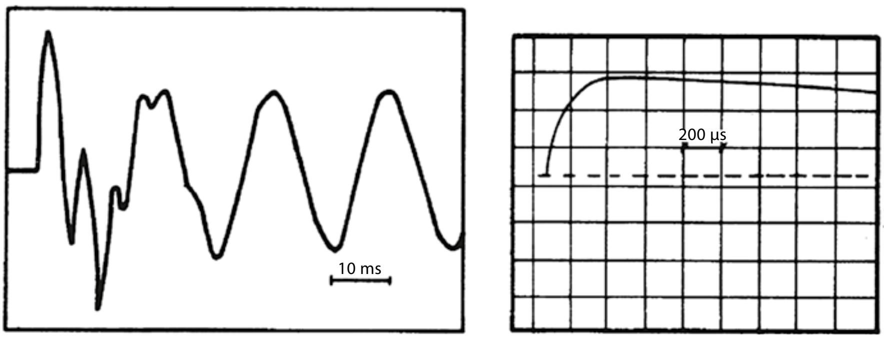


Figure 4.35 Slow front overvoltage (actual on left and laboratory test on right).

- fault inception
- fault clearing
- load rejection
- capacitive switching in
- inductive load switching out.

4.10.3.1 Line Energization

During line energization, a slow-front overvoltage occurs superimposed to the power frequency overvoltage. When the breaker closes, a travelling wave move along the line, originating a slow-front overvoltage (after some reflections/refractions).

The peak value of the overvoltage depends on the point-on-wave switching instant, and the Ferranti effect influenced by the presence of shunt reactors.

The overvoltage may be mitigated by synchronized switching or by the use of pre-insertion resistor.

When pre-insertion resistor is present, the transient phenomenon has two components: one when the resistor is inserted; and another when it is bypassed.

The resistor insertion time average value is specified (about 10 ms) but there is a random variation of few milliseconds (2-4 ms). Synchronized switching has also a random behavior as related to closing instant.

These energization overvoltages are determined by simulation with electromagnetic transient model software running a set of 100-200 cases (shots) characterized by the switching closing instant in the three phases.

It is assumed that the resistor insertion instant follows a Gaussian distribution defined by a mean value and standard deviation. As result, the maximum value of the overvoltage is determined (and the corresponding switching closing instants) and a set of voltages values in the sending, receiving and some intermediate distance of the line.

The values are used to define a statistical distribution of overvoltage (Gaussian or Weibull) through a mean, a standard deviation, and a truncated maximum value.

There are two ways for establishing the distribution of overvoltage: called "phase-peak" and "case-peak" methods. In the former for each shot, for one location, the peak value of the three phases are included in the distribution; in the latter, only the highest of the three phase peaks only is included in the distribution. Therefore they should be considered in different ways when designing the insulation.

Energization over an existing phase-to-ground fault may lead to higher overvoltage; however they are not used for line insulation design but only to checking surge arrester performance.

It should be noted that the phase-to-ground and phase-to-phase overvoltage distribution shall be obtained for insulation design.

A graph with the mean plus three standard deviation values of phase-to-ground overvoltage along a line is depicted in Figure 4.36.

4.10.3.2 Reclosing

After line opening, one or more tentative of reenergization may occur automatically. When the line is disconnected a trap charge is kept in the line (in the line capacitance) so the reclosing is an energization over the residual voltage of the line; this should lead to higher show-front overvoltage than for energization.

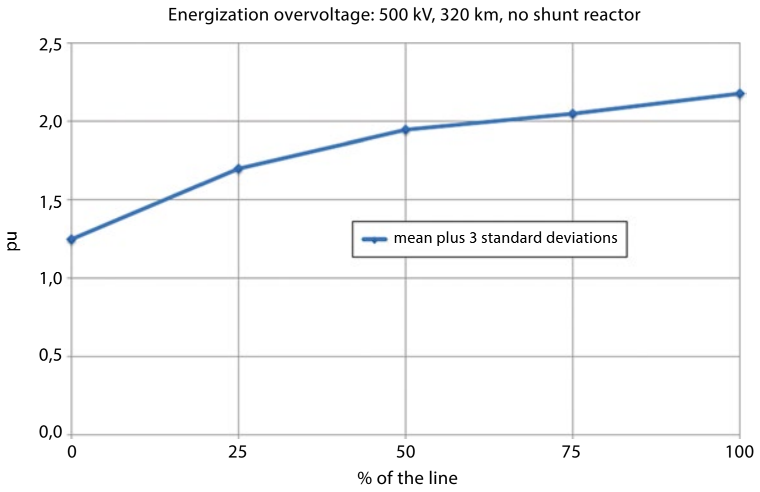


Figure 4.36 Expected maximum switching surge overvoltage during line energization.

For lines without shunt-connected reactor the trap charge is a DC voltage with certain damping (due to line conductance).

For line with shunt-reactor the line voltage is of oscillatory nature (with two frequencies superimposed, a combination due to the natural line frequency and the operating voltage frequency). In the studies, the worst instant of breaker contact closing shall be searched. After that, a statistical calculation around this worst position is done (random contact closing instant).

The reclosing overvoltages are mitigated by using pre-insertion resistor in the breakers or synchronized closing system. The trap charge can be controlled through: open resistor in the breaker; shunt reactor; inductive potential transformer, and by closing/opening a line to ground fast switch.

The phase-to-ground and phase-to-phase over-voltage distributions are searched to be used in the insulation coordination, in a similar way as for the energization overvoltage.

Figure 4.37 depicts a trap charge in a reactor shunt compensated line.

4.10.3.3 Load Rejection

Apart from the sustained overvoltage in the initial cycles there may occurs low-front overvoltages, in general lower than those for energization/reclosing.

Load rejection with phase-to-ground fault (before or after breaker operation) may be critical event for surge arrester performance.

4.10.3.4 Fault Application

When a fault occurs a travelling wave goes in the line and may cause high overvoltage in points of discontinuities (different surge impedances) or when summing up waves from different pass.

In general this overvoltage has short shape and is discharged by surge arrester without any high energy content.

Sometimes they are treated as fast-front surge.

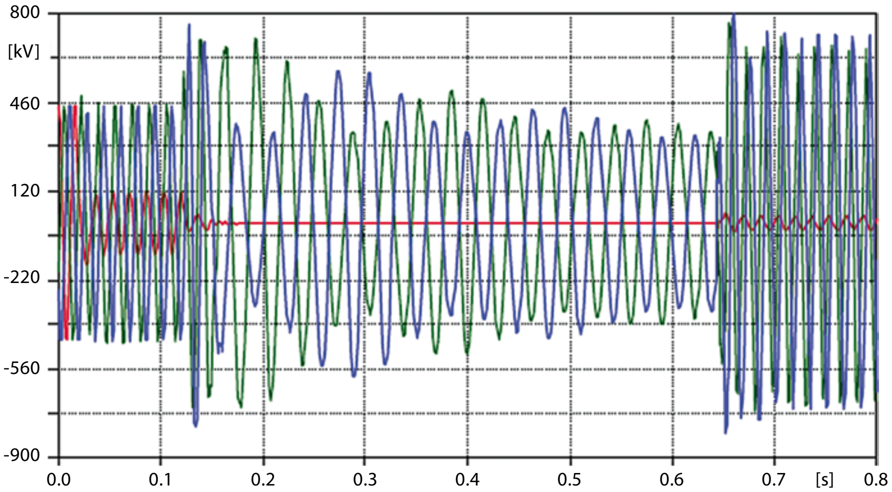


Figure 4.37 Trapped charge (500 kV system) from 0.12 to 0.65 s; unsuccessful reclosing (fault at phase A).

4.10.3.5 Fault Clearing

They are in general lower than energization/reclosing overvoltages and they depend on the type and distance of the fault, breaker sequence of opening, and prior network condition. Opening resistor may be used to mitigate them.

4.10.3.6 Inductive and Capacitive Load Switching

Capacitive load switching off does not lead to overvoltage; overcurrent during switching in is therefore of concern.

Inductive load switching off may cause local overvoltage when the breaker forces the current to zero before natural zero crossing.

Transformer energization may cause high inrush current the could lead to resonance in points of the system.

This type of overvoltage, in general, does not influence line design but substation design. Mitigation is obtained with closing/opening resistor or synchronized switching.

4.11 Insulation Coordination

4.11.1 General

When a low voltage stress is applied in insulation there is no flow of current. When this stress is increased to a sufficiently level, the resistivity along the pass through the insulation changes to a low value, conducting current (breakdown).

A number of factors influence the dielectric strength of the insulation (IEC 71-2):

- The magnitude, shape, duration, polarity of the voltage applied
- The electric field distribution in the insulation
- The type of insulation: air, liquid, solid, gas
- The physical state of the insulation (including ambient conditions).

Breakdown in air insulation is strongly dependent on gap configuration and polarity and on the wave shape of the voltage stress.

This withstand capability of insulation is determined through standard test:

- Sustained overvoltage sinusoidal wave
- Fast-front 1 min 1.2/50 μs waveform
- Slow-front 250/2500 μs waveform

Withstand capability is different depending on the wave polarity.

The insulation withstand depends on the ambient conditions, and it is referred to "standard atmospheric conditions".

- Temperature 20 ° C
- Pressure 101.3 kPa (1013 mbar)
- Absolute humidity 11 g/m^3.

4.11.2 Statistical Behavior of the Insulation

First of all it should be noted that some insulations are non regenerative (oil, paper in a transformer for instance) and others are auto-regenerative like the air. In the latter case the statistical behavior is discussed here-in-after.

When a certain number of shots, with the same wave, are applied in an insulation the breakdown may occur by some of them only.

Due to this, the insulation withstand is defined by a probability function (Gaussian or Weibull) (Figure 4.38).

Gaussian (Normal) Distribution

$$P(U) = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\chi} e^{\frac{-1}{2}y^2}\, dy \tag{4.123}$$

Where

$$X = (U - U_{50}) / Z$$

U_{50} being the 50% discharge voltage ($P(U_{50})=0{,}5$), and Z being the conventional deviation.

Table 4.16 shows some values.

P(y) = probability of not being exceeded

[1-P(y)] = probability of being exceeded

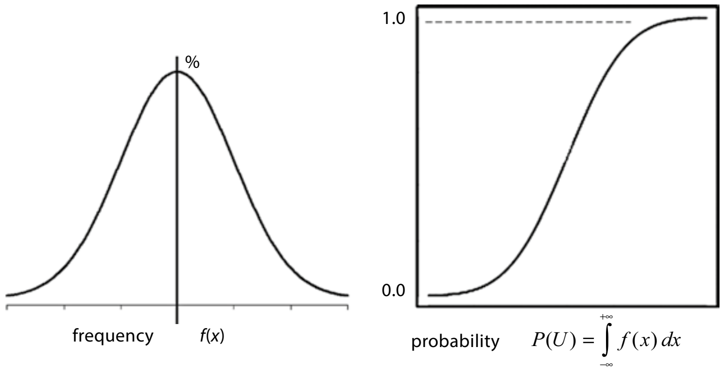


Figure 4.38 Gaussian distribution (frequency and probability).

Table 4.16 Frequency and probability

y	P(y) Rounded values	1 − P(y)
−3	0.001	0.999
−2	0 02	0.98
−1.34	0.10	0.9
−1	0.16	0.84
0	0.50	0.5
1	0.84	0.16
1.34	0.90	0.1
2	0.98	0.02
3	0.999	10^{-3}
4	0.999968	$0.3\ 10^{-4}$
5	0.9999997	$0.3\ 10^{-6}$

Weibull Distribution

The equations are:

$$P(U) = 1 - e^{-\left(\frac{U-\delta}{\beta}\right)^{\gamma}} \tag{4.124}$$

Where δ is the truncation value, β is the scale parameter and γ is the shape parameter.

$$\delta = U_{50} - NZ \tag{4.125}$$

$$\beta = NZ\left(\ln 2\right)^{-\frac{1}{2}} \tag{4.126}$$

This leads to the modified Weibull

$$P(U) = 1 - 0{,}5^{\left(1+\frac{U-U_{50}}{ZN}\right)^{\gamma}} \tag{4.127}$$

N = number of conventional deviations

The exponents determined by

$$\left(P\left(U_{50}-Z\right)=0{,}16\right) \tag{4.128}$$

$$\gamma=\frac{\ln\left[\dfrac{\ln\left(1-\ 0{,}16\right)}{\ln 0{,}5}\right]}{\ln\left(1\ -\ \left(1/N\right)\right)} \tag{4.129}$$

With truncation at ($U_0 = U_{50} - 4Z$), $N = 4$, results $\gamma \approx 5.0$ and finally

$$\left(x=\left(U-U_{50}\right)/Z\right) \tag{4.130}$$

$$P\left(U\right)=1-0{,}5^{\left(1+\frac{x}{4}\right)^{5}} \tag{4.131}$$

Characterization of the Insulation Withstand

The statistical behavior of the insulation (as a Gaussian distribution) is defined provided two values are known for instance, the mean U_{50}, and the standard deviation $Z = U_{50} - U_{16}$. Sometimes the value U_{50} is substituted by U_{10} or U_2.

When the Weibull distribution is used, the truncation value is also defined in terms of N conventional deviations (ex: N = 4).

The conventional deviation of the insulation can be assumed as:

- For fast-front (lightning) $Z = 0.03\ U_{50}$
- For slow-front (switching surge) $Z = 0.06\ U_{50}$

IEC 71-2 considers the value $U_{10} = (U_{50} - 1.3\ Z)$, to define the withstand capability of equipment insulation.

4.11.3 Insulation Coordination Procedure

4.11.3.1 Continuous (Power Frequency) Voltage and Temporary Overvoltage

The coordination is set based in the maximum voltage peak value phase-to-ground that is the phase-to-phase voltage divided by $\sqrt{3}$.

Insulation withstand of the insulator string varies depending on the pollution level.

Table 4.17 contains the specific creepage (mm/kV), to set the recommended distance depending on the pollution level. The distance referred is the contour of the insulator (creepage distance).

Table 4.17 Recommended creepage distance (IEC 71-2)

Pollution level	Examples of typical enviroments	Minimum nominal specific creepage distance mm/kV[1]
I Light	- Areas without industries and with low density of houses equipped with heating plants - Areas with low density of industries or houses but subjected to trequent winds and/or rainfall - Agricultural areas[2] - Mountainous areas - All these areas shall be situated at least 10 km to 20 km from the sea and shall not be exposed to winds directly from the sea[3]	16.0
II Medium	- Areas with industries not producing particularly polluting smoke and/or with average density of houses equipped with heating plants - Areas with high density of houses and/or industries but subjected to frequent winds and/or rainfall - Areas exposed to wind from the sea but not too close coasts (at least several kilometres distant)[3]	20.0
III Heavy	- Areas with high density of industries and suburbs of large cities with high density of heating plants producing pollution - Areas close to the sea or in any cases exposed to relatively strong winds from the sea[3]	25.0
IV Very Heavy	- Areas generally of moderate extent, subjected to conductive duate and to industrial smoke producing particularly thick conductive deposits - Areas generally of moderate extent, very close to the coast and exposed to sea-spray or to very strong and polluting winds from the sea - Desert areas, characterized by no rain for long periods, exposed to strong winds carrying sand and salt, and subjected to regular condensation	31.0

NOTE - This table should be applied only to glass or porcelain insulation and does not cover some enviromental situations such as snow and ice in heavy pollution, heavy rain, arid areas, etc.

[1]According to IEC 815, minimum creepage distance of insulatiors between phase and earth related to the highest system voltage (phase-to-phase)

[2]Use of fertilizers by spraying, or the burning of crop residues can lead to a higher pollution level due to dispersal by wind

[3]Distances from sea coast depend on the topography of the coastal area and on the extreme wind conditions

4.11.3.2 Slow-Front (Switching Surge)

There are two methods: deterministic; and statistical approaches.

In the deterministic approach a statistical value of the overvoltage is set equal to a statistical value of the withstand (both with certain probability)

$$U_{S50} + N_S Z_S = U_{W50} - N_W Z_W \tag{4.132}$$

U_{S50}, U_{W50} are the means of the overvoltage and withstand capability

Z_S, Z_W are the standard deviations (overvoltage-withstand)

N_S, N_W = number corresponding to a desired probability (form instance $N_S=3$; $N_W=4$), or the truncation points.

In the statistical approach the risk of failure is evaluated. The following assumptions are established:

- Peaks other than the highest are disregarded
- Shape is taken as identical to the standard waveform
- All overvoltage of the same polarity (the worst).

The risk is than calculated as

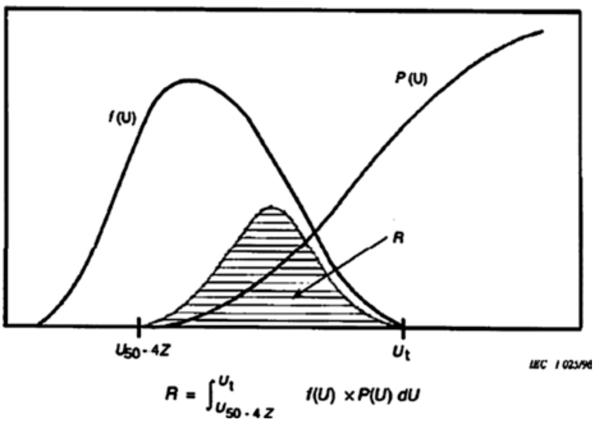
$$R = \int_{U_1}^{U_2} f(u)\,P(u)\,\mathrm{d}u \tag{4.133}$$

where:

$f(u)$ = probability density of the overvoltage
$P(u)$ = discharge probability of the insulation
U_1 = truncation point of the discharge probability
U_2 = truncation point of the overvoltage

Figure 4.39 shows the procedure.

A simplified approach consists in the assumption that the overvoltage (U_{S50}, Z_S) and discharge voltage (U_{W50}, Z_W) are Gaussian curves.



f(u) = probability density of the overvoltage occurrence described by a truncated Gaussian or a Weibull function
P(u) = discharge probability of the insulation described by a modified Weibull function
U_1 = truncation value of the overvoltage probability distribution
U_{50}-4Z = truncation value of the discharge probability distribution

Figure 4.39 Evaluation of the risk of failure.

Failure occurs when overvoltage is greater than withstand. The combination is also a Gaussian distribution in which the mean (R_{50}) and the standard deviation (Z_R) are:

$$R_{50} = U_{S50} - U_{W50} \tag{4.134}$$

$$Z_R = \sqrt{Z_S^2 + Z_W^2} \tag{4.135}$$

$$\text{Risk} = 1 - \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{0} e^{-\frac{1}{2}\left(x^2\right)} \tag{4.136}$$

$$X = \frac{x - R_{50}}{Z_R} \tag{4.137}$$

Example: Calculate the risk of failure for:

$$U_{S50} = 820\text{kV} \quad Z_S = 82 \text{ kV or } 10\% \tag{4.138}$$

$$U_{W50} = 1125 \text{ kV} \ Z_W = 45 \text{ kV or } 4\% \tag{4.139}$$

$$R_{50} = 820 - 1125 = -305 \tag{4.140}$$

$$Z_R = \sqrt{82^2 + 45^2} = 93.5\text{kV} \tag{4.141}$$

$$X = \frac{0 - (-305)}{93.5} = 3.2 \tag{4.142}$$

From Gaussian table values $X = 3.2$:

$R = (1 - 0.99931) = 0.0007$.

When there are n equal insulations stressed by the same overvoltage, the risk of failure R, of at least one insulation breakdown is:

$$R = 1 - \left(1 - R_1\right)^n \tag{4.143}$$

Where R_1 is the individual risk

Therefore for calculating the risk in the case of:

- energization overvoltage, once known distribution at sending, middle and receiving ends, calculation is made as "quasi-peak" method.

The following steps shall be followed:

- set one insulation defined by U_{W50}, Z_W
- calculate the risks R_s, R_m, R_r (at sending, middle and receiving end points)
- assume that N_s insulation are stressed by the sending overvoltage, N_m and N_r by middle and receiving overvoltage.

The total risk of a failure will be:

$$R = 1 - \left(1 - R_{\mathrm{s}}\right)^{N_{\mathrm{s}}} \left(1 - R_{\mathrm{m}}\right)^{N_{\mathrm{m}}} \left(1 - R_{\mathrm{r}}\right)^{N_{\mathrm{r}}} \tag{4.144}$$

Note: If the distributions were determined as “phase–peak”, than, the three phases risk has to be considered as for instance.

$$R_{r} = 1 - \left(1 - R_{\mathrm{r1\ ph}}\right)^{3} \tag{4.145}$$

R_{ri1ph} is the risk in one phase

4.11.3.3 Fast-Front (Lightning Surge)

The same concepts applied above for slow-front are valid for fast-front overvoltages.

4.11.3.4 Influence of Atmospheric Conditions

The air pressure, temperature, and humidity affect the withstand capability of an air gap or insulator.

Assuming that the effect of temperature and humidity cancel it other [1], than only the effect of air pressure (altitude) is present and the correction factor K_{a} is applied to the withstand capability of the insulation.

$$K_{a} = e^{m\left(\frac{H}{8150}\right)} \tag{4.146}$$

Where

H is the altitude above sea level (in meters) and the value of m is as follows:

$m = 1.0$ for co-ordination lightning impulse withstand voltages;

m according to Figure 4.40 for co-ordination switching impulse withstand voltages;

$m = 1.0$ for short-duration power-frequency withstand voltages of air-clearances and clean insulators.

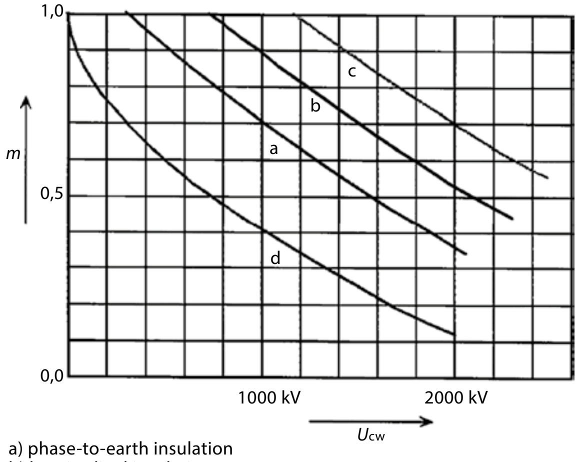
Note: The exponent *m* depends on various parameters including minimum discharge path which is generally unknown at the specification stage. However, for the insulation co-ordination purposes, the conservative estimates of *m* shown in (Figure 4.146) may be used for the correction of the co-ordination switching impulse withstand voltages. The determination of the exponent *m* is based on IEC 60-1 in which the given relations are obtained from measurements at altitudes up to 2000 m. In addition, for all types of insulation response, conservative gap factor values have been used.

For polluted insulators, the value of the exponent m is tentative. For the purposes of the long-duration test and, if required, the short-duration power-frequency withstand voltage of polluted insulators, *m* may be as low as 0.5 for normal insulators and as high as 0.8 for anti-fog design.

The values of *m* are shown in Figure 4.40.

In Figure 4.41 the distribution of withstand value of an example of insulation affected by atmospheric conditions is shown.

Figure 4.40 Dependence of *m* on the switching surge withstand voltage.



a) phase-to-earth insulation
b) longitudinal insulation
c) phase-to-phase insulation
d) rod-plane gap (reference gap)
For voltages consisting of two components, the voltage value is the sum of the components.

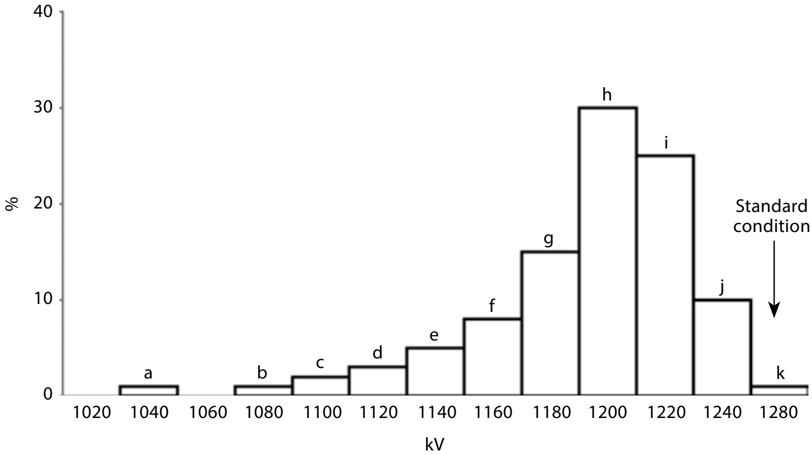


Figure 4.41 Distribution of 50% withstand value of an insulation affected by atmospheric conditions.

The effect of atmospheric condition is then considered in the risk of one insulation by applying the overvoltage distribution in the withstand capability affected, in each interval, and then calculating the weight average of the values of risk.

4.11.4 Withstand Capability of Self Restoring Insulation

The air gaps, filled or not with insulators, are of the self-restoring type. The geometrical configuration of the gap influences its withstand capability.

The critical flashover value (U_{50}), in kV, for "standard atmospheric condition", can be estimated as function of the gap distance (d) in *m* by:

For slow-front

$$U_{50} = k500d^{0.6} \quad 2 < d < 5 \tag{4.147}$$

$$\text{or} \quad U_{50} = k\frac{3400}{1+\frac{8}{d}} \quad 5 < d < 15 \tag{4.148}$$

k being the gap factor as shown in Figure 4.42.

Phase-to-phase insulation (see Figure 4.43) is also influenced by the factor α, defined as the ratio of the negative peak and the sum of the positive and negative peaks.

Table 4.18 shows the gap factors to be considered for α equal to 0.5 and 0.33.

- for fast-front overvoltages

$$U_{50} = k^{+} \ 500 \ \mathrm{d} \tag{4.149}$$

$$k^{+} = 0{,}74 + 0{,}26 \ \mathrm{k} \tag{4.150}$$

K is the gap factor for slow-front overvoltages

For positive polarity and/or insulator strings in order to evaluate effect of lightning impinging the substation:

$$U_{50} = 700 \ \mathrm{d}$$

- for sustained overvoltages

The withstand characteristic is shown Figure 4.44.

Finally in a tower there are many gaps subjected to the same overvoltage: conductor-tower (arm); conductor-guy wire; conductor-tower (lateral); conductor-to-ground; insulator string. The risk of failure in one tower R_t shall be estimated by:

$$R_t = 1 - \left(1 - R_{g1}\right)\left(1 - R_{g2}\right)\ldots\ldots\left(1 - R_{gk}\right) \tag{4.151}$$

R_{gk} is the risk of insulation gap k.

4.12 Electric and Magnetic Fields, Corona Effect

Ground level electric and magnetic field effects of overhead power lines have become of increasing concern as transmission voltages are increased. The electric fields are especially important because their effects on human beings and animals

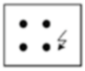
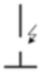
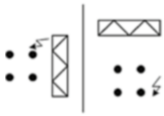
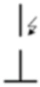
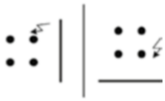
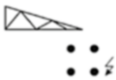
Gap type	Insulator	Factor k	
		Without	With
rod-plane		1.0	1.0
rod-structure (below)		1.05	
conductor-plane		1.15	
conductor-window		1.20	1.15
conductor-structure (below)		1.30	
rod-rod (3m below)		1.30	
conductor-structure		1.35	1.30
rod-rod (6m)		1.40	1.30
conductor-guy wire		1.40	
conductor-tower arm		1.55	1.50
conductor rod (3 m)		1.65	
conductor rod (6 m)		1.90	
conductor-rod (above)		1.90	1.75

Figure 4.42 Gap factor for slow-front overvoltages with and without insulator string.

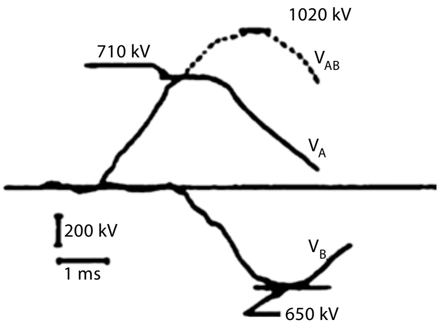


Figure 4.43 Phase –to–phase overvoltage.

Table 4.18 Gap factor phase-to-phase insulation

Configuration	α = 0.5	α = 0.33
Ring-ring or large smooth electrodes	1.80	1.70
Crossed conductors	1.65	1.53
Rod-rod or conductor-conductor (along the span)	1.62	1.52
Supported busbars (fittings)	1.50	1.40
Asymmetrical geometries	1.45	1.36

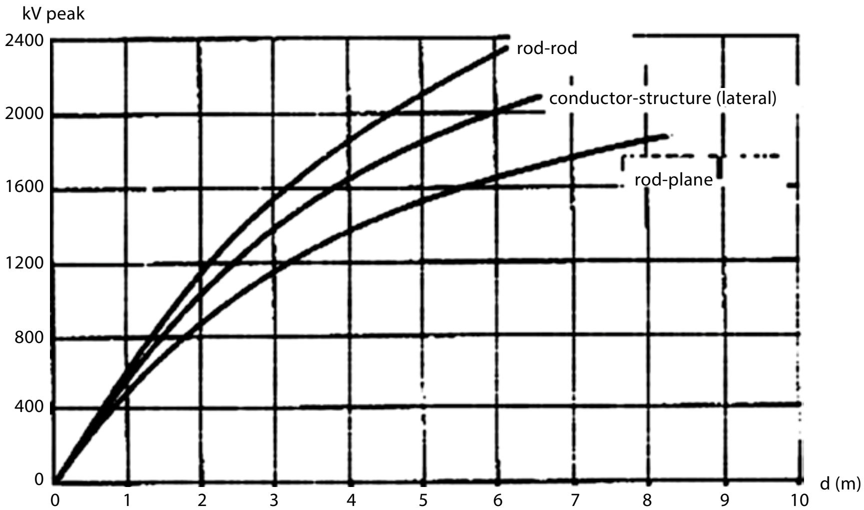


Figure 4.44 Withstand characteristic of gap (power frequency).

have been a concern in the last decades. Serious views still exist that prolonged exposure to electric and magnetic fields could be associated with adverse health effects or with increased risks. However, it is not appropriate to consider unlikely conditions when setting and applying electric field safety criteria because of possible consequences; thus statistical considerations are necessary.

The resultant electric and magnetic fields in proximity to a transmission line are the superposition of the fields due to the three-phase conductors. Usually some limitations, originated from the practice or researches are imposed to the maximum electric field at the edge of the right-of-way.

The evaluation of the electric and magnetic fields across the right-of-way of overhead transmission line can nowadays be made with high accuracy so that the possible health effects of such fields over humans, animals and plants can be evaluated.

Although there is no evidence of harmful effects of the magnetic fields over humans or animals, there are certain limitations imposed by the practice and by the good sense. International organizations like Cigré and ICNIRP have undertaken extensive investigations on such issue.

The range of maximum values expected and accepted as the usual field intensities of electric and magnetic fields are shown in Tables 4.19 and 4.20 below:

Although medical examinations in linesmen, performed in various countries, have so far failed to scientifically prove health problems directly attributed to electric and magnetic fields produced by overhead lines, some conventional limit values have been established for exposures from which the numbers given in Table 4.21 below gives an indication.

In general, limitations are according to Table 4.21, by ICNIRP, according to them maximum values for general public are set for the right-of-way border, while other values are established for occupational people.

Table 4.19 Range of maximum allowable electric and magnetic fields below overhead lines of any voltage (example)

Exposure Type	Electric Field Limit(kV/m)	Magnetic Field Limit (μT)
Difficult Terrain	20	125
Non-populated Areas	15-20	100-125
Road Crossings	10-12	50-100
Frequent Pedestrian.	5	50
Circulation		

Table 4.20 Range of maximum expected electric and magnetic fields below overhead lines as a function of line voltage

TL voltage (kV)	Electric field at ground level (kV/m)	Magnetic field at ground level (μT)
765	8-13	5
500	5-9	3
345	4-6	3
230	2-3.5	2
161	2-3	2
138	2-3	2
115	1-2	1.5
69	1-1.5	1

Table 4.21 Maximum electric and magnetic field values set by ICNIRP (ICNIRP 1997)

Limit values	General public	Occupational
Electric field kV/m	250/f	500/f
Magnetic field uT	5000/f	25000/f

According to ICNIRP new limits have been introduced as Guidelines for limiting Exposure to time-varying electric, magnetic, and electromagnetic fields (up to 300 GHz); the limit values for "general public" and "occupational workers" are established as below:

where f it is the frequency in Hz.

Regarding the maximum acceptable limits for the magnetic fields, there are no universally definitive numbers as some controversy is still worldwide existent especially about their real effects on the health of human beings and animals. While in some countries the regulations are more permissible, in others severe rules have been established.

Other two types of unwanted disturbances caused by overhead transmission lines on the environment are also of importance, namely:

Radio Noise or Radio Interference (RI) that is a disturbance within the radio frequency band, such as undesired electric waves in any transmission channel or device. The generality of the term becomes even more evident in the frequency band of 500 kHz to 1500 kHz (AM band). The frequency of 1000 kHz (1 MHz) is usually taken as reference for RI calculation.

Audible Noise (AN) produced by Corona of transmission line conductors has emerged as a matter of concern of late. In dry conditions the conductors usually operate below the Corona-inception level and very few Corona sources are present. Audible noise from AC transmission lines occurs primarily in foul weather. However, in general, it can be said that transmission systems contribute very little as compared with the audible noises produced by other sources. In the case of rural lines, the importance of the Audible Noise (AN) as well as of the Radio-Interference (RI) may be still lower, as the population density beside the line is generally too small.

4.12.1 Corona Effects

When a set of voltages are applied on the conductors of a transmission line an electric field or voltage gradient appears on its surface (conductor surface gradient). If this surface gradient is above a certain limit (Peek gradient or critical Corona or set gradient) the Corona discharges initiate.

Electric discharge phenomena produce various effects (power loss, high frequency electromagnetic fields, acoustic and luminous emission, ions and ozone generation).

High frequency electromagnetic fields interfere with radio or TV signals in the proximity of the lines.

A person standing near an overhead line whose conductors and/or assemblies are under Corona can sometimes hear a special noise: frying, crackling and hissing sounds and low frequency hum.

These effects are influenced by the transmission line characteristics (conductor size, bundle configuration, phase/pole spacing, conductor height to ground), conductor surface gradient and atmospheric condition (temperature, pressure, rain, snow, etc) the last ones a statistical behavior to the phenomenon is assigned.

The phenomenon presents different aspects if AC or DC line is under consideration.

Corona considerations in the design of transmission lines have been discussed in the Cigré TB 61 (1996) and Cigré TB 20 (1974). This publication includes discussion of Corona losses (CL), radio interference (RI) and audible noise (AN).

Factors influencing the choice of conductor bundles are discussed below. This section provides basis for selection of the conductor bundle.

4.12.1.1 Conductor Surface Gradient

Consider the case of two conductors above soil.

For AC or DC lines, the relationship between charge (Q) and voltage (V) on the conductors or shield wires is given by:

$$[V] = [H][Q] \tag{4.152}$$

H_{ij} are the Maxwell potential coefficients (refer to Figure 4.45):

$$H_{ii} = \frac{1}{2\ \pi\ \varepsilon_0} \ln \frac{2\ h_i}{r_{eqi}} \tag{4.153}$$

$$H_{ij} = H_{ji} = \frac{1}{2\ \pi\ \varepsilon_0} \ln \frac{D_{ij}}{D_{ij}} \tag{4.154}$$

where:

r_i = single conductor (sub index c) or shield wire (sub index sw) radius;

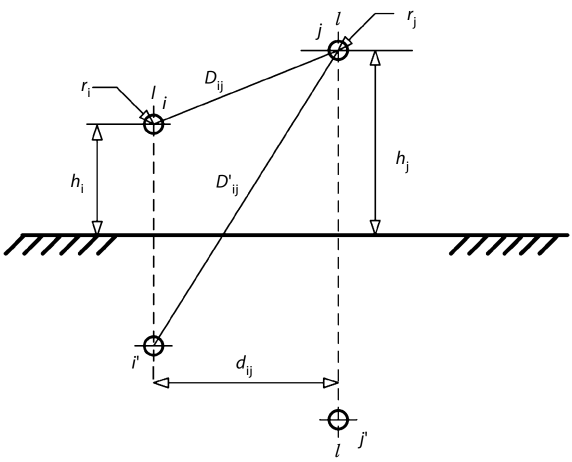


Figure 4.45 Symbols for λ_{ij} calculation.

$r_{eq} = R\sqrt[n]{\frac{nr_i}{R}}$ =equivalent radius of the bundle;

n = number of sub-conductors in the bundle;
R = radius of the bundle;

$$R = \frac{a}{2\sin(\pi / n)}$$

for a regular bundle with a distance between adjacent subconductors;

$h_{ij} = h_{\min} + \frac{1}{3}s$ = average height of the conductor or shield wire;

h_{min} = minimum distance of the conductor or shield wire to ground;
s = sag of the conductor or shield wire;
Equation above can be divided into:

$$\left[\frac{V_c}{V_{sw}}\right] = \left[\frac{H_{c-c} \quad H_{c-sw}}{H_{sw-c} \quad H_{sw-sw}}\right]\left[\frac{Q_c}{Q_{sw}}\right] \tag{4.155}$$

If the shield wires are grounded, then $V_{sw} = 0$ and the above equation system is reduced to:

$$[V_c] = \left([H_{c-c}] - [H_{c-sw}][H_{sw-sw}]^{-1}[H_{sw-c}]\right)[Q_c] \tag{4.156}$$

If the shield wires are isolated from ground then the corresponding equations can be deleted. In both cases the set of equations reduces to:

$$[V_c] = \left[H'_{c-c}\right][Q_c] \tag{4.157}$$

The number of lines and rows of the matrix $[\lambda'_{c-c}]$ is equal to the number of phases of an AC line or poles of a DC line. The charges are then calculated by:

$$[Q_c] = \left[H'_{c-c}\right]^{-1}[V_c] \tag{4.158}$$

Since it is assumed that the total charge of the bundle is equally distributed on the n subconductors, the mean gradient of a conductor in a bundle is given by:

$$g_a = \frac{1}{n}\frac{Q}{2\ \pi\ \varepsilon_0\ r} \tag{4.159}$$

The average maximum gradient of the subconductors is defined by:

$$g = g_a\left[1 + \frac{(n-1)\ r}{R}\right] \tag{4.160}$$

The critical Corona onset gradient is given by:

$$g_c = g_o\delta\ m\left[1 + \frac{k}{\sqrt{\delta r}}\right] \tag{4.161}$$

where:

g_c = critical Corona onset gradient (kV/cm);
g_o = Corona onset gradient (normal ambient conditions: 25 °C, 76 cm Hg) (kV/cm);
r = radius of the conductor (cm);
k = 0.308 for AC or DC (both polarities);
m = surface factor;
m = 1 smooth and polished surface
m = 0.6 to 0.8 actual dry weather service conductor
m = 0.3 to 0.6 raindrops, snowflakes, extreme pollution
m = 0.25 heavy rain
δ = relative air density (RAD);

$$\delta = K_d \frac{\rho}{273 + t}$$

P = pressure of the ambient air (cm Hg or Pa);
t = temperature of the ambient air (°C);
K_d as in Table 4.22.

In the line design the conductor surface gradient should be smaller than the Peek gradient and including a safety factor (ex: $g < 0.95$ g_c. This gradient is also the key factor in the interferences that the line may cause (radio, audible).

4.12.1.2 Corona Loss

AC transmission Corona losses (in dB) can be calculated based on equations presented in the references (Chartier 1983; Maruvada 2000)

$$P(dB) = 14.2 + 65\log\frac{E}{18.8} + 40\log\frac{d}{3.51} + K_1\log\frac{n}{4} + K_2 + \frac{A}{300} \tag{4.162}$$

Where:

n = number of subconductors
d = diameter of subconductors, cm
K_1 = 13 for $n \leq 4$ and 19 for $n > 4$

Table 4.22 Values of K_d

	K_d
Normal conditions (25 °C, 76 cm Hg)	
°C and cm Hg	3.921
°C and Pa	0.00294
IEC normal conditions (20 °C, 76 cm Hg)	
°C and cm Hg	3.855
°C and Pa	0.00289

E = maximum conductor surface gradient, kV/cm
A = altitude, m

$$K_2 = 10\log\frac{I}{1.676} \qquad \text{for } I \le 3.6 \;\; mm/h$$

$$K_2 = 3.3 + 3.5\log\frac{I}{3.6} \quad \text{for } I > 3.6 \;\; mm/h$$

I = rain rate, in mm/h

A distribution of fair and rainy weather has to be established.

4.12.1.3 Radio Interference

Radio interference (RI) is any effect on the reception of wanted radio signals due to any unwanted disturbance within the radio frequency spectrum. Radio interference is a concern only with amplitude modulation (AM) radio reception because frequency-modulated (FM) radio is inherently less sensitive to disturbances. Radio interference is evaluated by comparing the noise level with the radio signal, i.e. the signal-to-noise ratio (SNR), at the edge of the servitude or right-of-way, and for a frequency of normally 0.5 or 1 MHz using a quasi-peak detector with a bandwidth of 5 or 9 kHz according to CISPR or ANSI standards, respectively (1974; 1996). The RI level is expressed in dB above 1 μV/m.

Since RI and AN are caused by the same phenomenon, i.e. streamer discharges appearing on the positive conductor or during the positive half-cycle, the variation of RI with the weather conditions is essentially the same as for AN. Thus, the RI level is the highest in rain for AC lines, but lower in rain for DC lines

As RI is dependent on the weather conditions, it is appropriate to represent the RI level in statistical terms for each weather condition, such as the L_5 and L_{50} levels in fair weather or rain.

Note: L_x is termed the exceedence level; this is defined as the level that is exceeded x% of the time. For example L_{50} is the level that is exceeded 50% of the time and L_{90} is exceeded 90% of the time. The value x and the cumulative frequency are complementary to one another, i.e. x% = 100% - cumulative frequency (%).

Alternatively, the results may be presented as an "all weather" curve considering average climate conditions.

Cigré TB 61 (1996) reports "empirical" formulae for the radio interference level at the reference frequency of 0.5 MHz or 1 MHz, at a given distance from a three-phase line, for three basic weather categories (mean fair weather, mean foul weather and heavy rain), as a function of the main influencing parameters (conductor surface gradient, diameter of the subconductors, number of subconductors in the bundle, frequency, etc.). These formulae were based on the results of direct measurements of radio interference levels performed on operating and experimental lines with system voltages of up to 800 kV and bundles of up to four subconductors.

Sometimes "empirical" equations are given considering two approaches: BPA and Cigré TB 61. To compare the results of the two methods, the following characteristics of the two measuring standards have to be considered (Table 4.23).

For comparison of measurements performed using different receivers:

Value (CISPR) = Value (ANSI) – 2 dB

Table 4.23 Basic characteristics of CISPR and ANSI radio interference measurement standards.

	Receiver		
	Pass band	Charge/discharge constant	Measuring Frequency
CISPR	9 kHz	1 ms/160 ms	0.5 MHz
ANSI	5 kHz	1 ms/600 ms	1.0 MHz

For correction of measuring frequency:

Value (CISPR) = Value (ANSI) + 5.1 dB

Cigré approach consider (CISPR specification: QP: 9 kHz – 0.5 MHz) and the "heavy rain" RI in dB is:

$$RI_{hr} = -10 + 3.5g + 6d - 33\log\left(\frac{D}{20}\right)$$

where

g = maximum surface gradient (function of the mean height)
D = radial distance from the phase to the point
D = subconductor diameter

With: 10 m < D < 60 m, and the term 6d is valid for 1 cm < d < 2.5 cm only.

It should be noted that (see Figure 4.46):

- from the heavy rain value subtract 24 dB to get mean fair weather value
- from the heavy rain value subtract 7 dB to get "mean foul weather"
- from the heavy rain value subtract 3.5 dB to get "mean stable rain".

The equation applies for all phases, however the total RI can be calculated by:

$$E_i = 20\log\sqrt{\sum_{k=1}^{3} E_{ki}^2} \tag{4.163}$$

$$E_{kj} = 10^{\frac{RI_{kj}}{20}} \tag{4.164}$$

Ranking of the phase-fields:

$$RI_a \geq RI_b \geq RI_c \tag{4.165}$$

(dB (1 μV/m))

$$\text{If } RI_a - RI_b \geq 3dB: \quad RI = RI_a \tag{4.166}$$

$$\text{If } RI_a - RI_b < 3dB: \quad RI = \frac{RI_a + RI_b}{2} + 1.5 \tag{4.167}$$

Design criteria for RI from transmission lines are generally based on signal to noise ratios (SNR) for acceptable AM radio reception. Studies carried out on Corona-generated RI from AC and DC transmission lines indicate that the SNRs for acceptable radio reception are in the Table 4.24.

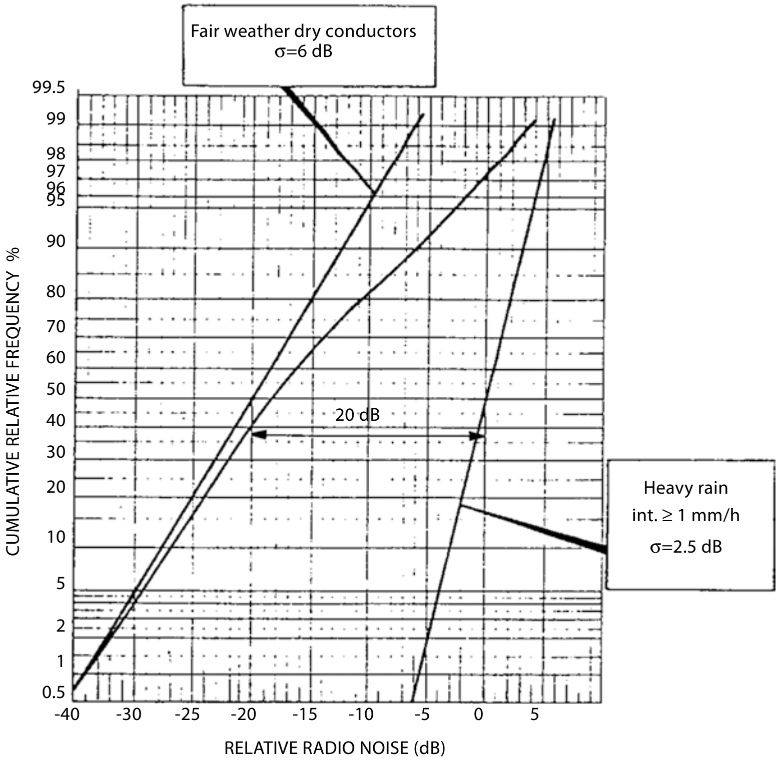


Figure 4.46 RI and weather.

Table 4.24 Quality of radio reception

Signal noise ratic Logarithmic (dB)	Code	Reception quality Subjective impression
30	5	Interference not audible
24	4	Interference just perceptible
18	3	Interference audible but speech perfectly received
12	2	Unacceptable for music music but speech intelligible
6	1	Speech understandable only with great concentration
0	0	Spoken word unintelligible: noise swamps speech totally

Minimum radio station signal requirement in many countries (ex: Brazil) is 66 dB for cities with population from 2500 to 10000 inhabitants. Similar condition probably applies to other countries and is used here as part of the criteria.

At present, there are no established design criteria for RI from DC transmission lines; so the tentative guidelines are for limiting the RI at the edge of the right of way to (66-18) = 48 dB or to keep a reception code 3 at the reception. The SNR above may be referred to average fair weather noise. For more stringent criteria, the noise shall be below 48-6 = 42 dB for 85% probability of not being exceeded (in fair weather), meaning that in 15% of the time the reception will be classified as between the code 2 (in fair weather). The reference frequency is considered here as 0.5 MHz, if 1 MHz is considered the noise is 6 dB lower.

4.12.1.4 Television Interference

Investigations regarding conductor Corona interference above 30 MHz are not as extensive as for RI in the frequency range up to 30 MHz. In practice, interferences to television reception (TVI) are more often caused by microgap discharges on power line hardware or by polluted insulators than by conductor Corona. Because of the higher frequency range, attenuation along a power line as well as that away from the line is considerably larger. Consequently, effects of local noise sources are much more pronounced for TVI. There are no indications that TVI should be of special concern to AC or DC lines; therefore, if a line has an acceptable RI level, then TVI need not be considered, and is not further discussed here (1974).

4.12.1.5 Audible Noise

The audible noise emanates from the air pressure variations that are caused by the Corona discharges, more specifically the streamer discharges created under positive DC voltage or during the positive half-cycle of the AC voltage. The audible noise is the result of numerous uncorrelated Corona discharges, resulting in a broadband noise spectrum covering the entire range of audible frequencies. AN from AC lines also contain a hum component (100 or 120 Hz) caused by space charge movement close to the conductor, correlated with the power frequency.

The human ear has a different response to each of these frequencies; therefore weighting filter networks are used for measuring the human response. The most common is the A-weighting network, in which case the audible noise level is stated as dBA above 20 μPa.

For the AC conductors, (1996) presents empirical formulas for direct calculation of AN from different sources. A Cigré formula for AN L_5 levels, derived from the original formulas, is also given. A formula developed by BPA formula is also presented and will be used here.

For "wet conductor" the average excitation function is:

$$\Gamma A_{50} = K_1 + 120 \log g + K_2 \log n + 55 \log d + \frac{q}{300} \tag{4.168}$$

	K_1	K_2
$n<3$	−169.7	0
$n\geq 3$	−182.7	26.4

For average fair-weather subtract 25 dBA

Range of validity: 230 – 1500 kV, $n \leq 16$, $2 \leq d \leq 6.5$ cm

The AN level in dBA is:

$$LA = \Gamma A + 54.3 - 11.4 logD \tag{4.169}$$

$$\Gamma A_5 = \Gamma A_{50} + 3.5 \tag{4.170}$$

The sum of the individual pressure values from all phases results in the total sound pressure at the point:

$$L_{ATot} = 10 \log \sum_{i=1}^{3} 10^{\frac{LA_i}{10}} \tag{4.171}$$

Note: The hum component of Corona is usually low, but might be taken into consideration separately in special "foul weather" conditions with large Corona loss.

The AC lines design criteria are defined based on subjective evaluation obtained from group of people.

Low complaints :< 52 dBA (equivalent to business office noise)

Moderate: (some) complaints = 52-58 dBA

Many complaints: >58 dBA

Moreover the weather condition has to be established and in some countries it is defined as maximum noise not to be exceeded at average rain = 42 dBA (average). This level corresponds to suburban living room noise (EPRI Transmission).

4.12.2 Fields

4.12.2.1 Electric Field

For the calculation of the electric fields close to the ground, first the V-Q-Maxwell potential coefficient are used (EPRI Transmission).

The charges in all phases and eventually grounded shield wires (Q) are calculated by:

$$[Q] = [H]^{-1}[V] \tag{4.172}$$

It should be noted that $V=(V_r+j\ V_i)$ is a complex number and so $Q=(q_r+j\ q_i)$

The electric field in a point N with coordinates (x_N, y_N) due to the charge q_a and its image q_a is:

$$\vec{E}_a = \tilde{E}_{x,a}\,\vec{u}_x + \tilde{E}_{y,a}\,\vec{u}_y \tag{4.173}$$

Where $\vec{u}_x$ and $\vec{u}_y$ are the unit vectors along the horizontal and vertical axes and $\tilde{E}_{x,a}$ and $\tilde{E}_{y,a}$ are given by:

$$\begin{aligned}\tilde{E}_{x,a} = {} & \frac{(q_{ra}+jq_{ia})(x_N-x_a)}{2\pi\epsilon\left[(x_a-x_N)^2+(y_a-y_N)^2\right]} - \\ & \frac{(q_{ra}+jq_{ia}v)(x_N-x_a)}{2\pi\epsilon\left[(x_a-x_N)^2+(y_a+y_N)^2\right]}\end{aligned} \tag{4.174}$$

And

$$\begin{aligned}\tilde{E}_{y,a} = {} & \frac{(q_{ra}+jq_{ia})(y_N-y_a)}{2\pi\epsilon\left[(x_a-x_N)^2+(y_a-y_N)^2\right]} - \\ & \frac{(q_{ra}+jq_{ia})(y_N+y_a)}{2\pi\epsilon\left[(x_a-x_N)^2+(y_a+y_N)^2\right]}\end{aligned} \tag{4.175}$$

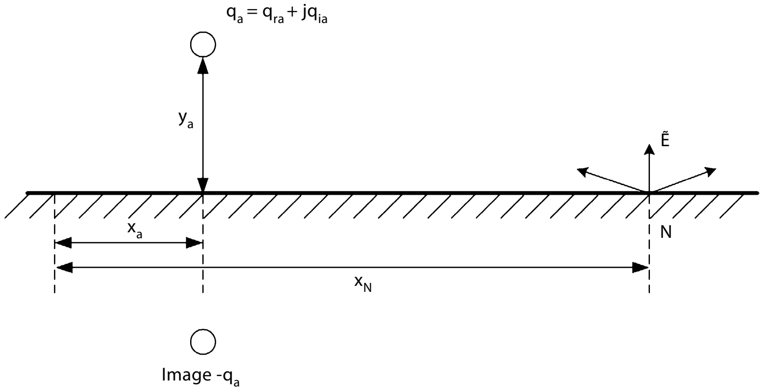


Figure 4.47 Calculation of the electric field at ground level.

The horizontal and vertical components, $\tilde{E}_x$ and $\tilde{E}_y$ of the electric field are calculated by adding the contributions of all the conductors (a,b,…):

$$\tilde{E}_x = \tilde{E}_{x,a} + \tilde{E}_{x,b} + \ldots \tag{4.176}$$

$$\tilde{E}_y = \tilde{E}_{y,a} + \tilde{E}_{y,b} + \ldots \tag{4.177}$$

The results is an equation where there are the real and imaginary parts of the charge and components in the x and y axis. To find the maximum values an specific calculation is needed (EPRI Transmission); one way is tabulating $\tilde{E}_x$, $\tilde{E}_y$ and $Et = \sqrt{E_x^2 + E_y^2}$ as function of the time and getting the maximum value of E_t.

For the electric field at ground level the x axis components of a charge and its image cancel themselves (Figure 4.47).

The equation is then:

$$E_{y,a} = \frac{q_a}{\pi\ \varepsilon_0} \frac{y_a}{\left(x_a - x_N\right)^2 + y_a^2} \tag{4.178}$$

Similar equations apply to other phases and the total field becomes:

$$E_t = E_{y,a} + E_{y,b} + \ldots\ldots \tag{4.179}$$

4.12.2.2 Magnetic Field

The phenomena and calculation procedure are presented in (EPRI Transmission) and is summarized here-in-after (Figure 4.48).

The variables to be considered are the flux density B and the magnetic field H. They are related by the equation

$$\begin{gathered} B = \mu\ H \\ \mu = \mu_0\ \mu_r \end{gathered} \tag{4.180}$$

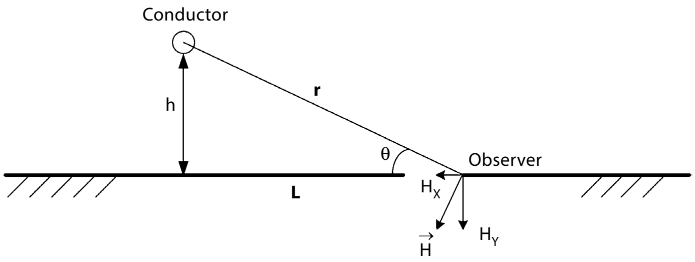


Figure 4.48 Magnetic flux at ground level.

The permeability of the free space is $\mu_0 = 4\pi 10^{-7}$ and μ_r the relative permeability is unity for all except ferromagnetic materials.

Assuming a circle in a plane perpendicular to the conductor whose center is on the conductor, the magnetic field along the circle is a constant given by:

$$H = \frac{i}{2\pi r} \qquad B = \frac{\mu\, i}{2\pi r} \tag{4.181}$$

Where i is the current and r the radius of the circle.

Simplified calculation of the magnetic field at ground level is given by:

$$H = \frac{i}{2\pi\sqrt{h^2 + L^2}} = \frac{B}{\mu} \tag{4.182}$$

$$H_x = H\sin(\theta) = H\frac{h}{r}$$

and

$$H_y = H\cos(\theta) = H\frac{L}{r} \tag{4.183}$$

For multi-conductor the superposition applies in a similar way presented for electric field. The maximum value has to be searched taking into consideration also that the current has real and imaginary parcels.

Another consideration relates to the image of conductors, they have to be located at great depth d that in a first approximation (being ρ the soil resistivity and f the frequency) d is given by:

$$d \cong 660\sqrt{\frac{\rho}{f}} \tag{4.184}$$

Accurate calculation may call for the use of Carson's equations. However for many purposes the earth current may be disregarded.

4.13 Overvoltages and Insulation Coordination

First, the reader shall realize that the line constants consideration are included in the section related to AC lines (Section 4.1.7) and is not repeated here reason why this section starts with overvoltages.

The selection of the optimum transmission line (bipole) alternatives encompasses the different components of the line, so that a global optimization can be achieved. The optimum choice only has a real meaning when electrical, mechanical, civil and environmental aspects are taken into account as a whole set, for which a satisfactory performance and reasonable costs are simultaneously looked for (Cigré TB 388 2009).

Regarding the transmission line itself, its design includes at first the electrical requirements such as power transfer capability and voltage which are specified from which the tower-top geometry, the electric field effects, the Corona effects, the overvoltage and insulation coordination and the required right-of-way are established. Then the mechanical design of the towers and foundations, the determination of conductors and shield wires stresses are carried out; finally the economics including direct costs, cost of losses, operation and maintenance cost along line life, are evaluated.

The design process is iterative as the electrical parameters can be met with a variety of solutions. The optimum solution is derived from interaction with planners and designers.

Note: this text is based on (Cigré TB 388 2009) that may be consulted if more details are necessary. See also Chapter 7 and for electrical constants details Section 4.1.7 (that includes AC and DC line constants).

4.13.1 Overvoltages

4.13.1.1 Types of Overvoltages

The definition of the insulation levels is dependent on different voltage stresses that reach the air-gaps and are so chosen as to result in the best compromise between a satisfactory electrical performance and reasonable costs.

To define the tower-top-geometry of the towers, in the case of a DC line, the following voltage stresses are considered: sustained due to operating voltage, and transient due to lightning and switching surge overvoltages. Therefore, the scope of this clause is an evaluation of the overvoltages in the HVDC system aiming at the DC line insulation design required.

The switching-surge overvoltages in a HVDC system occur in the DC as well as in the AC part of the system.

In the latter one, overvoltages are the result of the following switching operations: line energization; line reclosing, load rejection, fault application, fault clearing and reactive load switching, and all should be evaluated.

As related to HVDC system, the above mentioned overvoltages are also considered for the converter station insulation design; by the use of surge arresters, the overvoltages are limited to values corresponding to the arrester Maximum Switching and Lightning Surge Voltage Levels. The surge discharge capability of the arrester needs to be verified as part of the overvoltage studies for equipment specification.

Regarding switching surges fault application is the only one type of overvoltage to be considered because of the intrinsic process of the HVDC system. For line energization and reclosing, the DC voltage is ramped up smoothly from zero, and in the reclosing process the line de-energization process eliminates the trapped charge.

As for load rejection, it generally does not transfer overvoltages to the DC side. DC filter switching does not cause overvoltages.

Lightning overvoltages may start a fault in the DC line, however its effect is smaller as compared with AC system faults due to the fact that the fault current will be limited by HVDC station controls, the line voltage is ramped down and after a sufficient time for the trapped charge discharge, the voltage is ramped up to the nominal value or to a reduced voltage value (around 80% for example).

Shield wires are normally installed in the lines for reducing the number of faults, by providing appropriate shielding. The major point in the design is then to locate the shield wires in the right position. Shield wires may also be used as a communication medium for control of the converters, their design needs to take both functions into account.

Sustained overvoltages in the DC side of HVDC systems do not occur due to the intrinsic control process of the HVDC operation. It should be noted that overvoltages in the DC side may appear due to harmonic/filter/smoothing reactor resonance. It is considered here that this is a problem to be solved by the design of appropriate elements, and so such kind of stresses will not be considered herein for the insulation design of the DC line.

Determination of Switching Surge Overvoltage (Fault Application)

Switching surge due to fault application in a DC line, being the most important voltage stress to be applied to its insulation, will be evaluated hereafter.

MODELING

The overvoltages hereinafter are calculated with PSCAD/EMTP (Electromagnetic Transient Program) using models such as the one shown on Figure 4.49. The data of the Base Case are here also represented.

- Generator/receiving system
  They are modeled as a short circuit power, providing enough power as required. The short-circuit capacities used are: 9400MVA for single-phase short-circuit and also for three-phase short-circuit.

- The converter transformers of both terminals are specified in this model as:
  Two transformers per pole herein modeled with the following characteristics:
  Power = 400 MVA each

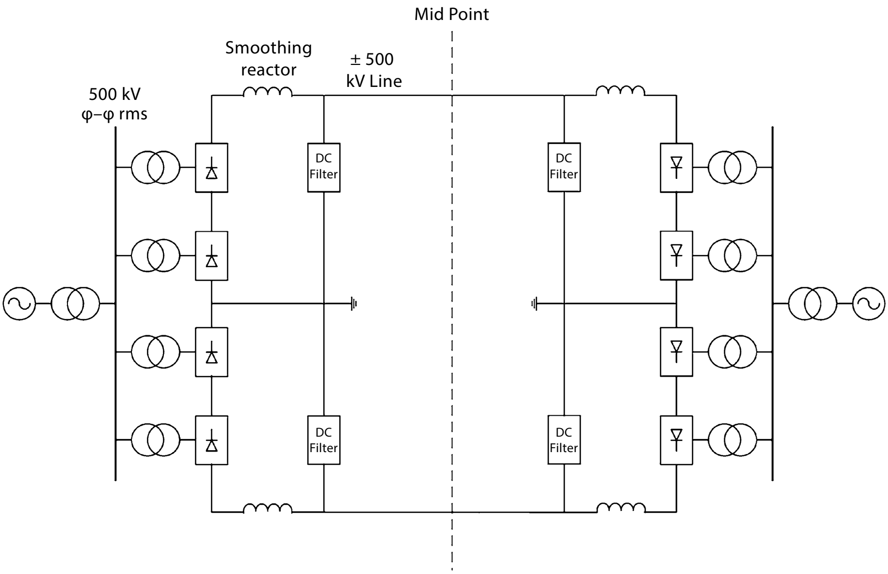


Figure 4.49 HVDC system modeling for fault application calculation (1300 MW).

Reactance $x_{cc} = 18\%$
Turn ratio = 500/199 kV at rectifier or 194 kV at inverter

- DC filters/smoothing reactor

The values used here are (EPRI EL 3892 1985):
Smoothing reactor of 200 mH;
DC filter as below (Figure 4.50)

- Simulation time step = 5 µs
- Converter stations

They are modeled using PSCAD/EMTP blocks. Converter control system are modeled according to (Szechtman et al. 1991)

There is a system voltage control in the inverter (γ_{min} = extinction angle control), line current control at rectifier (α = firing angle control). At fault inception in the HVDC line the current tends to increase and the control acts reducing the line current (different from HVAC systems). Also the line protection sensing the fault change α, γ, to values above 90° and the current goes to zero.

- DC line

  The line model is composed of eight sections, each one modeled as lossless line traveling wave equations. Line losses (resistance) are represented in the model at section end. Electrical parameters (resistance and inductance) are modeled as frequency dependent or constant. For more detailed analysis see Section 4.1.7.

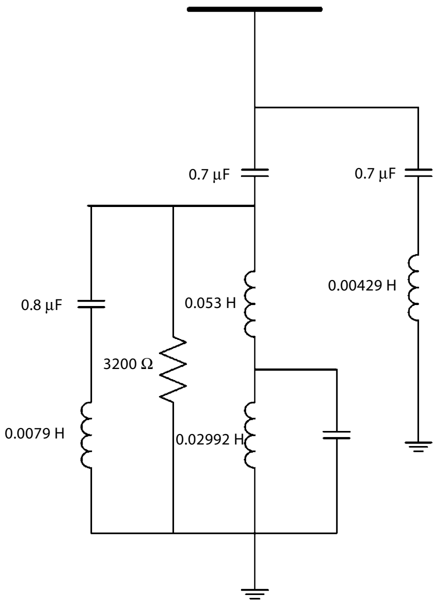


Figure 4.50 DC filter parameters.

FAULT APPLICATION PHENOMENA

For the initiation of the fault in the negative pole, a positive surge of value equal to the pre-fault voltage is injected in the fault point, and the resulting surge travels in both line directions, reflecting in the line end and coming back to the fault point. The traveling wave is coupled to the positive pole resulting in an overvoltage which values are due to the composition of the forwarded and of the reflected waves.

The maximum overvoltage occurs for a fault initiated in the middle of the line, within a time close to the travel time to the line end and back to the mid point of the first reflections. Faults in other locations produce smaller overvoltages. Due to this, the overvoltage profiles down the line are similar for every line length, as will be shown later. Line end equipment (filters, smoothing reactor and source) play an important role, as they define the traveling wave reflection coefficients.

CALCULATION RESULTS

For the Base Case calculation, the following points were taken into account: a line 1500 km long; equal sources at both ends (rectifier and inverter) and line parameters variable with the frequency.

Figure 4.51 shows the maximum overvoltage profile in the sound pole for a fault initiated at mid point of the other pole, and Figure 4.52 the voltage versus time in the mid/end point of the sound pole.

The maximum overvoltage reaches 2.0 pu, however the overvoltages are below 1.6 pu (20% lower) at 1/4 of the line. Standard deviation for insulation switching surge withstand is 6%, this means that the overvoltage in the major part of the line does not contribute to the risk of failure and therefore the line is designed considering mainly the maximum value (2.0 pu in this case). As example in the insulation coordination calculation the envelope shown in blue in the Figure 4.51 may be used to address risk of failure.

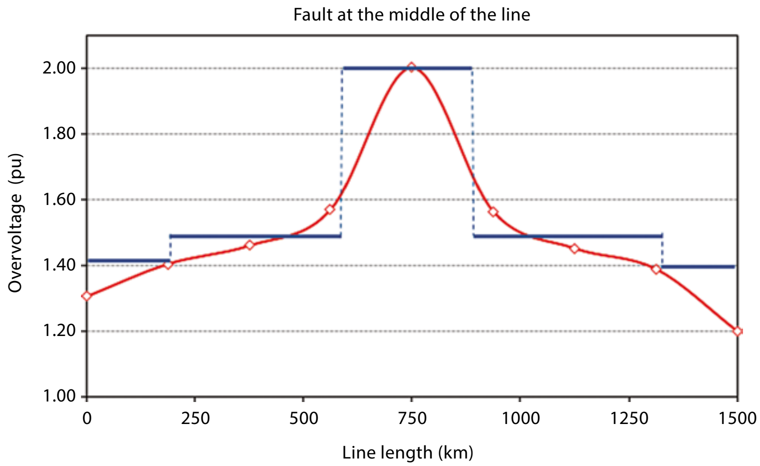


Figure 4.51 Overvoltage profile along the sound pole for a fault initiated at midpoint of the other pole.

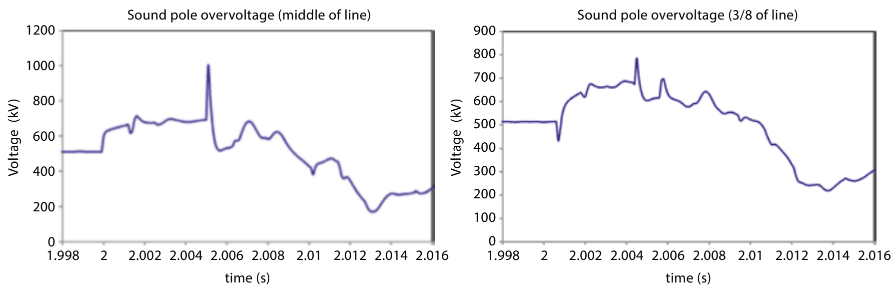


Figure 4.52 Fault at mid point, overvoltage in the sound pole (middle and 3/8 of l) (1,500 km line).

From here on, the line is split in several segments, identified as a fraction of its length (1/8, 1/4, 3/8 and so on). Figure 4.53 shows the overvoltage profile for fault initiated at other line positions. It can be seen that all values are below 1.8 pu and so do not contribute so much to the risk of failure.

4.13.2 Insulation Coordination

This section aims at designing the clearances and at defining the number and type of insulators to be used in the insulator strings.

The number of insulators is initially selected based on the maximum DC voltage withstand and on the assumption of a certain pollution level. The number of insulators obtained by these criteria is then verified by considering the overvoltage values. The clearances to be determined are: conductor-to-tower cross-arm, conductor-to-tower or objects (lateral), conductor-to-ground or objects (at the ground), and conductor to guy wires.

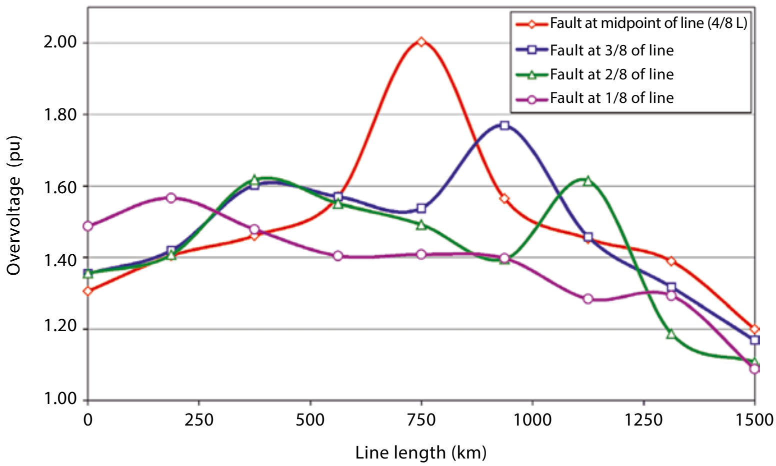


Figure 4.53 Overvoltage profiles, Base Case, fault in different positions.

Table 4.25 Clearances for operating voltages (m)

Operating Voltage (kV)	Clearance (m)
+500	1.20
+800	1.90

They are calculated for switching surge overvoltage withstand. However, the clearance to tower and guy wires as well as to edge of right-of-way shall be verified in the condition of insulation string swing due to wind in order to prevent flashovers and the touch of objects (such as trees) at the border of the right-of-way.

4.13.2.1 Operating Voltage Withstand

Air Clearances

For determining the minimum necessary conductor-structure clearances for operating voltage insulation, the following premises are considered:

- Withstand voltage regarding the most unfavorable condition: positive polarity, conductor-to-structure;
- Maximum operating voltage and correction for the atmospheric conditions: 1.15 pu.

The distances conductor-to-structure were obtained according (EPRI 1977) and are shown on Table 4.25.

Number of Insulators

In AC or DC system the number of insulators in a string is determined by adopting an environmental condition (pollution, air density) and choosing a creepage distance criterion for AC or for DC (Figure 4.54).

As example, by using a creepage distance (pole-to-ground) equal 30 mm/kV, the number of insulators and the respective insulator string lengths are determined and

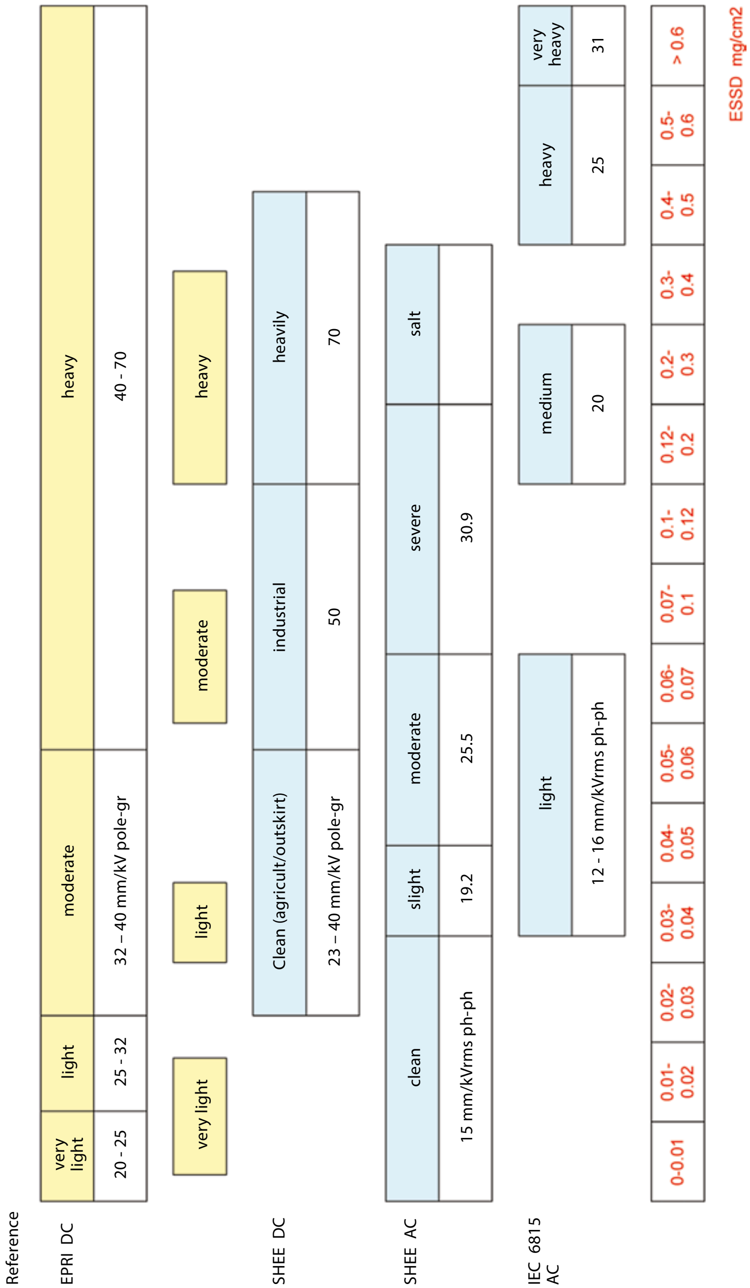


Figure 4.54 Creepage design criteria.

Table 4.26 Number of Insulator and String Length

Operating Voltage (kV)	Creepage distance Number of Insulators	30 mm/kV String Length (m) (*)
± 500	30	5.20
± 800	48	8.17

Notes:
The following type of insulator was considered:
- Anti-fog insulator, pitch of 165 mm and leakage distance of 508 mm
- Hardware length: 0.25 m
- Porcelain type or glass. Composite can be used in any area and is robust against vandalism and pollution.

It should be noted that the suitability of the insulator string length is verified considering switching surge and the gap conductor cross arm.

shown in Table 4.26. The creepage distances adopted are adequate with a good safety margin to zones with a pollution level classified as "light contamination".

For agricultural areas and woodlands 23 mm/kV is recommended, and for outskirts of industrial areas 40 mm/kV is recommended. Some references recommend as acceptable even lower creepage distances down to 20 mm/kV (for area classified as with "very light pollution"); however a higher figure is here considered as more appropriate.

As a reference, the Itaipu lines ("light pollution - agricultural area") were designed for 27 mm/kV and have shown adequate performance in more than 20 years of operation.

Insulator String Swing Angle

The swing angle of the conductor due to wind, as example, was calculated according Cigré/IEC (Cigré TB 48 1995) recommendation, using the following data:

- Line altitude = 300 m
- Average temperature:=16 °C
- Minimum ratio of vertical/horizontal span = 0.7
- Wind return period = T = 50 years
- Mean value of the distribution (m/s)= $\bar{V}$ =18.39 (10 min integration)
- Standard deviation =3.68 m/s
- Wind distribution with 30 years of measurements
- Terrain classification = B

Considering a Gumbel distribution (extreme values), the wind velocity to be considered, depending on the return period, is determined by:

$$V_t = \bar{V} + \frac{X}{C_1}\left(Y - C_2\right) \tag{4.185}$$

$$Y = -\ln\left(-\ln\left(1 - \frac{1}{T}\right)\right) \tag{4.186}$$

where:

V_t = Wind velocity (m/s) with return period T.
$\bar{V}$ = Wind velocity - mean (m/s).
S = Standard deviation (m/s).
$C_1 = 1.11237$ and $C_2 = 0.53622$ are coefficients, for a sample of 30 years [35].
T = return period (years).
It Results = $V_t = 29.52$ m/s

The insulator string deflection is calculated by:
The swing angle of an insulator may be related to the wind velocity by:

$$\bar{\Phi} = \tan^{-1}\left[\frac{(\varrho/2)V_R^2\, kDL_w + F_{wi}/2}{W_c + W_i/2}\right] \tag{4.187}$$

In this formula the following symbols are used:

ϱ air density
V_R reference wind speed
k correction factor taking into account the effect of wind span
D conductor diameter
L_w wind span
F_{wi} wind load insulator
Wc effective conductor weight taking into account the differences in the level of conductor attachments
W_i weight of insulator
$V_R = 1.05\ V_t$ (5 min integration) = 30.99
$Q = 1.18$ kg/m^3
$k = 1.0$
$D = 0.0382$ m
$L_W = 450$ m

By disregarding insulators parameters:

1.18*0.5*(30.99)^2 *1*450*0.0382 = 9748.5 Newtons
$W_C = 2.671$ kg/m × 450 m × 0.7(ratio L_P/L_W) × 9.81 = 8253.8 Newtons
$\varphi = 49.7°$

The calculations were done based on (Cigré TB 48 1995) Cigré TB 48, for a set of ACSR-Aluminum Conductor Steel Reinforced conductors; the results are shown on Table 4.27.

4.13.2.2 Switching Surge Withstand

Calculation Procedure

Once the switching surge overvoltages (as determined before) are known, the clearances are calculated based on the risk of failure considering the withstand capability of the gaps. This is estimated by:

Table 4.27 Swing Angle to be used together with the respective Clearances for the Operating Voltage

Conductor code	Aluminum/steel mm^2/mm^2	Aluminum MCM*	Swing Angle (°)
Joree	1.274/70	2.515	44.5
Lapwing	806/57	1.590	49.7
Bluejay	564/40	1.113	53.4
Tern	403/29	795	56.7

* 1 MCM = 0.5067 mm^2

Note: The conductor types and stranding taken as examples in this report can be further optimized in the case of a real project. There are cases were other conductor types (ASC Aluminum Conductor; AAC-Aluminum-Alloy Conductor, ACAR – Aluminum Conductor Aluminum-Alloy Reinforced; AACSR-Aluminum-Alloy Steel Reinforced) may be more adequate. These, however, will not be covered here. The entire methodology does however apply to them.

$$V_{50} = k\ 500\ d^{0.6} \tag{4.188}$$

where:

V_{50} = Insulation critical flashover (50% probability), (kV)
d = gap distance (m)
k = gap factor:
k = 1.15 conductor – plane
k = 1.30 conductor – structure under
i = 1.35 conductor – structure (lateral or above)
k = 1.40 conductor – guy wires
k = 1.50 conductor – cross arms (with insulator string)

Note: The standard deviation σ of the withstand capability is 6% of the mean.
The latter equation applies to Extra High Voltage System when 2 < d < 5 m.
An alternative equation when 5 < d < 15 m, is:

$$V_{50} = k\frac{3400}{1+8/d} \tag{4.189}$$

The clearances are determined based on the fault application overvoltage profiles, aiming at a certain flashover failure risk target (design criteria). It is proposed here a failure rate of 1 in 50 or 1 in 100 years. It will also be assumed, as design criteria, that 1 fault per 100 km per year (mainly due to lightning) can occur. The overvoltages shown on Figure 4.51 are used for this purpose. The following steps are carried out (together with an example):

- Select one line length and one rated voltage (Ex: 1500 km; 500 kV as the Base Case);
- Select one gap type and size (Ex: conductor-structure lateral = 3.0 m);
- Select the overvoltage profiles in the sound pole for fault in the middle of the other pole (Ex: maximum value is 2.0 × 500 = 1000 kV);
- Calculate the risk of flashover for the tower in the mid-point of the line for 1 gap (Ex: The critical flashover value of the gap is $V_{50} = 1.35 \times 500 \times (3.0)^{0.6} = 1305$ kV) the

overvoltage 1000 kV is at (−1305 + 1000)/(0.06*1305) = −3.9 σ, hence corresponding to a risk of failure of 5×10^{-5} (see Gaussian probability (2-9);

- Calculate the flashover risk of failure in the central section (Ex: suppose 300 km, the envelope of Figure 2-3, or 600 gaps in parallel subjected to the same overvoltage of the tower in the mid-point of the line, leading to a risk of failure of $600*5\times10^{-6} = 3\times10^{-3}$);
- Extend the flashover risk calculation for parallel gaps (towers) for the whole overvoltage profile (Ex:1.5 pu, see Figure 4.53 envelope, or 750 kV that is at (−1305 + 750)/(0.06*1305) = −7.0 σ and the risk $< 1.0\times10^{-8}$. Considering 800 km or 1600 towers the composite risk is $<1.6\times10^{-5}$,therefore negligible contribution to the value on item V above. For the third step of figure 2-3 the overvoltage is 1.4 pu also not contributing to the risk of failure);
- Repeat calculation of the flashover risks of failure for the gap, for fault at other points: or send, or 1/8, or 3/8, or 5/8, or 7/8, or receiving end of the line (ex: disregard this parcels as very few overvoltage values are above 1.6 pu);
- Calculate the weighted flashover average risk of failure, considering that each profile represents fault occurring in a section of (1/8) of the length of the line except seeding/receiving end profiles that correspond to (1/2) × (1/8) of the length. The total flashover risk R is then determined (Ex: $(3.0/8)\times10^{-3}$);
- Consider the number of occurrences (faults) and determine the probability of flashover (Ex: 1 fault per 100 km per year or 15 faults per year). Check against 1 in 50 - 100 years (Ex: $15\times(3/8)\times10^{-3} = 0.005$ or once in 200 yr); if the flashover risk is different, then select another gap size (Ex: 2.8 m as the risk can be increased) and go to step III above;
- Repeat for all gaps.

It should be noted that, if the line is designed with I-strings (as opposed to V-strings), then it is recommended to consider in the risk calculation the effect of possible winds simultaneously with the overvoltages.

There are two approaches for taking this point into account: first, by calculating the clearances for an established risk and admitting that such clearances shall be maintained with a certain swing due to wind (of about 15°); or second, considering the simultaneous occurrence of wind and overvoltage, and finally calculating the composite risk (to lead to 1 failure in 50 years).

Clearances for an Established Flashover Risk of Failure

The following Figures (4.55, 4.56, 4.57, and 4.58), taken from (Cigré TB 388 2009) in slight different conditions established here, show the clearances for the gaps above mentioned as a function of the line voltage. They were designed for a flashover risk of failure of 1/50 yr, no displacement due to wind, and the overvoltages were calculated using the J. Marti line model and the software EMTP-RV.

Switching Overvoltages with Conductor Displacement due to Wind

Cigré TB 48 (Cigré TB 48 1995) recommends the adoption of a swing angle caused by a wind intensity corresponding to 1% probability of being exceeded in a year

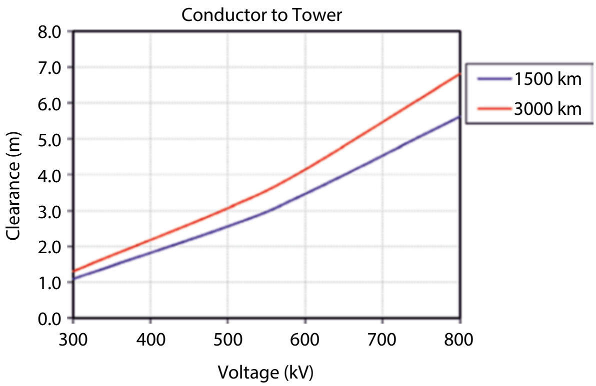


Figure 4.55 Conductor to tower clearances.

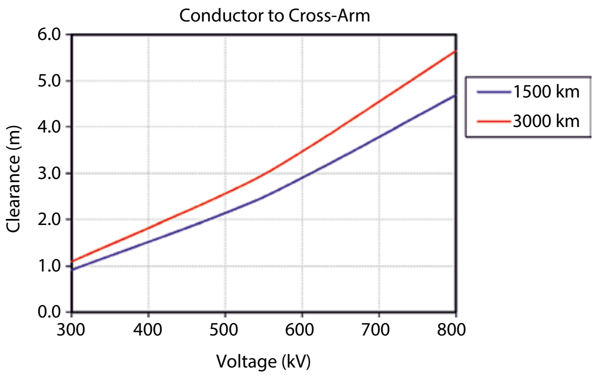


Figure 4.56 Conductor to cross-arm clearance.

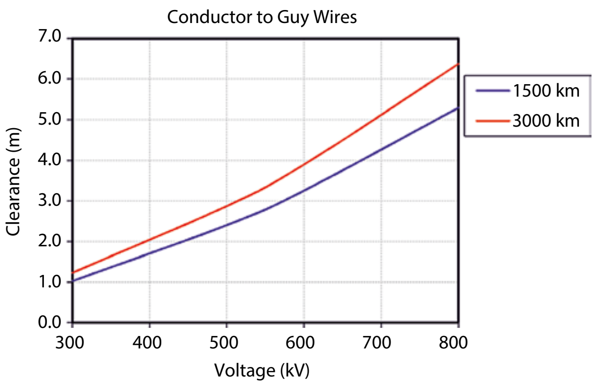


Figure 4.57 Conductor to guy wires clearance.

Figure 4.58 Conductor to object clearance (add 4.5 m to get Conductor-to-ground distance).

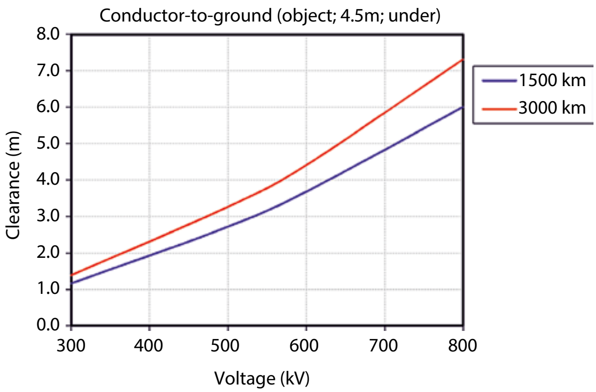


Table 4.28 Swing angle to be used together with Switching Surge Clearances

ACSR Conductor code	MCM*	Swing Angle (°)
Joree	2.515	13.4
Lapwing	1.590	15.3
Bluejay	1.113	17.0
Tern	795	18.6

* 1 MCM = 0.5067 mm^2

together with the occurrence of switching surge overvoltages. Using the wind distribution as per item 2.2.1, the wind intensity is 13.54 m/s.

The swing angles caused by this wind are shown on Table 4.28.

It should be noted that considering simultaneously: the conductor swing due to the wind with 1% probability of being exceeded in one year, and the clearances corresponding to a risk of 1/50 years; the final flashover risk will be much smaller than 1/50, therefore the stated criteria is conservative.

An alternative approach is to find a clearance considering the composite risk for overvoltage distribution and a swing due to the wind distribution.

Note: It should be alerted here that the results obtained in this example and others are applicable only to the parameters used, i.e. wind speed, probability functions, etc.

Composite Risk Calculation

Using this approach a swing angle lower than 8° is obtained.

Atmospheric Conditions

The calculations presented consider standard laboratory test conditions, however corrections should be considered if atmospheric conditions are different from standard one.

Table 4.29 Values of K_d

	K_d
Normal conditions (25 °C, 76 cm Hg)	----
°C and cm Hg	3.921
°C and Pa	0.00294
IEC normal conditions (20 °C, 76 cm Hg)	----
°C and cm Hg	3.855
°C and Pa	0.00289

$$V_{correct} = V_{s\tan dard}\left(\frac{\delta}{H}\right)^n \tag{4.190}$$

where:

δ is the relative air density (RAD);

$$\delta = K_d \frac{\rho}{273+t} \tag{4.191}$$

ρ = pressure of the ambient air (cm Hg or Pa);
t = temperature of the ambient air (°C);
K_d = as in Table 4.29:

H is the humidity correction; factor function of steam pressure that is calculated using maximum saturated steam pressure, humid bulb temperature, air pressure, and dry bulb temperature (also a correction curve is needed).

n = exponent function of the gap length

Atmospheric correction has a statistical behavior and this shall be taken into consideration in the risk of failure calculation. This can be simplified by changing V_{50} by the average value of the correction or by changing the gap withstand capability standard deviation (σ) by composite standard deviation that includes the standard deviation of the correction factor.

4.14 Pole Spacing Determination

The pole spacing requirements are determined considering the use of *I*- or *V*-strings.

4.14.1 Case of I-Strings

For the pole spacing evaluation, the swing angles of the insulator strings as determined before will be used.

4.14.1.1 Pole Spacing Required for Operating Voltage

The minimum pole spacing DP_{TO} is:

Table 4.30 Assumed Tower Widths

Operating Voltage (kV)	Tower Width (m)
±500	1.7
±800	2.5

Table 4.31 Pole Spacing (m) for Operating Voltage/strings

ACSR Conductor	Cross Section (MCM)*	Pole Spacing (m)	
		±500 kV	±800 kV
Joree	2.515	12.5	18.8
Lapwing	1.590	13.1	19.8
Bluejay	1.113	13.6	20.6
Tern	795	14.0	21.1

*1 MCM = 0.5067 mm²

$$DP_{TO} = \left(R + d_{\min} + \left(L + R\right)\sin\left(\theta\right)\right)2 + w \tag{4.192}$$

where:

dmin = Operating voltage clearance;

R = bundle radius $R = \dfrac{a}{2\sin\left(\pi / N\right)}$

a = subconductor spacing (as general rule, 45 cm is adopted);

N = number of subconductors in the bundle (N = 4 is adopted for all calculations here), leading to R = 0.32 m;

L = insulator string length;

θ = swing angle for the maximum wind speed with 50 year return period;

w = tower width at conductor level, as per Table 4.30.

The pole spacing values are shown on Table 4.31.

4.14.1.2 Pole Spacing Required for Switching Surges

The minimum pole spacing required for switching surges is calculated in a similar manner as before, except that the swing angles are those from Table 4.28. The results for ±800 kV bipole lines are shown on Figure 4.59.

It can be seen that the operating voltage criteria governs the pole spacing for ±800 kV voltages and of course for the other voltages as well.

Therefore, the values of Table 4.31 shall be used as pole spacing for *I*-string configurations.

4.14.2 Case of V-Strings

In this case there will be no swing angles due to wind at the towers the clearance requirements for switching surges will determine the pole spacing. However, the

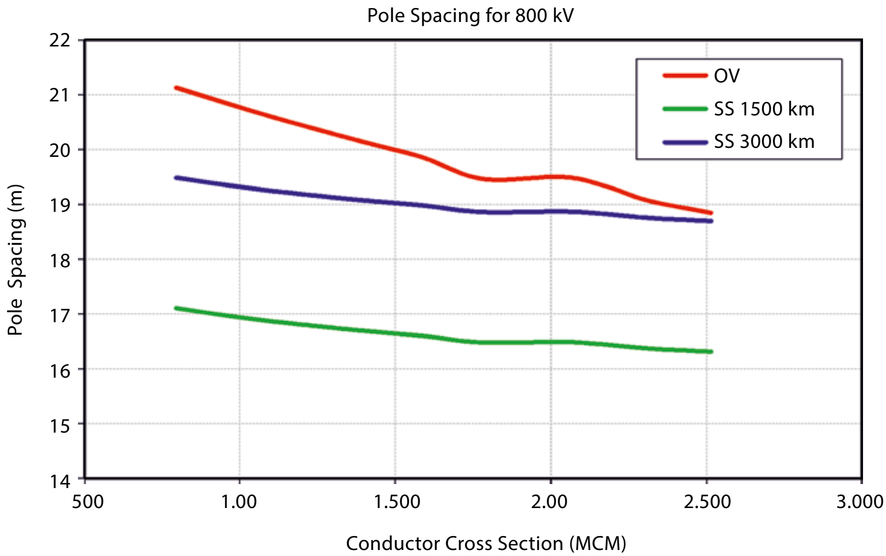


Figure 4.59 Pole Spacing (±800 kV, 750 to 3000 km). Nomenclature: OV → Operating Voltage; SS → Switching Surge.

V-strings having length (L) shall be inserted in the tower, meaning that the minimum pole spacing ($PS_{\min}$) for installation will be:

$$PS_{\min} = 2L\cos(45°) + w \tag{4.193}$$

where:

w = tower width;

It is assumed here that the V-string angle is 90 degrees, however this opening can be reduced.

The pole spacing requirement is otherwise calculated by:

$$\begin{gathered} DP_{TO} = (d_{\min} + R)\ 2 + w \\ (\text{provided that } DP_{TO} > PS_{\min}) \end{gathered} \tag{4.194}$$

The results are shown on Table 4.32.

In summary the pole spacing distances are:

- ±500 kV => 9.3 m
- ±800 kV => 14.4 m for line length
  15.6 for line length equal to < 2250 km
  16.8 for line length equal to 3000 km

It should be noted that clearances for insulation is not the only criteria to choose between *I*- or *V*-strings, for instance *I*-string offers less surface for pollution from

Table 4.32 Pole spacing requirements

Operating Voltage (kV)	Clearance Conductor Structure (m)			Bundle Radius (m)	Tower Width (m)	Pole Spacing (m)			
	1500 km	2250 km	3000 km			1500 km	2250 km	3000 km	PSmin
±500	2.55	2.83	3.06	0.32	1.70	7.4	8.0	8.5	9.3
±800	5.62	6.25	6.81	0.32	2.50	14.4	15.6	16.8	14.3

birds excretion, the Corona protection rings are simpler, and of course are less expensive as they have less insulators.

4.15 Conductor Current Carrying Capability and Sags

The current carrying capability of ACSR conductors were calculated based on Cigré recommendation (TB 207), that relates to AC current. It should be noted that the DC current has a lower heating effect than AC current due to the absence of the transformer and eddy current effects, however this will not be considered here. Therefore, the methodology of calculation can be considered as the same for both AC and DC lines.

The following assumptions are considered:

- Wind speed (lowest) 1 m/s
- Wind angle related to the line 45 degree
- Ambient temperature 35 °C
- Height above sea level 300 to 1000 m
- Solar emissivity of surface 0.5
- Cond. solar absorption coefficient 0.5
- Global solar radiation 1000 W/m^2

The maximum temperature of the conductor will be limited here to 90 °C (as design criteria commonly used in many countries) for steady state and in emergency or short duration conditions, although it could be accepted temperatures even above 100 °C for non-special conductors (Thermal Resistant Conductors may withstand a higher temperature in the steady state condition). However, the conductor is selected based on economic criteria (cost of line plus losses) leading to a maximum operating temperature in normal conditions much lower (~55 to 60 °C). Therefore 90 °C will eventually apply to pole conductors at abnormal conditions as well as to electrode lines and metallic return conductors. Figure 4.60 shows the current capability for some conductors, so that the corresponding values for intermediate sizes can be interpolated.

The sags are presented on Figure 4.61 for conductor temperatures in the range from 50 to 90 °C. The sag calculation was based on the following conditions:

- Span = 450 m
- EDS = Every Day Stress condition

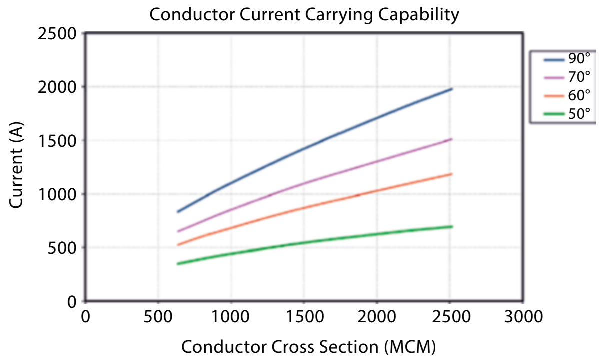


Figure 4.60 Conductor Current Carrying Capability for alternatives maximum temperature criteria.

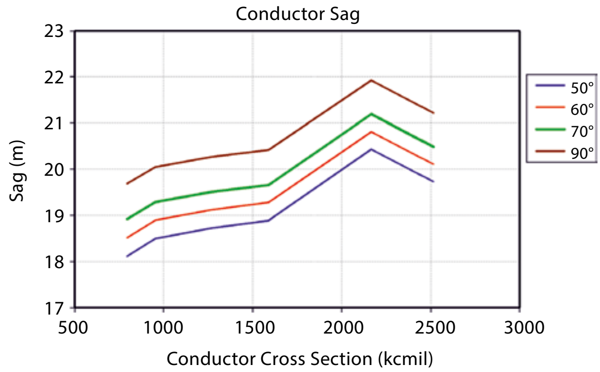


Figure 4.61 Conductor sags.

- Tension of 20% of the RTS (this is a simplification - ideally the EDS should be selected based on fixed H/w horizontal-tension/weight, the catenary's parameter);
- Temperature: 20 °C.

It can be seen that the sags vary from 18 to 22 meters, depending on the conductor temperature and type of conductor. It should be noted that the conductors conside-red in this graph are those of the tables shown before. Conductors with the same aluminum but different steel contents will have different sags.

4.16 Tower Height

The following distances are defined hereunder.

The conductor height at the tower (h_p) is:

$$h_p = C_S + sc + Ext + R \tag{4.195}$$

where:

h_p = distance from the center of the bundle to ground at tower;

C_S = clearance to ground at mid-span =12.5 and 19.5 m for ±500 and ±800 kV, respectively, determined by electric field criteria;

Table 4.33 Conductor and shield wire heights at tallest tower (Two shield wires; for one add 2.5 m to hg)

Voltage (kV)	hp (m)	hg (m)
±500	42.8	50.8
±800	50.8	61.8

sc = conductor sag at 90 ° C (criteria adopted), as per Figure 4.61 (22 m adopted for all conductors in this clause);

R = bundle radius;

Ext = tower extensions up to 3 × 3 m = 9 m

The shield wire height (h_g) at the tower is:

$$h_g = h_p + R + dis + D_G \tag{4.196}$$

where:

dis = insulator string and hardware length: 5.2 and 8.17 m for ±500 and ±800 kV, respectively;

The assumed values for shield wire to cross arm distance DG are:

D_G = 2.5 m (for the case of two shield wires),

or

D_G = 5 m (for the case of only one shield wire).

Table 4.33 shows the values to be used in the calculations which follow.

4.17 Lightning Performance

In order to get a good performance under lightning strokes, the design of HVDC lines should include the use of shield wires (one or two).

The shield wires reduce the direct strokes to the conductors. For the strokes that hit the shield wires, there will be an overvoltage that is coupled to the pole conductors and can cause flashovers or not.

To set a good design, some conditions shall be considered:

- The current of the stroke that hit the pole conductors should not produce an overvoltage greater than the insulation withstand of the line.
- The closer are the shield wires to the pole conductor, the better will be the performance due to strokes hitting the shield wires.
- The tower footing resistance and the corresponding tower footing surge impedance should be low, therefore requiring the use of an adequate grounding system, generally counterpoises at the towers.

In regions with ice, the second condition may be conflicting with the requirements of keeping a safety distance from the shield wire to the pole conductors during icing events.

The clearances at the tower are designed to withstand switching overvoltages with a pre-established risk of failure, or the operating voltage.

Once defined the required clearances, the Critical Impulse Flashover Capability E of the insulation (50% probability) for lightning surges (fast front overvoltages) are known.

With E, V_{op}- the operating voltage- and the conductor surge impedance Z, the critical "threshold current" I_{oc}, into the conductor for which a flashover will start is determined by:

$$I_{oc} = \frac{2\left(E - V_{op}\right)}{Z} \tag{4.197}$$

The striking distance r_{sc} is a function of I_{oc} and is calculated by:

$$r_{sc} = k\ 6.7\ I_{oc}^{0.8} \tag{4.198}$$

where:

r_{sc} = in (m)
I_{oc} = in (kA)
k is a factor different from 1 eventually adopted for shield wires or ground.

The horizontal distance X between conductor and shield wire is:

$$X = r_{sc}\left(\sqrt{1-\left(k-T\right)^2} - \sqrt{1-\left(k-R\right)^2}\right) \tag{4.199}$$

where:

r_{sc} = striking distance (m)
k = factor
$T = h_g^*$/rsc
$R = h_p^*$/rsc
h_g^* = average shield wire height (m)
h_p^* = average conductor height (m)

Three types of terrain may be considered, namely:

- Flat: in this case the following parameters are used in the equations above.

$$h_p^* = h_p - \mathrm{S_c}\ \left(2/3\right) \tag{4.200}$$

$$h_g^* = h_g - \mathrm{S_g}\ \left(2/3\right) \tag{4.201}$$

h_p, h_g are conductor or shield wire heights at tower; and S_c, S_g are the conductors and shield wire sags.

- Rolling: in this case:

$$h_p^* = h_p \tag{4.202}$$

$$b^* = \left(h_g - h_p\right) + \left(S_c - S_g\right)\ \left(2/3\right) \tag{4.203}$$

$$h_g^* = h_p^* + b^* \tag{4.204}$$

- Mountainous

$$h_\mathrm{p}^* = 2\ h_\mathrm{p} \tag{4.205}$$

Table 4.34 Protection for direct strokes

Voltage (kV)	E (kV)	hg^* (m)	hp^* (m)	2 shield wires			
				I_{oc} (kA)	r_{sc} (m)	X (m)	θ (°)
±500	3000	55.2	42.8	14.3	56.2	1.6	11.5
±800	4850	66.2	50.8	23.1	82.7	4.7	23.3

h_p*, h_g* as in the rolling case.

In this report the evaluations will be done considering rolling terrain, average tower (no extensions) and $k = 1$.

The protection angle θ is then:

$$\theta = \text{arc}\ \tan\left(\frac{X}{h_g - h_p}\right) \tag{4.206}$$

The line surge impedance Z is assumed here as 350 Ω.

When the lightning activities are low (and on icing regions where it is desired that the shield wires should not be in the same vertical line as the conductors), one shield wire may be a preferable design for economical reasons.

From Table 4.34 it can be seen that the minimum protection angle θ can be set at values from 11 to 23 degrees. The closer are shield wires to the conductors, the better is the lightning performance for back flashovers due the higher coupling factor.

As a consequence, the protection angle can be adopted as 10 degrees, when using two shield wires.

Note: Only EHS steel wire is considered for shielding purpose. However other material or characteristics may be used if one intend for instance to provide dual function: lightning shielding and communication (carrier or fiber optics).

4.18 Right-of-Way Requirements for Insulation

The Right-of-Way width (ROW) is defined considering the following aspects: Conductor swing and clearances to objects at the border of ROW, Corona and field effects. At this point, only the first condition is examined and the results will be partial.

In the ROW determination, clearances for operating voltage and I-type insulator string length are used.

The swing angles are calculated using the same parameters as clauses before, except that the ratio vertical to horizontal span is equal 1.0, and the span length should not exceed 600 m. It should be reminded that the wind intensity corresponds to 50 year return period. The swing angles are shown on Table 4.35.

The conductor sags (Table 4.36) were obtained by starting from EDS conditions and considering the wind load with the coincident temperature.

Table 4.35 Swing angles for ROW width definition

Conductor		Swing Angle (degree)
ACSR Code	Section (MCM)*	
Joree	2515	34.1
Lapwing	1590	39.1
Bluejay	1113	43.5
Tern	795	47.5

* 1 MCM = 0.5067 mm^2

Table 4.36 Sags for ROW width definition

Conductor		
ACSR Code	Section (MCM)*	Sag (m)
Joree	2515	36.5
Lapwing	1590	34.9
Bluejay	1113	34.5
Tern	795	33.6

* 1 MCM = 0.5067 mm^2

Table 4.37 Right Of Way (I-strings) in (m)

Conductor			
ACSR Code	Section (MCM)*	±500 kV	±800 kV
Joree	2515	62.1	73.2
Lapwing	1590	66.7	78.5
Bluejay	1113	71.3	83.8
Tern	795	74.3	87.2

* 1 MCM = 0.5067 mm^2

4.18.1 Line with I-Strings

The minimum ROW when using I-strings is determined by:

$$\text{ROW} = \left[\left(R + L + S\right)\sin\theta + d_{\min}\right] 2 + PS \tag{4.207}$$

Where:

d_{min} = operating voltage clearance
R = bundle's radius (m)
L = insulators string length
S = conductor sag
θ = swing angle due to wind (50 year return period)
PS = pole spacing

Table 4.37 shows the ROW width as function of the conductor type.

4.18.2 Line with V-Strings

The minimum ROW widths ("*V* strings") are calculated according to the same equation before but disregarding insulator string length. The results are shown in Table 4.38.

Table 4.38 Right of Way (V-Strings)

ACSR Conductor CODE	SECTION (MCM)*	±500 kV 750 to 3,000 Km	±800 kV <2,250 km	2,250 km	3,000 km
Joree	2515	53.2	59.6	60.7	61.8
Lapwing	1590	56.3	62.7	63.8	65.0
Bluejay	1113	59.9	66.3	67.4	68.5
Tern	795	61.9	68.4	69.5	70.6

*1 MCM = 0.5067 mm^2

Note that the results (for I- or V-strings) are partial as Corona effects were not yet considered. Also note that only horizontal design is considered (vertical design will led to smaller ROW).

4.19 Corona effects

4.19.1 Conductor Surface Gradient and onset Gradient

4.19.1.1 Conductor Surface Gradient

The parameter that has the most important influence on Corona performance is the conductor surface electric field or conductor surface gradient. Electrostatic principles are used to calculate the electric field on the conductors of a transmission line.

The procedure of calculation may be the same indicated for AC lines. However for DC lines simplified approach can also be used.

When bundled conductors are used, the electric field around the sub-conductors of the bundle is distributed non-uniformly, with maximum and minimum gradients occurring at diametrically opposite points and the average gradient at a point in between. Using the method known as Markt and Mengele's method, the average and maximum bundle gradients of a bipolar HVDC line, with n-conductor bundles on each pole, are given as (Maruvada 2000).

$$E_a = \frac{V}{n\ r\ ln\left(2H / \left(r_{eq}\sqrt{\left(\frac{2H}{S}\right)^2 + 1}\right)\right)} \tag{4.208}$$

where:

V = voltage applied (actually ± V) to the conductors of the line, kV
r = conductor radius, cm
H = conductor height, cm
S = pole spacing, cm

$$E_m = E_a\left[1 + (n-1)\frac{r}{R}\right] \tag{4.209}$$

Where:

r = sub-conductor radius, cm
R = bundle radius, cm

r_{eq} = equivalent bundle radius, cm

$$R = \frac{a}{2 \sin\left(\pi / N\right)} \tag{4.210}$$

$$r_{eq} = R\left[\frac{n\ r}{R}\right]^{1/n} \tag{4.211}$$

a = distance between adjacent subconductors, cm

Equations above give reasonably accurate results for the maximum bundle gradient, for $n \leq 4$ and for normal values of H and S.

Consider the line geometry indicated below as Base Case example for calculations in this session.

Voltage	± 500 kV
Conductor MCM	3 × 1590
Code	Lapwing
Diameter	3.822 cm
Bundle spacing	45 cm
Pole spacing	13.0 m
Minimum conductor-ground clearance	12.5 m

The conductor surface gradient (conductor considered parallel to ground at minimum height).

$$R = \frac{45}{2 \sin\left(\pi / 3\right)} = 26\ cm \tag{4.212}$$

$$\mathrm{r_{eq}} = 26\left[\frac{31.911}{26}\right]^{1/3} = 15.7 cm \tag{4.213}$$

$$E_a = \frac{500}{31.911\ \ln \dfrac{21250}{15.7\sqrt{\left(\dfrac{2 * 1250}{1300}\right)^2 + 1}}} \tag{4.214}$$
$$= 20.297\ kV / cm$$

$$E_m = 20.297\left[1 + \left(3 - 1\right)\frac{1.911}{26}\right] = 23.28\ kV / cm \tag{4.215}$$

As a general formulation the equations of the electrostatic phenomena described in Section 4.1 can be used. The charge-voltage equation in the matrix form is:

$$\left[V\right] = \left[H\right]\left[Q\right] \tag{4.216}$$

where:

V = voltages on the conductors and shield wires [kV]
Q = charges [kV*F/km]
H = Maxwell's potential coefficients [km/F]
The inverse equation is:

$$[Q] = [C][V] \tag{4.217}$$

Where:

C = the admittance coefficient (F/km).

Once known the charge in a bundle Q_b the average charge in one sub conductor is Q_b/n and the average field is

$$E_a = \frac{Q_b / n}{2\ \pi\ \varepsilon\ r_c} \tag{4.218}$$

r_c = sub conductor wire radius

The maximum electric field E_m is then calculated by the equation above.

When looking for the electric field in the shield wires the procedure used is as follows.

If the shield-wires are grounded at the towers, their voltages are zero and their charges are calculated by:

$$Q_{Sw1} = C_{SW1-C1}\ V_+ + C_{SW1-C2}\ V_- \tag{4.219}$$

Where C_{SW1}_C_1 is the mutual coefficient between shield wire 1 and pole 1(positive) and CSW_1_C_2 from shield-wire 1 and pole 2 (negative).

The electric field in the shield wire surface is:

$$E_{SW1} = \frac{Q_{SW1}}{2\ \pi\ \varepsilon\ r} \tag{4.220}$$

where:
r = shield wire radius

$$\varepsilon = \frac{1}{36\pi} 10^{-9} \quad F / m \quad or \quad \frac{1}{36\pi} 10^{-6} \quad F / km$$

In reference (Cigré TB 388 2009) it is found a calculation of shield wire surface gradient E_{SW} for a ±800 kV two twelve pulse converter per pole. In normal operation condition, for both poles at 800 kV, E_{SW} = 13.7 kV considering the shield wires and conductors position as it is in the tower. However, E_{SW} = 13.7 kV, if the calculation is carried with the position as it is in the mid-span. When in one pole the voltage is 800 kV and in the other 400 kV (emergency of one converter) E_{SW} = 18.9 kV and with 800 kV and zero isthe other pole E_{SW} = 24.1 kV (conductors and shield wire position as they are in the tower).

4.19.1.2 Corona Onset Gradient

When the electric field at the surface of a transmission line conductor exceeds a certain value, partial electrical breakdown of the surrounding air takes place, giving rise to Corona discharges.

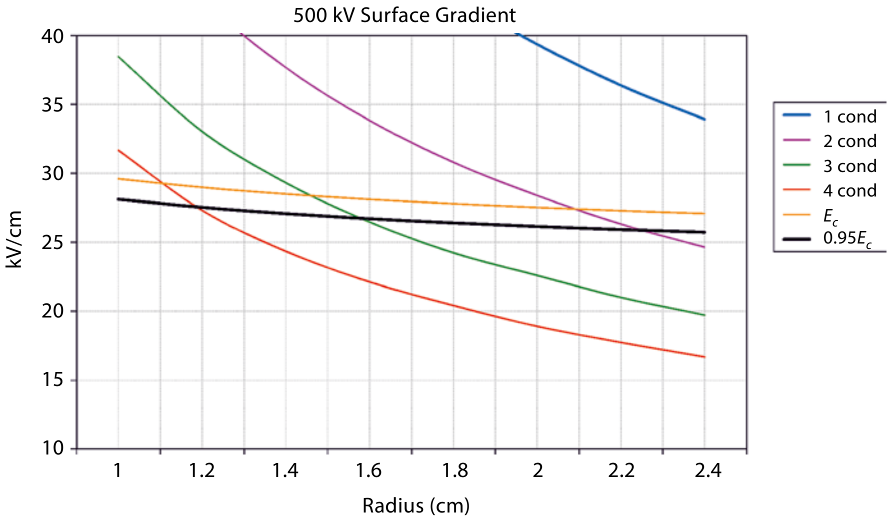


Figure 4.62 Conductor Surface Gradients for ±500 kV.

For the Base Case example in this session, 3×1590 MCM conductor Lapwing (1 MCM = 0.5067 mm²) and assuming $m = 0.82$; $\delta = 0.915$; $r = 1.911$ cm, the critical gradient is:

$$E_c = 30 \cdot 0.82 \cdot 0.915 \cdot \left[1 + \frac{0.301}{\sqrt{0.915 \cdot 1.911}} \right] = 27.6 \ kV / cm \tag{4.221}$$

Reference (Cigré TB 388 2009) shows graphs indicating conductor surface gradient (kV/cm) and critical gradient E_c as function of conductor radius. The figures for 500 and 800 kV are reproduced here (Figures 4.62 and 4.63).

4.19.2 Corona Loss

Corona losses on both AC and DC transmission lines occur due to the movement of both positive and negative ions created by Corona. However, there are basic differences between the physical mechanisms involved in AC and DC Corona loss (Maruvada 2000; Cigré TB 1974). On AC lines, the positive and negative ions created by Corona are subject to an oscillatory movement in the alternating electric field present near the conductors and are, therefore, confined to a very narrow region around the conductors. On DC lines, however, ions having the same polarity as the conductor move away from it, while ions of opposite polarity are attracted towards the conductor and are neutralized on contact with it. Thus, the positive conductor in Corona acts as a source of positive ions which fill the entire space between the conductor and ground, and vice-versa, for the negative conductor.

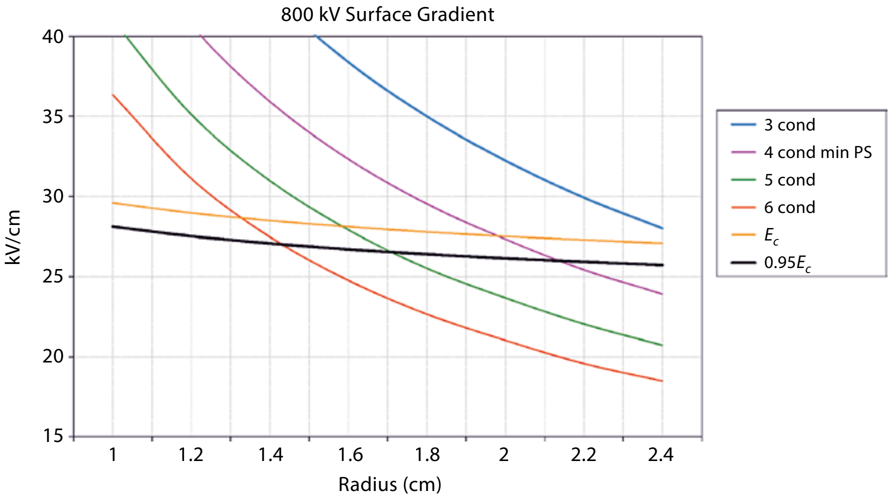


Figure 4.63 Conductor Surface Gradients for ±800 kV.

The case more widely used is the bipolar HVDC transmission line, the positive and negative conductors in Corona emissions having the same polarity as the respective conductor. Unipolar space charges fill the space between each pole and ground while ions of both polarities mix in the bipolar region between the two poles and are subject to some amount of recombination.

Theoretical calculation of Corona losses from HVDC transmission lines requires analysis of the complex electric field and space charge environment in the unipolar and bipolar regions. Such an analysis determines in the first step the electric field and ion current distributions on the surface of the conductors and ground plane and then evaluating Corona losses of the line. Ambient weather conditions have a large influence on Corona losses from the line. The losses are lower under fair weather conditions than under foul weather conditions such as rain, snow etc. However, the ratio of foul weather to fair weather Corona losses on a DC line is much lower than in the case of an AC line.

Because of the complexity of theoretical calculations and the large number of factors influencing Corona on practical HVDC transmission lines, it is often preferable to obtain empirical formulas derived from a large amount of data on long-term Corona loss measurements made on experimental lines with different conductor bundles and under different weather conditions. However, the amount of data available for CL from DC lines is much more limited than in the case of AC lines and, consequently, the accuracy and applicability of empirical formulas may be limited.

For unipolar DC lines, Corona losses may be calculated using an empirical formula derived from measurements made on an experimental line in Sweden (Knudsen et al. 1974), which is given as:

$$P = V_u k_c n r_c \; 2^{0.25(g-g_0)} \; 10^{-3} \tag{4.222}$$

where:

P = Corona loss, kW/km
V_u = line voltage, kV
n = number of sub-conductors in the bundle
r_c = sub-conductor radius, cm
g = maximum bundle gradient, kV/cm
g_0 = reference value of g, and kc is an empirical constant

The reference value is given as $g_0 = 22\ \delta$ kV/cm, where δ is the relative air density. The empirical constant is given as $k_c = 0.15$ for clean and smooth conductors, $k_c = 0.35$ for conductors with surface irregularities and $k_c = 2.5$ for the calculation of all-weather Corona losses.

For bipolar DC transmission lines, some empirical formulas have been developed for Corona losses in different seasons of the year and under different weather conditions. However, the following empirical formulas are recommended since they are derived using available experimental data from a number of different studies (Corbellini et al. 1996), for evaluating fair and foul-weather Corona losses of bipolar HVDC transmission lines:

$$\begin{aligned} P_{\text{fair}} &= P_0 + 50\ \log\left(\frac{g}{g_0}\right) + 30\ \log\left(\frac{d}{d_0}\right) \\ &+ 20\ \log\left(\frac{n}{n_0}\right) - 10\ \log\left(\frac{H\ S}{H_0\ S_0}\right) \end{aligned} \tag{4.223}$$

$$\begin{aligned} P_{\text{foul}} &= P_0 + 40\ \log\left(\frac{g}{g_0}\right) + 20\ \log\left(\frac{d}{d_0}\right) \\ &+ 15\ \log\left(\frac{n}{n_0}\right) - 10\ \log\left(\frac{H\ S}{H_0\ S_0}\right) \end{aligned} \tag{4.224}$$

Where P is the bipole Corona loss in dB above 1 W/m, d is conductor diameter in cm and the line parameters g (conductor surface gradient), n (number of conductors), H (height) and S (pole spacing) have the same significance as described above. The reference values assumed are $g_0 = 25$ kV/cm, $d_0 = 3.05$ cm, $n_0 = 3$, $H_0 = 15$ m and $S_0 = 15$ m. The corresponding reference values of P_0 were obtained by regression analysis to minimize the arithmetic average of the differences between the calculated and measured losses. The values obtained are $P_0 = 2.9$ dB for fair weather and $P_0 = 11$ dB for foul weather.

$$P(\text{W}/\text{m}) = 10^{P(\text{dB})/10} \quad \text{bipole losses in W/m}$$

In the economic evaluation it will be considered 80% of time fair-weather and 20% as foul-weather.

For the Base Case example:

$$P_{\text{fair}} = 2.9 + 50\ \log\left(\frac{23.28}{25}\right) + 30\ \log\left(\frac{3.822}{3.05}\right)$$
$$+20\ \log\left(\frac{3}{3}\right) - 10\ \log\left(\frac{12.513}{15 \cdot 15}\right) = 5.7$$
$$P_{\text{fair}}\left(\text{W / m}\right) = 10^{5.7/10} = 3.7\ \text{W / m}$$

Similarly: P_{foul} (W/m) =20.6 W/m and $P_{\text{tot}} = 0.8 \cdot 3.7 + 0.2 \cdot 20.6 = 7.1$ W/m.

4.19.3 Radio Interference and Audible Noise

While Corona losses occur due to the creation and movement of ions by Corona on conductors, radio interference and audible noise are generated by the pulse modes of Corona discharges. The current pulses induced in the conductors and propagating along the line produce RI, while the acoustic pulses generated by these modes of Corona and propagating in ambient air produce AN.

The characteristics of Corona-generated RI and AN on DC transmission lines differ significantly from those on AC lines. Firstly, while all three phases of an AC line contribute to the overall RI and AN of the line, only the positive pole of a DC line contributes to the RI and AN level. Secondly, the RI and AN levels of DC transmission lines under foul weather conditions such as rain etc., which produce rain drops on conductors, are lower than those under fair weather conditions. This is contrary to the case of AC lines on which foul weather conditions produce the highest levels of RI and AN, much higher than in fair weather. These two distinguishing features play important roles in predicting the RI and AN performance of DC transmission lines and in establishing the design criteria necessary for conductor selection.

4.19.3.1 Radio Interference

Both analytical and empirical methods may be used for calculating the RI level of DC transmission lines.

Some empirical methods have been developed for predicting the RI level of DC transmission lines under different weather conditions. Based on data obtained on experimental as well as operating lines, a simple empirical formula (for the bipole-as negative pole contribution can be neglected) has been developed (Cigré TB 1974; Chartier et al. 1983) for predicting the average fair weather RI level for bipolar HVDC transmission lines as:

$$\begin{gathered}\text{RI} = 51.7 + 86\ \log\frac{g}{g_0} + 40\ \log\frac{d}{d_0} + \\ 10\left[1 - \log^2\left(10\ f\right)\right] + 40\ \log\frac{19.9}{D} + \frac{q}{300}\end{gathered} \tag{4.225}$$

Where:

RI = radio interference level measured at a distance D from the positive pole with a CISPR instrument, dB above 1 μV/m
g = maximum bundle gradient, kV/cm
d = conductor diameter, cm
f = frequency, MHz
D = radial distance from positive pole, m

The contribution of the negative pole is 4 dB lower. The noise under foul weather is 3 dB lower

The reference values are $g_0 = 25.6$ kV/cm and $d_0 = 4.62$ cm.

Adequate statistical information is not presently available to determine the difference in the RI level between the average and maximum fair-weather values or between the fair and foul-weather values.

However, based on the results of some long-term studies (Maruvada 2000), the maximum fair weather RI may be obtained by adding 6 dB and the average foul weather RI may be obtained by subtracting 5 dB from the average fair-weather value.

Design criteria for RI from transmission lines are generally based on signal-to-noise ratios (SNR) for acceptable AM radio reception, similarly as presented for AC line (Section 4.1).

For the Base example the following value is obtained:

$$\begin{aligned} \mathrm{RI} &= 51.7 + 86\ \log\frac{23.28}{25.6} + 40\ \log\frac{3.822}{4.62} + \\ &10\left[1 - \log^2(10\cdot 1)\right] + 40\ \log\frac{19.9}{30} + \frac{600}{300} = 41.8\ \mathrm{dB} \end{aligned}$$

Note that it was assumed: $f = 1$ MHz; $D = 30$ m; $q = 600$ m.

4.19.3.2 Audible Noise

As in the case of RI, analytical treatment of AN from transmission lines requires knowledge of a quantity known as generated acoustic power density, which can be obtained only through extensive measurements on an experimental line using a number of conductor bundles and carried out in different weather conditions.

Based on measurements made on experimental as well as operating DC lines and the general characteristics of Corona-generated AN, an empirical formula has been developed (Chartier et al. 1981) for the mean fair weather AN, in dBA, from a DC line as:

$$\begin{aligned} \mathrm{AN} &= \mathrm{AN}_0 + 86\ \log(g) + k\ \log(n) + \\ &40\ \log(d) - 11.4\ \log(R) + \frac{q}{300} \end{aligned} \tag{4.226}$$

where:

g = average maximum bundle gradient, kV/cm
n = number of sub-conductors
d = conductor diameter, cm
R = radial distance from the positive conductor to the point of observation

The empirical constants k and $AN0$ are given as:

$$k = 25.6 \quad \text{for } n > 2$$
$$k = 0 \quad \text{for } n = 1,2$$
$$AN_0 = -100.62 \quad \text{for } n > 2$$
$$AN_0 = -93.4 \quad \text{for } n = 1,2$$

The maximum fair-weather AN (probability 10% of not being exceeded) is calculated by adding 5 dBA to the mean fair weather value obtained above, while the mean AN during rain is calculated by subtracting 6 dBA from the mean fair weather AN.

As in the case of RI, there are presently no regulations for AN from HVDC transmission lines. The Environmental Protection Agency (EPA) in the US recommends that the day-night average sound level L_{dn} (U.S. EPA 1974) be limited to 55 dBA outdoors. The level L_{dn} is defined as:

$$L_{dn} = 10 \log\left\{\frac{1}{24}\left[15 \cdot 10^{\frac{L_d}{10}} + 9 \cdot 10^{\frac{L_n+10}{10}}\right]\right\} \tag{4.227}$$

where L_d and L_n are the day and night time sound levels, respectively. However, since the highest level of AN from DC lines occurs in fair weather, it may be prudent to limit the L_{dn} (10%) of AN from HVDC transmission lines to 55 dBA, and this corresponds to 50 dBA for L_{dn}(50%). Reference (Chartier et al. 1981) indicates that the night and the all time distribution are close together by 1.5 dBA. Therefore assuming $L_d = L_n = 42$ to 44 dBA, it results $L_{dn} \sim 50$ dBA.

As a conclusion, the AN calculated by the equation above (average value) shall be limited to ~42 dBA at the edge of the right-of-way.

For the Base Case example the following value is obtained:

$$\text{AN} = -100.62 + 86 \log(23.28) + 25.6 \log(3) +$$
$$40 \log(3.822) - 11.4 \log(\sqrt{12.5^2 + (30 \quad 6.5)^2}) + \frac{600}{300}$$

AN = 38.2 dBA

Note that: $D = 30$ m; $q = 600$ m

In the Figure 4.64 the values of AN and RI as function of the lateral distance are shown.

It can be seeing that RI will govern the right-of-way width requirements. It should be remembered that the conductor position in the calculations were those in the mid-span. Sometimes the equivalent distance to ground (minimum distance plus 1/3 of the sag) may be used.

4.19.3.3 Final ROW Width

The final right-of-way of a HVDC line is chosen as the largest requirements for insulation coordination and Corona effect.

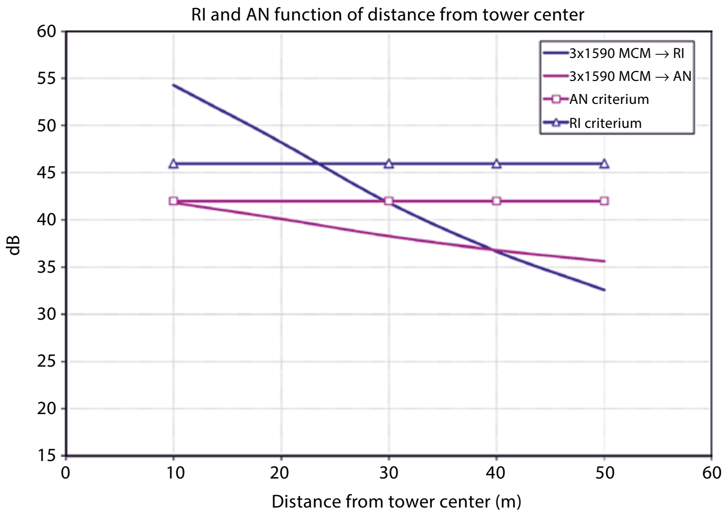


Figure 4.64 RI and AN values for the Base Case example and criteria.

Figure 4.65 (from (Cigré TB 388 2009)) illustrates what defines the (1/2 ROW) for ±500 kV, 3 conductors per pole. In this case, RI governs for conductors larger than 1400 MCM (insulation requirements are always smaller in this case).

4.20 Electric and Magnetic Field

4.20.1 Ground-Level Electric Field and Ion Current

4.20.1.1 Introduction

Induction effects under AC transmission lines are defined mainly in terms of the magnitude and frequency of the alternating electric fields at the ground level. In the case of DC transmission lines, however, the magnitudes of both the electric field and the Corona-generated ion currents at ground level are required to characterize any induction effects.

Corona-generated ion space charge fills the entire space between the conductors and the ground plane. In the cases of both unipolar and bipolar DC transmission lines, only positive or negative unipolar space charge exists at ground level. The combined presence of DC electric field and ion space charge is generally known as space charge field (Maruvada 2000).

Both unipolar and bipolar space charge fields are defined in terms of a set of coupled non-linear partial differential equations. Solution of these equations, with appropriate boundary conditions, provides a description of the electric field, space charge density and ion current density at every point and, consequently, at the surface of the ground plane.

Unipolar DC space charge fields are defined by the following equations:

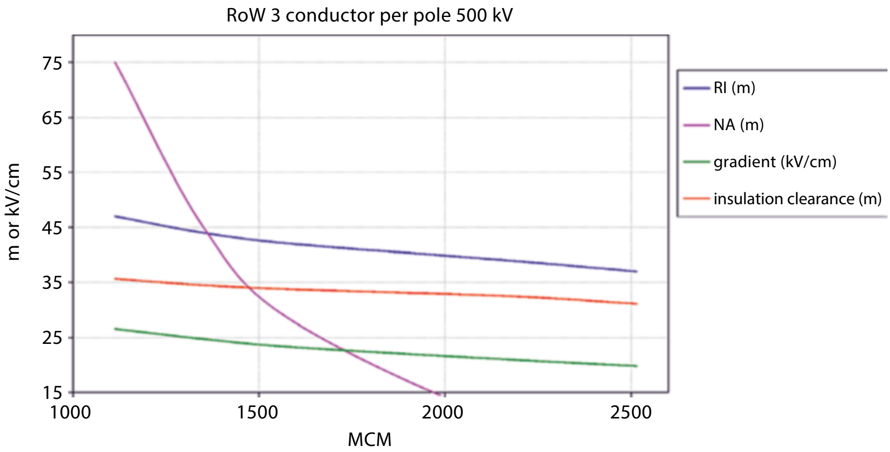


Figure 4.65 Half ROW requirements and gradient for ±500 kV (bipole having three conductors per pole).

$$\nabla \boldsymbol{E} = \frac{\rho}{\varepsilon_0} \tag{4.228}$$

$$\boldsymbol{J} = \mu\rho \boldsymbol{E} \tag{4.229}$$

$$\nabla \boldsymbol{J} = 0 \tag{4.230}$$

where $\boldsymbol{E}$ and $\boldsymbol{J}$ are the electric field and current density vectors at any point in space, ρ is the space charge density, μ is the ionic mobility and ε_0 is the permittivity of free space. The first is Poisson's equation, the second defines the relationship between the current density and electric field vectors, and the third is the continuity equation for ions. Solution of these equations, along with appropriate boundary conditions, for the conductor-ground-plane geometry of the HVDC transmission line, determines the ground-level electric field and ion current distributions (Maruvada 2000).

Corona activity on the conductors and the resulting space charge field are influenced, in addition to the line voltage and geometry, by ambient weather conditions such as temperature, pressure, humidity, precipitation and wind velocity as well as by the presence of any aerosols and atmospheric pollution. It is difficult, if not impossible, to take all these factors into account in any analytical treatment of space charge fields. Information on the Corona onset gradients of conductors, which is an essential input in the analytical determination of electric field and ion current environment, is also difficult to obtain under practical operating conditions. For these reasons, it is necessary to use analytical methods in combination with accurate long-term measurements of ground-level electric field and ion current distributions under experimental as well as operating HVDC transmission lines, in order to develop prediction methods.

4.20.1.2 Calculation Methods

- The first method for solving equations above for multiconductor dc transmission line configurations was developed by Maruvada and Janischewskyj (Maruvada 2000). The method, originally developed to calculate Corona loss currents, involves the complete solution of the unipolar space charge modified fields and, consequently, the determination of the ground-level electric field and ion current density distributions. The method of analysis does not include the influence of wind.

The method of analysis is based on the following assumptions:

  - The space charge affects only the magnitude and not the direction of the electric field
  - For voltages above Corona onset, the magnitude of the electric field at the surface of the conductor in Corona remains constant at the onset value.

The first assumption, often referred to as Deutsch's assumption, implies that the geometric pattern of the electric field distribution is unaffected by the presence of the space charge and that the flux lines are unchanged while the equipotential lines are shifted. Since HVDC transmission lines are generally designed to operate at conductor surface gradients which are only slightly above Corona onset values, Corona on the conductors generates low-density space charge and the ions may be assumed to flow along the flux lines of the space-charge-free electric field. This assumption is much more valid for dc transmission lines than for electrostatic precipitators where Corona intensity and space charge densities are very high.

The second assumption, which was also implied in Townsend's analysis, has been justified from theoretical as well as experimental points of view.

- Gela and Janischewskyj (Janischewsky et al. 1979) developed the first Finite Element Method (FEM) for solving the unipolar space charge modified field problem without recourse to Deutsch's assumption. This method has been used and improved by many authors. However the method is quite complex and difficult to be used for line designers
- A simplified method of analysis was developed at the Bonneville Power Administration (BPA) for determining the ground-level electric field and current density under unipolar and bipolar dc transmission lines. In addition to the two assumptions mentioned, other simplifying assumptions were made to develop the computer program ANYPOLE which was made available in the public domain. One of the simplifying assumptions made in this program was the replacement of bundled conductors by an equivalent single conductor.

The input data and the results of calculation for the Base Case example follows (Figures 4.66 and 4.67).

According to (Chartier et al. 1981) the values obtained using the default values for Corona and Ion information lead to results with 90% probability of not being exceeded.

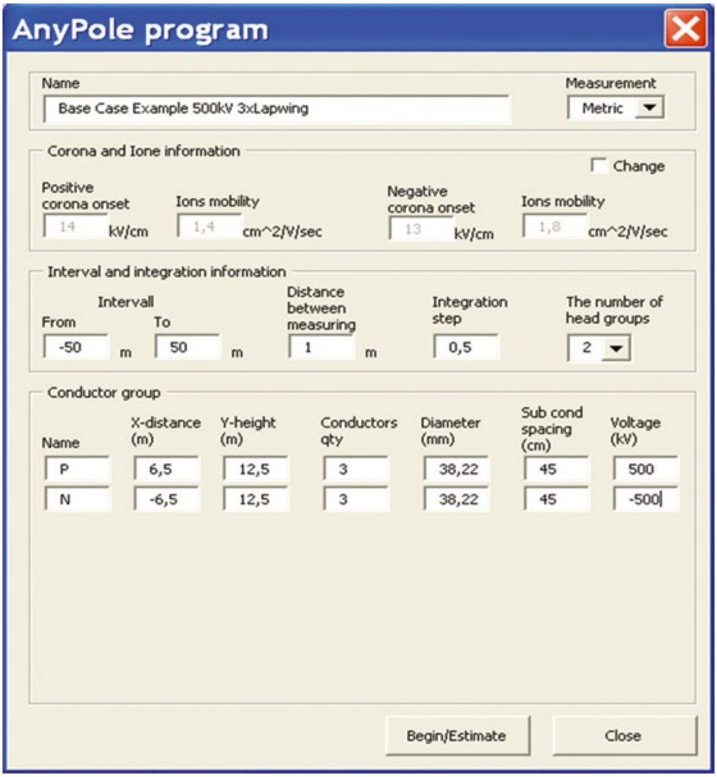


Figure 4.66 Input data Base Case example.

- Empirical methods are generally derived from extensive experimental data obtained preferably on operating HVDC transmission lines, but also on full-scale test lines. In order to derive valid and accurate methods, the experimental data should be obtained for lines of different voltages and configurations with a wide range of values for parameters such as conductor bundle, conductor height and pole spacing in the case of bipolar lines. The validity is usually restricted to the range of values of line parameters for which the experimental data, used to derive the empirical method, was obtained.

A semi-empirical method, called the "degree of Corona saturation" method, was proposed (Johnson et al. 1987) for calculating ground-level electric fields and ion currents under bipolar dc lines. The basic principle of the method is given by the equation,

$$Q = Q_e + S\left(Q_s - Q_e\right) \tag{4.231}$$

where Q_e is the electrostatic value of any parameter (electric field, ion current density or space charge density), Q_S is the saturated value of the parameter and S is the degree of saturation. The electrostatic value Q_e of the parameter can be calculated

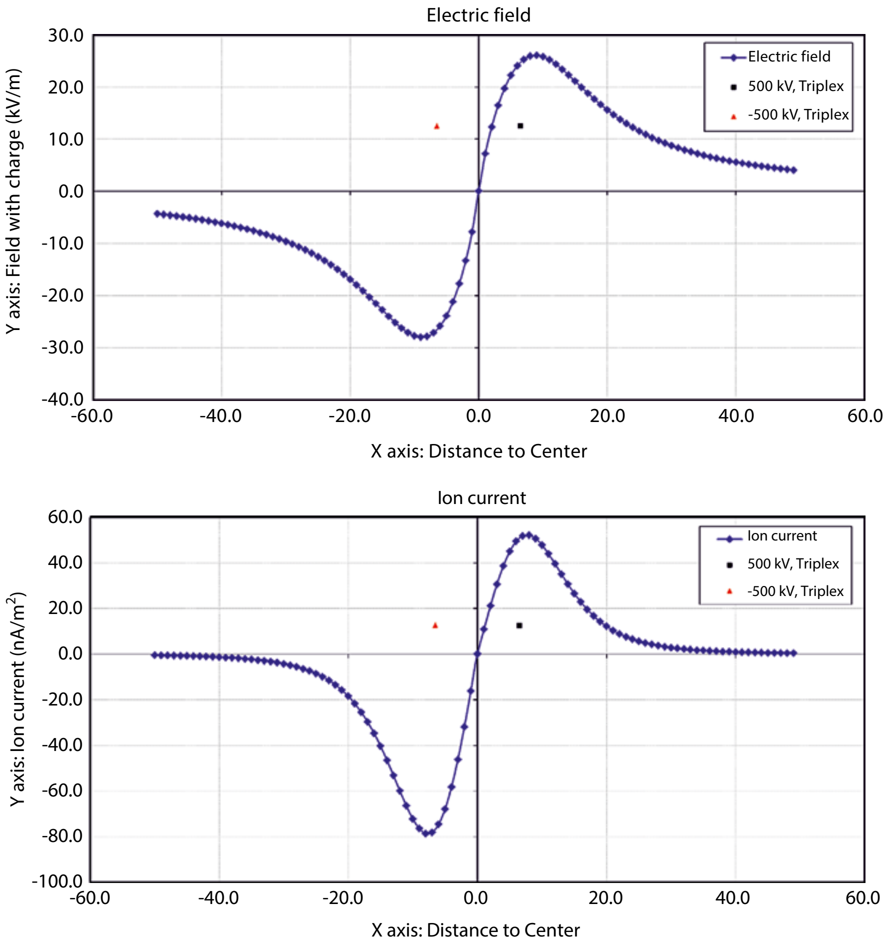


Figure 4.67 Results of calculation for the Base Case example.

using the well-established electrostatic field theory. It should be noted that the electrostatic values of current density and charge density are zero.

Equations were derived for the saturated values of Q_S of the electric field, ion current density and charge density, based on laboratory tests on reduced-scale models with thin wires of unipolar and bipolar dc line configurations. The degree of Corona saturation factor S was derived from full-scale tests carried out on a number of bipolar dc line configurations.

The reference (Johnson et al. 1987) presents the equations and parameters to carry on the calculations and are reproduced here

- *Maximum saturated values (positive or negative), within right of way (in the ground, close to conductors, bipolar lines) [4.6].*

$$E = 1.31\left(1 - e^{-1.7P/H}\right) V / H \tag{4.232}$$

$$J_{+} = 1.65 \times 10^{-15}\left(1 - e^{-0.7P/H}\right) V^2 / H^3 \tag{4.233}$$

$$J_{-} = 2.15 \times 10^{-15}\left(1 - e^{-0.07P/H}\right) V^2 / H^3 \tag{4.234}$$

P = pole spacing (m)
H = conductor height (m)
V = Voltage (kV)
E = Electric field (kV/m)
J = Ion flow (A/m^2)

- Maximum saturated values in the ground, at any distance "x" from the tower center provided that $1 < (x - P/2)/H < 4$

$$E = 1.46\left[1 - e^{-2.5\,P/H}\right].e^{-0.7(x - P/2)/H} V / H \tag{4.235}$$

$$J_{+} = 1.54\ 10^{-15}\left[1 - e^{-1.5\,P/H}\right].e^{-1.75(x - P/2)/H} V^2 / H^3 \tag{4.236}$$

$$J_{-} = 2.\ 10^{-15}\left[1 - e^{-1.5\,P/H}\right].e^{-1.75(x - P/2)/H} V^2 / H^3 \tag{4.237}$$

- Electrical Field without space charge

$$E = \frac{2VH}{\ell n\left(\dfrac{4H}{D_{eq}}\right) - \dfrac{1}{2}\ell n\left[\dfrac{4H^2 + P^2}{P^2}\right]} \left[\frac{1}{H^2 + (x - P/2)^2} - \frac{1}{H^2 + (x + P/2)^2}\right] \tag{4.238}$$

- Saturation factor

$$S = 1 - e^{-k(G - G_o)} \tag{4.239}$$

k = empirical coefficient
G = surface gradient (kV/cm)
G_o = empirical coefficient

- Values considering the degree of saturation

Table 4.39 Parameters Go and k for the weather conditions

		summer fair	spring fair	fall fair	summer humidity fog	summer rain	snow
	Go	9	14.5	12	7.5	6	12
positive 50%	K	0.037	0.041	0.039	0.06	0.058	0.03
	Go	3	11	10	3	6	11
positive 95%	K	0.067	0.086	0.092	0.086	0.087	0.045
	Go	9	14.5	12	8.5	6	12
negative 50%	K	0.015	0.021	0.017	0.045	0.058	0.03
	Go	3	11	11	3	6	11
negative 95%	K	0.032	0.065	0.07	0.063	0.087	0.045

$$Q = Q_e + S\left(Q_s - Q_e\right) \tag{4.240}$$

Q = value of a quantity (electrical field, ion flow, etc.)
Q_s = saturated value
Q_e = electrostatic value
S = degree of saturation

Information obtained from field tests (Johnson et al. 1987), parameters for the calculation considering the effect of weather, are shown in Table 4.39.

Moderate weather can be represented by “fall-fair” and extreme by “summer high humidity and fog”.

Below the results (with intermediate calculation values) for the Base Case example are shown (Tables 4.40 and 4.41).

4.20.1.3 Design Criteria

Reference (Cigré TB 473reports the analysis done by Cigré JWG B4/C3/B2.50 related to electric fields near HVDC lines and concluded:

“None of the scientific weight-of-evidence reviews conducted to date concluded that any adverse health effects of exposure are likely but micro-shocks under some conditions under a DC transmission line could be annoying or provoke startle”.

In the absence of any significant induction effects and the lack of evidence linking exposure to dc electric fields and ion currents with any health hazards, perception thresholds for dc electric fields and ion currents are generally used as criteria for the design of dc transmission lines. Figure 4.68 summarizes the results of an investigation conducted to evaluate the perception of electric field.

From the figure it can be seeing that:

- for 25 kV/m and 100 nA/m^2, 1/3 of the persons perceived the existence of the field
- for 15 kV/m and 15 nA/m^2, less than 10% perceived the field

Table 4.40 Data and intermediate values

	Worst value	at $X=20$ m
Voltage (kV)	+/−500	+/−500
Conductor diam (cm)	3.822	3.822
Number of cond.	3	3
Bundle spacing (cm)	45	45
Pole Spacing P (m)	13	13
Height H (m)	12.5	12.5
X distance center (m)	10	20
P/H	1.04	1.04
H/V	0.025	0.025
H/Deq	39.81	39.81
E_s maximum sat values	43.46	
J_+ 10^{-15} max sat values	109.21	
J_- 10^{-15} max sat values	142.30	
$X-P/2$	3.5	13.5
$X+P/2$	16.5	26.5
$(X-P/2)/H$	0.28	1.08
E_s sat at X		25.39
J_+ sat at X		19.26
J_- sat at X		30.55
G without space charge at X	10.5	5.2

Table 4.41 Results: E (kV/m); J (nA/m^2)

	Worst value	at $X=20$ m	Worst value	at $X=20$ m
	Spring	Spring	Summer high humidity/fog	Summer high humidity/fog
S 50% pos	0.302	0.302	0.612	0.612
S 95% pos	0.652	0.652	0.825	0.825
S 50% neg	0.168	0.168	0.486	0.486
S 95% neg	0.550	0.550	0.721	0.721
E 50% pos	20.4	11.3	30.7	17.6
E 95% pos	32.0	18.4	37.7	21.9
E 50% neg	16.0	8.6	26.5	15.0
E 95% neg	28.6	16.3	34.3	19.8
J 50% pos	33.0	5.8	66.8	11.8
J 95% pos	71.2	12.6	90.1	15.9
J 50% neg	24.0	5.1	69.1	14.8
J 95% neg	78.2	16.8	102.6	22.0

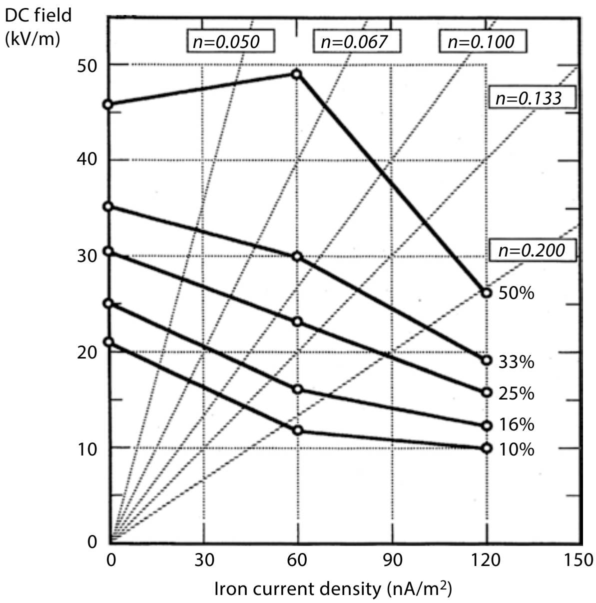


Figure 4.68 DC field intensities and ion current densities detected by various of the more sensitive subjects.

- Therefore a pair E and J can be selected as design criteria associated with aweather condition, for example:

- in any place inside the ROW: 25 kV/m; 100 nA/m^2, spring 50% values (average); or40 kV/m; 90 nA/m^2 summer high humidity/fog
- at the ROW edge 10 to 15 kV/m; 10 to 15 nA/m^2, summer high humidity/fog 95% values.

4.20.2 Magnetic Field

The magnetic field of transmission lines is calculated using two-dimensional analysis assuming conductors parallel over a flat terrain.

The magnetic field H_{ji} at a point(x_i, y_i) at a distance r_{ij} from the AC and DC conductor or shield wires with a current I_i (real part only) is calculated as if for AC lines.

Figure 4.69 shows the magnetic field for the Base Case example considering 1300 MW and ± 500 kV.

Note that the currents in the poles are of different polarity, therefore reducing the effect. For monopolar transmission the magnetic fields are higher. The magnetic field is of the order of the earth magnetic field ~50 μT.

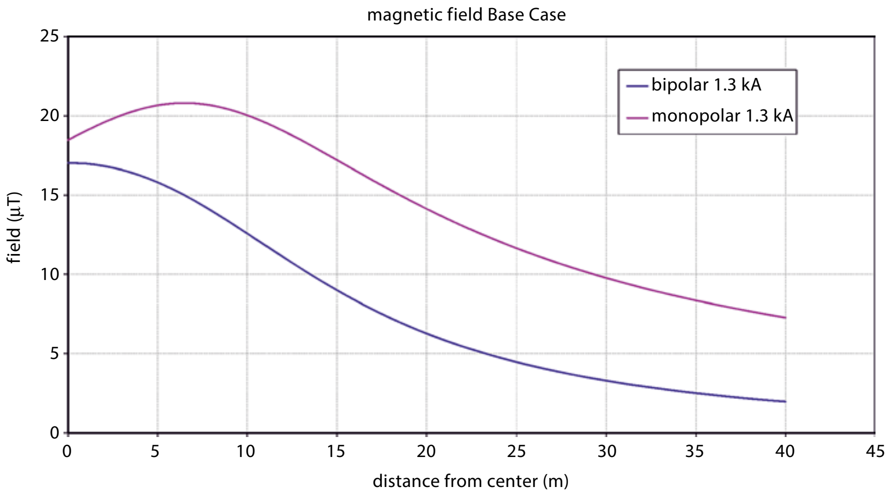


Figure 4.69 Magnetic Field.

4.21 Hybrid Corridor or Tower

Today important discussion has been carried out related to conversion of AC to DC lines. In these cases there comes the possibility of having AC and DC line close together or in the same tower.

In this case there will be interaction of electric and magnetic field and change in the conductor surface gradient due to induction from one circuit to the other, therefor influencing the Corona phenomena.

It is well accepted practice that Corona and field effects need to be taken into account when designing new AC and DC power lines, when up-rating the voltage of an existing AC line, or when converting existing AC lines to DC operation. The aim of this item is therefore to give a sufficiently detailed description of the characteristics and prediction of DC Corona and field effects and how to integrate these into converted line designs. The various technical descriptions have also attempted to emphasize those aspects which relate specifically to the conversion of AC lines to DC operation (Cigré WG B2 41).

4.21.1 Conductor Surface Gradient

The calculation procedure shall include the concept that the AC conductor surface voltage gradients are biased by the presence of the DC conductors, while the DC conductor surface gradients include a ripple emanating from the presence of the AC conductors, as illustrated in Figure 4.70. The calculation procedure proposed covers only electrostatic effects; any influence of space charges on the electric fields on the surface of the AC conductors is tentatively disregarded.

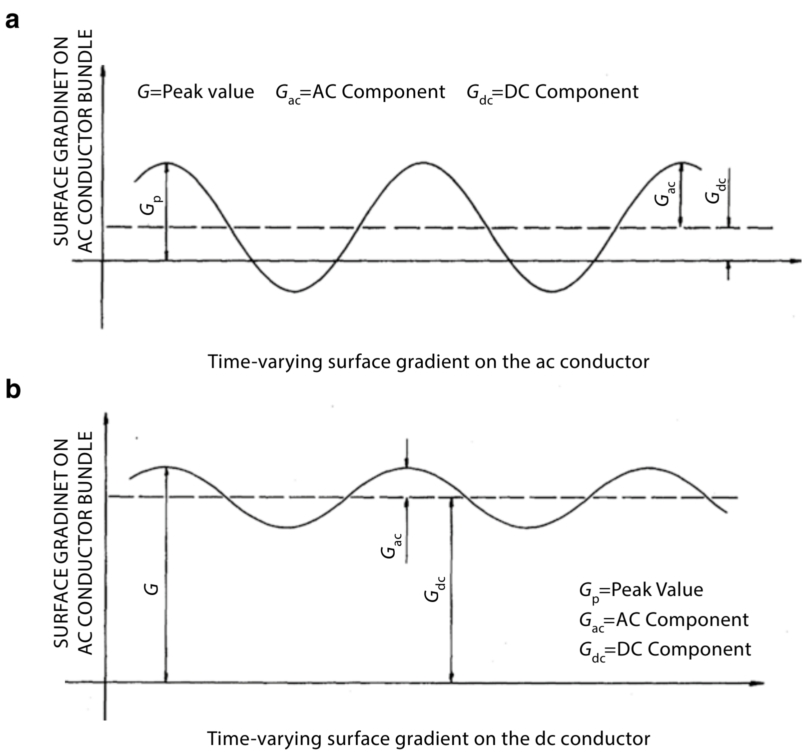


Figure 4.70 Conductor surface voltage gradients in hybrid configurations.

As discussed later, the Corona performance of a hybrid configuration can then be established by applying conventional calculation methods in the following way:

- Calculate the peak values of the combined AC and DC electric field distribution on the surfaces of the AC and DC conductors.
- The Corona performance of the AC conductors may be calculated as for conventional AC lines after dividing the peak values of the calculated conductor surface gradients by $\sqrt{2}$.
- The Corona performance of the DC conductors may be calculated using conventional DC empirical methods by applying the peak values of the conductor surface gradient.

4.21.2 Radio Interference

The calculation of RI from hybrid configurations presents some peculiarities.

- RI levels from DC lines are higher in fair-weather than in rain, and therefore primarily considered as a fair-weather phenomenon. On the other hand, RI levels from AC lines are considered as both a fair weather and a foul weather phenomenon. For hybrid configurations, it is therefore necessary to study both weather conditions.

- RI from AC conductors occurs around the peak of the positive half-cycle of the power frequency voltage, whereas RI from DC conductors for an equivalent gradient occurs all the time, primarily from the positive conductor.
- The nuisance value appears to be higher for AC than for DC.

The empirical formulas presented can be used to calculate the RI level of a hybrid configuration at any particular distance from each AC phase and DC pole conductor by applying the appropriate surface voltage gradients. With this information, the total RI level is determined by adequately adding those levels for the different weather conditions (Cigré WG B2 41).

Remind that:

For AC contribution: Foul weather RI = heavy rain-7 dB and fair = heavy rain -24 dB

For DC: fair negative weather RI = fair positive- 4 dB and foul = fair-3 dB.

4.21.3 Audible Noise

As with RI, the calculation of AN from hybrid configurations presents some peculiarities:

- AN levels from DC lines are higher in fair-weather than in rain, and therefore primarily considered as a fair-weather phenomenon. In contrast, AN levels from AC lines are much higher in rain and therefore considered as a foul weather phenomenon. For hybrid configurations, it is therefore necessary to study both weather conditions.
- AN from AC conductors occurs around the peak of the positive half cycle of the power frequency voltage, whereas RI from DC conductors for an equivalent gradient occurs all the time, and practically only from the positive conductor.

The empirical formulas presented can be used to calculate the AN level of a hybrid configuration at any particular distance from each AC phase and DC pole conductor by applying the appropriate surface voltage gradients. With this information, the total AN level is determined by adequately adding those levels for the different weather conditions.

Remind that:

For AC contribution: Fair weather AN = foul- 25 dB

For DC: foul weather AN positive = fair positive- 6 dB and foul negative = zero.

4.21.4 Corona Losses

Formulas for calculating Corona losses on AC lines and isolated DC lines are presented previously. However, due to the lack of full-scale test results there is no information available how to apply these formulas to hybrid configurations (one may use the concept of equivalent surface gradient as input in the presented equations for AC and DC lines.

4.21.5 Electric and Magnetic Fields

The AC electric field at ground is calculated by the conventional method described, with the DC conductors at zero potential. The result is an increase as compared with DC line only (Cigré WG B2).

The DC electric field and ion current density at ground level may be estimated in the same way as for isolated DC lines, with the AC conductors at zero potential.

The magnetic fields are calculated by the conventional method described. The AC and DC magnetic fields can be treated separately since the effects on humans are different (there are no induction effects from DC magnetic fields).

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Joao F. Nolasco graduated in Electric & Electronic Engineering and M.S. in Transmission Systems, as well as in Statistics in State University of Minas Gerais (UFMG), Brazil. Engineer in Siemens Brazil (Jan to June 1967) and then in Siemens Germany (1967-1969). Professor in the UFMG University (1968-1970), then started his career at the Electric Utility Cemig, where has been in sequence Planning Enginer, Design Engineer, Head of Electric Studies of T. Lines and finally Head of Transmission Line Department. From 1994 until today, he has acted as Consultant in both AC and DC Transmission Systems and Planning, providing services to several Utilities and private Transmission Companies in Brazil, Argentine, Chile, Peru, Bolivia, Suriname, Mexico, USA, South Africa etc. In Cigré he has been Member of SC B2 (Overhead Lines) - 1984 to 1998 - and then Convener of some WG's and TF's covering AC & DC lines (1998-2014). Author of more than 100 papers, several technical reports and two Technical Brochures. One of the authors of the Book "Overhead Power Lines" (Springer Verlag, Germany - 1993). He wrote and provided courses on Transmission and Distribution Lines at the University of Cape Town in 1989 and in other countries afterwards.

José Antonio Jardini has received his B.Sc. degree from the Polytechnic School at the University of Sao Paulo (USP) in 1963. Subsequently, he obtained his M.Sc. and Ph.D. degrees in 1970 and 1973, all from the same institution. From 1964 to 1991 he worked at Themag Eng. Ltd (Engineering Company) in the area of Power Systems, Automation and Transmission Lines projects. Currently, he is Full Professor in the Department of Engineering of Energy and Electric Automation at University of São Paulo. He is a member of CIGRE and was the Brazilian representative in the SC38 of CIGRE and member of WG B4 (HVDC & FACTS power electronics). At IEEE he is Fellow Member and Distinguished Lecturer of PES/IEEE and was also for IAS/IEEE. He is one of the authors of several Cigré Brochures on HVDC Lines Economics, Convener of JWG Electric of HVDC Transmission Lines, and Converter modelling. He had many volunteer activities at IEEE as: South Brazil section Chairman; region treasurer, IEEE Fellow Committee, nomination boards, Education Society Fellow Committee. Awards: IEEE HVDC Uno Lamm (2014); IEEE MGA Larry K Wilson(2010); IEEE innovation (2004); CIGRE B4 Technical (2011).

Elilson E. Ribeiro graduated in Electrical Engineering (1984) and M. S. in Electric Power Systems (1987) in State University of Minas Gerais (UFMG). Engineer of MF Consultoria (1987-1998). Professor in the Pontifical Catholic University of Minas Gerais (PUC Minas; from 1999 until today) and Director of NSA Consultoria. He has acted as Consultant, primarily, in the areas of electromagnetic and thermal modelling in equipment development (air core power reactors), grounding system design (for transmission lines, power substation and industrial installations), analysis of electromagnetic transients in electric power systems, analysis of electromagnetic interference from transmission lines and transmission line design.

Structural and Mechanical Design

5

Elias Ghannoum

Contents

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E. Ghannoum (✉)
Montreal, Canada
e-mail: elias@ghannoum.com

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5.1 Introduction

This chapter describes the studies made by Cigré in the area of structural design of overhead lines.

The first part is devoted to the Reliability Based Design (RBD) method, particularly IEC 60826 where Cigré SC22-B2 Committees played an important role in supporting and contributing to this international standard nowadays widely used worldwide. In this part, the principles of RBD are explained as well as the requirements of IEC 60826. This is followed in 2006 by a comparison of RBD standards to IEC 60826.

In the second part “tower top geometry and mid-span clearances” the methods to establish the distances between conductors and the supporting structure either in mid-span or at the tower are given as in the reference Cigré studies and Brochures.

The third part covers load control devices that were developed to reduce dynamic and/or static load on structures in case of a failure in order to reduce possibility of cascading events.

The fourth part covers the Mechanical Security of Overhead Lines Containing Cascading Failures and Mitigating Their Effects.

Finally, the fifth part covers the influence of line design parameters on line security.

5.2 Deterministic and Reliability Based Design (RBD) Methods

5.2.1 Historical Background

During recent decades, the IEC (International Electrotechnical Commission) Committee TC11 and Cigré Study Committee SC 22 (now SC B2) pioneered improvement of deterministic overhead transmission lines design criteria as well as the introduction of reliability/probability based design concepts, in, for example Cigré 1990 [2], Cigré 2001 [3], Ghannoum-Orawski, 1986 [4].

The technical work on reliability based transmission line design started in Cigré more than 40 years ago under the sauspices of Study Committee 22. Many experts, to name a few, such as Commellini, Manuzio, Cojan, Paris, White, Schjetne, Wood, Orawski, Kieβling, Henrioul, Rogier, Ghannoum, etc., contributed to this work either in the SC22 or in Cigré papers and publications.

Further technical development was pioneered by a joint effort between Cigré and IEC through both technical working groups SC22-06 from Cigré, initially chaired by Georges Orawski from the UK, and IEC/TC11/WG08 chaired by Elias Ghannoum.

As a result of the above technical work, a milestone occurred in 1991 when IEC 826[1] entitled "Loading and Strength of Overhead Lines" was published by IEC in 1991 as a technical report type II, i.e., a pre-standard document to be reviewed in a few years for the purpose of converting it to an IEC standard. This publication introduced reliability and probabilistic concepts for calculation of loading and strength requirements for overhead line components.

Subsequent work by Cigré SC22-WG06 helped in modifying the IEC report and, in October 2003, Standard IEC 60826 [1] was published by the IEC after a unanimous positive vote by National Committees.

This chapter aims to increase understanding of IEC 60826 as well as its application to overhead lines. It demonstrates why Reliability Based Design (RBD) methods constitute a major improvement compared to deterministic methods and summarizes the main features of IEC 60826.

[1] *The new number of this publication in the IEC catalogue is 60826 and the older version 826 is not anymore available.*

5.2.2 The Need for Reliability Based Design in Overhead Line Design

Many current standards and design practices in the world are deterministic in nature and some of them are even imported from other countries, despite major differences in climatic and terrain conditions.

However, it is fair to recognize that deterministic methods have evolved, and many utilities or countries tried to address deficiencies they have identified in their deterministic design practices by specifying additional loading cases and strength requirements, often much more critical than their basic standards.

Despite improvements, experience and technical studies have shown that deterministic methods have inherent deficiencies that cannot be addressed by minor changes in the design requirements, and can only be resolved by migrating to RBD. Some of the potential deficiencies of deterministic methods are given hereafter and practical examples are provided.

5.2.2.1 Possible Inconsistencies and Unbalance in Strengths of Components

The objective of deterministic methods is to comply, as a minimum, with the safety (or overload) factors required for each loading case specified. There are usually no requirements for a preferred sequence of failure in these standards and any sequence can be expected as a result of deterministic design.

In a number of reviews of standards and line failure analyses performed by the Author, it was found that the withstand of some angle and dead-end towers were in fact less than that of tangent towers. This is particularly true in lines located in icing areas where tangent towers are designed with wind and weight spans significantly exceeding average spans, while angle towers may be used at their maximum angles.[2]

Cases where tangent tower can withstand as much as 40–50 mm of radial ice, while angle towers can fail due to 35 mm of ice are not uncommon in locations with important ice loads.

5.2.2.2 Unknown Reliability Level

Except by a general inference from very long experience, it is very difficult to attribute a reliability value to any design based on deterministic principles. In fact these principles do not even recognize that load can exceed strength (both values are deemed to be constant) and often imply that whoever follows such principles should obtain a safe and reliable line.

The past experience is not always a good descriptor of reliability, especially if the experience with these design criteria is not long enough and the transmission line system covers only a small fraction of the total service area. For example, if the real probability of failure of existing lines designed according to deterministic loads is low, say 3 % every year, there is about 50 % chance that no failure will occur during a 20–25 year life span. Thus, the fact that no failures occurred during this period is not always a good measure of the actual line reliability.

[2] *This is usually the case in many lines, because line routes and line deviation angles often aim to use expensive angle towers at their maximum angles.*

5.2.2.3 Difficulty to Adjust the Overall Line Reliability

If a designer wants to increase the reliability of a given line because of its importance in the network, he has few means to assess the quantum of increase in the safety (or overload) factors he currently uses to improve the reliability. He simply does not have sufficient information to decide if an increase, say of 10 % or 30 % in the safety factors, would be significant enough or not.

5.2.2.4 Difficulty to Design Heterogeneous Structures such as Combination of Steel and Wood

When designing a structure using different materials, such wood poles and steel crossarms, if the same overload factors are applied to loads, they will lead to unequal reliability between these structural parts of the same structure.

For example, the compressive stresses of wood pole stresses in North America were given as average values. In recognition of this fact and the large strength dispersion of wood strength, a safety factor of 4 was specified for compression loads. If a wood crossarm is substituted by a steel section, the deterministic design methods do not have the appropriate tools to provide for a substitute and equivalent safety factor for steel crossarms.

5.2.2.5 Difficulty to Evolve with new Technologies

The above example of a structure involving different material can be extended to a more general issue of the equivalence between safety factors/overload factors to be applied to different structural components. For example, steel and concrete pole manufacturers recently challenged the large safety factors imposed on them by standards in North America arguing that steel pole properties are quite predictable contrary to wood poles.

The same could be extended to new types of materials such as poles made of fiber reinforced concrete or fiberglass, etc. Deterministic methods cannot provide designers with reliable guidelines to establish equivalent requirements between new material technologies and established ones.

5.2.2.6 Difficulty to Adjust Design to Local Conditions

Deterministic methods cannot efficiently cope with the variations in weather loading that occur in a service area. For example, not so long ago, North America was divided in only a handful of loading zones, each one as large as many European countries combined. Another major problem arises because the specified climatic loadings are not related to any specified return period. For example, the combined ice and wind load of 12.7 mm of radial ice and 385 Pa of wind pressure[3] specified in CSA C22.3 for Canada was estimated, using RBD, to correspond to return periods of 3 to 500 years, depending on the actual location.

[3] *This pressure corresponds to a 10 min wind speed of about 65 to 70 km/h for conductors at 10 m of height in a terrain type B.*

5.2.3 How RBD Methods Address the Deficiencies of Deterministic Design Procedures

The following basic principles are used by RBD methods in order to address the deficiencies stated above in deterministic methods:

5.2.3.1 Limit Loads are Specified

Contrary to deterministic methods that incorporate safety and/or overload factors, RBD specifies the limit loads[4] that the line has to withstand without damage. When limit loads are used, these are transferred to the conductors and then to hardware, to towers (suspension or dead-end) and to foundations. Therefore, each line component will be designed for the effects of the same limit loads considered for the line, without the risk of mismatch between components.

5.2.3.2 Loads and Strength are Recognized as Random Variables and Treated as such

There is no disagreement between proponents of RBD or deterministic methods that loads (e.g. ice, wind, temperature and their combinations) and strengths are random variables. When the randomness of loads and strengths are taken into account, there is an immediate recognition that absolute reliability cannot be achieved and that there is always a risk that design loads can be exceeded or component's strength can be less that design values.

Therefore, RBD design standards will have to specify an acceptable maximum probability of failure (or its complement to one, the minimum reliability) and provide means to modulate these probabilities if warranted by economics or the importance of the project.

5.2.3.3 Design Loads are Selected Based on the Required Return Period

It is widely accepted that yearly maximum climatic loads such as ice and/or wind, follow extreme distribution functions. With such statistical functions, designers can associate a value of loads for any selected return period.

The return period is an important parameter for qualifying reliability. For example, if a 150 year return period load is selected as the limit load to design for, the probability of exceeding this load is $1/150 \approx 0.67\,\%$ per year. In a 50 year life span, the probability of exceeding the same load is equal to $[1\text{-}(1\text{-}1/150)^{50}] \approx 28\,\%$.

5.2.3.4 The Characteristic Strength to be Associated with Load Q_T is also Dependent on Strength Dispersion and is Equal to the 10 % Exclusion Limit

Similarly, the strength is also a random variable, typically described by normal or log-normal distribution functions. The design strength is usually taken as the average minus 1 to 3 standard deviations. If the strength were chosen with an exclusion limit of 10 %, this value would correspond to the average strength minus 1.28× standard deviation in the case of a Normal distribution function.

[4] *These loads are sometimes called ultimate loads, but the wording "limit" is a preferred one.*

5.2.3.5 The Association of Q_T and (10 %) R will Yield an almost Constant Yearly Reliability of the order of 1/(2 T)

The line reliability and unreliability threshold corresponds to the condition where the load effect is equal to the strength. If load does not exceed strength, then the system (transmission line) is reliable. In the opposite case, the line would be in a failed condition.

If a load Q_T is associated with a strength corresponding to 10 % exclusion limit, the resulting reliability is almost constant and equal to 1/(2 T) in the normal range of variation of Q and R. This very significant relationship was uncovered and proven in previous papers and Cigré reports written by Ghannoum.

5.2.3.6 Yearly Reliability can be Customized by Varying the Return Period T of Design Loads

Increasing reliability with RBD can be done very easily, either by selecting loads with a higher return period, or strength with a lower exclusion limit. The former approach is more practical and accurate and was selected by Cigré and IEC.

5.2.4 How to Apply IEC 60826

5.2.4.1 Design Steps of IEC 60826

The design methodology as per IEC60826 can be summarized in Figure 5.1. It is noted that activities (a) and (h) listed in this figure are not within the scope of IEC 60826.

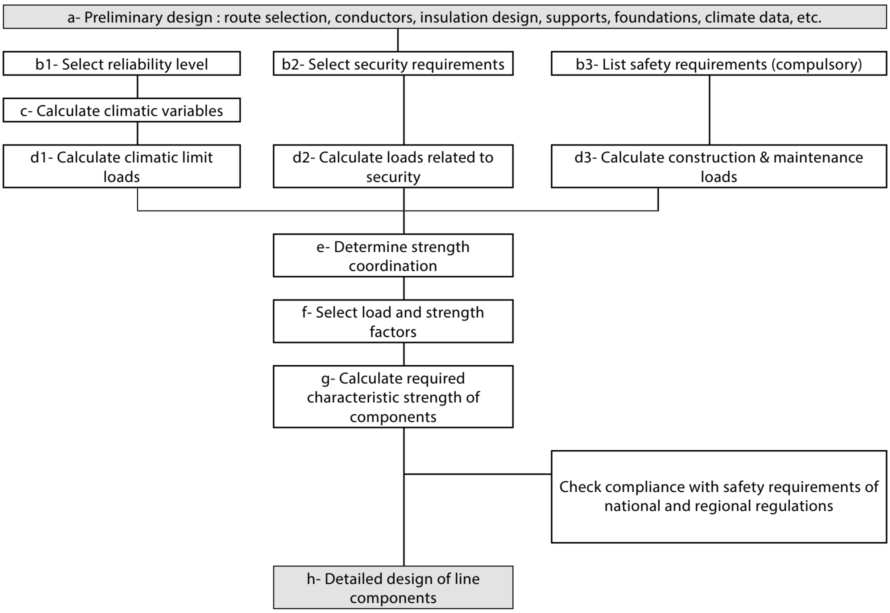

Figure 5.1 Transmission line design methodology according to IEC 60826.

5.2.4.2 Source of Design Requirements

The design according to IEC 60826 (see boxes b1, b2 and b3 in Figure 5.1) originates from the following requirements:

- Reliability: These requirements consist of climatic loads (wind, ice, temperature and their combinations) and aim to provide lines with satisfactory service performance. Statistical tools are used to quantify these loads.
- Security: These requirements aim to prevent or reduce risk of uncontrollable or cascading failures.
- Safety: These requirements aim to prevent human injury.

5.2.4.3 Reliability Levels

Three Reliability levels (I, II, III) are proposed in IEC 60826. These levels correspond to return periods of design loads of 50, 150 and 500 years. In general,

- Level I is considered minimum for all permanent lines
- Level II applies to lines with voltages equal or exceeding 230 kV
- Level III applies to important lines in excess of 230 kV that are a unique source of supply.

Other levels can be selected based local conditions or on an economical optimization between cost of increased reliability and present worth of future failures.

5.2.4.4 Security Requirements

Security requirements relate to behavior of lines once failure is initiated. They aim to prevent uncontrolled propagation of failures (cascading). In such case, components are allowed to reach stresses very close to their ultimate limit state (failure). It is noted that in IEC 60826, security is a deterministic concept, while reliability is probabilistic.

Security and reliability requirements are interrelated because both tend to increase the required strength of components. Security measures, if more critical than climatic loads (reliability requirements), can also increase reliability.

5.2.4.5 Safety Requirements

These are required to protect people from injury. They consist of construction and maintenance loads. It is aimed that the probability of failure under such loads should be very low.

5.2.4.6 Design Equation, General Format

$$\text{Load effect} < \text{Strength}$$

or:

$$Q_T < R_C$$

or: Load corresponding to a return period T < Characteristic strength R_C

The above equation has been expanded in the IEC standard to the form below:

$$\gamma Q_T = \phi_R \ R_C$$

where:

γ factor for span dispersion, default value equal to 1.0 for new lines
Q_T load corresponding to a return period T
ϕ_R global strength factor equal to the product of ϕ_S ϕ_N ϕ_Q ϕ_C
ϕ_S factor related to coordination of strength (sequence of failure)
ϕ_N factor related to number N of components
ϕ_Q factor related to the difference between tested and installed component
ϕ_C factor related to the statistical parameters of the characteristic strength

It is important to note that the load Q_T shall be the maximum along the space covered by the line. Furthermore, not only the maximum load intensity is important, but also its spatial coverage, as both affect design requirements and line reliability. Directional tendencies of wind or ice loads can be taken into account if confirmed; otherwise, it should be assumed that load direction always occurs in the most critical direction.

5.2.4.7 Loading Cases and Limit States

Limit states of strength of line components are defined for each component: a damage limit state (serviceability) and a failure (ultimate) limit state. Each group of loading requirements is associated with one of the limits states given below (Table 5.1).

5.2.4.8 Differences between Theoretical and Actual Reliabilities

IEC 60826 recognizes that the actual reliability may differ from the theoretical reliability when factors such the ones listed below are not properly accounted for:

- Actual use factors of components, particularly towers, are quite different from the assumed value of 1.0;
- The degree of correlation between loads and strengths
- Direction of wind speed in relation to that of the line
- Exclusion limit of strength different from the assumed 10 %
- Number of components subjected to maximum load intensity
- Quality control during fabrication and construction.

Methods to take into account the above factors are covered in the subject standard.

Table 5.1 Loading conditions and strength limits

Condition	Loads	Strength Limit State
Reliability	climatic, ice, wind, wind + ice, with a return period T	damage limit
Security	failure limit (torsional and longitudinal)	failure limit
Safety	construction and maintenance loads	damage limit

5.2.4.9 Use Factor of Components (U)

The use factor in IEC 60826 is defined as the ratio of the actual load (as built) to the limit design load of a component. For tangent towers, it is virtually equal to the ratio of actual to maximum design spans (wind or weight), and for angle towers, it also includes the ratio of the sines of the half angles of deviation (actual to design angles).

Use factor cannot exceed 1.0 and its influence on line reliability has been covered in the IEC standard. The use factor variation in overhead lines is inevitable because of the following reasons:

- Line components are mass fabricated
- Components are not specifically designed for each tower location or use
- Their design parameters reflect maximum usage along the line
- Effective loads on line components are location dependent (span and tower height at each location)

Globally, the use factor variation increases reliability. However, a large dispersion of use factor U may be an indication of a poor optimization (e.g. not enough tangent tower types or their parameters incorrectly selected). It is important to recognize that the preferred sequence of failure could also be altered if the use factor variation is not taken into account.

5.2.4.10 The Characteristic Strength R_C

IEC 60826 makes reference to the characteristic strength which is defined as the strength value guaranteed in relevant Standards. Sometimes, it is also called the guaranteed strength, the minimum strength, or the minimum failing load, and usually corresponds to an exclusion limit, from 2 to 5 %, with 10 % being an upper practical (and conservative) limit.

The strength distribution function is usually Normal (Gaussian). With stringent quality control, it tends to become a Log-normal function.

The characteristic strength can thus be calculated from the following equation, assuming it corresponds to a 10 % exclusion limit:

$$R_C = (10\%)R = R(1 - k\ V_R), \quad \text{where}$$

k = 1.28 for Normal distribution
k = 1.08 to 1.26 for Log-normal distribution.

In case the maximum intensity of load is widespread and covers a large number (N) of structures, the strength distribution becomes that of a chain or a series of N components whose strength is controlled by the weakest. Although the original distribution of strength can be Normal, that of the series of N structures will tend to be an Extreme (minima) type. Correction factors are provided in order to take into account the effect of the spatial coverage of the maximum load event on reliability (ϕ_N factor).

5.2.4.11 Strength Coefficient ϕ_S Related to Sequence of Failure

In IEC 60826, line components can be designed to fail (with a 90% probability) in a preferred mode called "preferred sequence of failure". The best (or least damaging) failure mode is the one where the consequences of the first failure on the line are minimized. Strength factors allowing to target a preferred sequence of failure are provided in the standard. It is generally accepted that angle towers, dead-end towers, conductors or foundations should not fail first, thus leaving tangent towers as the one to fail first. Table 5.2 specifies the strength factors applicable to the strength of the component not to fail first.

5.2.4.12 Wind Loads and Limitations of Wind Calculations

Wind loads on conductors and tower structures are the source of important and critical loading requirement for overhead transmission lines. Methods to calculate wind forces, starting with a reference wind speed, are provided in the standard for the following conditions:

- Spans between 200 m and 800 m
- Height of supports less than 60 m
- Altitude below 1300 m.

5.2.4.13 Ground Roughness

For the purpose of calculating wind pressure and forces, four categories of ground roughness (also called terrain types) are provided:

- A- Flat coastal areas and deserts
- B- Open country, cultivated fields
- C- Numerous low height obstacles
- D- Suburban areas.

5.2.4.14 Reference Wind Velocity

The reference wind velocity V_R considered in IEC 60826 consists of a 10 min. average, at 10 m height, in a terrain type B. The standard provides for conversion from other wind data, having different averages or located in a different terrain category, to the above reference value.

Table 5.2 Values of strength coefficient ϕ_S

Coefficient of Variation (COV) of R_1					
		5%	7.5%	10%	20%
COV of	5 - 10 %	0.92	0.87	0.82	0.63
R_2	10 - 40 %	0.94	0.89	0.86	0.66

Note: in the above Table, R_2 is the component designed more reliable than R_1

5.2.4.15 Wind Speed Design Cases

High wind is combined with average minimum daily temperatures, and a reduced wind (60 % of the reference value) is combined with the 50-year minimum temperature.

5.2.4.16 Wind Load Model

The conversion from wind speed V to wind forces follows the equation:

Wind force = k (½ $\tau\mu$ V^2), where k is the product of:

- height factor
- span factor
- response factor
- shape factor.

In IEC 60826, the k factor in the above equation takes the form of:

Wind force = A C_x G_c G_L (½ $\tau\mu$ V^2), with
G_c = the combined wind factor dependent on spans, height and terrain roughness category
G_L = Span factor
C_x = Drag (or force) coefficient

μ is the air mass per unit volume = 1.225 kg/m^3 (this is a default value, but adjustments of μ for different temperatures and altitudes are provided), τ is the air density correction factor given in Table 5 of IEC 60826.

A similar equation provides for calculation of wind forces applied to various types of transmission structures such as those made of angle sections, round pipe sections or steel poles. Drag coefficients are also provided for these tower types and take into account the compactness (or solidity ratio) of the windward face to reflect the shielding of wind on the leeward face.

5.2.4.17 Icing Types

Ice accretion on conductors and structures are the source of important loads, and often control the design in many northern countries. The standard covers three types of ice accretion: precipitation icing, wet snow, and in-cloud icing. Methods to calculate design icing are provided and cover a range of cases with various availabilities of statistical data.

5.2.4.18 Ice Loading Cases

Once design ice thickness or weight of ice per unit length of conductors has been statistically defined, this value is used in the following loading cases:

- Uniform ice formation
- Non uniform ice (longitudinal unbalanced icing, with all phases in a span subjected to the same unbalanced conditions)
- Torsional condition (unbalanced icing conditions occurring in opposite longitudinal directions thus creating a torsional moment on the structure).

5.2.4.19 Combined Ice Loads with Wind

The presence of wind during or after icing episodes requires special loading cases and combinations of ice and wind loads in order to account for their combined effects.

The calculation of combined forces due wind on ice covered conductors are provided in the standard and take into account: the ice thickness or ice weight per unit length of conductor, ice density, wind speed during icing, and drag coefficient of ice covered conductor.

Two combinations of ice, wind speed during icing, ice density/drag coefficient are provided for in the standard and consist of combining an extreme value of one variable (such as the 50 year value) with the average values of the other variables.

5.2.4.20 Construction and Maintenance Loads (Safety Requirements)

The loading conditions provided in the IEC standard supplement national regulations and safety codes. They are focused on reducing the risk of injuries to personnel working during construction and maintenance of the lines. These requirements should result in a very high reliability (risk of failure practically nil). The approach to deal with such loads is deterministic and consists of applying overload factors of 1.5 to 2.0 in order to insure such a high reliability. These loads are not usually combined with severe climatic loads, because construction and maintenance operations are not commonly undertaken during such weather events.

For example, loads during erection of supports are simulated by designing each support point for twice the static loads at sagging conditions. Under some conditions, and under controlled construction operations, the factor of 2.0 could be reduced to 1.5.

5.2.4.21 Security Related Loads

As explained earlier, these loads are intended to prevent cascading or uncontrollable failures. Minimum requirements are specified as follows:

- A broken phase load (torsional load) is applied on any one phase or overhead ground wire attachment point, and is equivalent to the Residual Static Load (RSL) calculated with bare conductors at average temperatures.
- A longitudinal load is specified, equivalent to a simulated fictitious ice load equal to the conductor weight applied on one side of the tower.

For lines that require a higher security level, additional security measures can be considered such as: Increasing the number of points where the RSL is applied, Considering the RSL in conjunction with some climatic load, and/or inserting anti-cascading towers.

5.2.4.22 Limit States of Conductors and Ground Wires

An example of limit states of strength of conductors and ground wires are provided in Table 5.3.

5.2.4.23 Limit States of Interface Components

Typical strength limit states of interface components are provided in Table 5.4.

Table 5.3 Damage and failure limits of conductors and ground wires

Types	Damage limit	Failure limit
All types	lowest of: - Vibration limit, or - the infringement of critical clearances defined by appropriate regulations, or - 75 % of the characteristic strength or rated tensile strength (typical range in 70 % to 80 %)	Ultimate tensile stress (rupture)

Table 5.4 Damage and failure limit of interface components

Type of interface components	Damage limit[1]	Failure limit
Cable connectors: Dead-end and junction fittings and Suspension fittings	Unacceptable permanent deformation or slippage	Rupture
Insulators (porcelain and glass)	70 % strength rating or broken shed (glass only)	Rupture of pin, cap, cement or shed
Hardware	Critical[2] permanent deformation	Rupture of hardware or shear of bolts

[1]Normally, hardware is designed in a manner to reduce or eliminate wear. Should wear be expected because of point to point contact, it should be considered in the design. In such case, the damage limit becomes: exceeding the excepted wear.

[2]Defined as the state where the hardware cannot be easily taken apart.

5.2.5 Conclusions

This chapter summarizes advantages of RBD methods over common deterministic based methods as well as the key features of standard IEC 60826 and its companion document, Cigré TB 178.

Local weather conditions are taken into account during the design process, and tools are provided in order to increase reliability and security if warranted either by the importance of the line or by local conditions.

This RBD method of IEC 60826 Standard should provide for more economical design for a given target reliability compared to safety factor methods or, inversely, a higher reliability for given limit loads.

The IEC 60826 has now been integrated in many international standards (ex. CSA C22.3, 2002, CENELEC EN 50341, IS 802, etc.) and utility practices. It represents a major contribution to the international trend in migrating toward reliability based design concepts in overhead line design.

5.2.6 References

[1] IEC 60826 - Ed. 3.0: Design Criteria of Overhead Transmission Lines (2003)
[2] Cigré WG06.: Loading and strength of overhead transmission lines, Electra No. 129, March 1990 (1990)

[3] Cigré WG22-06.: Probabilistic Design of Overhead Transmission Lines, TB 178 (2001)
[4] Ghannoum, E., Orawski, G.: Reliability Based Design of Transmission Lines According to Recent Advances by IEC and Cigré. International Symposium of Probabilistic Design of Transmission Lines, Toronto, June 1986 (1986)
[5] Cigré SCB2.: Probabilistic Design of Overhead Transmission Lines (Cigré Technical Brochure No. 178, February 2001)
[6] EN 50341–1:2001.: Overhead Electrical Lines exceeding AC 45 kV – Part 1: General Requirements – Common Specifications (EN or CLC)
[7] ASCE 74.: Guidelines for Transmission Lines Structural Loading: Draft as of June 2001
[8] NESC C2-2002.: National Electrical Safety Code C2-2002

5.3 Comparison of RBD Methods

5.3.1 Introduction

Since the publication of Technical Report IEC 826 in 1991, a number of other overhead line design codes based on reliability design methods (RBD) have been published. These documents have generally adopted many of the concepts given in IEC 826, but there are also some *substantial* differences.

The purpose of this Section 5.3 is to compare the methods adopted for the calculation of mechanical loadings for overhead power lines according to a number of these design codes with the latest version of the IEC document, IEC 60826 Edition 3 (October 2003). It is noted that more recent versions of the compared codes have been issued since this study was published by Cigré in 2006 in Cigré TB 289.

The main objective is to assess the level of consistency and the significance of any major differences between the different codes.

5.3.2 Documents Compared and References

The documents compared in this section are: IEC [1], Cigré [3], EN [6], ASCE [7], NESC [8].

In addition to the above standards, a comparison of wind loadings calculated in accordance with the General (or Statistical) Approach of CENELEC (CLC) National Normative Aspects documents produced by the National Committees of the following countries was also included in the study:

EN 50341-3-7	Finland	(NNA/FI)
EN 50341-3-9	Great Britain	(NNA/UK)
EN 50341-3-16	Norway	(NNA/NO)
EN 50341-3-18	Sweden	(NNA/SE)
EN 50341-3-19	Czech	(NNA/CZ)

Note: The symbols adopted in this document are those used in the documents listed above, but it should be noted that usage varies across the range of documents. Brief definitions of symbols are included in this paper, but for full details reference should be made to the appropriate document. It should also be noted that some parameters which are given similar titles or symbols in different documents are defined differently.

5.3.3 Basis of Design

In Table 5.5 the basic design requirements of compared standards are provided, particularly as regard reliability, safety, and security requirements.

5.3.4 Basic Design Equation

The relationships between loads and strength of line components are described in Table 5.6.

Table 5.5 Summary of design requirements according to different codes and standards

	IEC, Cigré	EN	ASCE	NESC
Reliability requirements	Yes	Yes	Yes	Yes
– Line reliability levels	3	3	–	–
– Line reliability factors	–	–	4	2
Return period T (years) of climatic load(1) (2)	50, 150, 500	50, 150, 500	50, 100, 200, 400	?
Security requirements(3)	Yes	Yes	Yes(4)	Yes(5)
Safety requirements(6)	Yes	Yes	Yes	No
Strength coordination	Yes	Yes(7)	Yes(7)	No
Limit state for:				
– Reliability (probabilistic)	Damage	Ultimate	Damage	Ultimate Ultimate
– Security (deterministic)	Failure	Ultimate	Failure	Ultimate
– Safety (deterministic)	Damage	Ultimate	Damage	

Notes related to Table 5.5
(1)Reference return period is usually 50 years
(2)Also called **limit load** in IEC/Cigré and **characteristic** or extreme load in EN. No specific name in ASCE.
(7)General guidance only provided for strength coordination
(3)To reduce risk of uncontrollable propagation of failures
(4)General guidance given but the magnitude for security loadings is not defined
(5)Concept stated only. No specific requirements, or guidance for calculation of security loadings is given.
(6)To ensure safe construction and maintenance conditions
(7)General guidance only provided for strength coordination

Table 5.6 Basic design equations used in the compared standards

Code	Design limit load	< Design strength
IEC, Cigré	Effect of Q_T	$< \Phi_S \times \Phi_N \times \Phi_Q \times \Phi_C \times R_C$[(1)]
EN	Effect of $\gamma_F \times F_{50}$ or effect of F_T	$< RK/\gamma M$[(2)]
ASCE	Effect of $\gamma \times Q_{50}$	$< \Phi \times R_n$[(3)]
NESC	$OCF \times L_{50}$[(4)]	$< R_n$

The nomenclature varies between the various documents.
Q_T, F_T, and L_T are defined as climatic loads having a return period T.
γ, γ_F are load factors applied to loads having a reference return period (refer to Table 5.8 to Table 5.10)
R_C, R_K and R_n are defined as the **characteristic** (IEC/Cigré, EN) or **nominal** (ASCE, NESC) **strength** specified in appropriate standards, also called **guaranteed strength** or minimum strength (or minimum failing load for IEC and percentage of an estimated breaking load for ASCE). This value corresponds usually to an exclusion limit of 2 % to 5 % (i.e. the value being reached with a 98 % to 95 % probability). When not specified or calculated, the exclusion limit is conservatively taken as 10 % (or with 90 % probability).
Notes related to Table 5.6:
[(1)]Φ_S, Φ_N, and Φ_Q are strength factors (IEC/Cigré) depending on strength coordination, number of components, and quality level respectively. Φ_C takes account of variation between the actual exclusion limit of characteristic strength, R_C, and the supposed 10 % exclusion limit. Values of Φ are usually less than 1.0.
[(2)]γ_M is the partial factor (EN) for material property covering unfavourable deviations from characteristic strength, R_K, inaccuracies in applied conversion factors and uncertainties in the geometric properties and the resistance model.
[(3)]Φ is a strength factor (ASCE) that takes account of variability of material, dimensions, workmanship, strength coordination and variation between nominal strength, R_n, and the (5 %) exclusion value, R_e. Values of Φ are usually less than 1.0.
[(4)]OCF is the Overload Capacity Factor (NESC) to be applied to L_{50}.

5.3.5 Combination of Loads

In Table 5.7, structure loading cases and conditions are provided for various standards and include probabilistic conditions as well as deterministic load cases.

5.3.6 Load Factors for Permanent and Variable Loads

5.3.6.1 Load Factors for Dead Loads

In Table 5.8, load factor for structure dead-loads (self weight of conductors and structures) are provided for each assessed standard.

5.3.6.2 Load Factors for Wind Loads

The following Table 5.9 describes structure load factor related to wind actions on overhead line components.

5.3.6.3 Load Factors for Ice Loads

Load factors are applied to ice loads (ice is a generic term use for frozen water that deposits on structures and conductors such as freezing precipitation or rain, wet

Table 5.7 Structure loading conditions

	IEC	Cigré	EN	ASCE	ANSI
Reliability Based Design Conditions	X	X	X	X	X
Limit wind load at reference temperature	X	X	X	-	-
Reduced wind load at low temperature	X	X	X	X	-
Uniform ice loads on all spans	X	X	X	(X)	-
Uniform ice loads, transversal bending	X	X	X	(X)	-
Unbalanced ice loads, longitudinal bending	X	X	X	(X)	-
Unbalanced ice loads, torsional bending	X	X	X	X	X
LP ice load and moderate wind load	X	X	X	-	-
LP wind load and moderate ice load	X	X	X	-	-
LP drag, moderate wind and ice load	X	X	-	(X)	-
Deterministic Security Conditions					
Torsional loads	X	-	(X)	(X)	(X)
Longitudinal loads	X	-	(X)	(X)	(X)
Deterministic Safety Conditions					
Construction loads	X	-	(X)	(X)	(X)
Maintenance loads	X	-	(X)	(X)	(X)

Notes related to Table 5.7:
LP Low probability (having a high return period T)
X The load combination is specified in the document and bases for the calculation of loadings given.
(X) The load combination is specified in the document, but only general guidance is given.

Table 5.8 Load factors for structure dead-loads (self weight of conductors and structures)

Code	Reliability Based Design Cases	Deterministic Load Cases
IEC, Cigré	1.0	-
EN	1.2	-
ASCE	1.0	-
ANSI	-	Metal Grade B = 1.50; Grade C = 1.90

snow, incloud icing. In Table 5.10, ice overload factors are given for different standards.

5.3.6.4 Combination Factors for Moderate Loads

Table 5.11.

5.3.6.5 Other Load Factors

In addition to the various overload factors in the previous tables, there are some additional structure load cases that are specified by each standard as described in Table 5.12.

Table 5.9 Load factors for wind loads

Reliability Level	1		2	3		
Return period T	50 years		150 years	500 years		
	(Q_{50})		($Q_{150} = 1.10^2$ Q_{50})	($Q_{500} = 1.20^2$ Q_{50})		
IEC, Cigré(1)	1.00		1.21	1.44		
EN(2)	1.00		1.20	1.40		
Reliability Factor	1		2	4		8
Return period T	50 years		100 years	200 years		400 years
ASCE/NESC	1.00		1.15	1.30		1.40
NESC (Grade)		Grade B			Grade C	
Wind		2.50			2.20	
(Wire Tension)		(1.65)			(1.30)	

Notes related to Table 5.9:
(1)Default load factors (IEC, Cigré) based on coefficient of variation (COV) up to 0.30 for wind speed and derived from the Gumbel distribution function
(2)Load factor (EN) depending on the selected reliability level and taking account of the possibility of unfavourable deviations from the characteristic load values, inaccurate modelling and uncertainties in the assessment of the load effects
(3)Calculated using "super-station methods"

Table 5.10 Load factors applicable to ice thickness or unit weight

Reliability Level Return	1		2		3	
Period T	50 years		150 years		500 years	
IEC, Cigré	(Q_{50})		(Q_{150})(1)		(Q_{500})(1)	
Ice thickness (2)	1.00		1.15		1.30	
Ice weight (2)	1.00		1.20		1.45	
EN: Ice weight (3)	1.00		1.25		1.50	
Reliability Factor	1		2	4		8
Return period T	50 years		100 years	200 years		400 years
ASCE: Ice weight	1.00		1.15	1.30		1.40
ANSI (Grade)		Grade C			Grade B	
ANSI (metal structures)		2.2(4)			2.5(4)	

Notes:
(1)If values of Q150, and Q500 are available from statistical analysis, these may be adopted.
(2)Default load factors based on COV up to 0.30 for ice thickness and COV up to 0.65 for unit ice weight and derived from the Gumbel distribution function
(3)Load factor (EN) depending on the selected reliability level and taking account of the possibility of unfavorable deviations from the characteristic load value, inaccurate modeling and uncertainties in the assessment of the load effects
(4)Calculated using "super-station methods"
(5)Load factors may be applied either to ice thickness or to the weight of ice per unit length of conductor

Table 5.11 Combination of ice and wind structure loads

Code	Wind load (with low probability ice)	Ice load (with low probability wind)
IEC, Cigré	Average of yearly maximum (Q_1)	Average of yearly maximum (Q_1)
EN	0.40	0.35
	for 3 year return value (Q_3)	for 3 year return value (Q_3)
ASCE	0.6 (glaze ice)	-
	0.5 (wet snow)	-
ANSI	-	-

Table 5.12 Additional structure load factors

Code	Wind load at low temperature (Min yearly temperature with return period T)	Security load[(1)]	Safety load[(1)] Construction and maintenance loads
IEC	$0.6^2 = 0.36$	1.0	1.5 (if careful works)
Cigré	–	-	-
EN	not specified	1.0	1.5
ASCE	-	1.0	1.0
NESC	-	-	-

Note: applicable to Table 5.12
[(1)]Security and Safety loadings are deterministic in nature and their magnitude is independent of reliability level.

5.3.7 Wind Loads

5.3.7.1 Terrain Roughness

IEC, Cigré, EN and ASCE define the roughness factor K_R, the roughness coefficient α, or the terrain factor k_T and the ground roughness parameter z_O for four different terrain categories. The definitions and values used in each standard are provided in Table 5.13.

5.3.7.2 Reference Wind Speed V_R

The reference wind speed (basic wind speed for ASCE) is defined as the wind speed measured at a height of 10 m above ground level, corresponding to an averaging period of 10 min (mean wind speed) or 2–3 seconds (gust wind speed) and having a return period T.

The reference wind speed V_R (basic wind speed V for ASCE) measured in weather stations typical of open flat terrain, such as airports (terrain category B for IEC and Cigré; II for EN; C for ASCE), is identified as V_{RB} ($V_{R(II)}$ for EN and V for ASCE). Where available wind data differ from these assumptions, conversion methods are provided in the Codes (Table 5.14).

5.3.7.3 Unit Action of Wind Speed on any Component of the Line

The following expressions are used:

Table 5.13 Terrain categories described in each standard

Terrain Category	Roughness characteristic	Code	Value	
			K_R	α
A	Large stretch of water upwind, flat coastal areas	IEC, Cigré	1.08	
I	Rough open sea, lakes with at least 5 km fetch upwind and smooth flat country without obstacles	EN	$k_T = 0.17$	$z_0 = 0.01$
B	Open country with very few obstacles, airports or cultivated fields with few trees and buildings	IEC, Cigré	1,0	
II	Farmland with boundary hedges, occasional small farm structures, houses or trees	EN	$k_T = 0.19$	$z_0 = 0.05$
C	Open terrain with scattered obstructions (Exposure C as defined in ASCE 7–02)	ASCE (NESC)	(1.0)	0.14
C	Terrain with numerous small obstacles of low height (hedges, trees and buildings)	IEC, Cigré	0.85	
III	Suburban or industrial areas and permanent forests	EN	$k_T = 0.22$	$z_0 = 0.30$
D	Suburban areas or terrain with many tall trees	IEC, Cigré	0.67	
IV	Urban areas in which at least 15 % of the surface is covered with buildings with mean height > 15 m	EN	$k_T = 0.24$	$z_0 = 1.0$
V	Mountainous and more complex terrain where the wind may be locally strengthened or weakened	EN	shall be evaluated separately possibly by meteorologists	

Note: the ASCE and NESC documents refer to one terrain category only.

IEC/Cigré $a = \frac{1}{2} \mu\, K_R^2\, V_{RB}^2\, C_x\, G$

- μ air density
- K_R roughness factor at the line location
- V_{RB} reference wind speed at flat and open terrain category B
- C_X drag coefficient for the component X being considered
- G combined wind factor depending on height above ground level, wind gust, dynamic response and terrain category

EN $a = \frac{1}{2}\, \rho\, K_R^2\, K_h^2\, (V_{R(II)})^2\, C_X\, G_X\, G_q$

- ρ air density
- K_R roughness factor at the line location

Table 5.14 Reference wind speed V_R

Code	Gust wind speed (Average period of 2–3 s)	Mean wind speed (Average period of 10 min)
IEC, Cigré	-	V_R
EN	$V_R = V_g$	$V_R = V_{mean}$
ASCE	V	-
ANSI	V	-

- K_h takes in account height effect for $V_{R(II)}$
- $V_{R(II)}$ reference wind speed at flat and open terrain category II
- C_X drag factor for the component X being considered
- G_X structural resonance factor for the component X being considered
- G_q gust response factor depending on height above ground level and terrain category (equals 1 if the gust wind speed is considered)

ASCE $a = ½ \mu K_Z^2 V^2 C_f G$

- μ air density
- K_Z takes in account terrain category and height above ground level
- V basic wind speed at flat and open terrain category C
- C_f force (i. e. drag) coefficient for the component being considered
- G gust response factor including span effect, depending on height above ground level and terrain category (This gust factor is derived from the Davenport model and ASCE neglects the resonant component of this model.)

5.3.7.4 Comparison of Combined Wind Factors for Conductors

The combined wind factor, G, for conductors which takes account of gust effects (dependant on span length), conductor height above ground level and terrain category is compared in this chapter with the following parameters:

G_c G_L of the IEC, Cigré document, where G_c is the combined wind factor for conductors with a span length of 200 m and G_L is the span factor ($G_L = 1.0$ for a span length of 200 m),

K_h^2 G_q G_{Xc} of the EN code, where G_q is the gust response factor and G_{Xc} the resonance factor for the conductor, also termed "span factor",

K_Z G_w of the ASCE code, where G_w is the gust response factor for conductors (wires) including span effect for wires. To make this value comparable it is multiplied by $(V/V_M)^2 = 1.43^2 = 2.04$, to take in account the reference to the 10 minute average wind speed.

The comparison of global wind factor for conductors resulting from span factor, height effect, and gust response to wind are given in Table 5.15.

The values obtained in Table 5.15 were calculated using effective conductor heights given in Table 5.16.

Table 5.15 Comparison of combined wind factors for conductors at terrain category B (IEC) or equivalent

Height in m	Code	200	Span length in m 400	600
	IEC, Cigré	1.84	1.73	1.624
10	EN	1.94	1.77	1.72
	ASCE	1.51	1.39	1.31
	IEC, Cigré	2.25	2.12	1.99
30	EN	2.32	2.17	2.08
	ASCE	1.81	1.68	1.61
	IEC, Cigré	2.44	2.30	2.16
50	EN	2.60	2.43	2.33
	ASCE	1.96	1.84	1.76

Table 5.16 Effective conductor heights used to calculate conductor wind loads

Code	Theoretical height	Location	For support calculation
IEC	Centre of gravity	Lower third of sag	Attachment point of (middle) conductor
Cigré	-	-	-
EN	Centre of wind pressure	-	-
ASCE	Centre of wind pressure	Higher third of sag (for no wind)	-

Table 5.17 Comparison of combined wind factors for towers

		Terrain type			
Height in m to CG of panel(1)	Code	A	B	C	D
	IEC	1.70	1.95	2.50	3.30
10	Cigré	1.70	1.95	2.55	3.30
	EN	1.69	1.94	2.38	3.96
	IEC	1.95	2.32	2.95	3.95
30	Cigré	2.00	2.30	3.00	3.90
	EN	2.06	2.51	3.01	4.48
	IEC	2.15	2.55	3.35	4.40
50	Cigré	2.15	2.50	3.25	4.40
	EN	2.29	2.86	3.69	7.50

It is noted that the factors given in Table 5.17 are based on tower panel height above ground level is measured at the centre of gravity (CG) of the panel.

5.3.7.5 Comparison of Combined Wind Factors for Towers

The combined wind factor, G, for lattice towers (depending on gust, height and terrain category) as used by IEC, Cigré TB 109, is compared in this chapter with the following parameters:

G_t of the IEC/Cigré document, where G_t is the combined wind factor for towers
$K_h^2 G_q G_{Xt}$ of the EN code, where G_{Xt} is the drag factor for the tower (G_{Xt} taken as 1.0)
$K_Z G_t$ of the ASCE code, where G_t is the gust response factor for the tower. To make this value comparable it is multiplied by $(V/V_M)^2 = 1.43\ ^2 = 2.04$, to take in account the reference to the 10 minute averaging wind speed.

5.3.8 Drag Coefficient

For conductors in IEC, Cigré and EN the recommended drag coefficient or factor $C_X = 1.0$.

ASCE recommends:

1,2 for shield wire
$1.23\text{-}0.032.(R_C)/3 \times 10^4$ for conductors
0.9 for snow coated conductor.

For lattice towers in IEC, Cigré and EN the same magnitude for the drag coefficient C_{xT} is recommended, depending on the solidity ratio of tower panel (ratio between solid steel area and overall panel surface). In ASCE slightly different values are given as indicated in Figure 5.2.

5.3.9 Span Factors

The span factor represents the relationship between span length and wind spatial effect on the span. It is recognized that the longer the span, the less a high wind

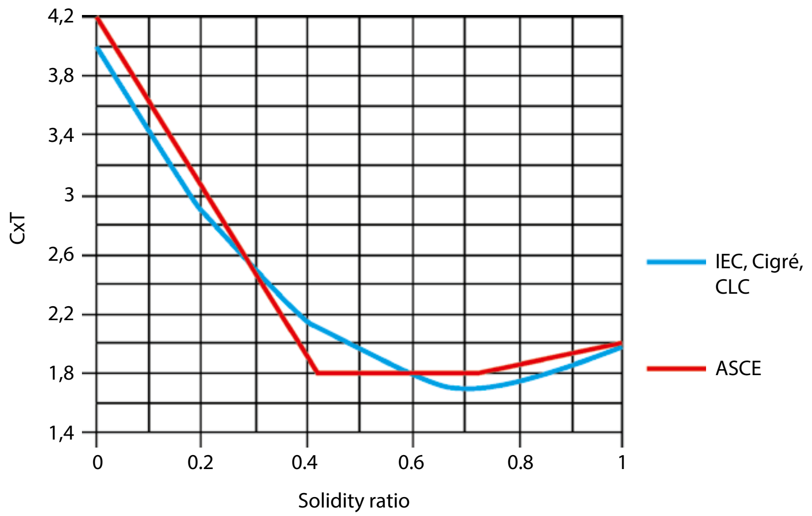

Figure 5.2 Drag coefficients for lattice towers.

event can uniformly encompass all the span. IEC, Cigré and EN have adopted similar span factors in all terrain categories (for example, in a terrain type B, the IEC span factor G_L gradually drops from 1.0 for a 200 m span to 0.85 for an 800 m span). Comparatively, the ASCE has adopted lower span factors, where this factor drops linearly from 1.0 to 0.7 for spans of 350 to 500 m respectively.

5.3.10 Ice Loads

In IEC, Cigré and EN the basic ice load, g (N/m), is referred to a conductor of diameter 30 mm 10 m above ground level. In ASCE reference is not given (refer to Table 5.18).

Many standards also require designing for unbalanced icing conditions as indicated in Table 5.19.

5.3.11 Combined Wind and Ice Loads

Althouth ice accretion on conductors is rarely in the form of a perfect cylinder, an equivalent round ice diameter is defined in all standards as being the uniform ice thickness that leads to the same unit weight on the conductor.

In addition to the above, many standards recognize that not only ice thickness is important for design of conductors and structures, but also the ice density, and its

Table 5.18 Comparison of reference ice loads

Code	Ice variable	Adjustment factors Diameter (K_d)	Height (K_h)
IEC	weight	X	X$^{(1)}$
Cigré	weight	X	X$^{(1)}$
	thickness	X	X$^{(1)}$
EN	weight	X$^{(2)}$	-
ASCE	thickness	-	-

Notes applicable to Table 5.18:
$^{(1)}$only for precipitation icing
$^{(2)}$no values specified

Table 5.19 Unbalanced icing condition

Code	Longitudinal bending	Transversal bending	Torsional bending
IEC	$\alpha_1 = 0.28$, $\alpha_2 = 0.7$	$\alpha_1 = 0.28$, $\alpha_2 = 0.7$	$\alpha_1 = 0.28$, $\alpha_2 = 0.7$
Cigré (TB 109)	$\alpha_1 = 0.28$, $\alpha_2 = 0.7$	$\alpha_1 = 0.28$, $\alpha_2 = 0.7$	$\alpha_1 = 0.28$, $\alpha_2 = 0.7$
EN	$\alpha_1 = 0.30$, $\alpha_2 = 0.7$	$\alpha_1 = 0.50$, $\alpha_2 = 1.0$	$\alpha_1 = 0.30$, $\alpha_2 = 0.7$
ASCE	mentioned but no values given	not specified	mentioned but no values given

Table 5.20 Comparison of drag coefficients and densities

Code		Precipitation Wet snow	In-cloud ice Soft rime	In-cloud ice Hard rime	Precipitation Glace ice
IEC	Drag	1.0	1.2	1.1	1.0
	Density	600	600	900	900
Cigré	Drag	1.0/1.4	1.2/1.7	1.1/1.5	1.0/1.4
	Density	600/400	600/400	900/700	900/900
EN	Drag	1	1.2	1.1	1.0
	Density	500	300	700	900
ASCE	Drag	0.9	see [8]	see [8]	see [8]
	Density	300-800	300	900	900

corresponding drag coefficient. Table 5.20 describes various ice densities and drag coefficients for each of the assessed standard.

5.3.12 Failure and Containment Loads (Security Loads)

IEC, Cigré, EN and ASCE define the torsional and longitudinal structure loads.

The guidelines given in these codes are in principle the same and consist of loads that attempt to reduce the risk of cascading failures in transmission lines. These loads are broken conductor loads in different combinations, mostly under every day conditions.

IEC and Cigré provide guidelines for additional security for important lines and lines subjected to heavy icing conditions.

5.3.13 Construction and Maintenance Loads (Safety Loads)

IEC, Cigré, EN and ASCE provide guidelines for construction and maintenance loads. These loads are treated as deterministic loads because their purpose is to protect workers during construction and maintenance activities.

5.3.14 Other Loads

EN provides additional guidelines for loads caused by:

- Short-circuit
- Avalanches
- Earthquakes.

ASCE provides additional guidelines for loads caused by:

- Galloping
- Flooding
- Vibration.

5.3.15 General Comparative Overview

All considered standards and practices share many common features. All adopt a reliability based (i.e. semi-probabilistic) method for calculation of climatic loads, essentially similar to IEC 60826. However, the European Standard EN 50341–1 still provides a deterministic "Empirical Approach" as an alternative for some countries.

IEC 60826 and ASCE 74 adopt alternative limit states of "damage", for use with reliability based and safety loadings, and "failure" for use with security loading cases. The other documents use "ultimate" limit state for all these loading cases. EN specifies a "serviceability" limit stage for the checking of clearances (see Table 5.4).

Climatic loadings tend to be the most important in the design of overhead lines, but all documents also give guidance on security loading cases and construction and maintenance load cases to be used for design. Neither security nor construction and maintenance loadings lend themselves completely to a reliability-based approach. In most documents security loading cases are based on arbitrary assumptions about hypothetical broken conductors causing unbalanced longitudinal occurring. These conditions are combined with climatic loadings based on low return periods.

There are minor differences in the formulation of the basic design equations, but climatic loadings are always based on weather events of a specified return period, usually 50 years (see Table 5.5).

The range of loading cases considered differs between the various codes, with IEC offering the most extensive range. IEC also provides the most detailed information on strength co-ordination between different elements, with only general guidance being given in EN and ASCE, and no explicit mention of this subject in NESC (see Table 5.2).

For load factors on wind loadings, IEC applies factors to wind speed. The other documents apply factors to wind load or pressure factors (Table 5.9). For ice loading, IEC offers alternative approaches of applying factors either to ice thickness or weight. The other documents apply factors to ice weight (Table 5.10).

For combinations of weather events occurring simultaneously, for example wind and ice loading, all documents assume that improbable events will not occur simultaneously, i. e. the maximum ice loading based on a 50 year return or higher return period event would occur simultaneously with a wind loading of much lower return period (see Tables 5.11 and 5.12).

The terrain categories and defining parameters used in the different codes are listed in Table 5.13 and the nearest equivalents between the different codes are grouped together. It should be noted that the subsequent wind loading calculations are based on Terrain Type B to IEC, taken as equivalent to Category II in EN or Category C in ASCE.

IEC and EN take a reference wind speed based on a 10 minute mean wind speed, whereas ASCE/NESC adopt a 3 second gust wind speed (Table 5.14).

Formulas for effective wind pressure, including the effects of terrain category, drag coefficient and gust factors are given in Table 5.15.

Combined wind loading factors including the effects of gust, height, and terrain are compared in Table 5.15 for conductors and in Table 5.17 for lattice towers.

A comparison of the values of drag coefficient for conductors and lattice towers are given in Clause 5.3.8. IEC/Cigré and EN all specify a value of 1.0 for conductors.

ASCE adopts a formula based on Reynolds Number for un-iced conductors, with a value of 1.2 specified for shield-wires and 0.9 for snow-covered conductors. For tower steelwork IEC/Cigré and EN use the same formula. Different, albeit similar values are given in ASCE.

A comparison of the span factors adopted in the different codes is given in Clause 5.3.9. There are fairly small differences between IEC/Cigré and EN, but ASCE varies significantly from the other documents.

Table 5.18 compares the use of adjustment factors on ice weight and thickness depending on conductor height and diameter, and Table 5.19 considers the treatment of unbalanced ice loading in the various documents.

Table 5.20 highlights the differences in drag coefficient on iced conductor and the density of ice adopted for different types of icing.

Clause 5.3.12 gives brief notes on the failure containment loads given in the different documents.

Clause 5.3.13 notes that all documents contain guidance on construction and maintenance loadings.

Clause 5.3.14 looks at other loading conditions not mentioned above. It notes the ASCE provides guidance on galloping, vibration, and flooding, which are not explicitly mentioned in the other documents. Also EN provides guidance on loadings generated by short-circuits, avalanches and earthquakes which are not addressed in the other documents.

Appendix A gives a comparison between conductor wind pressures, including gust, height and span related effects for a range of conductors for wind spans varying from 200–600 m and mean conductor heights of 10 m, 30 m, and 50 m. Terrain type B according to IEC or the closest equivalents to the other codes is assumed. This information is given in tabular form in Tables 5.21, 5.22, and 5.23, and in graphical form in Figure 5.4. It is shown that IEC/Cigré and EN agree fairly closely, but ASCE gives significantly lower values than either of the other documents. The main reason for this is believed to be the use of the simplified Davenport gust response model. It may be noted that the use of the full Davenport model is allowed as an option in ASCE, and this gives results much closer to IEC.

Table 5.24 provides a comparison of conductor wind loadings calculated in accordance with the EN-NNA documents for various European countries, with IEC/Cigré, ASCE, and the EN Main Body. The countries concerned are Norway, Sweden, Finland, Czech Republic, and the UK. This information is also provided in graphical form in Figure 5.4. It appears that the Norwegian, Swedish, Finnish, and UK NNAs give values similar to ASCE, whilst the Czech NNA follows EN.

5.3.16 Conclusions

The main objective of this Section was to compare the recently published International Standard IEC 60826 Ed.3 on "Design Criteria of Overhead Transmission Lines", issued October 2003 with the existing codes EN 50341–1, ASCE 74 and NESC C2, and to assess the consistency. These codes followed the Reliability Based

Table 5.21 Effective wind pressures on conductors for terrain category B to IEC assuming a reference wind speed of 24 m/s, a 10 minute average period and mean height of conductor of 10 m

Code	Terrain Category	Average Time	Adjusted wind speed (m/s)	Drag factor	Air density (kg/m^3)	Combined Factors for given span length					Effective Wind Pressures (N/m^2) for given span length				
						200 m	300 m	400 m	500 m	600 m	200 m	300 m	400 m	500 m	600 m
IEC	B	10 min	24.0	1.0	1.225	1.85	1.798	1.743	1.691	1.648	653	634	615	597	582
Cigré	B	10 min	24.0	1.0	1.225	1.85	1.798	1.743	1.691	1.648	653	634	615	597	582
EN	II	10 min	24.0	1.0	1.225	1.771	1.703	1.654	1.617	1.586	625	601	584	570	560
ASCE	C	3 sec	34.3	1.0	1.226	0.738	0.703	0.679	0.662	0.639	532	507	490	478	461
NESC	C	3 sec	34.3	1.0	1.226	0.738	0.703	0.679	0.662	0.639	532	507	490	478	461

Notes:
1) The terrain categories quoted are considered to be the nearest equivalents from the various codes.
2) The ASCE and ANSI adjusted wind speed values have been obtained by multiplying the 24 m/s 10 min mean wind speed by 1.43 to convert to 3 sec gust wind speed, as recommended in Appendix E of ACSE 74.
3) The combined factors and effective wind pressures include the effects of gust, conductor height and span length.

Table 5.22 Effective wind pressures on conductors for terrain category B to IEC assuming a reference wind speed of 24 m/s, a 10 minute average period and mean height of conductor of 30 m

Code	Terrain Category	Average Time	Adjusted wind speed (m/s)	Drag factor	Air density (kg/m³)	Combined Factors for given span length					Effective Wind Pressures (N/m²) for given span length				
						200 m	300 m	400 m	500 m	600 m	200 m	300 m	400 m	500 m	600 m
IEC	B	10 min	24.0	1.0	1.225	2.23	2.168	2.101	2.038	1.987	787	765	741	719	701
Cigré	B	10 min	24.0	1.0	1.225	2.23	2.168	2.101	2.038	1.987	787	765	741	719	701
EN	II	10 min	24.0	1.0	1.225	2.321	2.232	2.169	2.120	2.080	819	788	765	748	734
ASCE	C	3 sec	34.3	1.0	1.226	0.884	0.821	0.679	0.803	0.789	638	610	592	579	569
ANSI	C	3 sec	34.3	1.0	1.226	0.884	0.821	0.679	0.803	0.789	638	610	592	579	569

Notes:
1) The terrain categories quoted are considered to be the nearest equivalents from the various codes.
2) The ASCE and ANSI adjusted wind speed values have been obtained by multiplying the 24 m/s 10 min mean wind speed by 1.43 to convert to 3 sec gust wind speed, as recommended in ACSE 74 Appendix E.
3) The combined factors and effective wind pressures include the effects of gust, conductor height and span length.

Table 5.23 Effective wind pressures on conductors for terrain category B to IEC assuming a reference wind speed of 24 m/s, a 10 minute average period and mean height of conductor of 50 m

Code	Terrain Category	Average Time	Adjusted wind speed (m/s)	Drag factor	Air density (kg/m^3)	Combined Factors for given span length					Effective Wind Pressures (N/m^2) for given span length				
						200 m	300 m	400 m	500 m	600 m	200 m	300 m	400 m	500 m	600 m
IEC	B	10 min	24.0	1.0	1.225	2.43	2.362	2.289	2.221	2.165	857	833	808	784	764
Cigré	B	10 min	24.0	1.0	1.225	2.43	2.362	2.289	2.221	2.165	857	833	808	784	764
EN	II	10 min	24.0	1.0	1.225	2.60	2.50	2.43	2.38	2.33	918	883	858	839	823
ASCE	C	3 sec	34.3	1.0	1.226	0.96	0.92	0.90	0.88	0.86	695	667	648	634	624
ANSI	C	3 sec	34.3	1.0	1.226	1.01	0.97	0.94	0.90	0.90	727	697	676	646	646

Notes:
1) The terrain categories quoted are considered to be the nearest equivalents from the various codes.
2) The ASCE and ANSI adjusted wind speed values have been obtained by multiplying the 24 m/s 10 min mean wind speed by 1.43 to convert to 3 sec gust wind speed, as recommended in ACSE 74 Appendix E.
3) The combined factors and effective wind pressures include the effects of gust, conductor height and span length.

Table 5.24 Effective wind pressures on conductors under extreme wind loadings having been calculated in accordance with IEC, EN, ASCE and the EN-NNAs of Finland, Sweden, Norway and the UK

Comparison of Conductor Wind Loads derived from different Standards			
Basic Data	Symbol	Unit	Value
Reliability level			1
Return period of loads	T	years	50
Conductor diameter	d	mm	30
Conductor height (average)	h	m	30
Span length	L	m	400
Terrain category			II
Altitude (from sea level)	H_0	m	0
Air temperature	T_a	°C	15
Reference wind speed (terrain II)	V_R(II)	m/s	24.0

			IEC	ASCE	EN	EN - NNA			
Load Parameters (EN)	Symbol (EN)	Unit	60826	74	MB	FI	SE	NO	UK
Terrain category			B	C	II	II	II	II	II
Terrain factor	k_T	-	$K_R = 1.00$		0.19	0.19		0.19	
Ground roughness parameter	z_0	-			0.05	0.05		0.05	
Reference wind speed at site	V_R	m/s	24.0	34.3	24.2	24.2		24.0	21.4
Span factor	G_{Xc}	-	$G_L = 0.94$		0.81	0.65	0.50	0.70	0.51
Height correction factor	K_h	-		$K_Z = 1.26$	1.21	1.21		1.21	1.20
Gust factor for wind speed	k_g	-			1.36	1.36		1.36	1.06
Gust factor for wind pressure	$G_q = k_g^2$	-		$G_w = 0.65$	1.84	1.84		1.84	
Combined wind factor for L = 200 m	G_C	-	2.23						

(continued)

Table 5.24 (continued)

			IEC	ASCE	EN	EN - NNA			
Combined wind factor (See § 7.4)	G	-	2.10	1.03	2.17	1.74		1.88	2.21
Mean wind speed at conductor height	$V_h = K_h V_R$	m/s			29.2	29.2		29.0	
Gust wind speed at conductor height	$k_g V_h$	m/s			39.6	39.6		39.3	
Altitude factor for density		-	1.00		1.00	1.00		1.00	
Temperature factor for air density		-	1.00		1.00	1.00		1.00	
Air density	ρ or μ	kg/m^3	1.225	1.226	1.23	1.23		1.23	1.22
Gust pressure at conductor height	$(\mu V_h^2/2) G_q$	N/m^2	788		959	959	920	946	
Drag factor	C_{Xc}	-	1.00	1.00	1.00	1.00	1.00	1.00	
Load factor for wind load (or Speed)	γ_w	-	1.00	1.00	1.00	1.00	1.30	1.00	1.00
Design wind pressure	Q_d	N/m^2	788		959	959	1196	946	
Wind load of conductor per unit length	$Q_c = Q_d G_{Xc} d$	N/m	22.3		23.3	18.6	17.9	19.9	
Effective wind load on wind span	$F_c = Q_c L$	N	8911		9305	7444	7176	7948	
Effective wind pressure on conductor	$Q_d G_{Xc}$	N/m^2	743	593	775	620	598	662	615

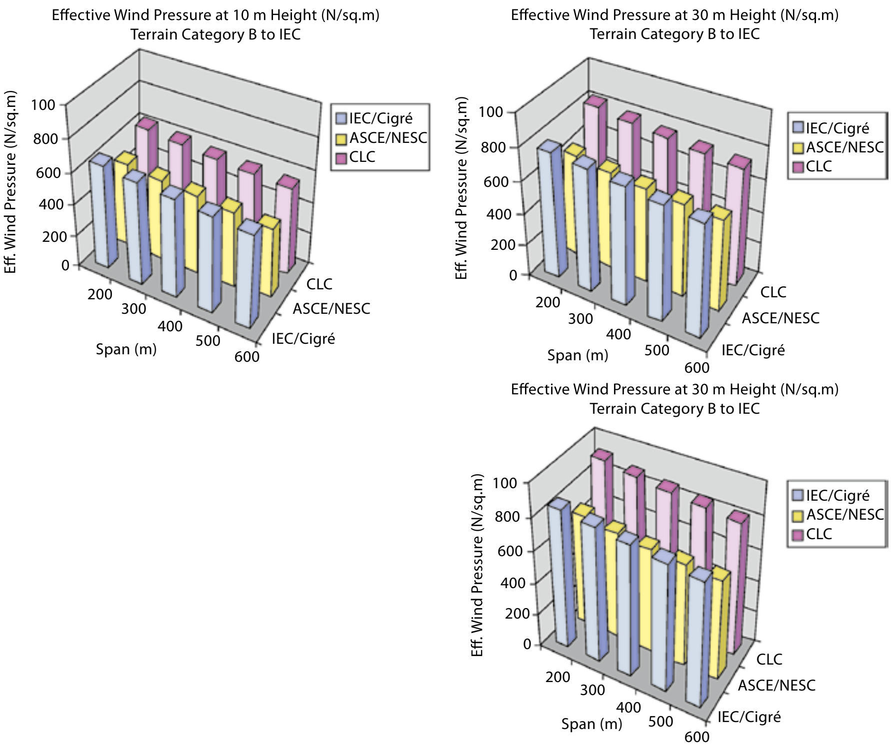

Figure 5.3 Comparison of Effective Wind Pressure on conductors for EN (CLC), ASCE/NESC, and IEC/Cigré for various span lengths and heights above ground level for Terrain Category B to IEC or equivalent.

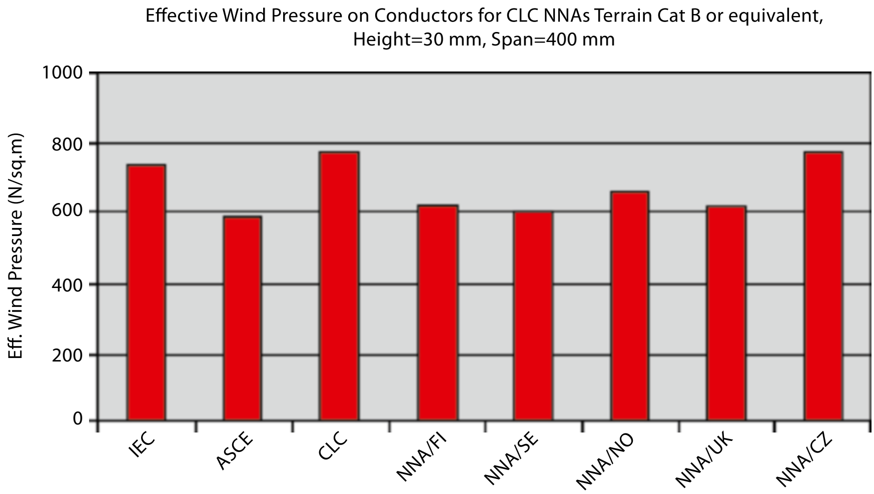

Figure 5.4 Effective wind pressure calculated according to various standards.

Design method developed in the Technical Report IEC 826 issued in 1991, a previous version of IEC 60826. Cigré WG B2.06 already contributed to the review of this Technical Report in Cigré TB 109 and with the Companion Document TB 178. The detection of the most significant differences between IEC 60826 and the other Codes is a new step in the improvement of RBD Codes.

This Section III concludes with the comparison of results of the numerical calculations of conductor wind loadings between the different codes, including the National Normative Annexes of EN 50341–3.

Appendix A - Sample Comparison of Wind Pressure for Different Codes
Calculations carried out by Chris Thorn and Pekka Riisiö in Tables 5.21, 5.22, 5.23, and 5.24.

The effective wind pressures, taking account of gust, span and height effects have been calculated in Tables 5.21, 5.22, 5.23, and 5.24 for wind span lengths between 200 m to 600 m:

Table 5.21: mean conductor height: 10 m
Table 5.22: mean conductor height: 30 m
Table 5.23: mean conductor height: 50 m
Figure 5.3 for mean conductor heights 10, 30 and 50 m

Table 5.24 provides a comparison between conductor wind loadings, calculated in accordance with the EN-NNA documents for various European countries, with IEC/Cigré, ASCE, and the EN Main Body:

Table 5.24: mean conductor height: 30 m; span length: 400 m.
Figure 5.4: mean conductor height: 30 m; span length: 400 m.

General Assumptions

Wind Speed: 24 m/s (10 minute mean wind speed, 10 m height, terrain type B)
Conductor diameter: 30 mm
Air temperature 15 °C

Notes: Terrain Categories are not entirely compatible between the different codes, but the closest equivalent has been chosen.

5.4 Tower Top Geometry and Mid-span Clearances

5.4.1 Introduction

The aim of this section of Chapter 5 based on Cigré TB 348 is to give guidance on the calculation of the geometric dimensions of the tower top to ensure that the internal electrical clearances necessary between live parts and earthed structures as well as between conductors in mid span are achieved.

The available clearances depend on the conductor and insulator set positions which vary due to wind action. The wind speed causes swinging of conductors and reduces the clearances. Therefore, wind loads are significant for defining the tower top geometry.

Cigré TB 48 on "Tower Top Geometry" [1], issued in 1996, already provided guidelines to check the internal clearances at towers. This section reviews those guidelines and extends them to the clearances between conductors within the span.

As the design of mid span clearances is more complex due to the additional influence of conductor sag and possible asynchronous oscillation of adjacent conductors due to differential wind, a questionnaire was issued by Cigré WG B2.06 to collect and compare existing national design methods.

The approach developed in Cigré TB 348 represents an improvement on the various empirical methods in use up to now.

- Section 5.4.2, Part, 1 analyses the existing practices on internal clearances, for which information was gathered by the questionnaire and completed with information from European Standards, including the empirical equations;
- Section 5.4.3, Part 2, deals with the determination of swing angles of conductors and insulator sets under wind load. It is assumed that wind speed is randomly distributed. Especially "still air" and "high wind" conditions are considered;
- Section 5.4.4, Part 3, compares available information on electrical clearances phase-to-earth and phase-to-phase required for the various conditions of lightning or switching surge impulse and power frequency voltages;
- Section 5.4.5, Part 4, gives proposals for the coordination of conductor positions and electrical clearances;
- Section 5.4.6, Part 5, demonstrates the approach developed by means of an application example.

The study presented is valid for all self-supporting and guyed overhead line supports and for all line configurations (vertical, horizontal, triangle).

The design guidance is limited to the influence of wind actions, but the approach philosophy can easily be extended to other issues such as:

- Differential conductor sags caused by differential ice accretion
- Combined ice and wind loading
- Ice drop
- Galloping
- Live line maintenance.

No design guidance is provided for those issues, but they are considered in 5.4.2., Part 1.

5.4.2 Part 1: Existing National Practices

In most countries existing practices for the definition of tower top geometry refer to National Standards or Codes, which quote appropriate formulae and meteorological conditions (temperature, wind, ice) to determine swing angles of:

- insulator sets at tower top
- conductor at mid span,

to associate them with corresponding internal electrical clearances.

Part 1 of Cigré TB 348 reviews the information referring to the different aspects of loading cases considered for the determination of internal clearances.

The information received from the answers to the questionnaire was completed with the design rules for clearances available in the National Normative Aspects (NNAs) EN 50341–3 to the European Standard EN 50341–1 [2]. Since the publication of Cigré TB 48, national practices have been changed in some countries.

The following countries responded to the WG B2.06 questionnaire:

Australia, Belgium, Brazil, Czech Republic, Finland, France, Germany, Great Britain, Italy, Japan, Lithuania, the Netherlands, New Zealand, Norway, Serbia, South Africa, Ukraine and USA.

The practices of the following countries have also been considered, as they are detailed in the NNAs of EN 50341–3:

Austria, Denmark, Estonia, Greece, Iceland, Ireland, Portugal, Spain and Sweden.

The internal clearances according to EN 50341–1 are summarized in Table 5.25:

- D_{pe} is the phase-to-earth clearance, that refers to the internal clearance between phase conductors and objects at earth potential, including the tower structure and the earth wire;
- D_{pp} is the phase-to-phase clearance, that refers to the internal clearance between phase conductors.

D_{pe} and D_{pp} are required to withstand lightning (fast front) or switching (slow front) impulse voltages. D_{pe_pf} and D_{pp_pf} are required to withstand power frequency voltages.

EN 50341–1 distinguishes three load cases for the internal clearances. They are summarized in Table 5.26.

All information gathered from the questionnaire and EN 50341 has been summarized in Cigré TB in various synoptic tables. All wind and/or ice load cases are classified per country with the corresponding type of clearance.

According to the answers to the questionnaire the most used load cases correspond to the recommendations of EN 50341–1. They have been ranked in Table 5.27 with the preferred clearance type according to Table 5.26. The rate of preference is given in %.

Table 5.25 Internal clearances according to the European Standard EN 50341-1

Voltage level		Clearance for lightning or switching impulse voltage		Clearance for power frequency voltage	
Nominal voltage	Highest system voltage	Phase-to-earth	Phase-to-phase	Phase-to-earth	Phase-to-phase
UR	*US*	D_{pe}	D_{pp}	D_{pe_pf}	D_{pp_pf}
kV	kV	m	m	m	m
110	123	1.00	1.15	0.23	0.37
220	245	1.70	2.00	0.43	0.69
380	420	2.80	3.20	0.70	1.17
480	525	3.50	4.00	0.86	1.47

Table 5.26 Type of internal clearance per load case (EN 50341–1)

Clearance type	Phase-to-earth	Phase-to-phase	Load case
1	D_{pe}	D_{pp}	Still air conditions with maximum conductor temperature or ice load
2	$k_1 \cdot D_{pe}$(1)	$k_1 \cdot D_{pp}$ (1)	Reduced wind load (T = 3 years)
3	D_{pe_pf}	D_{pp_pf}	Extreme wind load (T = 50 years)

(1) Reduction factor k_1 is defined by the National Normative Aspects of EN 50341–3

Table 5.27 Ranking of load cases for the internal clearances

Ranking			Preferred clearance type (Table 5.25)		
No.	%	Load case	No.	Clearance	%
1	76 %	Maximum temperature	1	D_{pe}, D_{pp}	72 %
2	68 %	High wind load	3	D_{pe_pf}, D_{pp_pf}	52 %
3	64 %	Reduced wind load	2	$k_1 \cdot D_{pe}$, $k_1 \cdot D_{pp}$	60 %
4	60 %	Extreme ice load	1	D_{pe}, D_{pp}	44 %

Galloping is mentioned by 32 % of the countries as a determining factor for mid span clearances. Other load cases are applied by only 24 % or less of the countries. Some countries consider different wind or ice loads on adjacent conductors.

Many countries use empirical equations for the mid span clearance between adjacent conductors if they are made of the same material and having the same cross-section and sag. These equations include three terms:

- The first term indirectly takes into account the differing wind speeds on the conductors. This term depends on the sag, the mean length of the suspension insulator set, the swing angle and the relative position of both conductors;
- The second term takes into account the system voltage;
- Finally the third term considers the outside diameter of conductor bundles, if any.

A synoptic table in Cigré TB 348 summarizes the parameters used by each country for their empirical equation.

5.4.3 Part 2: Swing Angles

Part 2 of Cigré TB 348 compiles the material on swinging of conductors due to wind loads, which is available to the WG B2.06. The wind action varies with time and space and can be described as randomly distributed using statistical approaches [1; 2; 3; 4].

Due to the boundary effect, the wind velocities increase with the height above ground. The longer the wind span the more the wind velocity will vary along this span. Relevant standards, take care of this effect by introducing a span factor. Additionally, the swing angles depend on line parameters such as ratio of wind span to weight span, conductor type, etc.

For the design of the tower top geometry the same meteorological data should be used as for the Reliability Based Design (RBD) [3; 4] methods.

Various experimental investigations were carried out on test stands in the past to study the relation between wind velocities and swing angles. The basic results are:

- The swing angle observed for a measured wind velocity, whether instantaneous or average over a certain period of time, scatter considerably;
- The majority of observed swing angles stay well below those determined theoretically using observed peak wind velocities and generally agreed formulae.

To determine the distribution of swing angles it is necessary to establish the time distribution of wind velocities.

For large wind velocities having a return period of more than two years the Gumbel distribution can be adopted, which is based on the measured annual maximum wind velocities.

For relatively small wind velocities the most appropriate approach to establish a time distribution would be to evaluate the wind statistics from weather stations over the year. Alternatively, this time distribution can be established based on a Weibull distribution, the parameters of which can be derived from wind velocities having a probability of occurrence of 1 or 2 years.

Often wind statistics refer only to the occurrence of maximum wind values without referring to wind directions. However, only winds acting perpendicularly to the span will cause the maximum swing angle. In order to take care of the variation of wind intensity with its direction the time probability of the swing angles can be assumed as being half of the corresponding wind velocities when the swing angle is more than 2°.

5.4.4 Part 3: Required Clearances

The required clearances should be derived from the electrical characteristics of the transmission system. There are various approaches available to determine the clearances necessary to withstand given electrical stresses.

According to IEC 60071–1 the standard highest system voltages, U_S, for equipment are divided into two ranges:

- Range I: above 1 kV to 245 kV included,
- Range II: above 245 kV.

For lines within range I lightning (fast front) impulses, U_{ff}, decide on the insulation level and for lines within range II switching (slow front) impulses, U_{sf}.

Standards IEC 60071–1 [5] and IEC 60071–2 [6] deal only with phase-to-earth clearances D_{pe}. Since the insulation is self-restoring the lightning withstand voltages, $U_{90\%\_ff}$, are specified for the probability of 90 % of being withstood. The coefficients of variation are assumed to be 3 % for lightning impulses and 6 % for switching impulses.

Cigré TB 72 [7] deals with the dielectric strength of external insulation and conductors, lightning and switching impulses. The lightning impulses to be used are those which can propagate beyond a few towers from the point of the lightning strike. For the purpose of determining clearances this is to be taken as $U_{50\%\_ff}$. The switching impulse voltage to be used, U_{sf}, is the highest that can occur on the lines (Table 5.28).

Table 5.29 lists the clearances under impulse voltages for some of the often used voltage levels according to the IEC, Cigré and EN formulae given in detail in Cigré TB 348.

In Table 5.29 the power frequency clearances, D_{pe_pf} and D_{pp_pf}, are given. The comparison reveals that the procedure according to EN 50341–1 results in less conservative data than TB 72. No information is given in IEC 60071–2.

5.4.5 Part 4: Coordination of Conductor Positions and Electrical Stresses

The study resulted in a proposal to consider at least two cases of designing tower top geometry and mid span clearances, taken into account the varying position of conductors and insulator sets under the wind action and the electrical stress of the air

Table 5.28 Clearances under impulse voltages

System voltage	Impulse voltages		IEC 60071-2		Cigré TB 72		EN 50341-1	
U_S	$U_{90\%\_ff}$	$U_{50\%\_ff}$	U_{sf}	D_{pe}	D_{pe}	D_{pp}	D_{pe}	D_{pp}
kV	kV	κV	kV	m	m	m	m	m
123	450	490	-	0.9	0.94	0.96	0.89	1.00
	550	590	-	1.1	1.13	1.17	1.07	1.20
245	850	920	-	1.7	1.76	1.83	1.67	1.86
	950	1030	-	1.9	1.97	2.05	1.87	2.07
	1050	1140	-	2.4	2.18	2.26	2.05	2.29
420	1175	1270	850	2.4	2.40	2.70	2.25	2.67
	1300	1410	950	2.9	2.80	3.20	2.64	3.15
	1425	1540	1050	3.4	3.25	3.73	3.02	3.68
525	1300	1410	950	2.9	2.80	3.20	2.64	3.15
	1425	1540	1050	3.4	3.25	3.73	3.02	3.68
	1550	1680	1175	4.1	3.90	4.48	3.60	4.40

Table 5.29 Clearances under power frequency voltage

System voltage	Cigré TB 72		EN 50341-1	
U_S	D_{pe_pf}	D_{pp_pf}	D_{pe_pf}	D_{pp_pf}
kV	m	m	m	m
123	0.32	0.42	0.23	0.37
245	0.64	0.85	0.43	0.69
420	1.16	1.52	0.70	1.17
525	1.68	2.20	0.86	1.47

Table 5.30 Coordination of conductor positions and electrical stresses

		Conductor and insulator positions	
Electrical stresses of the air gap		Still air or moderate wind during 99 % of time	High wind velocity with $T = 50$ years
	Probability	High	Low
Power frequency voltage	High	Covered by cases 1 & 2	Case 1
Lightning/switching impulse voltage	Low	Case 2	Not considered

gap by power frequency voltage and overvoltages caused by lightning strokes or switching operations (Table 5.30).

- Case 1 is described by conductor and insulator positions which would occur under the action of the design wind velocities having a return period T of say 50 years. These positions are combined with clearances required to withstand power frequency voltage. The probability of flashovers depends on the probability of occurrence of the corresponding design wind velocity. For a wind velocity having a return period of 50 years the probability of flashover will be 1 % per year at maximum.
- Case 2 is described by conductor and insulator positions which are assumed as not being exceeded during 99 % of the time. These positions are combined with clearances required to withstand the lightning or switching overvoltages with a probability of more than 90 %. The flashover probability is that by which the design overvoltage conditions will be exceeded.

5.4.6 Part 5: Application Example

The approach proposed to determine tower top geometry and mid span clearances is demonstrated by means of an example for a suspension tower equipped with a twin conductor bundle ACSR 564/72. The mean value of the yearly maximum wind velocities is 20 m/s (10 min mean value, height 10 m), the coefficient of variation is 14 %. The highest system voltage U_S is 420 kV and the switching impulse voltage U_{sf} is 1050 kV. The mean suspension insulator length is 5,0 m, the sag 20 m and the distance between sub-conductors 0,4 m.

The design of the tower top is performed in 5 steps. The detailed calculation is given in Cigré TB 348.

- The wind velocity with a return period of 50 years is calculated according to the Gumbel distribution function for extreme values. The moderate wind velocity is calculated using the Weibull distribution function;
- The wind velocities are adjusted to the time period of measurement and the height above ground according to the IEC 60826 equations. In Tables 5.31 and 5.32 the results are given for a 5 minute wind speed 20 m above ground level;

Table 5.31 Clearances between insulator set and earthed structure

	Wind		Insulator swing angle			Clearance		
Pos.	Wind condition	Wind speed	Mean swing angle	Standard deviation	Max. swing angle	Impulse voltage IEC	Power freq. voltage TB 72	Distance to earth
		$V_{20\,m}$	ϕ	σ_ϕ	$\phi+2\sigma_\phi$	D_{pe}	D_{pe_pf}	L_0
		m/s	°	°	°	m	m	m
1	$T=50$ years	32.0	42.2	2.2	46.6	-	1.16	4.99
2	Swing 1 % of year	16.1	12.9	1.5	15.9	3.40	-	4.97

Table 5.32 Clearances between adjacent conductors in mid span

	Wind		Conductor swing angle				Clearance TB 72		
Pos.	Wind condition	Wind speed	Mean swing angle	Standard deviation	Min. swing angle	Max. swing angle	Impulse voltage	Power freq. volt.	Dist. cond.
		$V_{20\,m}$	ϕ	σ_ϕ	$\phi-2\sigma_\phi$	$\phi+2\sigma_\phi$	D_{pe}	D_{pe_pf}	L_1
		m/s	°	°	°	°	m	m	m
1	$T=50$ years	32.0	43.7	2.2	39.3	48.1	-	1.52	-
2	Swing 1 % of year	16.1	13.5	1.5	10.5	16.5	3.73	-	6.70

- The results for the swing angle of the suspension insulator set at the tower and the swing angle of conductors at mid span are somewhat different;
- Further the scattering of the swing angle is determined:
  - The maximum swing angle at the tower is obtained by adding two standard deviations to the mean swing angle of the insulator. The maximum angles for the two positions of the insulator set are depicted in Table 5.31, and Figure 5.6;
  - For the adjacent conductors both the minimum and maximum swing angles are obtained respectively by deducting and adding two standard deviations. The most unfavourable positions of the swinging conductors are depicted in Figure 5.6;
- Finally the minimum electrical clearances taken from Tables 5.31 and 5.32 are used to determine the horizontal distance between:
  - The attachment point of the first conductor and the tower structure (5.0 m);
  - The attachment points of two adjacent conductors in a horizontal configuration (6.7 m).

The numerical results of the calculations are summarized in Figure 5.5 and Table 5.31 for the clearances between insulator set and earthed structure at tower and in Table 5.32 and Figure 5.6 for clearances between adjacent conductors in mid span. Cigré TB also compares these results for other alternatives.

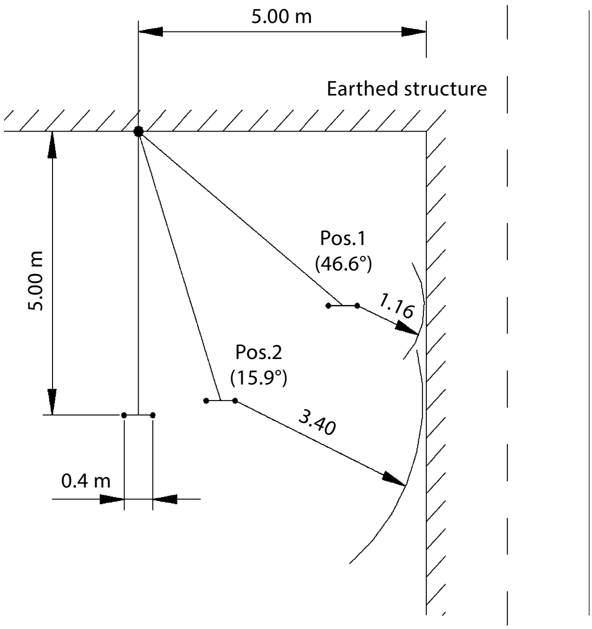

Figure 5.5 Example of clearances between insulator set and earthed structure.

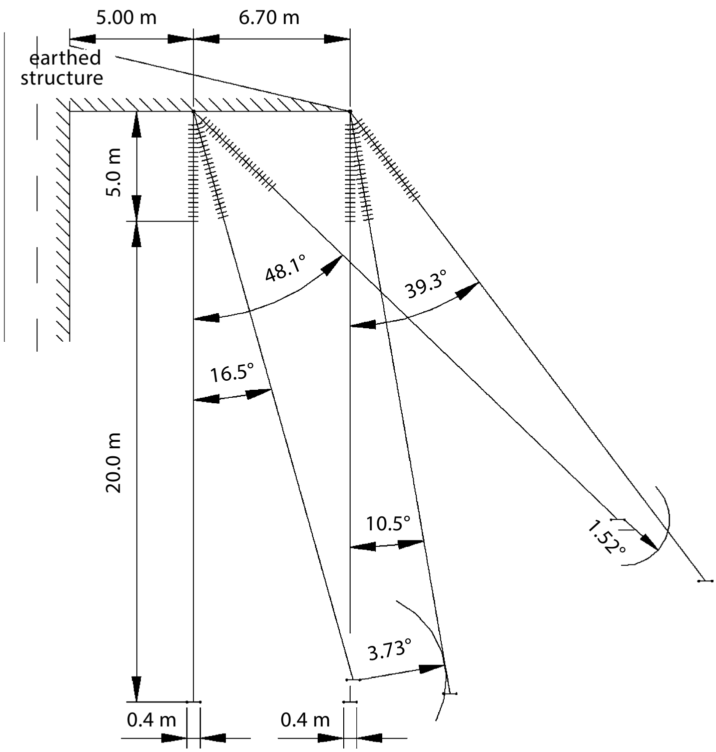

Figure 5.6 Example of clearances between adjacent conductors in mid span.

5.4.7 Conclusion

On the basis of the review of national practices, the study results in a proposal to consider two cases when designing the tower top geometry and mid span clearances in view of conductor and insulator swing under wind action. Reference wind speeds and ice loads as well as parameters, such as the number of standard deviations, have to be selected accordingly based on studies and experience.

5.4.8 References

[1] Cigré SC22 WG06: Tower top geometry. TB 48 (1996)
[2] EN 50341–1: Overhead electrical lines exceeding AC 45 kV – Part 1: General requirements – Common specifications (2002)
[3] IEC 60826: Design criteria of overhead transmission lines, Edition 3.0 (2003)
[4] Cigré SC22 WG06: Probabilistic design of overhead transmission lines. Cigré TB 178 (2001)
[5] IEC 60071–1: Insulation coordination – Part 1: Definitions, principles and rules
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[7] Cigré SC C4: TB 72: Guidelines for the evaluation of the dielectric strength of external insulation. Cigré (1992)
[8] Kiessling, F., Nefzger, P., Nolasco, J.F., Kaintzyk, U.: Overhead Power Lines – Planning, Design, Construction. Springer, Berlin/Heidelberg/New York (2003)
[9] Cigré SC22 WG06: Tower top geometry and mid-span clearances. Technical Brochure No. 348, June 2008

5.5 Load Control Devices

5.5.1 Summary

Electricity utilities need to design overhead lines to withstand potential cascade failures of towers, which could occur as the result of exceptional icing or rupture of conductors. Some utilities simply design the lines with section towers at frequent intervals and other utilities use special devices called «load control devices» (LCD), the function of which is to limit the stresses applied to the towers in the case of the application of exceptional longitudinal loads. These devices are usually based on one of the following principles:

- Releasing of the conductor from the tower,
- Sliding of the conductor through suspension clamps so as to balance the load,
- Elongation of the conductor fitting, so as to increase the apparent length of the conductor and to decrease its tension,
- Elastic deformation of the crossarms on the towers.

This Section based on Cigré study [1] describes the characteristics and performance of the elongating fittings occasionally used in Japan and the controlled sliding clamps used in France.

Some Japanese utilities have replaced conventional suspension sets by Suspension-Tension sets with elongating fittings, on existing lines under which buildings appeared after construction. These devices have been designed by EPDC (Electric Power Development Co, the research institute of Japanese Utilities) and make it possible to raise the height of conductors (in normal service) without replacing or modifying the existing suspension towers.

The first type of device is based on the unfolding of the fitting, triggered by the rupture of calibrated shear pins; the loads are damped by an impact-absorbing element. The second type of device is based on sliding of the shackle in a groove designed into the yoke plate.

In France, EDF systematically installs controlled sliding clamps on suspension towers. Each tower of a line is designed for a conventional asymmetric ice load. The sliding load of the clamp is chosen in a range of standard values such that if the actual load from the asymmetric ice load reaches the calculated load then the conductor will slide through the clamp. The suspension tower is thus protected from failure from exceptional longitudinal loads and at the same time the tower cost is not increased.

The results of a survey show very varied utilization of the LCDs in different countries: either not used at all, occasionally used or systematically used. The choice of device is based on many reasons and are linked to different local practices and parameters:

- The countries which systematically use LCDs, such as France, Belgium and Romania, give one or more of the following arguments:
  - The global cost of a line is reduced,
  - The efficiency of these devices has been checked in test stations and on several occasions in the field.
- The countries which use these devices in a non systematic way, such as Japan, do it in specific cases, like on existing lines to avoid the replacement of the towers when buildings are built under them,
- The countries, which never use LCD, give one or several of the following arguments:
  - Towers are systematically designed for specified longitudinal loads,
  - Icing is unknown or very rare in the country,
  - The efficiency of the devices is uncertain,
  - The increase of the conductor sag, generated by an LCD, is unacceptable in the view of public safety,
  - The use of controlled sliding clamps causes severe damage to ACSR conductors.

In conclusion, the utilities that want to go further in the field of load control devices, should concentrate on the following aspects: reliability, safety, and estimation of the cost effectiveness. With respect to this last aspect, the experience in some countries show that, for the future, the modifications and upgrading of existing lines are a potential field of application for LCDs.

5.5.2 Introduction

The most serious overhead line failure, which could have severe consequences affecting the grid operation, is the cascade failure of several transmission towers.

This cascade failure is usually initiated by the failure of a single tower or by the breaking of conductors and is the result of insufficient design strength of towers to withstand high longitudinal loads.

The choice of solution to avoid such damage will depend upon a compromise between the risk and consequences of a cascade failure and the extra cost of construction specified by the designer.

The most frequent solutions to limit or avoid series tower failures are, either to use section supports at regular intervals (also called anti-cascading towers), or to provide enough longitudinal strength to the suspension towers. In the second solution, the use of LCD can make it possible to limit considerably the magnitude of the longitudinal loads and thus the cost of the towers.

After a general presentation of the different categories of LCD, this Section describes some devices which are currently available. It then summarizes the experience of the countries that took part in the survey conducted as part of SC22 WG 06 of Cigré.

5.5.3 Classification of LCD

The task assigned to an LCD is to avoid major and costly line failures, which could occur in the case of certain exceptional loads, by releasing or limiting the stresses applied to a main line-component.

Practically, LCD are generally designed to protect the towers from exceptional stresses applied by the conductor in the case of unusual icing, cascading, etc.

Considering the existing devices, two categories of Load Control Device can be defined:

5.5.3.1 Load Release Devices

In this case, the conductor load that could cause the failure of towers is totally released from the tower so that the conductor system is not controlled (or there is a very limited control). Different types of devices exist:

- Devices in which the conductor grip within the tower attachment fitting is released, such as release type suspension clamps (there is no more control of the longitudinal tension),
- Devices in which the conductor or the fitting itself become detached from the tower, by means of mechanical fuses such as shear pins or safety bolts, associated with a system (such as a loose jumper) to prevent the conductor from falling down to the ground.

5.5.3.2 Load Reduction Devices

In this case, the conductor load that could cause tower failure is reduced to an acceptable value and the system maintains control of the conductors. Different types of devices exist:

- Devices acting on the fastening of the conductor within the fitting, such as controlled sliding clamps, in which the conductor slides when the longitudinal load exceeds a specified value,
- Devices which act on the length of the fittings (unfolding or sliding elements) so as to increase the apparent length of the conductor.
- Devices which enable elastic deformation or swinging of the crossarms of the tower to absorb longitudinal load.

Dynamic damping devices constitute another category of control equipment. These act on the origin of the stress and are designed to stop or reduce dynamic phenomena such as conductor vibration and galloping: damping jumpers, Stockbridge dampers, spacer-dampers etc. These devices cannot really be considered as LCD and these will not be addressed further.

5.5.4 Technical Data Related to Available LCD

This chapter gives the principles and characteristics of some important load reduction devices of two types:

- Special elongating fittings
- Controlled sliding clamps.

5.5.4.1 Special Elongating Fittings: Japanese Experience

These devices have been designed by EPDC and are mainly used in Japan. This is mainly due to the increasing restrictions to the building of new lines and the increasing urbanisation around the existing lines. In Japan new buildings are often built under existing lines and Japanese utilities must find solutions to compensate for the lack of height of the conductors from the ground and buildings, if possible without replacing or raising towers.

One solution is to replace the conventional suspension systems by Suspension-Tension Insulator Assemblies. These devices can also be used to improve the insulation level of the lines, by increasing the number of insulators without lowering the height of conductors. In these cases, the existing suspension insulator set is replaced by two tension sets suspended under a special suspension fitting, which in normal service is shorter than the conventional suspension set.

In order not to degrade the mechanical behavior of the existing towers in the case of conductor breakage in one span or unbalanced tension (unusual ice accretion or ice falling off), these devices have been designed as load reduction devices: an excessive differential tension across the tower elongates the fitting and increases the apparent conductor length so as to reduce its tension.

Two types of these fittings have been developed in Japan.

Type I

PRINCIPLE

The elongation of the TYPE I device is triggered by the breaking of shear pins and is damped by the deformation of an impact load absorber.

The following figures illustrate the functioning of the system in the case of conductor breaking in one span. 1) Situation in normal service (Figure 5.7). In this normal situation, no loads are applied to the shear pins or the impact load absorber.

2) Intermediate situation (Figure 5.8).

The metal suspension fitting moves to the right, due to the breaking of the conductor in the span to the left. If the dynamic load is too high for the shear pins, they break, which leads to the following situation.

3) Final situation (Figure 5.9).

The dynamic effects of conductor breaking are damped by deformation of the impact load absorber. In the final situation, the conductor tension is reduced by increasing the length of the span.

DESIGN CHARACTERISTICS

- The rupture strength of the shear pins is 40 to 60 % of the maximum working tension of the conductor.
- The permissible load of the shear pins against unbalanced conductor tension (ice drop, strong wind) is 40 % of the ultimate tensile strength of the conductor.
- Rupture of the conductor generates a sudden extension of the fitting, which creates a large impact load. The impact load absorber is designed to reduce this load to the same level as that existing in conventional suspension sets.
- The impact load absorber is designed to control loads up to 1.5 times the maximum working tension of the conductor.

MECHANICAL PERFORMANCE

The performance of the device was checked on an actual scale test line.

- Conductor breakage:
  - The final tension of the conductor in the opposite (intact) span is less than 60 % of the maximum working tension (with the worst atmospheric loads).
  - The impact load is less than with the conventional suspension sets, because of the impact load absorber.
- Unbalanced conductor tension (ice drop, unusual ice accretion, strong wind):
  - The unbalanced tension applied to the tower is less than 25 % of the maximum tension of the conductor in the case of ice drop or strong wind.
  - The special suspension hardware of the device is shorter than the conventional suspension set, so that the dynamic unbalanced tension and the swing

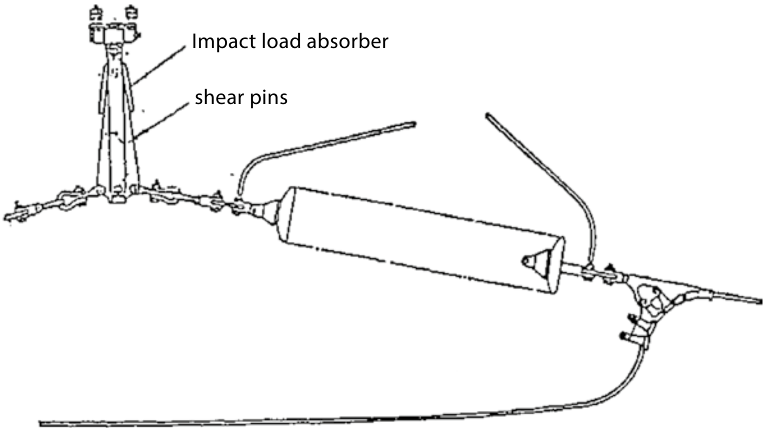


Figure 5.7 Initial geometry of an LCD type.

Figure 5.8 Intermediate position: after the conductor breaks but before the rupture of the shear pins.

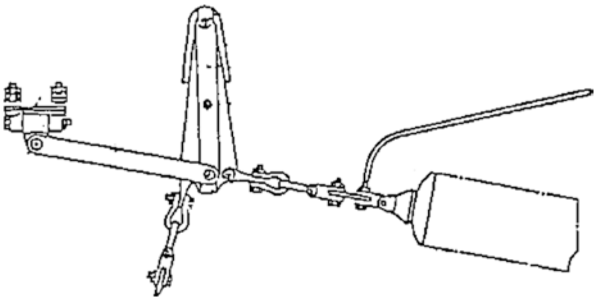
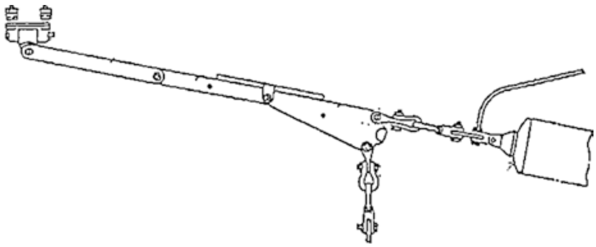


Figure 5.9 Final equilibrium position of the LCD after trigger.



angle are larger. The tests showed the need to consider wear design aspects considering the longitudinal swing of the device.

- Wear performance
  - The wear calculations, assuming an expected life of 50 years, showed no problem.

Electrical Performance

The tests showed that the device could withstand a power arc equal to or higher than that withstood with conventional tension sets.

Service Experience

At the present time, there are around 1245 Suspension-Tension Insulator Assemblies of this type installed, of which:

- 170 for 66 kV lines
- 875 for 154 kV lines
- 200 for 275 kV lines.

No data was given about the efficiency of these devices in real faults.

Type II

The elongation of the so-called "tension balance type" device occurs by sliding of the shackle in a groove designed into the yoke-plate; the overall elongation is shorter than with the TYPE I device, and consequently the increase in conductor sag is less.

Figure 5.10 illustrates the system functioning in the case of a conductor system breakage in one span, compared with a conventional device. The principle is worse for unbalanced tension due to ice drop or unusual ice accretion.

Note: After failure of the conductor in one span, the device enables the conductor tension in the opposite(intact) span to be reduced to 60% of the maximum working tension in the worst atmospheric loads.

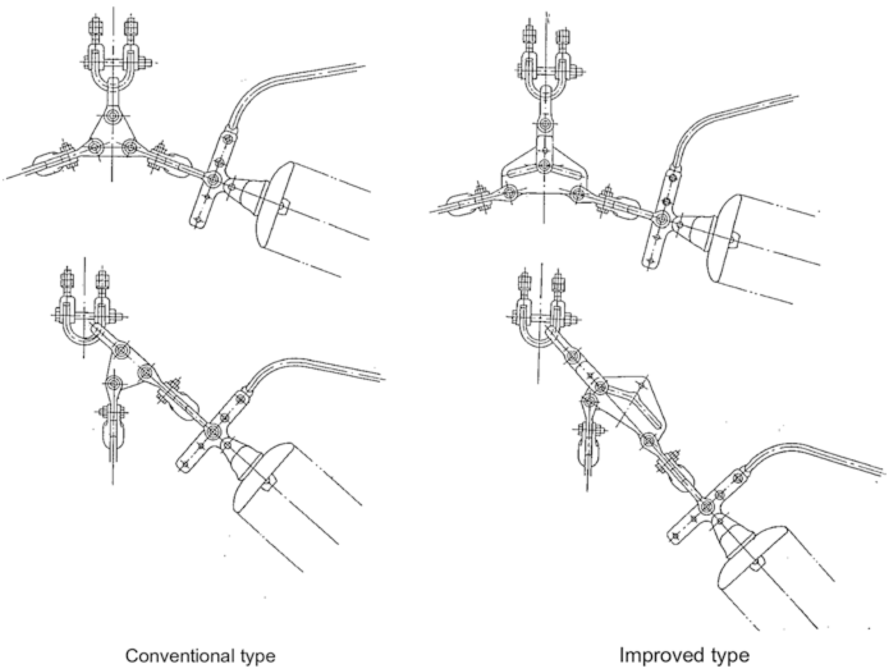


Figure 5.10 Type II Tension Balance LCD.

There are limitations for the use of such devices; they are not suitable in the case of high tension differences between spans (which might cause inopportune sliding or no sliding at all) and their efficiency in reducing the tension decreases with the number of successive suspension spans in a section.

It is worth mentioning the following elongating device, which is currently under consideration for use on tension towers in Japan.

5.5.4.2 Controlled Sliding Clamps

Controlled sliding clamps are used on a large scale in some countries, such as Belgium, Romania and France.

French Experience

In France, controlled sliding clamps have been used systematically for more than 45 years on all transmission lines, both for the phase conductors and earthwires. During this time, the technology of these devices has continuously evolved, in order to improve their performance, and to optimise their use and adapt them for new conductors (Fig. 5.11).

Principle of the Controlled Sliding Clamps

A controlled sliding clamp is made of a body in which rests the conductor and of a cover (see Figure 5.12). This cover is installed over the conductor by means of a system the pressure of which can be adjusted to make it possible to carry out the calibration of

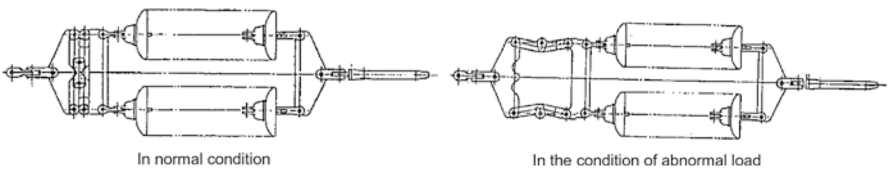
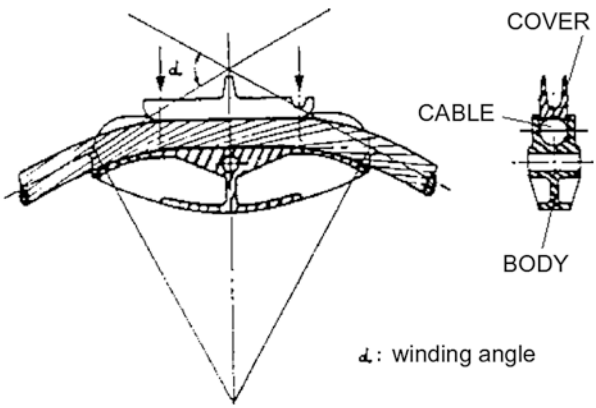


Figure 5.11 Elongating LCD type.

Figure 5.12 Controlled sliding clamp.



the load that causes the conductor to slide through the clamp. The first types of clamps used torsion bars and were called "elastic tightening clamps". EDF finally abandoned the use of torsion bars in 1980, in favour of clamps exclusively based on the controlled tightening of the bolts; these clamps are simply called "controlled tightening clamps"; they enable a more precise adjustment and allow better performance.

Calibration

The conductor must slide within the clamp at a specified longitudinal load, F_S, that may occur as a result either of a conductor rupture or an exceptional unbalanced ice load.

F_S = longitudinal load to be applied to the conductor for sliding

= Sliding load due to the tightening of the conductor in the clamp

+ Sliding load due to the vertical load applied to the clamp by the conductor

$= (f_1 + f_2).\ F_C + f_1\ .F_V$

f_1 = friction coefficient between clamp body and conductor

f_2 = friction coefficient between clamp cover and conductor

F_C = compressive load of the clamp cover

F_V = vertical load applied to the body (in the general case, this load is taken $= \sqrt{V^2 + H^2}$, to take into account the transverse load H)

F_S = longitudinal load at which sliding occurs

Each tower of a line is designed to resist asymmetric icing. EDF conventionally considers an ice sleeve of n cm (radial thickness) on all spans on one side of the tower and (n-2) cm on all spans on the other side; the value of n is 2,4 or 6, depending on the area, the ice density is taken 0.6. The loads are calculated while taking into account the deflection of the insulator sets. Table 5.33 gives some examples of application.

The sliding calibration of the suspension clamp is chosen from the following range of standard support loads: 8, 14, 20, 30 kN. For each tower, it is chosen as the value immediately higher to L-0.3 $\sqrt{V^2 + H^2}$, where 0.3 is the assumed value of the friction coefficients, V, H and L are the vertical, transverse and longitudinal loads applied to the conductor in the clamp, in the asymmetric icing assumption. Support loads greater than 30 kN require other solutions such as the use of clamps in series, the use of suspension- tension sets or the use of a tension tower.

Design of a Controlled Sliding Clamp

In order to make sure that the system operates correctly, the profile of the clamp body must be determined in a precise manner.

It is necessary that the conductor pressure be equally spread out over the useful length of the body to ensure a regular sliding on the basis of a longitudinal load determined by a precise adjustment. The length of the body is determined experimentally in such a way that the compression stresses do not exceed the maximum pressure allowable at the point of contact among the strands.

It is also necessary to calculate the radius of curvature of the clamp body so that the bending stresses within a strand remain acceptable.

A computer model, presented in Figure 5.13, was developed to calculate the optimal longitudinal profile of a clamp body.

Table 5.33 Order of magnitude of the loads applied to the supports with unequal ice loading

	Conductors			Ice overload	Mechanical tension in the conductor (daN)		Longitudinal stress (daN)		
									Tangent tower
Type	External diameter (mm)	Weight (daN/m)	Ultimate load (daN)	(cm)	End with ice n cm	End With ice (n-2) cm	Section Tower	225 kV (1)	400 kV (2)
		Conductor (4)							
ASTER 570	31	1.57	18 400	2	7 800	4 420	3 380	1 200	900
PETUNIA 612	32	2.24	32 700	4	14 000	9 500	4 500	2 000	1 600
		Earthwires (5)							
PHLOX 116.2	14	0.63	10 800	2	4 150	1 900	2 250		1 600
									(3)
PHLOX 228	20	1.24	21 200	4	10 700	6 800	3 900		2 000

Notes applicable to Table 5.33
(1) Length of the suspension set: 2.30 m for 225 kV
(2) Length of the suspension set: 3.45 m for 400 kV
(3) Conventional value (span < 1 000 m)
(4) All aluminum alloy conductors
(5) Aluminum alloy steel reinforced earth wires
Catenary constant: 2 200 m at 45 ° C
Length of the adjacent spans: 550 m

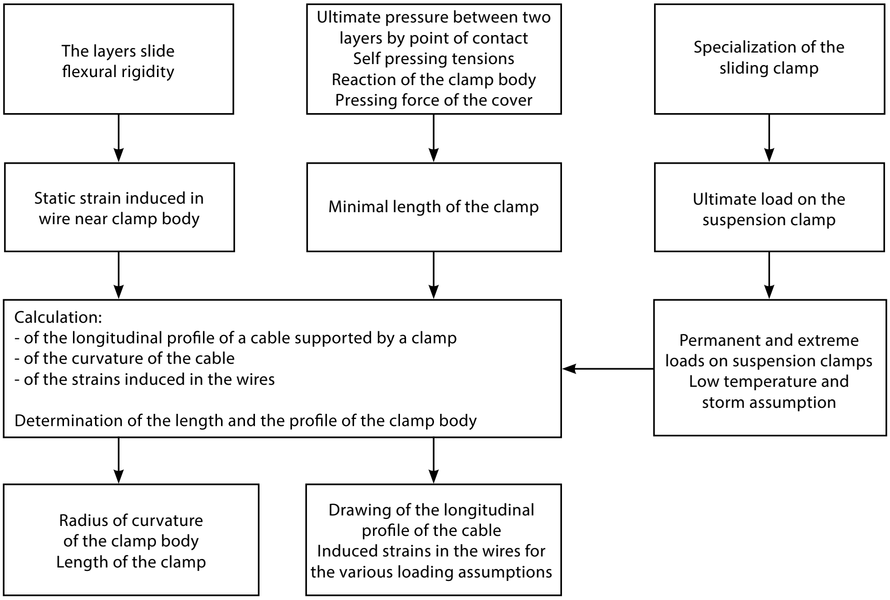


Figure 5.13 Research of the optimal longitudinal profile of a clamp body.

TEST

The accuracy of prediction of the load to cause conductor sliding depends on several factors: frictional coefficients, clamp and conductor manufacturing tolerances, etc.

It is necessary to reduce the dispersion as much as possible. Nevertheless, the precision on predicting loads that cause sliding, with respect to the clamp calibration load, cannot be better than 15 %.

To verify the sliding characteristics of the suspension clamps, tests are carried out with each new type of suspension clamp:

Measurement of Friction Coefficient Test Conditions

This test is performed with an adjustable sagging machine. The conductor rests on the body of the suspension clamp without the cover. The winding angle is between 20 and 30 degrees and the vertical load is given by Table 5.34.

The measurements of the sliding efforts are performed over a length of one meter.

Test Requirements

The friction coefficient shall not exceed 0.35.

Measurement of the Sliding Threshold Forces Test Conditions

- Measurements of sliding threshold values are made according to the cover pressure.
- The conductor is loaded at 20 % of its ultimate tensile strength in a suspension clamp with a winding angle of 15 degrees (in order to settle each wire in position).
- The cover is tightened to the value given by the manufacturer and the conductor is released.

Table 5.34 Vertical loads for sliding tests according to the type of suspension clamp

Suspension clamp class	Conductor	Vertical Load (kN)
A	ASTER 75	8,5
B	PHLOX 75,5	17
C	PHLOX 147	24
D	ASTER 570	40
E	PETUNIA 612	45
F	POLYGONUM 1185	45
G	POLYGONUM 1185	90

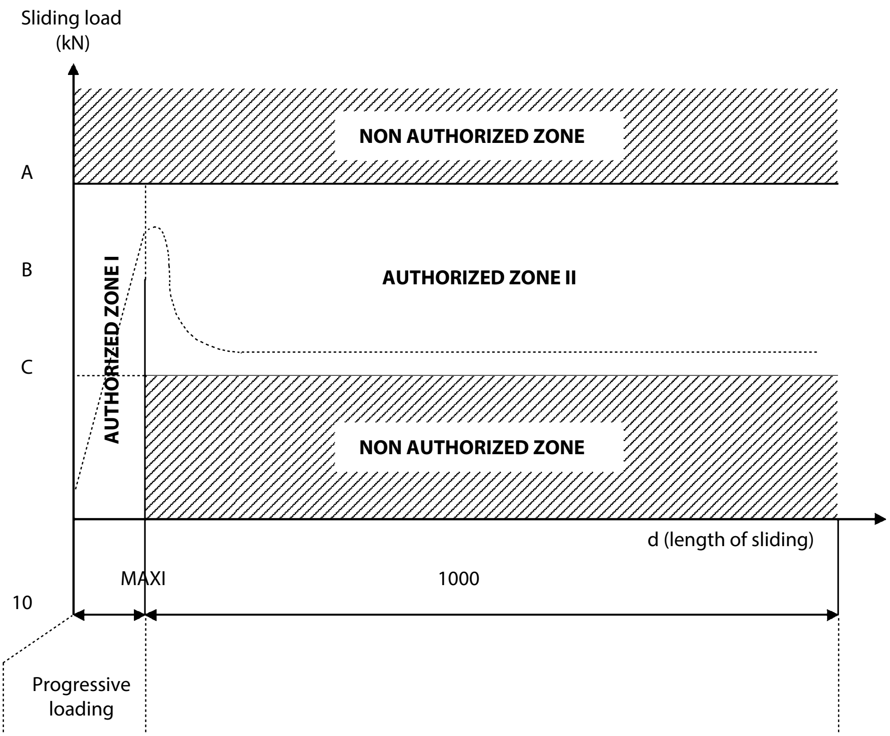


Figure 5.14 Design data for sliding clamps.

- The suspension clamp is then pulled over a length of one meter.
- The sliding force is the maximum tension applied to the conductor on the stressed side (the other being released).

Test Requirements

The value of the sliding force relative to the sliding length must remain within the allowable areas such as defined in Figure 5.14; the force must range between the values A and B following a displacement not exceeding 1 cm. The actual curve must be shifted by a value C so as to take account of the friction due to the vertical load according to the formula C = 0.05× UTS.

The breaking load of the conductor following sliding must remain higher than 95 % of the ultimate tensile stress (UTS) of new conductor for homogeneous conductors, and 90 % of the UTS for bimetal conductors.

Device Efficiency

Sliding Limitation

When sliding occurs it is stopped whenever the tension difference applied to the clamp on either side of the clamp falls below the calibration value.

Thus the sliding length depends mainly on the initial tension difference applied to the clamp, on the relaxation due to the deflection angle of the insulator set and hence on the length of this set.

The conductor sliding range observed in the overhead line network, in several cases of unequal loading, ranged from 1 to 2 m. For earthwires this value is much higher.

In case of a breakage of a conductor or a support, considerable sliding, of ten meters and more, were noted on towers located on either side of the defect.

On the other hand, the movement declines very rapidly on subsequent towers.

Finally, in some cases, in particular when sliding is considerable, the conductor can be damaged (rupture of strands, bundling and bird cage formation); this phenomenon however is very rare on conductors having an outside layer made of aluminium alloy (AAAC and AACSR conductors).

However, this inconvenience which requires the replacement of a length of conductor, is in all situations less serious than the destruction or damage of several support structures. The line downtime is reduced and the repair costs are considerably lower.

Action of Clamps During Real Faults

Among the incidents, whose consequences were limited by the action of sliding clamps, we can give the following examples (Table 5.35):

- In 1949, a 40 degree angle tower fitted with suspension sets and located in the mountains, with a high level difference, was carried away by an avalanche. Two of the three conductors were broken; the conductors slid in the clamps of several suspension towers. Only one crossarm was distorted.
- In 1964, after the rupture of the top of a 50 degree angle tower of a 400 kV line within the Paris area, damage was limited to 4 towers, as a result of sliding of the 6 conductors within their suspension clamps.

Table 5.35 Example of values used for the design of sliding clamp

RANGE (kN)	A (kN)	B (kN)	C (kN)
8	8	6.5	3.6
14	14	11	6.3
20	20	15.5	8.9
30	30	23	13.3

NOTE: C = (A + B)/4

- In 1971, an overall and persisting icing phenomenon, unusual within the area of Le Creusot, gave rise to an ice sleeve formation on the phase wires of a 400 kV line, with linear weight up to 15 kg. This overload was approximately 4 times higher than that considered in the line design calculation. The complete failure of the conductor bundle was prevented by means of the sliding of the conductors within the clamps of 5 successive towers. Only 2 of them were damaged.
- In 1974, an aircraft hit 2 of the 6 twin conductor bundles made of AAAC, of a 400 kV line. The 4 conductors slid in their clamps. The 2 suspension towers supporting the damaged span, had to be replaced, as well as some elements of the two adjacent tangent towers.
- In 1988, an aircraft hit the 3 twin bundles of a 400 kV line near a substation. The broken conductors slid in the clamps over more than 3 km. 2 suspension towers had to be replaced.

Belgian Experience

Since 1971, controlled sliding clamps have been systematically installed on the conductors of 380 kV lines.

The first aim was to reduce the weight and cost of tangent towers, by reducing the accidental stresses considered in the design of the towers with the assumption of conductor breakage (the effect of breaking all the conductors of the bundle).

The torsion moments have traditionally been calculated by application of the maximum tension of the conductors of the phase conductor on one side of the crossarm, without taking into account the dynamic and releasing effect due to the rupture of the phase conductors and the swinging of the insulator sets. This method, if roughly applied on 380 kV lines (equipped with twin bundles), would have led to un-economic tangent towers. The use of controlled sliding clamps was estimated to offer a reduction in the weight of tangent towers of 6 %.

These arguments do not apply to earthwires, because of the lower stresses and the lower potential load reduction and consequently sliding clamps are not installed on earthwires.

Two types of controlled sliding clamps are used. One type uses a torsion bar bolted in the body of the clamp and calibrated shear pins in the cover. The second type is based on the controlled tightening of the bolts.

In the lines, the conductors are systematically protected by armour-rods; the specified sliding load is determined as a function of the conductor type and is taken as a relatively high value to avoid inopportune sliding. No sliding in clamps has been seen in Belgium.

Romanian Experience

For the past 30 years, controlled sliding clamps have been used for the conductors of all transmission lines in Romania. These clamps are based on the controlled tightening of the bolts by a limited torque wrench. Their actual efficiency has not been measured on the network but no failure due to cascading has occurred, although most supports are guyed poles. RENEL is still working on the optimisation of the controlled sliding clamps.

Release type suspension clamps have been used, but very occasionally and only on lines without problems of conductor galloping. Their benefit has been demonstrated on several occasions.

5.5.4.3 Service Experience of LCD in Different Countries

The summary of the answers of the countries replying to the survey is given in Table 5.36.

5.5.5 Specification for an Ideal LCD

Load Control Devices (LCD) are devices designed and used to limit the damage to structures in case of a failure that occurs in a transmission line.

In a previous WG B2.06 report, published in Electra No. 193 [1] and Cigré TB 174 [4], a survey of existing LCD's installed on overhead lines was performed, including comments on their use in each country. This report is summarized in the chapter above. In the Electra report, a distinction was made between two types of devices: those intended to reduce loads applicable to structures and those completely releasing the conductors from structures. However, in this report the wording LCD is used to describe both types of devices indiscriminately.

The catastrophic line failures in 1998 (Canada) and 1999 (Europe) raised new interest about LCD's as well as questions about the performance of existing ones.

Consequently, WG B2.06 decided to prepare a basic generic specification or a list of properties of an ideal device that would be helpful to operators and designers of overhead lines. This work should help current and potential users of LCD's to check the performance of the devices they currently use or intend to use, and to promote the development of better devices by manufacturers that have a minimum number of non-compliances to the properties of the ideal device.

This report does not intend to compare and assess the performances of LCD's with other possibilities to limit failure containment, such as anti-cascading towers, strength coordination, etc.

5.5.5.1 Criteria for the Evaluation of a Load Control Device

An ideal Load Control Device should be judged by many design and performance criteria. Tentatively, the following criteria are considered and will be further discussed in this report.

- Compliance with the primary functions of Load Control Devices
- Tolerance of triggering action
- Design flexibility to fit the as-built support strength
- Safety issues on clearances
- Impact on construction and maintenance.

It can be argued that these criteria can be more theoretical than practical, but one purpose of this report is to alert developers and users of LCD's on the importance of

Table 5.36 Replies of various countries to the questionnaire on LCDs

COUNTRY/COMPANY	USE OF LCD/COMMENTS
ARGENTINA	**Not used**
AUSTRALIA	**Not used** Conductors are generally ACSR
AUSTRIA/TKW	**Sporadic use in the past:** only on a few towers on lines built before 1940
BELGIUM/TRACTEBEL	Systematic use for conductors of lines equipped with bundles; see paragraph Belgian Experience
BRAZIL/CEMIG	**Sporadic use**
CANADA/ONTARIO-HYDRO	**Not used**
HYDRO-QUEBEC	
	Sporadic use: 1) Controlled sliding clamps were installed for the reconstruction of 735 kV lines, after heavy icing events. No other incident has occurred since then, so the efficiency of this equipment has not been verified. 2) After erection, safety bolts for the attachment of the construction cable are used on « chainette towers ». A loose jumper is installed to retain the construction cable from falling.
CZECH REPUBLIC/ENERGOVOD	**Not used**
FINLAND/IVO	**Not used**
FRANCE/EDF	**Systematic use on all transmission lines;** see paragraph French Experience
GERMANY/BAYERNWERK	**Sporadic use in the past:** Now, the German utilities consider that 1) the reliability of LCD and their effectiveness has not been adequately demonstrated 2) the increase of the conductor sag is unacceptable, in view of public safety, because of the high density of population in Germany.
GREAT BRITAIN/NGC	**Not used**
INDIA	**Sporadic use**
ITALY/ENEL	**Not used** 1) All towers are designed to withstand a specified longitudinal load. 2) ENEL utilises ACSR conductors and argues that the wires are considerably damaged after sliding in the clamp. 3) ENEL is not convinced of the LCD efficiency, especially in mountainous areas.
JAPAN/EPDC	**Sporadic use; development in progress;** Raising the conductors on existing lines under which buildings appeared
KOREA/KEPCO	**Not used**

(continued)

Table 5.36 (continued)

COUNTRY/COMPANY	USE OF LCD/COMMENTS
NETHERLANDS/KEMA	**Not used**
NEW ZEALAND	**Not used**
NORWAY/STATNETT	**Sporadic use** When the sagging of the earthwire is considered less serious than a mechanical damage, sliding clamps are used for earthwires. The clamps are basically adjusted for a 30 kN sliding load. The tower tops are designed accordingly.
PORTUGAL/EDP	**Not used** 1) all towers (suspension or tension towers) are designed to withstand, in the worst conditions and with a certain safety coefficient, the rupture of a conductor or an earthwire 2) zones with potential icing are very rare in Portugal and avoided whenever possible.
ROMANIA/RENEL	**Systematic use for conductors; development in progress;** see paragraph Romanian Experience
SPAIN/RED ELECTRICA	**Not used**
SWITZERLAND/EOS	**Sporadic use;** In the case of double tension sets used for twin bundles, EOS uses special yoke plates to damp the dynamic effect of the rupture of the set.
USA/LINDSEY MANUFACTING COMPANY	**Sporadic use in the past;** since early 1970's, two LCD systems have been used in conjunction with porcelain line post insulators throughout North America : shear pins and elastic–plastic base. These devices were a type of mechanical fuses.

these criteria in any new development and promote their use as a rating method and/or a checklist to compare the potential performance of these devices.

5.5.5.2 Primary Function of Load Control Devices

This issue is one of the most important problems preventing or limiting the use of Load Control Devices. Some Load Control Devices reviewed may cause more harm when they trigger than if they had not. In order to prevent the consequential damage due to the trigger of the Load Control Device, the following guidelines are established and explained:

- The release of an LCD in a given support should not lead to unbalanced forces which could cause the failure of the support itself or neighboring supports

This is an obvious requirement, otherwise the purpose of introducing the LCD in the line would be defeated.

LCD's are likely to trigger in random sequences[5] on individual phases depending on the load level and the mechanical characteristics of these devices. There is no doubt that in such cases, there will be some imbalance in the loads applied to structures and these should be kept to a strict minimum.

Let us consider an LCD set to release a suspension or a dead-end string once a given vertical or longitudinal load is reached. If this LCD triggers, the loads on the structure itself and adjacent structures will become unbalanced and may cause structural failures. For example, a flat configuration suspension tower designed to support 100 % of a vertical ice load in all three phases, may break under a combination of loads such as 90 %-0 %-90 % (central phase is released) of vertical loads or 0 %-90 %-90 % (left phase released). Furthermore, these releases will impose a significant increase in the longitudinal and vertical[6] loads on the adjacent structures at the released phase and could cause their failure.

- The trigger of the LCD should cause the least amounts of dynamic loads

The trigger of an LCD can cause sudden changes in loads applied to structures and inevitable dynamic load effects. Designers of such devices should try to minimize dynamic loads that could have serious consequences on adjacent structures. This consideration is particularly important for all devices that completely release conductor loads from structures. Devices of the slip clamp type and dead-end string extensions create less dynamic loads than the previous devices.

- Load Control Devices Installed on a Line must be the least exposed to a cascade of Load Control Devices

In some cases, LCD's can fail in a cascading mode if one triggers at high load levels. Users and manufacturers of LCD's should develop some mitigation measures to prevent such events from occurring. Such measures may include the use of anti-cascading structures or limiting the number of LCD's in a series of suspension towers.

- The static forces following the release of a Load Control Device should be minimized

Users and developers of LCD's should analyze the structural behavior of the transmission line in the eventuality of their trigger action. Consequently, there is a need to develop special structure loading cases when LCD's are used in order to check the adequacy of tower strength to withstand the static loads resulting from a triggering of an LCD.

This report does not include requirements regarding the deterioration of the device and/or the conductor and regarding the performance under a variety of climatic conditions, e.g. if the device is frozen solid with ice.

[5] *In practice, LCD's will likely not trigger at the same load even if they are of the same type.*

[6] *In the case of separation of a suspension insulator string.*

5.5.5.3 Tolerance (Variability) of Triggering Action

Many devices are set to trigger at a certain load or stress level fixed in relation to the line component this device is supposed to protect. Unfortunately, the triggering load in almost all devices reviewed is quite variable and time dependent, thus creating difficulties when the user specifies the range of loads that would trigger their action.

For example one of the most used Load Control Device's is the slip clamp where the conductor is supposed to slip in the clamp if the resulting longitudinal load exceeds a certain threshold. Tests performed on slip clamps show not only a large dispersion in slip clamp trigger, but also a variability of this threshold with time.

For example, let us assume that the longitudinal strength of one tower crossarm is constant and equal to 20 kN and this crossarm is equipped with a slip clamp designed to slip before any longitudinal load causes the tower or its crossarm to fail. If the clamp threshold is set at 19.5 kN, and assuming a coefficient of variation (COV) of 20 % of this LCD, which is not uncommon, about 50 % of the clamps will not trigger prior to the tower failure. If we set the threshold at 15 kN, we secure that about 95 % of the clamps will trigger below 20 kN, some of them at a very low level of about 10 kN. In such circumstances, the tower would have an extra longitudinal capacity, paid for dearly, but unused because of the slip clamp. There could also be cases where the tower would have been able to withstand the longitudinal load, but the trigger of the slip clamp at low load levels would have already created a permanent fault.

The dispersion problem of the LCD is further compounded by the unavoidable dispersion of the strength of the component it intends to protect. For example the above strength of the crossarm, assumed constant at 20 kN, does not represent reality. Based on data from tower tests, the dispersion of strength of lattice towers is accepted to be in the range of 5 to 10 %. The combination of both dispersions of the component and the LCD increases problems of specifying a trigger load of the LCD.

Consequently the following guidelines are established as regards the tolerance of the triggering actions:

- The mechanical Load Control Device should have small strength dispersion (COV ≈ 2-3 %). In order to grasp the importance of this requirement, let us consider the same example above and assume an average strength of the crossarm of 20 kN and a COV of 10 %. The lower 10 % exclusion limit of the crossarm strength is equal to (1–1.28 * 10 %) * 20 kN = 17.4 kN. If it is required to ensure that in 90 % of the cases the LCD triggers before the tower, the trigger threshold will vary with the strength dispersion of this device. The strength factor of Table 5.23 in IEC 60826 [2] and in Cigré TB 178 [4] can be used to calculate the required strength of the LCD as a function of the strength dispersion of both the LCD and the component it needs to protect. If the strength dispersion of the LCD is 5 %, then we should set its average trigger threshold to about 20/1.15 = 17.3 kN. If the LCD dispersion is 20 %, the average trigger will be about 20/1.37 = 14.6 kN. This value is further reduced to 12.2 kN for a dispersion of 30 %. These numerical examples confirm that when the LCD dispersion increases, the trigger of the LCD has to be set a low value compared to the strength of the tower thus preventing in some cases the use of an available and expensive tower strength.
- The threshold of release of the Load Control Device should vary very little in time or with the mechanical loads to which the line is subjected.

5.5.5.4 Design Flexibility

During the design of a Load Control Device, it is important that the strength of the component that this device is protecting is known. For example, if a Load Control Device is supposed to disconnect the conductor from the support, the vertical capacity of any support of the line needs to be known. This capacity is not constant, but very dependent on the actual weight span. It would not be appropriate to specify the threshold of the Load Control Device in relation to the maximum spans; because very few supports are normally used with the maximum design spans.

For example, assume a tangent support is designed for a weight span of 900 m supporting a 20 N/m conductor with a limit ice load of 80 N/m. The support should be designed to support [900 m * (20 + 80) N/m] = 90 kN of vertical load if the insulator string weight is neglected. If this support is used with a 450 m weight span in the line, it will be able to withstand an ice load of [(90.000 N/450 m) − 20 N/m] = 1 80 N/m. It is obvious that the Load Control Device should trigger before the ice load reaches about 80–90 N/m otherwise, the tension in the conductor can increase substantially and cause other problems such as to angle towers.

The above examples raise the issue of the necessity of modeling the Load Control Device to fit the as-built support strength, as long as the latter is known.

Consequently, the threshold of the release of the Load Control Device should be adjustable in order to harmonize it with the strength of the line component to be protected, if variable.

5.5.5.5 Safety Issues on Clearances

In some cases, successful triggering of a Load Control Device might cause a safety problem and potential injury to people. For example, after the slippage of the conductor in the suspension clamp or a disconnection in the suspension clamp of the suspension insulator string, the conductor sag will increase and may pose a safety hazard, especially if the line is still in operation. This impact on safety would have been the same as a tower failure if the conductor slips in the clamp at a load level close to the tower strength (i.e., if the trigger threshold is equal to the tower strength). However, since perfect fine tuning between the trigger of the LCD and tower strength, due mostly to the dispersion in both values, is not currently possible, the early (premature) trigger of an LCD compared to the strength of the tower should be of concern to the users.[7]

Besides, the Load Control Device should have some kind of indicator that shows, at a distance, that this Load Control Device has triggered and needs a human intervention.

Consequently the safety guidelines are as follows:

- The release of a Load Control Device should not permit clearances to ground and objects to infringe minimum safety distances when the line is still live or when such reduced clearance can lead to risk of injury to people, except when specifically allowed by applicable standards and safety codes,

[7] *In the example above, imagine an LCD set to trigger at 12–15 kN while the tower has a strength capacity of 20 kN. If triggered at such low percentage of the tower strength, the LCD could cause safety hazards.*

- The Load Control Device should have visual indicators that confirm the triggering of the device, unless such action is obvious to the observer.

5.5.5.6 Impact on Construction and Maintenance

Construction and maintenance personnel will not likely work on lines equipped with release mechanism devices (except may be in the case of slip clamps) unless the release mechanism is disabled. Furthermore, the replacement of Load Control Devices should be made at the least possible cost.

5.5.5.7 Conclusion

At the time of writing all above generic specifications and properties of an ideal LCD are not currently fully met by any device currently used or available in the market.

Despite this situation, owners of transmission systems may decide, and have decided, to adopt some devices because they feel or they have found through experience that their advantages outweigh their inconveniences.

At a minimum, the specifications given in this document can be used to compare and select the best device, or the one that has the minimum number of non-compliance to these specifications.

In addition to the above, developers of new devices will find guidance in this document if they want to develop and validate better performing LCD's.

5.5.5.8 References

[1] Load Control Devices on Overhead Transmission Lines – Electra No. 193, December 2000 – Cigré WG B2.06
[2] Design Criteria of Overhead Transmission Lines – IEC 60826, Ed. 3.0, October 2003
[3] Probabilistic Design of Overhead Transmission Lines – Cigré TB 178, February 2001 – Cigré WG B2.06
[4] Load Control Devices on Overhead Transmission Lines, Cigré Brochure 174, December 2000

5.6 Mechanical Security of Overhead Lines Containing Cascading Failures and Mitigating their Effects

5.6.1 General

Overhead line cascades started to occur soon after the first lines were erected in the first part of the 20th century, and they continue to occur. Why?

The last 30 years have brought many improvements in overhead line design practice, more specifically with the introduction of the reliability-based design approach. But even with careful consideration of the various sources of uncertainty and variability in the loads and resistances, failures will still occur. The issue is no longer to assess whether "IF" it will happen but rather to address the "WHAT IF" and assess and limit the impacts of the consequences of cascading failures. With the difficulty in the prediction of extreme climatic loads, especially those loads associated with big storm events of all kinds, the utilities are searching for effective ways to improve the continuity of service of their power transmission grid.

Containing line cascades is a high priority for most utilities, especially for those that had been hardly hit by huge accidents in the past. The main objective of Cigré

TB 515 [11] is to help line designers and planners to achieve this challenging goal through a better understanding of line cascading phenomena. This understanding is essential for effective and sustainable mitigation, which must be accounted for in the general context of power grid planning and operations rather than be restricted to the mechanical line design process.

TB 515 [11] summarizes the most up-to-date knowledge gained by Industry on what causes cascading failures of overhead line supports and how to increase the mechanical robustness and security of transmission lines. Based on scientific research and the experience of several Cigré utility members with catastrophic cascading failures during big storm events over the last 15 years, the document outlines various cascade mitigation strategies and techniques that have been proven successful. In conclusion, the report suggests that the costs of preventive and mitigation measures and the associated gains in risk reduction of service disruptions be duly accounted for in the overall power grid reliability analysis in order to yield sustainable line security measures.

5.6.2 Exceptional Loads, Accidental Loads and Mechanical Security of Overhead Lines

Addressing the mechanical security of overhead lines requires careful consideration of the many loading conditions that may eventually trigger various types of failures. A distinction is made between exceptional loads, which are defined as climatic or natural loads in excess of design loads, and accidental loads. Exceptional loads are related to extreme natural events which can be characterized by a probability of occurrence and therefore be specified using a reliability analysis approach. Accidental loads result from events that are not specifically accounted for in design; they are considered deterministic as it is generally difficult to assign reliable values of probability of occurrence to various accidents.

From a line security perspective, both the exceptional and accidental loads have to be considered together. Clearly, accidental loads involving storms of large footprints are likely to trigger multiple failures of weak components while more localized consequences are expected when accidents happen in normal operational conditions. In traditional design practice, accidental loads on transmission lines have been represented by conductor failure (conductor breakage load or unbalanced residual static load (RSL)) occurring in normal operational conditions. Although conductor breakages or failures of conductor attachment hardware are rather uncommon in normal conditions, their likelihood is increased in severe weather conditions and their consequences will obviously differ. This highlights the importance of these considerations as they will influence the choice of security measures in the specific context of each utility.

5.6.3 Line Cascade or Multiple Support Failures?

Cascades of power line supports are (unfortunately) classical examples of failures by progressive collapse, and Figures 5.15, 5.16, 5.17, and 5.18 illustrate recent accidents. It is noteworthy that the study of progressive collapse of structures has

Figure 5.15 Longitudinal cascade on a 735 kV line in Canada during the Great Ice Storm of January 1998 (Photo: B. Breault, *La Presse, Montréal*).

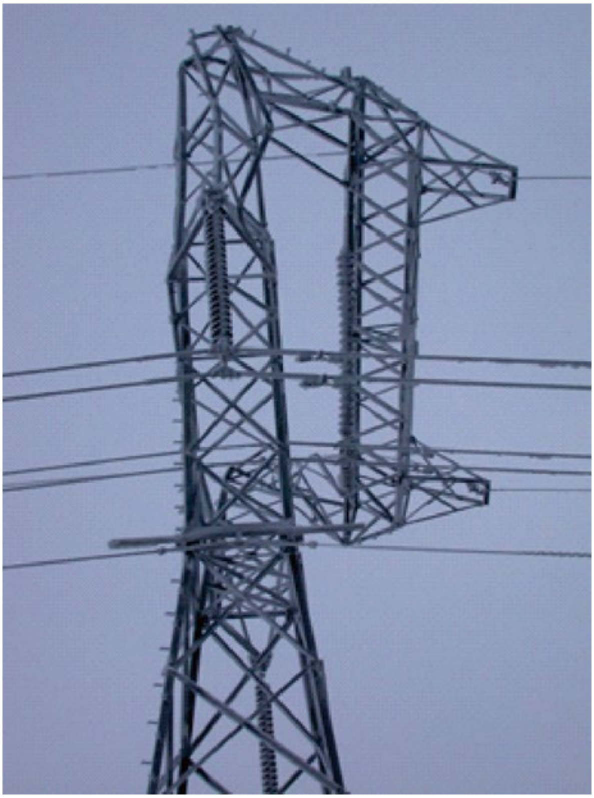


Figure 5.16 Close-up of tower top failure in a longitudinal cascade on 11 supports of a 500 kV line in Oregon (USA) (Photo: L. Kempner, Jr.).

Figure 5.17 Transverse cascade on the 400 kV D/C Rubí-Vandellós-Pierola line in Spain during a 2008 a High Intensity Wind (HIW) storm (Photo: J. Santana López).

Figure 5.18 Transverse cascade of five 400-kV towers due to a May 2006 a High Intensity Wind (HIW) storm in Czech Republic (Photo: P. Fronek).

emerged as a specific research domain in structural engineering only in the last decade [1, 2]. While the successive failures of several towers are not always the result of a domino-effect, they often are. The definition of cascades used in the international standard IEC 60826 [3] is adopted here: "… uncontrolled progression of failure (cascades) which might otherwise extend well beyond the failed section, whatever the extent of the initial failure." It is useful to distinguish between cascades triggered by vertical and longitudinal effects (Figures 5.16 and 5.17), and transverse effects (Figures 5.17 and 5.18) to understand how they happen, while cascade mitigation has to encompass all of them.

5.6.4 Learning from Recent Major Tower Cascading Failures

Chapter 2 of Cigré TB 515 [11] reviews the salient features of the most important cascading failures of the overhead line history, with more emphasis on the catastrophic line cascades that occurred in the last 20 years. This review points to triggering events (rupture of hardware conductor fittings, shield wires and conductors, and support failures) systematically occurring during extreme weather conditions such as high intensity wind storms (downbursts and tornadoes), hurricanes, large scale extreme synoptic winds, and ice storms. It includes the salient features of Cigré TB 344 Big Storm Events What We Have Learned (2008). These large scale weather events are incentives to intensify maintenance programs. Poor condition of the weakest elements sensitive to primary failures has to be registered systematically and mitigated. Vegetation management includes clearing vegetation and widening of corridors to avoid trees falling on conductors and supports, especially when fast-growing trees threaten the conductors.

One of the main conclusions of Cigré TB 344 is that an emergency response plan includes not only the emergency restoration systems and the spare parts, but also the complete organization, reciprocal assistance agreements and regular exercises. Crews must be very familiar with the restoration systems and their erection and use. A good balance between preventive and corrective measures is highlighted. To provide a practical example in some detail, the experience with emergency restoration systems in South Africa is presented in more details in Chapter 2 of Cigré TB 515 [11] Since 2001, Eskom's Transmission has been investing significant effort into developing and expanding their emergency restoration response capability. The utility has developed an emergency response strategy which involves a number of different restoration systems, each with different capabilities and strengths, and suited for use under different emergency conditions.

5.6.5 Current Understanding of Dynamic Line Cascading

Chapters 3 and 4 of Cigré TB 515 [11] present the current understanding on the response of OHL to accidental loads, describing (with some examples) the structural dynamics of a cascading line section. This understanding has been greatly enhanced by research advances in OHL computational dynamic analysis in the last 20 years. Careful numerical simulations make it possible to assess the cascading vulnerability of existing lines and to simulate the effects of various techniques or approaches to limit cascades. They are also instrumental in deriving and validating simplified procedures more amenable to design practice. Slower cascades such as those triggered by damage to towers or foundations are essentially quasi-static phenomena, while dynamic amplification effects of unbalanced loads need to be considered to describe faster cascades triggered by a rupture in the conductor system (cable rupture or hardware fitting). It should be kept in mind that static analysis of towers under various unbalanced load scenarios (including residual static loads (RSL) calculated assuming a conductor rupture) is only representative for “slow” cascades.

The magnitude of the peak dynamic load (PDL) alone may not necessarily provide a realistic indicator of the ability of the damaged system to contain the failure event. These aspects will be discussed in more details in upcoming Cigré TB. Generally, the impact of the event on the tower and foundations is affected by:

- The natural frequency of the tower and intact span(s)
- The response of tower members to transient loads of short duration
- The dispersion of the failure shock from the conductor support point into the superstructure
- Soil-structure interactions.

Current understanding of the response of OHL systems to accidental loads stems from a number of published experimental studies [4, 5], at both the reduced-scale and the full-scale, and several references are listed in Chapter 9 of Cigré TB 515 [11]. It is only recently that numerical simulations [6–8], have allowed the expansion of this understanding (see Table 5.37), with the possibility of simulating previous physical tests for validation purposes, and then as predictive tools for various failure scenarios for which experimental results are not available. One should keep in mind that each modeling scenario and physical test is unique with its own assumptions and physical characteristics. In particular, one should be careful in extrapolating specific results to other situations. This is an important caveat of small-scale tests results as it is practically impossible to replicate realistic problem parameters related to inertia effects and internal damping.

5.6.6 Recent Developments in OHL Cascading Mitigation

Prevention of cascades by effective failure containment measures is a critical aspect of line design. Chapter 5 of Cigré TB 515 [11] reviews several systems and strategies that have been developed and implemented in the last few decades, with variable degrees of success as, unfortunately, OHL systems continue to fail during big storm events. Older lines constructed before strict longitudinal load requirements started to appear in design guidelines are particularly at risk, considering the additional uncertainty in component resistance that comes from aging.

Table 5.37 Line parameters affecting the peak dynamic load (PDL) and the residual static load (RSL) due to conductor breakage

Line parameter	Effect on PDL and RSL
Conductor tension	The strain energy stored in the conductor in the intact profile is the primary source of kinetic energy following the broken wire event. Larger energy releases induce larger accelerations, and consequently larger conductor tensions in the intact profile will produce greater inertia forces and motions, and larger PDL. Heavy conductors, or conductors experiencing sustained overload will also result in a higher RSL.
Assembly Type (Suspension/ Strain)	Suspension I- or V-string insulators swing out, thus increasing the available slack and decreasing the RSL. However suspended spans will experience a second peak dynamic load as the healthy span “bottoms out” following conductor failure, which will increase the PDL (as it will be governed by the second peak). The assembly type also affects the load application rate. Towers fitted with suspension assemblies will initially see no load until the suspension assembly swings out, however strain assemblies will transfer an instantaneous step change or shock load propagated by the failure.
Length of suspension insulator string	Longer suspension strings, and specifically the ratio of suspension string length to slack, decrease the RSL. The same ratio may have the effect of increasing the PDL as the injection of more slack into the healthy section will allow further acceleration before the healthy section “bottoms out”.
Number of suspension spans from the assessed tower to the next dead-end structure	The number of suspension spans to the next strain point will tend to increase the RSL, since successive suspension sets also swing out, thus reducing the net slack length injection into the healthy span. However, the energy dissipated by successive suspension sets also moving will decrease the PDL. These effects typically saturate after about four spans.
Load application rate	The failure mode has a dominant effect on the PDL. This may vary from an instantaneous shock load (e.g. from severed conductor bundles) to a more gradual quasi-static application (e.g. from the longitudinal failure of an adjacent support).
Span/Sag ratio	Spans with lower span to sag ratios tend to produce a higher PDL and RSL.
Span length	PDL decreases with a decrease in span length (and more for flexible supports). A shorter span adjacent to the breakage point promotes dynamic interactions with successive spans, especially the second one.
Flexibility of adjacent supports	Adjacent supports may be deflected by the step change in conductor tension and thus damp the movement of the healthy span, thus lowering the PDL. Slower transverse wave propagation, increased duration of peak loads, increased peak tower displacements and increased interaction with intact cables also result. The effect is minimal on RSL.

(continued)

Table 5.37 (continued)

Line parameter	Effect on PDL and RSL
Flexibility of affected support	Flexible supports may absorb some strain energy when failing in a ductile failure mode not involving instability. However, this ductile collapse occurs after the failure shock load has been transmitted to the adjacent spans and their supports. Tower strength is a more important parameter than tower stiffness and ductile failure modes are beneficial for all types of supports, especially when the failure event does not involve cable breakages.
Supporting effect of ground wires	Where the ground wire remains intact during a failure event, it acts as a longitudinal guy that significantly reduces the longitudinal ground line moment. This will reduce both the PDL and RSL and induce strong dynamic interaction at the tower next to breakage point.
Intact phases	Decrease in PDL and wave propagation speed. Decrease in amplitude of tower displacements. Decrease in maximum tension in guy wires. No (or very little) dynamic interaction for stiff supports, more with guyed supports.
Plastic hinging or ductile failure of cross arm next to breakage point	Filters high frequency peaks of response. Reduces PDL at first support but increases dynamic interactions with next support. No or little effect on displacements of second support and on speed of transverse stress wave. Local failure of supports involving large displacement will significantly reduce RSL.

The first consideration in OHL cascade mitigation is to assess whether or to what extent the post-elastic reserve of the supports can be relied upon. Cascade mitigation devices such as control sliding clamps and load-limiting cross arms protect the supports from excessive loads by providing additional slack and localized dissipation of energy. Another approach is to combine the use of clusters of a few stronger suspension towers at regular intervals with regular suspension towers of nominal strength. Anti-cascading supports are intended to confine longitudinal failures to line sections within their boundaries: while stronger suspension supports may suffice to confine slow cascading line sections, anti-cascading strain supports are necessary to stop dynamic cascades that are induced by ruptures in the conductor-tension system. On power grids located in regions prone to atmospheric icing, line deicing provides a non structural solution, keeping in mind that other failure scenarios involving no icing will require proper mitigation as well. Finally, a few special load control devices are discussed, which have been considered by some utilities but have not been fully validated or implemented.

5.6.7 Security Design Criteria to Prevent OHL Cascades

Chapter 6 of Cigré TB 515 [11] reviews the line security design criteria for new lines as stipulated in the following documents: IEC 60826 [3], CENELEC EN 50341–1 [9], and ASCE Manual 74 [10]. While a comprehensive review of the criteria used by all Cigré utility members was beyond the scope of the work, some particularities specific to several utilities and countries have also been collected from two surveys, the first was conducted in 2001 by Ghannoum under a CEATI (Centre for Energy Advancement through Technological Innovation http://www.ceati.com/) project [12] and the second is an informal working group Cigré B2.22 survey conducted in 2010.

In 2001, at the initiative of its special interest group on Wind and Ice Storm Mitigation (WISMIG), CEATI sponsored a survey on the design approaches used by its utility members for overhead transmission lines under severe climatic loads due to wind and atmospheric icing effects. The survey questionnaire and collected responses, reproduced with CEATI's permission in Appendix B of Cigré TB 515 [11], pertained to new lines as well as lines to be upgraded. The respondents to the questionnaire represented 13 utilities from North America, Japan and some European countries. It is noteworthy that 12 of the 13 respondents stated that they make containment provisions to limit damage in case of weather exceeding the design loads. Eight utilities reported that they consider a broken iced conductor load (any conductor or ground wire, one at a time) for suspension tower design case, although none of the respondents has reported to consider any dynamic load effect on the tower either under bare or partial iced conditions.

To complement the results of the CEATI survey with more participation from other utilities members of Cigré, WGB2.22 has conducted an internal survey (among the WG members and their affiliates) specifically on current design practices used for preventing OHL cascade failures. Both the survey questionnaire and a summary table reporting the salient results are reproduced in Appendix C of Cigré TB 515 [11].

The results of the internal WGB2.22 survey indicate that most National Transmission Line Standards used in European and North American countries (Belgium, Czech Republic, Poland, Serbia, Spain, France, United States and Canada) and in other countries around the world (Australia, Brazil, Japan, South Africa) prescribe some design load criteria for preventing or mitigating the effects of OHL tower cascading failures. It is also usual practice in those countries with severe icing conditions, to install reinforcing stop structures or anti-cascading supports with an average interval of 10 spans (4 to 5 km). For most utilities, a stop structure is a strain tower, whereas for some others anti-cascading towers are suspension supports designed to resist large quasi-static unbalanced longitudinal loads.

Brazil has reported the successful use of an alternative containment load case that consists of the simultaneous application of 50 % of the everyday longitudinal load on all phase attachment points and full everyday tension at ground-wire on all suspension type supports. This practice provides a more continuous distribution of mechanical robustness along the line and therefore does not require a limitation on the number of spans in a line section between anchor towers. None of the transmission lines designed with this failure containment criterion has suffered any cascading failure to date.

The failure containment philosophy of Bonneville Power Administration in the United States (presented in some detail in Section 5.5 of Cigré TB 515 [11] is an intermediate design approach between the discrete robustness provided by stop structures or anti-cascading suspension towers, and the continuous robustness concept adopted by Brazil: it has proved quite successful as well as BPA has experienced only one line cascade to date, where damage was limited to the tower tops of 11 structures in a single-circuit 500 kV line in Oregon (see Figure 5.16).

5.6.8 Framework for Successful Design to Limit Overhead Line Cascades

In the light of the information presented before and with a clear understanding of the various possible cascading mechanisms, a combination of reliability-based design (RBD) and deterministic approaches seems inevitable, a fact that has been recognized by most utilities: i.e.

- Use RBD (also called Load & Resistance Factor Design LRFD) in the intact line system;
- Use pragmatic engineering based on judgment, imagination and experience for line security design. This combines deterministic considerations, careful analysis and decision-making about the acceptable extent of collapse and the acceptable other damage. Again, although the focus of Cigré TB 515 [11] is on technical aspects, economical considerations are crucial in the decision-making.

The question still remains open as to whether "Preventing local failure" or "Assuming local failure and mitigating its consequences" is the best way to go, but both approaches may be applied depending on the load level. A conceptual model is illustrated in Figure 5.19 (from Chapter 7 of Cigré TB 515 [11]) which relates environmental loading conditions in the line section and various robustness enhancement measures of diverse efficiency and cost to yield a range of extent of collapse or damage that leaves way for utilities to make decisions that best fit their specific contexts. For example, one could define acceptable ranges of failures (Nf) of 1 to 3 towers for accidents under every day operational conditions, 3 to 5 towers for accidents under severe environmental load conditions (ex. Intermediate combinations of ice and wind if applicable, or wind pressure with small probability of exceedance), and 5 to 9 towers for extreme (design-level) load conditions.

5.6.9 Conclusions and Recommendations for Future Action

The global grid reliability approach is now the ruling design method in most electric utilities. In this global context, security measures are specifically encompassed inside the analysis framework. A concern for OHL design engineers is that currently, global grid reliability models used by most utilities are not properly accounting for mechanical security aspects of lines. As a matter of fact, in the global grid context, what matters is the availability of any OHL line section to transit electricity: if any specific section is not available while the electric power can safely be

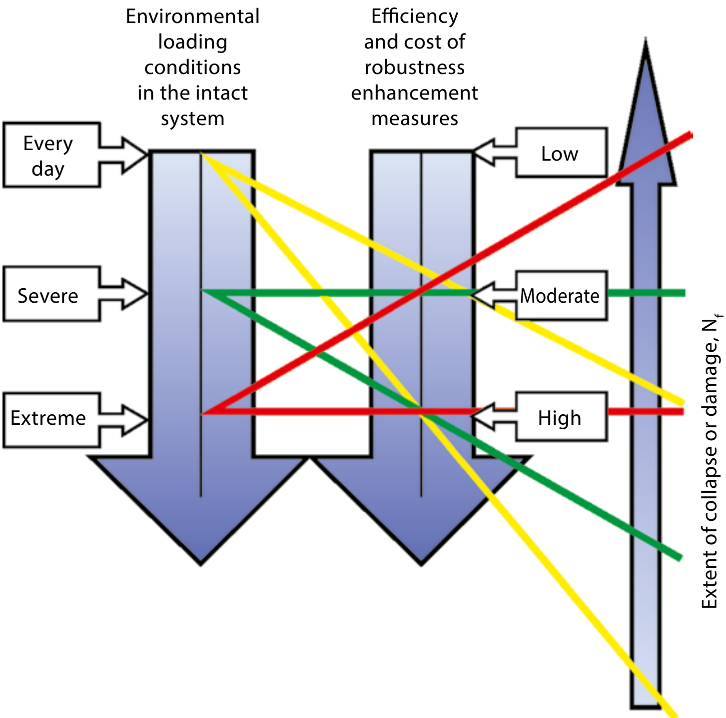


Figure 5.19 Schematic of incremental OHL cascade mitigation.

delivered to clients by an alternative route, the consequences of its "failure" are not as costly as if strategic "back bone" routes are affected. Since the global-grid analysis framework does not yet allow introducing different failure-containment options for different OHL routes, it is very difficult for OHL engineers to introduce innovative methods in their structural design and to develop failure containment strategies that can be both technically effective and cost-effective. Interesting mitigation options can therefore be rejected on the basis of lack of validation lack of understanding, or rigid traditional decisions. Since research and development funds for novel mitigation options are often linked to major capital investment projects, rejection of options due to lack of validation is a great concern.

In conclusion, it is suggested that the costs of preventive and mitigation measures and the associated gains in risk reduction of service disruptions be duly accounted for in the overall power grid reliability analysis in order to yield sustainable line security measures. For this to really happen, experts in mechanical/structural overhead line design will have to work together with grid reliability analysis experts. Cigrè SC B2 and its related normative bodies have the opportunity to take the leadership in this collaborative effort.

5.6.10 References

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5.7 Influence of Design Parameters on Line Security

5.7.1 Introduction

This chapter is based on a CEATI research study performed by Ghannoum (Ghannoum 2008) and a Cigré paper by the same author (Ghannoum 2008).

All transmission lines are designed for vertical and transverse weather loads such as wind as well as for combined wind and ice if in icing areas. Besides these loads, there are other types of loads that apply important longitudinal forces on transmission structures, the first are unbalanced ice loads (UIL) and the second broken conductor loads (BCL).

The requirements for longitudinal loads vary between design practices. IEC 60826 (Probabilistic Design of Overhead Transmission Lines 2001) and EN 50341

(Ghannoum and Orawski 1986) standards cover both UIL and BCL requirements for designing towers, while ASCE 74 (2006 draft) (EN 50341–1 2001) specifies only BCL requirements. The above loading conditions are discussed in this chapter and the results obtained provide some answers about the severity of UIL and BCL compared to weather loads such as wind and combined wind and ice loads as well as in order to assess their relative severity and impact on line and tower design.

Different types of structures (lattice single and double circuits, steel poles and wood H frames) with spans from 150 m to 475 m were used in documents (Ghannoum 2008; Ghannoum 2008). A parametric sensitivity study was also performed to provide a broader picture of the impact of many line parameters on UIL and BCL such as varying ice thickness, flexibility of structures, number of spans to next dead-end structure, suspension insulator length, and the use of a dynamic impact factor applied to the static residual load resulting from a broken conductor.

5.7.2 The Need for Unbalanced Longitudinal Loads

In the past 50 years, many utilities have suffered cascading structure failures that extended from about a dozen structures to over hundreds of structures. As a consequence of such types of failures, the design of lines for broken conductor loads (BCL) has been introduced in many practices and standards and recognized as one of the main methods that would prevent or reduce the risks of cascading tower failures. In addition to BCL, longitudinal unbalanced ice loads (UIL) can occur on overhead lines as a natural consequence of either ice accretion or ice shedding on conductors and structures and has to be dealt with in the design process.

5.7.3 Requirements of Standards, Design Codes, and Utility Practices

Standards and practices such as IEC 60826, ASCE 74, NESC, and EN 500341, as well as WISMIG[8] utility practices regarding unbalanced ice loads (UIL) and broken conductor loads (BCL) have been investigated. The most common security loads found in these references consist of broken conductor/wire loads,[9] calculated at every day tension (EDT). The major difference between IEC-EN (Probabilistic Design of Overhead Transmission Lines 2001; Ghannoum and Orawski 1986) and ASCE (EN 50341–1 2001) relates to the number of broken conductor points for a double circuit line. The ASCE proposes to double the number of broken conductor points from one broken phase to two. There is also a requirement in both IEC and EN (Probabilistic Design of Overhead Transmission Lines 2001; Ghannoum and Orawski 1986) to design for an unbalanced longitudinal load produced by the ten-

[8] *Utilities participating to the Overhead Line Design Issues & Wind and Ice Storm Mitigation Interest Group of the CEA Technologies Inc. (CEATI).*

[9] *In this paper, conductor is used as a general term for ground wires and phase conductors.*

sion of bare conductors and GW in all spans in one direction from the structure and with a fictitious overload equal to the weight, *w*, of the conductors and ground wire (GW) in all spans in the other direction.

As regards UIL, IEC (Probabilistic Design of Overhead Transmission Lines 2001) and EN (Ghannoum and Orawski 1986) specify three cases of unbalanced ice loads, longitudinal bending, transverse bending, and torsion where the heavily loaded spans are subjected to 70 % of design ice weight,[10] while the lightly loaded spans are subjected to 40 % of the heavily loaded spans. These ice loads are applied in various schemes that maximize either torsional or bending moments on the structure.

Based on the above requirements, the following longitudinal structure loading cases were used in this study, in addition to conventional weather loads (wind and combined wind and ice):

- Any one broken conductor or GW at every day tension (IEC and EN standards)
- Any two broken conductors (ASCE requirements for double torsion)
- Various ice unbalanced (transverse, bending and torsion) schemes as per IEC and EN
- Longitudinal unit conductor load (IEC and EN)
- All broken conductors and GW at EDT (optional in IEC)
- Any one broken conductor with a dynamic factor of 1.8 applied to the RSL (optional in IEC)
- Any one broken conductor or GW with maximum ice of 30 mm thickness (optional in IEC).

5.7.4 Comparison of BCL and UIL with Weather Load Cases

5.7.4.1 Methodology

In order to perform the necessary calculations of this study, five different lines, and structures were modeled in PLS-CADD, TOWER, and PLS-POLE[11] as indicated in Table 5.38. The three 230 kV structures (wood H frame, lattice steel, and steel pole) were first optimized for basic weather loads (transverse) and then used to assess the impact of longitudinal unbalanced loads on their design. It is noted that all longitudinal loads were calculated taking into account the flexibility matrix of structures as well the movement of insulator strings[12] in a section of about 15 spans or more.

The severity of longitudinal unbalanced loads was assessed in relation to transverse weather loads in many fashions, i.e. by comparing: a) Loads applied to a single GW or conductor point due to each load case, b) Net (total) longitudinal or transverse structure loads due to each load case, and c) The detailed design of structures (stresses in members, moments, foundations reactions, etc.).

[10] *In case the design ice load is specified in radial thickness, this should be converted to unit weight of ice on the conductor prior to applying the factors 70 % and 28 %.*

[11] *All the software are trademarks of Power Line Systems Inc.*

[12] *This option is called level 3, Finite Element analysis in PLS-CADD software.*

Table 5.38 Modeled lines and structures

	Span (m)	Height (m)	Vertical insulator length (m)	Ratio of slack to insulator length (%)
161 kV single circuit wood H frame	150	15.9	1.4	8 %
•230 kV single circuit wood H frame	300	22.7	2.2	27 %
•230 kV double circuit steel pole structure	400	55	2.2	55 %
•230 kV double circuit lattice steel structure	330	37.1	2.2	34 %
•735 kV single circuit lattice steel structure	475	40.5	6.0	32 %

A parametric study was also performed in order to assess the variation of the resulting loads with the:

a) Flexibility of structures, b) Length of insulator strings, c) Number of spans to the next dead-end structure, d) Magnitude of the design ice thickness, and e) Dynamic Impact factor.

Furthermore, clearances between conductors and overhead ground wires were calculated for various unbalanced ice conditions.

5.7.4.2 Modeled Structures

The main parameters of the modeled lines and structures are given in Table 5.38. It is noted that all conductors were strung using two limits: a) The initial bare conductor catenary parameter (horizontal tension/unit weight) should not exceed 1800 m at minimum temperature, and b) The maximum conductor tension should not exceed 75 % of the UTS under the most critical climatic condition.

The weather base cases used for the initial design of structures consisted of a wind speed of 30 m/s (10 min. average, at 10 m of height, in a terrain type B) as per IEC 60826 and an ice thickness of 30 mm (relative density of 0.9).

5.7.4.3 Results of Comparison Between UIL and BCL Loads and Weather Case Loads

These results given in Table 5.39 can be summarized as follows:

Transverse (IEC) and Longitudinal Loads on a Single Ground Wire (GW) or Conductor Attachment Point

Broken GW or conductor loads (longitudinal) are significantly larger (1.5 to 2.5 times) than wind loads (transverse) at the same point.

The residual static load (RSL) of a broken GW is more critical than a broken conductor load in proportion to their respective wind loads. This result is due to effect of the length of the insulator string in reducing the conductor RSL compared to the GW that does not have a suspension string.

The RSL of a broken conductor is about 40 to 70 % of the initial conductor tension. This percentage decreases with the ratio of the insulator string length to the slack in the conductor.

Table 5.39 Longitudinal loads (% of IEC wind) for various load cases and lines

	161 kV wood	230 kV Wood	230 kV steel pole	230 kV lattice	735 kV lattice
Longitudinal load on a single GW point due to broken GW 1	254 %	196 %	153 %	192 %	167 %
Longitudinal load on a single conductor point due to broken phase 3	160 %	153 %	133 %	157 %	106 %
Net (total) longitudinal loads due to broken GW 1	6 %	4 %	4 %	10 %	5 %
Net (total) longitudinal loads due to broken phase 3	12 %	10 %	10 %	21 %	32 %
Net (total) longitudinal bending loads due to unbalanced ice (70 %-28 %)	28 %	27 %	45 %	68 %	54 %

Net (total)[13] Transverse and Longitudinal Conductor and GW Loads on the Structure

Net or total structure loads resulting from one or two broken conductors are significantly smaller than the net wind loads. In the case of one broken GW, total loads are in the range of 4 to 10 % of total wind loads. In the case of a broken conductor, total longitudinal loads range from 10 % to 32 % of transverse wind loads.

Total unbalanced ice loads are significantly higher (1.7 to 4.5 times) than total loads due to one broken conductor, but still less than the total transverse wind loads.

5.7.4.4 Summary of Results Related to the Variation of the Suspension String Lengths (Table 5.38)

This study confirmed that for flexible structures, intact ground wires act as longitudinal guys that oppose broken conductor cases. This behavior significantly reduces total unbalanced loads acting on the H frame wood structures due to the breakage of one phase.

The drop of the RSL in % of the conductor tension prior to breakage (initial tension) is almost linear with the ratio of insulator length (Li) to the conductor slack (difference between conductor and chord lengths) for all lines, except for the 161 kV line with much shorter spans.

In the case of net (total) longitudinal loads acting on structures, all of them decrease with increasing length of insulators, except for broken GW cases where the opposite scenario occurs. It is noted that net (total) unbalanced ice loads are reduced by about 7 to 14 % in the range of increasing insulator lengths. The drop is lower for flexible structures than for the rigid lattice steel structures.

The linear variation of the RSL with the ratio of Li/slack shown in Figure 5.20 is an important result of the study. According to the author, it is the first time this finding it is being published in the technical literature.

[13] Net or total loads are the algebraic sum of all forces on the structure either in the longitudinal or transverse direction, depending on the load case.

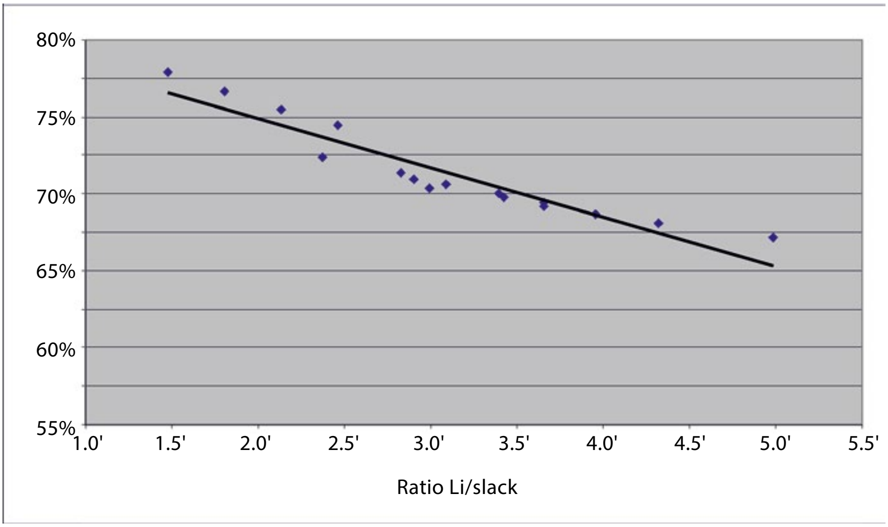

Figure 5.20 Residual static tension of phase 3 in % of initial tension (excluding the 161 kV).

Table 5.40 Global summary of the effect of insulator length (Li) on longitudinal loads

Line		Options of insulator lengths			
	Li (m)	1.1	1.4	1.7	2
161 kV wood	Li/Slack	9.7	12.4	15.1	17.7
	Broken ph-3	48 %	45 %	41 %	39 %
	Li (m)	1.8	2.2	2.6	3
230 kV Wood	Li/Slack	3.0	3.7	4.3	5.0
	Broken ph-3	61 %	58 %	56 %	54 %
	Li (m)	1.8	2.2	2.6	3
230 kV lattice	Li/Slack	2.4	2.9	3.4	4.0
	Broken ph-3	65 %	62 %	59 %	57 %
	Li (m)	1.8	2.2	2.6	3
230 kV pole	Li/Slack	1.5	1.8	2.1	2.5
	Broken ph-3	76 %	73 %	71 %	69 %
	Li (m)	5.5	6	6.6	7.1
735 kV steel	Li/Slack	2.8	3.1	3.4	3.7
	Broken ph-3	63 %	61 %	60 %	59 %

Note: Broken conductor tensions are given in % of GW or conductor tensions prior to breakage

5.7.4.5 Summary Results as Regards the Impact of Structure Flexibility

The common assumption of rigidity of structures increases the majority of loads compared to the real flexible behavior of the same structures, most noticeably with H frame wood poles (Table 5.40).

In the wood H frame structures (161 kV and 230 kV), the rigidity assumption leads to an increase of about 3 to 6 times in net (total) loads compared to the flexible calculations.

In the case of 230 kV steel pole, the ratio between rigid and flexible calculated longitudinal loads can reach a value of 2.35.

In the case of the 230 kV lattice steel tower, the ratio between rigid and flexible longitudinal load calculations can reach a value of 1.21.

For the 735 kV lattice steel tower, the most rigid structure in this study, the ratio between rigid and flexible longitudinal loads can still reach a value of 1.06.

Based on the above results, neglecting flexibility of structure when calculating unbalanced longitudinal loads will lead to unnecessary increased loads and therefore, an increase in the structure costs. This practice should be abandoned, particularly when there is reliable software that can perform such calculations easily.

5.7.4.6 Summary Results of the Effect of Number of Suspension Spans to Next Dead-end

In the majority of cases, the magnitude of unbalanced loads decreases when the number of spans between the studied structure and the next dead-end structure decreases (Table 5.41).

The reduction of total unbalanced ice loads (70 % and 28 %) is very sensitive to the number of spans to the dead-end (DE) structure, particularly when this number drops to 1 to 3 spans. The net (total) unbalanced ice loads drop from 100 % to (27 % to 59 %) for all structures, when the number of spans to the next DE structure drops from 7 to one span.

Net (total) loads on the structure are almost unaffected by the number of spans to the next DE structure for broken GW cases.

Net (total) loads due to broken conductors are affected by the number of spans to the next DE structure, but to a lesser degree than unbalanced ice loads. The lines that have the highest value of Li/Slack (161 kV wood H frame) showed the highest reduction in total loads when the number of spans was reduced.

Table 5.41 Variation of loads on a single point due to number of spans to the next dead-end

		7 spans	5 spans	3 spans	2 spans	1 span
161 kV wood H frame	Broken GW 1	100 %	100 %	99 %	96 %	87 %
	Broken ph-3	100 %	94 %	85 %	77 %	62 %
230 kV wood H frame	Broken GW 1	100 %	100 %	100 %	99 %	93 %
	Broken ph-3	100 %	98 %	94 %	88 %	72 %
230 kV steel pole	Broken GW 1	100 %	100 %	100 %	100 %	98 %
	Broken ph-3	100 %	100 %	98 %	95 %	83 %
230 kV lattice Steel	Broken GW 1	100 %	100 %	100 %	100 %	99 %
	Broken ph-3	100 %	100 %	97 %	92 %	78 %
735 kV lattice Steel	Broken GW 1	100 %	100 %	100 %	100 %	100 %
	Broken ph-3	100 %	100 %	98 %	94 %	81 %

If the number of spans to the next DE structure increases to more than 5 to 7 spans, there is little variation in the results.

5.7.4.7 Summary of Results Related to the Variation of the Design Ice Thickness

The main conclusions of structure loads evaluation using different design ice thicknesses of 25, 30, 35, 40, and 45 mm (Table 5.42) are: Longitudinal broken conductor loads and transverse wind loads are not usually affected by the ice thickness (all minimum broken conductor cases are considered at EDT).

Net (total) unbalanced ice loads increase at more than twice the rate of the increase of combined wind + ice loads when the ice thickness is increased. For example, in the case of the 735 kV line, total unbalanced ice loads increased 2.7 times between 25 mm and 45 mm of ice, while the combined wind + ice loads increased only 1.5 times in same range of ice thicknesses.

Unbalanced ice loads increase at higher rates with long spans and increasing ice thickness.

Lines using lattice towers with long spans and designed with 40 mm or more of ice thicknesses are likely to be vulnerable to unbalanced ice loads because these will control the design of many tower members.

5.7.4.8 Impact of Unbalanced Loads on Structures and Foundations

The three 230 kV structures were checked for the combinations of loading cases of Table 5.43.

Base on the above calculations, the following main results can be concluded:

230 kV wood H frame

Minimum[14] broken conductor loads and unbalanced ice loads (based on 30 mm of ice thickness) mostly affect the crossarm dimensions of this H frame structure. However, if additional security measures are used such as designing for broken conductors, either with a dynamic impact factor of 1.8 or under ice conditions, the class of the pole and size of crossarms will both be affected.

230 kV lattice steel structure

UIL and BCL were not found critical for the complete tower, but they were critical for some members directly affected by these loads (mainly crossarms and GW peaks). Depending on the combinations of broken conductor loads, the tower weight increased up to 45 % for the most conservative combination (case 6 of Table VI) compared to a tower designed only for weather loads. Similarly, the 230 kV square based lattice

[14] *In this paper, minimum requirements are those specified by IEC, EN or ASCE, i.e. RSL no wind or ice (EDT)*

Table 5.42 Total longitudinal or transverse loads (kN) for different ice thicknesses

		Radial ice thickness in mm				
Line type	Load case	25	30	35	40	45
161 kV wood H frame	Unbalanced ice (bending) 70-28 %	3.6	4.7	5.8	6.9	7.9
	IEC combined wind and ice load	15.8	17.9	19.9	22.0	24.1
230 kV wood H frame	Unbalanced ice (bending) 70-28 %	9.8	12.3	14.7	16.8	18.8
	IEC combined wind and ice load	107	120	134	147	160
230 kV steel pole	Unbalanced ice (bending) 70-28 %	43	54	64	74	91
	IEC combined wind and ice load	107	120	134	147	161
230 kV lattice steel	Unbalanced ice (bending) 70-28 %	47	61	76	89	104
	IEC combined wind and ice load	79	89	99	109	119
735 kV lattice steel	Unbalanced ice (bending) 70-28 %	107	140	176	231	293
	IEC combined wind and ice load	204	227	250	273	297

Table 5.43 Combinations of load cases for assessing the impact of UIL and BCL on structures

Load combinations	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
IEC wind and ice (30 mm)	x	X	X	x	x	x
IEC broken conductor		x		x	x	x
IEC unbalanced ice				x	x	x
ASCE broken conductors			X			
All broken conductors @ EDT					x	x
Broken conductor with dynamic impact factor of 1.8 on RSL					x	
One broken conductor with 30 mm ice thickness						x

tower, once designed for weather loads, will require a weight increase by 4 % for IEC and 10 % for ASCE[15] to sustain the minimum prescribed broken conductor loads.

230 kV steel pole

The maximum ground line moment of the steel pole is dictated by the wind load case, thus the pole foundation is not affected by BCL and UIL, except when conductors are broken under full ice case (30 mm). The pole arms are controlled by the broken

[15] *The larger percentage for ASCE requirements is due to the fact that ASCE requires two broken conductors for double circuit towers, while IEC requires, as a minimum, only one broken conductor.*

conductor loads either with the dynamic impact factor of 1.8 or with design ice thickness. The weight of the complete steel pole increases by about 9 % if the most severe security loads were adopted. In summary, the steel pole of this study (regular 12 sided polygon) designed for weather wind and ice loads is capable of withstanding important longitudinal poles without impact on its weight. This is mainly due to the regular 12 sided polygon used for this structure, and the fact that the weather load cases control the design of the steel shaft.

5.7.4.9 Clearances Between Conductors due to Unbalanced Ice Loads

Two cases of unbalanced loads cases were assessed for clearance purposes: the first where the conductor or the GW above is uniformly loaded with ice throughout the section, while the conductor below is bare at −5 °C, and the second calculations, where it was assumed that the upper single span of GW or conductor in the section is loaded with ice, while the lower conductor is bare at −5 °C.

- The results confirmed that unbalanced ice conditions can lead to reduced clearances, hence possible flashover either between vertical phase conductors or between the GW and the phase below it.
- Double circuit lower voltage lines were found more susceptible to clearance problems under unbalanced ice loads than higher voltages, particularly if the former are designed with long spans.
- Single circuit structures with horizontal configurations were less affected by unbalanced icing clearances between GW and conductors.
- In the case of the double circuit steel pole structure where the GW is above the conductor, about 20 mm of unbalanced ice can cause flashover between the GW and the lower phase. Comparatively, the 230 kV double circuit tower can handle up to 30 mm of ice unbalance.
- Partial icing applied on one span on an upper phase of a double circuit structure will sag due to ice overload as well as due to the longitudinal movement of suspension insulators. In some vertical tower configurations, a partial icing of 15–20 mm on one conductor span is sufficient to sag the ice covered conductor under the bare lower conductor. Thus partial icing in one span should be checked.

5.7.5 Recommendations

Based on the studies performed, the following recommendations are proposed:

- Standards and codes of practice should include specific requirements for unbalanced ice loads. IEC and EN standards cover this requirement but ASCE manual 74 only discusses them, but does not provide any values to be considered in the design.

- The contribution of the intact GW to the static equilibrium of the structure when subjected to UIL or BCL is real and very important, particularly in flexible structures: It should always be taken into account in the calculations of structure loads and their design.
- Clearances between conductors and ground wires under unbalanced ice loads conditions can lead to reduced clearances and possibly flashovers. This issue should be addressed by standards committees for possible inclusion of some requirements.
- The simplified methods of calculating the residual static loads (RSL) such as using Govers (NESC C2-2002 2999) are not needed anymore. The exact RSL can now be calculated using appropriate software.
- The cost penalty for increasing the security levels (broken conductor loads) is not very high for structures of the double circuit steel pole type having a regular polygonal section. The fact that these structures are located mostly in urban areas, may justify such increase in security.
- The transverse horizontal offset of the middle phase of a double circuit structure helps clearances in the case of unbalanced icing between phases. In heavy icing areas, it may be justified to design structures with an appropriate transverse horizontal offset. This also might reduce galloping problems
- In the case of lattice towers designed for ≥40 mm of ice and having long spans, UIL can be critical to structure design and will reflect in increasing structure weight, hence costs.
- It is strongly recommended to design structures with symmetrical square bases and bracing, particularly in icing areas. Lattice towers with rectangular bases are much more susceptible to failures from broken conductors and unbalanced ice loads.

5.7.6 Conclusions

This study confirmed that, for symmetrical cross-section structures, broken conductor loads can be critical locally for the design of crossarms and GW peaks. Similarly, unbalanced ice loads generate important longitudinal bending and torsional moments that could dictate the design of some structure parts. Furthermore, in flexible structures, the ground wire (GW) was found to act as a longitudinal guy in the case of longitudinal unbalanced loads.

Many important findings resulted from the parametric sensitivity study:

The natural flexibility of suspension structures will reduce unbalanced loads, even in self supporting lattice structures, and should be taken into account in all cases.

The number of spans to the next dead-end structure, and the length of the insulator strings were also found to significantly affect unbalanced loads.

Finally, it was confirmed that the importance of unbalanced ice loads relative to wind loads increase with an increasing design ice thickness. Lines designed for an ice thickness of 40 mm or more will be more affected by UIL than those designed for 25 mm of ice or less.

The difference in the design of symmetrical section steel structures with and without unbalanced loads was assessed and found to cause an increase in the lattice steel 230 kV tower weight from 4 to 10 % if minimum code requirements for unbalanced loads were used. This percentage increases to about 45 % if broken conductors with ice and all broken conductors at EDT are used. The steel pole structure was not noticeably affected by unbalanced loads because of its geometrical properties. Finally the wood pole H frame needed a change in its crossarm to resist minimum UIL and BCL.

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Elias Ghannoum is an internationally renowned expert having 43 years of experience in overhead transmission line design. He worked 28 years for Hydro-Quebec where he held the position of chief transmission engineer for 20 years. Since 1998, Elias started his own consultancy practice and provided expertise to many international clients such as The World Bank, Electricité de France, ESKOM, Power Grid Corporation of India, Transelec (Chile), Manitoba Hydro, etc. He also lectured during 15 years a graduate course on transmission line design at the Université Polytechnique of Montreal. Elias is Fellow of the Institute of Electrical and Electronics Engineers (IEEE) since 1994, and has received Awards from Cigré, the IEEE and the Canadian Standards Association for outstanding contributions to technical work on transmission lines. He is currently Chairman of IEC/TC7 on Overhead Conductors, Chairman of Working Group MT1 responsible for maintenance of all IEC/TC11 standards and Chairman of the Canadian Standards Subcommittee C22.3 responsible for overhead line design standard based on reliability principles. Elias has authored a very large number of technical papers and publications in Cigré, IEEE, ASCE, CEA.

Environmental Issues

6

Cathal Ó Luain, Lionel Figueroa, and Paul Penserini

Contents

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C.Ó. Luain (✉)
Dublin, Ireland
e-mail: cluasai@gmail.com

L. Figueroa • P. Pensrrini

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6.1 Introduction

Overhead Lines and Environmental Issues and their interaction have been under consideration within Cigré for many years. The issues covered have ranged from permit procedures, environmental impact assessments and consultation methodologies for Overhead Line projects to mitigation of environmental impacts be they visual, ecological, on land use or of construction and maintenance. The development of reduced visual impact designs and aesthetic designs has been traced and all issues associated with field effects inclusive of the debates on EMF and mitigation measures have been investigated. Life Cycle Assessment for Overhead Lines has been reported on. Many utilities and TSOs have addressed and provided information on all these issues.

Cigré Study Committee B2 *Overhead Lines* (formerly SC22) investigated the question of Overhead Lines and Environmental Issues initially in the eighties and a report was produced. It included material on EMFs and alleged health affects but because of sensitivities in that debate at that time it was never published as a Cigré TB. Matters moved on and attitudes changed. Overhead Lines and Environmental Issues were later dealt with through a number of dedicated working groups from the mid-nineties into the mid two thousands. These were WG 14, *Environmental Concerns and Regulatory Controls*, and WG 15, *Life Cycle Assessment and Environmental Concerns*.

A number of Cigré TBs were produced as listed below:

- Cigré TB 147 *High Voltage Overhead Lines - Environmental Concerns, Procedures, Impacts and Mitigations* (Oct 1999) (Cigre 1999).
- Cigré TB 265 *Life Cycle Assessment for Overhead Lines* (Dec. 2004) (Cigre 2004).
- Cigré TB 274 *Consultations Models for Overhead Line Projects* (June 2005) (Cigre 2005a).

An Electra article on *Environmental Management Plans (EMPs) for Activities Associated with OHLs* (Fitzgerald 2004) was also published.

Reports on Overhead Lines and Environmental Issues were produced for preferential subject (PS) 2 for the Cigré Paris Session in 1996 (Reports of Cigre 1996), for preferential subject 3 for the Paris Session in 2002 (Reports of Cigre 2002), preferential subject 2 for the Paris Session in 2004 (Reports of Cigre 2004a), preferential subject 3 for the Paris Session in 2004 (Reports of Cigre 2004b) and for preferential subject 1 for the Paris Session in 2010 (Reports of Cigre 2010a). These issues will be returned to in the 2014 B2 Paris Session in Preferential Subject 1 *Minimising the Impact of new Overhead Lines*.

With the reorganisation (and relabeling) of Cigré Study Committees in 2003 a new Study Committee, C3, System Environmental Performance, was set up. Henceforth all environmental matters would dealt with by working groups in this SC. and various TBs were produced by their working groups which are relevant to Overhead Lines as part of broader power systems developments. The C3 TBs relevant to Overhead Lines are.

- Cigré TB 487 Strategic Environmental Assessment for Power Developments (Feb 2012) (Cigre 2012a).
- Cigré TB 548 Stakeholder Engagement Strategies in Sustainable Development - Electricity Industry Overview (Aug. 2013) (Cigre 2013).

Cigré C3 Paris session reports from 2004 Preferential Subject (PS) 2 (Reports of Cigre 2004c), 2006 PS 2 (Reports of Cigre 2006), 2008 PS 2 (Cigre 2008), 2010 PS 1 (Reports of Cigre 2010b), 2010 PS 2 (Reports of Cigre 2010c), 2012 PS 1 (Reports of Cigre 2012) and 2012 PS2 (Cigre 2012b) contain many reports of interest in the area of Overhead Lines and Environmental Issues. These issues will be returned to in the 2014 C3 Paris Session in Preferential Subject 2 *Integrated Sustainable Approaches for T & D Development* and Preferential Subject 3 *Acceptance of High Voltage Transmission Assets near Urban Areas*.

A number of other C3 working groups also dealt with Environmental Issues and Overhead Lines. One was C3.04 *Corridor Management*. This working group was to review environmental issues relating to Overhead Lines corridor management for the whole of life for high voltage networks. Cigré TB, *"Corridor Management: An overview of international trends for high voltage networks"* Is expected to be published sometime in 2014. Another C3 WG, 08 *Internalising the External Environmental Costs of OHLs*, has essentially completed its work. A final mature draft is awaiting approval and a Cigré TB should be published in 2014.

Other working groups in B2 and some in other study committees also produced Cigré TBs relevant to Overhead Lines and Environmental Issues and impacts. The B2 ones are:

- Cigré TB 278 Influence of Line Configuration on Environment Impacts of Electrical Origin (Aug. 2005) (Cigre 2005b).
- Cigré TB 416 Innovative Solutions for OHL Supports (June 2010) (Cigre 2005c).

Other Study Committee's TBs from WGs or JWGs of interest are:

- Cigré TB 373 Mitigation Techniques For Power Frequency Magnetic Fields (Feb. 2009) (Cigre 2009).
- Cigré TB 473 Electric Field and Ion Current Environment of HVDC Overhead Transmission Lines (Aug. 2011) (Cigre 2011).

A Joint Working Group C3/B1(Cables)/B2 was set up in 2010. The terms of reference covered reviewing and updating of many of the issues dealt with in B2 TB 147 *High Voltage Overhead Lines - Environmental Concerns, Procedures, Impacts and Mitigations* (Oct 1999) (Cigre 1999). The JWG would address issues which relate to the processes, procedures and environmental impact assessment to obtain permits for transmission lines including the cases of proximity of electricity transmission lines and built development. It would also cover how transmission companies and organisations plan the routes of new transmission lines and design the lines to reduce environmental and visual impact in rural areas and near residential and commercial buildings. It would investigate how transmission companies and organisations deal with requests to underground proposed new overhead lines and with requests to relocate (or underground) existing lines when residential or commercial development is planned, or is newly built, near existing lines (It may be noted that in this Cigré B2 Green Book this latter topic of underground cables or overhead lines is dealt with in a separate Chapter 19). However a Cigré TB is unlikely to emerge from this JWG before 2015.

This chapter, in line with the general direction given, is based on summaries of the above Cigré TB with updates in some key areas, including Field Effects, Corona and other phenomena.

6.2 Environmental Procedures and Assessment - Guidelines

6.2.1 Strategic Environmental Assessment (SEA)

Strategic Environmental Assessment (SEA) is a form of environmental assessment that is meant to evaluate the effects of major new policies or planned developments on the environment, sustainability and stakeholder needs of large areas. Being a relatively new kind of assessment, it has emerged in several different forms and applications, such as:

- Environmental assessment for policies, plans and programs
- Regional assessments, referring to the environmental assessment of plans drawn up for a specific geographical area and
- Sector environmental assessment, designed for specific economic activities, such as energy. The latter is a common type, mainly due to the demands of multilateral financing agencies, who have required the use of this type of instrument for project approvals.

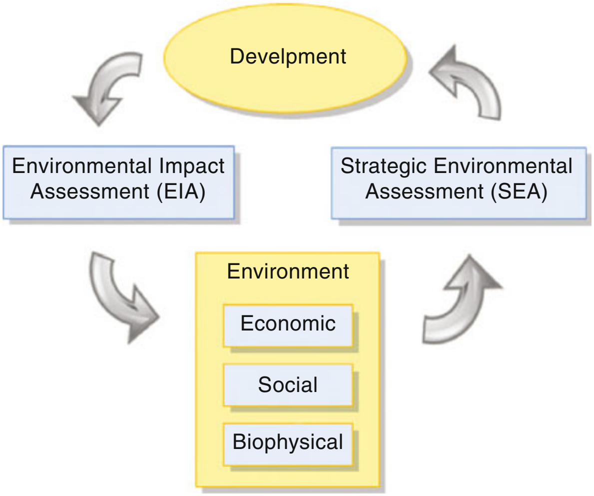


Figure 6.1 Illustration of the main difference between EIA and SEA.

SEA is often assumed to be simply an Environmental Impact Assessment (EIA) for large areas. One possible reason for this is that SEA shares its origins and common principles with EIA. However, there are significant differences between these two assessment methodologies. As illustrated in Figure 6.1 the fundamental difference between the two is that EIA most often focuses on the effects of a proposed development on the environment, while SEA aims to anticipate the effects of new developments on the environmental resources, sustainability and stakeholder needs in an area at a more conceptual stage. The SEA will help confirm the viability of the development concept and may contribute to the design or formulation of the development itself.

As a result of the similarities between EIA and SEA, the approach to SEA assessments has taken some common forms. One is the EIA-based approach, which involves applying the same kind of assessment procedures as in a traditional EIA, except on a broader scope and usually at an earlier stage of planning. The second is the sustainability-based SEA, in which an attempt is made to study the carrying capacities of the environment and the collective desire of the stakeholders for a preferred level and type of regional development.

6.2.1.1 SEA General Structure

The SEA legislation developed in 1969 in the US (with NEPA) stated the necessity to provide analyses of programmes, activities and regulations brought in by federal, state and local governments with reference to the effects these activities may have on the environment and the conservation and use of natural resources. In Europe, each country, within the EU, has enacted or legislated its own version of the SEA Directive 2001/42/CE. Each country has also created regulations and guidelines as to how the assessment will be administered, and how often it will be revised.

On March 21, 2003, during the Convention of Assessment of Environmental Impact, better known as the Kiev Protocol, fellow-members of the United Nations Economic Commission for Europe signed the Protocol of Strategic Environmental Assessment. Only in Spain, Portugal, Italy, Belgium and the Netherlands is an SEA mandatory for grid development planning or other plans in the power sector.

There are some countries, such as Brazil, South Africa, China and Australia, where SEA studies are not regulated by legislation, and, therefore, are not mandatory. Some countries have published guideline documents for undertaking SEA (e.g. South Africa and Canada). In other countries, SEA studies are being developed voluntarily or through informal agreements. The following generic stages are usually part of the process for conducting an SEA study

- Screening: identifying the need for SEA
- Scoping: setting targets and boundaries for the study
- Identification and assessment of alternative scenarios
- Report: analysis and report preparation and review
- Decision: consultation and decision making
- Monitoring: measure report, monitoring and follow-up.

The first step – Screening - is to determine if an SEA is actually needed. The entity responsible for developing the plan or programme (promoter) consults the authorities, with specific environmental responsibilities, to confirm if the plan or programme needs an SEA procedure. This is followed by a scoping process, which consists of identifying the issues to be addressed and the targets and boundaries that are pertinent to these issues. Alternatives for the plan or development are then considered.

For each alternative under consideration, the expected impacts are predicted, as is the significance of each impact on the environment, social conditions and sustainability of the area. Cumulative effects are also investigated for the areas involved. A preliminary report is prepared. The choice of a preferred plan or development option then takes into account the findings and suggestions of the SEA report. This process is accompanied by consultations with the authorities and with the public. Once approved, a monitoring process is put in place. The preliminary report is then made available to the public, and to those authorities with specific environmental responsibilities, in order to ensure an adequate review. Once the review period is concluded, the promoter must then take into account these results and draft the final version of the plan or programme.

SEA for transmission has been applied to plans and programmes, such as National Development Plans. It has also been applied as the first step of the planning process for regional and international power system interconnections. In these cases, the planning process provides the assessment of a region with the intent to select a "corridor" for the transmission line. A "corridor" is understood as the section of territory where technical, environmental and territorial conditions meet the requirements for routing power transmission lines and related plants. Alternatives are analysed based on indicators, and the best alternative is determined, as shown in Figure 6.2. When plans are implemented, monitoring of significant environmental

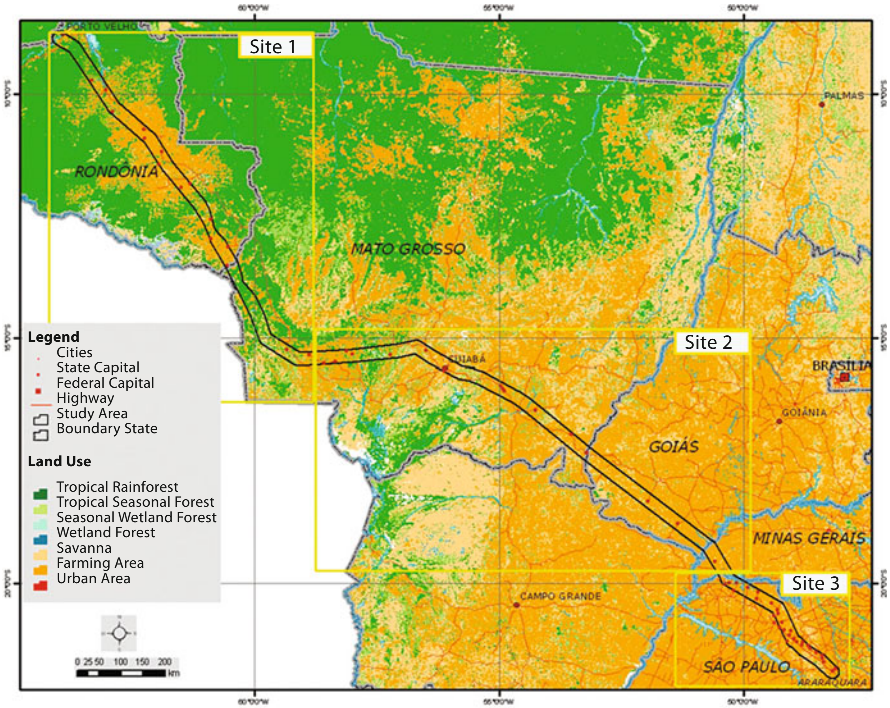


Figure 6.2 Transmission Line Corridor.

effects must be carried out to ensure that during the course of project development unanticipated effects are identified and the appropriate measures are taken.

One of the main steps in the SEA methodology is the development of indicators relevant to the selected objectives. Although many studies have used indicators, those used for SEAs are often interrelated in order to evaluate the effects of the plan or programme on the carrying capacities and sustainabilities of the resources found in the specific area. Therefore, the list of indicators may present significant variations depending on the country or the type of plan or programme being studied. Indicators can differ from country to country and may be different for generation and transmission.

6.2.1.2 Description of the Cigré TB 487 (2012a), SEA for Power Developments

Cigré TB 487, produced by WG C3.06 is divided into an Introduction and seven sections. An Executive Summary synthesises the TB. The Introduction presents the general concepts of SEA, the main characteristics of this type of environmental study and highlights its strategic level.

Section 1: Presents the main environmental and SEA concepts and definitions.

Section 2: Presents a specific comparison of SEA and Environmental Impact Assessment (EIA) studies, indicating the main differences between them.

Section 3: Describes general examples of SEA application and examines its major objectives, the reasons for developing SEA studies, existing legislation and the main responsibilities and accountabilities.
Section 4: Summarises the specific application of SEA studies for generation and transmission systems.
Section 5: Presents an overview of the indicators and other measurement techniques.
Section 6: Provides guidelines and recommendations for SEA in the power sector.
Section 7: Closes the TB with a brief conclusion.
Appendix 1: Presents a summary of SEA studies from each country participating in the Working Group.
Appendix 2: Presents a list of acronyms and abbreviations.

6.2.1.3 Guidelines

- It is imperative to conduct an SEA for major Plans and Programmes
- In all cases, SEAs should be strategic and comprehensive studies
- SEA should be included in national and regional long-term plans both for generation and transmission
- Define specific objectives and the scope of the study on which the assessment will be based and choose an appropriate method of measurement in accordance with the environmental authorities
- Identify different alternatives and analyze their effects
- Include analysis of environmental, social, economic, sustainability, accumulative effects and stakeholder needs
- Identify the stakeholders in the earlier stages of the process
- Take into account the results of public consultation
- SEA studies should result in meaningful deliverables, including proposals for mitigation, compensation and monitoring measures
- Make the results of the study and public consultation available in a Final Report
- Conduct a monitoring phase to provide feedback and to identify the value of lessons learned for the next SEA process.

6.2.1.4 Recommendations

- An appropriate communication plan should be established.
- Modelling tools should be developed to support the analysis of policies and plans, as well as decision making.
- Geographical Information Systems (GIS) should be used, particularly to analyse the cumulative and synergetic effects of the plan or programme.
- Build capacity and training on the SEA skills, which should be implemented.

6.2.2 Permit Procedures and Environmental Impact Assessment

6.2.2.1 Introduction

A survey was carried out by WG 14 on these issues (including others on OHLs and Environmental Issues, see sections below) and was reported on in Cigré TB

147 *High Voltage Overhead Lines - Environmental Concerns, Procedures, Impacts and Mitigations* (Oct 1999) (Cigre 1999). The relevant Section 2 of the Cigré TB gave information on the regulations, procedures, appeal processes, elements of EIA and outline of EIA processes in a range of countries at that time. Nevertheless it should be emphasised that national conditions vary considerably, as may the regulatory controls and environmental impact assessment processes in each country. Which procedures or practices to adopt therefore will depend to some extent on prevailing regulatory regimes in each country and on their unique cultural and environmental climates and it may depend also on the particular features of each project.

It was noted that it was evident that regulatory controls and associated EIA requirements were undergoing regular review and changing frequently. This is continuing and the position for any particular country needs to be confirmed directly or by way of more recent Cigré publications. Guidelines appropriate to the then situation are given below and many are still applicable.

6.2.2.2 Guidelines

- Efficient management of the licensing process is vital. Unnecessary reiteration in the licensing process should be avoided.
- It is desirable to develop a strategy which, while providing full justification for the project and meeting all environmental and consultation requirements, also anticipates that all decisions and procedures will be challenged.
- In the phase of recognition of the necessity and public interest of overhead line projects it is not desirable to have an open ended process. Co-ordination of licensing procedures should be undertaken to minimise delays in the whole process
- In the case of Overhead Lines with a national function a special regulatory process may be beneficial.
- Appeals procedures should have fixed time spans. While processes vary considerably and may involve operating through a number of levels it is essential for utilities to take all precautions and perform all necessary checks to ensure that any risk of losing the permit or licence is absolutely minimised.
- The use of environmental or community compensation schemes for communities affected by Overhead Lines should be considered, particularly where communities perceive only impacts and no specific benefits to them from a project. Various models exist which may prove appropriate depending on local circumstances.
- Models exist of changes to regulatory systems which involve earlier consultation, environmental compensation, commitments to further efforts to minimise overhead line impacts - particularly in the context of overall network lengths and development strategies - and design reviews. These may have relevance to evolving situations elsewhere depending on the stage of development of networks.
- Environmental requirements should be made clear in advance (e.g. in the Environmental Impact Assessment legislation) and confirmed in consultation with authorities. Nevertheless new requirements may arise in relation to the environmental impact studies or their methods of evaluation and it is desirable to try to anticipate these in so far as possible.

- Environmental specialists should be used to provide expert inputs on the overhead line impacts relating to their particular areas of expertise for inclusion in environmental impact statements. Various successful organisational frameworks exist for assimilating these.
- Comprehensive Environmental Impact Assessments should be carried out inclusive of all consultation requirements and environmental impact statements should cover the full range of necessary subjects, description of impacts and mitigation measures.

6.3 Environmental Impacts and Mitigations - Guidelines

TB 147 *High Voltage Overhead Lines - Environmental Concerns, Procedures, Impacts and Mitigations* (Oct 1999). Cigre (1999) reviewed the different types of impacts of Overhead Lines on the Environment under the heading listed below and in Section 6.4 and reported on them and on mitigations measures.

6.3.1 Visual Impact

Assessment and routing including different methodologies for routing for minimal visual impact were described. Routing guidelines were given and methods and tools for visual impact assessment described. Overhead line designs for minimal visual impact were dealt with including structures, conductors, insulators and fittings and methods of camouflage of full overhead lines or the principle elements.

The use of compact lines and pole structures to minimise right of way and impacts was outlined. The development of the "first generation" of aesthetic line designs in a number of countries such as France and Finland, and other solutions to reduce visual impact such as in Sweden (T Tower, see Figure 6.3) and in Hydro Quebec and South Africa (Chainette Cross Rope) were described and examples shown. Some of the aesthetic designs were developed through public competition. Such aesthetic or "landscape tower" designs have continued to multiply.

TB 416 *Innovative Solutions for OHL Supports* (June 2010) (Cigre 2005c) deals with the further development of such designs, be they intended for full lines routes, segments of line routes or used as special structures in particular locations. It gives designs from seventeen countries. Monopole supports are covered and more information is given on the Finnish and French (see Figure 6.4) aesthetic designs mentioned in Cigré TB 147 and developments since in those countries. Quite a few examples of the design of towers as artworks or transformation of some towers into artworks are given. A new Danish 400 kV single pole design with a stainless steel tube head framework supporting the insulator V assemblies in a delta formation is shown and Icelandic studies and competition results outlined.

TB 416 concludes "Demand for electricity has grown dramatically and the need for electricity will continue to grow. As a consequence, different regions of the world will face different challenges, concerning the environmental impacts, to

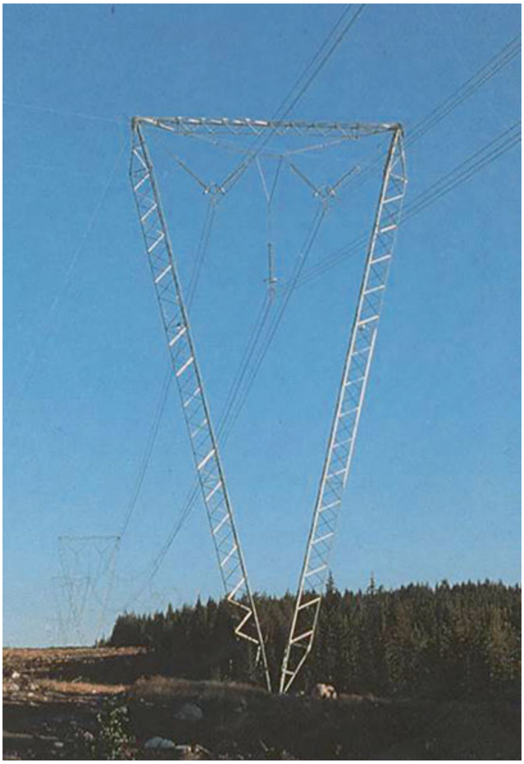


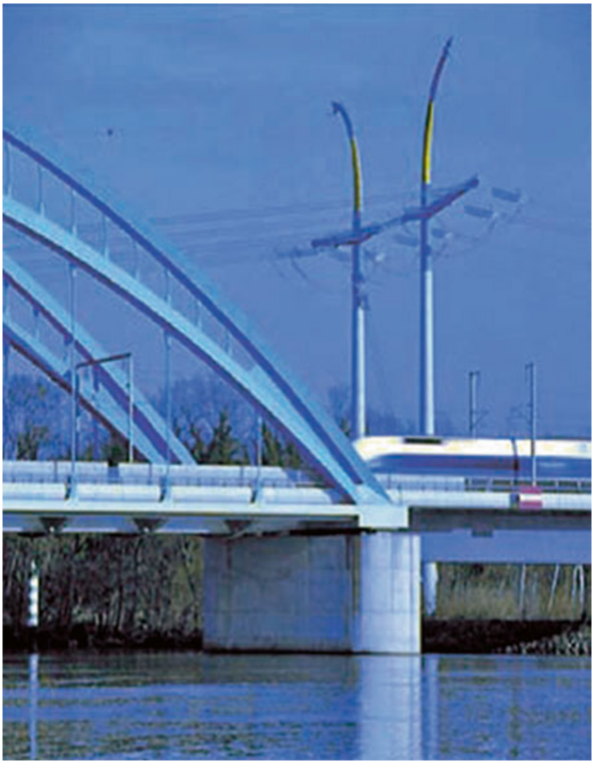
Figure 6.3 Swedish Reduced Visual Impact T Tower, which also reduces EMF.

supply more power. As far as transmission lines are concerned, some Utilities will have to construct long (up to 2500 km) UHV OHLs in the near future. For such lines, as reported in Cigré TB 416, the so called "aesthetic solutions" will be designed based on simplicity, invisibility, slenderness, compactness, all together driven by costs. On the other hand, in other regions of the world, the construction of new lines arouses more environmental and aesthetic concerns. With the growing demand, there will be more requests for alternative design solutions, i.e., for visually attractive landscape towers. In the majority of the cases, the desirable solution is to hide the structures, making them invisible or camouflaged. When, for any reason, this is not feasible, it is always possible to make them more aesthetic, more beautiful".

6.3.1.1 Guidelines on Visual Impact (Cigré TB 147, 1999)

- With regard to the visual impact of Overhead Lines the different approaches of trying to integrate an overhead line within the landscape or to assert the line within it may be used depending on the type of landscape, see Figure 6.5. The essential purpose of visual impact assessment is to describe the change in visual quality associated with the landscape setting and this assessment may be carried out by qualitative or quantitative methods.

Figure 6.4 Aesthetic Structure, France (I. Ritchie, K. Gustafson).



- Various qualitative systems are available and quantitative methods have been developed and are still undergoing development. Qualitative techniques are generally preferred for dealings with the public while quantitative methods are more in use for expert assessment but are being developed for use with authorities and perhaps the public.
- Careful routing of an overhead line is a most important aspect in reducing the visual impact of a proposed line. Utilities should have a set of well-developed routing guidelines. The possible use of power corridors or joint transportation corridors and power line corridors should be covered.
- The routing guidelines should outline, in some detail, the practical steps to be taken to route a line for minimal visual impact taking account of other constraints and should also include recommendations for optimum location of structures along a line route.
- The chosen methods of visualisation will depend on the audience being targeted. Selected methods are not so important as long as the results are lifelike and understandable to most people, not only experts. This is very important in the planning and permit process phase of the project.
- Photomontages are still the most suitable method for visual presentation to the public. The accuracy of structure location and placement within the terrain is

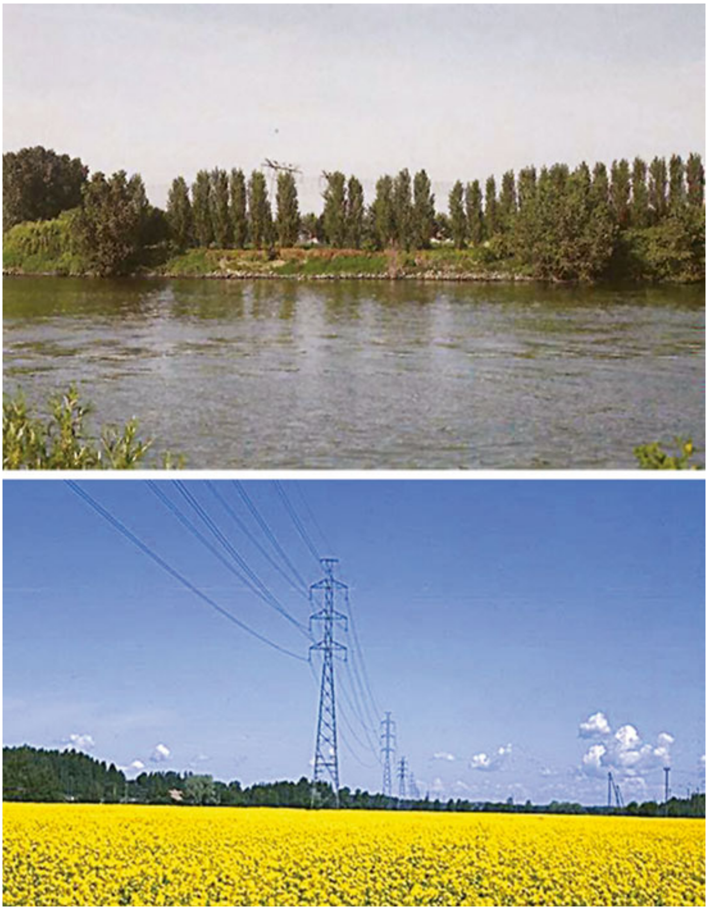


Figure 6.5 Landscape will determine whether integration within a landscape or assertion is the best approach.

crucial to public acceptance. They are also helpful in illustrating camouflage techniques and different designs.

- Digitised terrain models in themselves are not very effective for public presentation but if they are overlaid with digitally reconstituted photographs a basic visual presentation can be achieved. It is preferable to use photographs in conjunction with the terrain model.
- Digitised terrain models using GIS and Google Earth in combination with computer designed towers is a good tool to use for internal use in route selection as it can give an indication of the visibility of the line and structures from many different points of view. It is best suited where digitised maps are available.
- With regard to designs for minimal visual impact there is a strong tendency towards the use of compact lines as a mitigation measure to reduce visual impacts as well as for other reasons. Many utilities use multi-circuit towers to cater for

increasing environmental constraints however in regard to visual impact alternatives would have to be evaluated in each particular case.

- In the case of lattice towers cold formed steel and tubular sections instead of angle members have been used for reduced visual impact. For higher voltage levels lattice towers are considered to have less visual impact than other structures - while poles are used on the lower voltage levels for the same reason. Guyed towers, if acceptable, may reduce visual impact.
- Aesthetic designs of towers and unconventional structure designs have been developed. Many of these latter are used in *once off* or special situations. Their use was confined to limited applications initially but more recent designs have more widespread application.
- Camouflage of structures (using suitable colours) has been successfully used to reduce visual impact in certain locations in some countries but may not be permitted universally. Specially treated conductors are also effective measures that have been used successfully by utilities to reduce overall line impact, a significant portion of which can be attributed to conductor brilliance.
- Various insulator configurations can be used to reduce the visual impact of insulator assemblies. The use of composite insulators of suitable colour can be of advantage, as can specific colours of porcelain and glass insulators.
- Many of the above design options to reduce visual impact have cost debits and these should be balanced against their benefits.

Many of the latest designs are driven by the need to connect renewable energy sources.

New designs of reduced visual impact structures have emerged since the publication of Cigré TB 147 (1999) and TB 416 (2005c) such as the Danish Eagle Double Circuit Tower design with double crossarms below in Figure 6.6. About 160 km of this design has been built, replacing a single circuit 1150 MW 400 kV line with 2× 1800 MW. This design will form the backbone of the refurbished Danish 400 kV grid.

Other new designs are the Dutch Wintrack Pylon and the UK T Pole design with a prismatic arrangement of insulator assemblies (a test line built).

Composite Fibre insulated pole designs are being investigated. These pose many challenges.

Information is available on many of these new designs and investigations on the websites of the TSOs. An interesting development in the European Union is a touring exhibition showcasing pioneering structure design www.gridexpo.eu. This appeared in quite a few European cities in 2013 and more exhibitions are scheduled for 2014.

6.3.2 Impact on Land Use

- The impact of Overhead Line corridors on land use or the restrictions on the use of land near them will vary, depending on their earlier use and on the regulations relevant to them in the various countries.

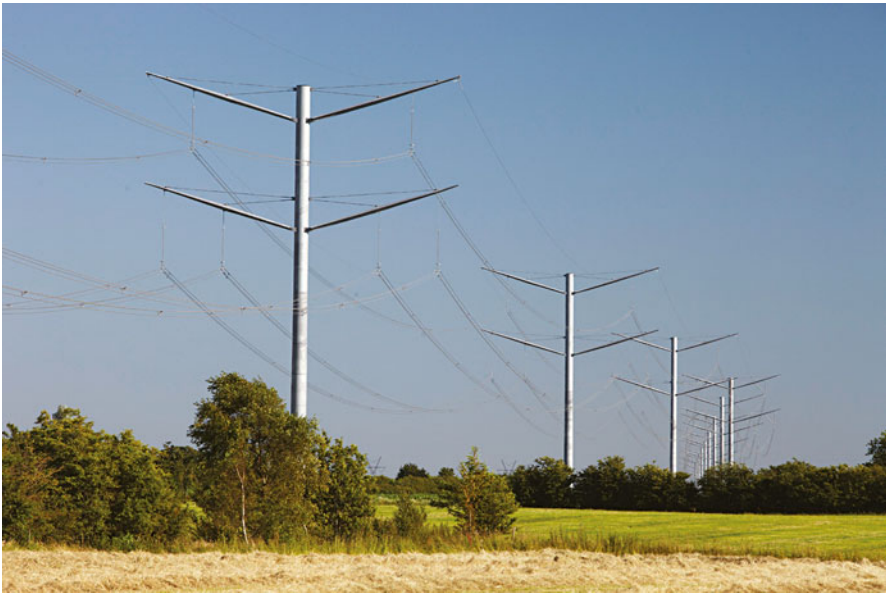


Figure 6.6 Danish Double Crossarm Eagle Tower.

- In forestry Overhead Line corridors will prevent timber production except for seeding stand and Christmas trees but loss of production should be compensated for. Corridors may have a positive effect (bio-diversity).
- In agricultural areas Overhead Lines do not hinder normal agricultural production however precautions may need to be taken with the use of some types of machinery or in performing some operations and structures may cause some interference. Optimising structure locations (if feasible) in such areas can mitigate impact and residual impacts or unavoidable construction and maintenance impacts can be compensated for.
- In industrial and urban areas impacts will depend on whether allowance was made for the line corridor or it was encroached upon and on the national regulations with regard to proximity of Overhead Lines to industrial buildings and to housing. In any case the effect of the line can be minimised by using the line corridors for car parking (see Figure 6.7), access corridors, bicycle paths, community gardens etc.
- If Overhead Lines are permitted in conservation, recreation or wilderness areas, and avoidance is not feasible, special precautions should be taken to minimise impacts. On the other hand line corridors adjacent to other infra-structural developments, such as roads or railways, could be beneficial.

6.3.3 Impact on Ecological Systems

- Route planners should identify sensitive sites, important for endangered species, and areas of special environmental and ecological significance, so that any

Figure 6.7 A double circuit 110 kV line corridor used as a car park in an industrial area (Ireland).

proposed Overhead Line can be routed away from these areas. If avoidance is impossible or very difficult, sufficient mitigation measures should be used after consultation with environmental experts and the environmental authorities.

- Consultation should be undertaken with an ornithologist to verify if vulnerable bird species can be influenced by the line and registration performed of primary ornithological functions or uses of the area to avoid key areas for birds and avoid separating these areas.
- Topographical features which are guiding lines and flight paths for migrating birds and/or are important for local movements of resident species and topographical elements such as cliffs and rows of trees that force birds to fly over power lines should be carefully mapped.
- Shieldwire or conductor marking (see Figure 6.8) should be carefully considered in areas with species known to be potential collision victims, and the design of such should be the result of an analysis of the biology and ecology of the target species.
- Special consideration should be taken when planning Overhead Lines in areas with wild herds. The route planning and the choice of construction period should be chosen after consultation with biologists and environmental authorities.

Figure 6.8 An example of a bird flight devices on the ground wire. A special trolley was developed to install the devices automatically on the wire (Spain).

- With regard to vegetation control, the preferred method to use depends on the actual situation. Mechanical control would normally be preferred from an environmental point of view. However, in some areas, especially with fast growing hardwood, chemical treatment will be preferred as a supplement to the mechanical control. If chemical control is necessary, it should be recommended to discourage high volume application of herbicides. A low volume of selective herbicides on target species should be recommended.
- Use of biological treatment, by using mushrooms on the cut surface of leafy stems, should also be seriously considered. This method has been recently developed. By lengthening the mechanical intervention cycle and avoiding chemical treatment, this method seems to constitute an efficient approach to problems of vegetation control and to the protection of the forest and wildlife environment.

6.3.4 Impact of Construction and Maintenance

- While many of the construction and maintenance impacts and issues appear to be common around the world, each project and its possible impacts should be viewed as unique. The possible impacts of a project must be specifically assessed and the possible mitigation measures determined.
- The impact of the removal of vegetation from the right of way depends on the terrain and vegetation traversed. Sensitive or valued areas should be avoided. Mitigation measures can include limited removal and retention where clearances allow it, the use of helicopters in sensitive areas, stepped removal, and replanting with lower height vegetation.

- In the case of access tracks impact can be reduced considerably if agreement with local landowners or land agencies can be achieved to use existing tracks or roads or access across lands. Tracks should follow the natural contour of the terrain and care should be taken to avoid erosion or impact on water-courses. Special temporary access systems or special temporary roadways can be used if necessary (Figure 6.9).
- On foundation and structure erection soil erosion should be guarded against. The placement of excavated material needs to be appropriate to surrounding land use and topsoil should be stored separately. All restoration work should be done in accordance with the requirements of the property owner, occupier or agency.
- During stringing activities with increased movement along the line route additional precautions should be taken to prevent any possible spread of decease or weeds in sensitive areas and helicopter stringing may be an option to reduce impacts. Conductor drum sites should be carefully chosen to minimise impact and restored as required after construction.
- The impacts of maintenance are generally less significant and apart from inspections or upgradings the main one is the on-going management of the right of way. Impacts and mitigation will be similar to those for vegetation removal. Precautions should be taken during helicopter patrolling to ensure no danger to live stock or blood stock in the vicinity of the line route.
- Environmental Management Plans provide the methodology and systems to link the measures proposed to reduce construction and maintenance impacts to action plans and site specific mitigation activities. Project specific quality plans should

Figure 6.9 Special Temporary Trackway (England).

be established and approved prior to the commencement of construction activities (see subsection below).

- Generally an overhead line is constructed to exist within an environment and operate securely and economically for many years. Any mitigation measures adopted for the construction and maintenance of the overhead line should take this requirement into account.

6.3.5 Environmental Management Plans

Where developments have been approved, there has been an increasing tendency for these approvals to be conditional on requirements for:

- Further environmental studies of the affected areas pre-construction,
- the introduction of environmental safeguards during construction and, in some cases,
- the carrying out of environmental audits post construction.

These are the main elements of an Environmental Management Plan (EMP). A survey carried out by a Task Force of B2WG15 reported in Electra (Fitzgerald 2004) on this whole area. The structure of EMPs was outlined and the report highlighted the methods and context of use of EMPs and some of the positives and negatives of their use. Significantly the survey also demonstrated that those companies that do not use or recognise a formal EMP process have increasingly strong controls externally directed to or internally applied to the environmental impacts of transmission line projects. A check list for an EMP was provided.

6.4 Fields, Corona and other Phenomena, Impacts and Mitigations

Electric and Magnetic Fields (EMFs) are physical phenomena which occur when electricity is flowing in power lines. In the last decades, health issues related to EMFs at Extremely Low Frequency (ELF) have emerged significantly and are important concerns for power system operators. Questions about possible health impacts of ELF-EMFs are often discussed animatedly during the consultation and dialogue phases of the planning and building process of new electricity transmission lines. After more than 50 years of research on this subject, the scientific community could not provide any solid evidence about any health hazard on living organisms associated with a prolonged exposure to ELF-EMFs at a lower level than the international recommendations.

Another phenomenon associated with transmission lines is the Corona effect which may have different consequences depending on many parameters (voltage level, weather conditions, conductors' configuration, pollution…). The main impacts of the Corona effect will be discussed along with audible noise, radio and television interferences and modification of the chemical composition of the atmosphere. Aeolian noise will also be addressed.

6.4.1 Electric and Magnetic Fields at Extremely Low Frequency (ELF-EMFs)

The following section deals with EMFs at power frequencies (mainly 50 Hz in Europe, Asia and Africa or 60 Hz in North America, Japan, Brazil…) which both are classified as Extremely Low Frequencies. Electric Field (ELF-EF) and Magnetic Field (ELF-MF) phenomena will be detailed in subsections 6.4.2 and 6.4.3.

The expression "electromagnetic radiation" is used to describe a fundamental physics phenomenon of electromagnetism: the transmission of radiant energy is carried by photon wave particles at the speed of light. It is also associated with an electromagnetic wave coupling magnetic and electric fields and propagating at the velocity of light. The 3 fundamental parameters describing this phenomenon (the wavelength λ, the frequency the electromagnetic oscillations *f* and the velocity of light c) are associated according the following formula:

$$\lambda = \mathrm{c} / f$$

For power frequency (e.g. $f = 50$ Hz) and considering that $\mathrm{c} = 300000$ km/s in a vacuum, then it comes $\lambda = 6000$ km. For such a long wavelength, the concept of propagation of electromagnetic waves is not relevant and the phenomena can be considered as quasi-static. As a consequence, in this frequency range, electric and magnetic fields can vary independently from each other. Neither is it relevant at extremely low frequencies, to refer to ionizing radiation. This is a non-ionizing radiation: the electromagnetic energy carried by each quantum is not sufficient to cause ionization of atoms (breaking chemical bonds in molecules) nor to be able to heat biological material.

6.4.2 Electric Field at Extremely Low Frequency ELF- EF

The electric field generated by a power line is related to the voltage expressed in Volts (V or kV). The strength of the electric field is expressed in V/m or kV/m. At ground level, it is at its maximum for a minimum clearance to ground of the overhead conductors, i.e. typically under the line at mid-span. Physical phenomena related to the ELF-EF are described in documents Cigre (2009) and Cigre (1980) and the calculation principles, especially "Equivalent charges method", are detailed in Cigre (1980).

6.4.2.1 Application to Transmission Lines

Many parameters influence the strength of the ELF-EF.

The electric field increases with the voltage level. Its strength reaches its maximum value under the line and rapidly decreases with increasing distance from the line. The electric field decreases to approximately one-third to one-tenth at 30 m from the axis of a single-circuit line, depending on its geometry, and to approximately one-hundredth of its maximum value after a few tens of meters more. Consequently, if the voltage level of the sources directly influences the value of the

Table 6.1 Electric-field strengths in the immediate environment (representative values at 1 m above ground)

Distance from the axis of the line	kV/m
Below a 400 kV, horizontal configuration, single-circuit line	1-5
30 meters from the axis of a 400 kV line	0.5-1.5
65 meters from the axis of a 400 kV line	0.1-0.4

electric field the distance between the sources and the spot measurement is another important parameter. The ELF-EF is also further reduced by grounded objects (e.g. trees, house, bushes…).

Typical measurements of electric field strengths values are given in Table 6.1 for a 400 kV line.

6.4.2.2 Recommendations for Electric Field ELF-EF Mitigation

Electric fields generated by an overhead transmission line can be reduced by modifying geometric or conductors' parameters.

Geometric Parameters

Reducing the phase-to-phase distance, i.e. compacting lines, is one of the most efficient methods to reduce the electric field. A compact line is an overhead line with voluntarily reduced dimensions in phase-to-phase and phase-to-metallic parts distances, (and consequently reduced length of the spans, and height of the poles) compared to a traditional line with an equivalent voltage, respecting (with a reduced –but still acceptable- safety margin) required minimal distances for safety of the public and the minimal internal distances so as to not degrade the quality of the service (Figueroa and Rault 2013).

Increasing the distance between the electric source and the area of exposure is naturally an efficient way to reduce the electric effects. Consequently, increasing the height of conductors in specific places is also effective to reduce ELF-EF exposure. There are different methods to increase the height of conductors:

- Increasing the horizontal mechanical stress of conductors
- Increasing the height of the pylons.

For double-circuit lines, low impedance configuration is strongly recommended for EF mitigation (optimized phase arrangement).

For single circuit lines, delta and triangle configurations give lower values of EF than vertical and flat ones (Cigre 2005b).

Conductor Parameters

Conductor configuration influences ELF-EF levels:

- Decreasing the sub-conductor cross section will increase the electric fields at the surface of the conductors and consequently will reduce ELF-EF levels at ground

Table 6.2 Influence of line parameters on EF-ELF mitigation

	Increase of phase to phase distance	Increase of conductor height above ground	Increase of number of sub-conductors	Increase of sub-conductor spacing	Increase of cross section of sub-conductors
Influence on the EF-ELF at ground level	↗↗	↘↘	↗	↗	↗

level. The effect is small for multi conductors' bundles and, in addition, it increases the Corona effect.

- The number of sub-conductors in a bundle is a significant parameter for electric field mitigation. As the number of sub-conductors increases, the EF at the surface of the conductors decreases which increases the ELF-EF at ground level.
- In the same way, increasing the spacing between sub-conductors will increase the ELF-EF at ground level.

More generally, all options for reducing the Corona effect will reduce the electric field at the surface of the conductors, and will consequently increase the electric fields at ground level. Table 6.2 sums up the influence of different line parameters on the ELF-EF values (Cigre 2005b):

Besides these mitigation techniques, it must be underlined that ELF-EF is easily reduced by any conductive object, even when poorly conductive such as trees, fences and usual building materials. As a consequence, whatever the magnitude of the external ELF-EF, the resulting exposure can often be neglected inside buildings.

6.4.3 Magnetic Field at Extremely Low Frequency ELF-MF

The magnetic field generated by a power line is related to the current expressed in Amps (A) flowing into the electrical circuits: this is a magneto static phenomenon. Physically the magnetic field strength "H" is expressed in Amps per meter (A/m) and is the strength of the magnetic field vector **H** related to the magnetic flux density **B** which is expressed in Tesla (T) or Gauss (G): 1 T = 10 000 G. Physical phenomena related to the ELF-MF are described in Cigre (2009). The relationship between H and B is: $B = \mu.H = \mu_0.\mu_r.H$. The permeability μ is the product of the vacuum permeability "μ_0" ($\mu_0 = 4\pi.10^{-7}$ H/m ~ $1{,}25.10^{-6}$ H/m) and the relative permeability "μ_r" related to the physical environment where the ELF magnetic field is studied. For information, $\mu_r = 1$ in most of physical environments except in ferromagnetic material where μ_r is significantly higher (e.g. Cobalt: $\mu_r = 250$, steel: $\mu_r = 10\,000$) and so, in most environments, H and B simply derive from 1 A/m = 1.25 μT. Considering this simple relation valid in most material including living tissues, it is a common practice to merge the two and simply call the magnetic flux density B as "magnetic field", and express it in Tesla (T) and more often in μT (1 μT = 10^{-6} T) considering the usual range of magnitudes of ELF-MF generated by power lines.

Methods used to calculate the ELF-MF are detailed in Cigre (1980).

6.4.3.1 Application to Transmission Lines

The main parameter influencing the ELF-MF strength is the current flowing in the conductors. Applied to the overhead line case, and assuming that weather parameters are constant, an increase of current will lead to a thermal expansion of conductors and then an increase of the sag. The magnetic field source is then closer to the ground, what results in an additional increase of the field magnitude at ground level. Respectively, at a few tens of meters from the line this sag variation effect can be neglected. Table 6.3 gives typical measured values of ELF-MF around transmission lines:

Figure 6.10 represents the ELF-MF pattern calculated at 1000 Amps along a perpendicular axis to the line at the middle of the span for a spot located at 1 meter above ground.

6.4.3.2 Recommendations for Magnetic Field ELF - MF Mitigation

Contrary to the ELF-EF, the ELF-MF cannot be reduced by conductive objects, except for highly conductive or ferromagnetic ones.

Magnetic field generated by an overhead transmission line can be mainly reduced using compensation methods or modifying geometric parameters. Unlike the electric field, the conductor configuration (number and spacing of sub-conductors or

Table 6.3 Magnetic flux densities in the immediate environment (representative values at 1 meter above ground level)

Distance from the axis of the line	μT
Below a 400 kV, horizontal configuration, single-circuit line	5-25
30 meters from the axis of a 400 kV line	0.5-5
60 meters from the axis of a 400 kV line	0.2-1

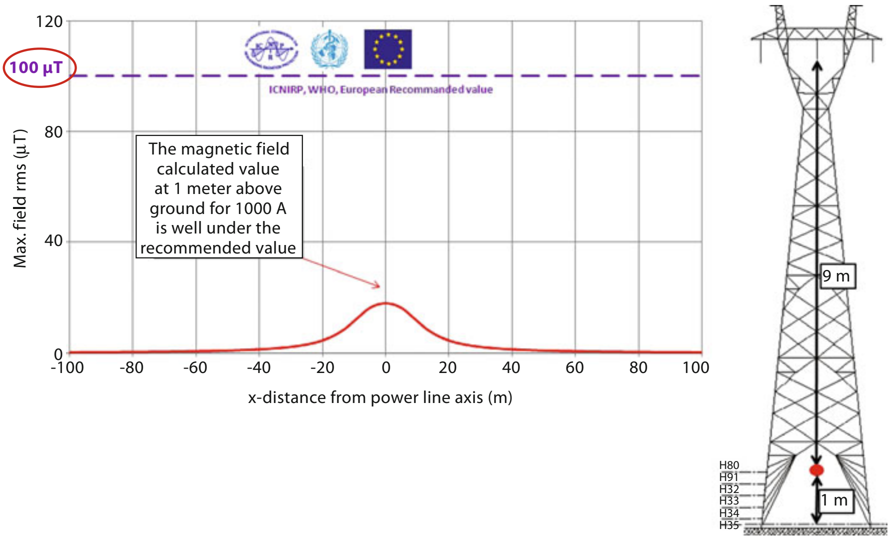


Figure 6.10 Typical ELF-MF pattern related to transmission lines.

total conductors cross section) has no influence on magnetic field magnitude at ground level. Phase splitting and phase cancellation are some very efficient solutions for ELF-MF mitigation. Ferromagnetic shielding solutions won't be described in the following parts as they are designed mostly for underground cables.

Geometric Parameters

Reducing distances between phases is the best way to mitigate ELF-MF. Thus the transmission line right of way is decreased which reduces the distance between the ELF-MF source and the spot measurement (Figure 6.11). Besides compacting lines increases the magnetic field compensation between the different phases of the circuit(s). This solution is very efficient especially for spot measurement in the vicinity of transmission line.

Increasing the distance between a measurement spot and the magnetic field source can be also carried out by increasing the height of conductors which is a simple way to locally reduce magnetic field exposure (note: "simple" here means easy to understand, but this does not mean that raising up towers or wires is a simple engineering process).

Table 6.4 sums up the influence of different line parameters on the ELF-MF values (Cigre 2005b).

Phase Splitting

The basis of the phase splitting principle is to convert a single-phase two conductor circuit into a single phase four conductor circuit in order to create a quadrupole which is a low field configuration as the ELF-MF decays at $1/r^3$ rate.

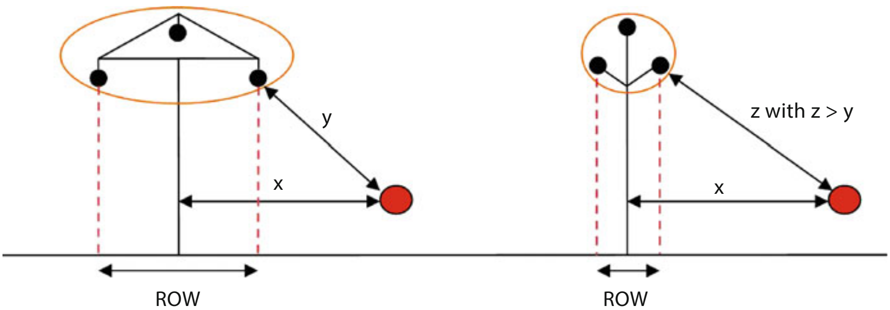


Figure 6.11 Compact line: MF-LF mitigation.

Table 6.4 Influence of line parameters on ELF-MF mitigation

	Increase of phase to phase distance	Increase of conductor height above ground	Increase of number of sub-conductors	Increase of sub-conductor spacing	Increase of total cross section
Influence on the ELF-MF	↗↗	↘↘	=	=	=

Concerning three-phase configurations, the splitting of phases aims at increasing the symmetry of the whole circuit, what can be done by splitting 2 phases or 3 phases (Cigre 2009): the resulting field will decay at $1/r^3$ rate rather than $1/r^2$.

Phase Cancellation
Phase cancellation is only applicable to multi-circuit configurations and is based on the same physical principles as phase splitting. Practically, it also applies the principle of increasing the symmetry of multi-circuit system. For double circuit' cases, phase arrangement of conductors influences the ELF-MF strength. It depends of the geometrical arrangement of the phase conductors in relation to the support (conductor configuration). The phase cancellation will be all the more efficient as the currents in the two circuits are balanced and flowing in the same way.

Compensation Methods
ELF-MF can be compensated using 2 technical methods:

- *Passive compensation:* this mitigation technique is related to Faraday-Lenz Law: "the induced electromotive force ε in any closed circuit is equal to the negative of the time rate of change of the magnetic flux through the circuit φ".

$$\varepsilon = -\frac{\mathrm{d}\varphi}{\mathrm{d}t}$$

Consequently when a coil or loop is placed close to an overhead transmission line and is subjected to ELF-MF, induced current flows in the coil and generates a magnetic field which compensates the original ELF-MF (Cigre 2009).

The efficiency of this solution will be influenced by several parameters including:

- Shape of the coil
- Location of the coil
- Electrical parameters of the coil
- Number of coils

- *Active compensation:* this mitigation technique uses an external power source in order to inject an appropriate current in the coil to optimize the field compensation. Current magnitude and phase has to be calculated according to the variation of ELF-MF in the space of interest due to the variation of current flowing into the conductors (Cigre 2009).

6.4.4 Assessment of the Exposure to Magnetic Field for Epidemiological Studies

For a given transmission line, magnetic field strength permanently varies over the time depending on the variation of the current flow. Human exposure to the magnetic field also depends on the time spent at a given distance from the line (Cigre 2007).

Table 6.5 Yearly current ratio proposition

Yearly current ratio (or field ratio)	Conservative	Very conservative
95%/rated	0.5	0.7
Mean/95%	0.5	0.7
Mean/rated	0.25	0.5

The dispersion of the magnetic field in a given set of values is assessed using standard deviation.

Other mathematical parameters may be used: the percentiles of the field values, I.E. the field value not exceeded during a given percentage of time. The median value is the 50th percentile. The 95th percentile of the field distribution is often considered as the annual maximum value during normal exploitation conditions.

Cigré (2007) has proposed values in order to assess the 95th percentile of the current distribution in the absence of any accurate information on this distribution, using a percentage of the rated value of the line (Table 6.5). The rated condition is defined as the maximum expected current load for a given transmission line taking into account regulations, several technical parameters, and territory constraints and are standardized at a national level.

6.4.4.1 Capacitive and Induced Effects

Electric field causes a displacement of electric charges in conductive objects such as vehicles, metal roofs or irrigation pipes and even in human bodies. The alternating field therefore generates an induced current inside the conductive objects, which magnitude is influenced by the shape and size of the exposed objects. The electric field inside the body is close to null due to the small potential difference generated by the induced current (a few μA) and the electric resistivity of human body (a few Ω/m). Consequently, whereas the external electric field generated by an overhead power line may be in kV/m range, the field induced in the body is much lower than 1 V/m. Corresponding induced currents are not detected by the person because they are several order of magnitude lower than the threshold of perception. Nevertheless, this induced current is sufficient to make a fluorescent tube glow.

When a person is exposed to an electric field and is in established contact with a conductive structure, several consequences may occur depending on their insulation from the ground (Cigre 1991).

Induced voltages are also a phenomenon related to electric fields. If a conductive object is not earthed, the electric field will induce a floating potential, which depends on the field magnitude and on the size of the object. During the transitory phase of establishing contact, when the distance between the object and the person is small enough and the voltage difference is sufficient, a small spark is generated. Once the contact is made, an induced (steady-state) current will flow as described previously.

As seen in 6.4.3, the magnetic field induces a 50 Hz current in conductive objects. The magnitude of the induced current is influenced by the magnetic field strength, the volume of the conductive object, and its impedance. Therefore the internal electric conductivity of the body is essential to determine the magnitude of the magnetically induced currents. Such currents inside the body cannot be felt by exposed persons and are well below electrical safety thresholds.

Concerning long metallic structures not well earthed, such as metallic fences or pipelines, which are built along transmission lines, an induced voltage is generated. If a person touches this conductive structure, an electrical loop (composed by the structure, the body and the ground) will be constituted. The induced voltage is proportional to the magnetic field magnitude and the size of the loop.

Usually the induced voltage level felt by a person touching the metallic structure remains low (a few volts), but this voltage level depends on how long the metallic structure is lying parallel to the line. This induction effect is a major electrical risk for electrical workers during maintenance tasks on parallel circuits. When contact is established, an induced current flows through the body, which might be dangerous during wet conditions, i.e. when the contact impedances are low.

6.4.4.2 Research on Biological and Alleged Health Effects

During more than 50 years of research on potential biological effects of electric and magnetic fields, the scientific community has published many collective expertise reports about the possible influence of a chronic low-level exposure to ELF-MF on human health. Although some epidemiological results have recurrently observed an association between exposure to ELF-MF and childhood leukaemia, it is widely recognized that the association with other illnesses (including solid adults and childhood cancers and adult leukaemia) is much weaker, if present at all. It is also recognized that, after more than 30 years of research on ELF-MF experimental studies have not evidenced any biological mechanism which would support the epidemiological observations.

Nevertheless, the research on potential biological effects of ELF-EMF is still progressing and international committees such as ICNIRP,[1] SCENIHR,[2] and national and international authorities, such as HPE[3] and WHO[4] regularly update their reports, advices, and health guidelines. The classification of ELF-MF as "possibly carcinogenic" with regard to childhood leukaemia was published by IARC[5] in 2001 and has not been challenged since then, which also means that no new study published since 2001 has changed this classification.

In contrast to the still unproven long term effects, acute effects of high electric and magnetic fields are well documented and scientifically established. Based on these known acute effects, international organization such as ICNIRP, IEEE[6] and international authorities such as the WHO have proposed exposure thresholds for

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[1] *International Commission on Non Ionizing Radiation Protection*

[2] *Scientific Committee on Emerging and Newly Identified Health Risks (working for the European institutions)*

[3] *Health Protection England (formerly HPA)*

[4] *World Health Organization*

[5] *International Agency on Research on Cancer, affiliated to the WHO*

[6] *Institute of Electrical and Electronics Engineers*

protecting the public and the workers, which have been endorsed by national or international legislations, such as in Europe.

In 2010, ICNIRP has updated its Health Guidelines regarding low frequency fields (up to 100 kHz) and has raised the reference level for the public up to 200 μT for power frequency magnetic field, and up to 1000 μT for workers, which was adopted by the European directive for limiting the occupational exposure to EMF.

Reference levels are contrasted with the usual range of higher exposures in epidemiological studies, which are well below 1 μT. Although all scientific committees (and notably the WHO) agree on the fact that the epidemiological evidence is much too limited to be used as scientific basis for legislation, the issue is debated in a lively fashion with important media coverage. Under the media and social pressure, some countries have adopted precautionary approaches based on lower values than the ones scientifically recommended at international level.

6.4.5 DC-EF and Ion Current Phenomena

6.4.5.1 Electric Field and Ion Current for Direct Current

Issues of static Electric Fields (DC-EF) and Ion Current (IC) in relation to High Voltage Direct Current (HVDC) Overhead Transmission Line will be described in this section. This sub-chapter will describe physical phenomena, calculation methods, impacts on humans and natural environment.

ICNIRP has set a limit only for DC magnetic field (DC-MF) at 40,000 μT. As the DC-MF generated by HVDC is around 50 μT (approximately the same level as the earth's magnetic field), it is almost 1000 times lower than the ICNIRP limit. Consequently DC-MF won't be detailed in the following parts. DC-EF and ion current phenomena are described in Cigre (2011).

Unlike ELF-EMF, Direct Current Electric and Magnetic Fields (DC-EMF) are not varying quickly over time (but they may have quasi-static variations). As for overhead networks working at power frequency, DC overhead grid will produce Corona effect but the ions generated by Corona effect will have different evolutions:

- For a positive polarity conductor: negative ions will be attracted toward the conductor and are neutralized on contact. Positive ions will move away from the positive conductor which will then be seen as a positive ions source.
- For a negative polarity conductor: positive ions will be attracted toward the conductor and are neutralized on contact. Negative ions will move away from the negative polarity conductor, which will then be seen as a negative ions source.

Consequently, for a unipolar DC transmission line, the region (accordingly called "space charge region") between the line and the ground is filled with ions having the same polarity as that of the conductors. For a bipolar DC transmission line, 3 space charge regions are created: a positive region under the positive conductor, a negative region under the negative conductor and a bipolar region between the positive and negative conductors.

Three physical quantities are closely related to each other regarding the electrical environment of a HVDC transmission line.

- Electric field E
- Ion current density J
- Space charge density ρ.

6.4.5.2 Recommendation for DC-EF and Ion Current Density Mitigation

As with a HVAC line, a HVDC transmission line may be designed in order to mitigate DC-EF and ion current density. Table 6.6 sums up the influence of geometric and conductors' parameters on EF-DC and IC.

6.4.5.3 Research on Biological and Alleged Health Effects

Static Electric Field

Unlike AC fields, no currents and fields are induced inside the body.[7] Depending of its strength, the electric field can be sensed by the movement of hair. The average threshold of perception is 40 kV/m.

But when the ion current concentration is higher, the threshold of perception will be lower as the hair can get electrically charged by collecting air ions. The reported threshold of electric field detection is around 25 kV/m under an HVDC transmission line.

Psychophysical experiments have examined the behavioural and psychological response of humans and animals exposed to high static electric fields. No effect has been reported.[8]

Biological impacts on animals have also been studied: no damaging effect have been reported regarding experiments on rat and their offspring, longevity of mice or neurotransmitter activity of rats.

Table 6.6 Influence of line parameters on DC-EF and IC mitigation

	Increase of conductor height above ground	Increase of number of sub-conductors	Increase of bundle spacing	Increase of total cross section
Influence on the DC-EF (E)	↘↘	↘↘	↗	↘↘
Influence on the IC (J)	↘↘	↘↘	↗	↘↘

[7] *It is not formally true as when the body is moving in a static field, induction effects may also occur. Nevertheless, they can be neglected here considering the magnitude of the electric and magnetic fields generated by HVDC links, which remain in the same order as natural static fields*

[8] *It should also be noted that high static electric fields can occur naturally, notably under stormy clouds.*

Consequently, as no behavioural, biological and psychophysical impact have been reported regarding electric field experiments, and as the typical threshold of detection for humans is close to 25 kV/m, then most of guidelines have set recommended limiting exposure to EF-DC to 25 kV/m.[9]

Air Ions

HVDC transmission lines are sources of air ions and also generate ozone gas. A typical value of ions concentration under fair weather conditions under the line is around 20,000 ions/cm^3, which is lower than ions concentration in large towns (up to 80,000 ions/cm^3). Double blind experiments have been conducted in order to determine physical response to air ions concentration. Small symptoms have been reported such as headache, husky voice, sore throat and dizziness for subjects exposed to 32,000 positive ions/cm^3. However respiratory irritation symptom cannot be associated with ionic current exposure levels, even at 500,000 ions/cm^3.

Besides, no evidence has been reported concerning impacts of long term exposure to ions current (neither positive nor negative) on asthma or hay fever.

In order to determine if an agent is the source of an increased risk of human cancer, IARC has convened task groups composed of expert scientists to review the published studies. The task group regarding impacts of DC-EF exposure concluded there is no evidence of carcinogenicity in humans and classified DC-EF as a potential carcinogenic agent.

6.4.6 Corona

6.4.6.1 Physical Phenomenon

Corona is an electric phenomenon related to high voltage Overhead Lines which may have different impacts on the environment considering characteristics of the line and weather conditions. The main ones are: audible noise, interferences at high frequency and atmospheric chemistry.

Corona is associated with the electric field level on conductors' surface. When this field exceeds the critical surface voltage gradient E_c of a cylindrical conductor, Corona occurs depending on weather conditions. E_c is calculated using the Peek's formula which is valid for smooth surfaces and cylindrical object.

In practice, the onset gradient is lower than E_c. Indeed, conductors are made of strands, and the irregularities on surface due to the manufacturing and the stringing of the conductors, induce a local increase of the electric field on surface. Weather is also a significant parameter, especially during rainy, foggy or dew conditions. Drops of water increase irregularities on the surface of the conductor. All this parameters produce a strong local increase of the electric field.

A surface state coefficient m ($m < 1$) can be defined on the basis of experiments to take into account these parameters. Consequently, for real conductors, Corona

[9] *Advisory Group on Non-ionising Radiation (AGNIR) "Particle deposition in the vicinity of power lines and possible effects on health". NRPB, 2004*

phenomenon occurs when the electric field on conductor surface E exceeds the critical surface voltage gradient E_c weighted by the surface state coefficient m:

$$E > m\ E_c$$

The physical manifestations of Corona are (Cigre 1974):

- Corona discharges in the air surrounding conductors' surface and fittings
- Discharges and sparking in stressed areas of insulators
- Sparking caused by imperfect contacts.

6.4.6.2 Corona Noise

Source of Corona Noise

Corona noise may be usually generated by overhead lines exceeding 220 kV (Cigre 1991). As seen in 6.4.6.1, the onset of Corona and its intensity are greatly influenced by the weather conditions. Therefore, audible noise level is higher during rainy or foggy conditions but not necessarily more perceptible due to the background noise of the rain. Mostly during fair weather period, noise is generated by any kind of pollution deposited on the cable or insulators (grease, insects, corrosion…).

The spectral analysis of the Corona noise shows there are several components (CISPR/TR 18-1 ed2.0 IEC 2010):

- A low frequency hum close to power frequencies
- A high frequency buzzing or crackling.

Humming is discrete tones occurring at multiples of the power frequency and is dominant at twice of this frequency (the noise is generated for each maximum and minimum value of the AC voltage).

Crackling is a broadband noise, characteristic of the Corona phenomenon, due to the significant energy contained in the mid and high frequency ($f > 500$ Hz), contrary to the environment noises where the main energy is contained in the low frequencies (Cigre 1991).

Measurement of Noise

The human ear spectrum is defined as the range of frequencies that can be heard by humans or animals. In average this spectrum is from 20 Hz to 20 kHz for humans, but may vary significantly from one person to another. Infrasound is a sound pressure wave oscillating at lower frequency than 20 Hz and ultrasound is a sound pressure wave oscillating at higher frequencies than 20 kHz.

Frequencies contained in the hearing range are sensed differently by the human ear. Indeed its sensitivity depends of the magnitude and the frequency of the sound pressure wave. The human ear is a highly sensitive receiver which can detect a large range of magnitudes. Therefore the sound pressure is expressed in decibels (dB) which is a logarithmic scale. To take into account the frequency characteristics of the ear, a noise is usually measured by A-weighted noise measurement devices.

Frequency A-weighting is defined by the international standard IEC 61672-1[10] which also defined sound level meters specifications. Thus, the noise is expressed in dBA. The threshold of hearing is 0 dBA and the threshold of pain is around 120 dBA.

Due to variations of noise in everyday life (nature, cars, industries, construction works…), the duration of measurement is crucial to assess the noise incidence. Several times the average levels of the fluctuating noise over the measurement period can be defined. The main one is called "Equivalent Sound Level" or L_{EQ}, expressed in dBA and is used by most regulations. Other means can be defined as L_{50} which is the equivalent sound pressure exceeded during 50 % of the time measurement.

Calculation of Audible Noise Levels

Several research centers studied Corona noise calculation and proposed empirical formulas during heavy rain conditions and for a single phase conductor. All the formula used the same variables such as the value of the electric field on conductor surface, the number and the diameter of sub-conductors. In order to assess the audible noise generated by a three-phase circuit, these formulas have to be applied for each conductor. Then the resultant sound pressure generated by the circuit is the logarithmic addition of the three sound pressures and is expressed in dBA. For a linear noise source, the sound attenuation is proportional to the logarithm of the distance to the source. Consequently, when the distance between the source and the measurement spot is doubled then the sound pressure decreases by approximately 3 dB. In practice the attenuation is influenced by many environmental parameters such as the nature of ground, vegetation, buildings (Cigre 1999).

Recommendations for Corona Noise Mitigation

Audible noise has to be studied when designing a new transmission line or upgrading the line voltage, especially for lines of voltage 220 kV or more. The voltage level of the line is the first parameter which has a direct impact on the Corona activity. As seen in Calculation of Audible Noise Levels above, increasing the distance between the noise source and the measurement point reduces the noise perception. Increasing the height of conductors does not have a strong impact on the noise mitigation. There are different ways to reduce Corona activity. Conductors' parameters have a significant influence on the Corona noise: increasing the number of sub-conductors or increasing conductor diameter has a significant influence on the Corona noise mitigation. Contrary to magnetic field mitigation (see 6.4.3) compact lines have a negative impact on the Corona activity and consequently on the noise generated by the line.

Table 6.7 sums up the influence of different line parameters on the Corona noise values (Cigre 2005b).

As explained in 6.4.9 (Physical Phenomena) above, pollution may be a significant parameter on the Corona activity. Several noise measurements highlighted that there may be higher noises close to towers, especially near angle towers compared to noise measurement at mid-span. The explanation is that the pollution on insulators and fittings increases the Corona activity, inducing local discharges. Consequently,

[10] *"Electroacoustics - Sound level meters - Part 1: Specifications" IEC, 2013*

Table 6.7 Influence of line parameters on audible noise mitigation

	Increase of phase to phase distance	Increase of conductor height above ground	Increase of number of sub-conductors	Increase of sub-conductor spacing	Increase of total cross section
Influence on audible noise	↘↘	↘	↘↘	↗	↘

washing fittings, insulators and conductors are an easy way to mitigate Corona noise on existing lines in a polluted environment. Suitably designed fittings should be used.

6.4.7 Radio and Television Interferences

6.4.7.1 Active Interferences

Radio and television interference, expressed in decibel (dB), generated by power lines, are not considered as an important environmental issue. However, in some case, interferences have to be studied regarding installations using frequency systems which are implanted in the vicinity of the line.

Transmission lines may cause radio interferences because of Corona, discharges and sparking at highly stressed area of insulators and sparking at imperfect contacts. These phenomena produce different shapes, amplitudes and repetition rates of current pulses generated by the ionisation of the air surrounding the conductors, and have different impacts on the radio interferences (Cigre 1991). The latter are characterized by:

- Frequency spectra
- Modes of propagation (along the wires or directly radiated)
- Statistical variations (depending on weather conditions).

Interferences produced by Corona are characterized by frequency range from 0.15 MHz to a few MHz. Most of the time, TV frequencies are not perturbed. These disturbances are mainly guided along the line and are attenuated according to the line configuration and the properties of the ground. Indeed, the electromagnetic radiation generated by current pulses does not contribute directly to the noise level. However the magnetic and electric fields associated with the spectral components of currents, propagate along the wires. The noise level is determined by the aggregation effect of the fields generated by the discharges along the line.

Polluted or wet insulators may produce interferences up to some tens of MHz and may have an impact on the bands of television broadcasting. Disturbances are directly radiated. The only efficient way to reduce this phenomenon is to wash insulators periodically.

Sparking at imperfect contacts may be a local source of frequency perturbations, but water may have a positive effect on bad contacts which can become bridged and as a consequence, the noise interferences are reduced.

The annoyance of radio and TV perturbations are determined by the "signal to noise ratio" at the receiving installation (Cigre 1974). Cigré proposed a scale in order to quantify the quality of reception perturbed by Corona disturbances and discharges on insulators (see Table 6.8).

The variation of the noise field according to the distance to the axis of the line is a decreasing function depending of the studied frequency and the configuration of the line (see Figure 6.12). The noise also decreases according to the distance to the line, but the decreasing rate depends of the line configuration (see Figure 6.13). This figure has been traced by taking a distance of 15 m as reference, horizontally from the point directly below the conductor. These figures have been established considering 500 kHz as the reference frequency (Cigre 1974).

Table 6.8 Quality of the signal according to the signal-to-noise ratio

Signal-to-noise ratio	Quality of reception – Subjective impression
30	Inaudible interference
24	Perception of interference
18	Audible interference
12	Bad quality for music, but speech is intelligible
6	Speech understandable with concentration
0	Speech unintelligible

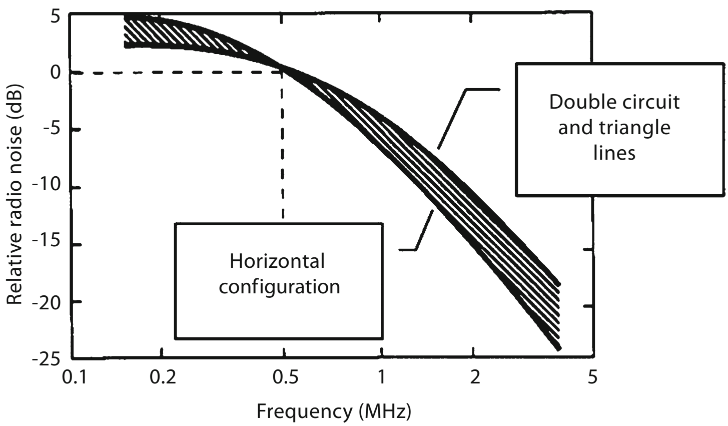

Figure 6.12 Noise level (dB) according to the frequency (MHz), depending of the line configuration.

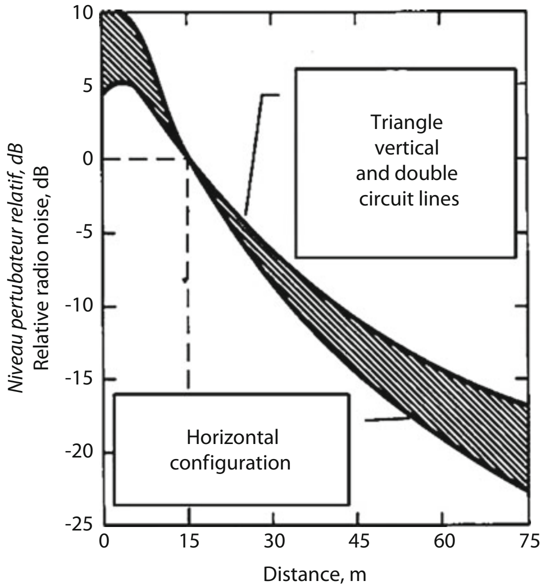

Figure 6.13 Noise level (dB) according to the distance to the line, depending of the line configuration.

Table 6.9 Influence of line parameters on radio interferences mitigation

	Increase of phase to phase distance	Increase of conductor height above ground	Increase of number of sub-conductors	Increase of sub-conductor spacing	Increase of total cross section
Influence on radio interference	↘	↘	↘↘	↗	↘

CISPR[11] is the international committee specialized in radio frequency interference and is part of the IEC.[12] This committee has been founded to define standards to limit frequency perturbations. The standard CISPR/TR 18-1 (2010) gives more information on the radio noise generated by the AC power lines in frequency ranges from 0.15 MHz to 30 MHz (AM broadcasting) and from 30 MHz to 300 MHz (FM and TV broadcasting). Radio interferences over 300 MHz generated by the line are not significant enough to be taken into account.

Table 6.9 sums up the influence of different line parameters on the radio interferences (Cigre 2005b), the results are very similar to the ones in Table 6.7, for the audible noise.

[11] *International special committee on radio interference*

[12] *International Electrotechnical Commission*

6.4.7.2 Passive Interferences

The interferences discussed above are directly produced by the power line so they are described as active interferences. In this case, lines may be seen as sources of disturbances. However transmission lines (such as large structures such as buildings, towers…) may be source of passive interference by reflecting and reradiating broadcast radio signals. When the tower is close to a broadcasting system, it may act as a secondary antenna, modifying the radiation characteristics of the broadcasting station (Cigre 1991). This problem can be solved by changing the position of the source or by improving the signal.

6.4.8 Atmospheric Chemistry (Ions and Ozone)

Corona discharges generate chemical reactions in the air surrounding the conductors. Ions and ozone are the main chemical components related with the Corona activity.

6.4.8.1 Ions

Ions are electrically charged atoms or molecules. It may be a positive ion (formed by the removal of electron(s)) or a negative ion (formed by the gain of electron(s)). Ions are naturally present in the air, formed by phenomena such as natural radioactivity, cosmic rays or thunderstorms or human activity such as exhaust gas emissions. The usual concentration of ions in the air varies between 100 and 2,000 ions/cm^3.

Table 6.10 shows typical air ion concentrations (Cigre 2011).

In the case of alternative power lines, the amount of ions generated by Corona discharges is relatively low. Indeed the electric field generated at the conductors' surface has an influence on ions movements. Due to the alternative shape of the field, ions will be continually attracted and repelled in the air surrounding the conductors. Moreover ions may collide with ions of the opposite polarity and are mutually neutralized. Consequently ions generated by AC power lines at ground level are much lower than natural ion concentration in the air (Cigre 1991).

Ions generated by DC transmission lines can reach a few tens of thousands of ions per cm^3: around 20,000 ions/cm^3 under the line at ground level (see 6.5.4.3).

6.4.8.2 Ozone

Ozone (or trioxygen) is a natural triatomic molecule constituted by 3 oxygen atoms (0_3). The human activity has a significant influence on the ozone concentration in the air: in a natural environment ozone concentration is around 50 ppb (50 ozone

Table 6.10 Typical ion concentration according different locations

Location	Air ion concentration (ions/cm3)
Fair weather open space	70 - 2000
In a large town	Up to 80000
30 cm above a burning match	200000 – 300000
1.5 m downwind of vehicle exhaust	50000

Table 6.11 Production of Ozone and Chemical Reactions on French Grid (400 kV)

Production (kg/h)	French 400 kV grid (21,000 km)	Global production in France (Natural and anthropogenic)
Ozone 0_3	72.7	13.6 10^6
Nitrogen dioxide NO_2	1.9	1.8 10^5
Hydrogen peroxide H_2O_2	0.24	5.3 10^4

molecules for 1 billion of air molecules) and may exceed a few hundred ppb in large town during a few hours. Corona discharges generate ozone in the vicinity of the conductors. Then ozone immediately reacts with other components in the air such as nitrogen oxides and hydrocarbons.

Mathematical models have been developed to assess ozone formed by Corona discharges taking into account multiple factors including atmospheric conditions, wind or ozone decay rate. These models conclude that most transmission lines around 345 kV do not generate detectable ozone levels. An alteration of the natural ozone concentration has been evaluated for lines exceeding 765 kV during adverse conditions (heavy rain, light wind and at a few meters from the conductors) (Cigre 1991). Calculations applied on the French EHV grid (400 kV) have estimated the production of ozone and its chemical reactions as given below in Table 6.11 (Cigre 1999).

These results show the global French EHV grid is negligible on a national scale. Measuring ozone directly under the line at ground level is difficult due to the variations of the background level of ozone in the environment which are far higher than the amount of ozone generated by Corona discharges.

6.4.9 Aeolian Noise

Aeolian noise is very uncommon phenomenon produced by overhead lines under very particular wind conditions. This phenomenon is independent of the voltage level or the current flowing into the line. Aeolian noise is the result of the wind blowing over conductors, insulators, through lattice towers or hollow fittings and depends of the speed and the direction of the wind.

The noise generated by wind on the conductors results from the shedding of air vortices. When the wind speed exceeds 10 m/s and if the wind is unfavourably oriented, this may cause a rumbling noise reaching a few tens of dBA (Cigre 1999). This noise can be mitigated by wrapping a wire along the cable in order to modify the shedding of air vortices or the use of specially shaped conductors.

Under well-defined conditions, the wind blowing over insulators can produce a high intensity pure tone noise of a few hundred of hertz. The reduction of this noise can be achieved by fitting rubber bushes within the insulators strings or by replacing some insulators with new ones with particular shapes.

6.4.10 Conclusions/Guidelines

- After more than 50 years of research on the subject of possible health impacts of ELF-EMFs, the scientific community could not provide any solid evidence about any health hazard on living organisms associated with a prolonged exposure to ELF-EMFs at a lower level than the international recommendations.
- However the ELF-EMF issue is a key one in the debate on new overhead line projects. It is recommended to continue to monitor EMF developments closely and to submit good quality information to the public, local authorities and utilities' own personnel.
- In contrast to the still unproven long term effects, acute effects of high electric and magnetic fields are well documented and scientifically established. Based on these, international organizations and authorities such have proposed exposure thresholds for protecting the public and the workers, which have been endorsed by national or international legislations, such as in Europe.
- Electric fields generated by an overhead transmission line can be reduced by modifying geometric or conductors' parameters. Magnetic field generated by an Overhead Transmission Line can be mainly reduced using compensation methods or modifying geometric parameters
- Overhead Line designs have been developed which lead to reduced magnetic fields. Some of these designs have been implemented. Their feasibility and costs have to be studied with respect to the issues involved in the area of magnetic fields
- The capacitive and induced effects of Overhead Lines are well known and adequate mitigation measures exist to deal with them.
- Audible noise aspects must be taken fully into account when designing new overhead transmission lines. The fact that this is the case does not always mean that they are of minor importance in regard to impacts and particular solutions must be sought. Effective design mitigation measures exist such as increasing the diameter of conductors and the number of sub-conductors.
- In the case of aeolian noise where conductor aeolian noise problems have arisen new techniques have been developed which reduce the audible noise level down to a low level compared to ambient noise levels. Insulator aeolian noise problems can usually be solved.
- Measures required to minimise radio and television interference are the same as for the reduction of audible noise. Difficulties from "passive" interference can generally be alleviated by improving the receiving aerial or its position.
- In the case of alternating currents there is no measurable ion density differential compared to the earth's natural ion density. In the case of direct current lines while ion density increases at ground level substantial research has not indicated any health effects.
- The increase of the ozone concentration in the vicinity of power lines is negligible.

6.5 Concerns and Issues, Consultation Models for OHL Projects and Stakeholder Engagement Strategies

6.5.1 Introduction

The survey carried out by 22WG14 revealed thirteen concerns and issues facing utilities for new lines and existing lines (both for upgrading and refurbishment and for operation and maintenance) and these were tabulated in Chapter 3 of Cigré TB 147 (1999). The top five were EMF Health Concerns, Visual Impact, Landowner Negotiations and Access, Community Opposition and Property Values. These would seem to be as valid today as then. Guidelines are given below in 6.5.2.

The work of SC22.15 produced TB 274 *Consultations Models for Overhead Line Projects* (June 2001) (Cigre 2005a). This is summarised and guidelines given in 6.5.3. The WGC3.04 dealt with similar issues in a somewhat broader context and Cigré TB 548 *Stakeholder Engagement Strategies in Sustainable Development – Electricity Industry Overview* (Cigre 2013) was produced by them. A summary and Guidelines are given in 6.5.4. These reflect and reinforce those of Cigré TB 274.

6.5.2 Concerns and Issues Facing Utilities -Guidelines

- Planning and environmental issues associated with both new projects and existing assets are major business issues for electricity utilities. As such they need to be given a suitably high priority so that, like all business risks, they are managed effectively. Environmental issues are increasingly important for companies and the communities they operate in. Visual amenity and EMF head the list of public concerns
- Good, appropriate communication is an inherent part of successful management of the issues. Each utility must decide what is most appropriate to suit its circumstances but the general guideline would be to ensure that active consideration is given to strategies required to meet business success and expectations of the public.
- Good practice in different forms and means exists worldwide. Examples are communication programmes or centres aimed at explaining the use of electricity and the environmental effects of overhead lines. It is up to utilities to benefit from others' experience.
- The fostering of good relations with landowners and occupiers affected by proposed overhead lines and with those on whose lands existing networks are in place is essential.
- Codes of Practice or Landowners/Occupiers Charters should be put in place to comprehensively cover all aspects of utility dealings with landowners. These should include access, construction and maintenance issues and also possible future changes in land use.

- These Codes or Charters should deal with the standards to be maintained in communication, consultation and workmanship as well as in personal contact.
- Early communication is vital to inform landowners of all aspects of the project including financial compensation methods and to optimise the route and location of towers on their property. The necessary resources should be dedicated to maintaining good communication throughout any construction or refurbishment project and to ensuring that general and individual agreements are honoured. (See Sections 6.5.4 and 6.5.5).

6.5.3 Consultation Models for OHL Projects

6.5.3.1 Introduction

In drawing up proposals for new overhead transmission lines, undertaking environmental impact assessment (EIA) and seeking rights, permits and consents to construct, transmission companies are increasingly, whether legally required or voluntarily, undertaking more stakeholder consultation. Community involvement can be key to the success of often controversial new transmission infrastructure proposals, requiring the use of innovative and "best practice" approaches. Public Hearings are a key feature of most processes, see Figure 6.14 A Public hearing.

It was hoped that Cigré TB 274 (2005a) would provide a useful reference for Cigré members and those working in electrical power systems, providing an overview of best practice approaches to consultation for overhead line projects and possibilities for improvement in this challenging area.

Figure 6.14 A Public Hearing.

Working Group B2.15 set about examining "best practice" consultation approaches in 2001, with an international survey of member countries. Responses were gathered to a series of questions relating to the type and nature of consultations undertaken, the extent of legislative requirements, timescales, key ingredients for success and whether consultation was undertaken in the ongoing management of transmission line assets. Further questions relating to the impact of market restructuring, society expectations and the use of new and emerging technologies were added in 2002. It was then decided that the results warranted production of a Cigré TB, which could usefully also include a number of "best practice" case study examples from around the world.

In addition to explaining the particular consultation approaches adopted in the case study examples briefly described below, Cigré TB 274 includes the full findings of the international survey and captures overall key ingredients for success.

6.5.3.2 Case Study 1: Austria

This first case study concerned a proposal for a new 95 km 380 kV double-circuit, lattice steel overhead line through predominantly rural parts of Austria, the planning of which started in the 1980s. Significant opposition was encountered from the public, politicians, community groups and local government.

Whilst there is no legislative requirement to undertake consultation (the permitting authority decides whether to consult on consent applications), Verbund Austrian Power Grid went to considerable lengths to engage with a wide range of stakeholders and adopted a range of approaches in the process, with considerable success.

6.5.3.3 Case Study 2: Canada

The second case study explained the consultation approaches taken when, in 1998, Hydro- Québec announced the construction of a new 140 km 735 kV overhead line, urgently needed to secure supplies to households left without power following a major ice storm. Special decrees were adopted by Government to amend certain laws and exempt the Company from others, including bypassing the normal public inquiry process for the initial 100 km section of the route, to be substituted instead by an information and consultation committee established by the Government.

Intense opposition, lobbying and legal challenge from well organised residents closest to the first section of line route ultimately resulted in a successful legal challenge to the Government decrees and normal regulations were subsequently reinstated for the remaining 40 kilometre section of overhead line. The Company therefore had to repeat the entire consultation process in 1999.

6.5.3.4 Case Study 3: Japan

The third case study explained the consultation approaches adopted by Tohuku Electric Power Co., Inc for a new 84 km 275 kV double-circuit overhead line to connect a coastal nuclear power plant with an inland switching station in Japan. Consultations started in the early 1990's and construction, which took 2½ years, commenced in 1998. See Figure 6.15 Basic Route Selection Work (Japan).

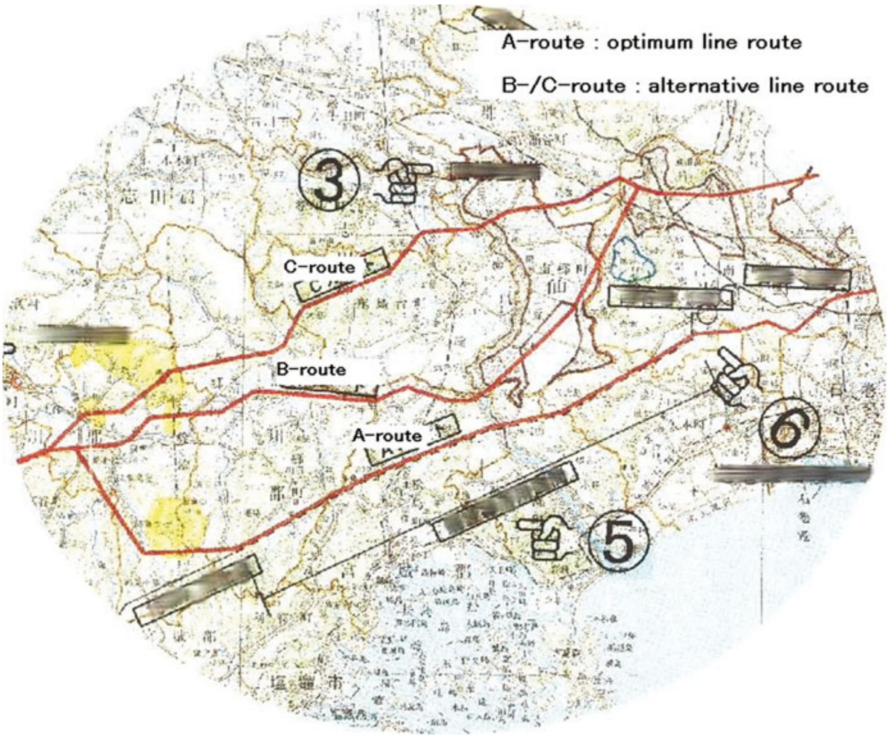

Figure 6.15 Basic Route Selection Work (Japan).

The new line passed quite close to urban areas and scenic spots such as a quasi-national park and a prefectural natural park. Nesting places of endangered bird species, Golden Eagles and Hodgson's Hawk Eagles, were discovered following ecological survey along the planned route corridor.

Line routing difficulties and risk of delays due to opposition on EMF, visual impact and/or nature conservation grounds were at the fore of the Company's concerns as they set about the planning of the project and undertaking consultation.

6.5.3.5 Case Study 4: UK

The fourth case study outlined the very effective use made by National Grid Transco of interactive virtual reality computer modelling when undertaking consultation in 2000 about options for a new sealing end compound. This formed part of a much larger and very contentious overhead line project in the north of England, the planning of which had started in 1990 and two major public inquiries had sat during the early-mid 1990s. The affected local planning authorities had always maintained their objections to the new line and the task of consulting on options for a sealing end compound was set about amidst considerable public opposition.

6.5.3.6 Case Study 5: South Africa

In explaining the approaches adopted by Eskom in South Africa, the fifth case study considered the consultation models that can effectively and usefully applied during the environmental impact assessment process, taking account of the particular legal system and the interests, concerns and culture of the various groups that are consulted. The case was made to explain why the development of a comprehensive public participation model should take due regard of the need for a sound public participation process, fair compensation and the final recourse to rights of expropriation by the transmission company.

6.5.3.7 Consultation Requirements Associated with Project Financing

Before outlining the findings of the international survey questions and drawing conclusions on the key ingredients for success in "best practice" consultation approaches, Cigré TB 274 gives examples and practical advice about instances where consultation can form an essential mandatory requirement when seeking project funding assistance financial institutions. By way of example, an overview of the consultation requirements of the European Bank for Reconstruction and Development associated with an electrical interconnector project between Romania and Hungary is provided, highlighting the need to plan for and fully comply with such requirements when seeking project funding assistance around the world.

6.5.3.8 Conclusions/Guidelines

The main findings of the Working Group, explained more fully in Cigré TB 274, were as follows:

- Most companies undertake much more consultation than legislation requires. Mandatory consultation requirements often only exist in environmental assessment legislation. Whilst consultation takes time, it helps identify likely concerns and possible points of objections; helps refine proposals, address concerns and smooth the eventual permitting process.
- Companies should establish a consistent approach to mapping stakeholders and understanding their viewpoints, needs and expectations.
- Use of independent specialists when considering options, preparing consultation information and assisting at advisory meetings, increases the credibility of the information presented and helps secure understanding and co-operation from stakeholders.
- Present as much information as possible, trying to get the balance right and tailoring information to suit the audience. Communicate via the best methods available (e.g. Company web-site, detailed publications or brochures, periodic newsletters, advertorials in local newspapers, etc).
- Conduct open and engaging consultation with a broad range of representative and interested groups. Different forms of consultation may be appropriate with

different bodies at different stages in the planning process. Initial consultations typically involve the permitting authorities. Public consultation frequently follows at least some initial EIA work to identify route options. Include governmental, non-governmental, permitting authorities, special interest environmental organisations, community, landowners and the public.

- Too often companies will wait until opposition organises and issues negative statements on the project. Early in the project it important that communities know how the project will benefit them in terms of increasing the reliability of the electrical network, in monetary compensation schemes and in job creation.
- Companies have to be pro-active in dealing with opposition and must give immediate information on issues related to EMF/Health, visual impact mitigation and nature conservation management.
- Provide full information about alternatives (e.g. routing, tower designs, rationalisation/removal of lower voltage lines etc) and where appropriate, allow some choices by stakeholders. Whilst consultation may provide some opportunity to influence decision-making, for example in route selection, this may not apply to all aspects of a project, such as undergrounding. In some senses, therefore, it is also about informing.
- Start consultations as early as possible. Consider engaging the public and other stakeholders in the scoping of the project EIA, consideration of the need for the line, transmission alternatives, the identification of route corridor options and ranking of route selection criteria. Thereafter, maintain engagement and feedback with stakeholders, openly sharing findings of option studies, environmental and social impact assessment studies.
- Consider opportunities to involve representatives of the permitting bodies as observers – can help reduce time subsequently taken to determine consent applications and gives the permitting body the opportunity to suggest adjustments to the communication strategy.
- Consider use of new and emerging computer based technologies that may assist the environmental impact assessment and consultation processes (e.g. virtual reality modelling). See Figure 6.16 Virtual Reality Model - Sealing End Compound (UK).
- Where seeking project finance assistance from funding institutions, check specific consultation requirements. Useful advice can be found in an IFC publication "Doing Better Business Through Effective Public Consultation and Disclosure" – A Good Practice Manual' (1998).
- Use "best practice" mitigation measures to minimize temporary construction and permanent environmental impacts. The costs of such measures often represent a very small percentage of overall project cost and assist enormously in securing community support.
- Specify environmental requirements in construction contracts and include penalties for non-compliance. Plan communication requirements during the construction phase of a project. Keeping the affected community and wider interests informed of the planned works and developing mechanisms for doing so throughout the construction phase can contribute enormously to the successful delivery of a new overhead line project.

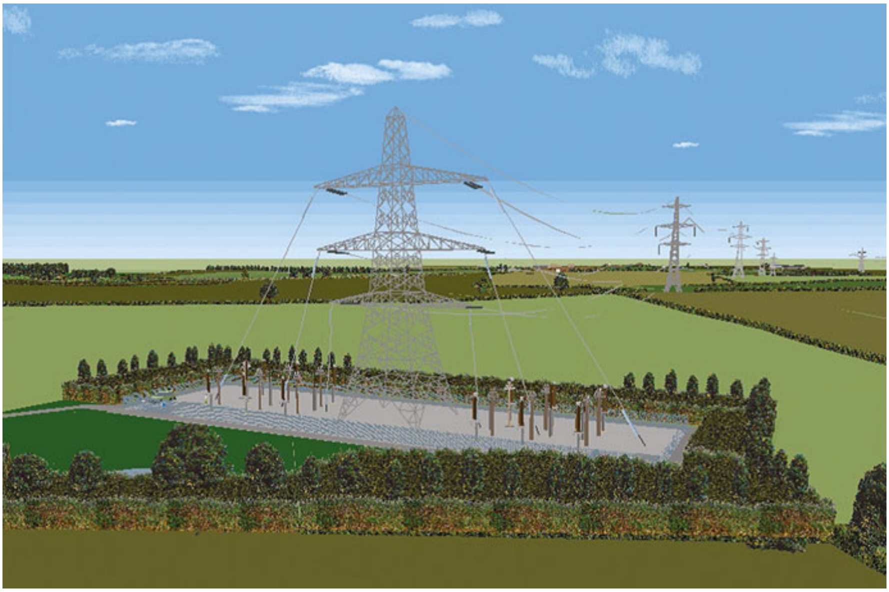

Figure 6.16 Virtual Reality Model - Sealing End Compound Option (UK).

- Approaches to publishing the results of consultation were found to vary. Consider outlining the results of consultations in environmental impact assessment reports explaining how it has influenced routing decisions or modifications to proposals.
- Where electricity markets have been opened up, lead times for projects may be shorter, requiring approaches that allow for more intense, albeit greater, public consultations. Opening up of markets can lead to less willingness to accept transmission proposals as being “in the public interest”.
- Most companies are facing increasing expectations within society for greater and earlier consultations to be undertaken, particularly with regard to new construction and replacement or diversions of existing overhead lines.
- Most companies use photomontages to provide clearly understandable visualisations, together with web-sites to provide information about projects.

6.5.4 Stakeholder Engagement Strategies

6.5.4.1 Introduction

The results of a survey of electricity organisations, and other recent experience, present an encouraging picture about stakeholder engagement in the sector. Electricity organisations worldwide were surveyed on their attitudes to, and experiences of stakeholder engagement, particularly in relation to the development of electricity construction projects, within the context of sustainable development.

The past few decades have seen large organisations respond more proactively to environmental issues, and increasingly now to societal pressures – two of the three legs of sustainable development (the other being, economic or financial). There has been a growing voice within communities to be heard and to seek to influence government or organisational decisions which affect them.

This pressure has been evident too within the electricity sector, particularly where electricity organisations are seeking to expand or change their networks or build new infrastructure. There is increasingly less acceptance by populations and communities that the electricity sector is acting completely in the public interest and therefore that their proposals should go non-scrutinised or unchallenged. This is especially true where organisations are no longer state owned.

Electricity organisations have been responding to this challenge by being more open and transparent in how they relate to the public. The traditional relationship has been one of "producer and consumer"; increasingly it is becoming additionally one of "organisation and stakeholder".

The relationship between organisation and stakeholder is primarily driven by legal and regulatory obligations, however the results of the survey show that the level of voluntary stakeholder engagement is increasing, which has the potential to unlock value and increase organisational performance as well as increasing public acceptance and enhancing reputation as socially responsible, trustworthy organisations.

6.5.4.2 Survey Findings

The survey found that stakeholder engagement policies are less common than environmental policies in electricity organisations. Environmental studies and detailed design are considered the most important stages of the project life cycle in which to undertake stakeholder consultation.

Legal obligations, reputation, values and ethical issues are the main drivers for stakeholder consultation and engagement. While formal environmental statements, major projects and legal requirements are key prompts for stakeholder consultation, policy development is not.

It is not surprising that legal requirements are the main motivation to undertake stakeholder consultation, but many companies choose to carry out consultation significantly beyond the minimum level required in order to improve relationships with stakeholders and gain public acceptance. Although many stakeholders are consulted or involved on a voluntary basis by most companies, there is no global common practice evident in identifying stakeholders. There was no single existing standard strategy amongst electricity organisations relating to stakeholder engagement.

A number of methods to engage stakeholders are used such as local meetings, newspapers and website links. Individual face-to-face meetings and community meetings are viewed as the most effective consultation method, followed by the use of websites. Most organisations report back to stakeholders on consultation results voluntarily See Figure 6.17 Stakeholder Consultation Session.

This provides clarity and transparency to stakeholders and gives organisations a greater insight into stakeholders "key concerns". Some electricity organisations monitor the outcomes of stakeholder engagement and communicate these internally to improve business process.

Figure 6.17 Stakeholder Consultation Session.

Electricity organisations believe that stakeholders are most concerned about nature conservation, visual impact and EMF/health issues.

A wide range of methods of engagement and stakeholder groups result in the need for a tailored, targeted approach to stakeholder engagement which should be influenced by the nature of the project, the stage of the project lifecycle, stakeholder groups and organisational constraints. Examples of good practice can also be found in the Case Studies in the Cigré TB 274.

The survey does not claim to be representational. The respondents to the survey may be those organisations which embrace engagement rather than those which have yet to see the benefits. Without further work, there is no way of establishing how representative the findings of the survey are.

6.5.4.3 Conclusions

Electricity organisations are increasingly recognising the benefit of stakeholder engagement, not only because of their commitments to sustainable development, but for the benefit of electricity infrastructure projects themselves, and for all the benefits of building relationships with key environmental and citizen organisations. Companies have indicated that they are prepared to learn from their stakeholder consultation and engagement exercises, and use the results to build best practice and improve processes within their organisations. The case studies show the wide variety of stakeholder engagement which is taking place for electricity projects.

Stakeholder consultation may be backed by legislation in many countries, but it is clear that many companies go considerably beyond the minimum, recognising the benefits of engagement. Even so, there remains a perception amongst some to consider the process as a regulatory obligation with which they must comply, rather than an essential component of the planning and delivery of a scheme. If consultation activities are driven principally by legal or regulatory requirements, there is a risk that organisations will not fully recognise stakeholder or customer drivers in their businesses, and not optimally respond to the needs of the societies they serve.

Many companies clearly recognise the business and reputational risks that come from poor stakeholder relations, and place a growing emphasis on social responsibility and transparency and reporting. In this context, good stakeholder relations are a prerequisite for good risk management. There is increasing emphasis within the electricity industry on good stakeholder engagement through creating transparency in key activities and ensuring the promotion of social responsibility.

However, it is clear that there is little common methodology in consultation or engagement across the sector. Electricity companies are more likely to develop their own processes, than look to the experience of others in the sector. Similarly, they are much more inclined to use engagement in the development of projects rather than in the development of policy or programmes.

The Working Group recognises the value of the use of stakeholder engagement strategies for electricity infrastructure projects within the context of sustainable development. Good engagement facilitates the sustainability of decisions made about projects, ensures social issues are considered as well as environmental ones, ensures that electricity organisations understand and consider the wider implications of their project decisions, and helps to ensure that trust with stakeholders is developed. Good engagement has the characteristics of being timely and transparent, so that stakeholders can influence the project decisions.

Critically, organisations must not see stakeholder engagement as a form of justification for projects by attempting to disguise "selling" tactics as "asking" or consulting. Therefore, meaningful early engagement and integration of stakeholders issues into project design from the beginning of the decision making process is key to ensuring that issues are tackled from the outset of a proposal, and acceptance of the project by stakeholders afterwards. Considerable amounts of time and resources are involved with setting up and running the process of stakeholder engagement through the project lifecycle.

Interestingly, time was found to be the key constraint for electricity organisations, ranking ahead of resources or finance. This infers that project programmes are considered to be very important. It therefore becomes more critical that consultation and engagement strategies are worked up as early as possible, and designed to produce effective outcomes. Early and good engagement can actually help project programmes.

Whilst a flexible approach to stakeholder engagement is beneficial, there is a global need for a standard set of principles for communication, consultation and engagement.

6.5.4.4 Key Principles/Guidelines for Stakeholder Engagement

The Working Group produced a set of 8 key principles for stakeholder engagement in the electricity sector, and believes that these key principles provide valuable guidelines for electricity companies when developing and implementing stakeholder engagement strategies.

Approach to Stakeholder Engagement

The approach to stakeholder engagement should be fundamentally consistent for all of a company's construction projects. This approach could be flexible, varying according to the scale and type of the project, but should still be consistent.

Consistency should occur across stakeholder groups and localities. The aim must be to establish trust among stakeholders.

Project Scoping (Proportional Approach)

The value from engagement should be optimised by scoping the requirements for the project. Be clear about the real constraints of the project – what engagement and communication can assist with, and what is out of scope. Be aware of what project phases are to be the subject of engagement. A lot of effort and resource on engagement at the margins of a project may realise limited additional benefit. It may also be beneficial to engage key stakeholders (particularly those representing different community interests) at the start of a project to establish their views on what they would consider to be a "proportionate approach".

Stakeholder Identification (Identify and Understand your Stakeholders)

Establish a consistent approach to mapping stakeholders and understanding their likely viewpoints, needs and expectations from engagement, and the potential value that could be realised from engaging them. There should be a clear commitment to community engagement at a local level. It is also important to define the "voiceless" or "hard to reach" stakeholders such as those with mobility difficulties, sight or hearing loss, literacy difficulties, alternative language requirements, etc; or people too busy to engage with traditional consultation methods. Identify and target these groups specifically.

Start Engagement Early

Early engagement in a scoped manner will help to build project awareness and understanding, so helping to reduce the risk of "surprise" later. Engage key stakeholders early in the scoping phase to enable them to contribute to the development of effective solutions. They may have information and views that will be of benefit to the proposal, and securing their endorsement for an approach to stakeholder engagement, and for securing data will be of considerable value. Stakeholders must have the opportunity to comment and influence at the formative stage. Be clear about the stage of the project when engaging: stakeholders should not expect all project details to be available at the early stages, and should appreciate that they are being involved in formative stages.

Targeted Mix of Consultation/Engagement Methods

A combination of methods for stakeholder engagement should be considered and chosen depending on the stage of the project, the stakeholder groups involved and their individual concerns, needs and priorities. Methods should be tailored to the required output, such as awareness building, gaining understanding, inviting comments, or enabling constructive debate. Methods could include provision of information through news media; published information sheets or leaflets; exhibitions; websites; on-line questionnaires; discussion events; workshops, perhaps independently facilitated; community panels, etc. Dedicated community liaison and engagement staff could be utilised. Regular engagement with key stakeholders will enable relationships to be developed and maintained.

Create an Open and Transparent Process

It is important to manage the expectations of stakeholders by clearly stating the objectives and scope of the engagement from the outset. Some aspects of a project will be "out of scope" for consultation, such as legislative or regulatory obligations, however it should be recognised that there may be different ways of satisfying these obligations. Similarly, timescales should be clearly defined at the outset. The engagement or project process should be openly publicised, and be clear, so that as many obstacles to engagement are removed as possible. Project information should be tailored for audiences in format and style, for example, non-technical material or specialist, detailed material.

Provide Feedback to Stakeholders (Monitor and Evaluate)

It is important that stakeholders can see how their comments have been taken into consideration. Feedback mechanisms should be developed to demonstrate how views have been considered and addressed. This is not necessarily a simple task for complex or controversial projects where large numbers of comments may be received. It is important to demonstrate not only that engagement has taken place, but that it has been an effective part of the process. It is important to be clear about how views are reflected in, or used to influence, subsequent decisions, processes and plans. When comments have been considered but the proposals have not changed, it is good practice to explain why not.

Engagement should be Proactive and Meaningful

Stakeholder engagement should be appropriate for the purpose and the target audience and should be proactive and meaningful. Stakeholders should generally be involved at project stages where they are able to influence an outcome or decision. The approach to the engagement of citizen communities should be proactive, accessible and inclusive.

6.6 Life Cycle Assessment (LCA) for OHLs

6.6.1 Introduction

Working Group B2.15 was set up in 2000 to examine Life Cycle Assessment (LCA) issues as applied to Overhead Lines and to study aspects of overhead line relating to Environmental Concerns. With regard to LCA the specific terms of reference were:

- To analyse LCA methods and existing tools and to ascertain their range of application for overhead lines.
- To develop methodologies as appropriate for Life Cycle Assessment of Overhead Lines, establishing recommendations to provide as complete a picture as possible of the interactions of an overhead line with the environment and to provide decision makers with information which identifies opportunities for environmental improvement.

For clarity it is useful to give here the definition of LCA from the Society for Environmental Toxicology and Chemistry (SETAC):

> *"The Life Cycle Assessment is an objective process to evaluate the environmental burdens associated with a product, process or activity by identifying, and quantifying energy and materials used and wastes released to the environment, and to evaluate and implement opportunities to affect environmental improvements.*
>
> *The assessment includes the entire life cycle of the product, processor activity, encompassing extracting and processing raw materials, manufacturing, transportation and distribution, use, reuse, maintenance, recycling and final disposal.*
>
> *The Life Cycle Assessment addresses environmental impacts of the system under study in the areas of ecological health, human health and resource depletion. It does not address economic considerations or social effects. Additionally, like all other specific models, LCA is a simplification of the physical system and cannot claim to provide an absolute and complete representation of every environmental interaction."*

The working group undertook a broad examination of LCA and LCA methodologies. A summary is given of how LCA developed and how it is classified and outlined in the ISO 14040 series. A full review was included of work done in Scandinavian countries on LCA on power systems and overhead lines. A very detailed explanation and comparison was provided of various LCA software packages, how they operate and their benefits.

To develop working group documents on LCA the approach adopted was to examine the main components of Overhead Lines – structures and foundations, conductors and insulators – and to initially assess in a qualitative manner the impact of these components on the environment through the production, use and disposal phases.

Furthermore a series of detailed quantitative LCA studies were carried out on the main Overhead Line components (using Japanese LCA software). The results of some studies (in Japan and Denmark) dealing with the Overhead Line as a system were also included. Finally conclusions and recommendations were presented.

Electric and magnetic fields(EMF), audible noise and other interference issues connected to transmission lines were not covered by Cigré TB 265 (2004), since they have already been dealt with in detail in Cigré TB 147 (1999), from SC 22.14, as well as by other working groups in Cigré and they, like visual impact, cannot be analysed using LCA methodologies. Some of the studies reported on were driven by demands of customers in deregulated markets for more information on the environmental effects of overhead lines.

This brochure should certainly assist in that regard. It is hoped that the information contained in Cigré TB 265 (2004) will be of benefit to Cigré members and those working in electrical power systems in providing an overview of Life Cycle Assessment, its application to Overhead Lines and the possibilities for environmental improvement. It could also serve as a model of the application of life cycle assessment to other components of an electric power system.

6.6.2 LCA Development and Early Applications

Chapter 2 of Cigré TB 265 (2004) is devoted to the description of the LCA development and early applications and also give an outline of ISO 14040 series. The introduction of LCA and an historic overview to LCA are briefly reviewed. The current applications of LCA are also examined.

Cigré TB 265 (2004) states that LCA is increasingly recognised as a potentially powerful environmental management tool and is increasingly being used in environmental management systems of companies as well as by governments in the policy-making process. References to application of LCA in the electrical industry are explored also in this chapter. Some studies have been carried out involving overhead lines.

6.6.3 Power System and Overhead Line LCA in Scandinavia

Chapter 3 summarised the Scandinavia LCA studies on power and transmission system. Vattenfall performed the first one in Sweden in the mid 1990s. Danish power companies have completed a similar, more recent study. The Scandinavian studies are the most comprehensive involving overhead lines, with available reports combined with accessible sources.

The results show:

- The methods were largely the same, and the results are expressed in the same functional unit (environmental impact per 1 kWh of electricity delivered to the consumer).
- The most significant environmental impact of the total electrical system is due to generation while the contribution from transmission is relatively small (0.3 % in Denmark).
- Network losses are a major source of environmental impact from power lines.
- The Swedish study shows that the transmission losses to a national grid customer amount to 2 % while for household customers (distribution) they are 9 %. See Figure 6.18.

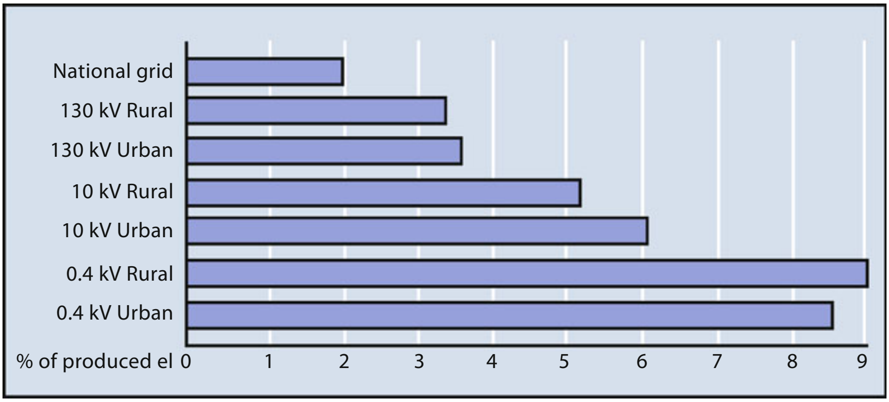

Figure 6.18 Transmission Losses in Electricity Supply Networks (Sweden).

6.6.4 Comparison of LCA Software

Chapter 4 of Cigré TB 265 (2004) describes the outline and what LCA software packages (JEMAI, TEAM, SIMAPRO) can do in general, and also compares some of their features. These software have similar functions, however because of their different origins (Japan, France, Netherlands) there are some differences. See Figure 6.19 General procedure for the calculation of Eco-indicators (Eco-indicator 99 [Netherlands]).

Therefore, it seems that consistent results cannot be obtained between different LCA software packages, and there is little meaning in comparing the final values of results derived from several different LCA software packages. Taking these differences between software packages into consideration, it is recommended that impact assessment comparison (between an original project and an improved one) should be carried out using the same LCA software.

In order to choose appropriate software for a specific LCA study, it is recommended to examine whether the function of the software as well as the database suitable for the intended LCA study.

6.6.5 LCA, Overview for OHL Components, Construction and Maintenance

An Overhead Line is a large system, which consists of several subsystems made up of various components, their transportation, construction work, maintenance activities, dismantling, recycling, transmission losses, and so on. Considering that elementary flows for the transmission system are the sum total of each sub-system, it is necessary to regard these sub-systems as one of the product systems to be studied.

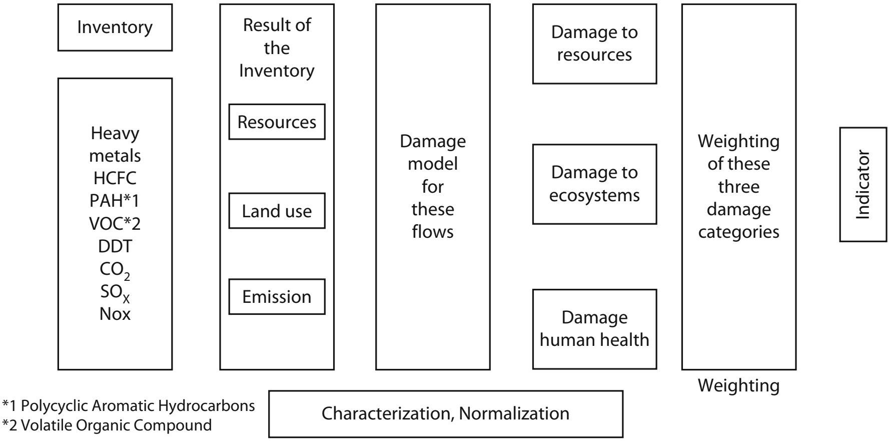

Figure 6.19 General procedure for the calculation of Eco-indicators (Eco-indicator 99 [Netherlands]).

Chapters 5 and 6 of Cigré TB 265 (2004) are devoted to the description of the major components or activities related to OHL, in terms of their material used (raw or recycling), corrosion protection, dismantling, recycling and scrapping. These chapters conclude with the listing of conclusions and recommendations to reduce the environmental impact of each component or activity in terms of LCA studies.

LCA, studies on some OHL components Chapter 7 of Cigré TB 265 (2004) shows some concrete calculations of LCA for several processes for OHL components (lattice tower, conductor (ASCE), porcelain insulator) based on the procedure specified in the ISO 14040 series. An actual analysis is carried out using the LCA software "JEMAI –LCA" which was developed by the Japan Environmental Management Association for industry (JEMAI).

6.6.6 LCA, Studies on OHL

Finally, Chapter 9 provides two detailed calculations of LCA for an Overhead Line. The first one covers a 154 kV overhead line build in Japan and was carried out using the LCA software "JEMAI – LCA". From this study, the WG recommend to reduce environmental impacts caused from OHL (excluding power transmission losses). The recycling of aluminium of the conductor seems the most effective way and efforts should continue in promoting aluminium recycling. Concerning transmission losses, the development of low resistance conductors seems an effective option. It should be noticed that this study was conducted based on the data mainly obtained in Japan and environmental impacts stemming from power transmission losses are largely influenced by its power generation sources.

In Denmark, as in Japan electricity production is largely based on fossil fuels. Their study show that only 0.3 per cent of the environmental impact of the Danish power system is related to the component of transmission overhead lines (Figure 6.20).

An interesting study, outside the WG, was presented in Cigré Paris C3 session 2012, Wang. W and A. Beroual, T. Mehiri, G. Tremouille 2012, *Life Cycle Assessment on a 765 kV AC transmission system*, Cigré Paris, Report C3-208 (Wang et al. 2012).

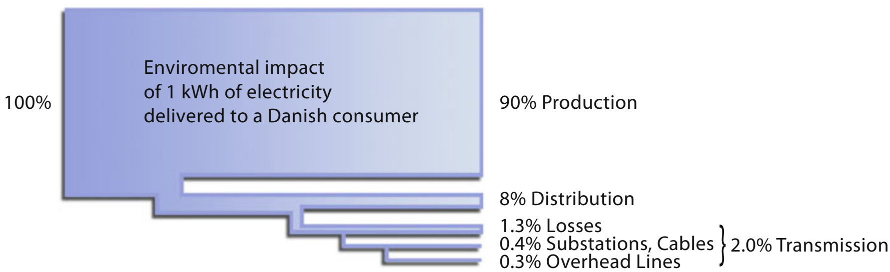

Figure 6.20 Breakdown of Environmental Impact of 1 kWh of Electricity delivered to a Danish Consumer.

In this paper, an LCA study was conducted, using SimaPro (one of the LCA software packages compared with two others in 6.6.4 above) on one 765 kV AC transmission system in Venezuela, with the aim of investigating the potential environmental impacts of a transmission system and locating the major sources of environmental burdens from one electrical transmission system.

The system consisted of the transmission lines, composed of conductors, ground wires, towers, foundations and insulators and the four substation fed by them. In the investigation of the substations, the considered components included major equipments such as power transformers, circuit breakers, current transformers, voltage transformers, shunt reactors, surge arresters, disconnects, etc, of course including their supporting frames and foundations; and constructions such as gantries, access roads, gravels in substations, etc.

Through the LCA study, it was shown that energy losses in transmission lines and power transformers and SF6 emissions of circuit breakers are the major sources of environmental impacts, while the materials production cannot be ignored.

6.6.7 Conclusions/Recommendations

Based on the work across the range of LCA issues investigated and informed by the studies undertaken within the working group and elsewhere, conclusions are presented in Cigré TB 265 and recommendations as given below were made.

- Life Cycle Assessment studies for overhead lines and overhead line components should be performed using the ***ISO 14040 Environmental Management - Life Cycle Assessment*** series. The goal and scope of any study, be it environmental reporting, product improvement or product comparison should be clearly set out, including identification of the intended audience.
- The product system and its boundaries must be properly defined and modelled. These will depend on whether the overall grid, an overhead line or overhead line components are being studied. This will also apply to the choice of functional unit and a relationship can be established between different units depending on the system boundaries.
- No matter which system is going to be analysed and how it is modelled, the allocation criteria should always be similar. Regardless of which product system is chosen, the representativeness of the population studied is one of the major requirements, if the results of the LCA study are to be taken seriously.
- With regard to Life Cycle Impact Assessment the choice of the impact categories to be considered should be justified in relation to the goal and should be initially included in the scope of the LCA study. The choice of characterisation indicators is critical at this stage.
- An LCA software package appropriate to the country or region in which the assessment is being performed should be used.
- The comparison between different LCA software packages shows that consistent results cannot be obtained, and there is little meaning in comparing the final

values of results derived from several different LCA software packages. Therefore taking differences between software packages into consideration, it is recommended that impact assessment comparison (such as a comparison between an original product and an improved one) should be carried out using the same LCA software.

- The overview of Overhead Line components showed that well established methods exist for recycling of some of the major overhead line components particularly steel towers and conductors. These methods should be availed of and efforts increased to recycle all overhead line components.
- Efforts should be made to keep the duration of Overhead Line construction to the minimum as significant environmental impacts can arise at this stage. It is recommended that Environmental Management Plans should be developed and used. If required by the authority or by the landowner, access roads should be removed and recycled. Maintenance activities should be organised and scheduled to eliminate or minimise environmental impact particularly painting of towers.
- The results of actual LCA studies carried out on some of the principal overhead line components lead to the following recommendations
  – To reduce environmental impact, especially to reduce resource exhaustion impact, it is strongly recommended that lattice steel towers should be recycled. It could reduce the amount of iron reserves consumption as well as zinc reserves consumption. Figure 6.21 shows Lattice Steel Tower impact on resource exhaustion for the different reserves as percentages within the total. In the case study, it was presumed that zinc is recycled; however recycling

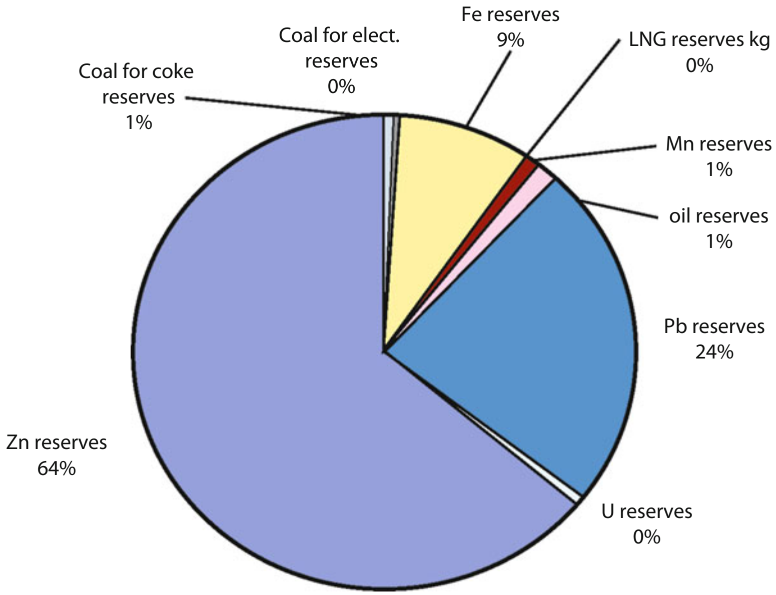

Figure 6.21 Lattice Steel Tower – Impact on Resource Exhaustion (Japan).

zinc is not as common as recycling steel. The extent of zinc deposits in the world is much less than those of iron and taking this situation into consideration it is also recommended that zinc recycling processing should be widely adopted.

- To reduce environmental impacts, such as gas emission related impacts as well as resource exhaustion impact, it is strongly recommended that conductors should be recycled. It is commonly known that the energy required for recycled aluminium is about 3 % of original aluminium production. The electrolysis process to extract alumina from bauxite for original aluminium production needs a large amount of electricity, while the aluminium recycling process basically consists of melting and moulding processes, which need less energy than the electrolysis process.
- Another way to reduce environmental impact is to reduce transmission losses. In this respect the development of low resistance conductor seems an effective way that could be recommended. Upgrading to a higher voltage power system may also seem to be effective; however a more comprehensive analysis of the whole power system would be needed to draw this conclusion.
- With regard to insulators only a small percentage of removed insulators are experimentally recycled as construction materials and a porcelain insulator recycling system is not fully established. Knowing that more energy is consumed in the insulator manufacturing processes of insulators than in the raw material manufacturing processes, establishment of the reuse of removed insulators as value added materials is desirable since material production itself for insulator production is not so energy consuming and it seems important to effectively reuse insulators which have already consumed energy in their manufacturing process.
- Another approach to reduce environmental impacts might be to extend the function as insulators as long as possible. In this respect development of efficient and reliable diagnostic methods as well as life span extension technology is recommended.

• The recommendations from the study on a 154 kV overhead line section in Japan reinforce those noted above.
  - To reduce environmental impacts caused from OHLs (excluding power transmission losses), recycling aluminium of the conductor seems the most effective way and it is recommended that efforts should continue in promoting aluminium recycling.
  - Furthermore in terms of natural resource preservation, recycling lattice towers especially zinc recycling, is effective. However zinc-recycling systems have not been established sufficiently compared to steel recycling systems, this might be another area to be focused on.
  - Concerning transmission losses, the development of low resistance conductors seems an effective option to recommend. Upgrading of OHLs to higher voltage ones might be another option, however further more detailed LCA studies, which would cover the broader power system, would be needed to conclude this.

  - It should be noted that this study was conducted based on the data obtained mainly in Japan and environmental impacts stemming from power transmission losses are largely influenced by its power generation sources. Knowing that, it is recommended that the situation (such as power generation sources) in each country should be reviewed when interpreting LCA results in each country.
- These are complemented by the recommendations from the Danish study on 1 km of 400 kV OHL which also included a comparative study on the use of new structure designs (single circuit) as against the traditional double circuit lattice steel tower design.
  - Using LCA studies to reduce the environmental impact requires an overview of the entity that the LCA study forms part of. This is particularly the case if a utility is willing to invest money in order to reduce the environmental impact. Otherwise, it is very likely that investment would not be made efficiently.
  - Technically, a reliable way to reduce the environmental impact from overhead lines is to ensure that a transmission tower is designed for two or more circuits. In this way the environmental impact related to concrete foundations and towers tends to be minimised per 1 kWh of electricity transported. New foundation design and construction could be another effective way to minimise the environmental impact.
  - LCA studies of components in the power system are still evolving. As far as models for the transmission grid are concerned results from the studies can be used as a supplement in evaluation of, for example, different types of towers or foundation technologies.
  - The lifetime of the different components of the overhead line should be estimated individually.
- The results of the study on the Venezuelan 765 kV transmission system points to the eco-design of a transmission system, that is to say, if ways to decrease a transmission system's environmental impacts are to be considered, focus should be put on the methods of reducing energy losses of conductors of transmission lines and power transformers and decreasing the SF6 emissions of circuit breakers. Besides, ways of minimising materials used in equipments are also beneficial to the reduction of environment load.

Life Cycle Assessment is a very valuable tool for overhead lines engineers, planners and utilities to assist in the evaluation of the impact or interaction of overhead lines and the environment. It can be used and developed across a range of applications from environmental reporting to product improvement and comparison. However it should be noted that its use has some restrictions.

LCA does not prioritise impacts; there is no differentiation between local impacts and those diluted in time and space. For instance it is not possible to differentiate between a large pollution over a short time period and smaller pollution over a longer period. It should also be noted that other tools and techniques exist to assess and reduce overhead line impacts on the environment and LCA results should always be evaluated in this broader context.

6.7 OHL and Sustainable Development

Taking account of the above Chapters on Overhead Line environmental impacts and mitigations, consultation models and Life Cycle Assessment the following may be stated with regard to Overhead Lines and Sustainable Development in the context of the three main pillars of sustainability: environmental protection, social progress and economic growth.

A transmission system allows the separation in space of electric power generation sites from consumption areas. A transmission network can use the advantage of a generation base which is widespread and diversified, and thus reduces the impact of generation on the environment. It is notable that an overhead transmission network enables easier and profitable use of renewable energies such as hydro and wind. Its structure allows the delivery of quality electrical power to each consumer safely.

This system optimises the use of generation, both nationally and internationally to ensure the balance between supply and demand at any time.. The meshed network pools power plants, optimises production costs and minimises environmental impacts including carrying a low carbon energy footprint (hydro, nuclear, wind, solar). The network is a link of solidarity that can accommodate renewable energy (wind in particular) which is not predictable enough to be operated independently of other energy sources.

The transmission network allows a fair distribution of electricity throughout a country which is essential for good development and regional planning. In this sense, the transmission grid is one of the pillars of sustainable development. Overhead Lines are (with underground cables and substations) the main component of the network and as such they make an important contribution to sustainable development.

- Only Overhead Line technology can design electricity transmission links with large capacities and capable of operating over long distances, in an economic fashion
- An Overhead Line can operate at high voltages in excess of 1 million volts, and allow several Giga Watt of power flow without increasing intensities and losses, A Direct Current (DC) OHL can carry many GW over several thousands of km. Comparative economics of OHL/UGC is favourable to OHL for the higher capacities (over 1 GW)
- An OHL project design takes into account the expectations of residents in addressing the following
  - A route is chosen after a consultation process, sensitive areas are avoided, suitable reduced impact designs are used and aesthetic towers as appropriate, 3D techniques are employed to ensure integration in the landscape.
  - Noise Reduction is ensured
  - EMF mitigation is applied
  - Row management is optimised
- In its operational phase, an OHL provides the expected performance in the long term and respects the environment. It ensures:
  - Low electrical losses,
  - Easy and fast fault location and fault repair

And the following are achieved
- Improved anticorrosion maintenance of supports
- Optimised vegetation maintenance of the row
- Increased biodiversity in the row

With appropriate maintenance and replacement of components or refurbishment, the life of an OHL can be greatly extended. Hence, an OHL is an asset that can be managed with flexibility. To maintain, refurbish or replace are all possible choices depending on the available resources of the society.

- An Overhead Line network can adapt to changes, even major work (with costs and difficulties being limited):
- The need to increase network transmission capacity due to increased consumption and new generation sites (wind farms) can be accommodated by refurbishment of Overhead Lines with the replacement of conductors, and strengthening of supports if necessary, or by voltage uprating.
  - If changes in climatic conditions or design philosophy have to be catered for towers can be strengthened mechanically.
  - In the case of a change of land use, an Overhead Line can be rerouted.
- Overhead Line materials are easily recycled at the end of life and have no significant residual impact.

The metals of towers and conductors can be fully recovered and recycled. The residual impact of an OHL is limited to foundations which consist mainly of neutral materials with respect to the ground (concrete).

6.8 Highlights

- Overhead Lines and Environmental Issues have been addressed within Cigré for many decades. Developments in a wide range of areas have been investigated and reported on. The ever present need for more efficient permit processes for overhead line projects and associated developments has been outlined.
- The emergence of Strategic Environmental Assessment and its broader role in ensuring sustainable development has been presented. Recommendations for its implementation are listed. The framework of Environmental Impact Assessment has been outlined and various broad guidelines given.
- Environmental Impacts of Overhead Lines and methods to mitigate them are described. In the case of visual impact this covers routing guidelines and mitigations for landscape as well as the development of reduced visual impact designs and aesthetic designs from across the globe.
- Impacts and mitigation measures and guidelines were presented for ecology and land use. The impacts of construction and maintenance of overhead lines are described and guidelines for their mitigation given. The development of Environmental Management Plans was pointed to.

- The impacts and mitigations of Fields, Corona and other elated phenomena were dealt with in regard to: Electric and Magnetic Fields, Research on Bio Effects and Alleged Health Effects, Electric and Magnetic Field Reduction, Noise and Interference and Atmospheric Chemistry. After more than 50 years of research on the subject of possible health impacts of ELF-EMFs, the scientific community could not provide any solid evidence about any health hazard on living organisms associated with a prolonged exposure to ELF-EMFs at a lower level than the international recommendations.
- The pressing requirements for gaining public and community acceptance of overhead lines have been described. Concerns and issues facing utilities and TSOs have been given. Methodologies of community and landowner consultation and stakeholder engagement have been presented. Examples of good practice consultation models and guidelines on stakeholder engagement polices have been given.
- The work done on Life Cycle Assessment was summarised in the following areas: early applications, power system and overhead lines LCA in Scandinavia, comparison of LCA software, LCA, overview for OHL components, construction and maintenance and LCA, studies on OHL. Conclusions/Recommendations were presented.
- The benefits of Overhead Lines and transmission networks in contributing to sustainable development have been summarised. It can certainly be said that over recent decades there has been a high level of development on all issues associated with Overhead Lines and Environmental Issues by Cigré, utilities and TSOs, resulting in improved processes, minimisation and mitigation of environmental impacts and continuous efforts to gain acceptance for overhead lines.

6.9 Outlook

- Overhead Lines Environmental Issues will continue to be of prime importance and indeed it can be forecast that they will increasingly dominate in many projects.
- Strategic Environmental Assessment (SEAs) studies will grow and develop. SEAs will be strategic and comprehensive studies and increasingly will be included in national and regional long-term plans both for generation and transmission. Modelling tools will be developed to support the analysis of policies and plans, as well as decision making.
- Regulatory regimes will continue to evolve in response to the urgent need to streamline processes. The use of community compensation schemes and commitments to reduce overall impact of networks will increase.
- Efforts will both continue and increase to mitigate the overall visual impact of overhead lines and more companies will introduce reduced visual impact designs or new aesthetic overhead line designs.
- Increased efforts will be made to further reduce and mitigate overhead line impacts on ecological systems and land use. Use will be made of Environmental Management Plans.

- With regard to EMF and Corona phenomena the expectations of society regarding the increase of its standard of living have to be taken into consideration by TSOs. EMF and disturbances related to Corona phenomena may be important concerns for people living in the vicinity of overhead transmission lines.
- These electric phenomena are currently taken into account by TSOs, by studying new transmission line designs which increase the fields compensation, or by working with manufacturers on new materials in order to decrease the Corona activity. Another aspect which is being developed by TSOs is the pedagogical approach on these particular subjects. The way to communicate (e.g. websites or dialogues with residents living close to the line) will be one of the keys to improve the acceptance of power lines.
- Consultation Models will be developed which will see companies undertake more consultation than required by legislation. They will conduct open and engaging consultation with a broad range of representative and interested groups.
- Companies will have to be pro-active in dealing with opposition and must give immediate information on issues related to EMF/Health, visual impact mitigation and nature conservation management.
- Electricity organisations will increasingly recognise the benefit of stakeholder engagement, not only because of their commitments to sustainable development, but for the benefit of electricity infrastructure projects themselves, and for all the benefits of building relationships with key environmental and citizen organisations.
- Many companies will clearly recognise the business and reputational risks that come from poor stakeholder relations, and place a growing emphasis on social responsibility and transparency and reporting. In this context, good stakeholder relations will be a prerequisite for good risk management.
- More companies are likely to undertake Life Cycle Assessment and to appreciate that it is a very valuable tool for overhead lines engineers, planners and utilities to assist in the evaluation of the impact or interaction of overhead lines and the environment.
- There will be an increasing appreciation of the role of Overhead Line networks in ensuring sustainable development.
- Cigré Study Committees and working groups will be active in supporting all the above developments.

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Cathal Ó Luain has a B.E. (1st Hons.) and an M. Eng. Sc. from University College Dublin, National University of Ireland. He worked for many decades with ESB (Ireland)/ESB International on home and overseas projects in a variety of roles: 400 kV OHL Construction Manager, OHL Design Specialist, PM for OHL/Substation projects in both permitting and construction phases and OHL Design and Engineering Manager. He has since worked with Azorom and with Fichtner Consulting Engineering (Stuttgart). He is now an OHL Consultant. He joined Cigré OHL Study Committee in 1986 and has served as working group secretary, convenor of two working groups, special reporter, Irish national B2 member and convenor of the Customer Advisory Group. He has authored various papers and contributed to and directed the production of technical brochures on OHLs and Environmental Impacts and Mitigation, Life Cycle Assessment for OHLs and Consultant Models for OHL Projects. He is a Distinguished Member of Cigré and a member of Engineers, Ireland.

Lionel Figueroa has a master's degree in electrical engineering. He is a member of Cigré, and is particularly involved in WGs related to EMF and GPR. He is also involved in the European Committee for Electrotechnical standardization (CENELEC). He is employed as an engineer in RTE, the French transmission system operator.

Paul Penserini was born in 1962. He has a graduate background in Civil Engineering and Structural Engineering from Ecole Normale Supérieure de Cachan. He received the PhD degree from University Pierre et Marie Curie, Paris, in 1990, in structural engineering. He has been manager at EDF R&D in charge of the Renardières Electical Laboratories. This Lab is operating tests and research in the field of underground lines, batteries, substation and IT equipment. Currently, he manages the expertise and research Department in the field of Transmission Lines at Rte. He has been contributing to Cigré and Jicable for many years.

Overhead Lines and Weather 7

Svein Fikke

Contents

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S. Fikke (✉)
Lørenskog, Oslo, Norway
e-mail: fikke@metconsult.no

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7.1 Introduction

Electric overhead lines are built and run through any type of terrain, from the maritime coast to the continental inland, from sea level to high mountains, and also in some of the most challenging climate zones of the world from rain forests to deserts, from tropical zones to the arctic. They are exposed to a wide variety of weather impacts like bush fires, extreme heat, sandstorms, typhoons, tornadoes, lightning, extratropical weather systems, sprays of sea salt, freezing rain, rime icing, wet snow, floods, etc. It is therefore of critical significance that such lines are designed in a secure manner to be prepared for any type of weather event and impact which otherwise could disrupt their reliable operation and cut off the expected supply of electric power to the society at its delivery point. On the other hand, it is likewise important that such lines are not built stronger and more expensively than they need to be, in order not to overinvest in more security than needed and also to avoid structures that are much heavier and visually more predominant than the public can or will accept.

There are many design codes and standards available for buildings and structures to cover loadings from strong winds, snow on ground, earthquakes, etc. (See for instance: ASCE (2009), CAN/CSA (2010), EPRI (2008), IEC TR 60826 (2003), NESC (2007), AS/NZ (1999) and the series of CEN EN 1991–1 for Europe.). Such codes and standards are likewise applicable for individual towers and masts for electric overhead lines. However, most of these building codes are developed for singular buildings or structures located in populated areas where adequate environmental data are available. Electric overhead lines frequently run through very remote and complex terrain where such conventional standards and codes have limited relevance. Accordingly, international standardisation bodies for the electric power industries (IEC, CENELEC, ASCE, AS/NZS and others), as well as many countries with particular needs, have established international and national codes to cover most of the needs for the development of their electric overhead grids. It is still however especially important to have a critical view on local weather effects along the line routes and what additional information and data are needed when a line is planned through unknown terrain where little or no adequate experiences may exist.

Such topics have been addressed by many Cigré SC B2 working groups for many decades. Especially the development of the IEC TR 60826 “Designing criteria for overhead transmission lines” has focused on the variety of environmental influences on design and operation of electric overhead power lines. This chapter is focusing on the learning from several Cigré TB, especially those dealing with atmospheric icing and various wind phenomena with particular reference to overhead lines in exposed terrain and climate.

Intentionally, this chapter contains only few references to standards, design codes, textbooks, etc., except current Cigré publications with some updates. This is mainly because, like many other fields of science, the science of meteorology is developing very fast, most due to the rapid increase in computer capacities together with direct and remote measurement technologies, especially from automatic sensors, weather radars, satellites, etc. Hence, the 3-dimensional physical and dynamical models of the Earth system, consisting of oceans, atmosphere and cryosphere (floating ice and glaciers) are constantly improving, leading to better weather forecasts and analyses, indeed also for the atmospheric boundary layer in complex mountain terrain.

Table 7.1 Cigré TB which have been used as background documents for this chapter

TB	*WG*	*Title*
179	22.06.01	Guidelines for field measurement of ice loadings on overhead line conductors (2001)
256	B2.16	Report on current practices regarding frequencies and magnitude of high intensity winds (2004)
291	B2.16	Guidelines for meteorological icing models, statistical methods and topographical effects (2006)
299	B2.12	Guide for selection of weather parameters for bare overhead conductor ratings (2006)
350	B2.06.09	How overhead lines respond to localized high intensity winds (2008)
410	B2.16	Local wind speed-up on overhead lines for special terrain features (2010)
438	B2.29	Systems for prediction and monitoring of ice shedding, anti-icing and de-icing for overhead power line conductors and ground wires (2010)
	B2.28	Meteorological data and analyses for assessing climatic loads on OHLs (Cigré TB 645, 2015)
485	B2.29	Overhead Line Design Guidelines for Mitigation of Severe Storm Damage (2014)

This chapter therefore deals with the main topics of weather impacts on overhead lines in more general terms, and referring to Cigré SCB2 TB where more information is found. For more specific questions and applications the reader is recommended to identify necessary updates at national weather services in order to be updated on particular needs, if they are not otherwise found in newer Cigré publications.

The main Cigré TBs referred to in this chapter are listed in Table 7.1.

This chapter does not discuss other second order effects from extreme weather, like heat waves, bush fires, floods, avalanches, lightning, sea salt, desert dust, etc., as these phenomena are treated elsewhere in both in Cigré SCs and National codes. A short comment on the combined effect of icing and pollution is however given.

Finally, this chapter summarizes some updated knowledge on global change issues relevant for overhead lines.

7.2 Wind

7.2.1 Overview

Many different wind systems are prevailing over the earth, depending on geographical location and differences in topography. Many of these wind systems have different names according to local or regional practices, but are often physically of similar nature. According to Cigré B2 TB 256 “Report on current practices regarding frequencies and magnitude of high intensity winds” (2004) the most characteristic wind systems are described as:

- Synoptic or extratropical storms
- (Sub-) Tropical wind systems, such as tropical cyclones, hurricanes, typhoons, etc.

- High intensity winds related to well-developed thunderstorms (supercells) tornadoes, twisters, downbursts, etc.
- Special wind systems, such as katabatic winds, bora, föhn, etc.

Especially in complex or mountainous (alpine) terrain the topography will influence both the mean wind speeds and the turbulence of the wind flow. Such topics are dealt with in Cigré TB 410 "Local wind speed-up on overhead lines for special terrain features" (2010). A particular feature not commonly recognised is that the gust wind speeds will often be higher on the leeward side of a steep mountain side compared to the windward side or over flat terrain. This phenomenon has taken down many power lines and buildings where such damages were not expected.

All these wind patterns are dealt with in these Cigré TBs, and their main topics are summarized in this chapter.

An important issue for dynamic line rating (DLR) is low wind speed and its related thermally driven turbulence. This is not yet (2014) fully treated in a Cigré TB. However, this is an example where there is on-going research in many countries. Therefore it is recommended to seek updated information at the time when such knowledge should be needed.

7.2.2 Extratropical Cyclones (after Cigré TB 256)

Extratropical storms, or polar front cyclones, are formed on the "Polar front" which persists as a sharp divide into the atmosphere between cold, arctic air on the polar side and warmer and more humid air on the tropical side. This frontal divide is circumpolar, in general undulating around 60° on the northern hemisphere. (It is connected to the "jet stream" in the higher atmosphere.) The polar front is normally in a situation of unstable equilibrium (like a small ball resting on the top of a larger ball.) Following a disturbance on this front, a cyclone, or low pressure system, is formed where the warm, sub-tropical air penetrates as a wedge (warm sector) into the colder air mass and slides over the colder, downwind air (warm front), like sliding up on an inclined plane. On the rear side, the colder air penetrates into the warmer air like a sail (cold front). Simultaneously the air pressure near the surface of the earth is lowered.

A typical example of such a system is illustrated in Figure 7.1.

The diameter of these cyclonic systems ranges between 500 and 3000 km, the smaller ones being often the most intense. In the North Atlantic region they start as small disturbances outside the eastern coast of North America and reach the strongest stage usually as they reach the north-eastern side of the Atlantic and the coastal states of northern Europe from France to the Nordic countries.

The wind then blows counter clock-wise around the depression in the northern hemisphere, and clockwise in the southern, with a minor component towards the centre due to the friction forces from the surface. The stronger the pressure gradient is (from the centre of the depression to the surrounding air), the stronger is the wind speed.

These systems move in a general West to East direction and increase in translation speed as they develop, often achieving translation speeds up to 40 km/hour. The

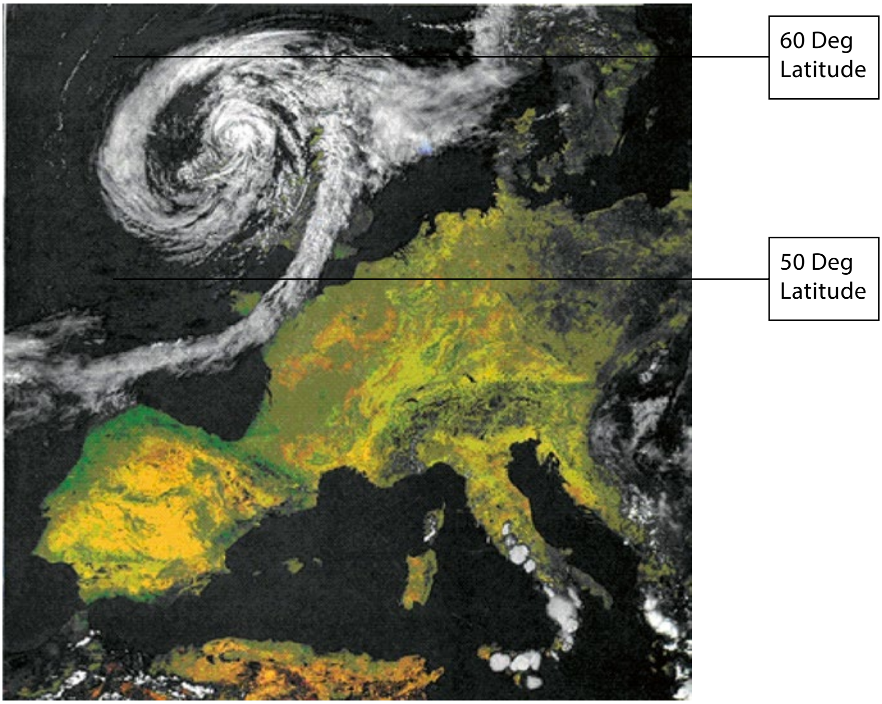


Figure 7.1 Satellite Image of Extratropical Storm in Northern Europe. The low pressure centre is over Ireland, while the warm front lies over Southern Norway and the cold front stretches over the British Channel, Bretagne and the Bay of Biscay. Thunderstorm activity is also evident over Italy (Photograph Ref Munich RE).

most gusty winds occur along the cold front, where a sharp change in wind direction often also is found (from WSW to NW on the northern hemisphere and from WSW to SW on the southern hemisphere). Also very intense shower clouds (Cumulonimbus, sometimes with thunderstorm cells) form along this cold front.

The energy connected to such fronts is connected to both the jet stream aloft and the sea temperature. The most intense cyclones occur in the months of October to January in the northern hemisphere. The gust wind speeds may exceed 50 to 60 m/s over sea or exposed land areas, mostly in northern regions.

Storm fronts that develop in the southern Antarctic ocean region occur over more expansive areas of ocean at low temperature, and as such tend to be predominately frontal rather that cyclonic. The impact of these southern storm fronts, with wind velocities in the range indicated above, are limited to those land masses around latitude 40 degree S.

Within the western Pacific Region, the Japanese Archipelago is located in the boundary of cold air and warm air currents, and strong winds from extratropical cyclones can also be frequently observed, but wind velocities under such a situation are significantly lower than those of typhoons that also occur.

Due to the large extension of such wind systems they are easily identified by regular meteorological observation networks ("synoptic scale") as well as by the regular weather forecasting models. Accordingly, where such wind systems are prevailing, there are generally well developed statistics for wind speeds and wind directions available for mechanical design of electrical overhead lines as well as for other structures on National levels.

7.2.3 (Sub-)Tropical Wind Systems

Tropical cyclones/hurricanes and hurricanes are also of "synoptic scale" and have potentially very severe low pressure weather systems that affect the tropical coastal regions during the summer months. The strict definition of a tropical cyclone (WMO 1995) is:

> *A non-frontal cyclone of synoptic scale developing over tropical waters and having a definite organized wind circulation with average wind of 34 knots (17.5 m/s) or more surrounding the sustained winds at the centre.*

The tropical cyclone is an intense tropical low pressure weather system where, in the southern hemisphere, winds circulate clockwise around the centre. In Australia, such systems are upgraded to severe tropical cyclone status (referred to as hurricanes or typhoons in some countries) when average, or sustained, surface wind speeds exceed 34 m/s. The accompanying shorter-period destructive wind gusts are often 50 per cent or more higher than this value. These high winds have a buffeting characteristic where the level of 'gustiness' can last for several hours from one direction, only to be followed shortly afterwards by winds of a similar but marginally less magnitude from the opposite direction as the eye of the storm passes a given point.

There are three components of these tropical events that combine to make up the total hazard - strong winds, intense rainfall and induced ocean effects including extreme waves, currents, storm surge and resulting storm tide. The destructive force of these storms is usually expressed in terms of the strongest wind gusts experienced. Maximum wind gust is related to the central pressure and structure of the system, whilst extreme waves and storm surge, are linked more closely to the combination of the mean surface winds, central pressure and regional bathymetry. Satellite photos of tropical cyclone "Fran" approaching Queensland, Australia, in March 1992 is shown in Figure 7.2, and typhoon "Lupi" approaching the coasts of Korea and Japan on 02 December 2003 is shown in Figure 7.3.

Hurricanes in the American region have similar characteristics to those in the Pacific. Experience in recent times in the eastern coastal region of the USA around the state of Florida resulted in significant damage to infrastructure. As an example a satellite photo of the hurricane Katrina, which caused catastrophic damage in New Orleans in August 2005, is shown in Figure 7.4.

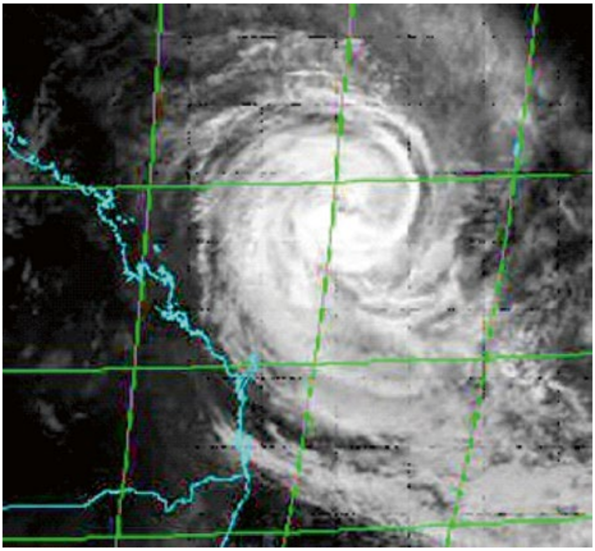


Figure 7.2 Tropical cyclone Fran approaching the Queensland coast in March 1992. Note the clockwise rotation on the Southern Hemisphere (Photograph Bureau of Meteorology – Australia).

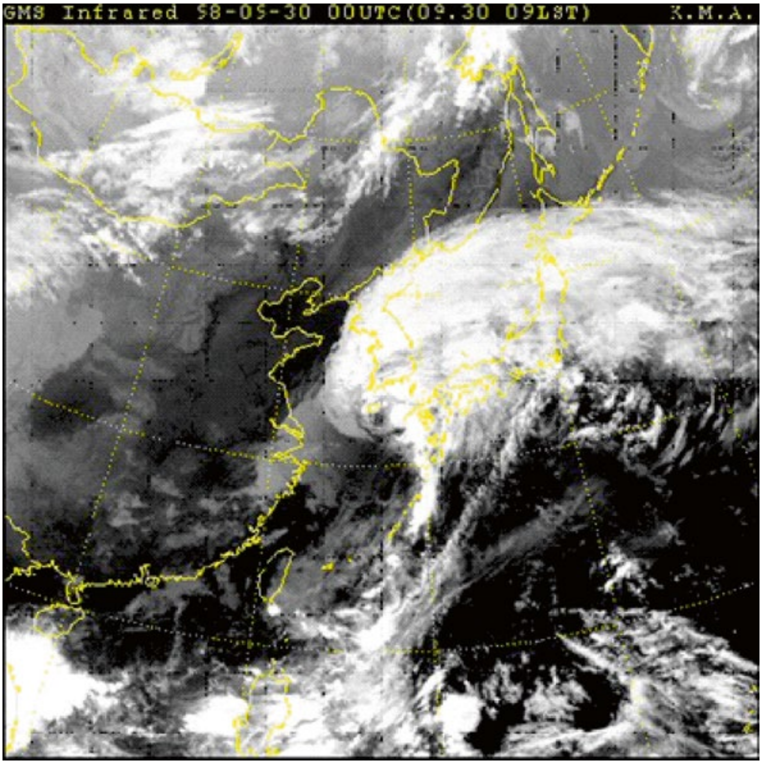


Figure 7.3 Satellite image of Typhoon "Lupi" 2 December 2003 approaching the coasts of Korea and Japan.

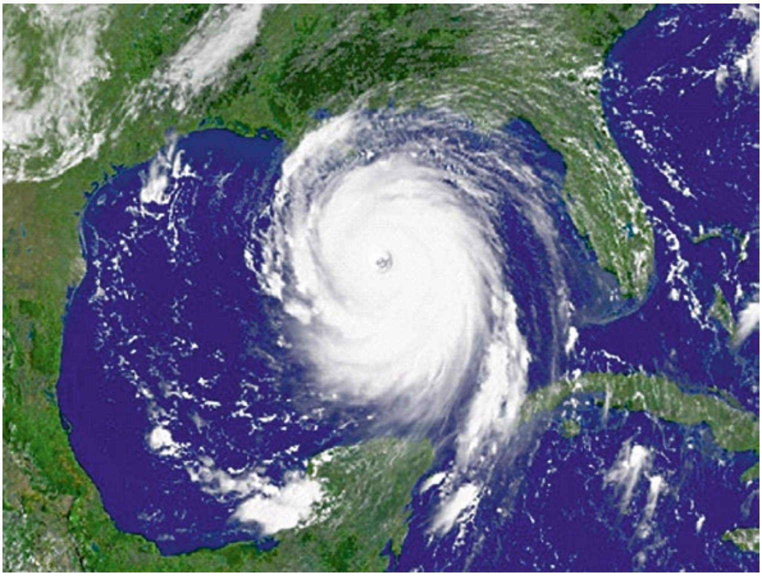


Figure 7.4 Satellite photo of Hurricane Katrina in the Gulf of Mexico, August 2005. Highest wind speed recorded: 280 km/hr, or nearly 80 m/s (Wikipedia).

7.2.4 High Intensity Winds Connected to Thunderstorms

Thunderstorms form in very unstable air masses, with cold air high up in the atmosphere and warm and humid air prevails near the surface of the Earth. When warm air start to “bubble” upwards from the surface it is cooled at the so-called adiabatic laps rate (0,98 °C/100 m for dry air) up to a level where the water vapour condenses, and a cloud is formed above. This condensation releases the “latent heat of evaporation” and this heat will slow down the lapse rate, and hence the air “bubble” will be even warmer than the surrounding air, and accordingly increase its vertical velocity. To compensate for the “lack” of air near ground, there will also be a strong downward wind within the cell (down-draughts). This is the basic principle of formation of a cumulonimbus cloud. Figure 5 shows a sketch of such a well developed thunderstorm cell.

As indicated in Figure 7.5, funnel clouds and eventually tornadoes may develop underneath the leading edge of such a thunderstorm. The visible funnel actually develops from ground, when dust is sucked upwards, or water vapour condenses on its way upwards. The strong winds connected to such tornadoes have a much wider diameter than the visible funnel itself. One example of a tornado with a visible funnel cloud is shown in Figure 7.6.

Well developed thunderstorms are also associated with strong circulating winds around the cell near the ground (clock-wise in the Southern Hemisphere and counter clock-wise in the Northern). However, except for the tornadoes, the strongest wind gusts are often connected to gust fronts connected to the strong down-draughts (down-bursts) as indicated in Figure 7.5.

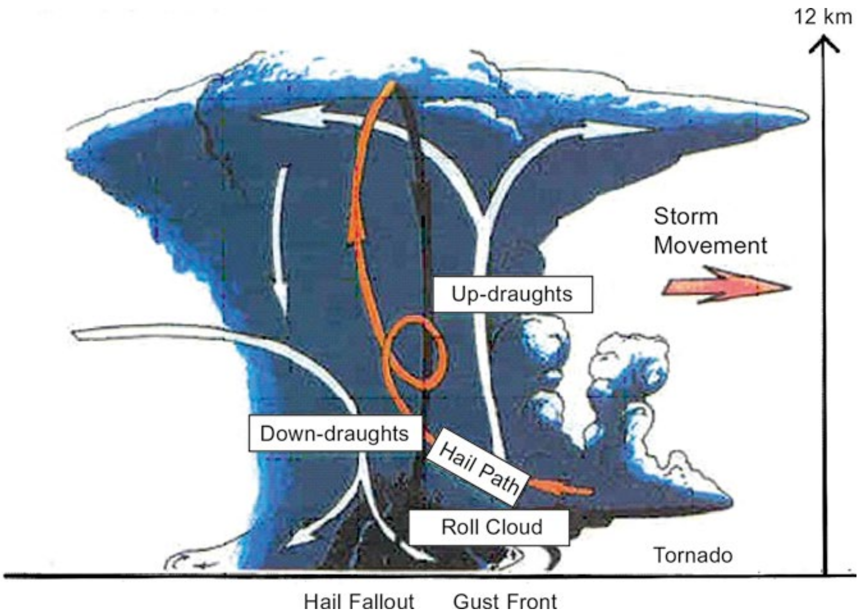


Figure 7.5 Schematic illustration of a mature supercell thunderstorm (Courtesy of Bureau of Meteorology, Australia).

Figure 7.6 Typical funnel cloud associated with a tornado (Photo: Bureau of Meteorology, Australia).

Due to the small horizontal scale of such phenomena there are generally very limited data for wind speeds associated with tornadoes. Also, they strike at different locations from time to time, and therefore it is very difficult to establish ordinary extreme wind statistics for design purposes of such winds. Due to the catastrophic damages such winds often are connected with, there is generally no demand or wish either to design overhead lines to withstand such wind forces, but rather to handle the consequences resulting from them in other manners. Countries where such winds occur have therefore developed their own procedures for such consequences these may have on their overhead line networks. See (Cigré TB 256) and (Cigré TB 350) for more details.

Cigré TB 256 also contains classification of these kinds of winds as they are defined in many countries.

7.2.5 Special Wind Systems (after Cigré TB 256)

Other sub-synoptic wind systems are frequently formed on the surface of the Earth, mostly due to strong temperature gradients, either vertically from ground surface and upwards, or horizontally along the surface when cold air may be trapped in (often high level) basins.

Small scale, tornado-like "dust devils" often occur over heated land surface, especially in the afternoon, in tropical or sub-tropical areas when intense sunshine on dry ground has created a strong thermal instability in the lowest 1–200 m of the atmosphere. Although these may reach high wind speeds near their centres, they seldom create significant damage due to their limited extension.

Another phenomenon, similar in principle, often occurs in the Arctic when cold air masses flow out from the arctic ice cover over the open sea in the North Atlantic and Polar Basin. Here the temperature differences may easily be more than 40 °C, and this may give rise to instability depressions in those areas. The wind speeds may be very high in these depressions and therefore cause severe damage to fishing vessels operating in such waters, and they may also hit the coasts of the Northern countries. Nowadays they are detected by satellites and are therefore better forecasted.

Under certain conditions of atmospheric stability, so-called katabatic winds occur in Alpine regions, both in Europe, South America, New Zealand, and other regions with similar charactersitics (Cigré TB 256). Katabatic winds develop on the leeward side of mountains and ridges where the air mass approaching on the windward side is colder than that on the leeward side. Due to its higher density the cold air plunges down from the ridge of a mountain range into the valley below, and can develop speeds of up to 60 m/s in extreme cases, and have devastating effects on overhead lines hit by them. The wind velocity of these winds increases with temperature differentials and mountain or fall height. The velocity is also increased when the wind currents are in the same direction.

One example of such a katabatic wind is in South Eastern Europe called *Bora*. Figure 7.7 shows an example the action of such a wind on an overhead line in Croatia.

Another well-known wind system of the same nature in mountain regions is the föhn wind. A characteristic property of föhn wind is that moist air is lifted over a mountain range where the water vapour is condensed and rains out on the windward side and hence releases the latent heat of condensation, while on the leeward side the air subsides at the dry adiabatic lapse rate and accordingly the air may be much warmer on this side. The föhn wind may also be relatively strong on the leeward side.

Figure 7.7 Conductors blow out during a Bora event in Croatia, January 2003. From Cigré TB 256 (Photo: F. Jakl).

7.2.6 Topographical Effects

Standard codes for wind engineering and design of structures include general rules for speed-up of winds over hills and escarpments and will provide the general wind engineering requirements for design of electrical overhead power lines. They consider mostly homogenous terrain, of various roughness factors, and certain idealised topographical features of two dimensions. There are however limitations for the application of these general rules for treating extreme terrain roughness, predominant hill forms and escarpments, such as many high and steep hills, mountains, valleys and fjords. As many overhead lines in mountain terrain will experience particular, and mostly unexpected, impacts of such phenomena it is important to improve the knowledge of them and how they may interact with an overhead line. Such topographic features may have length scales ranging from a few tens of metres up to several km.

Gust factors in the range of 1.8 - 1.9 (relative to 10 minute mean wind) may apply for wind speeds in such areas at 10 m height above ground. For comparison it can be mentioned that observations of high wind damage during tropical cyclones in Northern Queensland indicate that speed-up effects can also occur during high winds on the upper slopes and crests of coastal mountain range escarpments. Analysis of damage patterns suggest a speed-up of 20 % can occur frequently. The upper level of amplification of this speed-up is dependent on the escarpment slope profile, height and basic wind velocity. The AS/NZS 1170.2 Wind Actions (1999) provides for values of up to 50 %.

The introduction of probabilistic methods has especially encouraged more direct knowledge of any impact of nature on overhead lines.

Some examples of wind enhancements are found in places like:

- over hill crests
- near sharp edges (escarpments) exposed to high level winds over surrounding terrain
- behind elongated mountains (rotor formation)
- behind steep mountain sides (or edges) where particular turbulence may be formed (vortex "streets").
- on the side of hills and mountains (corner effect)
- in valleys (including converging mountains) or fjords where the airflow may be compressed locally (funnelling effect)
- katabatic winds like föhn and bora.

The wind enhancement over hill crests and escarpments are mostly implemented in standard wind codes. These phenomena are based on mechanical flow patterns. Aerodynamical phenomena such as rotors and vortex shedding (streets) are generally not considered in wind codes, although their magnitude may be very substantial. Some of these phenomena are very site specific and can hardly be treated in a wind code format. It was the intention of Cigré TB 410 "Local wind speed-up on overhead lines for specific terrain features" (WG B2.16, April 2010) to give a physical background for some of them and also to suggest a generalized method to handle vortex streets behind steep mountains.

Two well-known examples of small scale dynamic features are also referred to in Cigré TB 410, namely the leeward screw formed rotor behind the Rock of Gibraltar shown in Figure 7.8. In South-westerly winds this rotor introduces a strong perpendicular wind over the runway of the Gibraltar airport (point "B" in Figure 7.8), and also creates dangerous turbulence for low flying aircraft in that area.

Another example is from the island Ailsa Craig in the Firth of Clyde in Scotland, see Figure 7.9. This island is a bit elongated and the highest point is about 350 m.

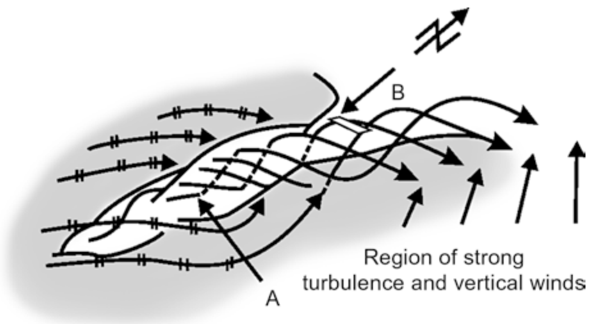
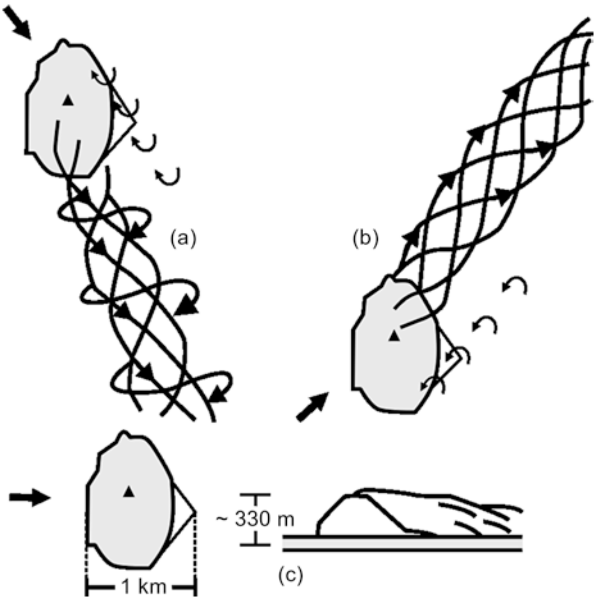


Figure 7.8 A leeward screw formed rotor from the Rock of Gibraltar.

Figure 7.9 A screw formed vortex street behind Ailsa Craig, Scotland.



The figure shows how vortex streets are formed in North-westerly winds and also South-westerly winds, causing difficult sailing conditions for smaller vessels on the Eastern side of the island. When there is a westerly wind only increased regular turbulence is experienced.

In order to determine the wind speed along an electric overhead line running in such terrain where significant vortex shedding may occur, it is necessary to evaluate point values that may significantly influence the wind speed at certain construction sites (tower or span) along the line on the leeward side of a steep hillside. An example is shown of a terrain with a steep side along a ridge in Figure 7.10. The topography is outlined with contour lines and locations relative to the construction point, P. Across the mountain ridge a cross section is described in Cigré TB 410 where the maximum declination angle $\alpha\max(\theta) > 30°$ occurs within specific sectors. The limiting cross sections are therefore defined to be located where the declination angle of the terrain is crossing this value of 30°. Eight main directions of the wind (N, NE, E, SE, S, SW, W and NW) are used to determine the wind at the specific site.

Such wind phenomena are well known from many countries, and TB 410 refers to Japan, New Zealand, Iceland and Norway, however scarcely reported in literature. It is also known from the mountainous island of Tenerife (Red Electrica, personal communication).

It is beyond the scope of this chapter to give a complete set of instructions how to deal with such winds, and the reader is referred to Cigré TB 410 for further information. However, a brief application example from the TB 410 is summarised in the following.

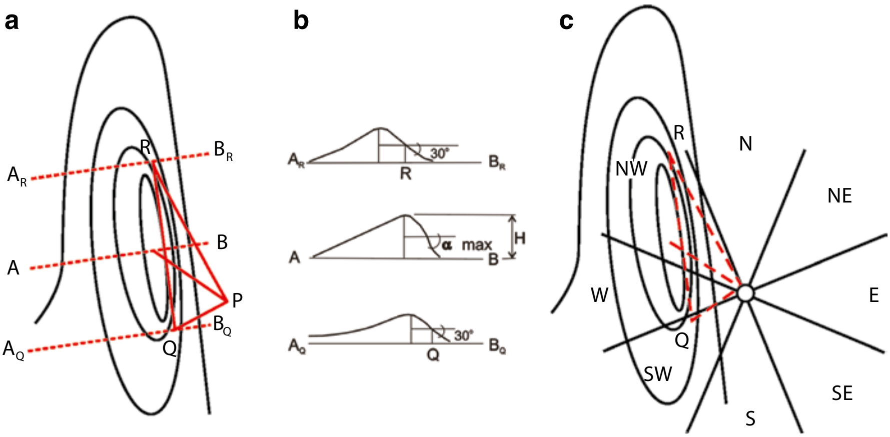


Figure 7.10 Example of steep terrain (*grey contour lines*) with possible wind gust enhancements at a construction point P. (**a**) shows the map, (**b**) vertical cross sections at three different sections, and (**c**) map with directional sectors seen from P.

Figure 7.11 shows the right-of-way of a new 132 kV line from a planned wind farm on an island in Northern Norway. This island is known to have extreme wind conditions, in particular behind the steep and sharp mountains on the island. The map shows that there are two areas with such rugged mountains, one in the northern part (points 1–2) and another and bigger in the southern part (points 3–4), on the windward side relative to the transmission line. In between them there is a plain area where the line is fully open to the Norwegian Sea towards west (left in the map).

The northern part consists of mountains mostly in the 200–300 m levels, but some peak up to the 400–500 m level. The southern part consists of somewhat higher peaks. Several of them are above 600 m asl.

The distances between the steep mountain sides and the line are typically 1–4 km.

The standard reference 10 minute average wind, 10 m above ground, is given by the wind code to be 29 m/s for this area. By applying the method described in Cigré TB 410 gust wind speeds of 55 m/s may be expected at 10 m height and 60 m/s at 20 m height in those areas where vortex streets may occur (1–2 and 3–4 in the map).

Further and updated information will be available in a new report from Cigré WG B2.28 on "Meteorological data and analyses for assessing climatic loads on OHLs" (Cigré TB 645, 2015).

7.3 Atmospheric Icing

7.3.1 Overview

Atmospheric icing may often be the most important single parameter for mechanical design of overhead lines, and also the most important weather element for disturbances in the operation of electric networks. A recent (February 2014) example

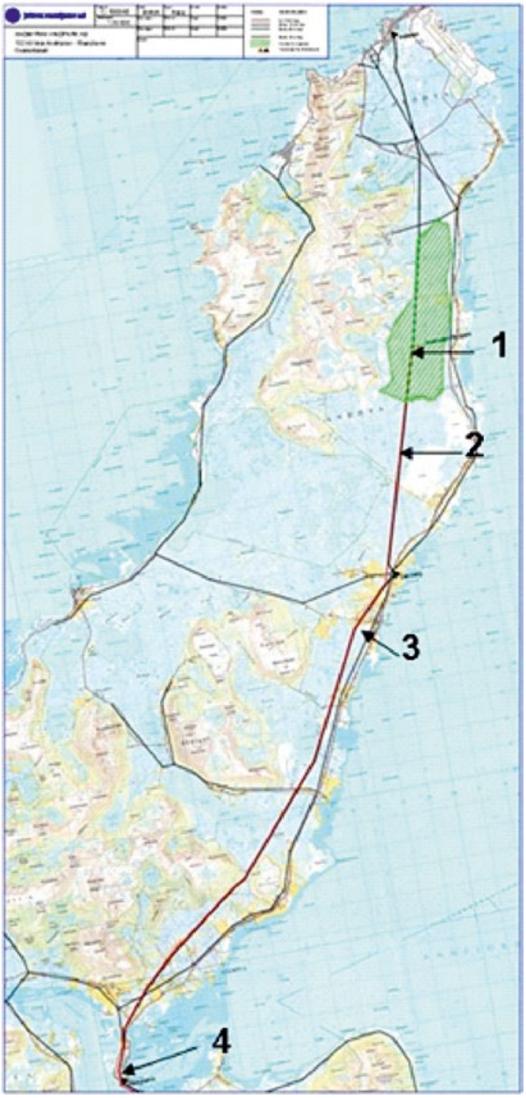


Figure 7.11 Right-of-way for a 132 kV line (*red line*) from a planned wind turbine park (Point 1) to a substation at Point 4. (The map is provided by the engineering company Jøsok Posjekt AS, Bergen, Norway.)

from Slovenia is shown in Figure 7.12. The Slovenian costs resulting from this icing storm damage was estimated to about € 500 million (F. Jakl, personal communication).

An example of rime icing from a high level mountain (1 400 m above sea level) is shown in Figure 7.13.

Atmospheric icing is described in great details in the Cigré TB 291 "Guidelines for meteorological icing models, statistical methods and topographical effects" (WG B2.16.03, 2006) and Cigré TB 179 "Guidelines for field measurements of ice loadings on overhead line conductors" (WG 22.06.01, 2001). It will also be updated

Figure 7.12 Freezing rain event in Slovenia February 2014 (Photo: F. Jakl).

Figure 7.13 Rime icing on a 420 kV line in Norway, 1400 m above sea level (Photo: S.E. Hagen).

with more recent knowledge and additional information in a new report from Cigré WG B2.28 on "Meteorological data and analyses for assessing climatic loads on OHLs" (soon to be published). The European COST Action 727 "Atmospheric icing on structures" have delivered a state-of-the-art report on atmospheric icing in Europe (Fikke et al. 2006).

7.3.2 Icing Processes

Atmospheric icing is a general term for several types of ice accretion as described in details in (Cigré TB 179) and (Cigré TB 291). Atmospheric icing includes in-cloud icing (hard rime and soft rime), precipitation icing (wet snow and freezing rain) and hoar frost. Often ice accretion is a mixture of two or more types (soft rime, hard rime and wet snow) depending on variations in the meteorological parameters during the icing event. Various shapes, densities, adhesion strengths, etc. result accordingly, see Table 7.2.

Glaze ice occurs in a temperature inversion situation in valleys on calm warm fronts. Raindrops in the warm (above 0 °C) air region can fall through a few hundred meters of sub-zero air to ground level. The raindrops are then super-cooled, i.e. still in the liquid phase but at sub-zero temperatures e.g. −1 to −5 °C.

On contact with a physical object, which may be an overhead line or tower structure, the raindrops freeze rapidly with virtually no trapped air within the accretion. Glaze icing produces the densest form of icing – a typical density being 900 kg/

Table 7.2 Classification of ice types with typical density ranges (Cigré TB 179)

Ice and snow type	Density (kg/m^3)	Description
Glaze ice	700–900	Pure solid ice, sometimes icicles underneath the wires. The density may vary with the content of air bubbles. Very strong adhesion and difficult to knock off.
Hard rime	300–700	Homogenous structure with inclusions of air bubbles. Pennant shaped against the wind on stiff objects, more or less circular on flexible cables. Strong adhesion and more or less difficult to knock off, even with a hammer.
Soft rime	150–300	Granular structure, "feather-like" or "cauliflower-like". Pennant shaped also on flexible wires. Can be removed by hand.
Wet snow	100–850	Various shapes and structures are possible, mainly dependent on wind speed and torsional stiffness of the conductor. When the temperature is close to zero it may have a high content of liquid water, slide to the bottom side of the object and slip off easily. If the temperature drops after the accretion, the adhesion strength may be very strong.
Dry snow	50–100	Very light pack of regular snow. Various shapes and structures are possible, very easy to remove by shaking of wires.
Hoar frost	<100	Crystal structure (needle like). Low adhesion, can be blown off.

m³ – and high ice loads are reached within hours. Icicles are often seen below the conductors as the raindrops freeze as they run off the lines. A typical picture of glaze ice is shown in Figure 7.14. The widely reported Canadian ice storm of January 1998 was due to glaze icing. Glaze icing may also result from in-cloud icing when the in-flux of cloud water is very high (Poots 1996).

Rime ice accretion occurs when small, super cooled water droplets (~10 μm) travel along with the wind flow in temperatures typically below −5 °C, and freeze spontaneously on contact with a physical body. The accretion formed is often strongly asymmetric with leading vanes into the wind direction, see Figure 7.15). This type of icing is often referred to as "in-cloud" icing and is common in hilly areas over the cloud base. The density of rime varies depending on the size and speed with which the water droplets freeze. Hard rime ranges in density from 300 to 700 kg/m³ while soft rime has densities of 150–300 kg/m³. Figure 7.16 depicts the dependency of droplet diameter on temperature for various types of accretion. Ice loads take days or even weeks to reach damaging levels. Rime ice often accretes more rapidly on small conductors or sharp edges.

Figure 7.14 Glaze ice in Slovenia February 2014. An "ice casting" of the conductor can be seen in the middle (Photo: F. Jakl).

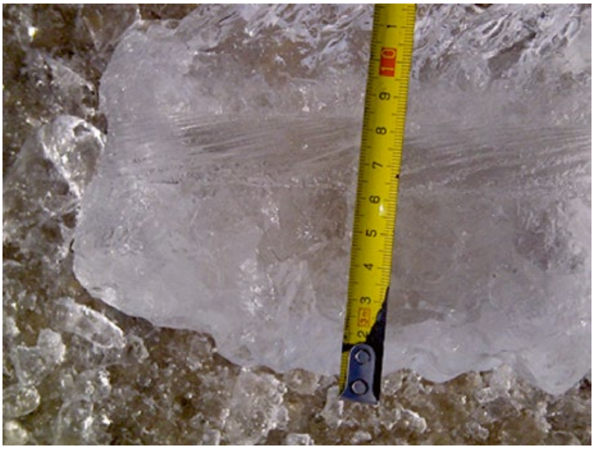


Figure 7.15 Rime icing vane (Wareing 1999).

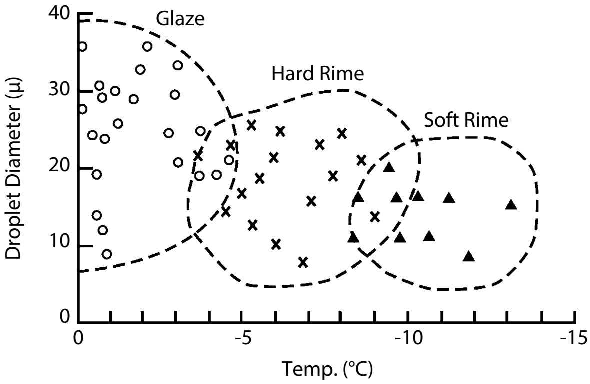


Figure 7.16 Ice accretion type as a function of temperature and droplet size (Kuriowa 1965).

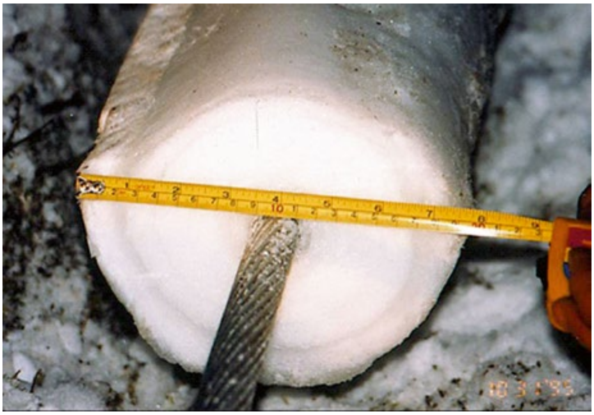


Figure 7.17 Wet snow accretion on overhead conductor (Courtesy Landsnet, Iceland).

Wet snowflakes occur as ice crystals suspended in a liquid water matrix at temperatures just above the freezing point, usually between 0,5 and 2 °C. At liquid water contents (LWC) between 15 and 40 % the flakes adhere readily to objects. They can reach a terminal velocity which is less than the local wind speeds. At LWC levels below 15 % the snow often fails to accrete on structures and lines but can penetrate into motors or other components. At LWC levels above 20 % the accretion often falls off objects.

The force of the wind compresses the snow on the surface and the accretion will become more compacted over time, meaning the porosity will decrease and density value as high as 850 kg/m^3 may be reached within the deposit. This phenomenon does not increase the overall snow load on the conductor but will affect only its density. A process of circular accretion can lead to very high loads being reached in a matter of hours, see Figure 7.17.

Many meteorological parameters are significant in relation to icing accretions. Table 7.3 shows the meteorological parameters associated with each icing type with those having the greatest influence denoted "■" and those with less influence denoted "□".

Table 7.3 Meteorological parameter associated with each icing type. Those that have greatest influence are denoted "■", those with less influence "□"

Type of icing	Precipitation icing		In-cloud icing			
	Glaze due to freezing rain	Wet snow accretion	Dry snow accretion	Glaze due to super cooled cloud/fog droplets	Hard rime	Soft rime
Wind speed	■	■	□	■	■	■
Air temperature	■	■	□	■	■	■
Precipitation	■	■	■			
Liquid water content of air	■				■	■
Water droplet size	■			■	■	■
Relative humidity	■	□		■	■	■
Liquid-water content of snowflake		■	■			
Snow flake size		■	■			

Some of these parameters are contained and recorded in the general observed parameters, and others are not. The parameters generally observed are the weather, air temperature, relative humidity, precipitation (precipitation intensity), wind speed, and wind direction. Moreover, some cases may include cloud type, cloud amount, cloud base and visibility. On the other hand, among the parameters which are not generally observed, the super cooled liquid-water content of air, distribution of the volume diameter (particularly mean volume diameter) of super cooled fog/cloud droplets, liquid-water content of snowflakes, etc. have a significant influence on the icing phenomena.

In order to estimate ice loads, several physical and empirical models have been developed for glaze due to freezing rain, including icicle growth, in-cloud icing and for snow accretion. Their application depends strongly on the availability of the meteorological parameters required as an input to the models.

7.3.3 Measuring Ice Loads

Ice loads are measured in many ways, mainly depending on prevailing icing type, but also from historic reasons. Such devices are described in Cigré TB 291, Fikke et al. (2006) and WG B2.28 (Cigré TB 645, 2015).

In Canada there has been an extensive measuring program for freezing rain since 1974 (Cigré TB 291) with the so-called "Passive Ice Meter" shown in Figure 7.18 (Cigré TB 291).

In Russia regular weather stations have been equipped with special designed racks for icing measurements since the 1940's – 1950's, as shown in Figure 7.19 (WG B2.28 Cigré TB 645, 2015).

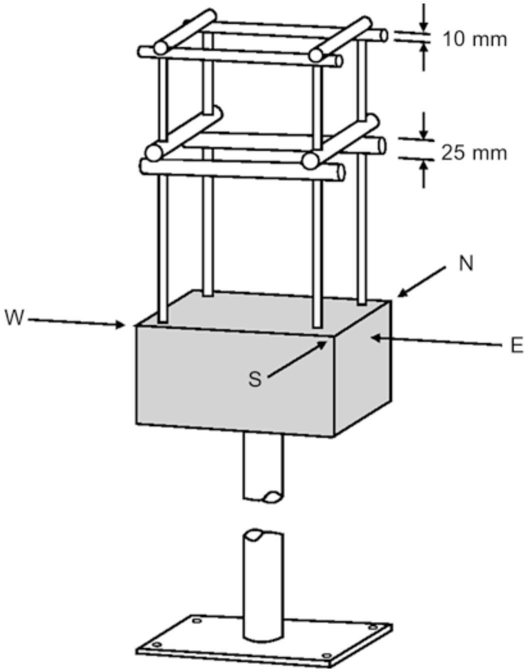


Figure 7.18 Passive Ice Meter used for measuring freezing rain in Canada (Cigré TB 291).


Figure 7.19 An icing rack from a Russian weather station (Courtesy S. Chereshnyuk, NTC-Power).

Some countries are using test spans, for instance in Iceland (measured since 1972) as shown in Figure 7.20 (Cigré TB 291).

In Norway a test rack, see Figure 7.21, was used to measure rime icing through the 1980's and 1990's (Cigré TB 291).

For instance in the UK a test site is established for icing measurements and hardware studies on the mountain Deadwater Fell, see Figure 7.22. Another test span is the Hawke Hill test site, Newfoundland in Figure 7.23 (CEA 1998).

Test spans like those in Figures 7.22 and 7.23 are especially useful for testing non-conventional conductor types as well as any type of hardware that may be exposed to extreme weather impacts.

7.3.4 Icing Models

Most of the following text is taken from (Cigré TB 291). However, as there have been quite substantial developments in the modelling of atmospheric icing, new opportunities have emerged by using modern weather forecasting models where icing models are embedded, see for instance (Fikke et al. 2012), (Nygaard et al. 2011) and (Nygaard et al. 2013).

Figure 7.20 Test span for icing measurements in Iceland. Many of these are mounted in orthogonal pairs, each span 80 m long (Courtesy Landsnet).

Figure 7.21 Rack for measuring rime icing in Norway (Photo: B.E.K. Nygaard).

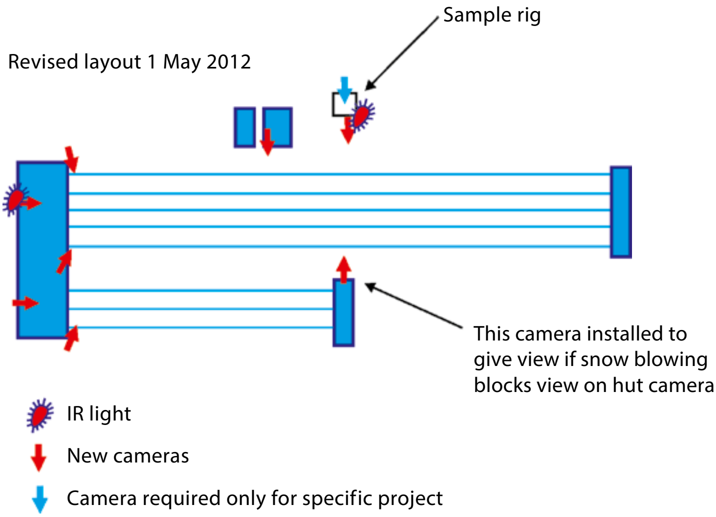


Figure 7.22 Layout of new Deadwater Fell test site (Courtesy J.B. Wareing).

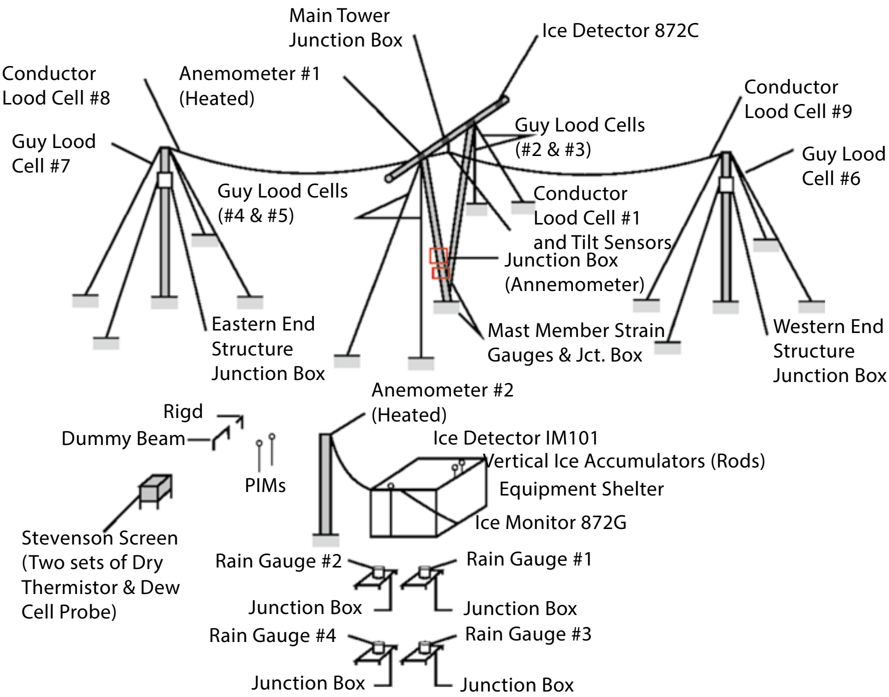


Figure 7.23 Hawke Hill test site, Newfoundland (Haldar 2007).

The use of icing models to provide ice load data is obviously attractive. They give an estimation of ice loads for defined conductors and are often restricted to a particular type of icing.

Estimating ice loads on conductor from models based on atmospheric data is a complex process involving:

- source of moisture (maritime air)
- cloud formation
- precipitation (for precipitation icing)
- liquid water content (LWC) in air (for in-cloud icing)
- terrain effects
- collision of drops or droplets with the ice surface
- accretion rate
- torsional rigidity effects
- change in accreting surface characteristics (size, roughness, shape)
- ice shedding
- local temperature/wind effects.

The selection of icing models is therefore dependent upon icing processes as described above. Some icing models use relatively simple approaches and are restricted to a particular type of icing, while others start from more fundamental equations and can address a range of icing types. Icing models may be used both to estimate ice loads for defined conditions and to compute icing statistics from a historical database of meteorological conditions. In most cases, essential input parameters such as LWC and droplet sizes are, in general, not available from a climate database and must be estimated from the available meteorological parameters.

It is beyond the scope of this chapter to give a complete description of the various icing models. The reader is referred to the International Standard ISO 12494 (ISO 2001), Cigré TB 291 and the WG28 report for more details on especially freezing rain (glaze ice) and in-cloud icing (rime ice). In the case of wet snow there has been some significant development in years which are only recently published and therefore not so widely known. The following text is mainly excerpts from Nygaard et al. (2013).

Ice accretion modelling – state of the art on wet snow models (WG B2.28 Cigré TB 645, 2015).

Different variations of simple cylindrical accretion models for wet snow are found in the literature (Finstad et al. (1998), Sakamoto and Miura (1993), Admirat (2008), Makkonen and Wichura (2010), Nygaard et al. (2013)). The basics of these models can be described with the following equation

$$\frac{dM}{dt} = \beta\, V\, w\, A \tag{7.1}$$

where dM is the accumulated snow mass per unit length during the time step dt, β is the sticking efficiency (the fraction of snow that sticks to the cylinder after collision), A is the cross-sectional area of the cylinder perpendicular to the snowflake impact speed V, while w is the mass concentration of wet snow in the air. The snowflake impact speed is the vector sum of the wind speed U and the terminal velocity of the snowflakes v_s:

$$V = \sqrt{U^2 + v_s^2} \tag{7.2}$$

The time dependent model is called a cylindrical model because it assumes that the snow deposit maintain its cylindrical shape.

Given meteorological data at a temporal resolution of Δt, (Eq. 7.1) can be numerically integrated forward in time, assuming that the meteorological conditions are constant within Δt. The integration scheme can be found in e.g. Nygaard et al. (2013)

Since w is not directly measured at regular weather stations, methods to estimate w based on the standard meteorological variables have been suggested. The most widely used parameterization relies on the measured water equivalent precipitation intensity at the ground P and the terminal velocity of the falling snowflakes v_s (Admirat 2008), by $w = P/v_s$. Another approach used by Makkonen and Wichura (2010) is to estimate w from observed visibility V_m by a formula presented in Makkonen (1989): $w = 2100 {V_m}^{1.29}$.

The sticking efficiency β, is introduced in order to account for the bouncing effect of snowflakes after collision with the cylinder. Due to the general lack of sufficient and precise wet snow measurements as well as limitations in the physical understanding of the collision process, a precise formula for this coefficient has not been attainable. However, simple empirical relations have been suggested based on both limited field studies and laboratory experiments (Finstad et al. (1998); Sakamoto and Miura (1993); Sakamoto (2000); Admirat (2008)). A commonly used parameterization has been a simple inverse relation to the wind speed by $\beta = 1/U$ (Admirat 2008). This was adopted in the international standard for atmospheric icing of structures (ISO-12494 2000), but its uncertainty is clearly underlined:

> *Estimation of the sticking efficiency* β *of wet snowflakes is presently quite inaccurate.* β *= 1/U should be seen only as a first approximation until more sophisticated methods to estimate β have been developed (*ISO-12494 2000*).*

A more recent calibration of the sticking efficiency has been published in Nygaard et al. (2013). By using 50 years of wet snow measurements, where many occurred during windy conditions, they showed that $\beta = 1/U^{0.5}$ gave a much better match with observations compared to the original approximation. Consequently, the parameterization described in Nygaard et al. (2013) is recommended unless sufficient amount of empirical data supports other methods or calibration factors.

For the density of the accreted snow ρ_s, it is recommended to use a formula on the form $\rho_s = k + 20\ U$, where k must be determined according to local conditions. Admirat (2008) found $k = 300$ based on some documented cases of wet snow in Japan, while including cases from France k was closer to 200. The density should however be limited to a maximum of roughly 750 kg/m^3, which is the highest reported in field studies (Eliasson et al. 2000).

7.3.5 Identification of Wet Snow

Identification of wet snow conditions has been discussed in the literature. Admirat (2008) assumed that all precipitation reaching the ground at 2-m temperatures between 0 °C and 2 °C was in the state of wet snow. Sakamoto (2000) used a somewhat similar criterion but found an upper temperature limit that changed with altitude and weather condition prevailing during the storm. Makkonen (1989) emphasized the role of atmospheric moisture for the presence of wet snow, and showed that one necessary condition was a positive wet-bulb temperature (Tw > 0 °C).Nygaard et al. (2014) identified the wet-bulb temperature interval between 0 °C and 1.2 °C as favourable conditions for wet snow accretion.

7.3.6 Application of Numerical Weather Prediction Models

The icing models described above deals with the physical accretion processes on the conductors, where the input parameters are known or can be anticipated with an acceptable accuracy. However, when the input parameters are not known or can be assessed indirectly from other sources, it has now become possible to generate parameters like liquid water content, cloud droplet sizes, and wet snow content in the air from regular numerical weather prediction models, see Fikke (2005), Nygaard et al. (2011), Fikke et al. (2012), Nygaard et al. (2013) and Nygaard et al. (2014).

Such models are useful for case studies, studies of design loads (climatology) and mapping of ice loadings for wet snow and rime ice loads. The numerical weather prediction models are still not fully reliable for forecasting low level temperature inversions and hence freezing rain.

A recent example is the ice load map developed for United Kingdom shown in Figure 7.24 (Nygaard et al. 2014). The map data are given with a resolution of 500 m × 500 m, and the overhead line designer can therefore enter the geographical coordinates into the data base and directly get the ice loads as well as the wind speeds and combined wind and ice loads to be used as design parameters for the specified line with the same resolution.

As can be seen from Figure 7.24, the ice loadings are specified in kg/m up to 10 kg/m. In the higher mountains, mainly in the Scottish Highlands, the rime ice loads may locally be higher or lower due to smaller scale variations in the topography where local conditions may increase or reduce the icing intensities.

This procedure is also included in the WG B2.28 Cigré TB 645 2015.

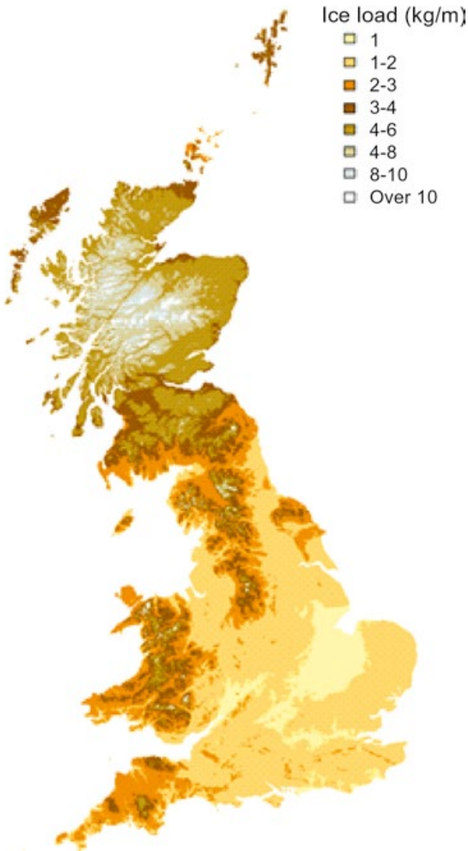


Figure 7.24 Combined wet snow and rime ice load map for the United Kingdom. Color code in *upper right corner* (Nygaard et al. 2014).

7.4 Other Topics

7.4.1 Combined Icing and Pollution

Pollution on insulators is well known both for sub-stations and for overhead lines. Such pollution may cause leakage currents and eventually flashovers for electrical equipment in industrial or coastal areas. Such pollution may be due to industrial dust, fine sand from deserts and spray of sea salt from oceans under strong wind conditions (over sea).

However, sea salt and industrial pollution may also act as condensation nuclei for droplets in clouds, far away from their origin. Under freezing conditions such droplets may freeze on insulators on overhead lines in mountains relatively far away from the coast line or industrial source as well. Flashovers due to this reason are reported in Fikke et al. (1993).

7.4.2 Effects from Changes in Global Climate

The Intergovernmental Panel on Climate Change (IPCC) issued in 2013 the first WG report to the Fifth Assessment Report on climate change in 2013 (IPCC 2013). This report discusses the scientific basis, and their main conclusion is a confirmation of the findings of the Fourth assessment report in 2007 (IPCC 2007). Due to various human activities the emissions the content of CO_2 is steadily increasing to record high levels and currently reaching the 400 ppm level, according to IPCC (2013) (See Figure 7.25).

Figure 7.26 shows the observed global mean combined land and ocean surface temperature anomalies, from 1850 to 2012 from three data sets. The top panel shows annual mean values. Bottom panel shows decadal mean values including the estimate of uncertainty for one dataset (black). Anomalies are relative to the mean of 1961–1990.

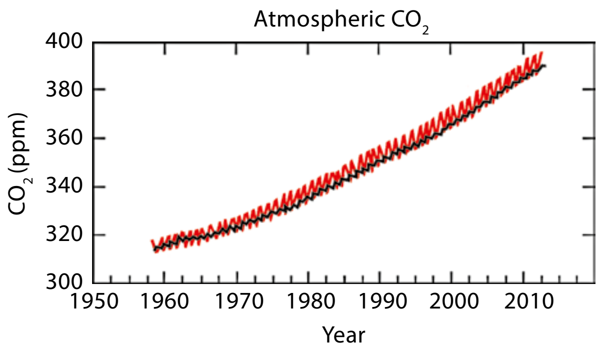


Figure 7.25 Increase in CO_2 in the atmosphere since 1958. *Red curve*: Mauna Loa, Hawaii, and *black curve*: South Pole.

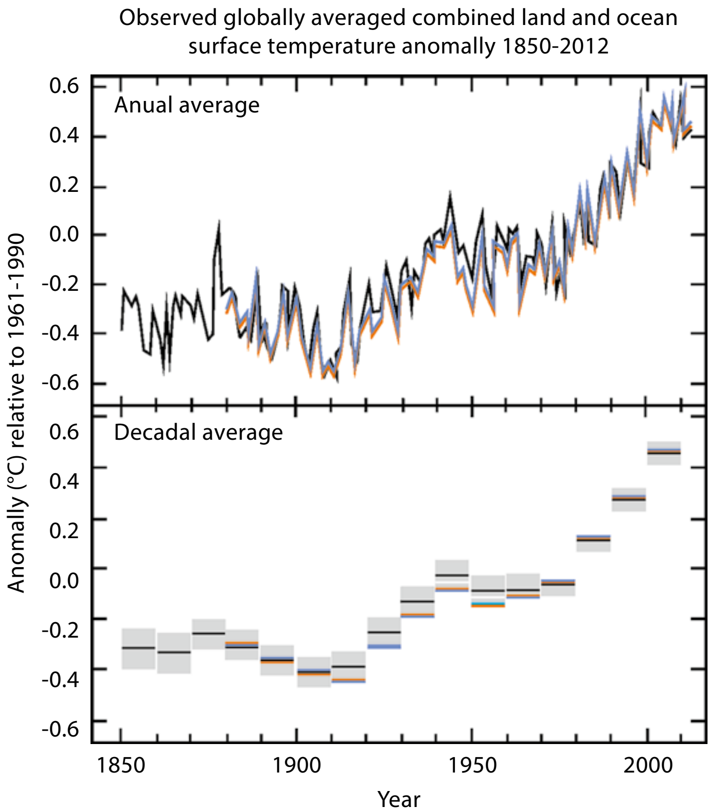


Figure 7.26 Observed global mean combined land and ocean surface temperature anomalies, from 1850 to 2012 from three data sets. *Top panel*: annual mean values. *Bottom panel*: decadal mean values including the estimate of uncertainty for one dataset (*black*). Anomalies are relative to the mean of 1961–1990.

As can be seen from Figure 7.26 the global temperature is constantly increasing on a decadal scale, although there are several shifts in global temperatures on the scale of a few years. The other sub-reports from IPCC Working Groups II and III were published in 2014 (WG II Impacts, Adaptation and Vulnerability) (IPCC 2014, WGII) and (WG III Mitigation on Climate Change) (IPCC 2014, WGIII). The Synthesis Report will be published in October 2014.

In 2012 IPCC also issued a Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation (IPCC, SREX 2012). As the title implies, this Special Report discusses the potentials of extremes of various weather phenomena in a warming atmosphere on a global scale, although with some regional examples.

In order to identify potential consequences for the international electric overhead industry it is necessary to look into more detailed reports where climate parameters are downscaled to a more regional and local scale. One such study for Europe was published in 2013 by the Norwegian Meteorological Institute, together with the Norwegian Academy of Science and Letters, in cooperation with the European Academies Science Advisory Council (easac) (NMI and DNVA 2013).

Another report was issued in February 2014 entitled: "Climate Change. Evidence & Causes. An overview from the Royal Society and the US National Academy of Sciences". (Roy. Soc. and NAS 2014). This report is structured as Question and Answers. As a summary to Q. 13 "How does climate change affect the strength and frequency of floods, droughts, hurricanes and tornadoes?" the report says:

> ***Earth's lower atmosphere is becoming warmer and moister as a result of human-emitted greenhouse gases. This gives the potential for more energy for storms and certain severe weather events. Consistent with theoretical expectations, heavy rainfall and snowfall events (which increase the risk of flooding) and heatwaves are generally becoming more frequent. Trends in extreme rainfall vary from region to region: the most pronounced changes are evident in North America and parts of Europe, especially in winter.***

It should be emphasized that regional studies like those mentioned above will constantly be published in most regions of the world. It is therefore not within the scope of this chapter to give a complete overview of reports of this kind, since such a summary may soon be incomplete or outdated. Any utility or other authority is recommended to review the available information locally whenever needed.

According to Fikke (2011) utilities in many countries have already incorporated precautions or considering adaptations for mitigating potential effects relating to their networks. Some of the most important findings were (name of informant is given in parentheses):

Canada, BC Hydro (J. Toth): Temperature increase will lead to higher beetle infestation, drier summers (fire risks, slope instability), more woodpeckers, changes in peak load patterns, etc. Higher precipitation rates may lead to river erosion and flooding, mudslides, increased corrosion, higher frequency and severity of wind and ice storms, hail storms and reduced opportunity for live-line work. Wind effects may affect the failure rates, recovery time and reliability, vegetation control practices and withstand levels of hardware. Other effects to be considered are: rising sea level (for coastal substations), melting permafrost, increased lightning activities, fog, in-cloud icing and transmission line ratings.

Australia (H. Hawes): Expected effects are mainly related to extreme storm intensities, rainfall intensities, insulator pollution, wildfire (bush fire) risk, etc.

United Kingdom (J.B. Wareing): Main focus areas are change in risks for high wind and wet snow accretion, thermal rating and changes in seasonal demands due to increased use of air conditioning.

Russia (S. Chereshnyuk): Melting of permafrost, flooding and landslides, wind loads may increase in some regions (and decrease in others).

Norway (S.M. Fikke): Wet snow and rime icing may increase in some areas and decrease in others, higher avalanche risks in many areas, reduced weather windows for helicopter operation for maintenance.

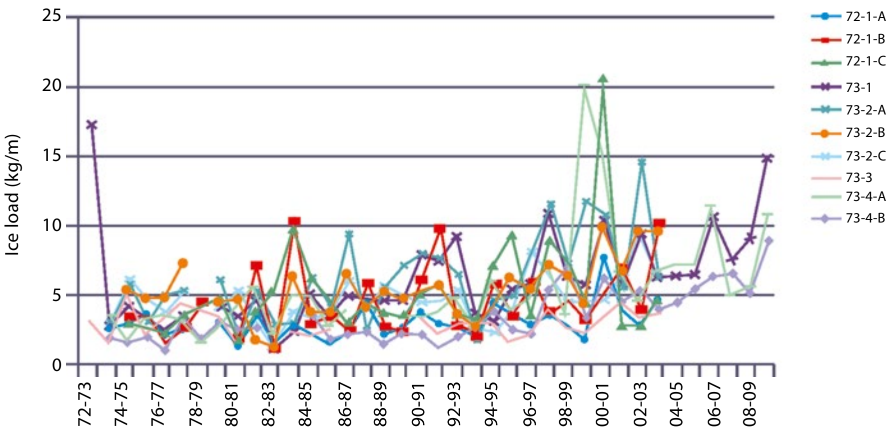


Figure 7.27 39 years of measurements of ice loadings on 10 different test spans in Iceland.

Iceland (Á. J. Elíasson): After 39 years of measurements it seems to be a small, but increasing trend in recorded ice loads since 1995, as shown in Figure 7.27.

TB 291 also mentions some potential developments for atmospheric icing, although the high uncertainties are strongly emphasized:

Wet snow: More seldom in coastal low-lands, but maybe more often on coastal mountains. For inland areas with a cold climate wet snow may increase in frequency and intensity at all levels.

Rime ice: Risk of rime ice may decrease in lower levels and increase in higher levels.

Freezing rain: Not possible to evaluate with current knowledge.

For tornadoes there are no trends identified in the literature. Global climate models do not show correlations between tornado frequency and global climate variations (valid for both the US and Australia) (Fikke 2011).

Acknowledgements The completion of this chapter was first of all made possible only by the support of all good Cigré colleagues of especially the Working groups B2.16 and B2.28 with whom I enjoyed an enthusiastic and fruitful collaboration with during many years. It would take too much space to mention them all. However, I am most grateful to Dr Henry Hawes, Australia, for his work on high intensity winds (Cigré TB 256 and Cigré TB 350), Dr André Leblond, Canada, for his efforts to complete the Icing Brochure (Cigré TB 291), as well as the Secretary of both WGs, Dr J. Brian Wareing, UK. I would also like to thank my good friend and icing colleague, Professor Masoud Farzaneh of UCAQ, Canada, for his great contributions to the mechanical and electrical aspects on atmospheric icing, both on conductors and in insulation systems. Dr Sergey Chereshnyuk is much appreciated for providing information on the vast research on icing climate in Russia over many years, to our community. I am indeed also indebted to my Norwegian colleagues: Dr Knut Harstveit for his fundamental work on turbulence formation behind steep hills, and to Dr Bjørn Egil Kringlebotn Nygaard for taking the science of atmospheric icing a huge step forward by improving the wet snow accretion model and implementing icing processes into regular weather forecasting models. Finally, I would as well like to thank Dr Dave Havard and Dr Normand Bell for their valuable review of this chapter.

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Svein M. Fikke has a M.Sc. in meteorology from the University of Oslo in Norway. His professional career ha-s been related to extreme weather impacts on infrastructure such as oil platforms, TV masts and towers, and electrical overhead lines, especially in complex mountainous terrain. He has been responsible for advising on ice and wind loadings on electrical overhead lines in Norway for 40 years, first at the Norwegian Meteorological Institute, then at the Norwegian Electric Power Research Institute and for the Norwegian TSO Statnett until retirement. After official retirement he has continued as a consultant, serving utilities both within Norway as well as in many countries abroad. He has been the Norwegian member of SC B2 and member and convenor of several working groups. Fikke received the Cigré Technical Committee Award in 2002, and has authored numerous papers in journals and to conference proceedings.

Conductors

8

Dale Douglass, Mark Lancaster, and Koichi Yonezawa

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D. Douglass (✉)
Niskayuna, NY, USA
e-mail: da.douglass@ieee.org

M. Lancaster • K. Yonezawa

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Definitions

AAAC (A3) All Aluminum High Strength Alloy Conductor.
AAC (A1) All Aluminum Conductor.
ACAR (A1/Ay) Aluminum Conductor Alloy Reinforced (the y identifies the type of aluminum alloy used for the core wires).
ACSR (A1/Syz) Aluminum Conductor Steel Reinforced (y represents the type of steel and z represents the class of zinc coating on the steel core wires).
Aluminum-Clad Steel Abbreviated as ACS, it consists of a steel wire with uniform aluminum covering thoroughly bonded to it. It has geater conductivity and corrosion resistance than ordinary steel but a slight larger thermal elongation rate and reduced tensile strength.
Aluminum Strand Compression Almost every type of concentric stranded conductor has outer layers of aluminum strands. Above the knee-point conductor temperature, the aluminum strands continue to expand faster than any reinforcing core and aluminum strand layers can experience compression forces rather than tension. This can increase the core stress and increase sag.
Ampacity The maximum constant line current which will satisfy the design, security and safety criteria of a particular line on which the conductor is installed. In this brochure, ampacity has the same meaning as "steady-state thermal rating."
Annealing The process wherein the tensile strength of copper or aluminum wires is reduced at sustained high temperatures, usually above 75 °C and 90 °C respectively.
Area Ratio The ratio of area for all surrounding helical conducting strands to the core area (called the Steel Ratio for ACSR).
Concentric Lay Stranded (Electrical) Conductor A conductor composed of a central core wire surrounded by one or more adjacent layers of conducting wires being laid helically with alternating orientations.
Creep Elongation see Elongation, Plastic
EC (grade aluminum) "Electrical Conductor" grade aluminum also called A1 or 1350-H19 alloy.
EHS (S3) Steel Wires Extra High Strength steel wires for ACSR (A1/S3y).
EDS (Everyday Stress) The tension or stress that a conductor normally experiences for most of its service life, typically at a conductor temperature of 0 °C to 25 °C without wind or ice.
EHV (Extra High Voltage) Lines Overhead transmission lines where the phase to phase ac voltage exceeds 300 kV but is less than 700 kV.
Electrical Clearance The distance between energized conductors and other objects such as conductors, structures, buildings, and earth. Minimum clearances are usually specified by regulations.
Elongation, Elastic Bare overhead conductors elongate under tension, increasing in length with increasing tension and decreasing in length with decreasing tension. Elastic elongation of conductor is "spring-like". The conductor returns to its original length (unloaded length) when tension is removed.

Elongation, Plastic Aluminum strands and, to a much lesser extent, steel strands, used in bare overhead conductors, undergo plastic (i.e. permanent) elongation as the result of tension applied over time. Initial plastic conductor elongation includes "strand settlement and deformation" which occurs during stringing and sagging (Initial Plastic Elongation), plastic elongation which occurs during relatively brief, high tensile-load events, and long-time "metallurgical creep" elongation which occurs at everyday tension levels over the life of the line. Metallurgical creep of aluminum is accelerated at sustained high temperatures (above 20 °C). The components of plastic elongation are not additive (e.g. the plastic elongation rate at high tension is less after the line has been in place for 10 years than when the line is first installed).
Elongation, Thermal Bare overhead conductors will expand or contract with changes in temperature. The rate of expansion or contraction is dependent on the conductor material and magnitude of temperature change. For ACSR conductors, the differential rates of expansion also shift tensile load between the aluminum strands and steel core.
HS Steel (S2) High Strength steel core wires for ACSR (A1/S2y).
HV (High Voltage) Lines Overhead transmission lines for which the phase to phase ac voltage is greater than 50 kV and less than 250 kV.
I.A.C.S. or IACS International Annealed Copper Standard.
IEC International Electrotechnical Commission.
Initial Plastic Elongation see Elongation, Plastic
INVAR steel Known generically as FeNi36, INVAR steel alloy is 36 % nickel. It has a thermal elongation rate equal to 30 % that of ordinary steel core wire with lower tensile strength and elastic modulus.
Lay length The axial length of one complete turn of the helix formed by an individual wire in one of the surrounding layers.
Lay Ratio The ratio of the lay length to the outside diameter of the helix formed by wires in one of the conductor layers.
Knee-point Temperature The conductor temperature above which the aluminum strands of an ACSR (A1/S1A) conductor have no tension or go into compression.
Manufactured Conductor Length The conductor manufactured length as wound onto a reel with little or no tension. Normally, for ACSR, the manufactured lengths of the aluminum layers and the steel core are assumed to be the same (at zero tension) under everyday temperatures of 15 to 20 °C.
Maximum Allowable Conductor Temperature (MACT) The highest conductor temperature at which an overhead power line can be safely operated (Also referred to as the line "design" or "templating" temperature).
Rated Tensile Strength (RTS) The calculated value of composite conductor tensile strength, which indicates the minimum test value for stranded bare conductor. Similar terms include Ultimate Tensile Strength (UTS), Rated Breaking Strength (RBS), and Calculated Breaking Load (CBL).
Ruling (Equivalent) Span A hypothetical, equivalent level span length where the variation of tension with conductor temperature or ice and wind load is the same as in a series of contiguous suspension spans with perfect tension equalization between spans.
Self-Supporting Conductor Bare stranded conductors used in overhead line catenaries are both conducting and capable of withstanding the tensions produced

by the weight of the conductor and both wind and ice loads, over the life of the line with only periodic supports at structures.

Stress-strain Curves These are plots of the complex relationships between mechanical tensile stress and conductor elongation. In the simplest case, these curves are approximated as linear but are commonly modeled by non-linear, higher order polynomials.

Suitably conservative weather conditions (for line rating calculation) Weather conditions which yield the maximum or near maximum value of conductor temperature for a given line current.

Thermal Rating This is the maximum electrical current that can be carried in an overhead transmission line (same meaning as ampacity) without exceeding the Maximum Allowable Conductor Temperature.

TW conductor A bare overhead stranded conductor wherein the aluminum strands are trapezoidal in cross-section.

UHV (Ultra High Voltage) Lines Overhead transmission lines where the phase to phase ac voltage exceeds 700 kV.

Uprating The process by which the thermal rating of an overhead power line is increased. While this term may also be used to refer to an increase in the operating voltage of an existing line, in this brochure the term is limited to an increase in the allowable current.

Weight per unit length This brochure generally uses conductor weight per unit length. Mass per unit length can be obtained by dividing the weight by the acceleration of gravity (approximately 9.81 m/sec^2).

8.1 Introduction

Self-supporting, bare concentric stranded conductors are an essential part of any overhead transmission and most overhead distribution lines. Their crossection area determines the line's electrical resistance. Their diameter, spacing, and height above ground determine the electrical and magnetic fields, Corona noise, and both inductive and capacitive ac line reactance. Limitations on the maximum power flow through AC and DC are often the result of the maximum operating sag and temperature of these same conductors.

Mechanically, wind and ice on bare overhead conductors produce the maximum longitudinal conductor tensions and both the vertical and transverse loads on the towers, foundations, and insulators, that typically govern the design and cost of these supporting structures.

The maximum sag of the energized conductors, at either the maximum ice load or more commonly, the maximum allowable conductor temperature (MACT), determines the spacing (span length) and minimum tower heights at each support point along the line. At minimum conductor temperature, the corresponding minimum conductor sag determines insulator "uplift" requirements in uneven terrain.

In terms of capital investment, the conductor system is a major cost component (i.e. typically 30 % to 35 %) of new lines and is the largest cost component in reconductoring an existing line. Conductors are an essential component in calculating life-cycle costs.

Bare stranded overhead power line conductors are manufactured with one or more helically wrapped layers of aluminum, concentrically stranded around a single or stranded core made up of aluminum or steel wires. If the core is steel and the surrounding layers are aluminum, the conductor is commonly named ACSR (Aluminum Conductor Steel Reinforced). This is the most common type of bare overhead conductor.

Some of the many available ACSR strandings are shown in Figure 8.1.

According to a Cigré questionnaire (Cigré 2003) circulated in 2000, in over 80 % of transmission lines around the world use ACSR. The composite strength of the conductor is determined primarily by crossection area and the ratio of steel to aluminum area.

As shown in Table 8.1, for four different ACSR conductors having approximately the same electrical resistance, the strongest ACSR design (30/7) in the table has a rated strength which is over 200 % higher than the weakest (36/1) while the larger steel core only increases the conductor weight per unit length by about 50 %.

The other advantage to using high steel content in ACSR conductors is a reduction in thermal elongation rate since steel elongates thermally at half the rate of aluminum. Of course the addition of steel to conductor increases the tower tensions and can raise the cost of new lines.

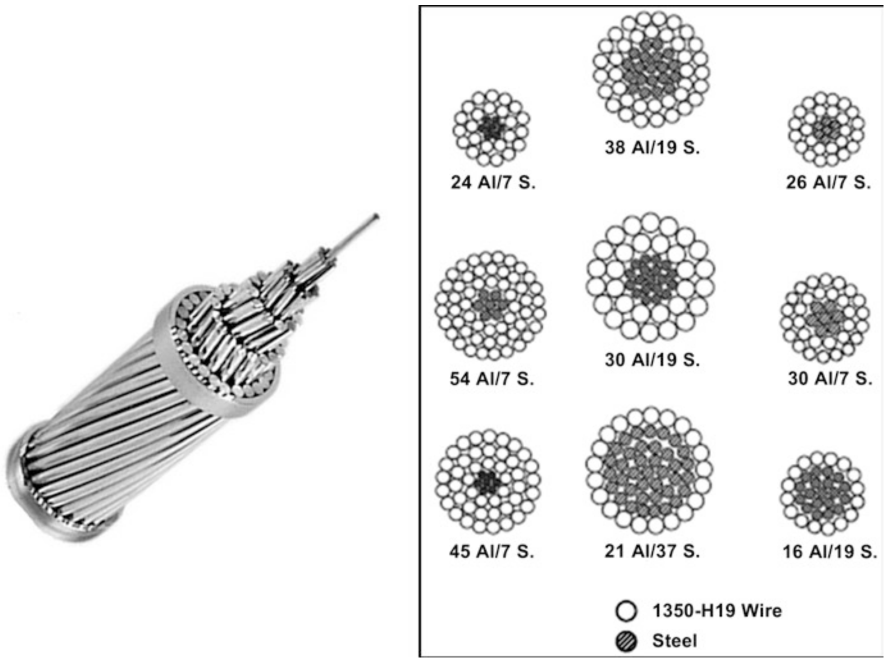


Figure 8.1 Photo of a multi-layer concentric lay stranded conductor with some common strandings of ACSR.

Table 8.1 Comparison of Mechanical Properties for Different ACSR Strandings. All have the same 403 mm^2 Aluminum Area

Aluminum Wires Number & diam [mm]	Steel core Wires Number & diam [mm]	Conductor OD [mm]	Rated Strength [kN]	Conductor Weight [kg/km]	Steel Core Weight [kN/km]
36×3.78	1×3.78	26.4	74.7	1200	88
20×5.06	7×2.25	27.0	97.0	1330	223
26×4.44	7×3.45	28.1	140	1630	512
30×4.14	7×4.14	29.0	170	1850	718

Recently, especially in line uprating applications, various core materials have been substituted for steel, primarily to further limit sag at high temperature while providing similar mechanical reinforcement.

By varying the diameter of the aluminum strands (e.g. round strands are normally between 2 and 5 mm in diameter), the number of layers (between 1 and 5 layers), and the area ratio of core to aluminum layers (usually between 5 % and 23 %), bare stranded conductors offer the line design engineer a wide variety of choices to meet various operating voltages, climatic conditions, environmental constraints, and both normal and emergency power flow requirements.

In describing various types of bare concentric stranded conductors, a variety of nomenclatures are used. In some countries, bare stranded overhead conductors of a particular type, size, and stranding are identified by a unique name. In North America, the 26/7 ACSR conductor with aluminum strand area totaling 403 mm^2 listed in Table 8.1 is named "Drake". Following the naming convention in IEC 61089, the same conductor would be named "403-A1/S1A-26/7" where the first number is the aluminum area in mm^2, the next that it is composed of A1 aluminum strands over a stranded steel core (S1) with A galvanizing, and the part is stranding (number of aluminum over the number of steel strands).

8.2 Conductor Materials & Manufacturing

Electrical phase and ground wire conductors used in overhead power lines are normally concentric lay stranded with aluminum wires. That is, the conductor is composed of a central core wire surrounded by one or more concentric layers of conducting wires being wound helically with alternating orientations. The central core wire(s) of the conductor can be made of steel or other high strength composite materials in order to increase the conductor rated tensile strength and limit thermal elongation. Because of its higher mass density, the use of copper conductor is uncommon in modern transmission lines.

Bare overhead phase conductors are usually classified as homogeneous or non-homogeneous. Homogeneous conductors are those in which the individual strands of wire composing the cable are of the same material. Homogeneous conductors manufactured with relatively pure aluminum are designated (IEC 61089) All-Aluminum Conductors (A1); those manufactured with an aluminum alloy are called All-Aluminum-Alloy Conductors (A2 or A3).

Non-homogeneous conductors consist of mixtures of different wire materials. The most common type of bare overhead phase conductor is a non-homogeneous cable consisting of aluminum strands covering a steel core, Aluminum Conductor, Steel Reinforced (ACSR or A1/S1A, etc.). Another non-homogeneous conductor is one composed of a mixture of relatively pure aluminum strands and aluminum alloy strands. This conductor is referred to as Aluminum Conductor, Alloy Reinforced (ACAR). Special types of non-homogeneous conductor have been developed which maintain stable physical and electrical properties even when operated continuously at temperatures of 200 °C to 250 °C. One of the best known and most widely used high temperature conductors is Aluminum Conductor Steel Supported (ACSS) (Overhead Conductor Manual 2007) which consists of one or more layers of fully annealed aluminum strands around a stranded steel core.

8.2.1 Wire Material Properties

There are two broad classes of aluminum and aluminum alloys: non-heat-treatable and heat-treatable. Non-heat-treatable aluminum and aluminum alloys can only be hardened and strengthened by some form of plastic deformation, such as rolling, drawing, swaging, etc. In general, and within limits, the greater the deformation, the higher the hardness and strength. The 1350 aluminum used in overhead conductors falls into the non-heat-treatable class. As used in the majority of overhead conductors, the individual strands of 1350 have been greatly deformed, or “work-hardened”, in the wire drawing process and are in a full-hard, or H19, temper. To indicate both the material and temper, the wire is referred to as 1350-H19 or A1. Since greater deformation during the wire drawing process is required to produce smaller diameter wire, the smaller wire will have been work-hardened to a greater degree and will exhibit a higher tensile strength (Figure 8.2).

Once hardened, both the non-heat-treatable and heat-treatable materials can only be softened by subjecting them to a thermal treatment. Although a gradation of “softness” can be achieved by controlling the temperature and time of exposure, the only softened temper used in overhead conductors is a full-soft, or O-temper. In this state, the material is said to have been fully annealed. Used only in one of the steel-reinforced composite cables, ACSS, the 1350 wire in this state is designated 1350-O. As compared with 1350-H19, 1350-O wire will have a much lower tensile strength, but will have much greater ductility and increased conductivity (Table 8.2).

Heat-treatable aluminum alloys can be strengthened by either plastic deformation, thermal treatments, or a combination of the two. For wire, the deformation takes place during the wire drawing process. Two thermal treatments are required: a “solution-heat-treatment” (SHT) and an “aging treatment”. The solution-heat-treatment conditions the material to give it the potential to be strengthened. It consists of an elevated temperature-time cycle followed by a quench. The SHT may be accomplished in-line during the manufacture of the redraw rod from which the wire is drawn, or as a separate operation after the manufacture of the redraw rod. After the wire is drawn, it is subjected to an elevated temperature-time aging treatment. The strengthening of the wire that occurs during the aging treatment is added to that achieved during the drawing process.

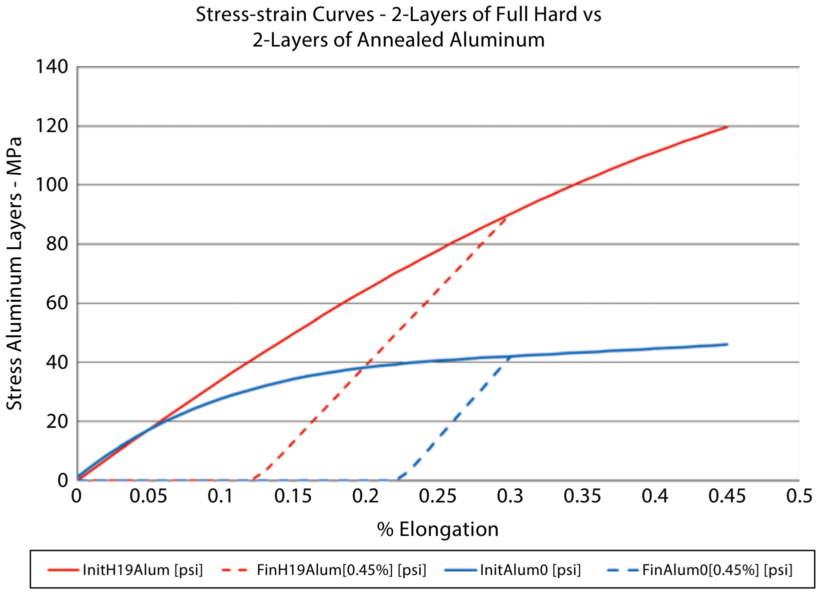


Figure 8.2 Stress-strain comparison of A1 "full-hard" aluminum strands to A0 "fully-annealed" aluminum strands. Note that full hard strands break at an elongation on the order of 1 % while fully annealed strands break at an elongation on the order of 20 %.

Table 8.2 Properties of conducting wires used in bare concentric stranded conductors for overhead lines

Type of Aluminum		Applicable Standards	Minimum Conductivity (%IACS)	Tensile Strength (Mpa)	Allowable Operating Temperature(°C)	
					Continuous	Emergency*
Hard Drawn 1350 H19 aluminum	AL1	IEC 60889	61.2	160–200	90*	125*
Heat-treated 6000 series aluminum	AL3	IEC 60104	52.5	320–400	90	125
Thermal Resistant Zirconium aluminum	AT1	IEC 62004	60	159–169	150	180**
Super Thermal Resistant Zirconium aluminum	AT3	IEC 62004	60	159–176	210	240**
Fully Annealed 1350 aluminum	A0	IEC 60121	63	59–97	350	350

*Manufacturers often suggest performing rating calculations at 75 °C/100 °C.
**The continuous and emergency temperature limits for TAL (AT1) and ZTAL (AT3) correspond to a maximum 10 % loss of tensile strength after 40 years and 400 hours, respectively (see IEC 62004 Annex A).

In applications where higher strength is required and lower conductivity can be tolerated, the heat-treatable aluminum alloy 6201 is used. This is an alloy containing magnesium and silicon that is capable of being processed into wire that is considerably stronger than 1350. In the T81 temper, 6201 (A3) wire has a nominal tensile strength range of 320 MPa or more as opposed to 160 MPa for 1350-H19 (A1) aluminum. However, its nominal conductivity of 52.5 % IACS is somewhat lower than the 61-62 % typical for 1350-H19 (A1).

The steel wire used in overhead lines is manufactured with one of several types of coatings in order to impart good corrosion resistance. There are three classes of zinc-coated, or galvanized, steel wire: A, B and C. The distinction among the three is the thickness of coating, which progressively increases from Class A to Class C. Two additional types of steel wire are aluminum coated. Aluminized steel wire has a relatively thin coating of aluminum, while aluminum-clad steel wire has a much thicker layer of aluminum coating. When used in ACSR, the terminology used to distinguish between the two is ACSR/AZ and ACSR/AW for aluminized and aluminum-clad, respectively. Another coating used for steel core wire consists of a zinc-5 % aluminum-mischmetal alloy which provides improved thermal stability at higher temperatures and improved corrosion resistance over that of zinc galvanized cores. Following the same scheme as used for galvanized steel wire, the use of this coating is indicated by ACSR/MA, MB, MC designations (Table 8.3).

Table 8.3 Material Properties of Conductor Reinforcing Core Wires

Core Material	Min. Tens. Strength (MPa)	Modulus of Elasticity (MPa)	Min. Elongation at Tensile Failure %	Coef. of Linear Elong. ($\times 10^{-6}$) per °C	Allowable Operating Temperature(°C)	
					Continuous	Emergency
A Galv. Steel	1400	210	3.0–4.0	11.5	180	200
Zn-5Al Steel					250	350
A Galv. HS	1600	210	3.0–3.5	11.5	180	200
Zn-5Al EHS					250	350
Zn-5Al UHS	1900	210	3–3.5	11.5	180	200
					250	350
CTC Carbon Fiber composite core	2200	125	2.0	1.6	180	200
3M Ceramic Fiber reinforced aluminum	1400	220	0.64	6	250	300
Alum Clad* Steel (AW) 20.3 % I.A.C.S.	1200	150	3	13.0	150	200
Galv/AW Invar Steel Alloy	1050	160	3	3.5	180/210	200/240

*Thinner aluminum cladding is also available with reduced conductivity and higher tensile properties

The steel core wire used in most ACSR overhead conductors is a medium-strength steel containing 0.50-0.85 weight percent carbon with a nominal tensile strength of 1400 MPa.

For applications requiring conductors with higher strengths, high-strength steel core wire with a 0.50 to 0.88 percent carbon and 0.50 to 1.30 percent manganese is used. Nominal tensile strength for the high-strength steel is in the 1600 MPa range. This type of steel core has been used for ACSR intended for very long spans in severe loading areas (Figure 8.3).

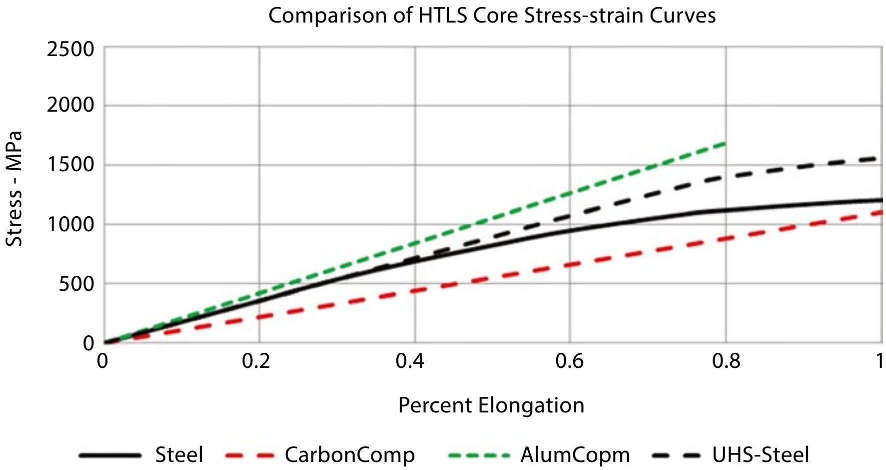


Figure 8.3 Comparison of stress-strain behavior of various core materials up to 1 % elongation.

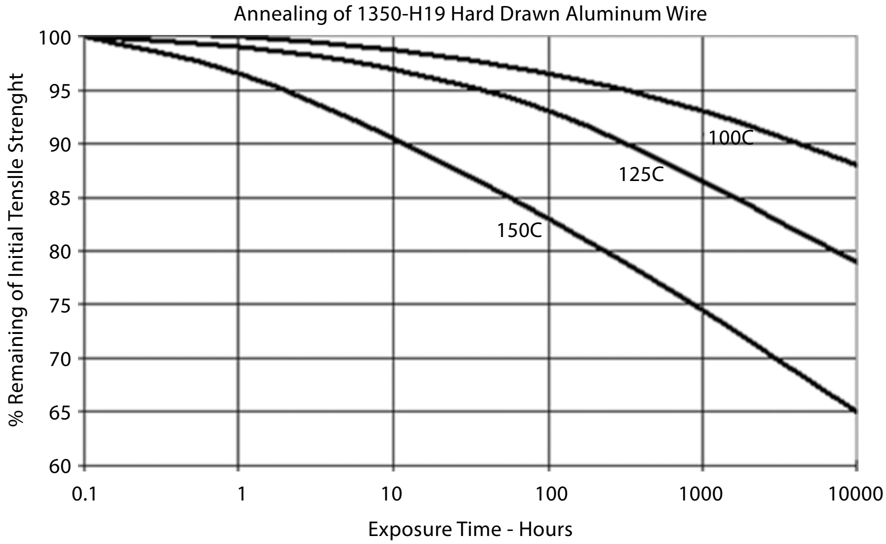


Figure 8.4 Typical annealing curves for aluminum wires, drawn from "rolled" rod, of a diameter typically used in transmission conductors (The Aluminum Association 1982).

The growing popularity of high temperature conductors using dead soft annealed, 1350-HO, aluminum has given rise to a new generation of increased strength steels, defined as ultra-high strength (UHS) core wire. These higher strength steel core wires exhibit similar or better ductility and fatigue characteristics than the present high strength steel core wire but have tensile strengths of 1900 MPa.

Use of an EHS or UHS core, as a direct replacement for a standard strength core, can increase the strength of the core and, depending on the steel to aluminum ratio, the strength of the total conductor.

8.3 Electrical & Mechanical Characteristics

Bare stranded conductors have physical, mechanical, and electrical properties that reflect the properties of the individual strands of wire that comprise the conductors. The properties of homogeneous cables quite naturally parallel the properties of their singular-type individual wires. Non-homogeneous conductors, however, possess properties that reflect the individual properties and relative percentages of the different materials forming the composite cable. Due to the stranding-induced helical form of the individual strands, both types of conductors exhibit lower composite tensile strength (4 % to 11 %), greater weight and higher resistance per unit length of conductor (2 % to 4 %) than would result from if all the component wires being straight.

The electrical characteristics of a conductor are one of the most important considerations when selecting a conductor. The conductor resistance determines the conductor losses and limits the maximum allowable current carrying capacity of the conductor. The inductive and capacitive reactance losses directly affect system performance.

Metal conductivity, cross-sectional area, construction, temperature, frequency and current density determine the electrical properties of a conductor. However, in service, these electrical properties are also influenced by the physical location of a conductor in relation to other conductors, and the earth.

General formulas for the calculation of dc and ac resistance, inductance and inductive reactance, and capacitance and capacitive reactance for transmission lines are presented in this section.

8.3.1 DC Resistance

The approximate dc resistance per unit length of a bare helically stranded conductor is proportional to the volume resistivity of the wire metal, inversely proportional to the cross-sectional area of all the conducting strands, multiplied by a stranding factor which increases the resistance by about 2 % to account for the helical wire length.

As shown in Cigré TB 207 (2002), the DC resistance for a non-homogeneous stranded conductor, with same diameter steel and aluminum strands, is a bit more complex:

$$\frac{1}{R_{dc}} = \frac{1}{R_s} + \frac{1}{R_a} = \frac{\pi\, d_s^2}{4\,\rho_s}\left(1 + \sum_{1}^{m_s} \frac{6 z_s}{K_{zs}}\right) + \frac{\pi\, d_a^2}{4\,\rho_a}\left(\sum_{m_{s+1}}^{m_a} \frac{6\, z_a}{K_{za}}\right)$$

Where:

- The subscripts "a" and "s" refer to aluminum and steel (or other core material) respectively.
- z is the layer number
- d is the strand diameter
- K is a multiplier which accounts for lay length
- ρ is the wire resistivity which is a function of temperature.

The resistivity of steel wire is about 8 times that of AL1 aluminum while the steel core area varies from 7 % to 23 % that of the aluminum in most common transmission conductors. As a result, including the steel core in the dc resistance calculation reduces the resistance of the aluminum layers alone by between 1 % and 2 %. Alternatively, 98 % to 99 % of the dc current flows in the aluminum layers.

Since the resistivity of a conductor wire materials is a function of temperature, the dc resistance calculated above is at the reference temperature of the resistivity values selected, typically 20 °C.

To determine the dc resistance at other temperatures, the known resistance must be corrected using the temperature coefficient of resistance for the conductor metal.

Over a moderate temperature range, such as 0° to 120 °C, the change in dc resistance is considered proportional to the change in temperature. Therefore, assuming a linear relationship, the dc resistance at any given temperature, T_2, may be calculated from a known resistance at a specified temperature by:

$$R_{T_2} = R_{T_{ref}}\,[1 + \alpha_{ref}\,(T_2 - T_{ref})]$$

where:

α_{ref} = temperature coefficient of resistance at the reference temperature, T_{ref}
T_{ref} = reference temperature, °C
T_2 = temperature at which new resistance is desired, °C
$R_{T_{ref}}$ = dc resistance at reference temperature T_{ref}
R_{T_2} = dc resistance at temperature T_2.

Exact values of temperature coefficient of resistance can be obtained from handbooks for various reference temperatures. For example, for ordinary aluminum wire with a conductivity of 61.2 % I.A.C.S., the temperature coefficient of resistance is 0.00404 at 20 °C and the conductor resistance increases approximately 4 % for every 10 °C increase in temperature.

8.3.2 AC Resistance

For a small homogeneous bare stranded conductor (all aluminum or all aluminum alloy), the ac resistance is equal to the dc resistance of the conductor at the same temperature. For larger diameter all aluminum stranded conductors, the ac resistance must be corrected for “skin effect”, the tendency for the electrical current density in the conductor to be higher in the outer layers of aluminum due to the radial magnetic field generated by the current within the conductor.

For example, at 60 Hz and a conductor temperature of 25 °C, the resistances of 120-A1-7, 250-A1-19, 500-A1-37, and 1000-A1-91 conductors are 0.5 %, 1 %, 3.5 %, and 13 % higher than the dc resistance due to skin effect.

One of the interesting things about skin effect is that while the dc resistance of the conductor increases with temperature, the skin effect decreases. For the 1000-A1-91 stranded conductor described in the preceding paragraph, the dc resistance at 75 °C is approximately 20 % higher than the dc resistance at 25 °C, but the additional increase in resistance due to skin effect, which is 13 % at 25 °C, is only 9 % at 75 °C. This occurs because the “skin depth” increases with the higher resistivity of the aluminum at the higher temperature.

Skin effect also causes an increase in the ac resistance of larger non-homogeneous ACSR conductors. For smaller ACSR conductors with one or three layers of aluminum strands, however, the ac resistance is also increased (at high current densities) by the axial magnetic field in the steel core:

- For small ACSR conductors, with a single layer of aluminum (usually 6 wires) around a steel core (usually one wire), the current in the single helically wrapped layer of aluminum wires causes a relatively high magnetic field in the steel core resulting in both eddy current and circulating current losses in the core.
- For somewhat larger ACSR conductors (e.g. 54/7) with three layers of aluminum wires, the current in each layer is coupled magnetically through the steel core in what is sometimes called a “transformer effect”. As a result, the middle layer current density is higher than the outer and inner layers and, at high current densities, the ac resistance can be as much as 5 % higher than that predicted by the combination of skin effect and temperature.
- For ACSR conductors having two or four layer of aluminum strands, the axial magnetic field in the core is quite low and there are neither core losses nor any transformer effect to adjust ac resistance for.

Cigré TB 345 (Cigré 2008) provides a detailed discussion of ac resistance calculations for bare helically stranded conductors with and without a steel reinforcing core. While a complete calculation method is included in the brochure, the calculations require detailed knowledge regarding aluminum or copper conductivity, wire diameters, lay lengths for each layer of conducting strands, and if there is a steel core, magnetic properties for the steel wires.

As an alternate to performing the calculations described in Cigré TB 345, conductor manufacturers may provide tables of ac resistance values as a function of conductor temperature and correction curves to apply for ACSR having an odd number of aluminum strand layers.

The preceding observations apply to any conductor with aluminum outer layers and a steel core high temperature conductors such as ACSS, GTACSR, and TACSR. In fact, for high temperature conductors, the increased current density may increase the ac resistance adjustments necessary to account for magnetic coupling of the aluminum layer currents through the steel core odd layered high temperature conductors.

For high temperature conductors having composite, non-magnetic cores, these conductors experience skin effect but not the axial magnetic field effects.

8.3.3 Proximity Effect

When two conductors carrying alternating current are spaced relatively close to one another, their mutual induction affects the current distribution in each wire. This distorts the cross-sectional current distribution in the conductors resulting in (1) greater current density on the near sides of the conductor when the current in the conductors is flowing in opposite directions, and (2) at the far sides of the conductor for currents flowing in the same directions. Similar to skin effect, this non-uniform current density, commonly called proximity effect, leads to an increase in resistance and heat loss. Proximity effect is directly proportional to the magnitude of the currents and inversely proportional to the distance between the conductors.

Multi-conductor bandles of bare stranded overhead conductors are normally installed with sufficient spacing such that proximity effects on ac resistance may be neglected.

8.3.4 Inductance and Inductive Reactance

Calculation of the inductance and inductive reactance of a transmission line involves a straightforward application of the familiar concepts of magnetic fields and magnetic induction. See for example, reference (The Aluminum Association 1982).

Inductance, L, of a electrical circuit is defined as the ratio of the voltage drop along the conductor, V, to the rate of change of current, i, passing through it:

$$V = L\frac{di}{dt}$$

The classic inductance formula for a single, round, straight wire in a two-conductor, single-phase circuit is:

$$L = \left[\frac{1}{2} + 2\ln\left(\frac{D}{r}\right)\right]10^{-7} \quad H/m$$

where:

D = distance between the centers of the two conductors (unit distance)
r = radius of the conductor (unit distance)

Note: D and r must be expressed in the same units.

The first term in the above equation results from flux linkages inside the conductor and the second from flux linkages outside the conductor. Since inductive reactance is normally calculated to a 1-meter radius from the conductor center, it is convenient to separate the second term as follows:

$$L = \left[\frac{1}{2} + 2\ln\left(\frac{1}{r}\right) + 2\ln\left(\frac{D}{1}\right)\right]10^{-7} \quad H/m$$

Where:

$1/2 \times 10^{-7}$ = inductance due to the flux inside the conductor
$2 \times 10^{-7}\ ln(1/r)$ = inductance due to the flux outside the conductor to a radius of 1 meter
$2 \times 10^{-7}\ ln(D/1)$ = inductance due to the flux external to the 1-meter radius of the conductor out to distance D

Where r and D are in meters.

Therefore, the equation for inductance may be written as two equations. The first equation for the inductance out to a 1 meter radius is:

$$L_1 = \left[\frac{1}{2} + 2\ln\left(\frac{1}{r}\right)\right]10^{-7} \quad H/m$$

The second due to the flux external to the 1-meter radius out to distance D is:

$$L_e = 2\,10^{-7}\ln\left(\frac{D}{1}\right) \quad H/m$$

In the case of a two conductor line configuration, D is the distance between conductor centers.

In most overhead power lines, the energized conductors are spaced far enough apart that the inductance due to spacing is quite a bit larger than the inductance to one meter. Therefore, while accuracy requires us to determine the inductance to 1 meter, the impact of conductor stranding or crossection area has a relatively small impact on the inductance of the three phase line. Since voltage drop along an overhead line is primarily due to the line's inductive reactance rather than the resistance of the electrical conductors, then reconductoring the line with a larger conductor or with a high temperature conductor will not reduce voltage drop significantly.

The more general method of calculating inductance and reactance expresses the distance between conductors in terms of geometric mean distance (*GMD*), and conductor radius in terms of geometric mean radius (*GMR*). *GMD* is the geometric mean distance between any number of conductors. *GMR* is the mathematically defined radius for a conductor that describes the inductance of a conductor for both internal and external flux out to a radius of 1 meter.

Substituting and converting to practical units of inductive reactance:

$$X_L = 0.1446\left(\frac{f}{50}\right)\log_{10}\left(\frac{1}{GMR}\right) + 0.1446\left(\frac{f}{50}\right)\log_{10} GMD\ \Omega / km$$

Where:

f = frequency, Hz
GMR = conductor geometric mean radius, m
GMD = conductor separation in terms of geometric mean distance, m

Separating terms and letting *Xa* represent the first term and *Xd* represent the second term:

$$X_a = 0.1446\left(\frac{f}{50}\right)\log_{10}\left(\frac{1}{GMR}\right)\Omega / km$$

$$X_d = 0.1446\left(\frac{f}{50}\right)\log_{10} GMD\ \Omega / km$$

Therefore:
Where:

X_a = inductive reactance due to the flux internal to the conductor plus the external flux to a radius of 1 meter.
X_d = inductive reactance due to the flux surrounding the conductor from a 1 meter radius out to the center of the parallel return conductor

For a two-conductor, single-phase line the total inductive reactance, phase to neutral, is two times the reactance for one conductor as calculated above.

$$X_L = 2\,(X_a + X_d)\,\Omega / km$$

The *GMR* of a conductor represents the radius of an infinitely thin tube whose inductance under the same current loading is equal to that of the conductor.

Similar equations can be developed for capacitance and capacitive reactance of an overhead line.

8.4 Limits on High Temperature Operation

For new transmission lines, particularly for operating voltages in excess of 300 kV, phase conductors are chosen to minimize electrical losses over the life of the line and must be large enough to minimize electrical Corona and audible noise. Given these environmental constraints, the phase current under system normal conditions seldom causes the conductor temperature to be much more than 5C to 15C above air temperature.

For existing ac lines, particularly those at operating voltages less than 300 kV, the power flow may occasionally cause the phase conductors to reach temperature well above air temperature. During such high conductor temperature events, there are three primary concerns:

- The sag of the self-supporting conductor must be limited to maintain adequate electrical clearances to ground, nearby buildings, and other conductors.
- The aluminum (or sometimes copper) strands in the bare overhead conductor must not be allowed to anneal, reducing the conductor design strength and leading to tensile failure under subsequent ice or wind loading events.
- The full-tension connectors must not be allowed to lose "pull-out" strength due to excessive high temperature cycling and again failing under high tensile load events.

Maintaining the minimum electrical clearances at every point along any overhead power line is the most essential concern because inadequate clearances can lead to public safety issues. Therefore, new overhead lines are normally designed and existing overhead lines are always uprated with a primary concern about the accuracy of high temperature sag calculations. Even during brief emergencies, minimum electrical clearances must be maintained.

Annealing of aluminum and copper wires does not immediately impact public safety. Therefore during system emergencies, some aging of connectors and conductors due to annealing may be tolerated as long as the cumulative effect of such events over the life of the line does not lead to a tensile failure.

8.4.1 Thermal Rating and High Temperature Limits (Cigré TB 601)

For any given high-voltage overhead line, it is common for two or more thermal limits to be specified. There is always a normal or continuous rating which specifies the maximum power flow allowed with the power system operating normally, and there is often a second (higher) emergency, or limited-time thermal rating, which specifies the maximum power flow after a system contingency which has an associated maximum duration (typically 15 minutes to 24 hours). The emergency rating is usually calculated for a higher conductor temperature than the normal rating and the maximum number of emergency events over the life of the line may also be limited.

The maximum allowable conductor temperature (MACT) used in calculating normal, continuous line ratings is chosen conservatively so that the aluminum or copper conducting strands will not be annealed significantly over the planned life of the line (e.g. 75 °C) and any connectors will not age prematurely.

The MACT used in calculating the emergency rating is often high enough (e.g. 100 °C) to cause some annealing of aluminum or copper strands over the life of the line and typically generates the maximum sags along the overhead line at which minimum electrical clearances must be assured by proper design and maintenance.

Regardless of the case, the two issues that require attention are the loss of conductor strength and increased conductor sag. Annealing causes a decrease in the conductor's strength and performance, necessitating the eventual replacement of this component. Because of the difficulty associated with taking a line out of service, and the large expense associated with the replacement of a circuit's conductor, the operator clearly needs to balance the need for increased load flow with the economic risk associated with the premature replacement of the component, and the loss of service life or the safety risk associated with providing inadequate clearances.

8.4.2 Maintaining Electrical Clearances (Cigré TB 244)

If the maximum allowable conductor temperature is to be increased, then the corresponding maximum conductor sag will increase and existing electrical clearances will decrease. A careful physical review of the line under everyday conditions is required for the computation of revised line clearances at the new higher temperature. With steel-reinforced aluminum conductors (e.g. ACSR), the thermal elongation rate at high temperature must also be re-evaluated as discussed in later sections of this brochure.

If the electrical clearance, corresponding to the new higher conductor temperature, is determined to be above the appropriate legal minimum at all points along the line, then no modifications need be undertaken. Verification of adequate sag should be undertaken after establishing higher ratings without physical modification of the line. The calculation of clearances at high conductor temperatures should consider the possible permanent elongation of aluminum conductor due to extended operation at high temperature.

If electrical clearances corresponding to the new higher conductor temperature are inadequate, then either the support points must be raised, the conductor tension increased, suspension clamp positions changed, or conductor length reduced. All such physical modifications must be carefully considered and strain structures reinforced if these conductor changes increase the maximum conductor tensions.

8.4.3 Limiting Loss of Tensile Strength (Cigré TB 244)

For conductor temperatures above 90 °C, hard-drawn aluminum (AL1) (and copper strands) will lose significant tensile strength ("anneal") over time. Steel core wires do not anneal for temperatures below 300 °C do not affect the tensile strength of steel strands. Aluminum conductors having a steel core (ACSR) experience loss of composite strength if operated above 90 °C but, since the strength of the steel core is unaffected, the reduction in tensile strength in the aluminum strands is of less concern than for phase conductors made entirely of aluminum (or copper) strands.

Aluminum strands made from rod made by the continuous casting process are less susceptible to annealing than those drawn from "rolled rod." Since the rod source for an existing stranded conductor may be unknown, it is conservative to assume "rolled rod" as the source of aluminum wires.

Copper wires also anneal at high temperatures similar to aluminum as shown in Figure 8.5 (Hickernell et al. 1949).

For both copper and aluminum wires, the conductor temperature must remain above 90 °C for an extended period of time for the reduction of strength to become significant. For example, with reference to Figure 8.4, an all aluminum conductor at 100 °C must remain at that temperature for 400 hours to lose 5 % of its tensile strength. This loss of tensile strength is cumulative over the life of the line so routine emergency operation at 100 °C may be unacceptable over time even though individual events may persist for no more than a few hours.

As the conductor temperature increases, the rate of annealing increases rapidly. At 125 °C, an all aluminum conductor will lose 5 % of its tensile strength in only 30 hours.

The loss in tensile strength, at temperatures above 100 °C (above 125 °C for wire from continuous cast rod) may be limited by using "limited time" ratings where high currents are allowed only for brief periods of time. As noted in many references, the presence of a steel core, which does not anneal, reduces the loss of strength for ACSR conductors.

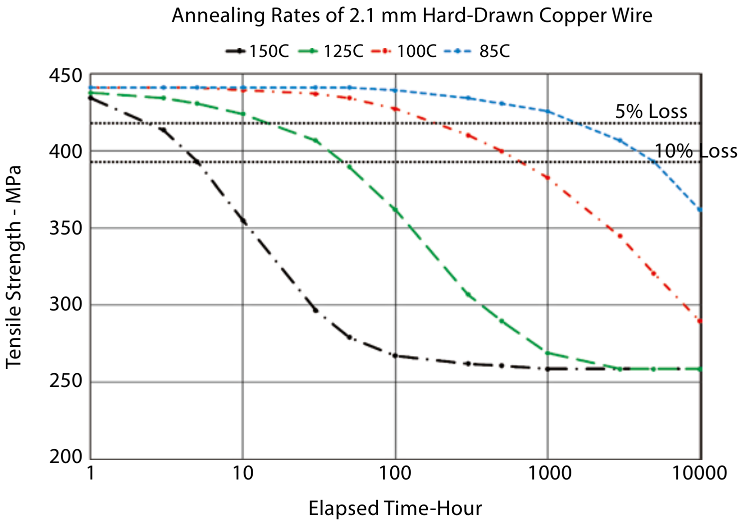


Figure 8.5 Annealing rates for 2.1 mm diameter hard-drawn copper wire.

8.4.4 Avoiding Connector Failures

Unless an increase in rating is preceded by a careful inspection of the energized conductors, connectors, and hardware, the higher operating temperatures may result in a reduction in reliability. As described in reference (Cigré 2002), the detection of "bad" compression splices prior to their failure during high tension loadings is not simple. Regardless of the probability of mechanical failure a connector is usually considered failed if it operates at a temperature in excess of the conductor.

There are two types of connectors: low tension and full tension dead-ends and splices. Low tension connectors include compression and bolted types and are used at strain structures in "jumpers" and other locations where the full rated mechanical load of the conductor will not develop. Full tension splices are found in span and at termination points of line sections.

One of the greatest challenges in increasing the line capacity without replacing the conductors concerns evaluating the connectors. This is the result of a number of factors:

- The workmanship of old connectors is problematic.
- There may be a variety of existing connector types to evaluate.
- Infrared temperature measuring cameras are unrealiable at normal electrical load levels.
- Corrosion in connectors is hard to detect.

As a result of these uncertainties, an effort should be made to identify old connectors that are likely to fail under increased electrical loads. This can be done with infrared or resistance checks [30]. If the condition of existing connections is uncertain, then shunts or mechanical reinforcement should be considered in order to avoid mechanical failures at high current loading.

8.5 Sag-Tension & Stress-strain Models

Sag-tension calculations are a very necessary part of the line design and uprating process. Cigré TB 324 (2007) discusses the calculation methods in use and includes detailed and technically rigorous examples.

Historically, for most overhead transmission lines, the sag of conductors (or tension) is measured at the time of construction when the line is not energized. At the time of installation, the conductors are at a temperature of 10 °C to 35 °C and tensioned to no more than 10% to 30% of their rated tensile strength. Once the line is constructed, the phase conductors may be subject to high temperatures during periods of high electrical loading and both the lightning shield wires and phase conductors must remain intact during high ice and wind load events for an expected useful life of 40 years or more. Under all foreseeable conditions, the conductors must not break under high tension, fatigue under persistent wind-induced motions, nor sag such that minimum electrical clearances are compromised.

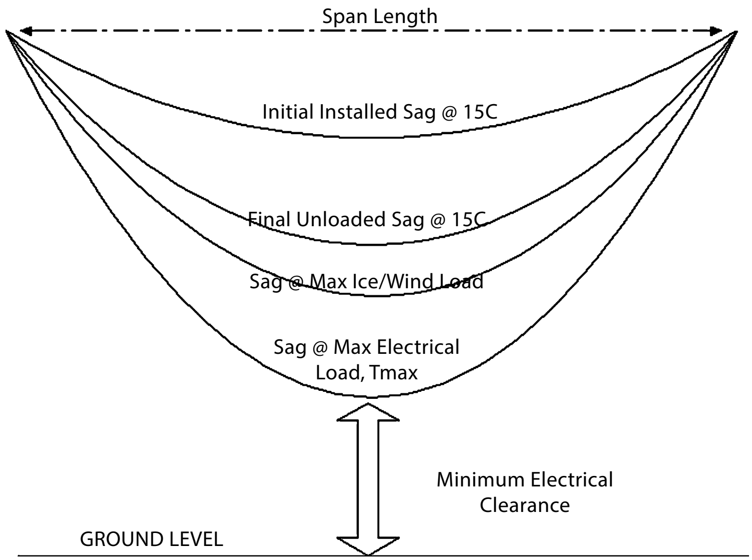


Figure 8.6 Catenary variation with conductor temperature, ice & wind loads, and time after installation where Tmax (MACT) is the maximum conductor temperature.

To assure that these conditions are met over the life of the line, the engineer must specify initial measured (i.e. stringing) sags, based upon the following "sag-tension" calculations:

- Sags and/or tensions after plastic elongation of the conductor due to severe ice and/or wind loads and to long-term creep elongation of aluminum strand layers under normal everyday tension (difference in sag between the Initial and Final Sag at 15 °C in Figure 8.6).
- Sags and tensions for all foreseen temperatures, over the life of the line, including those (above 50 °C) which may result from high electrical current loads (See sag at maximum electrical load in Figure 8.6). The maximum conductor tension under ice and wind loads which "strain" structures (i.e. dead-end and angle) must withstand and the corresponding maximum sag which must not infringe on minimum electrical clearances.
- Conductor tensions during the coldest periods of winter to allow for sufficient self-damping to prevent Aeolian vibration-induced fatigue over the life of the line.

8.5.1 The Catenary Equation

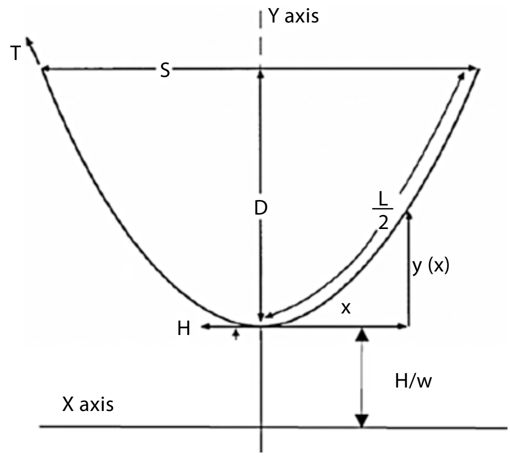
The catenary equations (both exact and approximate) are examined for both level and inclined spans. The various relationships between sag, tension (horizontal and total), weight per unit length, and span length are studied and explained in Cigré TB

324. The concept of "slack" (difference in length between conductor and span) is defined and an important discussion of limits on calculation accuracy is included.

Both approximate "parabolic" equations and the exact hyperbolic catenary equations are explained. The catenary constant (tension divided by weight per unit length) is shown to be an essential parameter of these equations (Figure 8.7).

Figure 8.8 shows a typical relationship between sag, conductor tension, and "slack", calculated with the catenary equation. As explained in the brochure, an increase in any or all of the components of conductor elongation (e.g. thermal, elastic, and plastic) leads to greater sag and reduced tension.

Figure 8.7 The Catenary Curve for Level Spans.



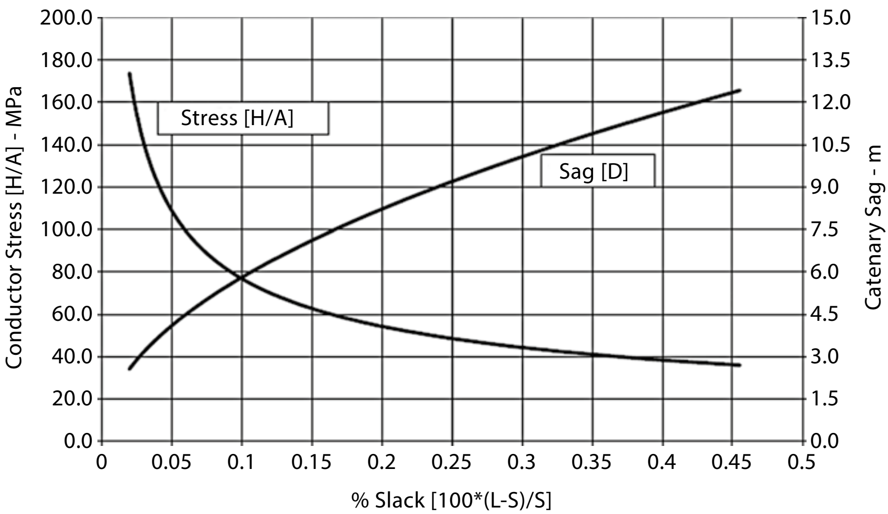


Figure 8.8 Conductor Stress (H/A) and Sag (D) vs. %Slack (100*(L-S)/S) where L = conductor length and S = Span length based on the catenary equations.

The catenary equation for a conductor between supports at equal heights or at different heights is the same. It is expressed in terms of the horizontal distance, x, from the vertex (or low point) of the catenary to a point on the catenary which is y(x) above the vertex. The catenary equation is given by:

$$y(x)=\frac{H}{w}\left[\cosh\left(\frac{wx}{H}\right)\text{-}1\right]\cong\frac{wx^2}{2H}$$

The expression on the right side of the preceding equation is an approximate parabolic equation based upon the first term of the MacLaurin expansion of the hyperbolic cosine. The approximate parabolic equation is valid as long as $x^2\ w^2/12H^2 << 1$.

For a level span, the low point is in the center, and the sag, D, is found by substituting x = S/2 in the preceding equations. The exact catenary and approximate parabolic equations for sag become the following:

$$D=\frac{H}{w}\left\{\cosh\left(\frac{wS}{2H}\right)\text{-}1\right\}\cong\frac{wS^2}{8H}$$

The preceding approximate parabolic equation is valid as long as $w^2\ S^2 / 48\ H^2 << 1$. Hence, it is usually not valid for long, steep, nor deep spans such as may be found in river, lake or fjord crossings. On the other hand, one can readily see the relationship between sag, tension, weight per unit length and span length in the approximate equation (e.g. Sag, *D*, is proportional to the square of the span length, *S*) in the parabolic equation.

8.5.2 Mechanical Coupling of Spans

Transmission lines are usually comprised of multiple line sections. Each line section is terminated at each end by a strain structure that allows no longitudinal movement of the conductor attachment points and that the terminating insulator strings experience the full tension of the conductors. Tangent suspension structures are used within the line section to support the conductors. At suspension structures, the insulators and hardware used to support the conductors are usually free to move both transversely and longitudinally to the line and any modest difference in conductor tension between adjacent spans is equalized by small movements of the bottom of the insulator strings.

This tension equalization between suspension spans works reasonably well for modest changes in conductor temperature and small differences in ice and wind loading. Cigré TB 324 explains how this simplifies the sagging of conductor during construction and stringing and in simplifying sag-tension calculations with the assumption of a "ruling" or "equivalent" span.

The discussion of slack, and the sensitivity of tension and sag to it, is applied to demonstrate how tension equalization at suspension supports occurs and under what conditions errors in calculation become significant. The physical understanding of the ruling span concept, as described in the brochure, is helpful in identifying those line design situations where it should not be used.

8.5.3 Conductor Tension Limits

Sag-tension calculations are normally performed with multiple constraints on tension and sag. For example, the maximum tension under a specified wind and ice load condition may be limited to 50 % of rated strength and the conductor tension under everyday conditions may be limited to a tension over weight per unit length value of 1000 meters.

The brochure describes the purpose of various tension limits and recommends references that provide guidance in setting specific values.

8.5.4 Conductor Elongation – Elastic, Plastic, and Thermal

The most important differences in sag-tension calculation methods involve the modeling of conductor elongation due to changes in tension, temperature and time. In the simplest elongation model ("Linear Elongation"), plastic elongation is ignored, and conductor elongation under tension is assumed elastic. In a somewhat more sophisticated model ("Simplified Plastic Elongation"), plastic elongation is represented by a typical value based on experience. In the most accurate conductor elongation model ("Experimental Plastic Elongation"), plastic elongation is calculated based upon experimental laboratory conductor test data. In the experimental plastic elongation model, plastic increases in the conductor length are calculated (including initial strand deformation and settling, worst-case ice/wind load events, and long-time "creep" elongation due to sustained normal tension) based upon line design assumptions and historical field data.

The linear elongation model is simple to understand and allows algebraic solutions to sag-tension conditions. However, by ignoring plastic conductor elongation, maximum structure tension loads and conductor sag at high temperature may be overestimated.

The Experimental Plastic Elongation model has several advantages: (a) it yields realistic structure tension loads; (b) calculation of high temperature sags with ACSR (A1/SA1) is more accurate; and (c) the plastic elongation of the conductor can calculated based assumed loading events rather than using a typical value based on experience (Figure 8.9).

8.5.5 Sag-tension Calculation Methods

Cigré TB 324 acknowledges the widespread use of numerical solutions to sag-tension calculations but uses graphical representations to provide the reader with

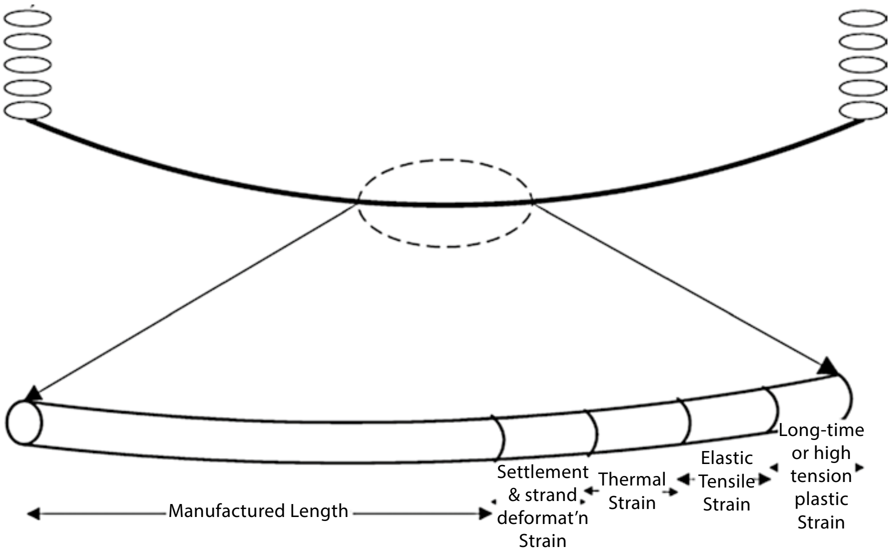


Figure 8.9 Conductor elongation diagram.

insight concerning the advantages and limitations of calculation methods of varying complexity. In this discussion, the conductor elongation models are used in combination with the catenary equation to determine sag-tension values for typical high temperature and ice/wind loading events. The sag-tension solutions presented in this chapter illustrate how plastic elongation and thermal elongation, influence the tension distribution between aluminum layers and steel core in ACSR (A1/SA1).

Typical sag-tension calculation results also are discussed. The usual meaning of initial and final conditions is explained and their calculation demonstrated for the different conductor elongation models. The interaction of the steel core and aluminum layers under high tension and high temperature conditions is demonstrated graphically.

8.5.6 Parameter Sensitivity

Variation in the thermal elongation coefficient of a stranded aluminum conductor can have considerable influence on the sags calculated for a line at high conductor temperatures. As shown in Figure 8.10, the sag (vertical axis) at 100 °C (9.7 m) increases by 200 and 500 mm when the coefficient of thermal expansion (CTE, horizontal axis) is increased by 10 % and 30 %, respectively.

It is clear from the discussion that, even with very careful laboratory tests and modern calculation methods, sag calculation errors cannot be less than 100 to 200 mm and are generally considerably greater.

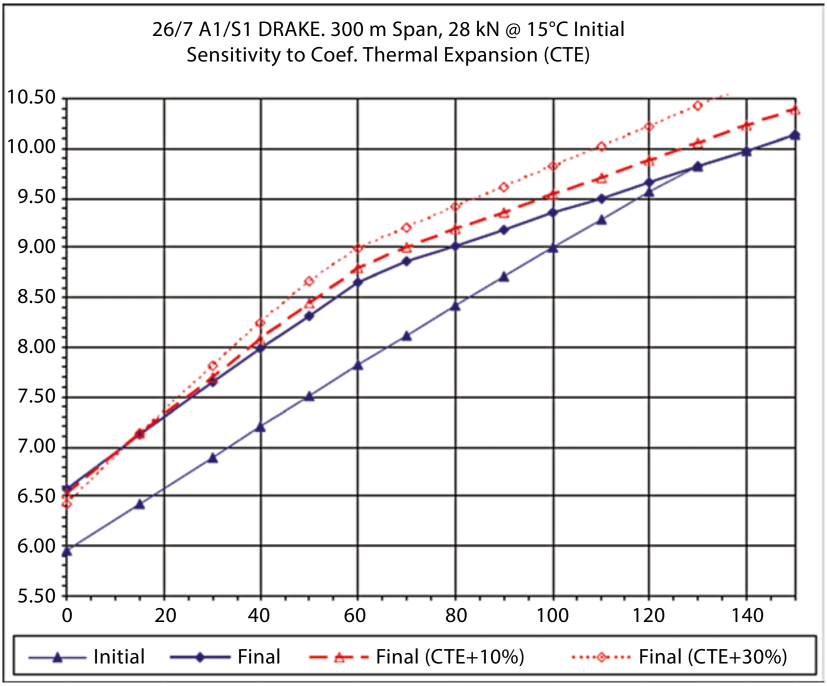


Figure 8.10 Influence of variation in the coefficient of thermal elongation on high temperature sag.

8.5.7 Sag-Tension Conclusions

The sag-tension calculation process, with both exact and approximate catenary equations, is described in some detail. Three conductor elongation models are defined and the more complex, experimentally based model is recommended because its use allows the line designer to estimate both high temperature sags and maximum structure tension loads with superior accuracy.

Given the prevalence of numerical calculation tools, there is little need to use the approximate catenary equations or the simplified elastic conductor elongation models but the ruling span assumption of tension equalization between spans appears to be sufficiently accurate to be used in many new line designs.

Regardless of the calculation technique and conductor elongation model selected, there is a need for sufficient clearance buffers in the design of new lines and the uprating of existing lines because of uncertainties in modeling the load sequence and detailed mechanical behavior of bare stranded overhead conductors.

Concentric-lay stranded conductors elongate elastically under small tensile loads applied for very short times. Under such loads, it is valid to represent the complex behavior of a conductor by a simple elastic modulus.

The elongation of concentric-lay stranded aluminum conductors, however, is both elastic and plastic in response to tension applied over time. Figure 8.11 plots data from a standard stress-strain test performed in a laboratory on a sample, typically 10

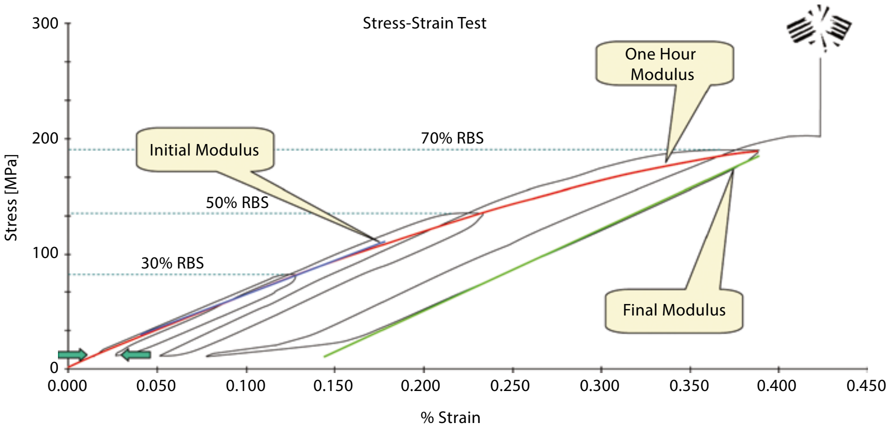


Figure 8.11 Typical stress-strain test results with 1-hour initial curve drawn and both initial and final modulus shown. RBD = RTS.

to 15 meters in length. The cable sample is loaded into a long bed tensile test machine and an initial bias tension load of 5 kN or 8 % of the conductor rated tensile strength (RTS), whichever is smaller, is applied. Tension is then applied three consecutive times, at increasing tension levels of 30 %, 50 % and 70 % of the conductor rated strength. The tension is held for 30 minutes at the 30 % tension level and one hour at both the 50 % and 70 % tension levels. At the end of each hold period the tension is reduced to the starting bias tension. The conductor is loaded a fourth, and final time, and pulled to 80-85 % of its calculated RTS. The extensometers are removed from the sample and the conductor is pulled to tensile failure.

Notice that the conductor length increases plastically during each hold period and that the final modulus (slope) after each hold period, is approximately the same.

In order to model the stress-strain behavior of non-homogeneous conductors such as ACSR, two such tests are done. The first is on the complete conductor and the second is on the steel core alone. The difference between the two stress values is the stress in the aluminum layers.

By having separate stress-strain curves, creep elongation rates, and thermal elongation rates, the complex sag variation at both high temperatures and high tensions can be calculated.

This is also particularly important with high-temperature conductors which must be modelled by such a two-part stress-strain experimental model to determine high temperature sags accurately.

8.6 Special Purpose Conductors

There are two broad categories of special purpose conductor which are meant to be alternatives to the use of ACSR or A1, all aluminum concentric stranded conductors in certain new lines or in up-rating existing lines. The first category is suitable for operation at moderate temperatures (<100 °C) including conductors using alternative materials to those used in ACSR such as heat-treated high strength aluminum alloys (A3) either alone or in combination with regular aluminum strands (ACAR conductors), AACSR (Aluminum Alloy Conductors Steel Reinforced), or non-round motion control conductors such as Self Damping Conductor and Twisted Pair (TP). The second conductor category is suitable for continuous operation above 100 °C and includes both annealed and zirconium alloys of aluminum and both high strength steel, INVAR steel and high temperature carbon and metal composite cores.

These various conductors and their application in the uprating of existing overhead lines is presented in detail in references (Cigré 2003) and (Overhead Conductor Manual 2007). Cigré TB 244 contains many references to more detailed discussions of each conductor.

8.6.1 Conductors for Use with Maximum Temperature <100 °C

In most new lines, particularly those designed for operating voltages above 300 kV, limits on normal or emergency power flow are more likely to be electrical rather than thermal. Cigré TB 643 delivers information on the operation of conventional conductor systems at temperatures higher than traditional ratings of 75°C continuous operation and 100°C emergency for short excursions to allow for continued operation during contingencies. Operating conductor systems above 100°C allows for higher current flow over existing lines, but has short and long term consequences that must be considered for the safe operation of the line (Cigré 2015)

8.6.1.1 All Aluminum Alloy Conductor (AAAC)

For transmission lines strung with ACSR, designed, for relatively low temperature operation (50 to 65 °C), restringing with AAAC can offer a significant improvement in thermal rating. AAAC conductors have a higher strength to weight ratio than ACSR and, if strung to a similar percentage of rated tensile strength (RTS), can be rated for higher temperature operation than ACSR, without exceeding design sags. It should be noted however, that stringing to a similar percentage of RTS would result in a much higher ratio of horizontal tension (H) to unit weight of conductor (w), which can cause problems for lines sensitive to Aeolian vibration.

The alloy used in AAAC is, most commonly, a heat-treated aluminum-magnesium-silicon alloy, designated by IEC 60104. There are many tempers available, varying in strength and conductivity. Conductivities range between 52.5 % and 57.5 % IACS (EC grade Aluminum has a conductivity of 61 % IACS), while strengths vary between 250 MPa and 330 MPa. As a rule of thumb, the higher the conductivity of the alloy, the lower the strength, and vice versa.

Aluminum alloy conductors (295 MPa, 56.5 % IACS) have been widely used in the UK to replace ACSR (“Zebra”, 400 mm^2 nominal aluminum area, 54/7 × 3.18 mm strands). Comparing properties, an AAAC with the same diameter as Zebra will be 3.5 % stronger, 18.5 % lighter and have a 5 % lower DC resistance. Matching either the resistance or the strength of Zebra gives similar results, but with a slightly smaller conductor. If climatic conditions and tower capabilities permit the use of a larger conductor, then an AAAC with the same unit weight as "Zebra" will be 24 % stronger, have a 20.5 % lower DC resistance, but have a diameter almost 10 % larger.

Where the AAAC can be strung at a similar percentage of RTS to ACSR, thermal rating increases of up to 40 % can be achieved with a conductor of the same diameter and 50 % with a conductor of the same weight. This may require additional mechanical damping since the H/w ratio of the AAAC will be higher than the ACSR that it replaces. There are no ferromagnetic or transformer effect losses with AAAC.

AAAC generally has good corrosion performance. The lack of a steel core removes the possibility of galvanic corrosion taking place, such as is possible in ACSR. However, corrosion is still possible, especially in coastal regions, and it is often standard practice to use greased AAAC to prevent corrosion by salt aerosols.

8.6.1.2 Aluminum Conductor, Alloy Reinforced (ACAR)

ACAR combines strands made from aluminum alloy, typically the same as that used for AAAC, and EC grade aluminum. This allows the properties of the conductor to be optimized for a particular application. By increasing the amount of EC grade aluminum used, the conductivity of the conductor is increased, though at the expense of strength. Likewise, if the number of alloy strands is increased, the mechanical strength of the conductor is increased at the expense of conductivity. Again, as with AAAC, the benefits of using ACAR conductors to replace ACSR conductors will depend on allowable stringing tensions.

8.6.1.3 Shaped-wire Conductors

Overhead line conductors are normally constructed from helically wound wires with a circular cross section. This results in a conductor cross-section containing fairly large inter-strand voids, with ~20 % of the total cross-sectional area of the conductor being air. By using wires with a trapezoidal shape, conductors can be constructed with an increased proportion of metal within their cross section. Compacted conductors can be homogenous like AAAC/TW, with all strands except the king wire being of trapezoidal shape, or non-homogenous like ACSR/TW, with a round-wired, steel core surrounded by trapezoidal aluminum wires. However, the strands that make up shaped-strand conductors need not be trapezoidal. One conductor design has mosaic ("Z") shaped strands that effectively lock together.

Shaped-wire conductors have a larger aluminum area and thus lower resistance than a normal round strand conductor with the same outside diameter. When reconductoring an existing line with shaped-wire conductor, the increased weight of the conductor will result in slightly higher tower loads, but climatic loads due to wind and/or ice will not be increased, as these are a function of diameter. For wind-only loading conditions, loads may actually be lower, as the aerodynamic properties of the surface result in a lower drag coefficient at high wind speeds. One example of shaped-wire conductor that achieves a low drag coefficient is one that has an oval cross-section, the orientation of which varies along its length, giving a "spiral-elliptic" shape.

Furthermore, shaped-wire conductors have been shown to possess slightly better characteristics of energy absorption of vibration, due to the higher surface area of the contacts between strands of adjacent layers which results in lower inter-strand contact stresses (Figure 8.12).

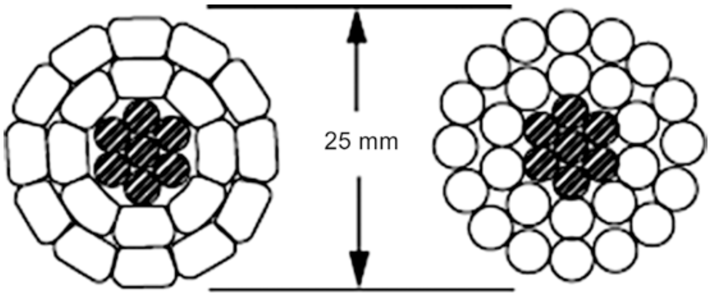


Figure 8.12 Comparison of "same diameter" TW and conventional "round stand" conductors. The aluminum area and weight per unit length of the TW conductor is approximately 20 % higher.

8.6.1.4 Motion-resistant Conductors

Shaped-wire conductors have also been used to reduce the effects of wind-induced motions. Such conductors include "self-damping" (SDC) conductor, which incorporates small gaps between the successive layers of strands, allowing energy absorption through impact.

Another conductor which resists motion is the "Twisted Pair (TP)" conductor, consisting of two standard round conductors wrapped about one another with a helix approximately 3 meters long. This resists motion due to its aerodynamic characteristics and is widely used in the United States.

Existing lines are normally designed or reconductored with TP or SDC in order to improve their resistance to ice galloping flashovers and to Aeolian vibration. At least theoretically, TP can be made with any of the conductors discussed in this section, possibly including those designed for operation at high temperature.

8.6.2 Conductors for Operation at High Temperature (>100 °C)

There are many types of High Temperature conductor including – TACSR (or ZTACSR), GTACSR (or GZTACSR), TACIR (or ZTACIR), ACCR, ACCC, and ACSS. Each is stranded with a combination of aluminum alloy wires for conductivity, and reinforced by core wires of steel or a composite carbon or metal material. Steel core wires must be coated with a zinc layer to prevent corrosion between the steel and aluminum. The composite core materials do not. The properties of the various alloys and tempers of aluminum and the various composite core materials and high strength steel core wires are compared in Tables 8.4 and 8.5. For example, TACIR is manufactured with layers of TAL aluminum alloy wires over an Invar steel core and ACSS is available in both round wire and trapezoidal wire constructions with standard strength or high strength core wires (Figure 8.13).

Any of the HTLS conductors is capable of operating continuously at temperatures of at least 150 °C. Some of the conductors can be operated as high as 250 °C

Table 8.4 Characteristics of Aluminium and High Temperature Aluminum Alloy Wires

Type of Aluminum		Conductivity (%IACS)	Min. Tensile Strength (MPa)	Allowable Operating Temperature(°C)	
				Continuous	Emergency*
Hard Drawn	1350-H19 (A1)	61.2	159–200	90	120
Thermal Resistant	TA1	60	159–176	150	180
Extra Thermal Resistant	TA3	60	159–176	210	240
Fully Annealed	1350-0	63	59–97	200–250**	250**

*Emergency operating temperature is not well defined but it is generally agreed that the emergency temperature should not apply for more than 10 hours per year.
**Fully annealed aluminum strands can operate at temperatures in excess of 250 °C but are normally limited to lower temperatures because of concerns about connectors and steel core wire coatings.

Table 8.5 Conductor core materials for use in High temperature low sag conductors

	Min. Tensile Strength (MPa)	Modulus of Elasticity (GPa)	Minimum % Elong. @ Tensile Failure	Coef. of Linear Expansion (×10-6)
Galv. Steel HS	1230–1320	206	3.5	11.5
Galv. Steel EHS	1765			
Alum. Clad (AC) 20.3 % I.A.C.S.	1103–1344	162	3	13.0
Zinc-5%Al. Mischmetal Standard				
High Strength	1380–1450	206 (Initial)	3.5	11.5
	1520–1620	186 (Final)		
Galv. Invar Alloy	1030–1080	162	3	2.8-3.6
CTC Carbon Fiber composite core	2200	125	2.0	1.6
3M Ceramic Fiber reinforced aluminum	1400	220	0.64	6

without significant changes in their mechanical and electrical properties. Each conductor type has certain advantages and disadvantages, which are discussed briefly in the following.

8.6.2.1 High Temperature Conductor Materials

These conductors, designed for high temperature operation, consist of various combinations of the aluminum and steel wire materials listed in Table 8.4 and Table 8.5.

Zinc-5 % Aluminum mischmetal coated steel wire is capable of operation at higher temperatures than normal galvanized steel wire (i.e. 250 °C instead of 200 °C). Invar steel wire has a notably lower rate of thermal expansion when compared to

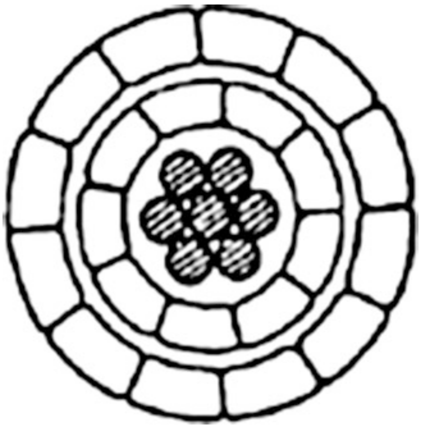


Figure 8.13 Self-damping (SD) conductor showing the small radial gap between layers.

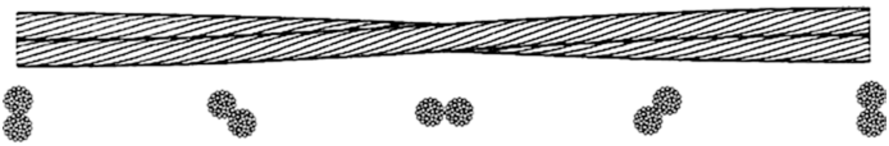


Figure 8.14 Twisted Pair conductor which consists of two conventional conductors wrapped helically about each other with a lay length on the order of 3 meters.

ordinary galvanized steel core wire but has somewhat lower tensile strength and modulus (Figure 8.14).

TA1(TAL) and TA3(ZTAL) aluminum wires have essentially the same conductivity and tensile strength as ordinary electrical conductor grade aluminum wire but can operate continuously at temperatures up to 150 °C and 210 °C, respectively, without any loss of tensile strength over time. Fully annealed aluminum wires are chemically identical to ordinary hard drawn aluminum, have much reduced tensile strength, and can operate indefinitely at temperatures even higher than 250 °C without any change in mechanical or electrical properties.

Where a conductor construction referred to could be made up using either the TA1 or the TA3 zirconium aluminum alloy, it is described as (Z)TAL.

As described in the following, high temperature conductors are manufactured with various combinations of the aluminum wire materials shown in Table 8.4 and the reinforcing core materials shown in Table 8.5.

8.6.2.2 (Z)TACSR

(Z)TACSR has the same construction as conventional ACSR, with galvanized steel wires for the core and either AT1 or AT3 thermal-resistant zirconium aluminum alloy wires. With the AT3 aluminum, the core is normally coated with mischmetal rather than using conventional galvanizing.

(Z)TACSR conductor is, in almost all respects, identical to conventional ACSR conductors. The aluminum alloy used in (Z)TACSR has a slightly higher electrical resistivity than standard hard-drawn aluminum, but in all other respects the two conductors are almost identical. Unlike the conductors described below, (Z)TACSR is not, by design, a low-sag conductor. It has the same thermal elongation behavior as ACSR. The main advantage of (Z)TACSR is that its aluminum alloy wires do not anneal at temperatures up to 150 °C for AT1 and 210 °C for AT3 whereas temperatures above 100 °C would cause annealing of the aluminum strands in standard ACSR.

TACSR is currently used in place of conventional ACSR in many new transmission lines in Japan.

8.6.2.3 G(Z)TACSR

Gap-type conductor has a unique construction. There is small gap between steel core and innermost shaped aluminum layer, in order to allow the conductor to be tensioned on the steel core only. This effectively fixes the conductor's knee-point to the erection temperature, allowing the low-sag properties of the steel core to be exploited over a greater temperature range. The gap is filled with heat-resistant grease (filler), to reduce friction between steel core and aluminum layer, and to prevent water penetration (Figure 8.15).

During installation of G(Z)TACSR, the aluminum layers of conductor must be de-stranded, exposing the steel core, which can then be gripped by a come-along clamp. The conductor is then sagged on the steel core, and after compression of a steel clamp, the aluminum layers are re-stranded and trimmed, and aluminum body of the dead-end clamp compressed. Although this special erection technique is different from that employed with conductors of standard construction, the compression splices and bolted suspension clamps are similar. In addition, in order to assure proper performance of this conductor, a special type of suspension clamp hardware must be installed every five suspension spans if the line section contains more than 5 suspension spans (Figure 8.16).

8.6.2.4 (Z)TACIR

As with (Z)TACSR, (Z)TACIR has a conventional stranded construction (identical to ACSR), making use of material innovations to give properties allowing the conductor to be operated at high temperatures. In place of the steel strands of (Z)TACSR, it has galvanized or aluminum-clad invar alloy steel wires for the core and (Z)TAL wires surrounding them. Table 8.4 shows basic characteristics of TAL and ZTAL wires. ZTAL resists annealing up to a continuous temperature of 210 °C.

Invar is an iron-nickel alloy (Fe—36 % Ni) with a very small coefficient of thermal expansion. The typical properties of invar wire are shown in Table 8.5. The

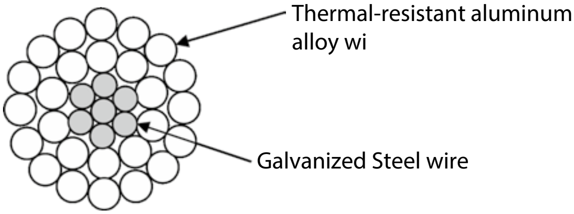
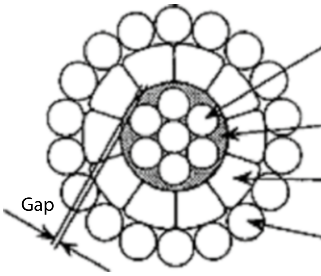


Figure 8.15 (Z)TACSR high temperature (not low-sag) conductor.

Figure 8.16 Cross-section of GTACSR conductor.



coefficient of thermal expansion of invar wire is around one third that of galvanized or aluminum-clad steel wire.

The installation methods and accessories for the conductor are virtually the same as those used for conventional ACSR. A slight lengthening of compression type accessories is required only to satisfy increased current carrying requirements.

8.6.2.5 ACSS and ACSS/TW

Aluminum Conductor Steel Supported (ACSS) is manufactured with both round and trapezoidal aluminum strands. In either case, ACSS consists of fully annealed strands of aluminum (1350-0) concentric-lay-stranded about a stranded steel core. ACSS is not available in conductors with a single strand steel core.

The coated steel core wires may either be aluminized, galvanized, zinc-5 % aluminum Mischmetal coated or aluminum clad. The steel core is available in either standard strength or high strength steel. The “high strength” steel has a tensile strength about 10 % greater than standard steel core wire. In appearance, ACSS conductors are essentially identical to standard ACSR conductors. ACSS is typically available in three different designs: “Standard Round Strand ACSS”, or with “Trapezoidal Aluminum Wire” in constructions with equal area or equal diameter to conventional round wire constructions. Special high strength constructions are also available (Figure 8.17).

In all designs, the use of annealed aluminum strands yields much higher mechanical self-damping than standard ACSR of the same stranding ratio.

Because the tensile strength of annealed aluminum is lower than 1350-H19, the rated strength of ACSS is reduced by an amount dependent on the stranding (e.g. 35 % for 45/7, 18 % for 26/7, 10 % for 30/7) compared to similar constructions of ACSR. In fact, a 45/7 ACSS conductor, with standard strength steel core wire has about the same rated tensile strength as a conventional all aluminum conductors made with hard drawn aluminum wire. The reduced strength of ACSS is normally offset by using extra-high strength or more recently ultra high strength steel core wires, or by using a higher steel core area, or by doing both.

Since the tension in the annealed aluminum wires is so low, the thermal elongation of ACSS is essentially that of the steel core alone. Similarly, given the low tension in the aluminum strands, ACSS does not creep under everyday tension loading. ACSS/TW constructions behave in the same manner as ACSS but have the added advantages of reduced ice and wind loading and reduced wind drag per unit aluminum area.

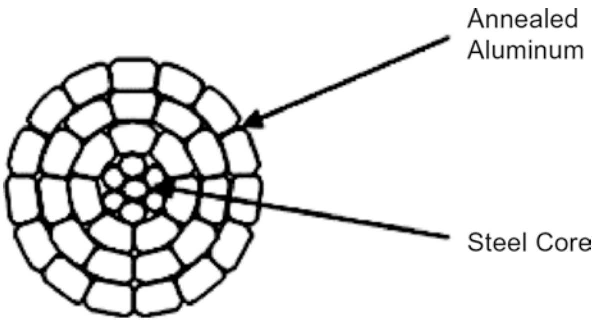


Figure 8.17 ACSS/TW typical construction.

8.6.2.6 ACCR Conductor

3 M Corporation has developed an HTLS conductor consisting of AT3 zirconium aluminum alloy strands over a reinforcing core of ceramic fibers in an aluminum matrix. The conductor has been thoroughly tested in the laboratory, is available commercially, and has been used primarily in reconductoring existing lines. The high elastic modulus of the aluminum composite core and its low thermal elongation rate (half that of steel) makes the conductor particularly useful in existing lines with heavy ice loads and minimum high temperature sag clearances. Special connectors and support hardware are available in two designs from several manufacturers. It has a slightly larger minimum bending radius than stranded steel products, but otherwise installs with the same tools, methods and equipment as ACSR. There is an ASTM standard for the core (B976) and for the complete conductor (ASTM B978). There are presently no IEC standards for the core or the complete conductor but IEC 62004 and ASTMB941 cover zirconium aluminum strands.

8.6.2.7 ACCC Conductor

Composite Technology Corp. developed a HTLS conductor with a carbon-reinforced high temperature thermoset resin core. Carbon fiber has a very low thermal elongation rate which makes this conductor very effective in limiting sag at high temperatures.

The ACCC conductor uses trapezoidal, annealed aluminum (TW) wires over a single strand composite core. The core is unique among HTLS or conventional conductors, having a core which consists of a single large "strand" though multiple carbon fibers are embedded in the resin surrounded by an outer layer of fiberglas strands also embedded in resin (Figure 8.18).

Given the thermoset resin, the manufacturer recommends a maximum continuous operating temperature of 180 °C which is somewhat lower than the other HTLS conductors with steel or aluminum composite cores.

Extensive laboratory tests and field testing of this conductor was especially important in proving that the core material is able to survive when correctly handling during tension stringing and when subject to sometimes severe ice and wind loading.

The low thermal elongation rate of carbon-reinforced resin should result in little or no increase in sag with temperature above the knee-point temperature making this conductor ideal for reconductoring existing lines with severely limited sag clearances. The relatively low modulus of the core (2/3 that of steel) combined with

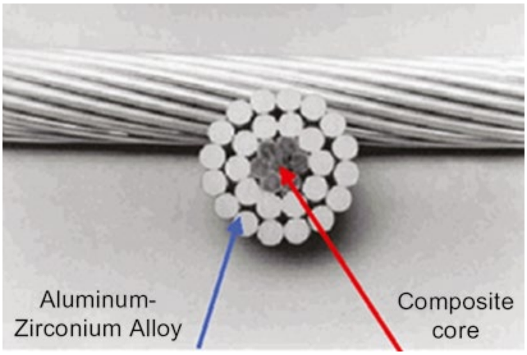


Figure 8.18 ACCR conductor showing the stranded metal composite core.

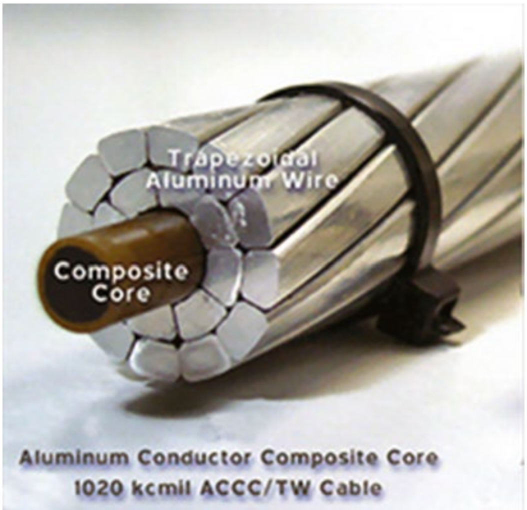


Figure 8.19 ACCC conductor showing its carbon fiber thermoset resin core.

low strength annealed aluminum makes its use in heavy ice loading areas challenging. A higher strength carbon core has been tested (Figure 8.19).

8.6.2.8 Other HTLS Conductors with Carbon Fiber

Several manufacturers have introduced other carbon fiber-reinforced conductors with both annealed and zirconium aluminum alloy strands. Several are quite similar to the CTC conductor. One interesting HTLS variation uses a stranded carbon fiber core (for improved flexibility) with the individual carbon fibers embedded in a thermoplastic (rather than thermoset) resin to be capable of higher temperature operation than carbon fibers in a thermoset resin. The individual core strands are each made from carbon fiber reinforced PPS high performance thermoplastic with a thermoplastic outer capping layer. This conductor combines the high temperature, low sag benefit of carbon fiber plus the flexibility, redundancy and ease of installation of stranded steel products. The stranded core allows tension stringing in a manner the same as ACSR.

8.7 Selecting the "Right" Conductor

Selection of the best conductor for a particular transmission or distribution line depends upon many factors, such as power requirements, terrain, ambient conditions, costs of conductor and supporting structures, and governmental and environmental constraints. In addition to the strength and electrical resistance of the conductor, pertinent properties of interest include the stress-strain relationship, thermal characteristics, and inductive and capacitive reactance.

Conductor selection can be complex when an existing line is to be reconductored in order to increase its electrical power capacity. The replacement conductor must be chosen in order to avoid exceeding the longitudinal tension and the transverse and vertical loads on the existing structures while maintaining electrical clearances and environmental limitations.

With new lines, when the line is long and costly, a complete economic and environmental analysis may be justified. For new lines, at an existing system voltage class, standardization of conductor sizes and types is an important consideration.

With HVDC lines, as demonstrated in Cigré TB 388 (2009), the electrical load factor is generally higher than for AC lines due to the high cost of terminal converter stations but the economic analysis is similar.

The selection process includes both the size and type of conductor but also the number of conductors in the phase bundle.

8.7.1 Factors in Conductor Selection for New Lines

In new AC and HVDC transmission lines, beside the issues of standardization, inventory control and ease of maintenance, the factors that can affect the choice of conductor include the following:

- Ampacity/Thermal Rating
- Audible Noise
- Electrical Losses over the life of the line
- Corona Noise
- Ground and Edge ROW Clearance
- Structure Tension Loads
- Structure Transverse Loads
- Capital Cost of land, structures, and conductor system.

As an example, as shown in the following figure, the maximum conductor tension loading of strain structures can be studied to seek the best choices for both conductor rated strength and installed everyday tension. All three conductor choices have approximately the same ac resistance and outside diameter.

The choice of sub-conductor diameter and number per bundle also determines the conductor surface gradients for HVDC as shown in the following (Cigré TB 388 2009).

The consequences of poor conductor selection can persist for many years or may require significant field repair efforts. Some of the most common problems are:

- Corona Noise Complaints
- Audible Noise Complaints
- Rapid Corrosion Deterioration
- Excessive Wind Vibration leading to conductor fatigue
- High Electrical Losses
- Limited Uprating Options
- Mechanical Failure during severe storms (Figure 8.20).

8.7.2 Replacement Conductor Selection for Existing Lines

If conductor is to be selected for the purpose of increasing maximum power flow on an existing line, then the project goal is typically to increase the line's thermal rating without needing to replace the existing structures and foundations. This is typically accomplished by selecting a replacement conductor capable of operation at higher temperature than the existing but having the same outside diameter, similar tension loads on structures and reduced sag at high temperature (Figure 8.21).

The actual process of choosing a conductor to replace the original conductor is complex. TB 244 (Cigré 2003) provides examples and insight into the process. In

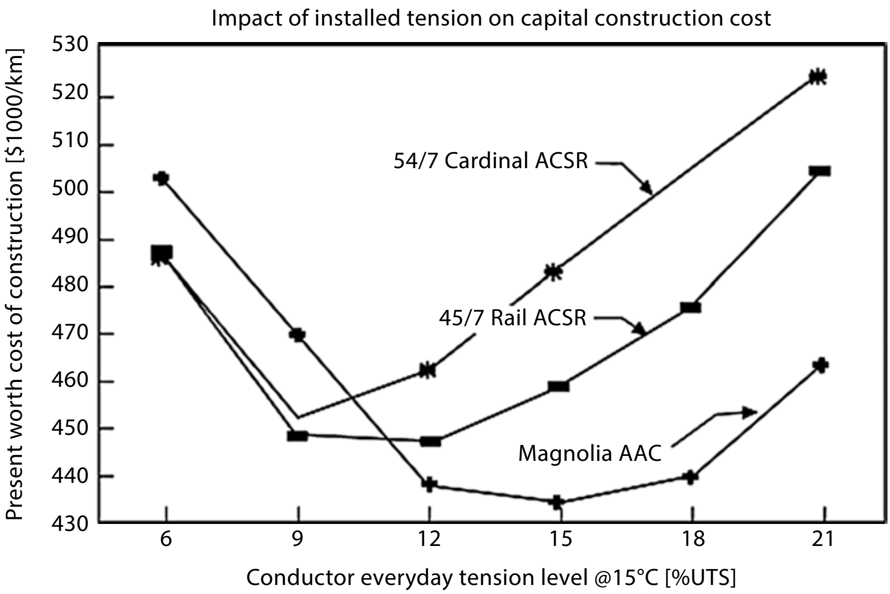


Figure 8.20 Example of how installed conductor tension affects construction cost of lines for three ACSR strandings.

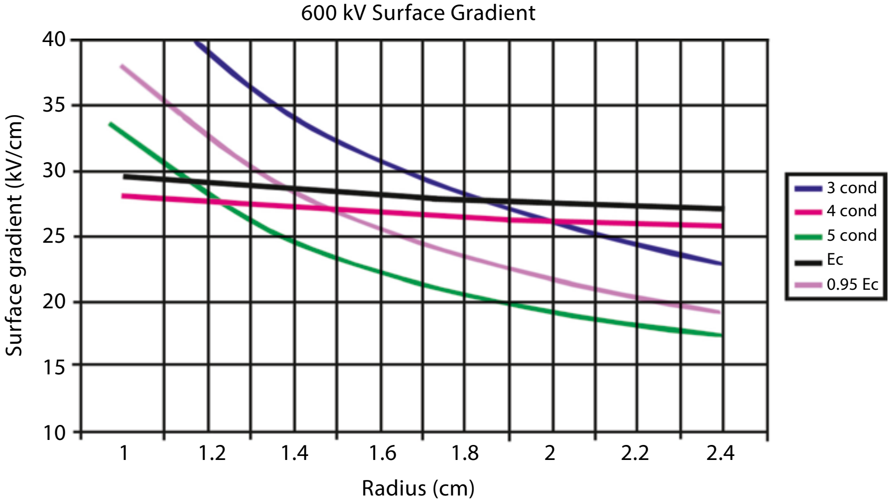


Figure 8.21 Example of how sub-conductor diameter and number of subconductors per phase bundle affects the electric radial surface gradient for HVDC 600 kV.

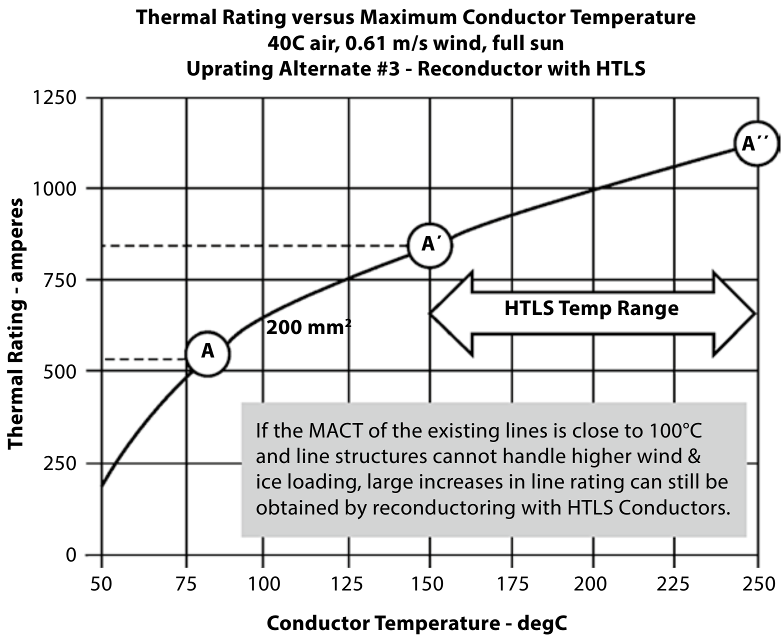


Figure 8.22 llustration of how maximum allowable conductor temperature affects line thermal rating and why high temperature are advantageous.

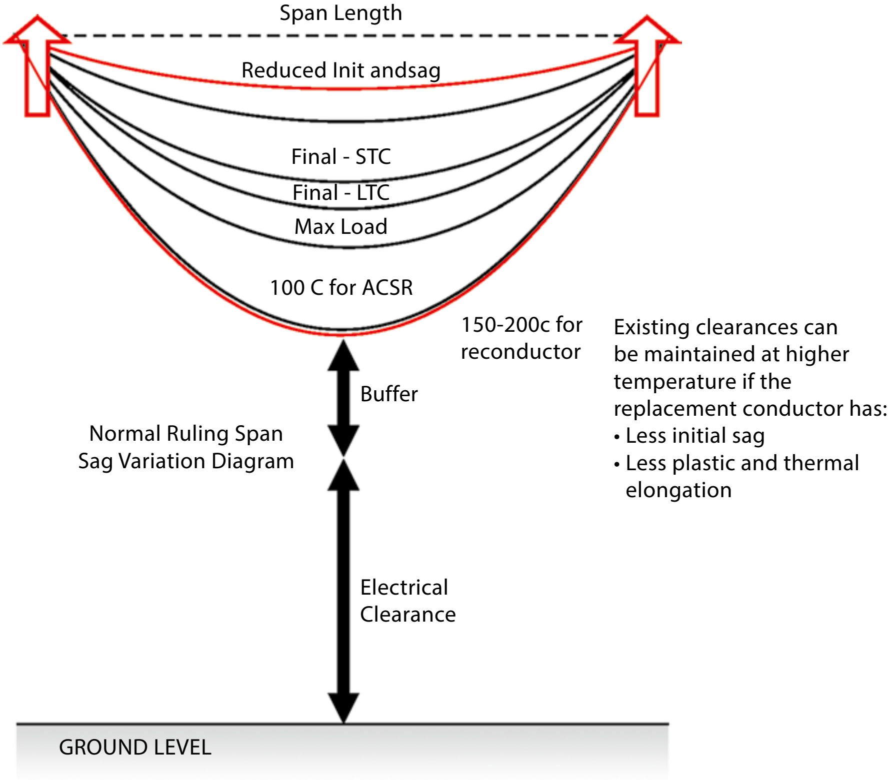


Figure 8.23 Pictorial diagram showing how replacement of a conventional conductor with HTLS allows operation within the original maximum sag allowance at high temperature.

essence, if the maximum allowable conductor temperature (MACT) of the existing line is less than 75 °C, then there are a number of uprating methods available without necessarily reconductoring with a high temperature conductor. But if the MACT is in the range of 100 °C or more, then reconductoring with HTLS conductor is typically necessary to increase the thermal rating significantly. These comments are illustrated in Figure 8.22.

Figure 8.23 shows how the use of an HTLS conductor allows conductor operation at increased MACT without needing to raise the existing structure.

Chapter 18 of this book presents far more detailed analysis involving the use of high temperature conductors for uprating.

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Dale Douglass received a BSME in 1963, an MSEE and PhDEE in 1964 and 1967, respectively, from Carnegie-Mellon University in Pittsburgh, PA, USA. Since 1999, he has been a Principal Engineer with Power Delivery Consultants, Inc., in Ballston Lake, NY. In 1996, he was elected an IEEE Fellow for "contributions to understanding the characteristics and applications of overhead power transmission conductors". From 2000-2006, he was chairman of Cigré WG B2.12 (Electrical Aspects of Transmission Lines). Since 2006, he has been the U.S. representative to SC B2 and chair of WG B2.55 (Uprating Existing Lines). In 2007 he was given the Technical Committee Award and in 2012 was named a Distinguished Member of Cigré by the US National Committee. He has published over 70 technical papers and been the primary author of multiple Cigré technical brochures.

Mark Lancaster has BSc, BSEE and MBA degrees including the Georgia Institute of Technology, and is a registered Professional Engineer. He is employed at Southwire Company, Carrollton, Georgia, USA where he is Director of Overhead Transmission Engineering. He has been in wire and cable manufacturing, R&D and applications since 1987 and has been active in the development of new HTLS conductors, line monitoring and dynamic line rating, holding 4 US patents in these areas. He is active in industry groups including IEEE Overhead Lines, ASTM International and Cigré and has held several leadership positions in these organizations including Chairman of ASTM B01 Conductors Committee from 2009-2014. He is a co-author of the Southwire Overhead Conductor Manual and contributor to the Cigré Overhead Green Book.

Koichi Yonezawa received his electrical engineering degree from Nagoya university. He joined Sumitomo Electric Industries in 1992 and now works for J-Power Systems, which is a subsidiary of Sumitomo Electric. Over the past 20 years, he has engaged in design and engineering of bared conductors related to OHTL, especially HTLS (High temperature low sag) conductors. In study committee B2(Overhead lines) he is a Japanese member of TAG (Technical Advisory Group) 04.

Fittings

9

Pierre Van Dyke, Umberto Cosmai,
and Christian Freismuth

Contents

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P. Van Dyke (✉)
Varennes, Canada
e-mail: vandyke.pierre@ireq.ca.com

U. Cosmai • C. Freismuth

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Summary

The conductor of an overhead transmission line is considered to be the most important component of the line. However, there are many fittings that are required to hold it in place, protect it against vibration phenomena, make it visible to airplane, etc. This chapter describes those fittings with their pros and cons as well as their production processes, how they must be handled and tested.

This chapter is separated into the following sections:

- Processes and technologies for the production of fittings
- Surface finishing and corrosion protection
- Main electrical properties required on fittings
- Quality test procedures for new fittings
- Test procedures to assess the adequacy of old fittings
- Handling of new fittings
- Failure mechanisms
- Influence of fitting designs on other line components
- Connections
- Clamping systems
- Aeolian vibration dampers
- Spacers and spacer dampers
- Aerial wire markers
- Joints and fittings for conductor repair.

List of Symbols

d	Conductor diameter (m)
f_{upper}	Upper frequency (Hz)
H	Horizontal component of the mechanical tension of the conductor (N).
l	Distance of installation of the bretelle clamp (m).
l_{node}	Location of the first node of vibration (m)
L_1	Length of entrance (m)
L_2	Length of contact area (m)
L_3	Length of uncompressed part (m)
m	Mass per unit length of the conductor (kg/m)
R	Resistance (Ω) or (μΩ)
R_{as}	Aluminium sleeve resistance, uncompressed (μΩ/m)
R_{asc}	Aluminium sleeve resistance, compressed (μΩ/m)
R_c	Conductor resistance (μΩ/m)
R_{con}	Contact resistance (μΩ)
R_j	Resistance of a used joint

R_{j0}	Resistance of a new joint
R_{joint}	Joint resistance (μΩ)
$R_{j,Tj=Tc}$	Calculated resistance value at which the joint and the conductor would be at the same temperature
R_s	Joint resistance (μΩ)
S	Distance between the low points of the catenary of adjacent spans
T	Temperature (°C)
W	Weight per unit length of the conductor under the assumed conditions (N/m)
x	Length of conductor outside joint (m)
$\rho = \frac{H}{W}$	Catenary parameter (m)
γ	Exit angle: Angle between the tangents or the suspension clamp body profile at the last points of contact with the conductor (degrees or radiants)
γ_m	Maximum exit angle: Angle between the tangents of the suspension clamp body profile at the ends of the main profile (degrees or radiants)
α	Turning angle: Angle between the tangents at inflexion points of the curve of the conductor. This angle is the vector sum of the two sag angles and the line angle (degrees or radiants)
α_m	Maximum turning angle: Turning angle of the conductor in the case of the highest load which the clamp can support. This angle is slightly greater than the maximum exit angle (degrees or radiants)

List of Abbreviations and Acronyms

AAAC	All aluminum alloy conductor
AAC	All aluminum conductor
AACSR	Aluminum alloy conductor steel reinforced
AASC	Aluminum Alloy Stranded Conductor
ACAR	Aluminum conductor alloy reinforced
ACSR	Aluminum conductor steel reinforced
ADSS	All-dielectric self-supporting fiber optic cable
AISI	American Iron and Steel Institute
ASC	Aluminum Stranded Conductor
AWM	Aircraft warning markers
BR	Polybutadiene rubber
BS	British Standards
DIN	Deutsches institut fur normung (German national standard)
EHV	Extra high voltage
EN	European Standards
EPDM	Ethylene propylene diene monomer (M-class) rubber
FFH	Factory formed helical fittings
FKM	Fluorocarbon rubber
HC	Hydraulic compression fittings
HCI	Hydraulic compression and implosive fittings
IEC	International Electrotechnical Commission

IEEE	Institute of Electrical and Electronics Engineers
ISO	International Organization for Standardization
NBR	Nitrile rubber
NR	Natural rubber
OPGW	Optical ground wire
PVC	Polyvinyl chloride
RI	Radio interference
RIV	Radio interference voltage
RTS	Rated tensile strength
SR	Silicon rubber
SVD	Spiral vibration damper
UV	Ultraviolet

9.1 Introduction

Most fittings which are used for the installation and maintenance of overhead transmission lines look like very simple pieces of metal assembly incorporating sometimes composite or elastomer material. However, those fittings must sustain all kind of mechanical, electrical, chemical, and environmental loads. No chain is stronger than its weakest link. Therefore, it is important to be extremely cautious when chosing the right fitting for an overhead line. In this chapter, many insights are provided to the reader regarding the design and test of fittings.

Most of the work reported here comes from Cigré Working Group reports or work in progress.

9.2 Production Processes and Technologies

Fittings or hardware for transmission lines are in their great majority metal parts made out of steel, iron, aluminium and copper. The production processes and technologies involved in their manufacturing are basically the same as for other similar metal parts and include forging, casting, cutting, turning, milling, drilling, rolling and welding. The application of such manufacturing processes is evident of some typical examples of fittings, Figures 9.1, 9.2, and 9.3. These amnufacturing

Figure 9.1 Example of an adjustable extension link with different hole settings.

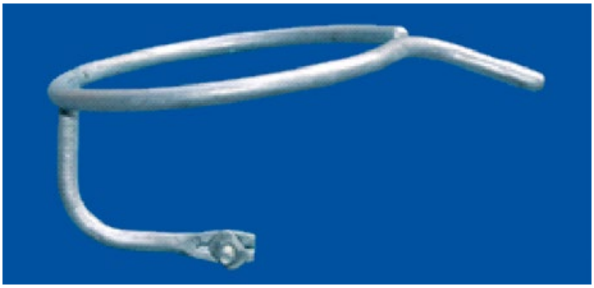


Figure 9.2 Example of a rolled arcing ring.

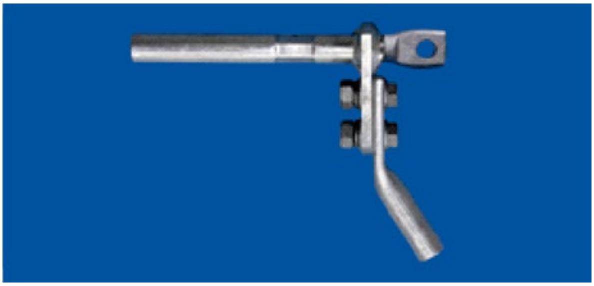


Figure 9.3 Example of a dead end clamp with a welded cable lug connection.

technologies are well known and do not have to repeated here. On the other hand, because of their extremely demanding exposure to harsh environment, particular attention should be and is given to the surface tretament and the surface protection of fittings. These issues will be coverd in detail in the following section.

9.3 Surface Finishing and Corrosion Protection

9.3.1 Introduction

Surface finishing of transmission line hardware and fittings comprises a range of industrial processes that alter the surface of the manufactured item to achieve a certain property.

Surface finishing is made for one or more of the following purposes:

- Increase durability, hardness and surface friction
- Improve decorative appeal and remove surface imperfections (when necessary)
- Increase corrosion resistance
- Improve RIV and Corona performance
- remove burrs and other surface flaws
- modify electrical conductivity
- Increase staining resistance, chemical resistance, wear resistance
- Improve solderability
- Protect the conductor's surface in contact with fittings.

The most common methods are: grinding, tumbling, sand blasting, brush finishing and surface plating or chemical treatment.

9.3.2 Grinding

Surface grinding uses a rotating abrasive wheel to remove flashes, sharp edges and other surface irregularities creating a flat surface on fitting components after cutting, casting or forging. The pieces are generally held by hand. Typical treatable materials include cast iron, forged steel, forged aluminium, aluminium and zinc castings, aluminium extrusions, stainless steel, brass and bronze castings.

9.3.3 Tumbling

Vibratory finishing machines are used to deburr products and remove sharp edges. The material is inserted inside a drum filled with abrasive pellets (Figure 9.4) and vibration is applied to create uniform smooth surfaces. The vibration frequency and magnitude are usually variable, allowing effective treatment for a range of small to large sized parts.

9.3.4 Sand Blasting

Sandblasting is a general term used to describe the operation of propelling a stream of fine particles at high-velocity to clean or etch a surface. Sand is the most commonly used material, but other small relatively uniform particles such as steel grit, metal pellets, copper slag, walnut shells, powdered abrasives, are also used.

Figure 9.4 Aluminium pieces and abrasive pellets inside the tumbler.

Sand-blasting workstations are sometimes employed to obtain a uniform matte texture and a specific surface roughness of transmission line fittings.

Sand blasting of clamp bores of spacer-dampers or dampers, for the purpose of increasing its slip force, is generally not permitted, as this treatment can cause abrasion of the conductor if there is clamp slippage.

9.3.5 Brush Finishing

Brushing the surface of conductors and fitting clamps is a necessary operation before installation of any type of fitting, especially suspension clamps and compression joints to remove the oxide layer of aluminium that is not electrically conductive. If the resistance between clamp and conductor is high and a power arc occurs, the clamp may be damaged and in few cases clamp explosions have been reported.

Grease compound is applied on surfaces of compression fittings in contact with the conductor or earth wire to prevent aluminium oxidation before installation.

9.3.6 Corrosion Protection

Corrosion of a metal occurs when it is in contact with an electrolyte that, in some situation, can be simple water. Around overhead transmission lines there are frequently sufficient air-born pollutants, such as sulphur dioxide, to provide quite strong electrolytes in combination with humidity and rain water.

Resistance to corrosion is of primary concern when choosing materials for fitting components.

The selected materials should be resistant to: chemical corrosion caused by humidity and air-born pollutants, galvanic corrosion due to contacts between dissimilar materials in the presence of an electrolyte, and electrolytic corrosion caused by voltage unbalance between metal surfaces bridged by an electrolyte.

The use of galvanized malleable cast iron, galvanized steel, stainless steel, aluminium alloys, copper and copper alloys should provide favourable resistance to chemical corrosion. Aluminium and aluminium alloys have a natural corrosion protection consisting of a thin oxide layer. Superficial treatments like anodization can further improve, when necessary, the corrosion resistance of aluminium and zinc alloys. However, certain substances react chemically with aluminium and therefore any contact between aluminium and these materials should be avoided. Among others, those most frequently encountered during storage erection and operation are lime, cement dung and fertilizers.

Grease coating or painting of conductor fittings is not considered reliable for a long term corrosion protection but can improve the corrosion protection performed by more durable systems. Fittings may be provided with an oxide-inhibiting compound intended to reduce metal oxidation at metal-to-metal electrical contact points. These compounds are commonly used in compression fittings to fill internal voids and to prevent ingress of water during service.

Figure 9.5 Galvanic series for general purposes. The galvanic series arranges metals according to their tendency to corrode and can be used to determine whether galvanic corrosion is likely to occur and how strong the corrosion reaction will be.

Galvanic corrosion can best be avoided by reference to the galvanic series (Figure 9.5). Metals toward the top of the series are anodic, active, and will corrode faster, while metals toward the bottom of the series are cathodic, passive, and less subject to corrosion. If two or more dissimilar materials are to be in contact in the fitting, they should not be too far apart on this list and, where possible, the material with the greater surface area should be made anodic. Aluminium is anodic with respect to most commonly used materials such as copper, nickel, lead, iron and steel including stainless steel. Therefore, any contact between aluminium and these metals in the presence of moisture will give raise to galvanic corrosion of the aluminium at a rate and to a degree determined by the nature of the other metal and of the type of the electrolyte involved.

Particular attention should be paid for the design of aluminium-copper terminations. The contact zone between the two metals should be protected from ingress of moisture by a seal and the edges coated by painting. Moreover, the copper part of the fitting should be positioned below the aluminium part to avoid the leaching of the rain form the copper to the aluminium.

The only metals commonly used on transmission lines, that can be safely in contact with aluminium are zinc, cadmium, tin and consequently items that are galvanized, cadmium plated, tin plated and obviously alumowelded or aluminium-cladded parts.

In any case, the selection of materials, for application in areas with high atmospheric pollution, should be made taking into account the nature of the pollutants involved. This is because the position of certain metals and alloys in the galvanic series is dependent on the aggressive agents considered. For example, stainless steel can be either anodic or passive cathodic depending on the electrolyte.

9.3.7 Surface Protection of Ferrous Materials – Galvanizing

Galvanization is the process of applying a protective zinc coating to steel or iron, in order to provide corrosion resistance by forming a physical barrier between the basic metal and the air. Moreover, zinc acts as a sacrificial anode protecting the basic metal even if the barrier is scratched or abraded.

When exposed to the atmosphere, zinc reacts with oxygen to form zinc oxide, which further reacts with water molecules in the air to form zinc hydroxide. In turn, zinc hydroxide reacts with carbon dioxide in the atmosphere to yield a thin, impermeable, tenacious and quite insoluble dull gray layer of zinc carbonate which adheres extremely well to the underlying zinc, so protecting it from corrosion. This is similar to the protection provided to aluminium and stainless steels by their own oxide layers. The performance of a zinc coating depends largely on its thickness, and on the kind of environment to which it is exposed (Figure 9.6).

In conductor fittings, galvanized steel is mainly used for the elements of the clamp locking systems and sometimes for other components such as hinge pins and bolts, frames, and stranded steel cables. The zinc protection is generally made by hot dip galvanization, in accordance, for example, with ISO 1461 (2009), except when spring steel is used (e.g. Belleville washers) for which this process is considered unsuitable as it can compromise the elastic properties of the basic metal.

In any case, the thickness of the zinc deposit shall guarantee corrosion resistance for the whole life of the line. Considering an average consumption of zinc of 0.8 to 1.2 μm per year, typical of rural and suburban areas, a minimum galvanizing thickness of 40 to 50 μm can guarantee the protection for the expected life of the line (35 to 60 years). The protection provided by zinc deposit, especially on small items such as bolts, nuts and pins, may be insufficient when they are constantly exposed to corrosive industrial atmospheres. Marine and salty environments also lower the lifetime of galvanized items because the high electrical conductivity of sea water

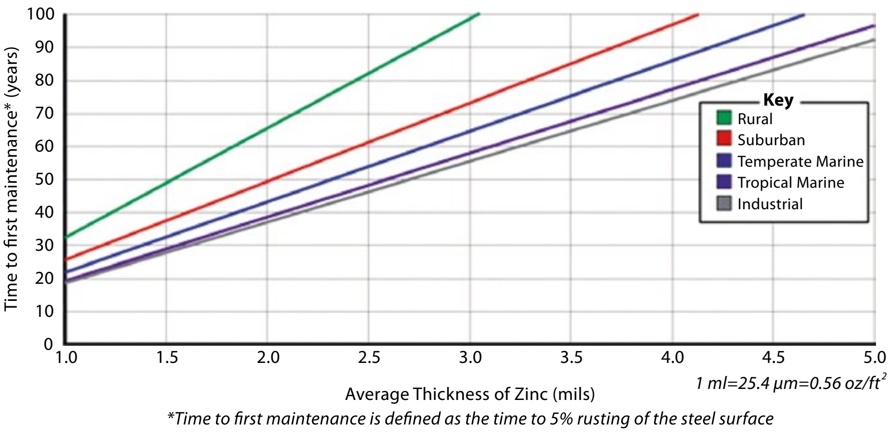


Figure 9.6 Zinc consumption rate in various environments (Data from The American Galvanizers Association (1 mils = 25.4 μm)).

increases the rate of corrosion (Figure 9.6). For these applications, other materials such as copper, stainless steel and aluminium are sometimes preferred.

The hot-dip galvanizing process consists of completely immersing the parts in a minimum 98 % pure zinc bath. The bath temperature is maintained at 435 °C (815 °F) or higher. During immersion, the zinc reacts with iron in the steel to form zinc-iron alloy layers which improve the zinc adhesion and constitute a further protecting element. Once the fabricated item reaches bath temperature the articles are withdrawn slowly from the galvanizing bath. Excess zinc is removed by draining, vibrating, and/or centrifuging. Articles are cooled either by immersion in a passivating solution or water or by being left in open air.

All external threads are cut or rolled before hot dip galvanizing. Internal threads can be cut before or after hot dip galvanizing. If cut or tapped after galvanizing they shall be oiled or greased.

The breakaway head bolts cannot be of galvanized steel because after installation the fractured area remains exposed to corrosion; thus stainless steel and aluminium alloys (anodized) are used. Belleville washers and other spring elements made in chrome-vanadium steel (50 CrV4) or Ck75 unalloyed steel can be electroplated or mechanically galvanized.

Electrogalvanization is an electroplating process of applying a layer of zinc on a ferrous object by using a sacrificial zinc anode suspended in a solution made of zinc and saline. An electrical current is introduced to this setup with the zinc anode being attached to the positive side of the power source while the steel to be galvanized is attached to the negative side. In this way, the positively charged zinc ions given off by the anode are attracted to the negatively charged steel.

This method is scarcely used for ferrous components of overhead line fittings for two reasons. First of all, because of the high risk of hydrogen embrittlement during the process and second because the maximum thickness of the zinc deposit (15-20 μm) is generally insufficient to guarantee a long term protection of the basic metal. Cases of electrogalvanized Belleville washers found broken in service because of hydrogen embrittlement have been reported.

Mechanical galvanization of iron and steel is made in accordance with ASTM B695-04 (2009) or equivalent standard. It is a plating process that imparts the coating by cold welding fine zinc particles to a workpiece. It is commonly used to overcome hydrogen embrittlement problems. The process involves tumbling the workpieces with a mixture of water, zinc powder, media, and additives. The coating is provided in several thickness classes up to 100 μm. However, for small items (lower that 0.5 kg) a coat of up to 75 μm can be conveniently obtained.

Chromating can be performed on zinc-coated parts to make them several times more durable depending on chromate layer thickness. The chromate coating acts like a paint, protecting the zinc from white corrosion.

9.3.8 Stainless Steel Surface Finishing

Stainless steel can be employed instead of galvanized steel in highly polluted areas: austenitic stainless steels (AISI 300 series) and ferritic stainless steels (AISI 400 series) are the most commonly used. Belleville washers made of stainless steel are also available in AISI 301 and other equivalent materials.

Aestivation is used to improve the surface condition of stainless steel by dissolving the iron that is embedded in the surface by machining, forming or other manufacturing steps. If allowed to remain, the iron corrodes and often gives the appearance of large or small rust spots on the stainless steel. In order to prevent this condition, the stainless steel finished parts are immersed in a solution of nitric acid, without oxidizing salts, for a specific period of time, to dissolve the embedded iron and restore the original corrosion-resistance surface by forming a thin transparent oxide film. Passivating is used as the cleaning operation for castings, stampings and machine finished parts.

9.3.9 Aluminium Surface Finishing

Aluminium has an inherent corrosion resistance due to the thin hard oxide coating that forms rapidly and directly when a fresh surface of this material is exposed to air. This oxide layer usually attain a thickness of 0.1-1 μm that does not increase significantly from continued exposure to air and does not come off, forming a permanent insoluble film that effectively protects the underlying metal against external corrosive agents and spontaneously reforms on abraded surfaces.

Aluminium fittings can withstand most industrial, marine and chemical atmospheres providing the proper alloy is selected. For example, copper content in an aluminium alloy increases the material strength but reduces its corrosion resistance. Aluminium alloy bolts, used in transmission line fittings, are of type AA 7075 (high strength aluminium alloy bolts with mechanical properties equivalent to mild steel fasteners of class 5.8) or AA 6061-T8.

Additional resistance, when necessary, can be obtained by anodizing. That is an electrolytic process which increases the oxide layer thickness. The result is a surface that is smooth, hard and corrosion resistant. The recommended anodizing thickness for surfaces exposed to severe environmental conditions is 20-25 μm.

Generally, aluminium casting components of transmission line fittings do not require additional anticorrosion treatments while extruded aluminium bolts and fasteners should be anodized if likely to be used under moisture conditions. All aluminium bolts and nuts require to be greased to reduce friction and prevent seizing during fitting installation and this further improves corrosion resistance.

9.3.10 Copper Surface Finishing

There are very few bundled lines using copper conductors. For these lines fittings made of phosphor bronze or aluminium bronze are mainly used, in combination with copper alloy or stainless steel fasteners.

Copper is considered as being greatly resistant against atmospheric corrosion and other form of corrosion caused by many chemical. However copper becomes very susceptible to corrosion in a significant rate in medias that contain chloride ions. Organic inhibitors are mainly used to increase the corrosion resistance.

9.3.11 Rubber Surface Conditions

Attention is paid to the fact that some types of rubber, containing free sulphur or chlorine, when in contact with metallic elements, originate corrosion phenomena that will induce the progressive erosion of the metal itself. Organic rubber also requires to be protected from the attack of ozone, generated by Corona discharges and ultraviolet radiation, while silicon rubber is not sensitive to these agents.

Chloroprenic rubber and EPDM rubber, that are the most used in transmission line fittings, have an inherent ozone and UV radiation resistance. When necessary, the protection of organic rubber is made by means of special waxes included in the compound. The waxes continuously migrate on the rubber surface creating a protective coat that restores itself in case of abrasion but becomes discontinuous when the rubber is charged in tension.

Corona discharges on the phase conductors increase the presence, in the surrounding area, of ozone and the acid producing oxides of nitrogen. This phenomenon does not affect metallic materials but deteriorate rapidly organic materials like elastomers, if they are not suitably protected. The Corona discharge problem can be solved by a correct design of the line but, on the assumption that, in certain circumstances, there will still be a residual level of discharge, it is important to choose elastomers which have good resistance to attack from such substances.

Elastomers made not sensitive to ozone are also protected from ultra violet radiations. The protection can be maintained in service enabling the elastomer to work under condition of peak efficiency i.e. mainly in compression: elastomers working in tension or shear can suffer severe cracking and are more sensitive to the attack of ozone and UV radiations.

Elastomers which do not readily conduct electricity are liable to produce electrical current discharges through the pollutants coating the surface. Such discharges encourage a further growth of carbon deposit leading to an escalating tracking situation generating also radio interferences and audible noises.

The problem is avoided using non insulating elastomers so that the electrical resistance between spacer clamps lies within certain limits. The resistance should be significantly less than the surface pollutants, but not so small that the power dissipated by the leakage current, within the spacer, cannot be safely accommodated.

Cases of electrolytic corrosion of aluminium conductors inside rubber lined clamps have been reported (Tunstall and Ferguson 1987). The corrosion product was white powder largely consisting of Bayerite ($Al(OH)_3$). The corrosion rate was considered proportional to the current flowing through the spacers due to the voltage unbalance between subconductors and an increase of the rubber electric resistance to a minimum of 2 MΩ was suggested in order to reduce the current. In Figure 9.7, a case of aluminium corrosion under a rubber cushioned clamp is reported.

Figure 9.7 Corrosion inside a rubber cushioned clamp helically attached.

9.4 Electrical Properties

9.4.1 Corona and RIV

The term "Corona" is used here to cover all the phenomena connected with the appearance of conductivity in the gas surrounding a conductor at high voltage. This conductivity is due to the phenomenon of ionization.

The Corona phenomenon results from a too high voltage gradient on the surface of fittings or conductors. The Corona discharge is an electrical discharge caused by the ionization of a gas surrounding the fitting or conductor that is electrically energized. The discharge appears when the gradient of the electrical field is high enough to form a conductive region. This conductive region enables electrical discharges in a limited area but it does not lead to complete phase to phase or phase to earth flashovers.

The critical gradient for a smooth cylindrical body with 10 mm diameter is approximately 27 kV/cm whereas the gradient drops down to 21 kV/cm for stranded conductors. Considering severe weather condition on the line, the voltage gradient shall not be above 17 kV/cm to meet all set requirements.

The voltage gradient on strings and fittings can be determined by using software calculations. Various software analysing tools are available to simulate the electrical field distribution on fittings and whole strings (Figure 9.8).

By the use of optimized geometrical designs (e.g. Corona protection rings) the voltage gradient can be reduced to uncritical levels.

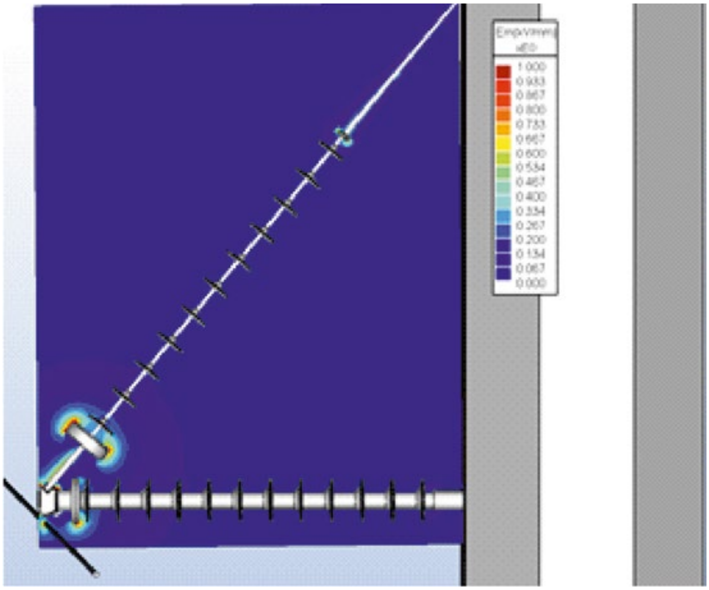


Figure 9.8 Electrical field distribution.

Figure 9.9 Streamers on a suspension clamp.

The phenomenon of ionization can result in two types of electrical discharges:

- The first type of discharge is the so called negative Corona or glowing point. Negative Corona is characterised as blue light with less intensity. A low hearable noise is radiated from the discharge.
- The second type is the so called positive Corona discharge or streamers. The streamers are characterised as sparkle with white light. Again a hearable noise radiate from the discharge (see Figure 9.9).

Each Corona discharge emits electromagnetic waves which result in a hearable noise, interferences with radio broadcasting and energy losses. The interferences with radio broadcasting are caused by the radio interference voltage (RIV). This radiated emission can be measured as described in the CISPR 16-1 and CISPR 18-2. The Corona and RIV performance of fittings and strings can be determined by laboratory tests described in IEC 61284, clause 14.

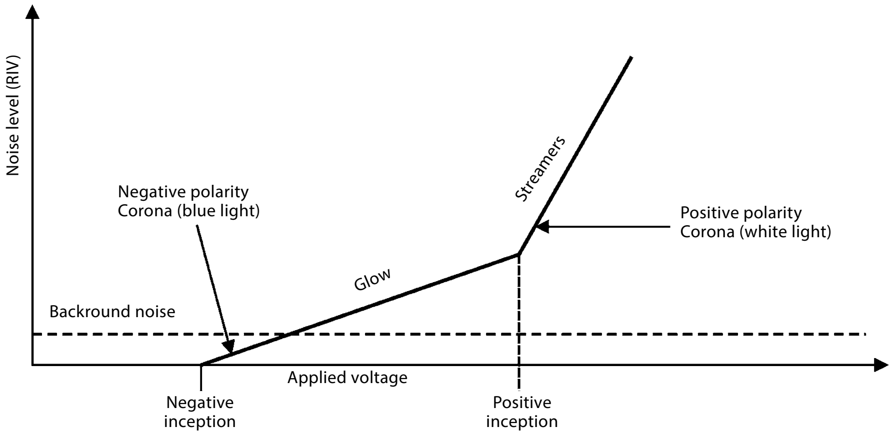


Figure 9.10 Typical relationship between observed Corona and RIV.

The most susceptible frequency range for interference caused by Corona is between 0.5 and 1.5 MHz. Therefore a typical RIV measurement is taken at 1 MHz.

Corona extinction, inception voltage and RIV limits must be clarified between purchaser and supplier.

Corona discharges also cause energy losses which have to be considered. The losses are indicated in Watt per meter (W/m). The typical loss of an overhead transmission line in dry weather condition is a few kilowatts per kilometer. In heavy rain the losses can reach 10 kilowatt per km and rise up to 100 kW/km in freezing conditions.

The typical relationship between Corona and RIV is shown in Figure 9.10. The Noise level (RIV) is typically stated in dB to provide a wider measurement range. The inception of streamers is linked to a significant increase of the RIV level.

Observation of Corona discharge can be done by different methods.

- By the use of a Corona camera. This kind of camera allows the observation of discharges at daylight condition. Due to the fact that Corona discharges emit ultraviolet radiation the camera is able to visualize the phenomena (see Figure 9.11). This type of camera can be used as handheld in labs as well as fixed on helicopters for live line investigations.
- Observations by field glasses or night vision cameras are also possible but these methods require fully darkened conditions to visualize the phenomena.

9.4.2 Short Circuit Loading

Overhead lines and their fittings shall be designed to withstand a short circuit current caused by a phase to earth or phase to phase fault. The Overhead line and their fittings shall not get damaged due to mechanical and thermal impacts in case of a short circuit loading.

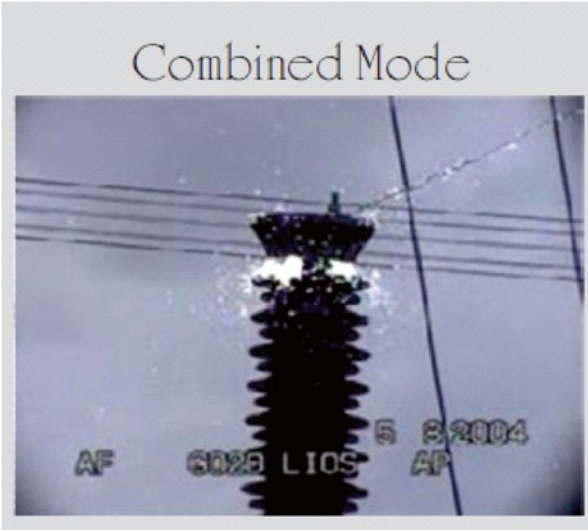


Figure 9.11 Picture taken by DayCor® Corona Camera.

Flashovers on insulator strings or fault currents caused by damaged components (e.g. conductor breaks) result in high short circuit currents.

The causes of power arc events in an overhead line can be:

- Overvoltages due to a direct lightning strike, switch operations or back flashover, which cause air breakdown between the metal parts that form the lowest striking distance e. g. directly between the ends of arcing horns.
- Pollution flashover at nominal voltage (in case of an isolated earth fault) or line to ground voltage. Beside a spontaneous flashover, pollution flashovers often develop from partial arcs formed across the insulator shank. These partial arcs have a $U\text{-}I^{-x}$-characteristic, which can form a complete power arc when moving away from the shank towards the shed edges.
- Conductor approach due to wind or reduced electric strength of atmosphere in the case of fires under spans.

The first and second causes are in direct relation to the insulator string design, while the third one is dominated by the overall line design and special conditions respectively.

In case of flashovers the protective fittings are loaded with high current peaks and enormous thermal stress. The duration of the short circuit is linked with the switch off time of the circuit breaker. According to EN 50341-1:2001, clause 5.2.2 the design shall be based on a short circuit duration of 1,0 s for fittings but the real in service switch off time shall be considered too.

The value of a power arc along a transmission line with an overhead earthwire is highest at the sub-station positions and becomes lowest in the middle of a line. The distribution of the arc current is shown in Figure 9.12.

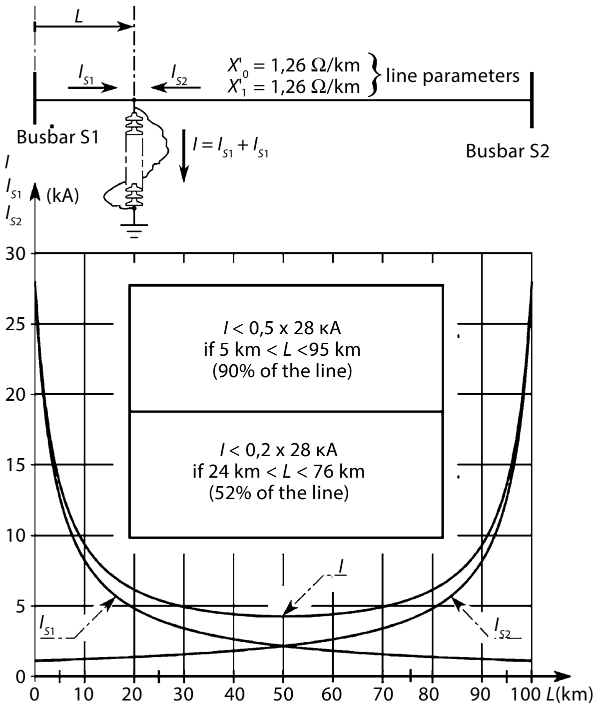


Figure 9.12 Example of a fault supply current distribution.

Near the substation busbars (extremity of the line), the short-circuit current is higher and the supply circuit is unbalanced. In the middle of a line, the fault current is significantly lower, however the supply circuit is practically balanced. This balanced situation can cause more severe damages, because of lack of movement of the power arc.

Arcing devices shall be able to protect the other fittings against thermal and mechanical damages in case of a power arc. The arcing devices may be damaged after the arc due to the thermal stress and must be replaced. The temperature can be up to 18000 °K in the arc root.

The protection function of an appropriately designed device is shown in Figure 9.13. On the arc ring and the end burning sphere, typical arc burning spots are shown. AC power arc tests are described in IEC 61467.

Not only fittings in the strings are affected by short circuit currents but also fittings in the spans. The spacer and spacer dampers should be designed to accommodate the mechanical loads arising from the effect of short circuit currents flowing in the bundle.

One important design load on spacers is due to short-circuit electro-mechanical forces. The clashing of subconductors due to strong attraction forces inside the bundle induces large deflections on conductors resulting in large tension increases (see Figure 9.14). Depending on the spacer type, components of these forces, acting towards the centre of gravity of the bundle, induce compression loads and bending moments in the components and clamp arms of the spacer. It is well known that

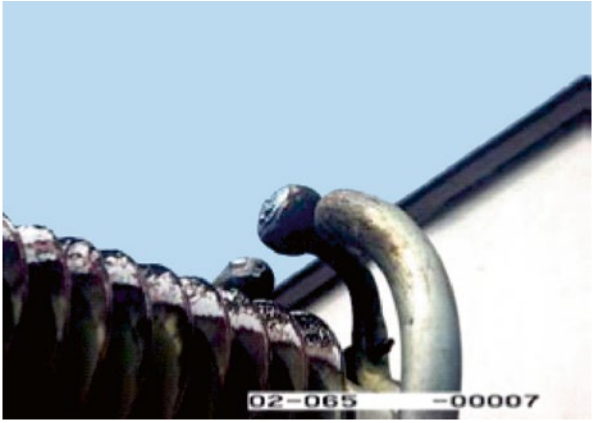


Figure 9.13 Arcing ring after 30 kA for 0.5 seconds.

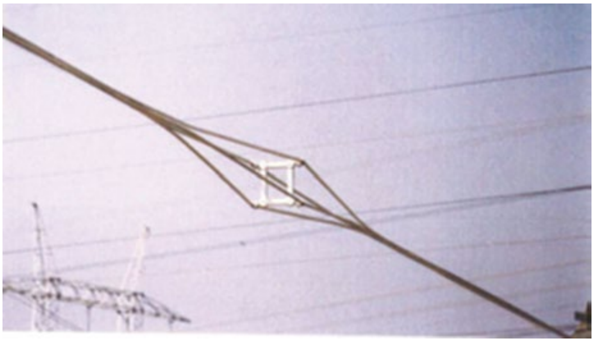


Figure 9.14 Short circuit test of spacer damper.

compression forces can reach up to 16 kN and above for a short-circuit current near 50 kA. The compression load depends not only on short-circuit current, but also on the initial tension in the subconductors, their diameter, spacing, as well as subspan length. The greater the subconductor spacing, the greater the load will be. A subspan length of 30 m or more will not induce significant change in the compression load. For shorter spans, as the spacer compression will increase significantly, it is recommended to evaluate properly the effect using published methods (Lilien and Papailiou 2000).

In service, spacers should withstand mechanical loads imposed on them due to environmental or short circuit conditions. To simulate this, load compression and tension tests as well as simulated short circuit tests should be carried out in accordance with IEC 61854.

9.4.3 Electrical Contacts

Electrical contacts are subjected to severe electrical, mechanical and corrosive stresses. The purpose of a connection is to provide a long-lasting and adequate electrical and mechanical connection between various fittings and/or conductor.

Current carrying fittings like joints and parallel groove clamps shall have a lower electrical resistance value than an equivalent length of conductor. The temperature of the fittings shall also stay below the temperature of the conductor.

Further, current carrying fittings shall not reach temperatures which could cause permanent changes to the mechanical properties of the components they are attached to. An electrical aging and heat cycle test for joints is described in IEC 61284, clause 13.

Electrical contacts can be made by the following methods:

- Bolted connection:
  Two or more conductive items are electrically connected by the mechanical pressure generated by a bolt-nut connection. The contact surfaces shall be designed in a way to guarantee a proper electrical connection.
  Application: Parallel Groove clamps, loop connections at dead end clamps
  Advantage: Easy inspection without special equipment. Dismantling and reinstallation is possible without special tools.
  Disadvantage: Bolted connection can get loose by vibration or environmental impacts
- Compression fittings:
  Compression joints and compression dead end clamps are state of the art items to connect conductors mechanically and electrically. The connection is made by a connection based on compression (deformation) of a metal sleeve onto the conductor.
  Application: compression dead end clamps, compression joints, loop connections
  Advantage: good electrical and mechanical connection. The connection surface is well protected against environmental impacts. No risk of loosening.
  Disadvantage: Investigation is more difficult after installation. Additional compression tool is required for installation.

Electrical contacts must be handled with care to obtain a good connection. Nonconductive oxide layers (e.g. Aluminium oxide) shall be removed before installation to reduce the electrical resistance between the connected items. Additional precautionary measures to prevent accelerated aging and oxidations of the contact areas are recommended.

The investigation of electrical connections can be made during an inspection of the string of energized and non-energized lines. The connections can be checked visually, mechanically and also electrically. The following investigation can be done:

- Remaining tightening torque values of bolted connections
- Damages due to vibration, power arcs or corrosion
- Replacement of whole clamps without dismantling followed by detailed investigations in laboratory. e.g. cut out compression clamps without opening the bolted loop connection.

- Radiographic investigation of compression clamps.
- This method provides a view inside of a compression clamp to verify its proper installation (Figure 9.15).
- Thermal investigation by infrared photography.
- This test must be done on an energized line to see the temperature distribution on the conductor and fittings. No hot spots shall appear at electrical connections especially on bolted clamps and compression fittings (Figure 9.16).

9.5 Test on New Fittings

9.5.1 Introduction

Tests on transmission line fittings are generally performed in accordance with the following International Standards:

IEC 61284 Overhead lines Requirement and test for fittings (published 1997)

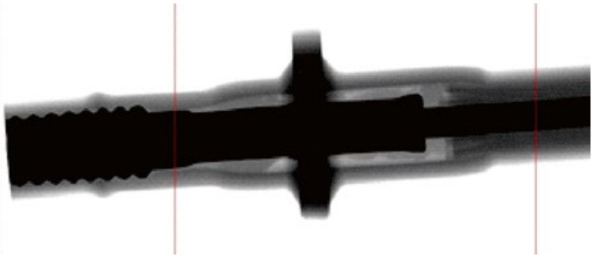


Figure 9.15 Radiographic picture of a compression clamp.

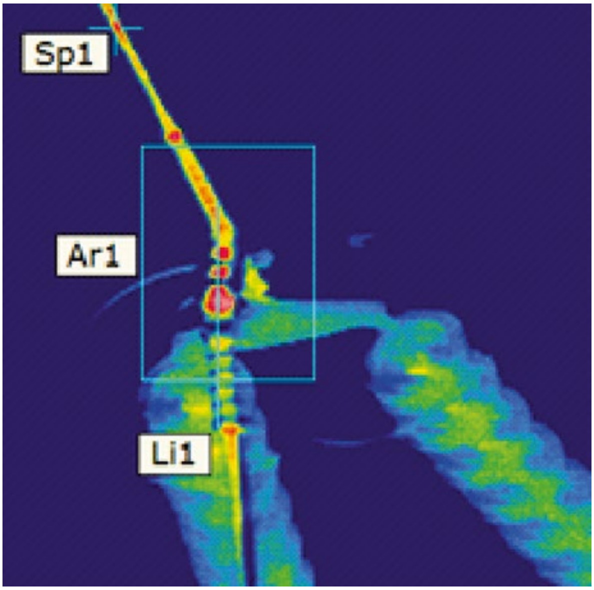


Figure 9.16 Thermal image of compression clamp.

IEC 61854 Overhead lines Requirement and test for spacers (published 1998)

IEC 61897 Overhead lines Requirement and test for Stockbridge type aeolian vibration dampers (published 1998).

A proposal for the revision of these Standards has been prepared by Cigré WG B2.25 and is under the evaluation of IEC TC11 MT1.

In the above IEC standards, a number of test parameters are left to the agreement between purchaser and supplier and the main utilities have issued their own technical standards to specify these parameters and to prescribe additional tests dictated by specific environmental condition. It is evident that requirements of countries such as, for example, Saudi Arabia, Norway and Brazil are somewhat different.

Tests are divided in three categories:

- Type tests
- Sample tests
- Routine test.

The above mentioned standards specify for each category the tests to be executed. In addition, other tests such as, power arc tests, short circuit tests, corrosion tests (Figure 9.17), ageing and fatigue tests can be agreed between purchaser and supplier.

Testing procedures of fittings for optical cables are given in the Cigré WG 22.11 papers entitled “Guide to fittings for optical cables on transmission lines. Testing procedures. Part 2A and 2B.

Figure 9.17 Salt fog test on ferrous components of overhead conductor fittings.

9.5.2 Type Tests

Type tests are intended to establish design characteristics. They are normally made once and repeated only when the design or the material of the fitting is changed. When performed officially, these tests are witnessed by the purchaser's representatives. Independent test laboratories may be employed to perform the type test or at least some of them.

The results of type tests are recorded as evidence of compliance with design requirements.

First of all, visual examination, dimensional and material verification are performed on the samples to ascertain conformity in all essential respect to the contract drawings. Corrosion protection tests are performed on fittings containing components that are not resistant to atmospheric attack. They are mainly ferrous components that are generally hot-dip galvanized. Tests to verify the resistance of organic materials, such as the elastomers used in some fitting clamps and in spacer damper articulations, to ozone and ultraviolet radiations, are also considered.

Mechanical tests like damage and failure load tests, clamp bolt tightening tests, compression and tension tests and simulated short circuit tests (Figure 9.18) are carried out to verify the required efficiency and integrity of the fittings under the loads imposed during installation, maintenance and service. Performance tests like clamp slip tests, characterization of the elastic and damping properties of spacer dampers and vibration dampers (Figure 9.19) and effectiveness of vibration dampers are performed to ascertain the ability of the various fittings to perform the functions for which they were designed. Long term tests such as fatigue tests, heat cycle tests and ozone resistance tests are performed to prove that the fitting will be

Figure 9.18 Simulated short-circuit current test on a hexagonal spacer damper.

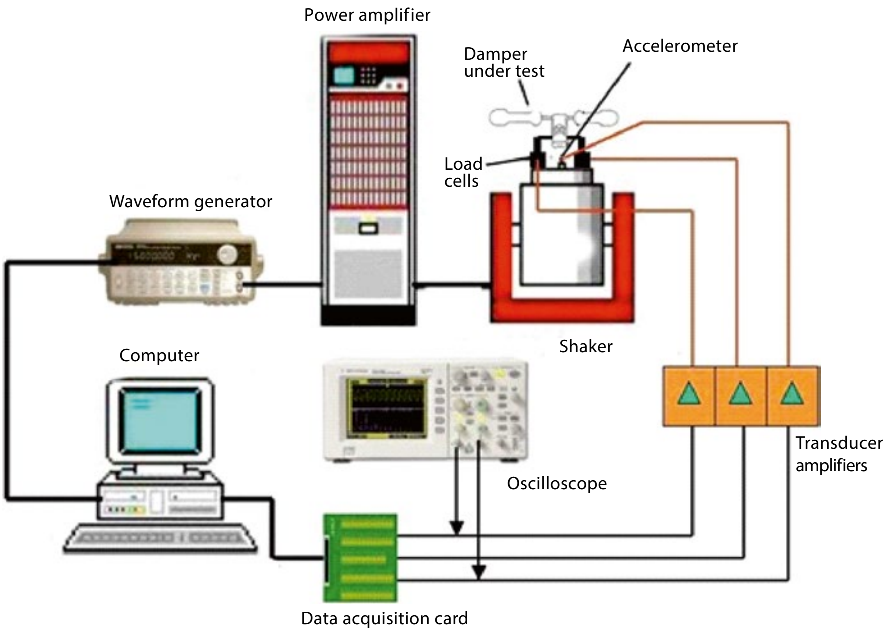


Figure 9.19 Layout of the test stand for vibration damper characteristic tests. The damper is vibrated in the frequency range of interest. At each frequency step the reaction force and the phase angle between the force and the damper clamp displacement are measured.

able to maintain their functionality in the whole range of environmental conditions and for the whole life of the line.

Electrical tests such as Corona and RIV tests, magnetic loss tests and electrical resistance tests are established to verify the compatibility of the fittings with the electrical parameters of the line.

A number of tests are prescribed to characterize elastomers. These tests are intended to establish satisfactory and reproducible products rather than to obtain data relevant to the performance in service. Test data along with supplier's guaranteed values form the basis for acceptance of sample tests and quality control tests. These tests are generally performed on specimens obtained from the vulcanization of an appropriate quantity of the rubber mix used to manufacture the elastomeric components of the fittings.

Field vibration tests are performed on new lines before commissioning as a final check of the damping systems installed on conductors and shield wires. Tests are performed on single and bundled conductors and involve both vibration damper and spacer damper systems. The scope of the test is to demonstrate the ability of the damping systems to control aeolian vibration within the safety limits internationally accepted. For bundled conductors, subspan oscillations are also recorded. The tests are generally carried out by means of specific vibration and oscillation recorders. The duration of the field measurements is generally established as one month and can be extended if during the test period the occurrence of winds transversal to the line is deemed to have been insufficient.

9.5.3 Sample Tests

Sample tests are similar to the type tests and are intended to verify the quality of materials and workmanship as well as to demonstrate the compliance with the requirements of the Purchaser Technical Specification. Typical sample tests are: visual examination, dimensional and material verification, slip tests, tensile tests, strength and deformation tests and performance tests. Sample tests are usually performed by the manufacturer in the presence of the purchaser's representative, at the end of the production, prior to shipment.

The samples to be tested shall be selected at random from the lot offered for acceptance. The purchaser has the right to make the selection. Generally, the sampling plan procedures according to ISO 2859-1 (1999) and ISO 2859-2 (1985) (inspection by attributes) and to ISO 3951 (inspection by variables) (2005 and 2006) is applied and the detailed procedures (inspection level, acceptable quality level, single, double or multiple sampling, etc.) is agreed between purchaser and supplier. If the specimens pass the sample tests, the relevant lot is considered as accepted by the purchaser.

9.5.4 Routine Tests

Routine tests are intended to prove conformance of fittings to specific requirements and for supervision of the production with an increased probability of defects. Routine tests are made on every fitting and non-destructive test methods, such as, for example, magnetic, radiographic, ultrasonic, dye penetrant and proof load are used.

Whole lots of fittings may be subjected to routine tests and those which do not conform to the requirements are discarded.

9.5.4.1 Quality Assurance

A quality assurance programme taking into account the requirements of the different type of fittings can be agreed between the purchaser and the supplier to verify the quality of the fittings during the manufacturing process. A Quality Manual specifying the quality control procedures is issued by the fitting manufacturer and included in the contact documents.

Detailed information on the use of quality assurance is given in the ISO 9000 (2005), ISO 9001 (2009), ISO 9004 (2009) Standards.

Quality Control System shall ensure that, as far as possible, every production part complies with the original specification and performance as confirmed by design and type test. During production, tests and inspections shall be carried out on a strict sampling basis complying with the Quality Plan approved by the purchaser.

Tests and inspections outlined below represent an example of the continuous quality control to be performed by the manufacturer and to be audited by the purchaser.

- Material and casting processes shall be certified as conforming to the specification by the manufacturer.
- Chemical analysis shall be made on sample basis.
- Non-destructive tests, such as X-ray shall be made on samples to determine the soundness of the castings.
- Functional dimension measurements shall be made on sampling basis.
- Surface finishing in important areas shall be visually inspected and objectively controlled by reference to a master standard approved by purchaser during type tests.
- Strength and function of parts shall be determined on sample basis by destructive tests conforming, as far as possible, to the realistic operation conditions of the fittings.
- Protective coatings of ferrous materials shall be checked according to internationally accepted standards including zinc thickness measurements and adhesion properties.
- Elastomer specimens shall be additionally checked for mechanical and physical properties and performance.

9.6 Tests on Aged Fittings

9.6.1 Introduction

As the transmission grids around the world age, there is increased need for a consistent method of evaluating "aged" fittings, defined here as fittings installed for over 30 years. This section will discuss methods for evaluating these fittings (Cigré B2.32 2011).

In addition to the general aging factors most commonly recognized such as material degradation and corrosion, the prudent engineer working in the field of electrical transmission and distribution should recognize that energized components in the current path may suffer degradation of any "electrical interfaces" through which the current passes, and which are prone to thermal cycling. The result of this aging phenomenon may be a rise in resistance of the electrical interface, which would result in localized heating and, if left unchecked, may ultimately result in thermal runaway and melting of the mechanical components, and catastrophic mechanical failure of the conductor system in tension.

Utility responses from a survey indicated that the components most often indicating deterioration (number of utilities responding is in bracket) are in order (Figure 9.20):

- Spacers and spacer-dampers (13)
- Conductor splices and joints (11)
- Suspension hardware (9)
- Vibration dampers (8)
- Dead end hardware (8).

Figure 9.20 Samples of deteriorated hardware. Clockwise from *top left*: Aeolian Vibration Dampers, Quad Bundle Spacer, Interphase Spacer, Conductor Compression Fitting, Aircraft Warning Marker, Suspension String "U" and "Eye" Bolts.

About 70 % of the utilities use the results of tests of aged fittings to guide future overhead line maintenance. Other uses of test results include: estimating the remaining lifetime of the class of components, development of new fittings, extrapolating to the condition of other lines of similar age.

The following topics will be discussed in the following sub-sections:

- Guidelines for Evaluation of String Hardware
- Guidelines for Evaluation of Conductor Fittings
- Guidelines for Removal, Packaging and Labeling of Samples.

9.6.2 String Hardware Evaluation Guidelines

String hardware stands for "components that are used to mechanically attach conductor fittings together with the insulators, and insulators to the tower. See Figures 9.21 and 9.22. They are not in direct contact with the conductor and, therefore, are not exposed to continuous current flow. Insulators are not classified as string fittings for this paper.

In service, these fittings are mainly exposed to static and dynamic mechanical loads as well as short circuit currents and environmental influences. String fittings are primarily designed from a mechanical and electrical point of view to withstand short circuit currents up to one second.

String fittings are mainly produced from structural steel (straps, yoke plates), quenched and tempered steel (ball fittings), and iron castings (sockets, clevises).

The assessment of old fittings should include the following mechanical and, if necessary, metallurgical investigations to evaluate the technical status and compare these results with the required design characteristics as well as actual requirements (standards).

A certain quantity of specimens (i.e., minimum of 10 pieces) should be tested to achieve a normal representative distribution of results.

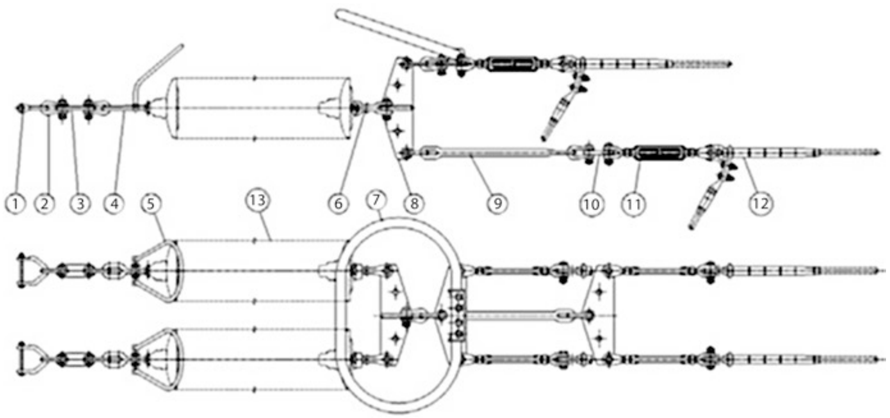


Figure 9.21 Items 1 to 11 are classified as string fittings *1* "V" Shackle, *2* Anchor Shackle, *3* Eye Fitting, *4* Ball Link, *5* Arcing Horn, *6* Socket Clevis, *7* Arcing Horn, *8* Yoke Plate, *9* Link, *10* Chain Link, *11* Turn Buckle, *12* Compression Dead-end, *13* Insulator String.

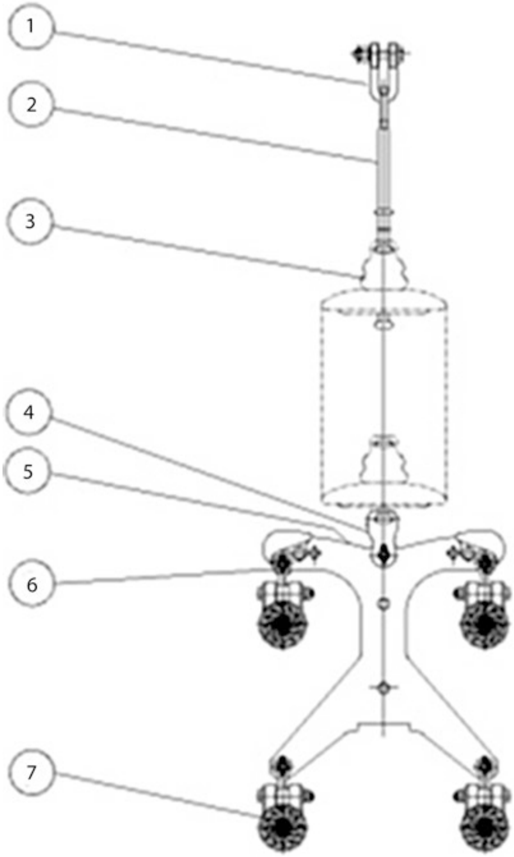


Figure 9.22 Items 1, 2, 4, 5, and 6 are classified as String Fittings *1* Anchor Shackle, *2* Ball Link, *3* Insulator String, *4* Socket Clevis, *5* Yoke Plate, *6* Clevis Eye, *7* Suspension.

It is recommended to report essential string and line parameters such as:

- Placement, where fittings have been installed
- Type of tower
- General condition of line
- Damping system installed
- History of the fittings and the line
- Design history
- Environment (sea coast, mountainous, industrial, predominant wind direction)
- Age of line
- Line voltage
- Conductor size and tension
- Condition of tower vang (plate).

Recommended tests are given in Table 9.1, and typical mechanical test set-ups are shown in Figure 9.23.

Table 9.1 Recommended tests

Type of Test	Activity	Which fittings	Measurement or observation	Standard
Visual Inspection	General condition of surface	All		
	Percentile of corroded surface (%):	All	0-25/25-50/50-75/75-100 %	
	Mechanical damage	All	Cracks, abrasion, indication of rocking	
	Electrical damage	All	Punctures, welding points	
	Wear of holes	All		
	Welding of string components (due to short circuit) such as shackles to eye fittings	Shackles, Bolts, Plates and Eyes		
Dimensional Inspection	Diameter of bolt	Bolts	Wear on diameter of bolt and remaining area	
	Diameter of pin	Pin fittings	Wear on diameter of pin and remaining area	
	Diameter (ovality) of holes	All holes		
Corrosion Protection	Thickness of remaining zinc layer	All steel parts		ISO 1461
Non-destructive Tests	Penetration test to detect tiny cracks	All parts		
Mechanical Tests	Tensile test to discover: Fracture surface	All where appropriate to take samples		Samples according: DIN 50125
	Brittleness Elongation Yield Strength	All where appropriate to take samples		Calculation and setup: EN 10002/1
	Breaking Strength	All where appropriate to take samples		IEC 61284
	Impact test (Charpy)	All where appropriate to take samples		EN 10045

(continued)

Table 9.1 (continued)

Type of Test	Activity	Which fittings	Measurement or observation	Standard
Alternative: Metallurgical Investigation	Metallographic examination Spectrum analysis to investigate the carbon and nitrogen content	All		

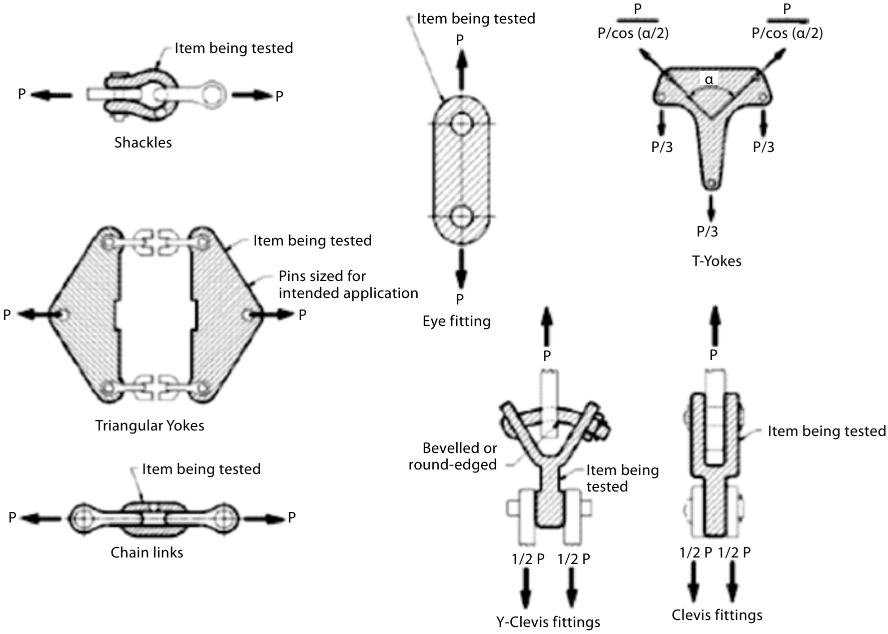


Figure 9.23 Typical mechanical testing of string hardware.

The investigation results should be the basis for a classification into one of these categories:

- *Category 1*: Items correspond to requirements – Unrestricted usage
- *Category 2*: Items partly correspond to requirements – Restricted usage
- *Category 3*: Items do not correspond to requirements – Replacement urgently recommended.

The individual utility will determine which category the evaluated fittings fall into.

9.6.3 Conductor Fittings Guidelines

Conductor fittings are components that are in direct contact with the conductor, and they are generally used to tension, support or join conductors. They also include conductor bundle spacers and vibration control fittings. For purposes of this paper, fittings that are installed on earth wires can be evaluated as conductor fittings.

During their service life, conductors may experience additional stresses at points of application of conductor fittings such as support points, joints and clamping points. These stresses may be of mechanical (static and dynamic bending, compressive stresses) and thermal in nature (heating due to short time currents at current carrying interfaces between conductor and fitting, aged electrical contacts and/or magnetic losses), and can result in localized aging of the conductor.

The assessment of the state of overhead lines should therefore include the evaluation of whether conductor fittings and conductor at the point of application still comply with design characteristics and present requirements, respectively. Original specification and design criteria at the time of the line erection may differ from today's requirements, and should be noted. In some cases, relevant information will simply not be available.

Initial field inspection can be done with thermal cameras for joints and dead-ends to determine potential fittings that should be evaluated.

For the purpose of conductor fittings evaluation, it is recommended to cut out a representative number of fittings samples with a sufficient length of conductor without opening the fittings.

The guidelines for removal, packaging and labeling of samples are outlined in the next subsection. Testing procedures should follow relevant standards such as IEC 61284, IEC 61854 and IEC 61897 for fittings, and IEC 61089 for conductors. Acceptance criteria will be dictated by line standards currently in force.

9.6.3.1 Proposed Testing for Conductor Fittings

- Visual examination (corrosion, mechanical/thermal damage, wear)
- Corrosion protection (galvanizing)
- Mechanical tests (failure load, slip, tensile)
- Electrical tests (for current carrying fittings)
- Elastomer Aging tests.

9.6.3.2 Visual Examination

- All products should be labeled appropriately as outlined in the next sub-section. Each fitting should be examined for wear, abrasion and fatigue. Indicators of wear include black oxide powder, dimensional impressions, and discoloration of material.
- Photos of items should be taken with an appropriate scale in background for reference. Any impressions should be measured using appropriate instruments.
- Items such as suspension clamps can be disassembled, and conductor damage and failure should be noted. If a mechanical clamp slip test is to be conducted, the clamp should not be disassembled prior to the slip test.

- Samples can be radiographed to determine if failures under the conductor fitting exist. Samples can also be magnet particle inspected for cracks as outlined in ASTM E-709 and ISO 9934.
- Compression joints may be sectioned and dissected to determine corrosion and heating effects. This may be done after mechanical tests.
- For products such as spacer-dampers, spacer clamps and liners should be inspected for thermal damage and wear. In addition, elastomer elements should be inspected for damage.
- For products such as warning markers, color retention can be estimated in comparison to the inside of the marker.
- For helical rods, rods should be unwrapped and inspected for evidence of corrosion.

9.6.3.3 Corrosion Protection

- Visual evaluation should estimate percent of surface area that has corrosion. Locations of corrosion should be noted. Non-destructive magnetic electronic instruments can estimate the thickness of galvanizing on the parts by measuring the change in the flux density. These measurements should be compared to the original specifications of the parts.

9.6.3.4 Mechanical and Electrical Tests

- Tension fitting
  - Tensile testing of a fitting installed on existing conductor should be conducted per IEC 61284 Sub-clause 11.5.1. See Figure 9.24.
  - In addition, for bolted dead-ends and wedge-type dead-ends, the products can be removed and tensile tested to failure.
- Suspension fitting
  - Clamp slip tests can be conducted per IEC 61284 Sub-clause 11.4.2 on the existing conductor. See Figure 9.25. In this case, the clamp should not be

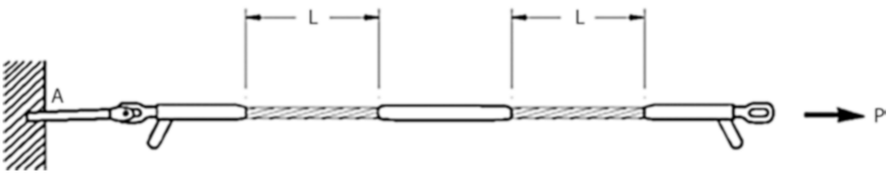
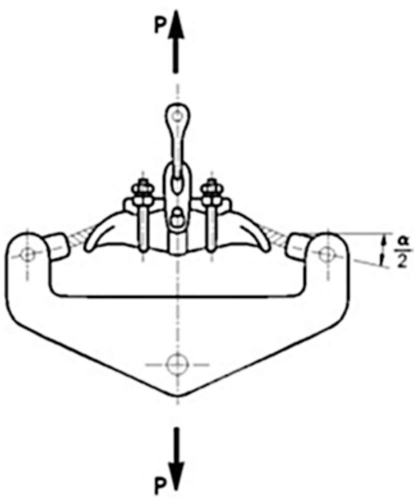


Figure 9.24 Typical tension fitting test (Splice shown, but not required for tension fitting test).

Figure 9.25 Typical suspension slip testing.

removed prior to test. If applicable, bolt residual torque should be measured using a tightening method. The procedure for measuring residual torque of clamp bolts is to tighten the bolt with a torque wrench until the bolt starts to rotate relative to the thread. The torque at which the bolt starts to move shall be considered as residual torque. Residual torque can be indicative of sufficient remaining clamping force. If locking nuts are used on the bolts, residual torque may not be valid.
  - With a bolted clamp, the clamps can be retested on a new piece of conductor for a baseline comparison.
  - Vertical strength tests can be conducted per IEC 61284 Sub-clause 11.4.1 using the old clamp on a new piece of conductor or cable. See Figure 9.26. This value should be compared to the original design requirements. This will determine whether the strength of the clamp is still within specified limits.
- Splice joint
  - Electrical – resistance measurements should be taken across the joint and compared to the resistance of an equal length of conductor. Resistance measurements should be made and recorded in micro-Ohms (μΩ).
  - Heating test – The joint should be electrically loaded to the rated current in continuous operation until conductor and joint reach steady-state temperatures. The temperature of the joint should be less than the temperature of the free conductor. After heating, the assembly shall be allowed to cool down to ambient temperature and a resistance measurement should be taken. Any significant changes in resistance before and after heating can be indicative of an aged electrical contact. See IEC 61284 Sub-clause 13.5 for more details on heating tests.
  - Tension test sample per IEC 61284 Sub-clause 11.5.1 to determine strength reduction. See Figure 9.24.

Figure 9.26 Typical vertical strength test.



- Spacer clamps
  - Clamp slip tests can be conducted per IEC 61854 Sub-clause 7.5.1 on the existing conductor. In this case, the clamp should not be removed prior to test. Residual torque of clamp bolts should be measured using the method described earlier.
  - If the spacer was not returned with existing conductor, the clamps can be retested on a new piece of conductor.
- Spacer-dampers
  - Spacer-damper energy dissipation testing should be conducted according to IEC 61854 Sub-clause 7.5.5 Characterization of the elastic and damping properties test. The results could be then compared to initial values (if available) or typical spacer-damper performance of the spacer-damper specified today.
- Dampers
  - If possible, residual torque on bolts should be measured before removal from the conductor in the field.
  - Energy dissipation testing – Testing should be conducted according to IEC 61897 Sub-clause 7.11.2 Damper characteristic test. This data should be compared to performance of the damper before field exposure. Since damper characteristic tests have been conducted for over 30 years, some data may be available on the damper.
  - Attachment of weight to messenger cable – Testing should be conducted according to IEC 61897 Sub-clause 7.8.
  - Attachment of clamp to messenger test – Testing should be conducted according to IEC 61897 Sub-clause 7.9
  - After the two previous tests, the messenger cable should be taken apart and inspected for wear and fatigue failures.
- Interphase spacers
  - Clamp slip tests can be made in accordance with IEC 61854 Sub-clause 7.5.1.
  - Mechanical strength test can be made of the complete assembly and compared to initial tensile strength tests.
- Aircraft warning markers
  - Clamp slip tests can be made in accordance with IEC 61854 Sub-clause 7.5.1.
- Armor rods and helical splice rods
  - Mechanical testing can be conducted on the individual rods. The tensile strength can be compared to the theoretical strength of the material. The material can be analyzed to determine the alloy, if not known.
  - For Helical Splice Rods - Electrical resistance tests can be conducted on the individual rod and compared to the resistance of the conductor to verify the resistance of the total splice is less than the resistance of the conductor. To determine the total resistance of the helical splice, take the average resistance of the individual helical rods and divide it by the total number of rods in the splice.
- Elastomer materials - Over time, elastomer materials may degrade. Elastomers are normally used for either energy dissipation for damping purposes or for

stress reduction. The material may degrade in two primary ways. The first being hardening of the material which may embrittle the material. In addition, the electrical properties may change which could enhance corrosion or breakdown of the material through tracking.

- Hardness measurement should be made and compared to initial value (if known). Value should be within 30% of initial value. Exceeding 30% may suggest the elastomer losing its effectiveness in strength, compression, resilience, and abrasion resistance.
- Electrical measurements should be made across the installed product to determine the conductivity of the material and compared to initial specified value. If no specified value, refer to product manufacturer.
- Visual inspection should be done of the elastomer to determine if the elastomer has ozone cracks. Examination of elastomer can also be done under magnification for crack inspection. Further testing can be done for ozone cracking according to ISO-1143-1.

9.6.4 Guidelines for Sample Removal, Packing and Labeling

9.6.4.1 Sample Removal

For testing of old fittings, it is necessary that a sufficient number of samples are evaluated. It is important that products that have failed be thoroughly inspected, so the reason for the failure is understood and corrective actions can be taken to avoid similar failures in the future. Only one sample will not give sufficient information about the condition of the product covering the whole line; therefore, larger amounts of the same product should be removed when it is possible.

In other cases the utility may wish to know the condition of old fittings that are installed and samples must be taken from lines in operation or from lines when they are disconnected for maintenance. Typical samples which may be taken are:

- From towers/spans exposed to high levels of vibration
- From towers/spans exposed to heavy climatic loads (ice and/or wind loads)
- From towers/spans exposed to pollution and corrosion
- From critical towers such as road, railway, and water crossings
- From towers where failures have occurred earlier.

9.6.4.2 How Many Samples should be Taken?

It is difficult to recommend a minimum required number of test samples. Removal of samples normally requires an electrical outage of the overhead lines, and therefore it is very expensive to remove test samples. Often only a limited number of samples are available. The more samples that are tested will give better information about the failure distribution. Unfortunately, more samples also requires longer maintenance crew time and cost. Ideally, a minimum of ten samples should be removed and evaluated.

9.6.4.3 Photos

Before an aged fitting is removed from the line, photos should be taken of the fitting, showing where the fitting is located in the string and in the span. Photo documentation is the best method to describe failures, and can often prevent misunderstandings.

9.6.4.4 Handling and Packaging

The test object must be carefully removed and not allowed to fall from the tower. Falling from the tower can cause damage to the fitting when it impacts the ground, and may result in misleading conclusions from testing.

It is important that the test samples be packaged properly, so they will not be damaged during transport. Metal fittings should be packed in wooden boxes. For test samples that require lengths of conductors, such as splices and dead ends, it is important that the fittings are handled and packaged properly so there will be no further damage to fittings and conductors. The conductor must be fixed at the exit of the clamp to avoid movement and damage. For test objects that consist of long conductor lengths, the conductor must be fixed to a pallet and coiled up with a diameter no less than 60 times the conductor diameter in order not to damage the conductor.

9.6.4.5 Labeling of Samples

Good labeling is necessary to be able to identify where samples have been installed prior to dismantling and testing. The objects should be marked with:

- Abbreviation for the name of the line
- The tower number and side of tower, alternatively the span number
- The phase and circuit, alternatively earth wire
- Date of removal
- Contact information of person responsible for the sample.

The marking must be written with waterproof pen so it will not disappear during storage and transport.

9.7 Safe Handling of Fittings

9.7.1 General

Fittings shall be handled carefully during reception and storage at the construction camp, as well as during transportation at site and installation. General simple rules are suggested in the following.

Conductor fittings shall be taken out of the boxes as soon as they are received at the construction camp. Long permanence in poorly ventilated areas, especially in cold and humid weather can favour the formation of white rust on galvanized components.

Figure 9.27 Spacer dampers and other fittings stacked in the construction camp yard.

Units shall be stored in shelves under a shelter and not piled on the ground (Figure 9.27) or covered by plastic sheets. Units shall be handled carefully, avoiding crashes that could damage their surface creating Corona problems or damage the fastening system especially when breakaway bolts are present.

The installation shall be made in accordance with the manufacturer instruction approved by the utility representatives and generally included in the contract documents.

Training relevant to the correct installation of any fitting shall be imparted to the linemen. The ability of the linemen to install correctly any fitting especially compression joints, spacer dampers and interphase spacers shall be demonstrated through trial installation at the contractor camp, and certified by the utility representatives.

Spare fittings and spare parts shall be made available to the linemen at the site especially loose components such as, for example, nuts, bolts, washers, armour rods and clamp keepers. The replacements of any component shall be made only using spare parts supplied by the manufacturer of the relevant fitting. The most common replacement is the fitting clamp bolt that, when not captivated, can be easily lost during the installation. It should be pointed out that not original bolt and nuts, even of the same size and the same type of thread, may not be suitable for the different class of fit, for the different galvanization characteristics and for the different trunk length. The contractor shall demonstrate the availability of the tools necessary for the correct installation of the conductor fittings, as well as the safety equipment for the linemen. Most important tools are: cable carts, torque wrenches, socket spanners and compression machines.

The installation of conductor fittings especially spacers, vibration dampers and joints is made by lineman crews that often are left alone along the line under construction. In some cases, linemen are not properly trained and do not dispose of proper tools. Sometimes, they are also paid at piece rate, so they prefer to be fast than accurate. Hence, the installation of fittings especially compression joints, spacers and vibration dampers shall be witnessed and verified from the ground by a foreman. It is worth repeating that even one single clamp not correctly installed can produce conductor failure and expensive outages.

The foreman shall also control the torque wrench efficiency and calibration every day and assure that the linemen are always equipped with the required tools and spare parts.

Given that many problems experienced in the field are due to poor handling and installation practices, Cigré Study Committee B2 has appointed Working Group 50 to carry out a survey of current practice by manufacturers, contractors and utilities to ensure correct handling and installation of fittings and conductors. This will be done by means of a questionnaire and subsequent analysis of the responses together with inputs from experts in the WG and AG-06. Following on from this, guidelines would be produced with the aim of promoting good practice to minimise handling and installation problems with fittings and conductors.

9.7.2 Installation of Spacers and Spacer Dampers

Spacers and spacer dampers must be installed as soon as possible after stringing operations and adjustments to obtain initial tensions, preferably within 24 hours (IEEE 2003, 2004).

The linemen shall dispose of a suitable cable cart able to keep the bundle in its design configuration during the installation of spacers. The cable cart shall distribute its weight evenly on each subconductor of the bundle to avoid longitudinal misalignments of spacers and prevents the linemen from keeping the subconductors in place during the installation.

Care should be exercised to ensure that the concentrated load of the person, cart, and equipment does not increase the sag sufficiently to cause a hazard such that the cable cart cannot pass an obstacle under the line. When possible, spacers and spacer dampers as well as other in-span fittings, can be better installed using a bucket truck (Figure 9.28).

The manufacturer shall provide clear installation instructions and spacer distribution tables. They shall contain information about: correct orientation of the spacer, the datum point for subspan length measurements, both for suspension and tension span extremities, the position of the spacers in relation to mid-span joints, night warning lamps and other devices installed on the conductors.

The in-span positioning of the spacer dampers is very important for the correct behaviour of the damping system. The installation and location of this units on the conductors vary with the type and brand and are normally done is accordance with the manufacturer's recommendations. The replacement of a spacer damper with a

Figure 9.28 Bucket truck used for installation of spacer dampers.

unit supplied by a different manufacturer is not recommended. Ground targets or cart distance counters are necessary for accurately locating the spacers.

It is advisable to release spacer clamps before any further relative sag adjustment between sub-conductors. Cases of spacer damper failures due to this operation have been reported several times.

The training of the linemen should be made setting up at ground level a short span of about 3 to 4 m of single or bundled conductor. Each lineman should be invited to install some spacers on the trial span during which the relevant part of the following points should be carefully explained:

Set up of the spacer for the installation: It should be explained: how to open and tighten the clamps, the orientation of the spacer in respect to the bundle (asymmetric spacers shall be installed with alternate orientation), the top position and so on.

Cleaning of the conductor and the clamp bore: Foreign materials into the clamp groove can damage the conductor and contribute to the clamp loosening.

Avoid longitudinal misalignments of the spacer clamps: Some spacer dampers with low stiffness in the direction longitudinal to the conductor axis can be installed with the clamps not correctly aligned even if a proper cable cart is used.

Control the washer position: The right orientation of the Belleville washer and the right position of the plane washer should be regarded in case of clamp disassembling and reassembling. Moreover using nutcracker clamps, attention shall be paid to avoid entrapment of the washer between clamp cap and clamp body.

Use of torque wrench and other not conventional tools: Latching fastener clamps and other not conventional clamp requires special installation tools which use shall be carefully explained.

Breakaway bolts: The mechanism of breakaway bolt shall be considered. It should be recommended not to drop the sheared head on the ground. Problems with the cattle eating the bolt heads have been reported. In a normal span, the number of sheared heads can be between few units to more than 200 depending on the number of circuits and bundle configuration.

Correct installation of helical rods: The best installation procedure, to minimize permanent deformations and Corona and RIV effects, shall be recommended.

Measurement of the subspan length: Measurement devices and procedures shall be explained and verified on the trial bundle.

The linemen should have access to proper tools, as follows:

Torque wrench: Has to be short and light; the pre-set of the required torque shall be made only by means of a specific tool and cannot be changed even accidentally by the linemen.

Spanner: Using breakaway bolts, a normal spanner is sufficient, although a torque wrench should be available for the repositioning of spacers. It is preferable to use a ratchet spanner instead of fork spanner, adjustable wrench or others.

Special tools: If necessary.

Plastic brush and flannel clothes: They are required to remove mud and other foreign materials from conductors and clamps before installation.

Moreover, the linemen shall dispose of a number of spare components such as, according to the case, bolts, breakaway bolts, washers and armour rods.

9.7.3 Installation of Vibration Dampers

Vibration dampers are normally placed on the conductors immediately following clipping to prevent any possible wind vibration damage (IEEE 2003, 2004). Damages due to aeolian vibration can occur in a matter of a few hours at initial tensions. Vibration dampers are generally located at span extremities. Their installation does not require cable carts. The positioning and the quantity per span of aeolian vibration dampers are very important for the correct performance of these units and should be carefully accomplished in accordance with the manufacturer's recommendations. Stockbridge dampers that are the most used on transmission lines, are installed with their counterweights below the conductor and in line with it. The clamp bolts are tightened to the specified torque using a torque wrench, unless break away bolts are used.

Spiral vibration dampers (SVD) are installed at span extremities but the positioning is not critical as they are sufficiently long so that an antinode is always present along their length in the range of aeolian vibration frequencies. SVD are generally installed on shield wire and on small phase conductors.

9.7.4 Installation of Compression Fittings

Installation of joints, splices and repair sleeve of the compression type, is a critical operation in the construction of a transmission line (IEEE 2004). Manufacturer's instructions shall be clearly illustrated and followed carefully step by step (Figure 9.29). The utility's representatives should check for the use of the proper dies and properly functioning presses. These fittings serve two purposes: as strength members and as electrical contact members. Their proper function and long life both depend on proper installation. The correct size dies, which fully close in the press, are critical to reliable operation (Figure 9.30). Cleaning of the conductors prior to insertion into the fittings is necessary for good electrical contact. Dirty conductors will produce poor joint contact and could lead to premature failure. Even new, clean conductors have a layer of insulating aluminum oxide on their surface that should be cleaned immediately prior to making the presses to provide a good electrical contact. The inside of all compression fittings, the outer conductor portion

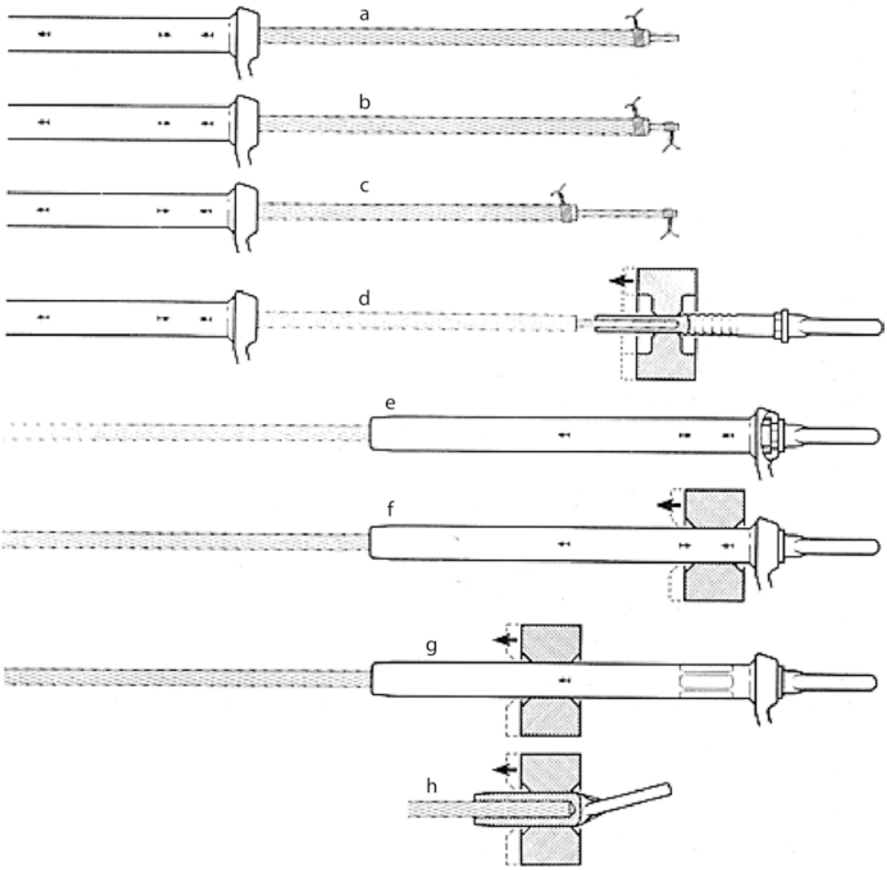


Figure 9.29 Assembly sequence for compression of a dead end joint.


Figure 9.30 Compression of a dead end clamp.

that has to be compressed, including the exposed steel core for ACSR, shall be thoroughly cleaned of all grease with a suitable solvent and dried before compression. The outer strands of the conductor shall be thoroughly scratch brushed until shiny, wiped clean, and immediately coated with an approved jointing compound, to prevent oxidation before compression of the outer sleeve.

An emery cloth or metallic brush having steel wires 0.2-0.3 mm long can be used for this operation.

When aged conductors are joined, the cleaning process is especially critical. On old blackened conductors, it is sometimes advisable to unwind and clean all the elementary wires prior to compressing the joint or deadend. Even for new installations, some utilities require that each layer be unwound and cleaned with a brush previously dipped in inhibitor compound.

In preparing ACSR cable for jointing particular care shall be taken to ensure that the steel strand of the core is not cut or nicked by the cutting tool. To prevent it the innermost aluminium layer shall be only partially cut and then broken off.

The joint as a whole and the line of compressions along the outer sleeve shall be straight after compression.

When, during stringing operations, a compression fitting is to be pulled over a stringing sheave it shall be protected by an approved oversleeve.

9.7.5 Installation of Preformed Fittings

All preformed fittings shall be installed in accordance with the manufacturer's recommendations.

The outer surface of the cable shall be thoroughly cleaned of all grease with a suitable solvent and dried and the outer layer vigorously brushed before application of the preformed fitting, as per compression fittings.

Armour grip suspension units shall be installed such that the ends of preformed rods are suitably aligned in order to obtain the best Corona performance. Difference in alignment should not be more than 15 mm.

Preformed fittings for use in tension positions and for clamping purposes shall not be re-applied and shall be destroyed after their first removal.

9.7.6 Installation of Other Fittings

The installation procedures of other fittings such as: bolted suspension clamps, aircraft warning spheres, counterweights and interphase spacers are relatively simple and do not require detailed manufacturer's instructions.

9.7.7 Live Line Installation

Many utilities require that their lines be maintainable under live conditions. Live line working is a specialized skill entrusted to selected linemen well trained to perform operations efficiently and safely. Tools form a critical part of this activity and their conservation, transportation and use follow strict rules. There are two main live line working methods: stick and bare hand techniques. The stick or "distance" technique uses long insulated poles, special tools and special equipments to perform live line operations. The conductor fittings, if required, should be designed in order to be installed and removed using the insulated pole equipped with special tools.

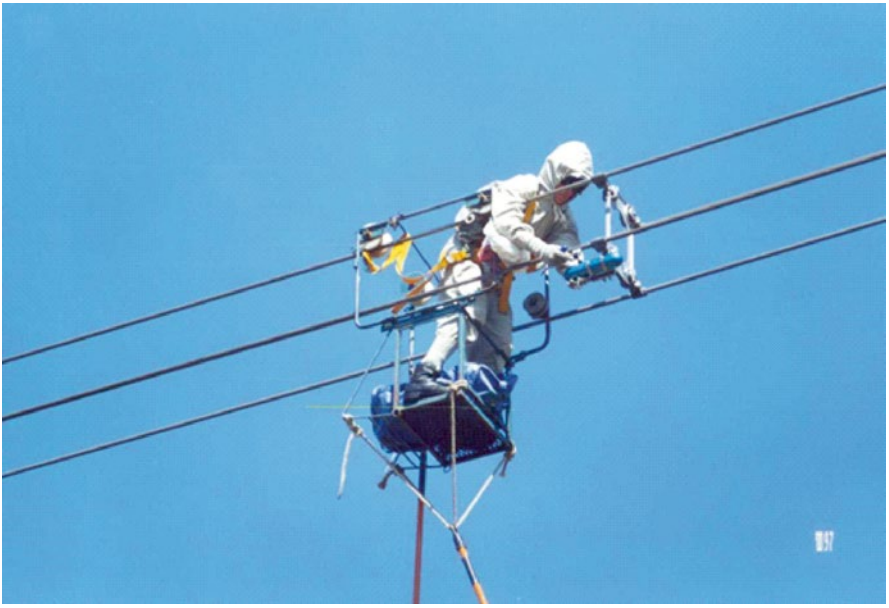


Figure 9.31 Hot line installation of a vibration recorder.

The bare hand technique is used for high voltage lines, typically 135 kV and above. In this method, the linesman, suitably dressed and equipped (Figure 9.31), is raised to the potential of the energized part of the line, by other linemen standing on the tower cross arm or by helicopter and operates with his hands using the same tools and the same procedures employed on not energized lines.

9.8 Damages on Fittings in Service

A questionnaire entitled "Survey of Experience with Repair Methods for Fittings and Conductors of Power Transmission Lines" was circulated among power network operators worldwide (Cigré B2.47 2015). A total of 38 replies were received from 16 countries. Although the results may not be statistically significant, the questionnaire's replies, along with the input of the group experts, provide a good basis for reviewing the current remedial action practices on conductor fitting systems.

As shown in Figure 9.32, "controllable" factors (i.e. installation and quality issues) appear to be the cause of a significant proportion of damage to conductors and fittings. It is therefore possible to think that, although transmission lines are vulnerable structures, due to their exposition to environment and their flexible nature, better hardware design, manufacturing and installation practices still have the potential to greatly reduce the occurrence of conductor and fittings damage.

With reference to Figure 9.33, it appears that hydraulic compression and implosive (HCI) fittings, spacers and dampers have a similar level of failure occurrence, while suspension clamps and related hardware have a low occurrence of failure. AWMs failure is less frequent, probably because of the relatively low number of units installed.

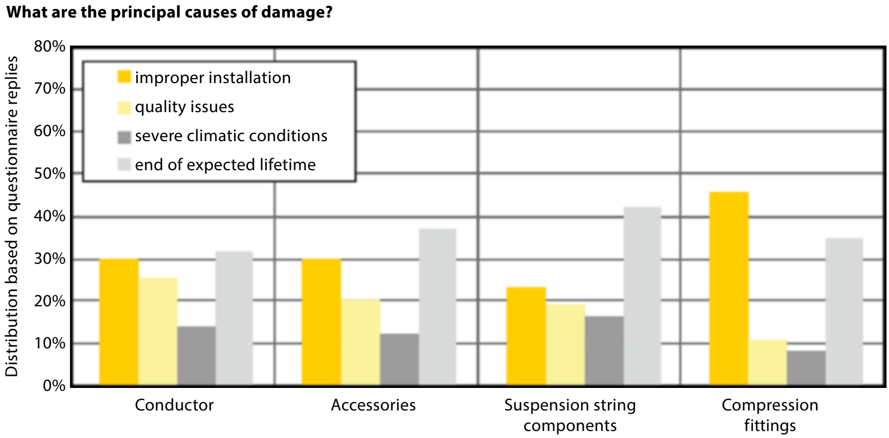


Figure 9.32 Principal causes of conductor and fittings damages.

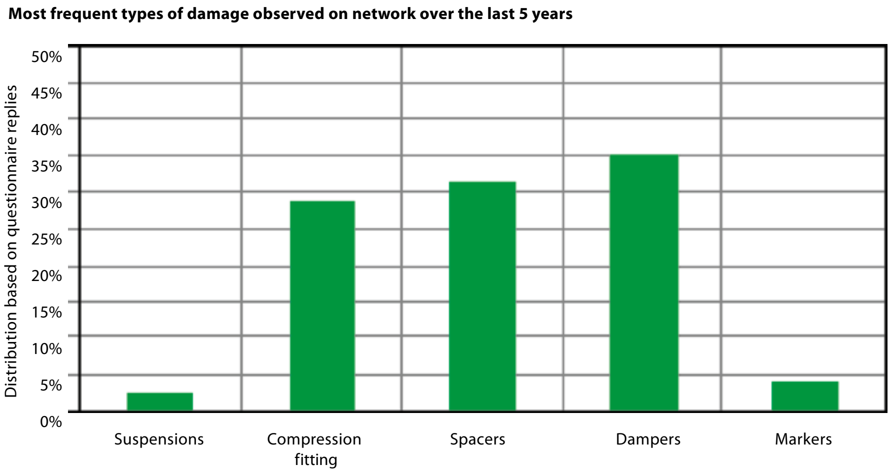


Figure 9.33 Most frequent types of conductor fitting failures.

9.9 Influence of Fittings Design on Other Components

One of the greatest scientists in the field of transmission line: Charles Rawlins, wrote "Any device added to an overhead line has its own built-in hazard". The hazard is represented by the increased number of clamps that can get loose under the effect of vibration and thermal cycles and by the possible interference between the additional device and other conductor fittings or hardware components. For example, warning spheres installed on a shield wire interfere with the performance of the vibration dampers installed at span extremities. In fact, warning spheres, as well as any other warning device, divide the shield wire span into subspans in which aeolian vibration can be easily entrapped and cannot be mitigated by the vibration dampers. In these cases, the application of additional vibration dampers in each subspan should be considered, even if this increases the number of clamps installed. Sometimes, the vibration dampers of the shield wire are installed inside the earthing loop and interfere with it as shown in Figure 9.34.

On single or bundled phase conductors the installation of devices such as, for example, interphase spacers, surge arresters (Figure 9.35), night warning devices, etc. influence the performance of the damping elements (vibration dampers and spacer dampers) limiting their field of influence and forcing a nodal point on the conductor in which high alternate bending stress can be generated by aeolian vibrations.

Fitting manufacturers recommend that spacer dampers be installed at a distance of at least 2 m from other fittings such as splices (Figure 9.36) in order to avoid concentration of masses that can generate a nodal point at high vibration frequencies of the conductors.

It should also be carefully considered that any damping device cannot reduce the conductor vibration to zero but only mitigate it within safety limit. The residual vibration may excite the resonances of other fittings or hardware components whose

Figure 9.34 Vibration damper of a shield wire installed inside the earthing loop.

Figure 9.35 Surge arrester installed on twin bundle.

natural vibration frequencies fall in the range of conductor vibration frequencies. In these circumstances, elements, like for example, night warning lamps, arching horns, raquettes and Corona rings may fail in fatigue.

Failures of thousands of arching horns in a line in North Africa due to residual aeolian vibration on a twin bundled line have been reported some years ago.

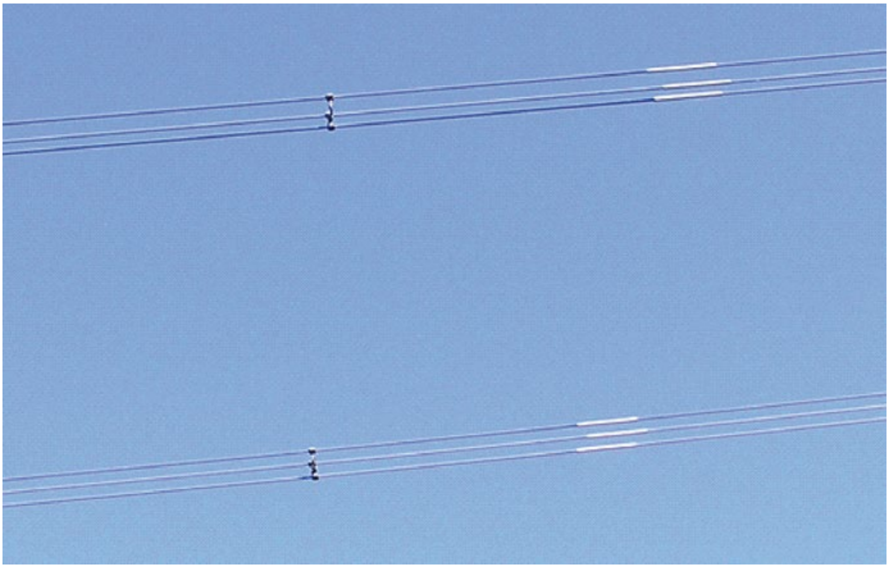


Figure 9.36 Spacer dampers installed at a suitable distance from compression joints.

Another possible interaction between fittings and conductors is represented by the corrosion that can be produced by the coupling of dissimilar materials in presence of moisture as reported in a previous section.

9.10 Connection Types

String hardware is used to connect insulators with towers and conductors under mechanical load. Different types of connections are available to provide a secure mechanical and electrical link.

Clevis-eye connections and ball and socket connections are standardized internationally according to the Standards described in the subsections.

The fittings must be able to withstand the specified mechanical loads as well as the electrical short current loads caused by power arcs and short circuits conditions.

The general requirements are specified in the IEC 61284, clause 4.

The hardware can be equipped with additional protective fittings to control power arcs. The protective fitting attachment can be made as specified in the following DIN standard.

- DIN 48068, Protective fitting attachment; for overhead lines, connection dimensions.

9.10.1 Clevis-Eye Connection

The clevis eye connection is typically used to connect yoke plates with other items like insulator clevises. The limited degrees of freedom in different axes have to be considered when using clevis eye connection.

- IEC 60471 and DIN 48074, Eyes and clevises; connecting dimensions.

  Examples shown in Figures 9.37 and 9.38.

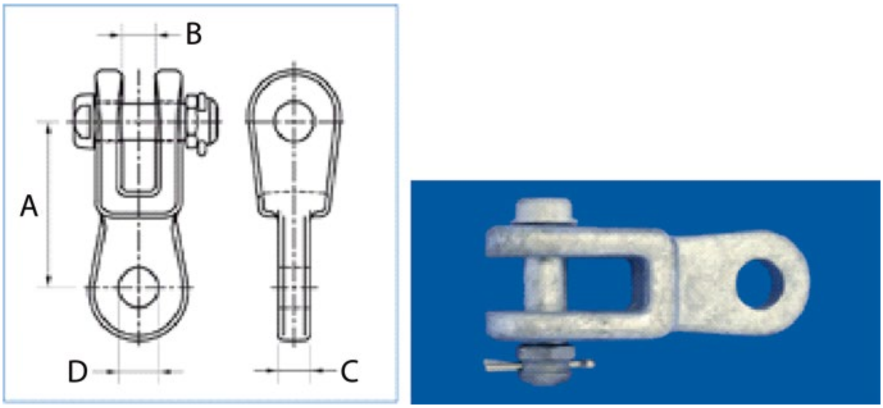


Figure 9.37 Clevis eye.

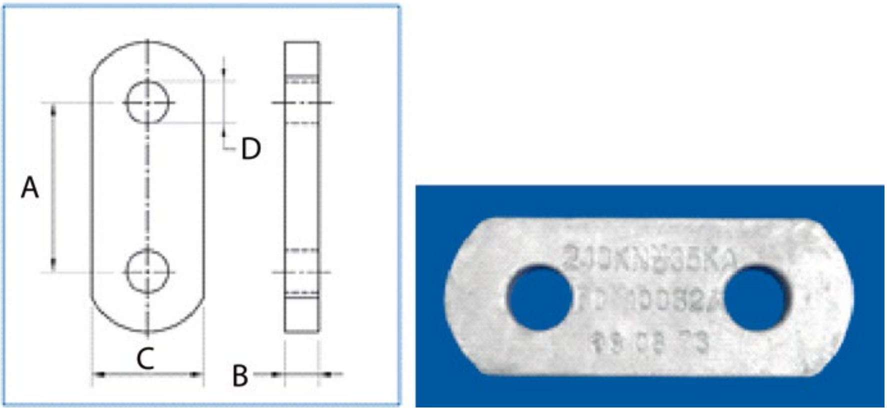


Figure 9.38 Double eye.

9.10.2 Ball-Socket Connection

Ball socket links are mainly used for connecting insulators.

The following standards are applicable for the dimension of ball socket couplings.

- IEC 60120, Dimensions of ball and socket couplings of string insulator units
- ANSI C 29.2/52-3 for Ball 16
  /52-5 for Ball 18
  /52-8 for Ball 22
- IEC 60372, Locking devices for ball and socket couplings of string insulator units - Dimensions and tests

Examples shown in Figures 9.39, 9.40, and 9.41.

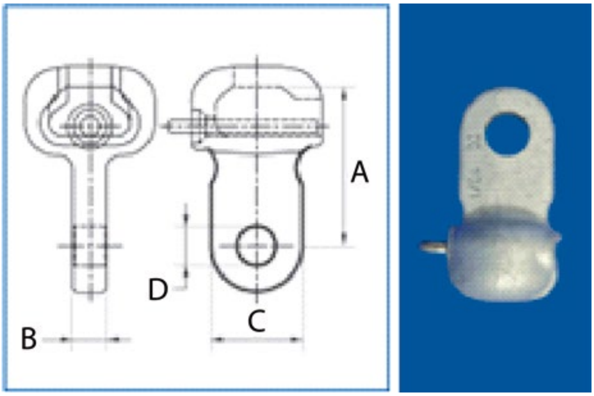


Figure 9.39 Socket tongue.

Figure 9.40 Insulator with socket.

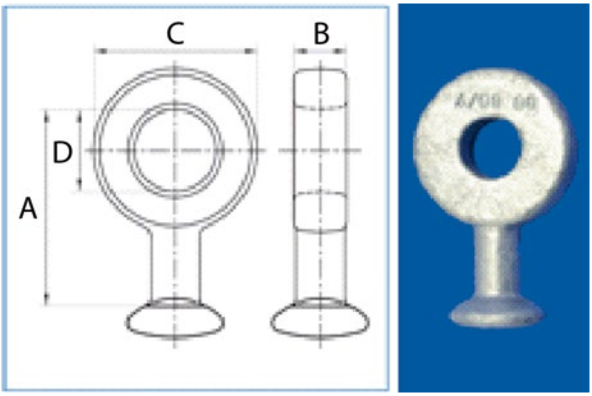


Figure 9.41 Ball eye.

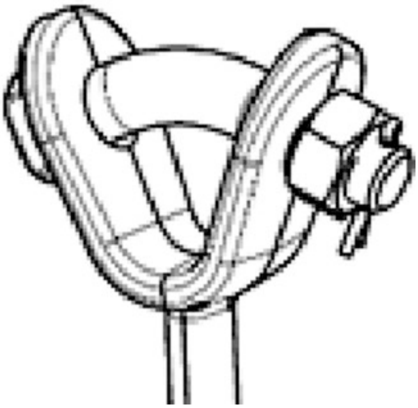


Figure 9.42 Y-connection.

9.10.3 Y-Connection

This type of connection can be used to achieve more freedom of degrees in two axes (Figure 9.42).

- Y connections according to EN 61466, Composite string insulator units for overhead lines with a nominal voltage greater than 1 kV - or specific requirements.

9.10.4 Oval Connection

The oval shape of the connection provides a more flexible connection but the short circuit capacity is lower due to the decreased surface of contact compared to eye connections described in 9.10.1. A typical oval connection is shown in Figure 9.43.

- Oval eyes connections according to EN 61466, Composite string insulator units for overhead lines with a nominal voltage greater than 1 kV - or specific requirements.

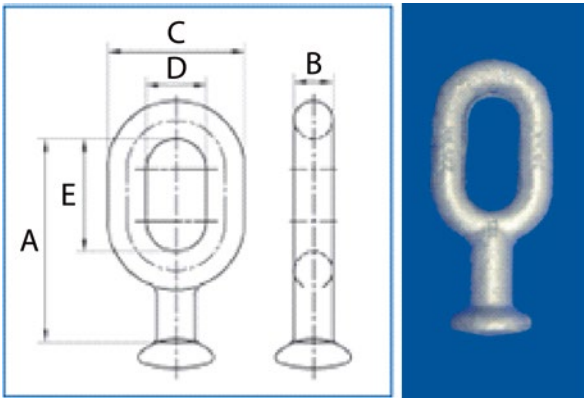


Figure 9.43 Oval Ball eye.

9.10.5 Bolted Connection

Bolts with different sizes and material grades can be used. Each bolt shall be secured after installation against loosening by a split pin or other appropriate device.

Bolts will be used in the following applications

- According DIN 48073, Connecting bolts for overhead power lines.

9.11 Clamping Systems

9.11.1 General Principles

Experience has shown that although successful clamp designs for overhead transmission conductors and other overhead cables are wide ranging in concept and form, they tend to conform to some or all of the following general design principles:

- The clamp should be capable of easy, reliable installation, preferably verifiable by ground based inspection and should provide a safe, reliable, non-damaging, long-term grip on the conductor.
- High, localised clamping stresses should be avoided and the clamp conductor groove should be smooth and free from irregularities.
- Particular attention should be paid to the edges of the clamp where the conductor has its last point of contact. These should be smooth and rounded to avoid creating any stress concentrations or mechanical damage to the outer conductor strands.
- Captive parts should be used and an energy storing mechanism is required to prevent clamp loosening due to the effect of vibrations, thermal cycling, cold flow and conductor creep.
- All materials should be compatible with the conductor to avoid corrosion.
- In the case of conductors of unusual constructions and shapes, such as GAP high temperature conductor and T2 conductor, particular care needs to be taken regar-

ding the mechanism of exerting the clamp's grip to avoid both short term and long-term damage.
- In the case of overhead optical fibre cables, clamp designs should reflect the need to ensure that the integrity of the fibre optics is fully protected under all anticipated operating conditions. There were some early instances of damage to these cables because conventional clamps were used.

In the following sections, the word "clamp" is used to mean the type of clamp to which the section refers.

Practically 99 % of vibration failures take place very near to or at the clamp location. Consequently, clamp design is of great importance for the mechanical integrity of the conductor and thus for the operational safety of a line. Nevertheless the conductor/clamp combination is not susceptible to a quantitative approach and so there are more practical engineering design rules, which have evolved from experience over the years, for a good, practical clamp design (Cigré 22.11 TF3 1989).

Fatigue aspects of the conductor/clamp systems are covered in Chapter 10.

9.11.2 Suspension Clamps

9.11.2.1 Function

Suspension clamps are used to suspend the conductors from a tower and have to fulfil a number of duties such as to:

- Withstand the mechanical loads imposed by the conductor;
- Avoid damage to the conductor in the clamp area
- Prevent/reduce strand failures because of vibrations as much as possible
- Assure good resistance to corrosion
- Assure sufficient Corona inception voltage for the respective voltage level of the line
- Withstand short circuits, have low contact resistance and low electrical losses
- Assure simple and safe installation.

A wide range of suspension clamps is used on overhead lines. These clamps have to perform the important function of safely carrying the conductor in the context of combinations of the normal static loads and dynamic loads caused by vibrations, galloping, wind and ice drop.

At one end of the scale is the *conventional* metal-to-metal clamp where the conductor is carried in a contoured metal body and secured by a keeper using U bolts or bolts locating in captivated nuts or threaded holes in the clamp body. The clamp is attached to the suspension hardware via shackles and links. At the other end of the scale is the clamp in which the conductor is completely enclosed by elastomeric housings carried in metal shells and secured to the conductor by helically formed rods. Variations exist between these two types, including the fitting of helically formed rods on the conductor under the clamp and the use of *long bodied* curved clamps where loads are high, such as river crossings.

Some clamps are designed to meet a *slip load* window arising from unbalanced longitudinal loads.

9.11.2.2 Design of Suspension Clamps General Aspects

The function of a suspension clamp is to support the conductor under all the conditions which could occur in service without reducing the breaking strength of the conductor (Cigré SC22 WG01 1989). The effect of clamp design on the fatigue performance of conductors is also of paramount importance and may be evaluated through fatigue tests (IEC 62568 2014).

Mechanical Aspects

The mechanical failure load of the suspension clamp must be checked with the maximum exit angle of the conductor from the suspension clamp.

The mechanical failure load depends on the maximum working load and the safety factor.

The maximum working load is determined by the wind loads in conjunction with the vertical loads and the line angle.

The user of the suspension clamp should therefore consider the following:

- The maximum vertical load depending on the weight span S
- The maximum horizontal wind load
- The maximum horizontal load provided by the conductor at an angle tower
- The maximum turning angle
- The safety factor.

Turning Angles

The profile of suspension clam should accommodate the various required turning angles, for example:

- Low tensioned conductor with a high turning angle: assumption of high temperature.
- High tensioned conductor with a small turning angle: assumption of low temperature.
- High tensioned conductor with a high turning angle: assumption of ice or wet snow load.
- Conductor at an angle tower: assumption of maximum line angle and maximum sag angles.
- Conductor with negative turning angle: assumption of a tower in a low position subject to uplift and requiring counterweights.

For straight line towers a simple formula relating half the turning angle (symmetric spans), to the vertical and horizontal tensions is given by:

$$\tan\frac{\alpha}{2} = \frac{SW}{2T} = \frac{S}{2\rho} \tag{9.1}$$

Where

S is the length of the weight span (m). The weight span is the distance between the points where the tangents to the two adjacent spans are horizontal,

W is the weight per metre length of the conductor under the assumed conditions (N/m),

T is the horizontal component of the mechanical tension of the conductor (N)

and $\rho = \dfrac{T}{W}$ is the catenary parameter.

For example, it has been shown that in France more than 99 % of the straight line suspension towers have a maximum turning angle less than 30 degrees.

Body and Keeper Profile

Theoretically, the profile of the body should follow the natural curvature of the conductor and should not reduce the breaking strength of the conductor. But as there are different load assumptions, it is not possible to satisfy this theoretical requirement under maximum, minimum and average turning angles.

An optimal profile design of the body and keeper must be found for the different load assumptions and the contact length of the suspension clamp. The profile of the body must also cope with asymmetric adjacent spans, i.e. with different sag angles on each side of the clamp.

On metal-to-metal clamp, the main profile of the body shall be rounded and curved into a bell mouth at the ends in order to avoid damage to the conductor in the case of exceptional overloads (Figure 9.45). This consideration should also be applied to the keeper design when conductor uplift is assumed.

Mobility

A suspension clamp shall be able to rotate in a longitudinal vertical plane in order to accommodate asymmetrical loads and different spans on each side of the clamp. The amount of rotation required at the pivot point is generally much greater for earth wires than for phase conductors because of the short link in the support assembly of the former.

It is commonly thought that the axis of rotation should not be more than a few conductor diameters from the conductor axis. In the case of a slip clamp, the rotational axis of the clamp should be, as near as possible, at the same height as the longitudinal axis of the conductor.

Suspension clamps shall be so designed that the moment of inertia related to the rotational axis is minimised in order to reduce dynamic stresses.

When ‘V’ strings are used, the suspension clamp assembly shall have a lateral mobility and will be tested with transversal loads (Figure 9.44).

Sliding

A conductor in a suspension clamp should slip at a known sliding force in order to accommodate the overloads which are estimated for an overhead line. For a locked clamp, the minimum sliding force shall be defined. For a slip clamp which can be

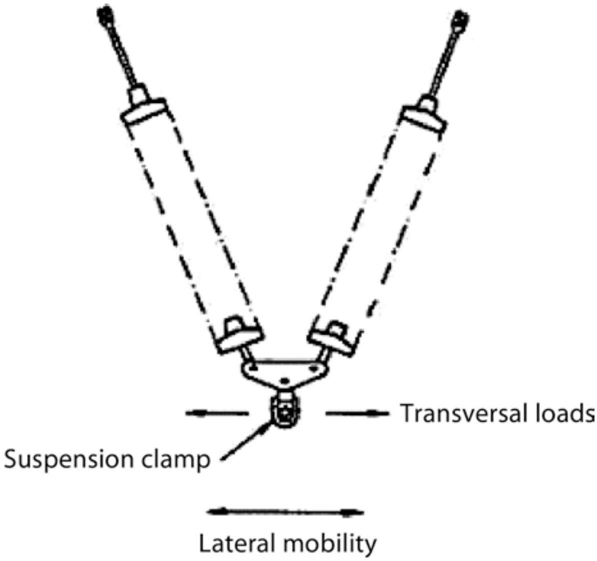


Figure 9.44 'V' string with a suspension clamp.

used as a mechanical fuse to avoid line cascade, the conductor shall slip at a controlled sliding force.

Short-Circuit Capacity and Flashovers

The suspension clamps shall withstand short-circuit currents without any damage to the conductor or to the suspension clamp. The short-circuit capacity of a suspension clamp is defined by the current intensity and current duration, both of which should be evaluated.

Whilst keeping the clamp mass low is an advantage, the contact area and contact pressure between conductor and clamp must withstand high current flows during flashovers, i.e. in these cases, the suspension clamp has to act as a current carrying clamp. This requirement may contradict the requirements for good vibration behaviour of the clamp. As is usual in these cases, the design will ultimately be a compromise.

Radio Interference

The Corona performance or RIV level of the suspension set with all accessories should be evaluated.

Electrical Losses

The magnetic losses of suspension clamps should be evaluated. They are generally measured in laboratoty using a low cosφ wattmeter.

Corrosion

The components of suspension clamps should be protected against corrosion in order to provide an adequate service life.

Surface Finish

To prevent damage to the conductor surface, all parts of the clamp in contact with the conductor should be smooth.

Counterweights

Straps may be used to fix counterweights.

Design for Live Line Maintenance

Some utilities require suspension clamps to be so designed that the clamp can be installed on or dismounted from the conductor with live line tools. The number of separable parts shall, in general, be kept to a minimum.

9.11.2.3 Basic Types of Suspension Clamps

Suspension clamps have an effect on the fatigue life of the conductor based on how the suspension clamp accommodates the cable motion.

There are different types of suspensions that are used in transmission construction:

- Bolted suspension clamps on bare conductor;
- Bolted suspension clamps over armor rods;
- Release bolted suspension clamps;
- Helically attached elastomeric suspension clamps (HAES);
- Elastomeric suspension clamps without helical rods (ES).

Bolted Suspension Clamps on Bare Conductor

The bolted suspension clamp on bare conductor (Figure 9.46) offers the least amount of protection against vibration fatigue. The reason for increased fatigue is twofold. Firstly, the high compressive loads of the range-taking bolted suspension clamp, which may cause damage to, or indentations in, the aluminum conductor. These indentations are effectively stress raisers. Secondly, the bending amplitude due to cable motion (either aeolian vibration or galloping) is high since the cable is not armored. The curvatures are much larger, interstrand microslip amplitude increases, small cracks may be generated and some may propagate to cause complete strand failures.

This type of suspension is normally used in areas where aeolian vibration levels are low and galloping is not expected. Often, these clamps are used in conjunction with dampers, which reduce cable vibrations. This type of suspension clamp is used in probably over 50 % of the suspension application.

The various parts of a typical design are shown in Figure 9.45. Different designs of metal-to-metal suspension clamps are available and some are shown in Figure 9.46.

Definition of terms related to suspension clamps (Figure 9.45):

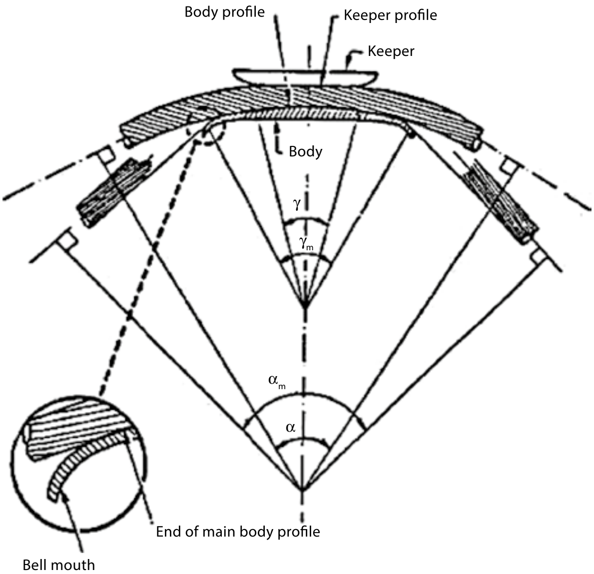
Body: Part of the clamp where the conductor rests.

Keeper: Part of the clamp which clamps the conductor to the body.

Profile: Longitudinal curvature of the body or the keeper.

Exit angle γ: Angle between the tangents or the body profile at the last points of contact with the conductor.

Figure 9.45 Technical terms related to suspension clamps.



Maximum exit angle γm: Angle between the tangents of the body profile at the ends of the main profile.

Turning angle α: Angle between the tangents at inflexion points of the curve of the conductor. This angle is the vector sum of the two sag angles and the line angle.

Maximum turning angle αm: Turning angle of the conductor in the case of the highest load which the clamp can support. This angle is slightly greater than the maximum exit angle.

Sag angle: Angle between the clamp (generally horizontal) and the portion of the conductor exiting the clamp.

Figure 9.46 shows some examples of metal-to-metal suspension clamps while Figure 9.47 shows a special clamp for a long river crossing.

Bolted Suspension Clamps over Armor Rods

The bolted clamp over armor rods (Figure 9.48) offers moderate protection against vibration fatigue. This type of suspension clamp is commonly used in areas where moderate levels of cable motion are expected and is probably used in at least 25 % of suspension clamp applications overall. These helically formed wires are wrapped around the conductor, effectively stiffening the conductor at the suspension clamp location. A larger size suspension clamp body is then placed over the armor rods. The addition of armor rods improves the fatigue endurance of the conductor in two ways. Firstly, the extra layer of high strength rods spreads the high compressive load of the suspension clamp over a larger area. This in effect reduces the static compression on the conductor. Secondly, the increased stiffness of the rods reduces the bending angle at the suspension clamp during cable motion. This reduction in bending angle reduces curvature on the conductor and thus improves its fatigue performance. Moreover, the addition of armor rods adds a small but useful amount of additional damping through friction between the rods and conductor (Rawlins 1979).

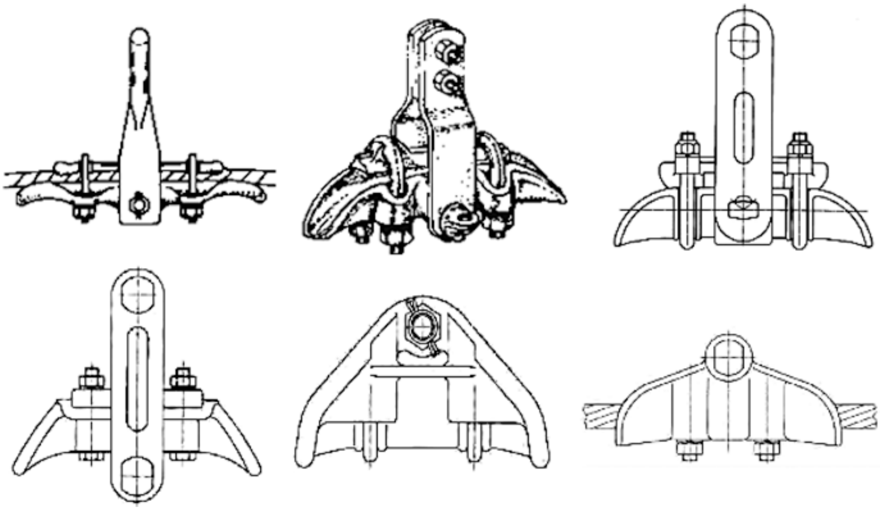


Figure 9.46 Different types of metal-to-metal suspension clamps.

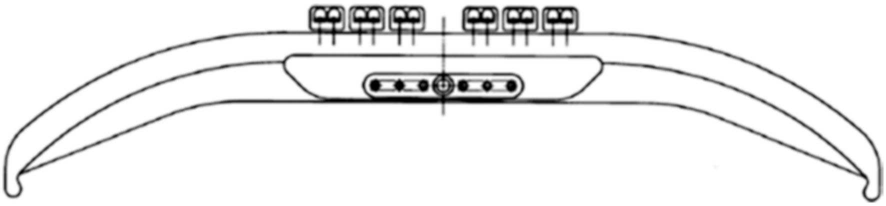


Figure 9.47 Special River crossing clamp made from hard drawn aluminum alloy material.

Figure 9.48 Typical bolted suspension clamp over armor rods.

Care must be taken when choosing the wires diameter since an armor rod which is too stiff will simply move the conductor bending stress from the clamp mouth to the rod ends where conductor fatigue may occur. The armor rods should be made of a similar metal as the conductor or ground wire it is applied to, in order to avoid electro-chemical corrosion. Table 9.5 shows the different material combinations that are acceptable. The preferred solution in all circumstances is to apply armor rods of the same material as the wires on which it is applied.

Bolted Suspension Release Clamp (or Slip Clamp)

A release clamp is a suspension clamp in which the conductor should slip at a defined sliding force. A conductor shall slip in a clamp only in the case of exceptional overloads caused by:

- Breakage of a conductor or another element of the overhead line, such as a tower, hardware, etc.
- Unequal ice loadings on the adjacent spans.

More details are provided in (Cigré SC22 WG01 1989) regarding the sliding characteristics required and how to test this type of clamps. Some provision should be included to take into account that the sliding force may change with time as corrosion and dust may change the friction coefficient of the clamp and conductor.

Helically Attached Elastomeric Suspension (HAES)

The Helically Attached Elastomeric Suspension (HAES) clamp type (Figure 9.49) offers the highest protection against vibration fatigue. It is a special stress reducing suspension clamp that utilizes and elastomeric insert and helical attachment rods. This

Figure 9.49 HAES suspension clamps.

device was initially designed in the 1950's and is still regarded today as the best suspension arrangement from a fatigue endurance standpoint. The increased fatigue life performance in both aeolian vibration and galloping can be attributed to a reduction in not only dynamic stresses but also static stresses. The helical rods gently but securely attach the suspension clamp to the conductor, which almost completely eliminates any notching to the conductor, thereby eliminating the high stress riser associated with notching. The elastomeric insert reduces the dynamic stress since the vibrating conductor bends over a larger cushioned area. This suspension clamp is heavily used in areas where galloping occurs due to its fatigue endurance characteristics. The overall performance history of this type of suspension clamp has been excellent and is probably used in less than 10% of the suspension applications for conductor. It is, however, the suspension clamp that is used predominantly on OPGW and ADSS. The disadvantages of this type of clamp are: the cost, much higher in respect to metal-to-metal clamps, the installation that is longer and more complicated due to several loose components and the impossibility to reuse the clamp if dismounted.

Cigré Working Group B2.49 has recently published recommendations for safe design tensions with such clamps (Cigré TB 653 2016)

Elastomer Type Suspension

In recent years elastomer suspension (ES) units which do not utilize helical rods have been developed and are becoming more popular. Those clamps are lighter and cheaper than the HAES and it takes less time to install them. Figure 9.50 shows sample designs available.

Fatigue tests have shown that fatigue performance of conductors is improved with ES clamps compared to standard clamps.

9.11.3 Spacer and Spacer-Damper Clamps

9.11.3.1 Introduction

A spacer clamp must be capable of easy installation on the conductor and provide a safe, reliable long-term grip.

Figure 9.50 Two different ES type suspension clamps.

The design of such clamps should aim to:

- Avoid high, localised clamping stresses - this is a function of clamp length, clamping force (bolt torque) and clamp geometry
- Avoid damage to the conductor due to clamping surface irregularities - the conductor contact surfaces must be smooth
- Minimise the possibility of incorrect installation
- Ensure that, if feasible, all components are captive - bolts may be peened or, if in a blind tapped hole, secured by an O-ring to the clamp keeper which itself may be secured to the body of the clamp by a tie or captive hinge
- Incorporate a stored-energy mechanism to prevent clamp loosening due conductor vibration, to temperature cycling and conductor creep
- Exert an adequate, non-damaging long-term grip on the conductor - axial and torsional grip are often specified by the end user
- Be manufactured from a material that is compatible with the conductor to avoid corrosion
- Be profiled to minimise the possibility of Corona and RI (Radio Interference) discharge at specified line voltages
- Allow ground level inspection to verify correct installation
- Preferably, be capable of being installed with hot line/bare hand techniques.

Elastomer-lined clamps generally have some range-taking capability whereas metal-to-metal clamps should ideally be matched to the conductor diameter in question, although a very limited degree of ranging is possible.

Metal-to-metal clamps may be installed over helical, factory-formed rods to provide an enhanced degree of conductor protection.

There are a number of clamp types with widely differing characteristics including:

9.11.3.2 Cantilever Clamp

The cantilever clamp is a metal-to-metal clamp secured by a captive, galvanised steel bolt bearing on a plain and split washer and secured by a captive, galvanised steel nut (Figures 9.51 and 9.52). Belleville washers (Figure 9.53) may be used instead of split washers to enhance energy storage and the bolt or nut may incorporate a locking mechanism, such as a nylon patch or ring.

Experience have demonstrated that cantilever clamps are very sensitive to incorrect installation and in particular to undertorque.

9.11.3.3 Opposed Hinge Clamp

The opposed hinge clamp (Figure 9.54) is a heavy duty metal-to-metal clamp which, because of its hinge/conductor/bolt geometry, imposes a significantly higher grip on the conductor than the cantilever clamp (Figure 9.51) which has a conductor/bolt/hinge geometry. The opposite hinge clamp almost completely encloses the conductor. The clamp keeper pivots on a detachable or captive hinge and is secured by a galvanised steel bolt bearing on a plain and split washer and secured by a captive,

Figure 9.51 Cantilever bolted.

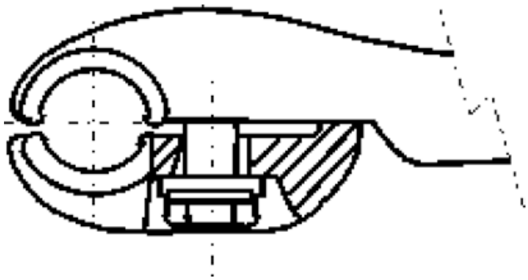


Figure 9.52 Break-away head.

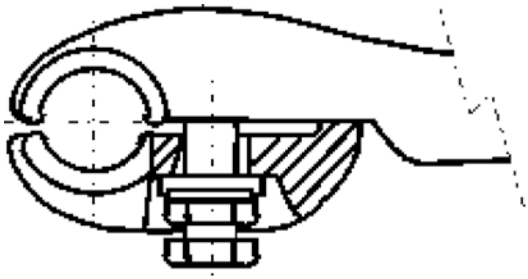


Figure 9.53 Belleville washers.

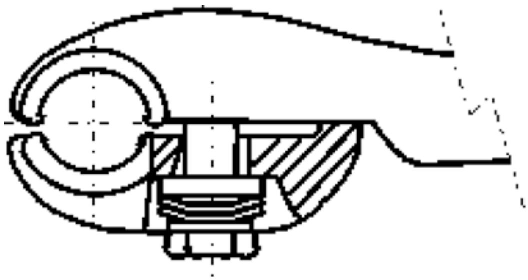
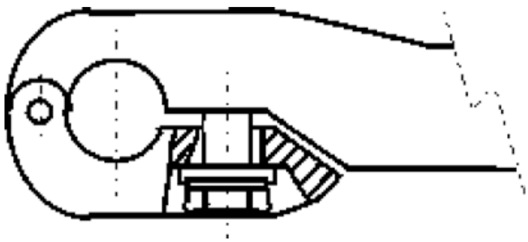


Figure 9.54 Hinged bolt.



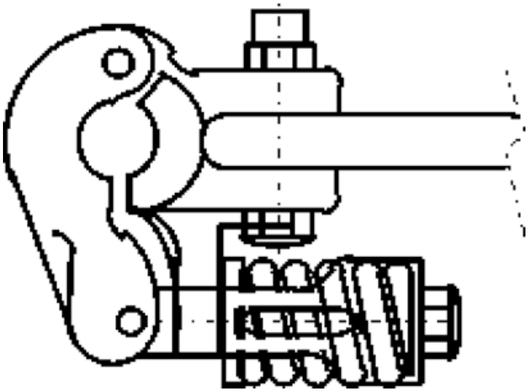


Figure 9.55 Coil spring loaded.

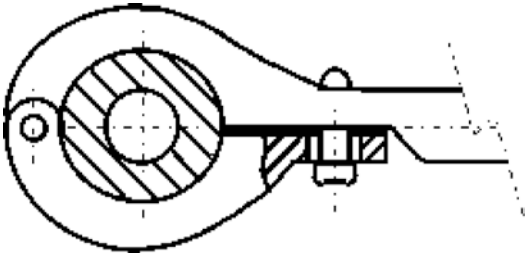


Figure 9.56 Hinged latching.

galvanised steel nut. Belleville washers may be used instead of the split washer to enhance energy storage and the nut may incorporate a locking mechanism, such as a nylon patch or ring.

Because of the high mechanical advantage offered by the clamp geometry, the bolt installation torque for the opposite hinge clamp is generally about 50 to 75% of that of the equivalent cantilever clamp to avoid excessive localised clamping stresses in the conductor.

As an alternative to the bolt, a loaded coil spring may be used to exert a constant clamping force on the conductor (Figure 9.55).

9.11.3.4 Elastomer-Lined Cantilever or Hinged Clamp

Clamp types described in the two preceding sections can also be used with an elastomer lining.

A widely used version of the elastomer-lined clamp utilises a boltless construction with an opposite, captive hinge and fastener (Figure 9.56). The clamp is lined with elastomer inserts which cushion and grip the conductor. The clamp is closed using a special tool and locked by a quarter-turn fastener or a latch. The clamp is not reliant on a bolt being correctly tightened, therefore there is no danger of conductor damage or clamp loosening arising from this source. The design is such that the elastomer remains under a predetermined degree of compression under all service conditions. A bolt may be used in place of the quarter-turn fastener (Figure 9.57).

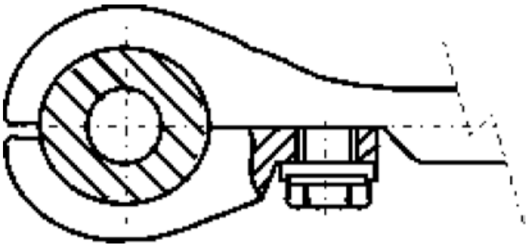


Figure 9.57 Cantilever bolted.

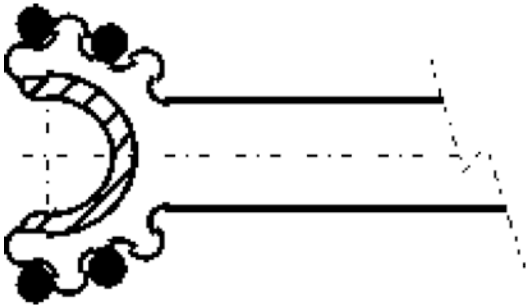


Figure 9.58 Elastomer-lined.

The formulation of the elastomer is critical to the satisfactory long-term performance of the clamp. Essential properties include good resistance to ageing, pollution, environmental effects, ozone and grease. Compression set must be at a minimum to ensure that a positive grip is always exerted on the conductor. Electrical semi-conductivity must also be controlled within defined limits and there must be no corrosive interaction between the constituents of the elastomer, such as carbon, and the conductor strand material.

The slip load achieved by elastomer-lined clamps is significantly less than with metal-to-metal clamps. This is acceptable because, if an exceptional event causes the elastomer-lined clamp to move, there will be no consequential damage to the conductor.

9.11.3.5 Helically-Attached Clamp

The helically-attached clamp is a bolt-less construction in which the conductor is cushioned in a U-shaped elastomer-lined clamp and securely held by helical, factory-formed rods (Figures 9.58 and 9.59). The clamp is generally elastomer-lined to protect the conductor, although some unlined clamps are in use. Correct installation may easily be verified from ground level. The rods must be manufactured from material compatible with the conductor strands. Essential properties of the elastomer include good resistance to ageing, pollution, environmental effects, ozone and grease. Compression set must be at a minimum to ensure that a positive grip is always exerted on the conductor. Electrical semi-conductivity must also be controlled within defined limits and there must be no corrosive interaction between the constituents of the elastomer, such as carbon and the conductor strand material.

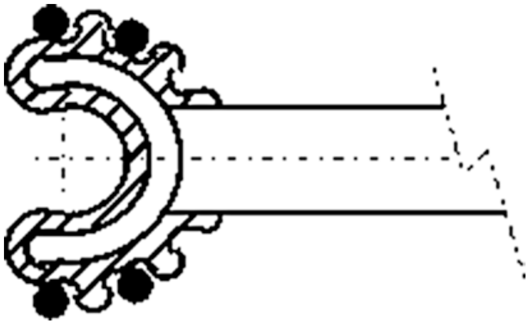


Figure 9.59 Elastomer-covered.

The elastomer can be bonded or inserted into the clamp bore in order to prevent any ingress of pollutants and moisture whilst in service. The characteristics of the helical rods should be such that their ends are facing towards the centre of the sub-conductor bundle to minimise Corona and RI discharge at specified line voltages.

The slip load achieved by helically-attached (rubber lined) clamps is significantly less than metal-to-metal clamps. This is acceptable because, if an exceptional event causes the helically-attached clamp to move, there will be no consequential damage to the conductor (Figures 9.58 and 9.59).

9.11.4 Vibration Damper Clamps

Vibration dampers tend to use metal to metal bolted cantilever type clamps but the geometry is somewhat different to that used for spacers. The body of the clamp, which includes the mechanism for attaching the messenger cable, is *hooked* so that it will hang on the conductor whilst the clamp keeper is fastened into place.

Experience has shown that vibration damper clamps can have wider range taking capabilities than spacer clamps because the service conditions are less severe.

Versions of the helically attached clamp are also used and have the same *hook* feature.

The plastic helically formed impact vibration damper is a one piece construction and has a helical gripping section with an internal diameter less than that of the conductor.

9.11.4.1 Helically Attached Damper Clamps

The helically attached damper clamp is a boltless construction in which the conductor is cushioned in a U-shaped elastomer-lined clamp and securely held in place by helical factory formed rods as shown in Figure 9.60. Sets of four or six helical rods are generally used to that purpose. The rods must be manufactured from material that is compatible with the conductor strands. It is possible to do live line work with the helical rod attachment but it is more tedious than with a bolted clamp. Correct installation may easily be verified from ground level.

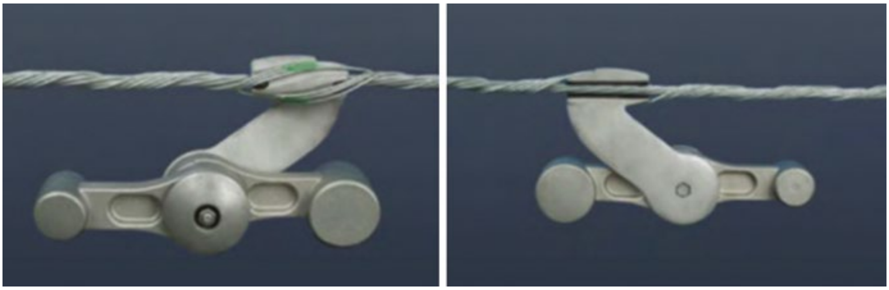
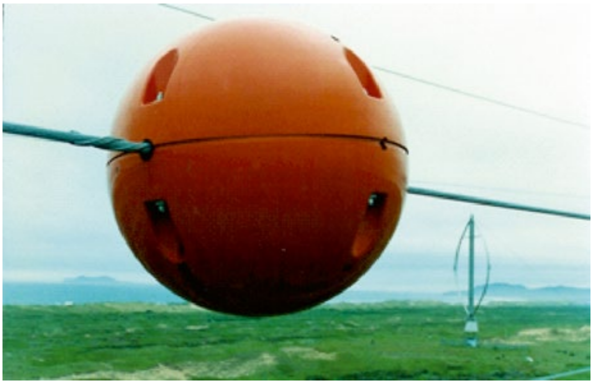


Figure 9.60 Aeolian vibration damper with helically-attached clamp.

Figure 9.61 Aerial warning marker with helically-attached clamp.



Helical rod attachment introduces a small additional amount of damping in the system but its main advantage is that it reduces the conductor bending severity at the damper clamp. It does so because the rods provide a local increase of the conductor bending stiffness and the elastomer allows the conductor bending to be more distributed along the clamp whilst maintaining the vertical and longitudinal grip on the conductor. The discontinuity of the conductor slope is thus reduced considerably in comparison to a metal-to-metal clamp. Since there are many cases where the bending amplitude is more severe at the damper clamp than at the suspension clamp, this clamp increases the efficiency of the damping system.

Aeolian vibration dampers with helically attached damper clamps are mainly used on small conductors, ground wires and river crossing long spans.

9.11.5 Other Fittings Clamps

Other fittings such as interphase spacers, aerial warning markers, detuning pendulums, etc. use the same variety of clamps than the one seen in the previous sections. Figures 9.61 and 9.62 show such examples.

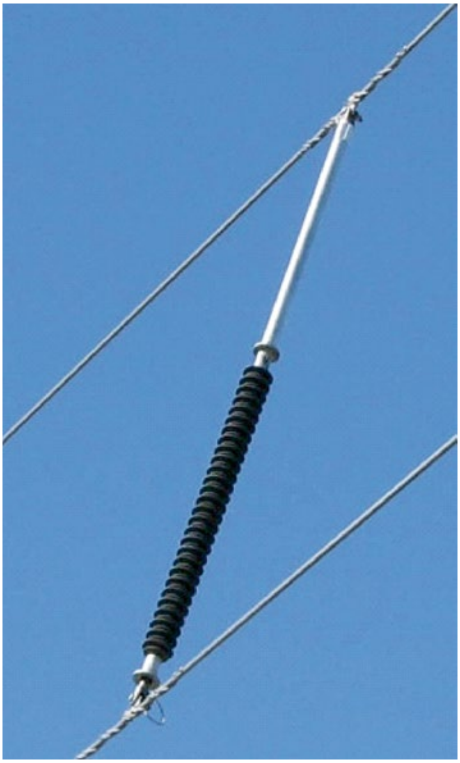


Figure 9.62 Interphase spacers with helically-attached clamp.

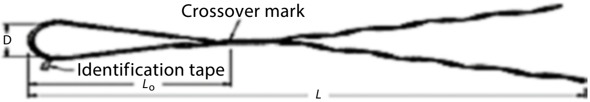


Figure 9.63 Single layer helical termination.

9.11.6 Termination (dead-end) Clamps

Termination clamps hold the conductor in towers where the line is to be supported, and therefore, the full mechanical tension of the line is to be applied. In this section, some types of termination clamps are presented, such as compression, wedge, helical formed wire and bolted types. This is not an exhaustive list but it gives the reader an overview of the different designs and types that are commonly used.

9.11.6.1 Helical Terminations for Conductors

Helical dead-ends are used to terminate conductors. They have been used successfully for the past 40 years. The typical device is designed to hold the mechanical load of the conductor and is not designed to transfer electrical loads. Most helical terminations for smaller ACSR and conductors of homogeneous construction (such as AAAC or AASC) are single layer, as shown in Figure 9.63.

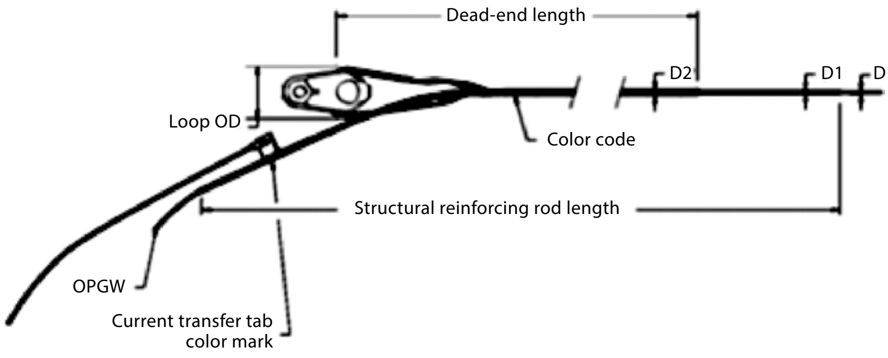


Figure 9.64 Two-layer helical termination.

Helical terminations for ADSS, OPGW and high temperature conductor can consist of a two layer design (Figure 9.64). The structural reinforcing rod layer is similar to an armor rod layer and increases the contact length of the dead-end. The second layer is a helical termination that is wrapped over the structural reinforcing layer. The helical termination is designed such that the bore of the helical wrap is smaller than the diameter of the conductor. This results in compressive force being applied to the conductor along the contact length of the product. Typical single layer helical terminations will develop a minimum of 90 % RTS on homogeneous AAAC (or AASC) and single layer ACSR. The helical termination only contacts the outside layer of the conductor so it must pass the compressive load into the inner layer of the conductor. In case of multi-layer ACSR, the helical dead-end cannot pass enough holding strength onto the core to develop 90 % RTS of the conductor. In these cases, specially designed two-layer helical terminations may increase the holding strength above the 95 % RTS level.

Conductor construction may also affect the holding strength of helical terminations. Trapezoidal wire construction can also affect holding strength of the helical termination if bridging of the wire occurs and does not allow the compressive load to pass onto the core wires.

There is low stress concentration since the compressive load is applied over a long contact length. In addition, the relatively low weight concentration does not result in forcing nodal points at the ends of the termination. This reduces the bending strain during cable motion such as aeolian vibration.

Typical Installation

Most applications of helical terminations include a reinforcing thimble for attachment to the insulator. The helical dead-end is simply wrapped around the conductor. No special tools are required. The conductor can be permitted to extend through the termination loop of the dead-end.

9.11.6.2 Wedge Type Dead-End Clamps

Wedge type dead-end clamps are used for terminating overhead conductors. A typical wedge-type dead-end clamp used on both transmission and distribution lines is shown in Figure 9.65.

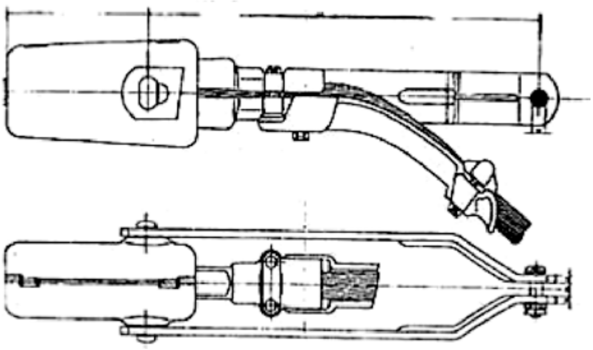
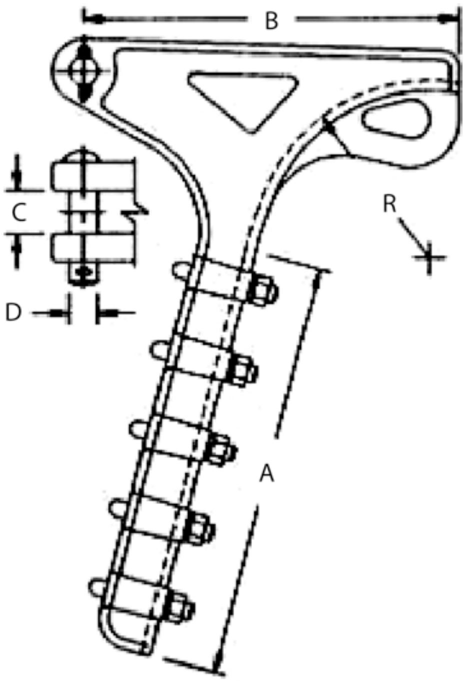


Figure 9.65 Wedge type dead-end clamp.

Figure 9.66 Bolted quadrant type dead-end clamp.



9.11.6.3 Bolted Type Dead-End Clamps

Bolted dead-ends are commonly used to terminate conductors. In such fittings, the conductor passes through this clamp without being cut. The bolt torque and the length of the clamp are calibrated to prevent the slipping of the conductor and avoid any damage on the outmost layer.

Typical devices for lower voltage transmission and distribution lines are called bolted quadrant type dead-end clamps as shown in Figure 9.66.

Devices that are mainly used on distribution lines, such as bolted straight type dead-end clamps, are shown in Figure 9.67.

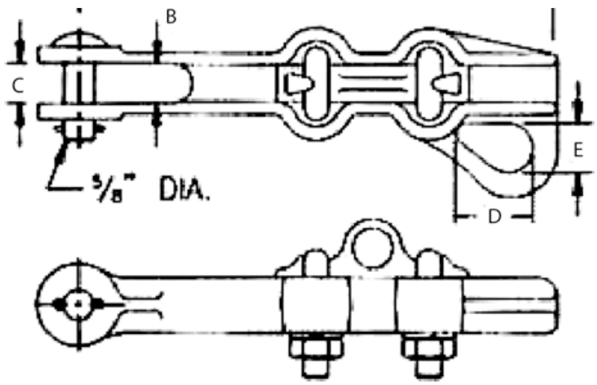


Figure 9.67 Bolted straight type dead-end clamp.

9.11.6.4 Testing

Testing is normally focussed on holding strength. Typical testing includes loading to destruction to determine ultimate holding strength (up to 95 % RTS). Typical tests performed, for example, in accordance with BS 3288 may be conducted. In addition, long-term sustained loads testing at appropriate operating tensions (35 % RTS) have been conducted to verify creep and long-term holding performance.

9.11.6.5 Compression Clamps

These clamps are usually expected to withstand at least 95 % of the rated breaking load of the conductor without any slippage or breakage of the conductor-clamp system.

Description and Design

Compression clamps are composed of two main parts:

- An aluminium or aluminium alloy tube compressed over the conductor so that tube and conductor "become one". When the clamp is installed as a deadend, it has an aluminium connection pad to which a jumper loop can be joined, usually by bolts (2 or 4 bolts, depending on the clamp's size), as can be seen in Figure 9.68.
- A steel terminal inserted into the aluminum tube attach the clamp to the insulator string (Figure 9.69). It is also inserted into the aluminium tube and joined to it by compression. In ACSR, the steel core is inserted into this terminal and compressed.

There are two types of compression methods: Implosive: They are compressed by means of an explosive charge triggered by a fuse (Figure 9.70).

Compression dies: They are compressed using dies, compressors and pumps. Different dies are used for conductors of different sizes (Figure 9.71).

Figure 9.68 Aluminium tube of a compression clamp.

Figure 9.69 Steel terminal of a compression clamp.

Figure 9.70 Implosive clamp.

Figure 9.71 Die compression clamp.

Both types must fulfill the following electrical and mechanical characteristics:

- They must assure a good contituity of the electrical circuit, avoiding the creation of hot spots in conductor-clamp junctions.
- The compression clamp must be designed in such a way that it does not harm the conductor during the compression process.
- The conductor-clamp system must be able to withstand at least 95 % of the conductor breaking load without slippage or breakage.
- Corrosion must be prevented by applying grease or inhibitor to prevent water and pollution from entering the clamp.

9.11.7 Fatigue Failure at Suspension/Clamping Point

Practically 99 % of vibration failures take place very near to, or at, a clamp location. Clamp design is of great importance for the mechanical integrity of the conductor and thus for the operational safety of a line (Cigré B2.47 2015).

Fatigue failure of wires is the most common form of conductor damage. It occurs at points where motion of the conductor is restricted, such as suspensions and dead-ends, but also where any other conductor fitting (e.g. vibration damper, spacer) is attached.

This type of damage is generally caused by wind-induced motion such as aeolian vibration, subspan oscillation or galloping. It is not self-limited, and may eventually lead to a failure of the entire cross-section of aluminium wires. Typical fatigue breaks are shown in Figures 9.72, 9.73, 9.74, and 9.75.

9.11.8 Wear and Abrasion at Clamping Point

Wear and abrasion of conductors is most often associated with loosened damper (Figure 9.76) spacer or spacer-damper clamps. When the clamping loosened damper (Figure 9.76) force is reduced sufficiently to allow conductor movement inside the spacer clamps, damage to the outer layer of wire starts and may propagate over time to the entire cross-section of aluminium wires, depending on the contact

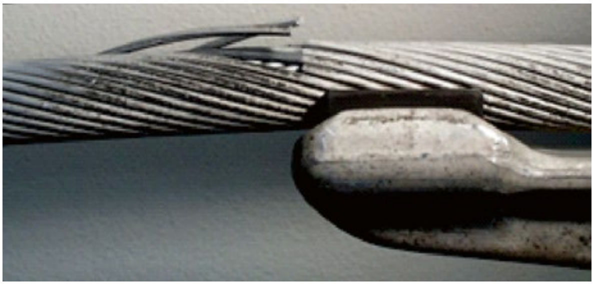


Figure 9.72 Fatigue failure at suspension clamp.

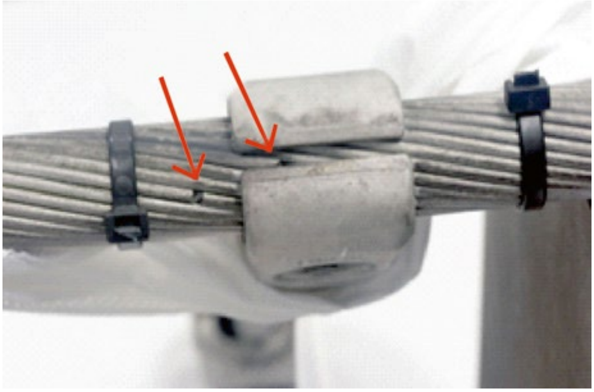


Figure 9.73 Fatigue failure at spacer-damper clamp.

Figure 9.74 Fatigue failure at vibration damper clamp.

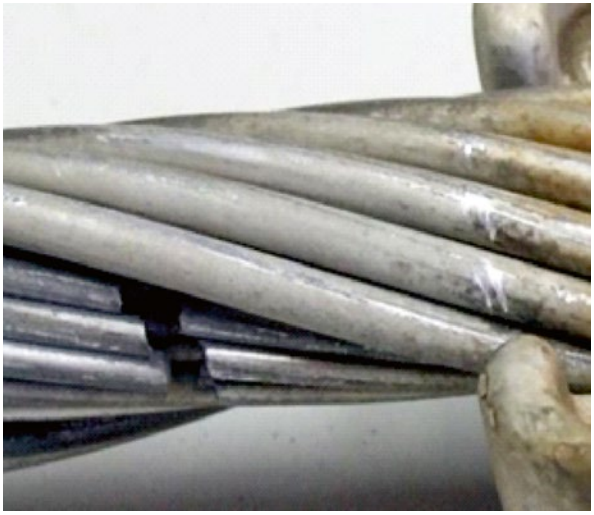


Figure 9.75 Fatigue failure underneath helical fittings.

condition between the clamp and the conductor, see Figures 9.77 and 9.78. Loose rubber-lined clamp may reduce the extent of abrasion damage, although this kind of clamp is not immune to conductor wear and abrasion issues (Cigré B2.47 2015).

Clamp loosening of vibration dampers may also lead to abrasion damages to the conductor, although in many cases, the damper will slide to the span's lowest point, instead of wearing the conductor at its initial position. In some cases however, loose fittings sliding across the span may lead to severe damage, as shown in Figures 9.79 and 9.80.

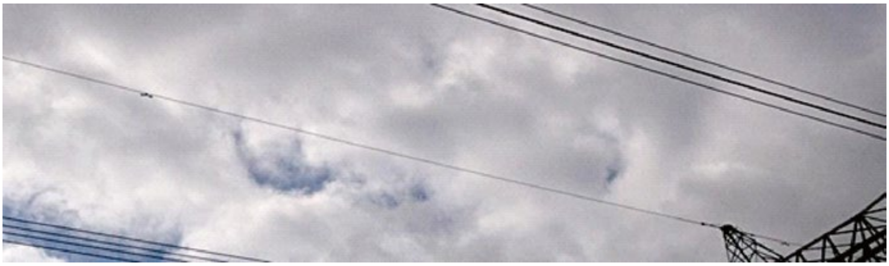


Figure 9.76 Damper displaced towards the span center on ground wire.

Figure 9.77 Wear and abrasion at spacer clamp.

Figure 9.78 Wear and abrasion at vibration damper clamp.

Figure 9.79 Wear and abrasion damage caused by a loose damper clamp resting against a warning marker clamp.

Figure 9.80 Wear and abrasion damage caused by a loose damper clamp resting against a warning marker clamp.

9.11.9 Corrosion Damage

The atmosphere contains humidity that by condensation on metallic devices generate a film of water containing different substances such as O_2, CO_2, nitrogen oxides… This humid corrosion leads to a reaction where chemical products and electric charges operate. It is called electrochemical corrosion (Cigré B2.47 2015).

This corrosion damage can often be detected on bi-metallic conductors, small diameter wires and in maritime or industrial environment.

Compression of fittings during conductors installation generates micro-breaks that can slightly alter the galvanisation of steel parts, which can initiate internal corrosion in the fitting. After a while, a failure can occur on the conductor near the fitting. That happens primarily with bi-metallic conductors.

Figure 9.81 shows corrosion damage inside an elastomer-lined clamp where the elastomer had an inadequate resistivity.

Figure 9.81 Corrosion damage inside elastomer-lined clamp caused by electrochemical incompatibility between the rubber and the conductor.

9.12 Aeolian Vibration Dampers

9.12.1 Type of Aeolian Vibration Dampers

9.12.1.1 General

This section provides a classification of the various types of aeolian vibration dampers used on overhead transmission lines. It describes the most popular dampers used. Other damper types other damper types have been used and/or patented.

Aeolian vibration dampers are used on single conductors or earth wires or conductor bundles where dampers are directly attached to each sub-conductor. On bundles, they may be used in conjunction with spacers or spacer dampers.

The damper shall be designed so as to

- Damp aeolian vibration;
- Withstand mechanical loads imposed during installation, maintenance and specified service conditions;
- Avoid damage to the conductor under specified service conditions;
- Be capable of being removed and re-installed without damage to the conductor;
- Be free from unacceptable levels of Corona and radio interference under all service conditions;
- Be suitable for safe and easy installation. The clamp design shall retain all parts when opened for attachment to the conductor. Furthermore, the clamp design shall be such that the damper, during installation, can be suspended on the conductor before tightening the clamp;
- Ensure that individual components will not become loose in service;
- Maintain its function over the entire service temperature range;
- Avoid audible noise;
- Prevent water collection.

Other desirable characteristics which are not essential to the basic functions of the damper but which may be advantageous include:

- Verification of proper installation from the ground;
- Ease of installation and removal from energized lines.

9.12.1.2 Stockbridge Type Dampers

Stockbridge dampers are made of a clamp to attach it onto the conductor, one messenger cable attached onto the clamp protruding on both sides and one mass at each end of the messenger (Figures 9.82 and 9.83). It constitutes a spring-massdamping system where the mass is located at the end of a messenger cable which acts as a spring and a damper. The spring effect comes from the flexural stiffness of the messenger and the damping dissipation from the friction between the messenger strands. Since there is virtually no tension in the messenger, its strands may slide more easily on each other and they dissipate more energy than the equivalent steel cable strung on a line.

Basically, the Stockbridge damper has two resonant frequencies, the first one corresponding to the flapping of the messenger-mass, and the second one to a torsional rotation of the mass at the end of the messenger.

The concept has evolved and some manufacturers have used asymmetrical masses weight and/or messenger length to obtain different ratio of stiffness over weight and thus different resonant frequencies on both side of the damper for a total of four

Figure 9.82 Schematic of a Stockbridge damper.

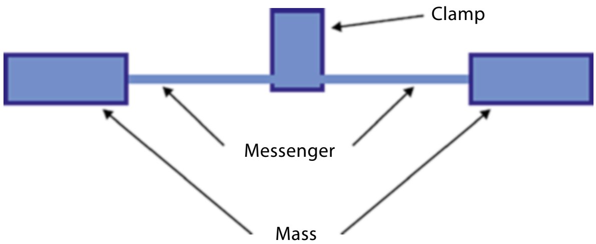


Figure 9.83 Stockbridge dampers on a quad bundle of a river crossing.

resonant frequencies. Other manufacturers have added torsional resonances by using asymmetrical masses on the messenger which induces torsion to it. Those different designs have been tested on a test line with a single ACSR Bersfort conductor strung at a H/w of 2300 m on a 450 m span length and it has been found that there was no significant differences in the resulting bending amplitude of the conductor they intended to protect (Van Dyke et al. 1997) (Figure 9.83).

Stockbridge dampers are cheap and efficient against aeolian vibrations, however they may be damaged through fatigue of the messenger when subjected to severe aeolian vibrations. Many cases of damaged Stockbridge dampers have been reported due to ice shedding, galloping or increased severity of vibrations due to ice accretion on the conductor.

9.12.1.3 Dampers with Elastomeric Articulations

In order to solve the fatigue problems experienced by Stockbridge dampers on Hydro-Quebec and other utilities transmission lines (Loudon 1999), an aeolian vibration damper with an elastomeric articulation similar to the one used in spacer dampers was developed (Figure 9.84). Stoppers were included in the damping articulation to protect the damping mechanism and prevent the masses from hitting the conductor during ice shedding events or other types of overloads. This damper has two resonant frequencies and its efficiency is similar to a Stockbridge damper (Van Dyke et al. 2001). They have been installed since 2000 with good results.

9.12.1.4 Spiral Impact Dampers

A spiral impact damper consists of a helical PVC (Polyvinyl chloride) rod installed over the conductor (Figure 9.85). It impacts the conductor which dissipates energy. They are installed at span ends for ease of installation but they are not position sensitive since their length is such that they usually cover a vibrating portion of the conductor. They are efficient on smaller diameter conductors vibrating at higher frequencies which induces more acceleration for a given displacement.

Figure 9.84 Damper with elastomeric articulations.

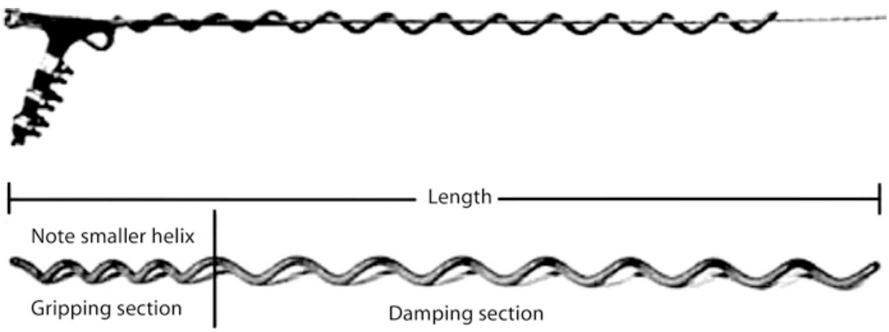


Figure 9.85 Impact damper.

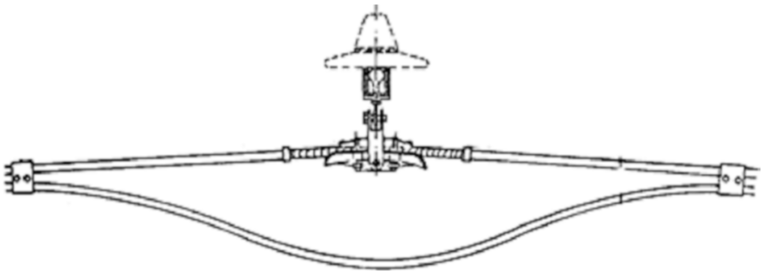


Figure 9.86 Bretelle damper.

It is possible to install two units in parallel or in series.

General guidelines are as follows:

- Any galvanized steel cable up to 13 mm
- Light weight OPGW up to 18 mm
- ADSS up to 25 mm
- ACSR up to 18 mm
- Covered AAAC or AASC up to 18 mm.

9.12.1.5 Bretelles

The bretelle (Figure 9.86), which consists of a jumper loop connecting two adjacent spans at the suspension point, is widely used in France. Its discovery as a damping device was largely accidental. Originally it was conceived as a safety device, but when this requirement was reduced on the French system, vibration problems became apparent. Normally it is made from pieces of leftover conductor that are the same size as the line on which it is used.

Although the bretelle concept may be economically attractive, there are numerous factors to be considered for its use. The configuration does not lend itself to indoor laboratory investigations, making it difficult to conduct a thorough investigation of the design variables. On large conductors, it can become unwieldy and difficult to install. Maintenance of conductor-to-tower clearance can result in higher tower costs.

Sometimes, this is avoided by supporting the center of the hanging loop at the suspension clamp, but the effect of constraining the loop has not been fully evaluated.

Because of its close association with the French electrical system, most of the data available on the use of bretelles are associated with aluminum alloy conductors (Almelec) rather than ACSR, but the basic concept would still apply.

The ability of a relatively short length of conductor to damp an entire span is probably due to its extremely low tension. On the French system, the bretelle is installed with a sag of 30 to 40 cm. The distance from the suspension clamp to the end of the bretelle is calculated according to the following empirical formula (Quey and Rols 1976):

$$l = \frac{d}{2}\sqrt{\frac{H}{m}} \tag{9.5}$$

Where

l = distance of installation of the bretelle clamp (m).

d = conductor diameter (m).

H = conductor horizontal tension (N).

m = conductor mass per unit length (kg/m).

Generally, this distance appears to be long enough for a node to form at the end of the bretelle within the most common range of vibration-producing wind velocities. For the French design, the end of the bretelle could be expected to reach a node at a wind velocity of about 5.4 m/s (19 km/h).

9.12.1.6 Festoon

Festoon dampers, shown in Figure 9.87, have been used on numerous long spans. Like the bretelle, they consist of leftover conductor and are relatively inexpensive. The

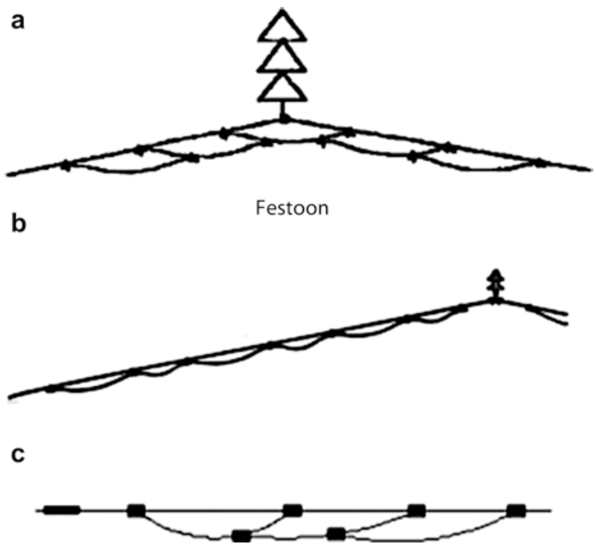


Figure 9.87 Festoon dampers. (**a**) and (**b**) are festoon dampers at suspension points; (**c**) is a festoon damper at deadend points.

primary problems that have been reported in the use of festoons have occurred at their clamps. Some designs have used uniform length loops that could, conceivably, allow a standing wave to be established on the conductor in spite of the festoon. Although this could occur only at one frequency, it would seem more logical to avoid the possibility.

In Norway and other cold countries, festoon dampers are preferred to Stockbridge-type dampers on long fjords because the latter can be damaged by both conductor galloping and aeolian vibration of increased severity, during periods of icing. Rawlins (1989) investigated the effect of ice coating on overhead ground wires and concluded it may dramatically increase the amount of aeolian vibration energy imparted to the conductor.

Festoon dampers have been widely used in long spans usually with satisfactory experience (Ervik et al. 1968). However, in the long crossing spans of the Bay of Cadiz and the Messina Channel (Falco et al. 1973), festoons were installed initially, but after some strand failure on the conductors, they were replaced by Stockbridge-type vibration dampers.

9.12.1.7 Torsional Dampers

Torsional dampers were developed by Buchanan and Tebo (US patents 2215541A, 1936 and 2271935, 1938) (Figure 9.88). These dampers were used in large numbers

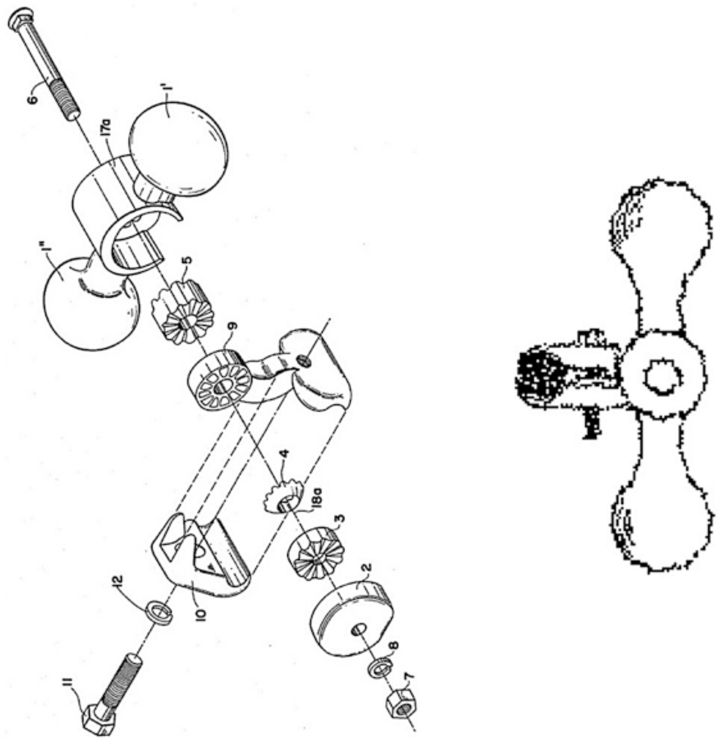


Figure 9.88 Torsional damper.

in Canada and in some other countries. They had a one resonant frequency mechanism and they also relied largely on conductor torsional damping to dissipate energy. Indeed, the excentric position of the torsional damper induced torsion when the conductor was excited in a vertical direction.

The production of those dampers was subsequently abandoned because their efficiency was not sufficient compared to Stockbridge dampers but some units are still in service on some lines.

9.12.2 Conductor Damage due to Failure of Damping Mechanism

Vibration dampers use stranded steel wires or elastomer elements to dissipate the vibration energy imparted to the conductor by the wind. As such, these devices are themselves prone to experience fatigue-induced degradation.

A sign of fatigue in the messenger cable of Stockbridge-type dampers is the drooping or sagging of the masses, as shown in Figure 9.89. Such damage may be caused by excessive vibration levels, a poorly designed damping system, or inferior hardware quality. It may also be caused by large dynamic loads such as galloping or ice shedding events. In corrosive environments (e.g. seashore, polluted area), corrosion of the messenger cable may be a failure mechanism.

In most cases, only one or two vibration dampers are installed within a single span. Therefore, a damaged unit may significantly reduce the overall span damping, potentially creating fatigue failures of the conductor at the attachment point or where conductor motion is restricted.

Figure 9.89 Damaged vibration damper (mass drooping).

9.13 Spacers and Spacer Dampers

9.13.1 Type of Spacers

9.13.1.1 General

This section provides a classification for the various types of spacers and spacer dampers used on overhead transmission lines with bundled conductors.

Typical conductor bundles comprise two, three or four sub-conductors. In special cases, bundles with six or eight sub-conductors have also been used. However the number of sub-conductors is irrelevant in the description of the various types of spacers and spacer-dampers.

A spacer or spacer damper typically consists of a central frame and conductor clamps that are connected to the central frame. The particular properties of the central frame, the conductor clamp - as well as the properties of the connection between the central frame and the conductor clamps - are used to differentiate the various types of spacers and spacer dampers. When rigid or articulated spacers are used, vibration dampers are also generally used.

The history of spacers and spacer dampers has seen a wide variety of designs. Therefore there always will be exceptions to any general classification. However, the classification presented here should be suitable for the majority of spacers and spacer dampers. Each type is accompanied by a representative figure.

9.13.1.2 Rigid Spacer

A rigid spacer restricts the distance between the conductor clamps to the nominal values of the sub-conductor spacing. The clamps do not allow for any significant movement of the sub-conductors with regard to each other.

A rigid spacer can either have a metallic type clamp (Figure 9.90) or an elastomer-lined, rod-attachment type (Figure 9.91).

Rigid spacers with metallic clamps are almost exclusively used for jumpers. In the jumper, the mechanical tension of the sub-conductor is very low and, with the exception of short circuit loads, significant dynamic stresses will not occur in the spacer clamps in service. The rigid clamps can therefore be used in this particular case.

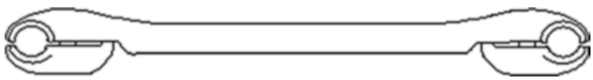


Figure 9.90 Rigid spacer with a metallic type clamp.

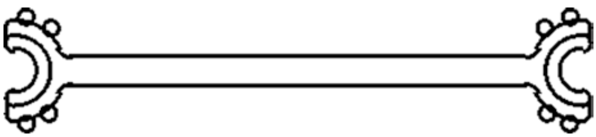


Figure 9.91 Rod-attachment type.

Rigid spacers with elastomer-lined clamps also known as semirigid spacers were introduced more than thirty years ago.

9.13.1.3 Articulated Spacer

An articulated spacer restricts the distance between the conductor clamps to the nominal values of the sub-conductor spacing. However, it allows rotation of the conductor clamps around a well-defined axis in relation to the central frame (Figure 9.92).

Articulated spacers are used on twin, triple and quad bundle. Sub-span lengths can be relatively short in this kind of installations. Care to minimise wear must be taken in the design of the articulation.

9.13.1.4 Flexible Spacer

A flexible spacer allows for large displacements of the conductor clamps with regard to each other in the plane perpendicular to the conductor axis. Elastic properties are typically incorporated into the spacer design to ensure that the spacer will restore the bundle's nominal configuration when the external loads are removed.

The flexibility in the spacer can be achieved in a number of ways. Typical designs are shown in Figures 9.93, 9.94, and 9.95.

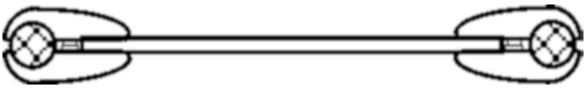


Figure 9.92 Articulated Spacer.

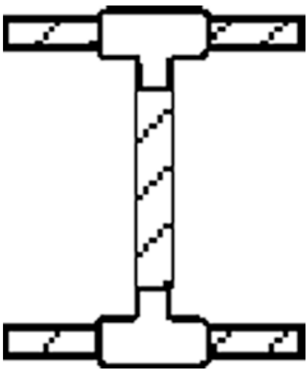


Figure 9.93 Spring spacer.

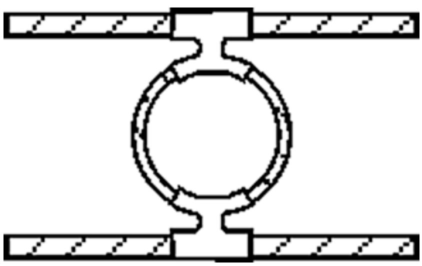


Figure 9.94 Ring spacer.

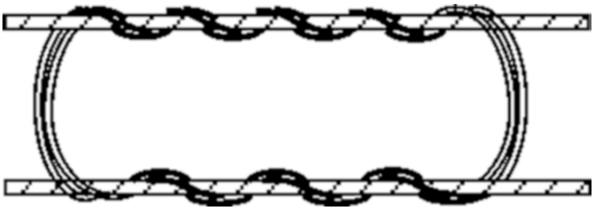


Figure 9.95 Hairpin spacer.

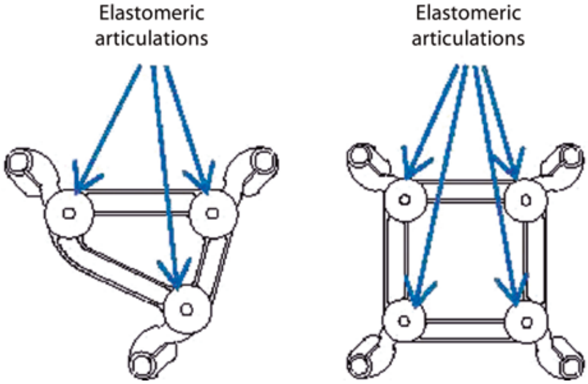


Figure 9.96 Spacer dampers.

9.13.1.5 Spacer Damper

A flexible spacer is called a spacer damper if large displacement of the conductor clamps results in significant energy dissipation either within the connection between the central frame and the conductor clamps and/or in the central frame itself (Figure 9.96).

9.13.2 Materials Used in Spacers

9.13.2.1 General

In the design of spacer dampers, flexible spacers, articulated spacers and rigid spacers (simply called "spacers"), the basic criteria for the selection of materials and combination of materials must take into consideration the service life requirements in terms of mechanical loads, electrical loads and environmental conditions.

There are materials that have been used for many years in spacer technology, with satisfactory results. The list includes:

- Aluminium alloys;
- Galvanised steel;
- Galvanised malleable cast iron;
- Stainless steel;
- Zinc aluminium alloys;
- Neoprene and some other types of elastomers.

9.13.2.2 Material Requirements and Selection Criteria

Spacer materials should have adequate mechanical strength over the whole range of service temperature. They should withstand the thermal cycling due to the climate and the current loading of the conductors. Typical problems are: elastomer deterioration at high temperature, especially in rubber-lined clamps, hardening of elastomers and embrittlement of steel at low temperature.

Spacer materials should be resistant to: chemical corrosion caused by humidity and airborne pollutants, galvanic corrosion due to contacts between dissimilar materials in the presence of an electrolyte, and electrolytic corrosion caused by voltage difference between metal surfaces bridged by an electrolyte.

Galvanisation of steel components should provide sufficient resistance to chemical corrosion. Aluminium and zinc alloys have a natural corrosion protection that can be further improved, when necessary, by surface treatments like anodising.

Grease coating or painting is not considered reliable for long-term corrosion protection.

Galvanic corrosion can best be avoided by reference to the galvanic series. If two or more dissimilar materials are to be in contact in the spacer, they should not be too far apart in this list and, where possible, the material with the greater surface area should be made anodic. See section 9.3.6 for more information.

In all cases, the selection of materials for application in areas of high atmospheric pollution should take into account the nature of the pollutants involved.

The spacer materials should have appropriate resilience to withstand impulsive loads, and the components subjected to fatigue and to rubbing should be formed from materials which have good resistance to these actions.

Corona discharges at the surface of spacers increase the presence of ozone which rapidly deteriorates organic materials if they are not suitably protected. These materials also need to be protected from ultraviolet radiation.

Elastomers should be semi-conductive because non-conductive elastomers will be prone to electrical discharges as a result of the pollutants coating on their surface. Such discharges promote further growth of carbon deposit, leading to an escalating tracking situation and generating radio interference and audible noises. Elastomers with too high a carbon content and, therefore, too high conductivity are liable to burn out and cause galvanic corrosion between the carbon in the elastomer and the conductor strands.

Elastomers for spacers have to withstand contact with oil and grease used in conductors manufacturing and stringing equipment. In addition, the elastomers should not absorb water.

Damping elastomers used in spacer damper articulations should have large hysteresis losses, appropriate stiffness and good fatigue resistance over the entire range of service temperature.

9.13.2.3 Commonly Employed Materials

Aluminium-silicon alloys, generally of primary production, are currently employed to cast the components of spacers for aluminium-based bundled conductors. Current casting technology mainly involves gravity and pressure die casting. The most common aluminium-silicon alloy is the Al Si 12-ISO R 164, better known as LM6 (BS1490). The ductility of this alloy can be slightly improved by heat treatment, but it is normal practice to enhance its mechanical characteristics by modifying the alloy using sodium, sodium salts or strontium.

Primary and secondary aluminium alloys with higher copper content (but no more than 1 %) are used for spacer components not in direct contact with the conductors. Copper improves the mechanical characteristics of the alloy but reduces its corrosion resistance.

For spacer components that are extruded or forged, aluminium-magnesium-silicon alloys type AA 6060 and AA 6063 are used. These alloys have an excellent corrosion resistance and must be submitted to heat treatments to improve their mechanical characteristics.

There are very few bundled lines equipped with copper conductors. For these lines, spacer components made of phosphor bronze or aluminium bronze are mainly used, in combination with copper alloy or stainless steel fasteners.

Galvanised steel is largely used for the elements of the clamp locking mechanism and sometimes for other components. The zinc protection is generally achieved by hot dip galvanising, in accordance, for example, with ISO1471, except when spring steel is used. Bolts and nuts are made of low or medium carbon steel and are generally in accordance with ISO 898. The most commonly used are hexagonal head bolts of property class 8.8 and 6.8, together with hexagonal nuts of the appropriate class.

Belleville washers and other spring elements are made of chrome-vanadium steel (50CrV4) or Ck75 unalloyed steel. They can be electroplated or mechanically galvanised in accordance with ASTM B695 or equivalent standard.

Stainless steel can be employed instead of galvanised steel in highly polluted areas: austenitic stainless steels (AISI 300 series) and ferritic stainless steels (AISI 400 series) are the most used.

Aluminium alloy bolts can be of type AA 7075 (high strength aluminium alloy bolts with mechanical properties equivalent to mild steel bolts of class 5.8) or AA 6061-T8.

Some spacers contain lengths of galvanised steel cables. Others use or consist entirely of helical rods made of aluminium alloy, generally of AA 6061-T8 type.

Inertial masses used in spacers are made either of galvanised, malleable cast iron or zinc alloy.

A number of synthetic rubbers have been used to date for spacer damper articulations and for clamp lining. Two broad groups can be identified: organic rubber and mineral rubber. The first is the most commonly used while the second (silicon rubber) is employed in special cases involving high temperatures (>200 °C) and very low temperatures (< −30 °C). However, it should be noted that silicon rubber has poor resistance to fatigue and abrasion.

Natural rubber (NR) by itself has poor resistance to ageing, ozone, UV radiation, oil and grease. However, with appropriate additives, it can be compounded to perform satisfactorily.

Synthetic rubber is prepared by reacting suitable monomers to form polymers; its elastomeric properties have to be developed by further compounding and the possible combinations are infinite. Fillers, such as carbon black, silica, oils, waxes and fatty acids are used. Elastomer compounds are carefully formulated to fulfil all mechanical, chemical and thermal requirements. Rubber must be protected from ozone and ultraviolet radiation, while silicon rubber is not sensitive to these agents. The protection is achieved by means of special waxes that continuously migrate to the rubber surface creating a protective coating that restores itself after abrasion. However, the coating becomes discontinuous when the rubber is tensioned mechanically.

Rubber compounds are either commercially available or specially formulated for specific purposes. The most common types are: Neoprene (chloroprene rubber), EPDM (Ethylene propylene diene monomer (M-class) rubber), NBR (nitrile rubber), FKM (fluorocarbon rubber), and SR (silicon rubber). Special compounds consist of combination of two or more basic rubbers such as, for example, BR (polybutadiene rubber) and NBR, charged with appropriate fillers.

9.13.3 Conductor Damage due to Failure of Damping Mechanism

Spacer dampers using elastomers as damping elements and clamp liners are subject to problems related to elastomer degradation (Figure 9.97). The main degradation mechanism is the hardening and loss of elasticity, which may be accelerated by various factors related to service conditions (e.g. UV and ozone exposure, high temperature, large dynamic loads) and hardware design and quality.

Failure of the damping mechanism will generally affect a large number of spacer-dampers on a given line section, and in severe cases, may lead to considerable fatigue damage at the spacer-damper clamp or at the suspension points.

9.14 Aircraft Warning Markers

9.14.1 Introduction

Aircraft Warning Markers (AWMs) are highly visible indicators used on tall structures, such as overhead power lines, to warn low flying airplanes and helicopters of the obstructions. In most jurisdictions, they are legally mandated for public safety (Cigré TF B2.11.03 2006). They are also used in some cases to warn oversized road vehicles of the presence of conductors above the road.

Figure 9.97 Damaged spacer-damper elastomer element.

9.14.2 Current Practices

AWMs are attached or suspended on the uppermost conductor on the structure, shield wires and OPGWs.

Typical locations requiring AWMs:

- Near airports
- River, lake or fjord crossings
- On elevated spans
- Across roads or railways
- Helicopter routes
- Near police headquarters
- Near hospitals
- Valley crossings
- Near military bases
- Over gas or fuel lines
- Over construction sites
- Low flying areas
- Emergency/rescue flight routes.

The need for AWMs may also be guided by the height of the conductors above the ground. Some utilities will use the AWMs on lines at heights greater than 40-50 metres above ground.

9.14.3 Visibility of AWMs

The most important feature of the AWMs is visibility (Figure 9.98). This is achieved by proper placement, size, shape, colour (or alternating colours), and by illumination. The visibility of AWMs is enhanced by the choice of colours to contrast with natural background during all seasons. Orange or red tones make the AWMs quite

Figure 9.98 Aircraft warning markers with *red white* colouring installed on adjacent earthwires.

visible during summer and winter seasons in most countries, but these colours are less effective when the AWMs are viewed against natural foliage during autumn or against ploughed fields. Mixed or alternating white and orange are used in some jurisdictions, improving visibility during all seasons.

The size of AWMs varies generally from 30 cm up to 120 cm in diameter. The spacing between AWMs generally varies from less than 50 m to 100 m.

9.14.4 Types of AWMs

There are several distinct designs of AWM:

- Concentric spherical AWM, which consists of two hemispheres attached by helical rod clamp to the conductor or earth wire (Figure 9.99).
- Concentric spherical AWM, attached to the conductor by a bolted clamp (Figure 9.100).
- Concentric non-spherical AWM consisting of two non-spherical shells attached by bolted clamps to the conductor (Figure 9.101).

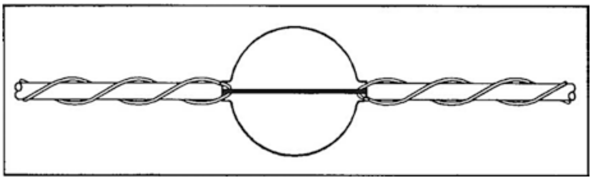


Figure 9.99 Schematic sketch of spherical aircraft warning marker attached using helical rods (s.a. Figure 9.69).

Figure 9.100 Concentric spherical AWM with bolted clamps.

Figure 9.101 Non-spherical AWM with bolted clamps on a single conductor.

- Self-illuminating marker consisting of a light drawing power from the conductor (Figure 9.102).
- Suspended spherical AWMs which can be used on single or bundle lines (Figures 9.103 and 9.104).

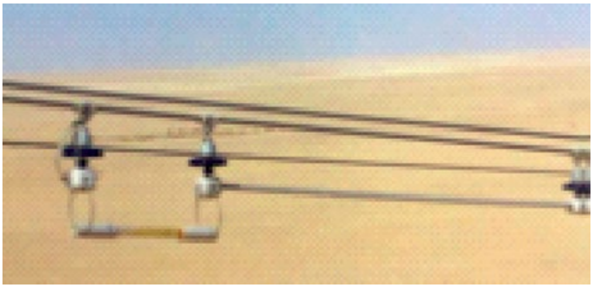


Figure 9.102 Self-illuminating catenary light AWM.

Figure 9.103 Suspended spherical AWM with bolted clamps on a single conductor.

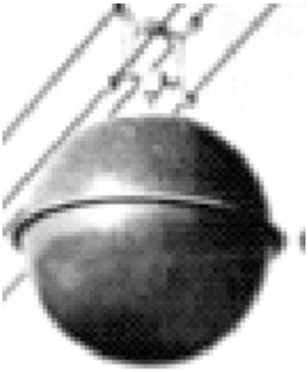


Figure 9.104 Suspended spherical AWM attached to spacer damper on a four-conductor bundle through rubber bushed clamps.

Other, less usual, markers are:

- Concentric perforated circular plates
- Suspended perforated cones (Conical type)
- Suspended tear-drop shape attached to the conductor by a clamp.

On tall towers supporting river crossings, painted sections with contrasting colours, usually white and international orange, plus flashing lights at the tops of the towers are also used. In Japan flashing lights or red and white painted sections are required on towers, but markers are not required on conductors.

The two most common basic shapes of AWMs generally used are spherical and conical. They can be attached around the conductor, or suspended below it. There are also concentric non-spherical markers and self-illuminated markers.

The AWMs are generally made from a range of materials: Fibreglass, polyethylene and poly-carbonate resin, and aluminium.

The weight of AWMs depends on the design, size and material. The range of weights varies from 1.65 kg to 42.5 kg. There is some concern that the weight of AWM should not contribute significantly to the conductor sag.

A survey showed that the preferred designs or types by utilities are the spherical type with helical rods and the spherical type with bolted clamps.

9.14.5 Installation, Inspection and Maintenance of AWMs

AWMs may be installed using live-line techniques. Depending on the AWM design and conductor tension, end span damping may be insufficient and it may be required to install additional damping between the AWMs.

Inspection of AWMs is done from the ground, by cart and by helicopter. Most utilities inspect once a year. Maintenance consists of retightening clamp bolts, replacing clamps and spheres. In the case of self-illuminating AWMs, the replacement of catenary lights has to be done every 7 years.

Regarding installation and maintenance of AWMs:

- AWMs are easy to install, but difficult to maintain
- Most important problems are on fjord crossings due to vibration
- There are difficulties getting power interruptions for maintenance
- Maintenance needs use of a cart, long reach bucket and/or helicopter
- AWMs are placed on earth wires, because maintenance would require an outage if on phase conductors
- Maintenance is difficult on street crossings due to traffic
- Self-Illuminated AWMs experience lamp breakages due to vibration.

Figure 9.105 shows one of the practical aspects of installation, with a lineman carrying out the installation of aircraft warning markers of an estimated diameter of 60 centimetres, which is a common size.

Figure 9.105 Lineman installing AWMs showing sizes.

9.14.6 Problems with AWMs

The most serious problem with AWMs is loss of colour, which reduces marker visibility and impairs the function of the marker. The second most serious problem is ultraviolet degradation of the marker material, which results in cracking and eventually in disintegration. Although these problems may greatly affect the marker's function, they generally don't lead to conductor damage.

Falling AMWs from the conductor or earth wire is due to loosening, or breakage of clamp bolts and loosening of the clamp (Figure 9.107) or breakage of helical clamp rods, or to the disintegration of the body of the AWM. Problems related to AWM clamping system lead in some cases to important conductor damage by abrasion, or by cutting of the aluminium wires by the loose aluminium shell.

Marker oscillation may bring rattling. Audible noise may also be caused by high wind velocities. Spherical AWMs with flanges (protruding rim used to strengthen and/or attach the two hemisphere together) may cause oscillations, loosened clamps and damage.

When installed on phase conductors, cases have been reported of markers producing Corona discharges which burnt the conductor (Figure 9.106). Arcing has been observed which resulted in the ignition of the sphere.

Other problems include: damage from hunters or gun shots (Figure 9.105), loose lamps, broken helical rods, loose bolted clamps, failure of welds, damage from hail and reduced clearances due to additional weight of AWMs. Catenary lights are very expensive and have limited life (typical lamp nominal duration is 30000 hours).

Figure 9.106 Burn/ Corona damage resulting from loosened AWM.

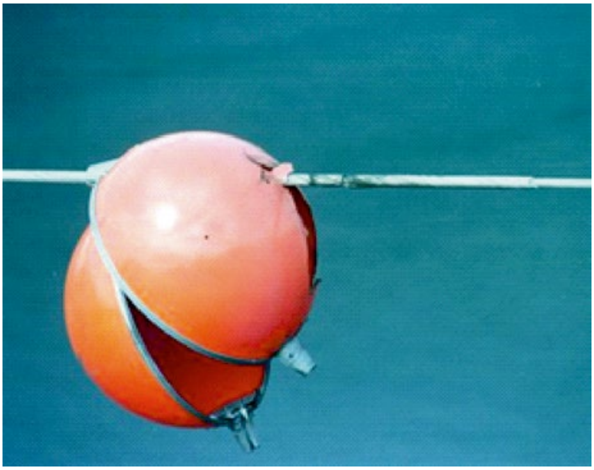


Figure 9.107 Damage from failed clamps of a AWM.

AWMs are often installed on critical spans with difficult access such as river crossings, making any remedial action more complex.

9.15 Joints and Fittings for Conductor Repair

9.15.1 Introduction

Of all the components used in a transmission line, the conductor is the most important, but it is also the most susceptible component to suffer from any fitting failures. This leads to a high occurrence of damage on this component.

Conductor damage leads to partial or total loss of electrical and mechanical continuity. For lines where the current is high enough, excessive damage (e.g. all aluminium wires of an ACSR broken) may lead to heating and annealing of the steel core, which may lead to a complete failure of the conductor in tension. Moreover, the portion of the tensile strength taken by the core in an ACSR is not as high has one may think and the core alone in most cases would not be able to carry the expected tension in the conductor. Therefore, access to effective remedial actions to restore the mechanical and electrical properties of conductors is imperative.

Moreover, for the last decade numerous failures of joints have been reported on transmission lines, the reasons for which have included asymmetrical installation of aluminium sleeves as well as accelerated ageing and deterioration of the contact surface in the joint due to increased electrical load. Consequently, it is also imperative to repair those joints and understand their degradation mechanism (Cigré WG B2.47 2015).

9.15.2 Failure of Joints (Cigré WG22.12 2002)

9.15.2.1 Failure Mechanisms

The failure of a joint is usually the result of an increased resistance due to corrosion, leading to an unacceptable increase in temperature and unstable mechanical conditions. Very few joints have been reported to display failure resulting purely from mechanical loads.

The reported events involving basically mechanical failures have occurred on joints that have been asymmetrically installed, where the ingress of the aluminium layers of an ACSR at one end of the joint has been less than 2.5 times the conductor diameter (Cigré WG 22.12 2002).

Detection of asymmetrically installed aluminium sleeves on ACSR can be performed by a reluctance test. Detection of asymmetrically installed aluminium and steel sleeves on ACSR can be performed by a radiographic test.

Mechanical failures of ACSR joints caused by corrosion of the steel core on ACSR, causing mechanical failure of joints, have not been reported so far. However, intense corrosion of the steel core has been detected in the vicinity of the steel sleeve. Detection of this corrosion can be performed with a boroscope test.

Main Reasons for the Failure of Joints

The main reasons for the failure of joints have been identified as follows: corrosion of the aluminium contact surfaces, improperly cleaned conductors, and asymmetric installation of the aluminium sleeve and steel sleeve (on ACSR). All these reasons for failures can be attributed to an increased resistance across the joint. The total resistance across the joint consists of the conductor resistance, the sleeve resistance and the contact resistance. Only the latter will change with time in service.

Since the stranding creates a non-homogenous conductor and the compression of the joint does not completely eliminate the voids between strands, water, sometimes contaminated, will penetrate the joint. The water will then remain in the cavities until it evaporates through the air gaps inside the conductor. This will take time, depending on the temperature in the joint and the humidity in the surrounding atmosphere.

Figure 9.108 AWM with gunshot damage.

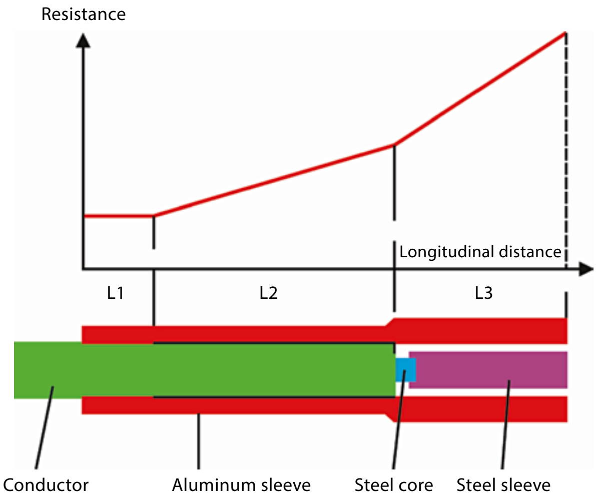


Figure 9.109 Distribution of Resistance in Joints.

The water will, during the time inside the joint, change the oxygen content along the route, creating differences in potential. The difference in potential will create crevice corrosion in the aluminium, inside the joint. The time it takes for the water to dry influences the severity of the crevice corrosion.

Corrosion of the steel core is generally a result of galvanic corrosion. It has been observed that when the temperature of the galvanised steel core rises above 60°C, the protective role of the galvanising with respect to the steel can be reversed. The steel then "protects" the galvanising (Figure 9.108).

Distribution of Resistance Along a Compressed Joint

The resistance of a compression-type joint has been found, by laboratory measurements, to be distributed in the following way:

- The first part of the resistance, the entrance of the joint (marked as L1 on Figure 9.109), includes a portion of the conductor, a portion of the aluminium sleeve and the contact resistance.
- The second part of the resistance, the compressed part of the joint (marked as L2 on Figure 9.109), includes a portion of the conductor and a portion of the aluminium sleeve resistance.

- The third part of the resistance, the uncompressed part of the joint (marked as L3 on Figure 9.109), includes a portion of the aluminium sleeve and the steel sleeve. The resistance of the steel sleeve can be neglected in the calculation, in the same way as the steel core resistance can be neglected in an ACSR due to its very high resistance.

  The following empirical model for calculation can be used.

$$R_s = \frac{1}{\frac{1}{R_c 2\left(L_1 + x\right)} + \frac{1}{R_{asc} 2L_1}} + \frac{R_{con}}{d} 2L_2 + \frac{1}{\frac{1}{R_c 2L_2} + \frac{1}{1.08 R_{asc} 2L_2}} + R_{as} 2L_3 \tag{9.6}$$

Where

R_s = joint resistance (μΩ)
d = conductor diameter (m)
L_1 = length of entrance (m)
L_2 = length of contact area (m)
L_3 = length of uncompressed part (m)
x = length of conductor outside joint (m)
R_c = conductor resistance (μΩ/m)
R_{as} = aluminium sleeve resistance, uncompressed (μΩ/m)
R_{asc} = aluminium sleeve resistance, compressed (μΩ/m)
R_{con} = contact resistance (μΩ).

The contact resistance (R_{con}) is dependent on the type of compression used, e.g. hydraulic or implosive, intermediate or continuous, hexagonal or concentric. It can be determined experimentally.

Example

The following calculation example is given for an ACSR ZEBRA conductor joint having the following dimensions; D = 0.0286 m, L_1 = 0.075 m, L_2 = 0.155 m, L_3 = 0.132 m, x = 0.005 m, R_c = 67.4 μΩ/m, R_{as} = 19.5 μΩ/m, R_{asc} = 21.4 μΩ/m, R_{con} = 60 nΩ;

R_s = 13.76 μΩ and the conductor resistance for the joint length will be: R_c = 49.54 μΩ.

The calculations show that this new joint has a resistance of 28% of that for the same length of conductor.

9.15.2.2 Field Testing Methods of Joints

The electrical resistance of a joint is the main factor for assessing its condition. It can be determined using temperature measurement methods, resistance measurement methods or both.

It is not possible to detect the asymmetrical installation of joint sleeves using the temperature measurement method since the temperature distribution in the aluminium will be too uniform.

When using a resistance measurement, an asymmetrical installation of the aluminium sleeve results in too small a difference in the obtained resistance value to be detectable. Calculations of the change in resistance over a joint indicate that an asymmetry of 20 mm will give the same increase in the resistance as a temperature increase of 1 °C and a doubling of the contact resistance gives an increase of 10 °C at maximum conductor design temperature.

Detection of asymmetrical installation of the aluminium sleeve on ACSR can be performed by a reluctance test.

Detection of asymmetrical installation of the aluminium sleeve on AAC or ASC, AAAC or AASC and of the steel sleeve of ACSR can be performed by a radiographic test.

Detection of steel core corrosion in the vicinity of a steel sleeve can be performed by visual inspection with a boroscope.

These different test methods are described in detail in the following sections.

Temperature Measurement Tests

The reliable measurement of joint temperature is highly dependent on the current flowing through the joint. For example, a current of 0,4 A/mm^2 gives a temperature difference of only 7 °C between the conductor and the joint when the joint has a contact resistance 65 times larger than the contact resistance of a new joint (Figure 9.110). Since the thermal conductivity of aluminium is very high, the temperature will be equalised along the joint. It would therefore be difficult to detect

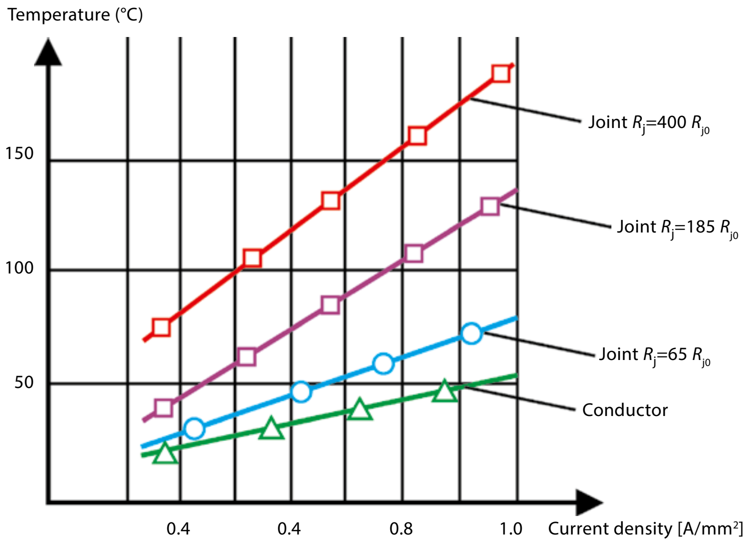


Figure 9.110 Joint temperature as a function of phase current.

joints that have an unacceptable contact resistance at one end, but a lower resistance at the other end. Also, the higher resistance at one end will not be detected if the resistance is measured across the entire joint. To increase the chance of detecting defective joints, the current flow in the overhead line should be increased as much as possible. The temperature detection along the joint gets more difficult under some ambient conditions when the heat generated in the joint is transferred to the surroundings e.g. rain, snow or high wind velocities.

Figure 9.110 shows conductor and joint temperatures taken from an existing transmission line that has been in service for 40 years, obtained during indoor laboratory tests with direct currents. The labels on Figure 9.118 indicate the resistance of the used joints (R_j) as compared to the resistance of a new one (R_{j0}).

Infrared Photography

Infrared photography detects heat radiated in the infrared spectrum (Tavano 1996). Detected temperatures at the joint are compared with detected temperatures at the conductor. The resolution is normally 1 °C. Infrared photography can be performed from the ground or from a helicopter. In the following sub-sections both methods are described.

Measurement of temperature by infrared photography can be a time-saving method enabling a utility to get a good indication of the condition of the joints along a line.

The infrared energy measured by the instrument pointed at the object of interest is the sum of the energy emitted, in a specific wavelength window, by the object itself and of the ambient energy radiated by the surroundings and reflected by the object towards the instrument. The latter, in the case of very reflecting objects (with low emissivity coefficient), can be a considerable proportion of the total measured energy and it is essential to accurately determine its value in order to determine the actual amount of energy emitted by the object. The surface structure will also influence the radiated energy.

A joint over-temperature is usually detected by comparing the brightness of the joint, with the unaided eye, on the screen with a suitable reference. This reference is usually the ground, the other half of the joint or the conductor when airborne surveying is used. In order to detect the over-temperature, the joint must appear brighter than the reference on the screen. Due to the lower emissivity of the joint compared with the ground, a fault-free joint appears darker than the ground, because the radiation from the cold sky is partly reflected from its surface. The colder the appearance of the sky and the lower the emissivity of the joint, the darker the joint appears on the screen. Therefore the less overcast the sky, or the higher the cloud ceiling, the higher the over-temperature needed for the joint to appear bright. Consequently a defective joint becomes more difficult to detect without making point measurements. This relationship is shown in Figure 9.111. In order to generalise the diagram the radiation temperature of the sky is plotted on the horizontal axis as an under-temperature when compared with ambient or the ground. The plotted curves show the critical joint over-temperature above ambient that is needed for the joint to appear brighter than the ground, on the screen, for different emissivities. One advantage of this plot is that the results are more or less independent of the ambient temperature even though this

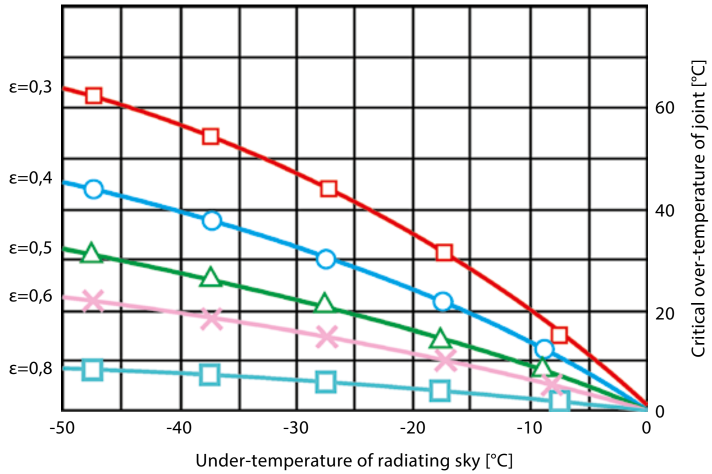


Figure 9.111 Critical over-temperature needed for a faulty joint to be detected.

specific diagram is plotted using an ambient temperature of 0 °C. The diagram shows that when a thermo graphic inspection is made under good conditions, e. g. emissivity of 0, 5 and under-temperature of the sky of −15 °C, the critical joint over-temperature is approximately 8 to 12 °C. This means that the temperature of the joint will be an average of 10 °C higher than that of the conductor.

Note: The relationship between temperature and emissivity is given by the Stefan-Boltzmann law.

When a thermographic inspection is performed from the ground, the situation is different. The joint is always shown on the image as brighter than the sky in the background. Therefore it is not possible to visually detect joints with an over-temperature. Instead, the temperature of every joint must be measured with a camera having a sufficiently high resolution (Tavano 1996) and compared with other joints.

Effect of Weather Parameters

It has been observed that the results of infrared photography are not only highly dependent on the weather conditions but also on the interpretation of the image. Most of the atmospheric interference, e.g. background light, light reflection, solar heating (e.g. overcast), should be reduced to a minimum. As far as meteorological conditions are concerned, measurements carried out with different conditions of solar radiation (from cloudy to clear sky) have indicated that the infrared cameras that operated over a wave length range of 8-12 μm are less influenced by illumination conditions. Further, the wind velocity has a strong influence since the projected surface of the joint is approximately twice the surface of the conductor. The objective should be to make the measurements under the following weather conditions:

- Overcast sky.
- Wind velocity less than 1 m/s.
- No atmospheric precipitation.

Emissivity Coefficient

Figure 9.112 shows the error of measurements (the average error obtained with different infrared cameras), as a function of the emissivity coefficient assumed for the joint (Tavano 1996). The measured temperature is particularly influenced by the assumed emissivity, especially for low values. It should be noted that the emissivity is dependent on both the length of time that the joint has been in service and the amount (and type) of pollution prevailing at the line section being studied.

Measurements performed on ACSR (Davidson et al. 1974) that had been in service for different periods, indicated that both the emissivity and the absorptivity reach a high level over a period of five to ten years. Figure 9.113 shows a typical profile of the change in absorptivity and emissivity of a joint over time in service. It should be noted that the actual speed of increase depends on the environment.

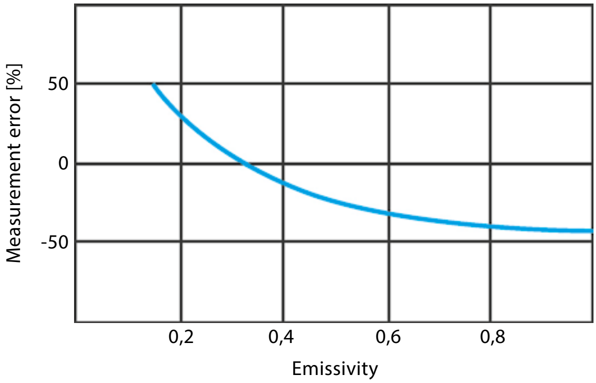


Figure 9.112 Measurement Error as a Function of Emissivity (Tavano et al. 1996).

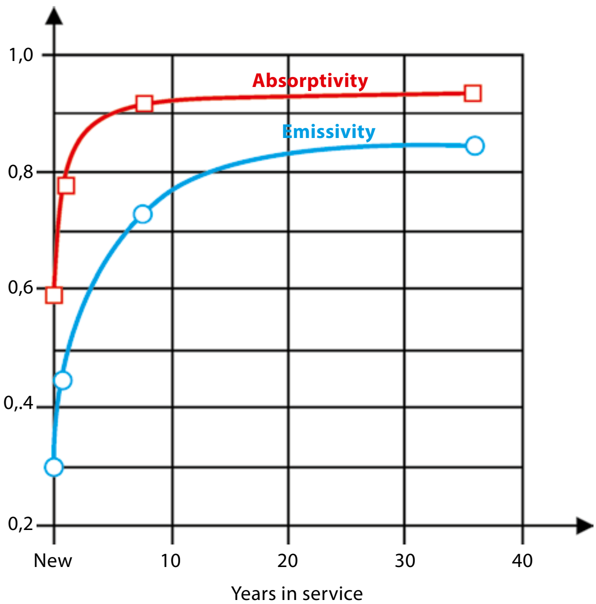


Figure 9.113 Typical Absorptivity and Emissivity as a Function of Time (Pirovano et al. 1998).

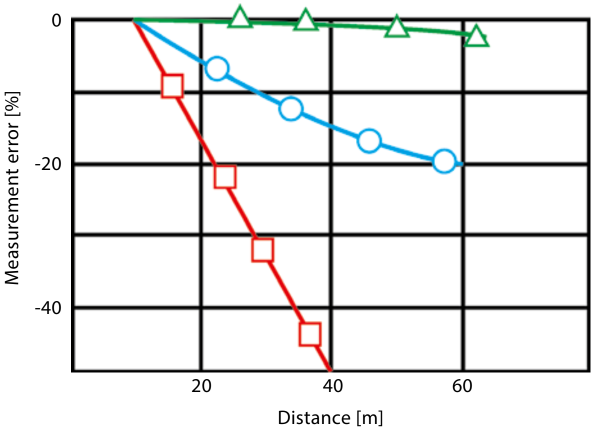


Figure 9.114 Measurement error as a function of distance to the object for different infrared cameras (Pirovano et al. 1998).

Distance to Detected Object

The average errors as a function of the distance to the joint for different infrared cameras are indicated in Figure 9.114 (Pirovano et al. 1998). The results show that, in general, instruments with a smaller field of view and better resolution allow more accurate measurements to be obtained at longer distances. In particular an infrared camera with a zoom lens showed that the use of the zoom increased the measuring performance at greater distances. However, the use of this narrow type zoom for measurements by helicopter is not recommended because of difficulties in focussing on the objects.

One infrared camera offered the possibility of automatically changing the objective, which is particularly useful for measurements made from a helicopter. Initially, a wide lens objective is used and once a hot spot is located it is possible to measure its temperature with a high precision using a 5° window.

Temperature Rise

In order to obtain reliable values with the infrared method, the current loading of the overhead transmission line should be such that the temperature rise in the conductor would be at least 20 °C above ambient. At lower temperature rises, detection of problematic joints will be more difficult or even impossible.

Data to be Recorded

The following data should be recorded during the infrared inspection:

- Temperature of the joint.
- Temperature of the conductor or the temperature difference between conductor and joint.
- Ambient temperature.
- Electrical load in the conductor.
- Wind velocity and direction.
- Ground/sky radiated temperature.

The interpretation of the results is difficult since the infrared measurement is influenced by so many parameters. It is recommended that the test records should include well-documented weather and loading data for the individual joints being assessed. A low over-temperature under some weather and load conditions may give a high over-temperature under other service conditions.

Temperature Transducers

Temperature transducers to be used should be either of the Pt-detector (resistance) or the K-detector (thermocouples) type. The contact shape, measuring range, accuracy and the measurement time for the temperature transducers should be appropriate for the purpose of the test.

Effect of Weather Parameters

It has been observed that the results of temperature measurements of joints are highly dependent on weather conditions. Most of the atmospheric interference e.g. background light, light reflection, solar heating, as well as the absorptivity and emissivity factors do affect the results. In addition, the wind velocity has a strong influence since the projected surface of the joint is approximately twice the surface of the conductor. Also atmospheric precipitation has a very strong influence on the obtained results. Since no studies have been carried out on the effect of rain, it is recommended that the use of any formulae that are available for temperature calculation with rain or other precipitation be avoided.

Temperature Rise

The current loading for the overhead line should be such that the temperature rise in the conductor would be at least 20 °C above ambient, to increase the probability of obtaining reliable values. At low temperature rises the probability of detecting faulty joints will be lower.

Data to be Recorded

The following data should be recorded during an inspection with thermocouples.

- Temperature of the joint.
- Temperature of the conductor.
- Ambient temperature.
- Solar radiation.
- Absorptivity coefficient for the joint.
- Absorptivity coefficient for the conductor.
- Wind velocity and direction.
- Electrical load in the conductor.

Contact Points for Measurements

The temperature of the joint should be measured at each crimped contact part of the joint where the heat is generated (Figure 9.115).

Figure 9.115 Temperature measurement.

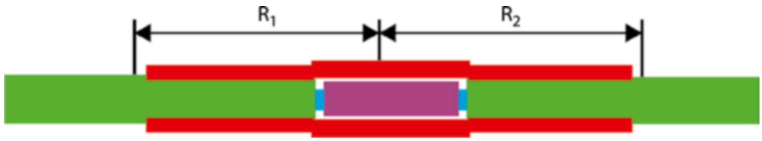


Figure 9.116 Resistance measurement method.

The temperature of the conductor should be measured at a sufficient distance from the end of the joint such that the conductor temperature will not be influenced by the joint (Figure 9.115).

Interpretation of Results
The temperature measured under actual weather conditions should be translated to that which would be measured under more typical ambient conditions. For example: 20 °C ambient temperature, 1 m/s wind velocity, 45° wind angle to the conductor, sea level, and solar noon, in order to improve the interpretation of the obtained data from different test conditions.

The calculation procedure for the translation of the measured temperature for the purpose of this comparison should take into consideration the heat distribution along the joint and towards the conductor. It should be noted that the steady state model for the heat balance calculation in conductors introduced in (House and Tuttle 1959) does not deal with joints.

From the calculated temperature values for the joint, the maximum value should be used for comparison with the appropriate acceptance criterion.

9.15.2.3 Resistance Measurement Method
The resistance should be measured from the conductor, in the vicinity of the joint, to the centre of the joint (Figure 9.116). The resistance measurement should be taken for each half of the joint since the degradation along the joint could be different. It has been observed that out of all joints with an increased resistance, around 10 % have unacceptable degradation over just one half of the joint.

It is worth noting that equation 9.6 allows the contact resistance to be measured without measuring all parts of the material involved in the joint, and that the user will be mainly interested in the incremental increase of contact resistance.

9.15.2.4 AC Resistance Measurement on a Live Line
In order to obtain a meaningful value of the measured voltage drop, the level of current in line should be appropriate for the resolution of the measuring instrument

used (Örmin and Bartsch 1998). It should also be noted that since resistance is a function of temperature, it is also necessary to measure the conductor and joint temperatures.

The following measurements should be made.

- Temperature of the conductor.
- Temperature of the joint.
- AC voltage drop over each half of the joint.
- Electrical load in the conductor.
- The position of the measuring points.

Contact Points for Measurements

The contact points should be such that they give good contact with at least one of the conductor strands. The distance between the end of the joint and the contact point should be as equal as possible for all measurements.

The temperature of the joint should be measured at each crimped contact part where the heat is generated.

The temperature of the conductor should be measured at a sufficient distance from the end of the joint such that the conductor temperature will not be influenced by the joint.

Resistance Measurement on a non-energised Line

To derive a reliable value of the voltage drop, at least four different DC currents should be applied in sequence. The current-feeding contacts should be installed on the conductor at a distance of least half a meter from the end of the joint in order to have the current distribution equalised in all strands. It should also be noted that since resistance is a function of temperature, it is also necessary to measure the conductor and joint temperatures.

The following measurements should be made.

- Ambient temperature.
- Temperature of the joint.
- DC voltage drop over each half of the joint.
- Current load in the conductor.
- The position of the points of measurement.

There are instruments available on the market, which display a calculated resistance rather than the voltage drop. When using this instrument the measurement of the current load in the conductor could be neglected.

The measurement of the DC voltage drop should be made from the conductor, in the vicinity of the joint, to the mid-point of the joint from both ends in order to obtain the resistance over each half of the joint.

Current-Feeding Contacts

The current-feeding contacts should be such that they give good contact and distribution of the current in all strands of the conductor. A recommended minimum distance between the joint or measuring contact and the feeding contact is 0.5 metres.

Measurement Contacts

The measuring contacts should be such that they give good contact to at least one of the conductor strands. The distance between the end of the joint and the contact should be as equal as possible for all measurements.

The temperature of the joint should be measured at each crimped contact part where the heat is generated.

Interpretation of the Results

The ratio of joint- to conductor resistance is widely spread over the range of conductors used, even for the same design of joint, e.g. 10 to 45 % for one type of joint. These circumstances indicate that it is not practical to use the ratio of joint- to conductor resistance as a criterion for the interpretation of results.

It is recommended that the joint resistance R_{joint}, is classified according to three reliability levels for each combination of conductor and joint using the same parameters as in the current carrying capacity calculation for conductors (Figure 9.117). For the interpretation of results, all resistance values should be translated to the same temperature, for example 20 °C. Out of the calculated resistance values for the joint, the maximum value should be used for comparison with the appropriate acceptance criterion.

Figure 9.118 illustrates the effect of the joint resistance at different temperatures and loading, for ZEBRA conductor.

9.15.2.5 Reluctance Tests

The aim of the reluctance test is to detect the asymmetrical installation of the aluminium sleeve on ACSR by measuring the magnetic resistance (reluctance) of the joint.

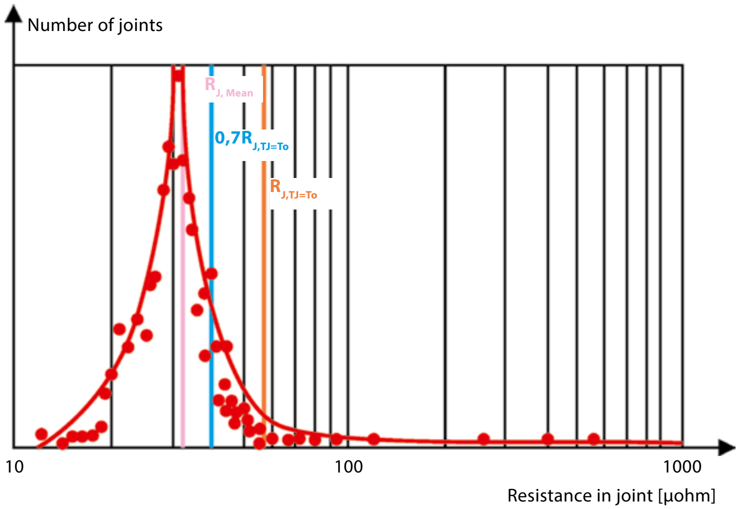


Figure 9.117 Distribution of Resistance in a population of joints, where: *R* is resistance, *T* temperature, j joint and c conductor.

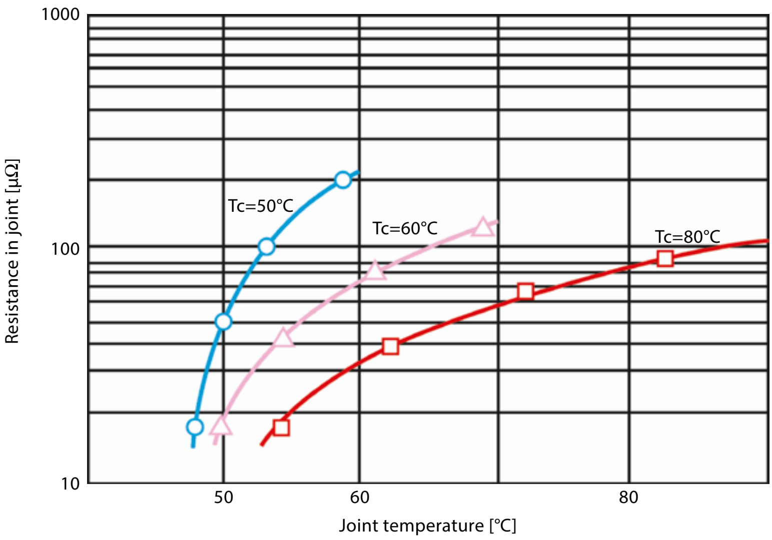


Figure 9.118 Joint resistance vs. temperature.

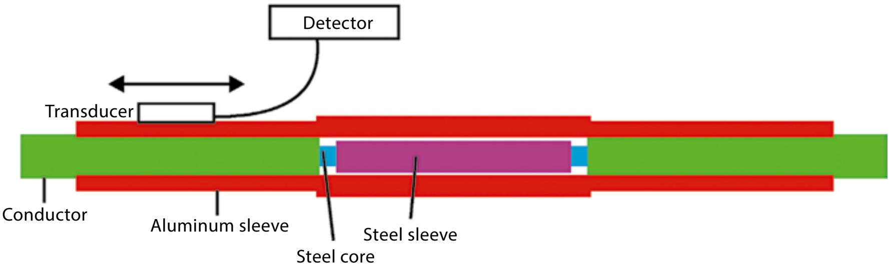


Figure 9.119 Reluctance test set-up.

Set-up of the Reluctance Test Equipment

The asymmetry of the aluminium sleeve versus the steel sleeve should be detected by the use of a magnetic detector. The detector should be thoroughly calibrated for the actual type and size of joints with the aim of giving a proper detection of each end of the steel joint. It should be taken into consideration that the compression joint might be bent so that the steel core is not concentric inside the aluminium sleeve. Furthermore, the increased distance from the outer surface to the steel sleeve should be taken into account when the aluminium sleeve has an uncompressed section in the middle.

The transducer should slowly be carried along the joint axis and when the ends of the steel joint are detected, those points should be marked (Figure 9.119).

Interpretation of the Test Results

The ratio of joint- to conductor depth of engagement ($\Sigma\ L_1 + L_2$ in Figure 9.109) is widely spread for the same type of conductor, due to the use of different crimping factors. In turn, the depth of engagement is a factor of both mechanical and electrical behaviour. This indicates that the ratio of joint- to conductor depth of engagement should be used as a criterion for the interpretation of the asymmetry.

Out of the calculated asymmetry values for the joint, the maximum value corresponding to the appropriate acceptance criterion should be used.

9.15.2.6 Radiographic (X-ray) Tests

The aim of the radiographic test is to detect asymmetrical installation of the aluminium sleeve on AAC or ASC, AAAC or AASC, ACAR, and ACSR as well as the asymmetrical installation of the steel sleeve on ACSR cores.

Set-up of the Radiographic Equipment

The X-ray film should be placed on the top of the joint. The exposure should be selected in such a way so as to allow the detection of the end of the steel core within the steel sleeve. Because it may be difficult to detect the ends of the aluminium sleeve, the ends of the aluminium sleeve should be marked with straps of lead.

The X-ray tube should be hung beneath the conductor at a distance such that a suitable exposure time and beam angle will be maintained (Figure 9.120).

Interpretation of the Results

Since there are different types and dimensions of joints on the market that may result in different image effects at the radiogram, the interpreter should be familiar with the particular type of joint under consideration.

The ratio of joint- to conductor depth of engagement is widely spread for the same type of conductor, due to the use of different crimping factors. In turn, the depth of engagement is a factor of both mechanical and electrical behaviour. This indicates that the ratio of joint- to conductor depth of engagement should be used as a criterion for the interpretation of the asymmetry.

Out of the calculated asymmetry values for the joint, the maximum value corresponding to the appropriate acceptance criterion should be used.

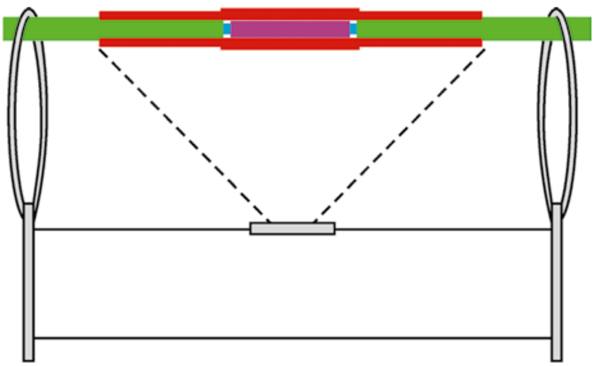


Figure 9.120 Set-up of radiographic equipment.

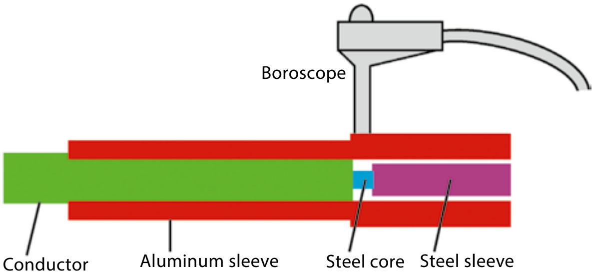


Figure 9.121 Set-up of the boroscope test.

9.15.2.7 Boroscope Test

The aim of the boroscope test is to detect corrosion of the steel core in ACSR, in the vicinity of the steel sleeve.

If the joint has been filled with grease during installation, the boroscope test is not useful.

Set-up of the Boroscope Test

Before detection, a hole, with an appropriate dimension for the lens, should be drilled through the aluminium sleeve in the immediate vicinity of each end of the steel joint (Figure 9.121). It should be noted that the wire strands of the steel core must not be damaged by this procedure.

The detector should be equipped with an internal light for illumination of the zone to be inspected.

After the inspection has been performed, the drilled holes should be sealed with aluminium plugs.

Interpretation of the Results

The interpreter should be aware that the image of the surface of the steel core will depend on the type of corrosion protection applied to the steel sleeve, i.e. red lead paint, zinc-rich paint, hot dip galvanising, oil rich paste, or other treatments.

From of the images of the corrosion of the steel core, the worst-case image should be used, corresponding to the appropriate acceptance criterion.

9.15.3 Replacement of Joints

This section covers the acceptance criteria for joints as well as the methods of replacing joints that do not meet the requirements specified in this paper.

9.15.3.1 Acceptance Criteria

To reach a higher degree of confidence in the joints on an old transmission line, a set of acceptance criteria should be determined. The criteria could be given for three levels of reliability, reflecting the importance of the line in terms of its sensitivity to outages, the occurrence of line crossing points and the risk to people beneath the line. The transmission line owner should state the requirements for the reliability of the particular section of the line where the joints are installed.

Since there is the ability to run standard conductor types (ACSR, AAC or ASC, AAAC or AASC and ACAR conductors) at temperatures up to 100 °C and many countries assume a maximum normal design temperature of less than 75 °C the resistance of the joint will be the triggering value for immediate replacement. In that case the expectation of future increases in current loading should be taken into account.

Criterion Levels for the Resistance or the Temperature of the Joint
The three recommended criterion levels for resistance or temperature are:

- For joints where a failure and a drop of the conductor have a high influence and endanger the reliability of the line: $R_{\text{joint}} < 0.7R_{\text{j},T_\text{j}=T_\text{c}}$
- For joints where a failure and a drop of the conductor have an influence and jeopardise the reliability of the line: $R_{\text{joint}} < R_{\text{j},T_\text{j}=T_\text{c}}$
- For joints where a failure and a drop of the conductor have a low influence on the reliability of the line. $R_{\text{joint}} < R_{\text{j},T\text{j}=T\text{c}} + 10\ \text{K}$.

Note: 1 The first level expresses in other words that the joint resistance should be less than 70 % of the calculated resistance value at which the joint and the conductor would be at the same temperature.

Note: 2 The third level represents approximately the limit of possible detection by infrared photography under very good conditions (see section 6.1.3).

Figure 9.122, (House and Tuttle 1959) illustrates a typical graph of the three levels of acceptance criteria calculated for hydraulically compressed Zebra conductor joints.

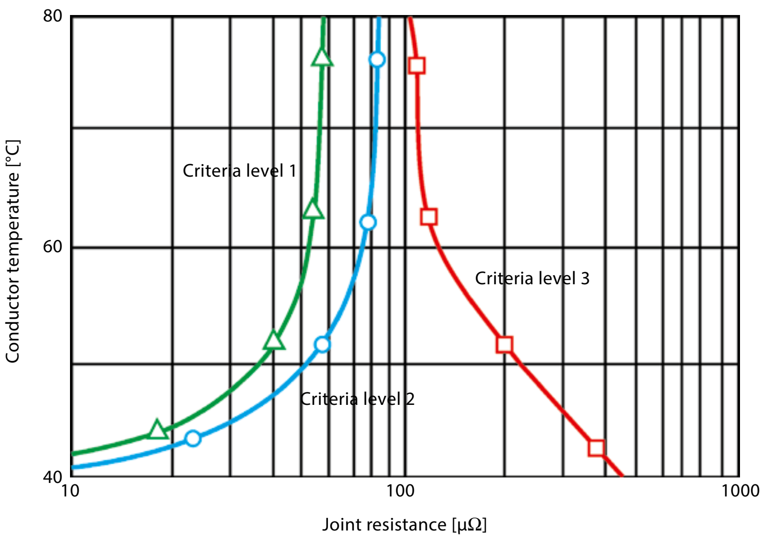


Figure 9.122 Acceptance criteria for joints.

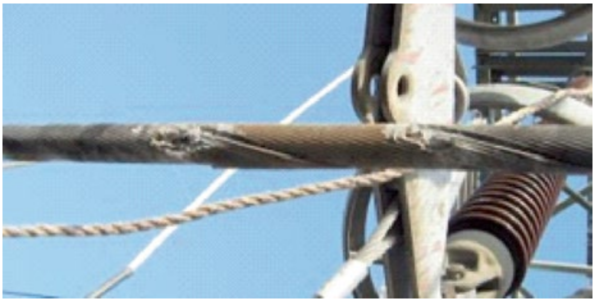


Figure 9.123 Lightning strike and flashover damage.

Table 9.2 Acceptable joint resistances

Criterion level	Joint resistance (μΩ) at conductor temperature	
	50 °C	80 °C
1	36	58
2	52	83
3	216	102

Example, taken from Figure 9.123, of acceptable joint resistances at the three different criterion levels (Table 9.2).

Criterion Levels for the Asymmetry of a Joint
The recommended criterion levels for asymmetry are:

- For joints where a failure and a drop of the conductor have a high influence and endanger the reliability of the line: Asymmetry < 7 % of the intended depth of engagement
- For joints where a failure and a drop of the conductor have an influence and jeopardise the reliability of the line: Asymmetry < 12 % of the intended depth of engagement
- For joints where a failure and a drop of the conductor have a low influence on the reliability of the line: Asymmetry < 18 % of the intended depth of engagement.

Criterion Levels for the Corrosion of the Joint
The recommended criterion levels for corrosion are:

- For joints where a failure and a drop of the conductor have a high influence and endanger the reliability of the line: No signs of corrosion, “rust strain”
- For joints where a failure and a drop of the conductor have an influence and jeopardise the reliability of the line: No signs of severe surface corrosion, “layer of rust”
- For joints where a failure and a drop of the conductor have a low influence on the reliability of the line: No signs of pitting corrosion, “deep-seated rust”.

Note: If surface corrosion has been detected, the joint may not require replacement if the joint is going to be filled with grease.

9.15.4 Types of Conductor Damage

Apart from conductor damages, already described in previous chapters, occurring at suspension or fitting clamps induced by a broken or inadequate fitting and corrosion, other phenomenon may lead to conductor damages.

9.15.4.1 Lightning Strike and Flashover Damage

Lightning discharges on overhead power lines can induce flashovers which can severely damage the conductors, as shown in Figures 9.123 and 9.124.

9.15.4.2 Basketing or Birdcaging

Basketing, or birdcaging, occurs when conductor wires are loaded in compression, causing them to buckle and in severe cases, flare outward radially, forming shapes similar to baskets or birdcages, as shown in Figures 9.125 and 9.126. This

Figure 9.124 Lightning damage on conductor (shield wire above).

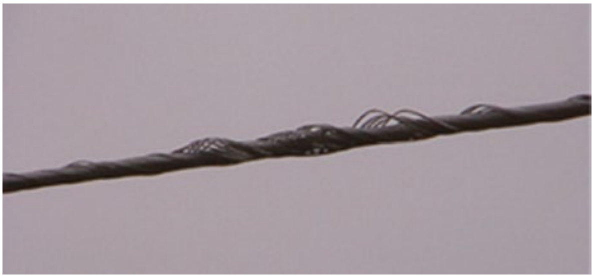


Figure 9.125 Birdcaging due to mishandling during stringing.

Figure 9.126 Birdcaging of ACSS/TW conductor.

Figure 9.127 Aluminium damage caused by cable reel during stringing.

Figure 9.128 Aluminium damaged due to bicycle cart.

permanent deformation may be induced during stringing, installation of compression fittings, or by excessive heating of the conductor in service.

9.15.4.3 Nicks and Kinks

Nicks and kinks in conductors are generally produced during line construction; either by faulty equipment (e.g. reels, sheaves, conductor cart) or by handling (e.g. faulty installation of a comealong, conductor dragged on the ground). Figures 9.127 and 9.128 show examples of conductor damage due to improper or poor handling practices. This type of damage can usually be avoided with appropriate handling techniques during construction.

9.15.4.4 Damage due to Conductor Clashing

Damage due to conductor clashing mainly occurs with bundled conductors, when one subconductor clashes with another, see Figure 9.129. Clashing damage may occur during service due to severe subspan oscillation and short circuits, or during construction, in spans where the conductors have been temporarily put in place without installing spacers. Ice shedding and galloping may also cause conductor chashing (Figure 9.130).

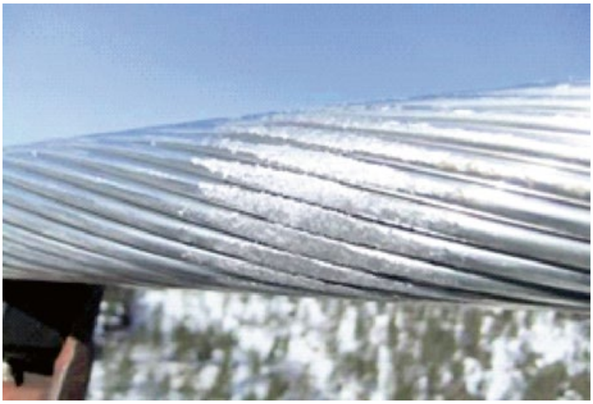


Figure 9.129 Damage caused by clashing of implosive fitting on adjacent sub-conductor.

Figure 9.130 Repair of damage caused by shield wire clashing with conductors (ice shedding, galloping).

Clashing of jumper conductors and fittings can also generate important damage, as shown in Figure 9.131.

9.15.4.5 Gunshot Damage

Gunshot damage may be observed on conductors, aerial warning markers, and insulator strings. These are popular targets with vandals, especially in proximity to hunting grounds.

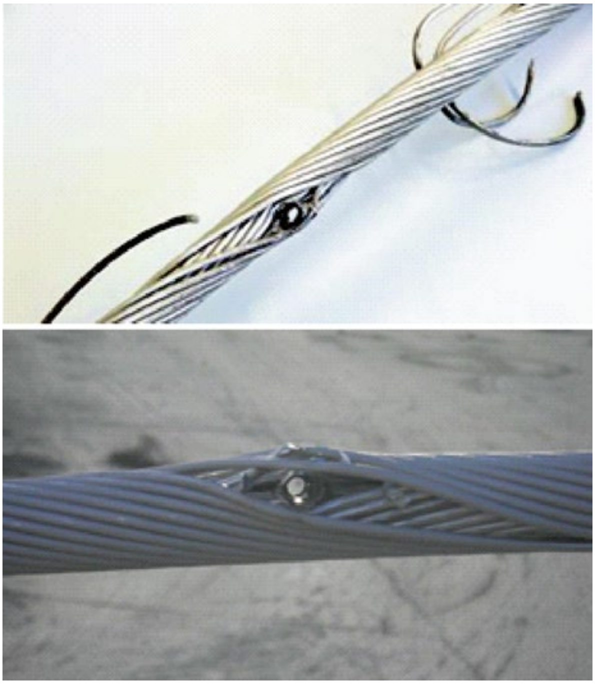
As shown in Figure 9.132, gunshots may produce significant damage to conductors.

9.15.5 Classification of Conductor Condition

Performing a reliable assessment of a conductor's condition is not easy, particularly for fatigue breaks, as contrary to other types of damage, wires may be broken in inner layers, while the outer layers may still be intact. In many cases, the extent of

Figure 9.131 Damage to compression dead-end caused by clashing of jumper end fitting.

Figure 9.132 Gunshot damage.



damage may only be fully evaluated once the clamp has been opened or the helical fittings removed, as shown in Figure 9.133.

Furthermore, even when the conductor is accessible for visual inspection, outer layer damage may not reflect the full extent of damage in the conductor, as shown in Figure 9.133. A complete assessment of fatigue damage should establish the number of damaged wires, the extent of damage in length and, in the case of ACSR, an evaluation of the steel core integrity.

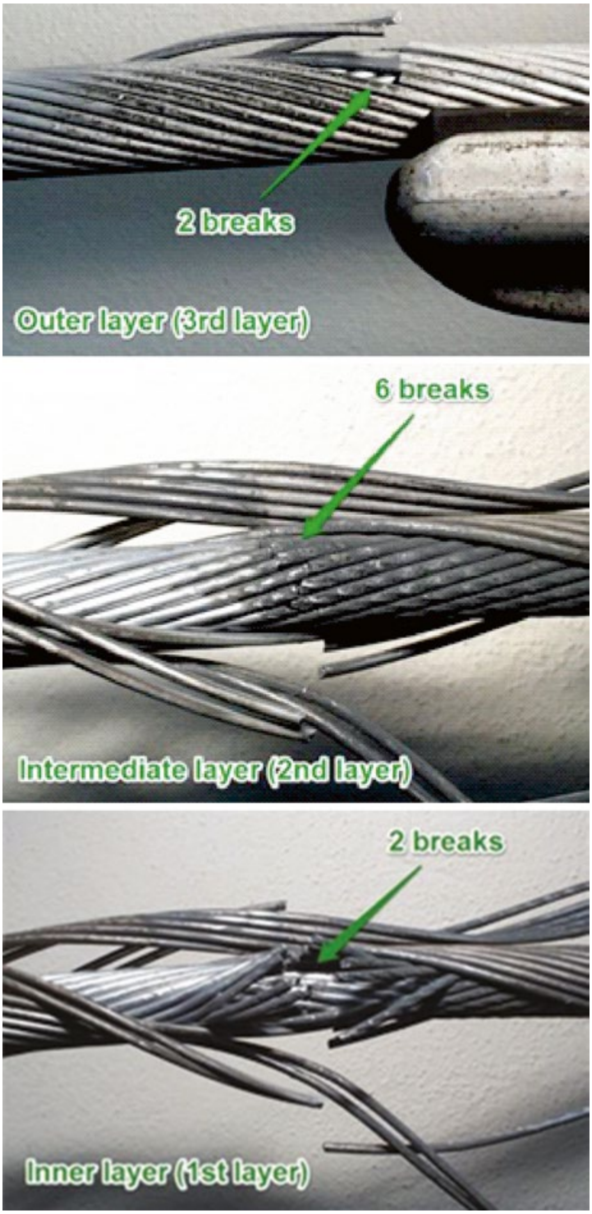


Figure 9.133 Severity of fatigue failure hidden in inner layers of a conductor.

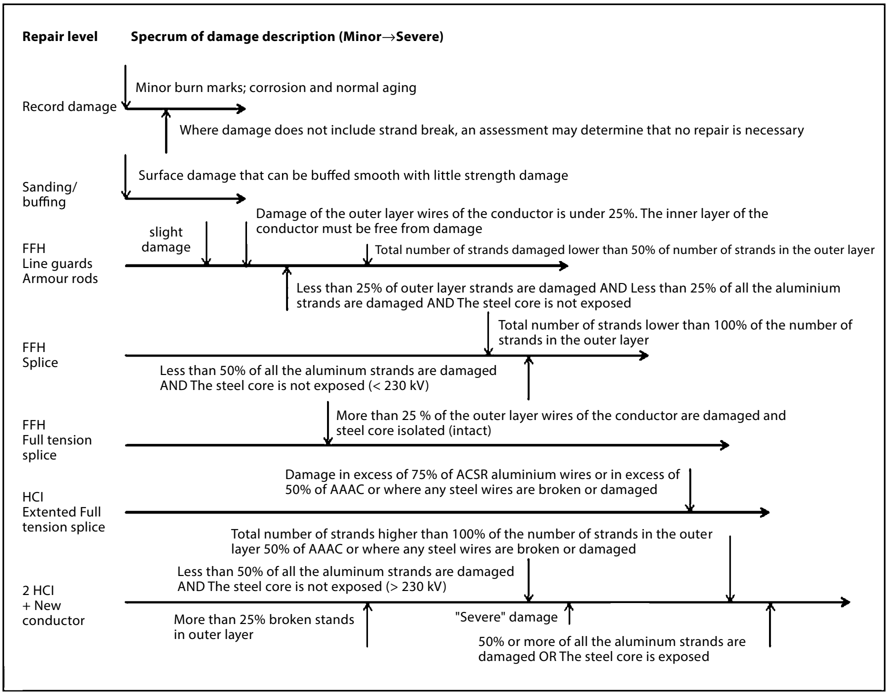


Figure 9.134 Typical conductor damage descriptions used by utilities.

Figure 9.134 presents an example of damage descriptions used by utilities to quantify the extent of damage by expressing the number of damaged wires as a percentage of the number of wires in the outer layer or as a percentage of the total number of aluminium wires in the conductor. In both cases, it is important to note that damages wires in all layers, not only the outer one, need to be considered in the evaluation of damage extent.

9.15.6 Remedial Actions Used by Utilities

Depending on the severity of damage, a wide spectrum of remedial actions are available, ranging from polishing with emery cloth or sand paper for minor damage to the complete removal and replacement of the conductor. Between these two extreme measures, a variety of solutions exist, mainly in the form of various types of factory formed helical (FFH) fittings and hydraulic compression and implosive (HCI) fittings. As evidenced in Figure 9.135, FFH fittings usage tends to decrease in favour of HCI fittings as the severity level increases.

The location of the conductor damage within the span and also with respect to surrounding elements to the line may have an important impact on the repair method chosen. The positioning of repair fittings needs to be analysed at three different levels:

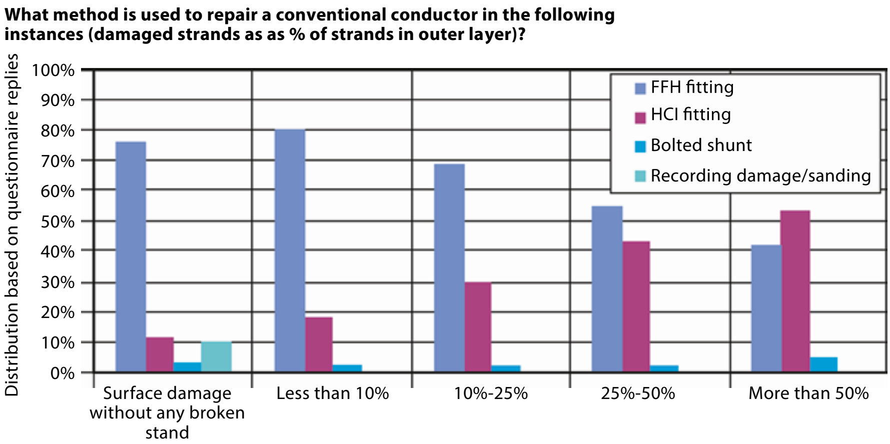


Figure 9.135 Repair method as a function of damage severity, based on questionnaire replies.

Table 9.3 Examples of criteria used by respondents to reconductor a span or line section

Respondent ID	Criteria	Action
A	Presence of more than three repair fittings (HCI or FFH) within a single span (for a single conductor)	Consult engineering for evaluation of reconductoring
B	Presence of more than three repair fittings (HCI or FFH) per line kilometer (for a single conductor)	Remove and replace conductor
C	Presence of "several" HCI repair fittings within a line section.	Remove and replace conductor for the whole line section

- Location of the span with respect to surrounding environment (e.g. road/river crossing)
- Number of repair fittings within a single span or line section
- Location within the span, with respect to other fittings.

Many respondents to the questionnaire don't allow the installation of FFH or HCI fittings in spans crossing rivers, railroads and/or highways, at the time of construction as well as for maintenance/repair purposes.

In some instances, when the number of FFH or HCI fittings within a span reaches a threshold value, a complete removal and replacement of the conductor within the span may be preferred. Table 9.3 shows a few examples of criteria used by respondents to determine if reconductoring is necessary for a span or line section.

Repair methods near clamps are a source of further complexity. While in general, spacers and spacer-dampers can be moved without excessive impact on their motion control performance, repositioning of vibration dampers should be addressed with caution.

With regards to HCI joints, a minimum distance of 8 m is prescribed by many utilities between the joint, suspension clamps, dead-ends and other joints. Others require larger spacing, from 16 m up to 33 m.

FFH repair fittings can be installed closer to other fittings than HCI joints, although minimum distances still need to be respected. Minimum values of 100-200 mm are generally prescribed.

Suspension clamps obviously can't be displaced, and damage in the vicinity of these fittings may require special measures. The most straightforward case is when the existing suspension unit can accommodate the larger diameter of the conductor covered with armour rods or line guards. In other cases, the replacement of the suspension clamp with a larger one, or the insertion of a new conductor segment with two HCI fittings might be necessary.

In general, damage in the vicinity of HCI deadends is handled by cutting out the conductor and inserting a new conductor segment with the use of a new dead-end and an additional HCI joint. Bolted or FFH dead-end shunts are also available for such applications.

9.15.7 Conductor Repair using FFH Fittings

A factory formed helical (FFH) repair fitting is composed of multiple individual rods – generally between 7 and 15 per set. Depending on the fitting type, these rods may be separate or preassembled in subsets.

Repairs with these fittings can be performed without having to cut the conductor; their installation is done by hand and does not require any tool.

FFH fittings work using a "self-tightening" force. The inner diameter of the rods is slightly smaller than the conductor diameter on which they are installed. Once installed on the conductor, the rods are elastically deformed and generate a gentle radial pressure over their length. When a tensile load is applied on the conductor, the helical rods elongate and their inner diameter decreases, which in turn increases the radial pressure they apply on the conductor.

FFH fittings must be carefully adapted to the conductor needing repair, with regard to both dimensions and material.

9.15.7.1 Types of Fitting

A thorough assessment of conductor damage is necessary before choosing the proper Factory Formed Helical (FFH) repair fitting. The FFH repair fitting should be chosen to ensure a full restoration of the mechanical and electrical integrity of the system.

Table 9.4 and the following sections present different types of FFH repair products available for various degrees of damage.

Making a reliable assessment of the extent of damage is a difficult task. Decisions made based on the recommendations given in this section should take into account the reliability of the assessment. In doubt, take action towards the safe side.

Table 9.4 Type of FFH repair fitting with respect to observed level of damage

Number of damaged wires observed*	Location of damage	Type of FFH repair fitting recommended	Level of restoration
Up to 25 % of number of wires in outer layer**	support point & in span	Line guards (sometimes referred to as *patch rods* when installed in span) See Section 9.15.7.1	AAC or ASC, AAAC or AASC, ACSR, AACSR, ACAR: Restore 100 % of RTS and electrical properties
25% up to 50 % of number of wires in outer layer**	support point & in span	Armour rods See Section 9.15.7.1	AAC or ASC, AAAC or AASC, ACSR, AACSR, ACAR and galvanized or aluminium-clad steel: Restore 100 % of RTS and electrical properties
	in span	Line splices (or FFH conductor splice) See Section 9.15.7.1	AAC or ASC, AAAC or AASC, ACAR and galvanized or aluminium-clad steel: Restore 100 % of RTS and electrical properties
Up to 100 % of complete aluminium or aluminium alloy section**	support point	Armour splice (or FFH repair sleeve) See Section 9.15.7.1	ACSR, AACSR: Restore 100 % of electrical properties. Restore 100 % of RTS if the steel core is intact.
Up to 100 % of complete section of conductor, including steel core	in span	FFH Full tension splice See Section 9.15.7.1	ACSR, AACSR: Restore 100 % of SMFL/RTS and electrical conductivity.

* Total number of aluminium or aluminium alloy wires damaged in ALL of the conductor's layers

** ACSR/AACSR steel core must be intact

As FFH repair fittings are intended to restore the mechanical strength of a damaged conductor, their lay direction should be the same as the lay direction of the wire layer on which the fitting is applied.

Proper size selection of the fitting is critical, and should be made in accordance with the manufacturer's recommendation, based on the conductor size, type and stranding. The recommendations of Table 9.5 assume that the FFH fittings applied are properly designed and tested.

The FFH fitting should be made of a similar metal as the conductor or ground wire it is applied to, in order to avoid electro-chemical corrosion. Table 9.5 shows the different material combinations that are acceptable.

As shown in Table 9.5, the preferred solution in all circumstances is to apply FFH fittings of the same material as the wires on which it is applied. Other combinations described as acceptable in the above table have been used with success in the past, but should be carefully analysed on a case by case basis when chosen as an option.

Table 9.5 Selection of FFH material with respect to conductor/ground wire material

		Conductor material (layer on which the FFH is applied)			
		Aluminium/ Aluminium alloy	Aluminium-clad steel	Galvanized steel	Copper/ Copper-clad steel
FFH material	Aluminium alloy	**Preferred**	Electrical continuity only	Not recommended	AVOID
	Aluminium-clad steel	Not on AC energized conductor	**Preferred**	Acceptable	AVOID
	Galvanized steel	Not recommended	Not recommended	**Preferred**	Not on AC energized conductor
	Copper-clad steel	AVOID	AVOID	Not recommended	Preferred

FFH repair fittings are generally supplied with refaced or ball ended finish (see Figure 9.136), depending on the rod diameter used to make the product. This type of end finish is intended for sub-EHV applications - less than 345 kV. For EHV applications, a “parrot bill” finish is recommended to meet Corona and RIV requirements.

Line Guards

Line guards can be used for conductor repair at support points or in span (often referred to as patch rods when used in span). In both cases, they will restore 100 % of the mechanical strength (RTS) and electrical conductivity of a damaged conductor as long as the total number of strands in the conductor does not exceed 25 % of the number of strands in the outer layer. In ACSR, the steel core must be intact in order to restore mechanical strength of the conductor (Figure 9.137).

Armour Rods

Armour Rods are intended for use to protect an undamaged conductor at a support point. They can also be used in span or at support points for conductor repair, restoring 100 % of the mechanical and electrical integrity of a damaged conductor as long as the total number of strands damaged in the conductor does not exceed 50 % of the number of strands in the conductor’s outer layer. In ACSR, the steel core must be intact (Figure 9.138).

Helical Splice

Helical splices are used to repair conductors when the damage level exceeds 50 % of the outer layer strands. As opposed to armour rods and line guards, where a set is composed of separate helical rods, helical splice sets are generally supplied with single rods glued into subgroups with conductive grit applied to the inner surface.

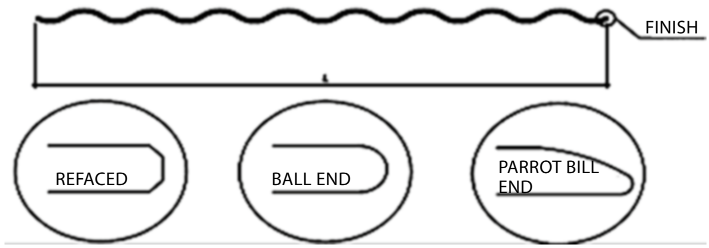


Figure 9.136 FFH end finishes (Courtesy of Saprem).

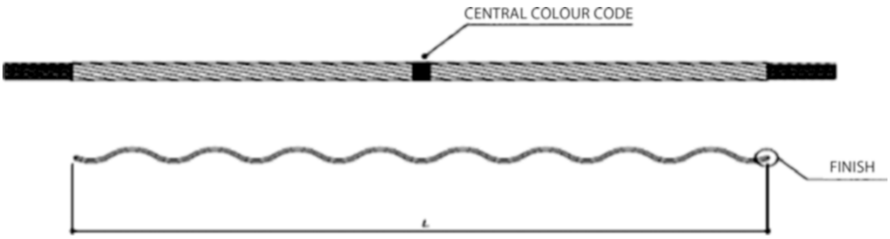


Figure 9.137 Line Guards (Courtesy of Saprem).

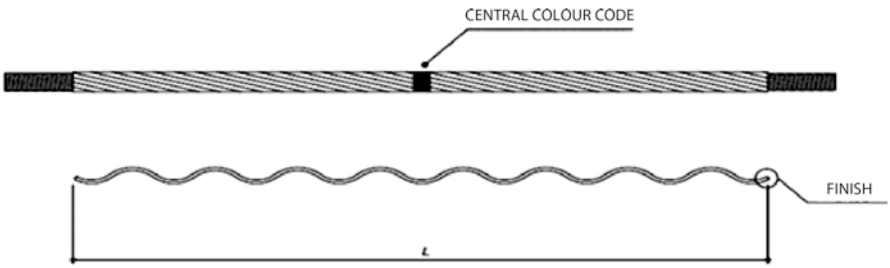


Figure 9.138 Armour Rods (Courtesy of Saprem).

Conductor Splice (Line Splice)

Conductor splices are designed as a single component splice to perform conductor repair in the mid-span area.

Conductor splices will restore the original electrical properties of all conductor types, and the mechanical strength of all homogeneous conductors, regardless of the severity of the damage. For composite conductors, such as ACSR and AACSR, only the strength of the aluminium portion will be restored, which means that in order to restore 100 % of the conductor's RTS, the steel core has to be intact (Figure 9.139).

Figure 9.139 Conductor/Line Splice (Courtesy of Saprem).

Figure 9.140 Armour Splice (Courtesy of Saprem).

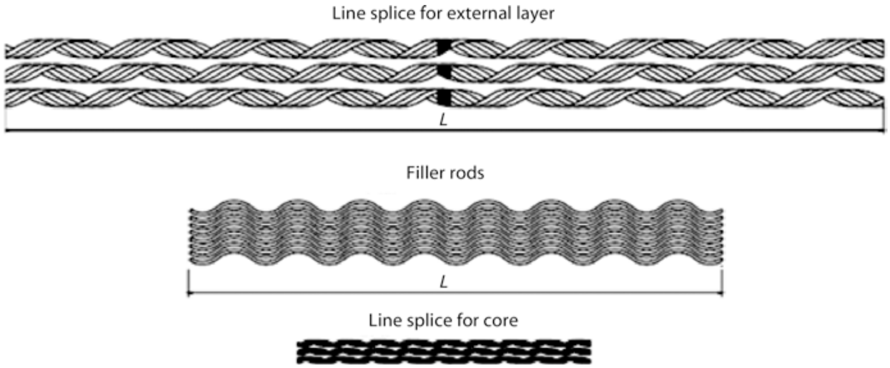


Figure 9.141 Full Tension Splice (Courtesy of Saprem).

Armour Splice (FFH Repair Sleeve)

Repair sleeves use a design similar to conductor splices, but are intended for conductor repair at support points. The repair sleeve should be considered when damage occurs in the support area or where installation would place the ends of the repair rods too close to existing armor rods.

Armour splices will restore the original electrical properties of all conductors types, and the mechanical strength of all homogeneous conductors, regardless of the severity of the damage. For composite conductors, such as ACSR and AACSR, only the strength of the aluminium portion will be restored, which means that in order to restore 100 % of the conductor's RTS, the steel core has to be intact (Figure 9.140).

ACSR Full Tension Splice

This product is recommended when damage to the inner core is suspected. This type of FFH fitting is designed as a three-component assembly as shown in Figure 9.141, and is intended to be used for mid-span repairs.

Full tension splices are made of three components:

- Core/Line splice for the repair of the steel core
- Filler rods, placed over the core splice rods to re-establish the original outside diameter of the conductor
- Outer/Line splice to be applied over the external layer of aluminium wires.

When used, Full Tension Splices will restore the original electrical and mechanical properties of composite conductors, regardless of the amount of damage to the core or envelope.

9.15.7.2 Application Guidelines

Conductor Preparation and Installation Procedure for Single Component Fittings

The following application steps should be followed when using line guards, armour rods, conductor splices, repair sleeves and OPGW repair splices:

- Thoroughly wire-brush the damaged conductor over the full length of the area to be covered by the device.
- Apply a gritted inhibitor to the full length of the area before applying the splice.
- Follow the standard application procedures provided by the FFH fittings manufacturer.

The brushing of the conductor is intended to remove the oxide layers at the interfacing surfaces, and is critical for the full restoration of electrical performance.

All FFH repair fittings are intended for a single-use application, and should only be used for that specific application. These products should not be reused or modified under any circumstances.

When line guards and armour rods have been applied, there should be a slight gap between the rods. Figure 9.142 shows examples of good and bad practices in that regard.

Conductor Preparation and Installation Procedure – ACSR Full Tension Splice

The following application steps should be followed when using FFH full tension splices for repair applications.

- Thoroughly wire-brush the damaged conductor over the full length of the conductor to be covered by the full tension splice.
- Apply a gritted inhibitor to the full length of the area before applying the full tension splice.

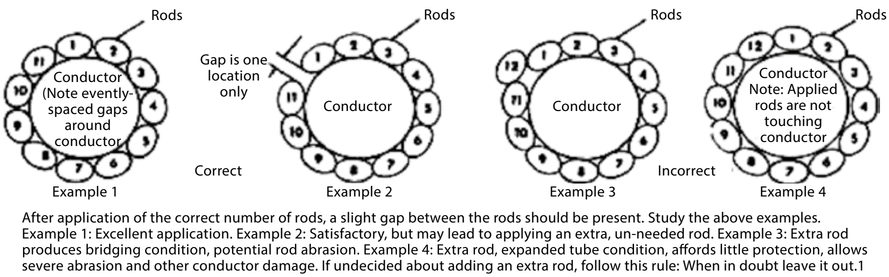


Figure 9.142 Examples of good vs. bad practice for the application of line guards and armour rods (Courtesy of Preformed Line Products Co.).

Follow the standard application procedure provided by the FFH manufacturer to install the full tension splice, as outlined in Figure 9.143.

Location of FFH Repair Fittings along the Conductor

The correct positioning of FFH fittings is essential to its performance and to avoid causing further damage to the conductor.

When installed a certain distance from any other fitting, the FFH repair fitting should be applied in the centre of the damaged area.

To avoid excessive discontinuities in the bending stiffness of the conductor/FFH assembly, a minimum distance of 500 mm should be kept between the rod ends and existing clamps or rods. Please see Figure 9.144.

When the condition illustrated in Figure 9.144 cannot be respected, an alternative solution must be used. Sometimes a conductor splice may be replaced by an armour splice (see Section 15.7.1.3.2); but in some cases, a tailored solution might be required.

In any case, the application of FFH repair fittings at support points requires careful planning. For example, installation of Line guards, Armour rods or Repair sleeves will in most cases require a larger suspension clamp to accommodate the increased diameter. In other cases a tailored solution will be needed. If vibration dampers need to be moved from their original position, a careful review of the damping performance of the new configuration should be performed.

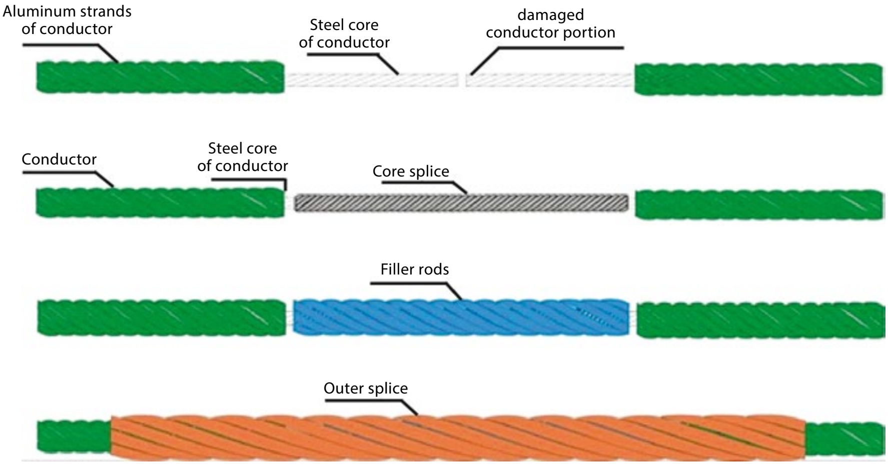


Figure 9.143 Installation of full tension conductor splice (Courtesy of RIBE Electrical Fittings).

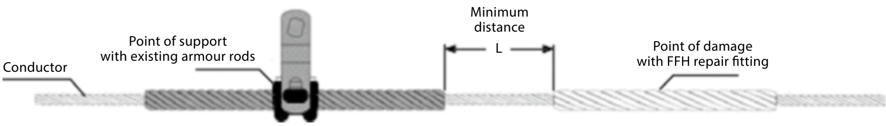


Figure 9.144 Placement of FFH repair fitting close to a support point (Courtesy of RIBE Electrical Fittings).

9.15.8 Conductor Repair Using HCI Fittings

A hydraulic compression or implosive (HCI) fitting is made of a round tube, generally in aluminium, which is installed on the conductor by being radially compressed, using either a die and hydraulic pressure or explosive charges. This important deformation of the tube creates a permanent, strong electrical and mechanical bond with the conductor.

The installation of most HCI fittings – except repair sleeves – requires to cut the conductor at the damage location. This operation, along with other procedures to install the fitting, will reduce the conductor length, which need to be compensated either by using a splice with an appropriate length, or using a combination of two splices with an additional length of conductor.

9.15.8.1 Hydraulic Compression Fittings

Types of Fitting

A thorough assessment of conductor damage is necessary before choosing the proper Hydraulic Compression (HC) fitting. The HC fitting should be chosen to ensure a full restoration of the mechanical and electrical integrity of the system.

Table 9.6 and the following sections present different types of HC products available for various degrees of damage.

Proper size selection of the fitting is critical, and should be made following the manufacturer's recommendation, based on the conductor size, type and stranding. Consult with manufacturer for application of trapezoidal wire constructions. Crimping die must be approved by the manufacturer.

For applications above 230 kV, it is imperative not to nick or scratch the aluminium body of the HCI fitting. Special care must be used at the end tapers.

Repair Sleeve

Repair sleeve can be used for conductor repair of minor damages in span. They will restore 100 % of the mechanical strength (RTS) and electrical conductivity of a damaged conductor as long as the damage to the conductor does not exceed % of the outer strand layer as specified by the manufacturer. In ACSR, the steel core must be intact to allow the restoration of the conductor's mechanical strength. For smaller conductors, single U-shaped repair sleeves are available. For larger conductors, typical repair sleeves consist of two-piece interlocking elements (semi-circular) which slide/mate together during assembly (Figures 9.145 and 9.146).

Full tension Splice

Full tension splices are intended for conductor repair of significant damages at suspension support points or in span. Depending on the length of the conductor for in span repairs, use the following: a full tension splice (standard length) or a special splice of applicable length or a second splice with a section of new conductor. Repairs at suspension support points will require two full tension splices with a section of new conductor (Table 9.7 and Figures 9.147 and 9.148).

Table 9.6 Type of HC fittings with respect to observed level of damage

Number of damaged wires observed	Location of damage	Type of hydraulic compression fitting recommended	Level of restoration
Minimum damage up to % of outer layer wires*	In span	Repair Sleeve	AAC or ASC, AAAC or AASC, ACSR, AACSR, ACAR: Restore 100 % of RTS and original electrical conductivity
Significant damage (up to complete section of conductor, including steel core)	In span	Full tension splice (standard length) or Full tension splices (2) and a suitable length of conductor or Longer full tension splice (length appropriate for the repair)	AAC or ASC, AAAC or AASC, ACSR, AACSR, ACAR and galvanized or aluminium-clad steel: Restore 100 % of RTS and original electrical conductivity
Any damage (up to complete section of conductor, including steel core)	At deadend	Full tension deadend (standard length) or Full tension deadend (standard length) and full tension splice and a suitable length of conductor or Longer full tension deadend (length appropriate for the repair)	AAC or ASC, AAAC or AASC, ACSR, AACSR, ACAR and galvanized or aluminiumclad steel: Restore 100 % of RTS and original electrical conductivity
Any damage (up to complete section of conductor, including steel core)	At suspension	Full tension splices (2) and a suitable length of conductor	AAC or ASC, AAAC or AASC, ACSR, AACSR, ACAR and galvanized or aluminiumclad steel: Restore 100 % of RTS and original electrical conductivity

* manufacturer's recommendation for % of damaged outer layer wire

Figure 9.145 U-shaped repair sleeve for smaller conductors (Courtesy of Burndy).

Figure 9.146 Repair sleeve with two-piece interlocking elements (Courtesy of Burndy).

Table 9.7 Type of full tension splice with respect to conductor type

Type of full tension splice	Conductor Type
Single sleeve/tube (material to match or be compatible with the conductor)	AAC or ASC, AAAC or AASC, ACAR, ACSR (single steel stranded core), galvanized or aluminium-clad steel
Aluminium sleeve/tube and steel sleeve/tube	ACSR (single and multi-steel stranded core)

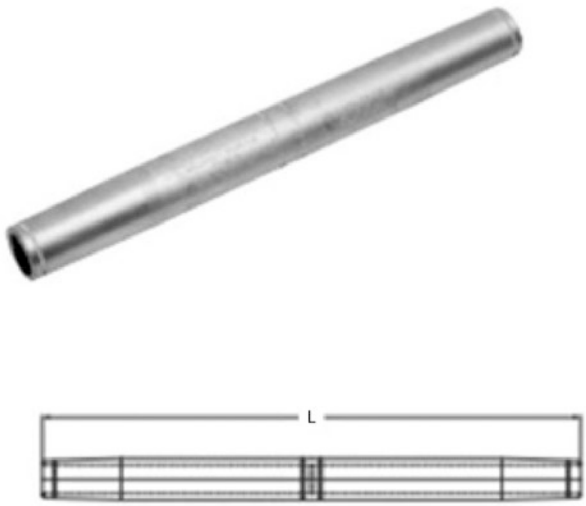


Figure 9.147 Full tension splice with single sleeve for homogeneous conductors (Courtesy of Burndy).

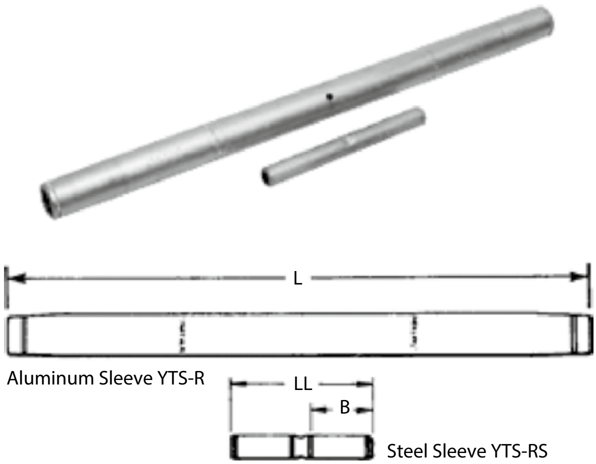


Figure 9.148 Full tension splice with an aluminium sleeve and steel sleeve for ACSR applications (Courtesy of Burndy).

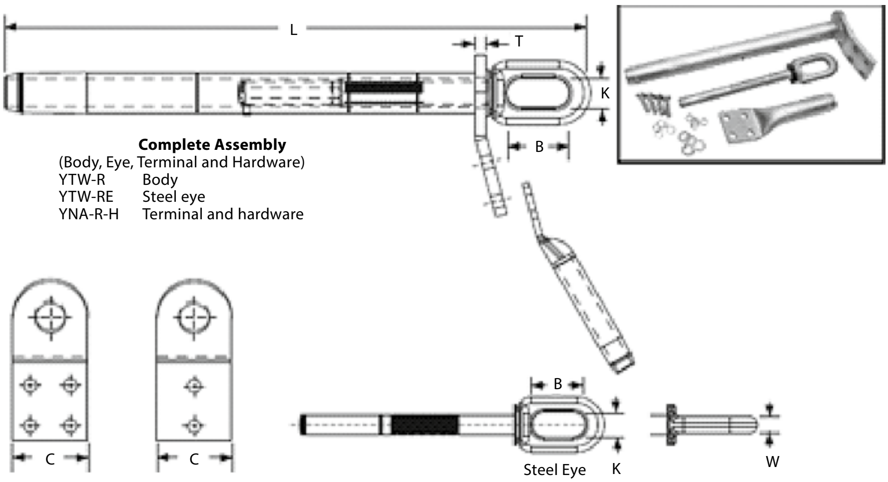


Figure 9.149 Full tension deadend onsisting of an aluminium sleeve with welded pad and steel eye or clevis for AAC or ASC, AAAC or AASC, ACAR, ACSR applications (Courtesy of Burndy).

Full Tension Dead-End

Full tension dead-ends are intended for conductor repair at dead-end support. A special dead-end of suitable length or a splice with a section of new conductor will be required for repairs (Table 9.7 and Figure 9.149).

9.15.8.2 Implosive Fittings

Background of Technology

Implosive fittings are commonly used in the Nordic countries and in North America. The implosive fitting was invented end of 1960 and has been widely used with good service experience. The fitting consist of an aluminium tube with a solid steel bolt (Table 9.8).

Table 9.8 Type of full tension dead-end with respect to conductor type

Type of full tension splice	Conductor Type
Steel eyebolt or clevis	galvanized or aluminium-clad steel
Aluminium sleeve/tube with welded pad and steel eyebolt or clevis. The steel eyebolt or clevis is not crimped onto the steel core of the ACSR.	AAC or ASC, AAAC or AASC, ACAR, ACSR (single steel stranded core)
Aluminium sleeve/tube with welded pad and steel eyebolt or clevis. The steel eyebolt or clevis must be crimped onto the steel core.	ACSR (single and multi steel stranded core)

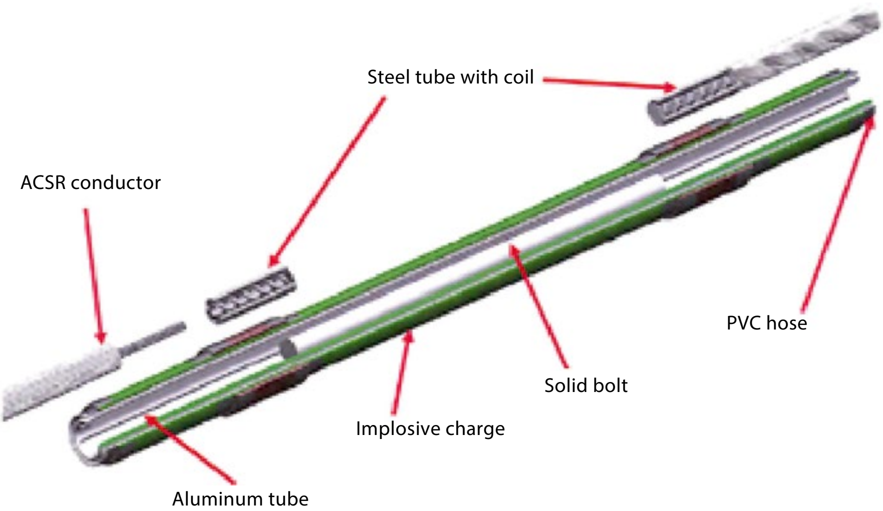


Figure 9.150 Full tension implosive repair joint for ACSR.

As opposed to HC fittings described in the preceding section, implosive connectors utilize the energy in a small implosive charge to compress the aluminium sleeve with only radial deformations to the conductor, rather than mechanical compression using hydraulic equipment. The aluminium tube is wrapped with a detonating fuse, which must have the correct amount of implosive to obtain the required connection after installation.

As with HC fittings, implosive fitting should be selected to fully restore the mechanical and electrical integrity of the system (Figures 9.150 and 9.151).

Installation of implosive fittings does not require heavy equipment and is therefore advantageous in remote areas where transportation of heavy compression tools can be an issue. The installation can be performed rapidly and with very good quality.

Since the implosive fitting consist of explosives, it is necessary to handle the fittings according to national regulations. Installation of implosive fittings creates considerable noise during detonation and care must therefore be taken to avoid concern from the public or to disturb local wild life.

Figure 9.151 Detonation of an implosive joint during installation.

Figure 9.152 Implosive repair sleeve (Courtesy VP metall).

Figure 9.153 Implosive full tension splice with extended length for repair purposes (Courtesy VP metall).

Product Range

The different types of HC fittings described in are available on the market as implosive compression fittings and should be selected on the same basis (Figures 9.152 and 9.153).

Handling and Storage

Correct handling and storage is essential for implosive fittings. In addition to correct handling during installation, it is important that the implosives are handles with care both during transportation and storage. There are national requirement on how implosives shall be transported by truck, and there are also limitations for transportation by air freight.

In most countries, there are requirements for temporary storage on site. The implosive fitting must be stored in an explosive proof container which is safe against theft.

9.15.8.3 Application Guidelines for HCI Fittings

Evaluation of the Condition of an Old Conductor

Cutting out an old fitting should always be done at least 10 cm from the end of the aluminium tube. After having removed the aluminium strands, check the conductor visually:

For any sign of corrosion on the aluminium strands (white powder between the strands), more conductor has to be cut out, or this powder must be removed and the aluminium strands must be brushed in the area that will fit into the fitting.

For any sign of corrosion on the visible steel (red/brown spots), more conductor needs to be cut out. There must be no signs of corrosion on the steel that will fit into the fitting.

If the old fitting was sloped, the end that points upwards is most disposed to corrosion.

For obvious signs of overheating on the old fitting more conductor length needs to be cut out. Signs of considerable overheating include dark color on the conductor, sliding or burnt strands.

If the conductor contains old filling compound from the old joint, this part has to be cut away.

On old conductors where the steel core is greased, this grease may spread to the aluminium strands. If so, contact the constructor.

If the part that has to be cut out of the old joint is so long that a repair joint may not be used, at least 30 meter of new conductor has to be used, centered onto the old joint.

If there are any corrosion further out on the conductor, consider changing the whole section of conductor instead of just the joints.

Conductor Preparation for Installation

Every conductor with an outer layer of aluminium will have an oxide coating. The thickness and insulating property of this layer is dependent on how old the conductor is, and the climate it has been exposed to.

The conductor ends must always be brushed before installation of implosive fittings on an old conductor (not necessary on a conductor recently delivered from factory). All the length that is to go into the connector must be brushed.

It is important that the brushing is done in a dry environment. The brush must be rust proof. The brushing must be done along the strands. In that way a larger part of the strand surface is cleaned, and no particles will be left between the strands. A rust proof circular brush on a drill is proven to give the best result. (e.g. 75 mm diameter with a 0.25-0.35 mm twisted thread). The brushing of the conductor is intended to remove the oxide layers at the interfacing surfaces, and is critical for the full restoration of electrical performance.

Check that the correct fitting is used. Check that all fitting components are clean and dry before installation. The conductor must be cleaned before installation. Water, ice, snow, and dirt must be removed. Dry the conductor and the steel core with a suitable rag or twist.

It is of utmost importance that the fitting is correctly installed. Inaccuracy may cause reduced gripping length, and reduced holding strength.

Application Procedure for Hydraulic Compression Fittings

The following figures present the principal steps for the installation of different types of hydraulic compression fittings. The crimping dies prescribed by the HC fitting manufacturer should always be used (Figures 9.154, 9.155, and 9.156).

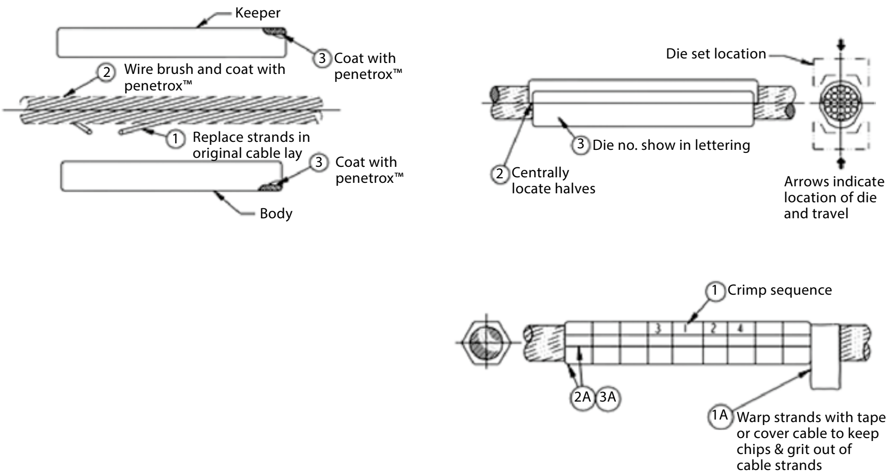


Figure 9.154 Typical installation of a repair sleeve – clockwise from *top left* (Courtesy of Burndy).

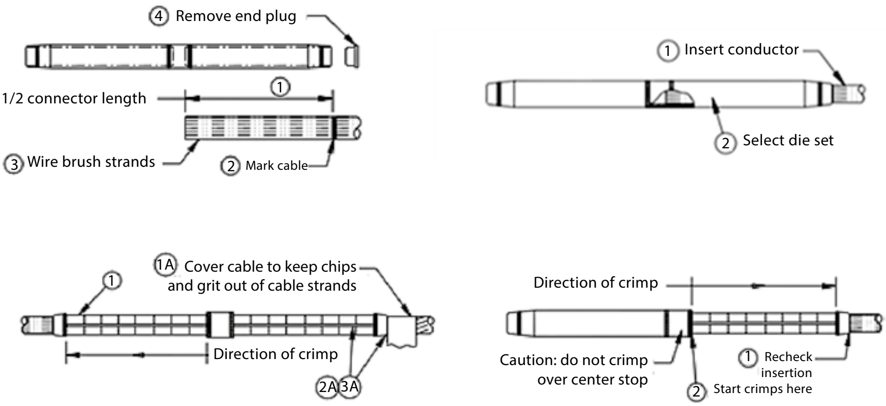


Figure 9.155 Typical installation of a single component full tension splice – clockwise from *top left* (Courtesy of Burndy).

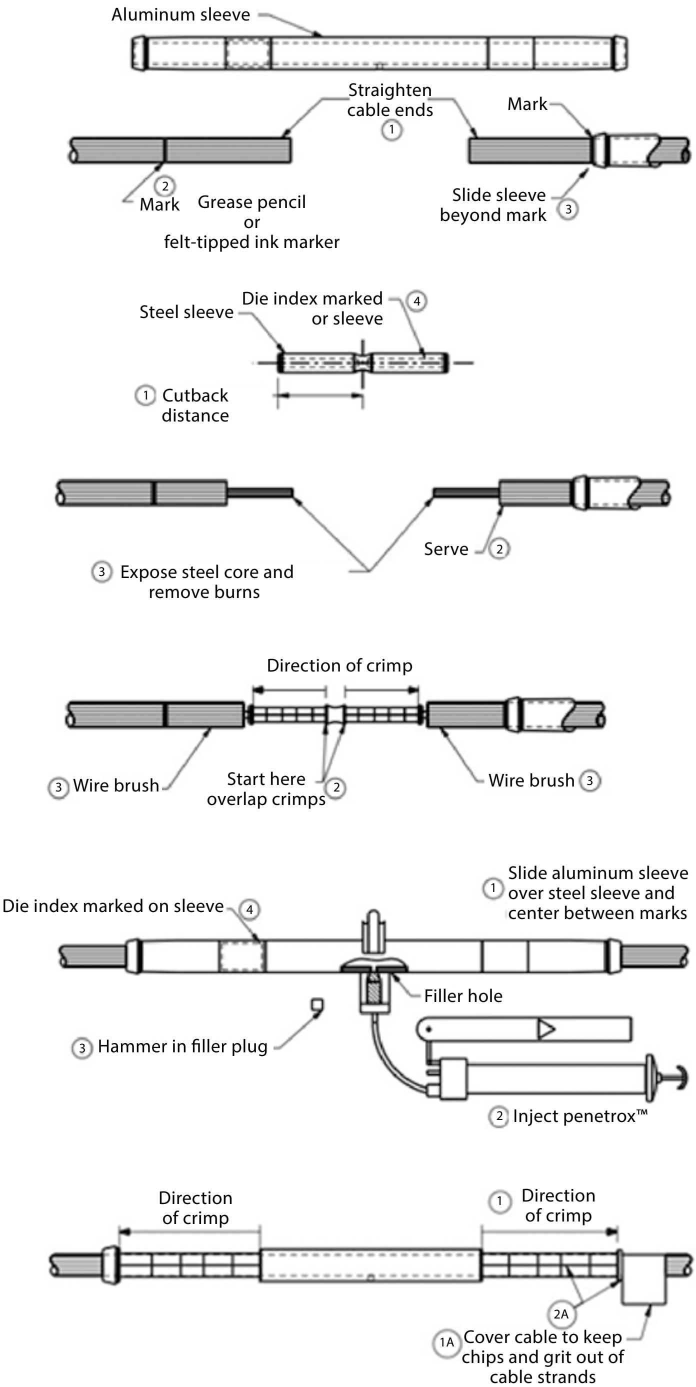


Figure 9.156 Typical installation of full tension deadend without and with crimping the steel eyebolt onto the steel core for ACSR – clockwise from *top left* (Courtesy of Burndy).

Application Procedure for Implosive Fittings

Installation crew using implosive fittings should be thoroughly trained and instructed on how to handle explosives. The user must comply with local laws and regulations pertaining to transportation, handling, storage and use of explosives. A responsible person must ensure that all safety regulations are adhered to and that the site of detonation is properly secured.

The explosive is a detonating cord. It is very stable and may be stored for an extended period of time. The fittings may be fired at temperatures between +60° and −30 °C.

The time fuse must be dry and without kinks or bends and must not be damaged. The fuse length should be a minimum of 100 cm with a burn rate of 105 to 130 s/m, which should give the personnel involved enough time to reach safety. The burn rate should be verified for new and different types of time fuse.

The blasting cap is sensitive to impact and heat and must be handled with care. Follow supplier recommendations.

No personal should be closer than 50 m to the fitting at the time of detonation.

The connectors are used on dry conductor, fully greased aluminium alloy conductors and ACSR with fully greased steel core. In rainy conditions measures have to be taken to avoid water inserting into the compression area.

If greased conductor is used, remove excess grease from the conductor surface and from the steel core. Grease or other type filler compound must not be applied to the fitting components or conductor before installation.

Detonation

Check that the explosive is tight around the main sleeve. Put the conductor ends, connected with the joint, on the rack, at about 1 meter above the ground. A simple wooden rack may be used. Mark the conductor at the sleeve extremities.

Tape the detonator to the explosive charge. Check that the detonator is placed correctly, parallel to the conductor, and taped tight against the explosive.

After detonation remove remains of the PVC hose, and the joint is finished. Check the marks to make sure that the conductor did not slide out (Figures 9.157 and 9.158).

Installation in Extremely Dry Conditions

Under extremely dry conditions the development of hot gases and remnants of the time fuse may at the moment of detonation, ignite grass or dry vegetation under the

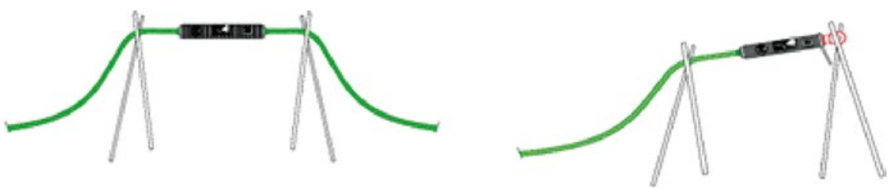


Figure 9.157 Rack used for installation of implosive fitting from the ground (Courtesy of VP metall).

Figure 9.158 Full tension implosive joint before and after detonation (Courtesy of VP metall).

firing rack. The site should be secured against fire hazard by removal of dry grass or vegetation or by soaking the site with water. The safety fuse should be tied to the rack so the remnants of the glowing fuse may easily be located. A fire extinguisher should be readily available at the site.

Installation in Rainy Weather

A sloping conductor may provide a path for water both on the outside and between the strands. Therefore, always elevate the joints and tilt the dead-ends such that water will run away from the fitting during installation. Water must, not under any circumstances, be allowed to collect inside the fitting during installation!

9.15.9 Other Types of Repair

9.15.9.1 Repair of Conductors and HCI Fittings with Bolted Shunts

A significant advantage of Bolted Shunts, due to their compact design, is the ability to utilize several installation methods, including hot-sticks, gloves, or barehanded on energized lines; from distribution class voltages through EHV without the requirement of an outage (Figures 9.159, 9.160, and 9.161).

9.15.9.2 Repair of HCI Fittings with FFH Fittings

FFH compression splice shunts are designed to restore complete electrical conductivity and a portion of the mechanical strength to HCI splices that are found to be excessively hot during thermal line inspections. The splice shunt is applied directly over the compression splice and over the conductor for some distance on either side of the splice (Figure 9.162).

Mechanically, the splice shunt is designed to restore 100 % of the strength of the aluminium strands of ACSR and 10 % or more of the strength of the steel core. 100 % of the mechanical strength is restored for AAC or ASC and AAAC or AASC conductors. The design of the compression splice shunt will be in accordance with the dimensions of the compression splice (diameter and length), and is generally available as a tailored solution to specific applications.

FFH shunts are also available for compression dead-ends, as shown in Figure 9.163.

Figure 9.159 Various types of bolted shunts, for installation at a compression dead-end, at a compression splice or at a suspension clamp (Courtesy of Classic Connectors).

Figure 9.160 Installation of a bolted shunt on an energized line using hot sticks.

Figure 9.161 Installation of bolted shunts on an energized line using barehanded methods.

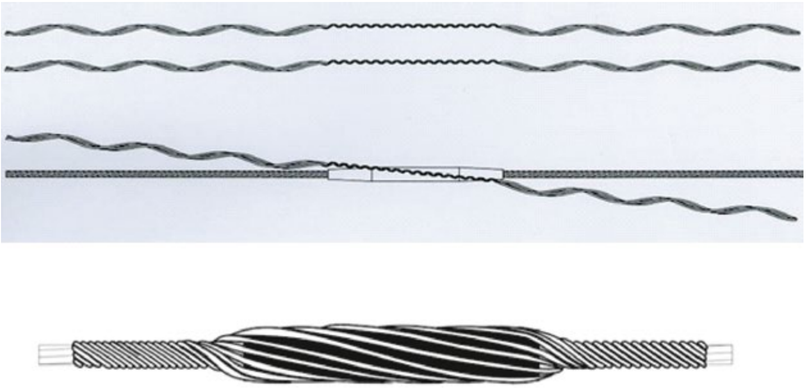


Figure 9.162 Various designs of splice shunt.

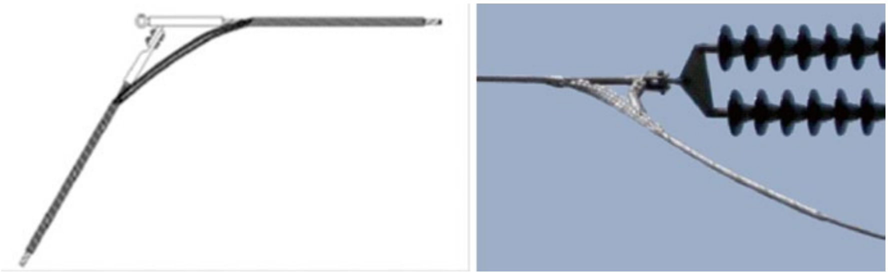


Figure 9.163 FFH dead-end shunt.

9.16 Highlights

Most fittings look like very simple piece of metal easy to manufacture and put on the market. However, without the proper design and precautions, inadequate fittings may be installed on lines with consequences that will be much more expensive than the simple cost of the improper fitting.

This chapter has shown that the knowledge to produce good quality fittings is available. For example, many tests have been devised and are available to validate that overhead line fittings will work adequately. Moreover, fittings and conductors work as a system and it is imperative to make sure that there won't be any inadequacy whether from material or design incompatibility as explained.

Many fittings such as suspension clamps, dampers, spacer and spacer-dampers, connections, aerial wire markers, joints and fittings for conductor repair have been described in details. Moreover, a lot of field experience has been detailed regarding those specific fittings in order to illustrate how to design and use them.

Finally, the last section explains how to repair conductors depending on how severely it has been damaged.

9.17 Outlook

The world of transmission line is seen as being very conservative. However, in recent years, there has been an increasing use of non-conventional conductors to reduce drag force, increase ampacity, reduce the sag and/or increase the span lengths, etc. Some of those conductors are believed to be less rugged than conventional conductors and more performing fittings have been and are still developed to fulfill the new requirements.

Acknowledgement The initial work of Wolfgang Troppauer and the final review of content and language by Jean-Marie Asselin are gratefully acknowledged.

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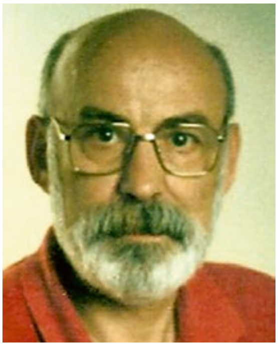
Pierre Van Dyke has B.Eng., Master Certificate in Project Management, M.A.Sc. and Ph.D. degrees. He is currently Senior Research Scientist at Hydro-Quebec Research Institute (IREQ) as well as Associate Professor at Sherbrooke University, Associate Professor at Quebec University in Chicoutimi (UQAC), IEEE editor PES Transactions on Power Delivery and Convenor of CIGRE TAG 06 'Mechanical behaviour of conductors and fittings'. He is author or co-author of more than 50 papers and two books. He has designed aeolian vibration dampers, interphase spacers and suspension clamps and performs R&D and consulting on aeolian vibrations, wake-induced oscillations, conductor galloping, and climatic loads on overhead transmission lines using a full scale test line, a laboratory test span, and fatigue test spans among other facilities.



Umberto Cosmai is an international independent consultant with more than 50 years of experience in overhead transmission lines. He worked for ENEL as laboratory engineer and researcher, then he joined the company DAMP, as technical director. He performed educational activity and authored several national and international papers and three books. He also co-authored the book titled "Wind Induced Conductor Motion" edited by EPRI Palo Alto CA (USA). He presented seminars on overhead conductor vibrations and performed field vibration measurements in 30 Countries worldwide. He is chairman of Cigré WG B2.25. In 2012, he received the Cigré Technical Committee Award.

Christian Freismuth has B.Eng. and M.A. degrees. He is working at Mosdorfer Ges.M.B.H where he holds the position of Application and Development Engineer where he does consulting, design and calculation of vibration protection systems for conductors and performs type tests on fittings and strings. He is also member of Cigré B2 and of the National Committee for Overhead Transmission line OVE.

Conductor Motions

10

Umberto Cosmai, Pierre Van Dyke, Laura Mazzola, and Jean-Louis Lillien

Contents

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U. Cosmai (✉)
Orino, Italy
E-mail: covis@iol.it

P. Van Dyke
Varennes, Canada
E-mail: vandyke.pierre@ireq.ca.com

Laura Mazzola • Jean-Louis Lillien

K.O. Papailiou (ed.), *Overhead Lines*, CIGRE Green Books,
DOI 10.1007/978-3-319-31747-2_10

10.1 Summary

Overhead line conductors are subjected to sustained and not sustained motions. The former are cyclic mechanical vibration and oscillations which derive their energy from wind forces applied to conductors. The latter are transient motions due to several different causes.

Conductor motions have important implications for the design, security, maintenance and service life of overhead line conductor systems and, in some cases, even the supporting towers. While with careful design the adverse effect of most of them can be avoided or minimized, some, in particular galloping, do not yet have operationally-acceptable solutions which cover all the circumstances (Tunstall 1997).

Reliable transmission line design requires that sustained and not sustained conductor motions are controlled below critical levels to avoid fatigue damage and other effects that can jeopardize the stability and the integrity of the structures.

The main characteristics and effect of the wind induced conductor motions are described in Section 10.3.1.

The phenomenon of vortex shedding which causes aeolian vibration is illustrated in Section 10.3.2.1 and the evaluation criterion of vibration levels based on the Energy Balance Principle, in Section 10.3.2.2. The wind characteristics and the relevant terrain influence on the energy transferred to the conductors are duly analyzed in Section 10.3.2.3. Conductor self-damping and fatigue endurance play an important role in the definition of the dynamic behaviour of the conductors. For this reason, the state of the art for determining these conductor characteristics through laboratory tests is examined in details in Sections 10.3.2.4 and 10.3.2.7. The effect of tension on conductor vibration behaviour and the Cigré studies on safe design tension are documented in Section 10.3.2.5. Section 10.3.2.6 deals with the calculation of the vibration levels considering the wind power function in turbulent regimes and the variation of conductor tension. The performance of the additional damping devices usually installed on single and bundled conductors is evaluated in Sections 10.3.2.8 to 10.3.2.11.

The modern methods to assess the vibration severity of overhead conductors at the design stage, as well as before commissioning and during the service life of the line are described and discussed in Section 10.3.2.12.

Section 10.3.3 takes into consideration oscillation phenomena typical of bundled conductors known with the collective term of “wake induced oscillations” and, in particular, subspan oscillation that is the most potentially dangerous between them.

The mechanism of conductor galloping generated by strong wind on iced conductors is illustrated in Section 10.3.4; the effects on transmission line structures and the various mitigation methods and devices are also evaluated.

Non sustained motions, that can influence the design and the performance of transmission lines, are briefly considered in Section 10.4.

Cigré Study Committee 22 and successively Study Committee B2 have been very active in the field of conductor motions. A remarkable number of documents have been published and most of them have been consulted for the preparation of this chapter. These documents, listed in Section "References", comprise: 9 Technical Brochures, 13 papers published in Electra, 11 WG reports and 11 papers presented in Cigré general sessions and symposia.

10.2 Symbols and Units

A	forcing point transverse acceleration, peak value (m/s^2)
a_{n}	vibration single amplitude at the nth node (mm)
D,d	diameter of the conductor (m)
d	Diameter of outer layer individual wire (m)
E_a	Modulus of elasticity of outer-layer wire material (N/m^2)
E_W	energy introduced by the wind (Joule)
E_C	energy dissipated by the vibrating conductor (Joule)
E_D	energy dissipated by the damper (Joule)
EI_{min}	sum of individual wires bending stiffness (Nm^2)
F	exciting force, peak value (N)
f	vibration frequency (Hz)
fy_{max}	vibration parameter (m/s)
$fnc(\mathrm{A/D})$	reduced wind power function (Ws^3/m^5)
L	span length (m)
l	subspan length (m)
LD/m	index of span dimension (m^3/kg)
m	conductor mass per unit length (kg/m)
n	number of vibrating loops in the span
n_c	number of vibration cycles
P_W	wind power imparted to a length of conductor (W)
P_C	power dissipated by the conductor (W)
S_C	Scruton number
S_n	inverse standing wave ratio (ISWR) at the nth loop
T,H	conductor tension (N)
V	wind velocity (m/s)
x	bending amplitude measurement arm (m)
y_b	bending amplitude (μm)
Y_{ib}	reversed bending amplitude (μm)
y_{max}	antinode vibration amplitude (mm)
Y_a	antinode single amplitude at the first decay cycle (mm)

Y_n	vibration single amplitude at the nth antinode (mm)
Y_z	antinode single amplitude at the last decay cycle (mm)
$\sqrt{Tm}$	characteristic impedance of the conductor (N s/m)
β	free span vibration angle (rad)
σ_a	bending stress at the clamp mouth (N/mm^2)
δ	logarithmic decrement
ε_a	bending strain at the clamp mouth (microstrain) ($\mu\varepsilon$)
λ	wavelength (m)
$\lambda/2$	loop length (m)
ρ	density (kg/m^3)
θ_a	phase angle between force and acceleration (deg)
ω	circular frequency (rad/s)

10.3 Wind-Induced Conductor Motions

10.3.1 Introduction

Modern structures, exposed to natural wind, can be subjected to severe vibration and oscillation.

If not suitably controlled, these wind-induced motions may have disastrous consequences. One of the classic examples is the collapse of the Tacoma Narrow Bridge in Washington that, in 1940, was completely wrecked by a moderate wind (Den Hartog 1956). Slender, plain structures, with low internal damping, are the most sensitive to wind induced motions. They are, for example: towers, skyscrapers smoke stacks of welded steel, decks and cables of suspension bridges, petrol tanks, guy ropes, stay cables and suspended cables. Constructions of bricks, concrete, riveted steel and bolted steel are less sensitive to wind-induced motions. Overhead transmission lines are the mechanical structures with the greatest extension of slender flexible elements: the conductors being, generally, highly exposed to natural wind. Under the wind action, the conductors can vibrate and oscillate as a result of different types of aerodynamic and aeroelastic instabilities. These motions, if not mitigated within safe limits, can lead to fatigue failures of the conductor strands, damage to other line components and black-out of the lines. Means of controlling or avoiding them have been pursued for many years with varying degrees of success.

Three main categories of cyclic conductor motion are recognized. These are: aeolian vibration, wake induced oscillation and galloping. The typical shape of these motions is illustrated in Figure 10.1.

Observations of actual transmission lines indicate that they occur most frequently and with the greatest severity where the terrain is smooth and the vegetation is low and sparse.

The most direct effect on vibrations by terrain appears to be through the generation of turbulence in the wind striking the conductors. The turbulence has the effect of reducing the coherency of the resulting aerodynamic forces with the general

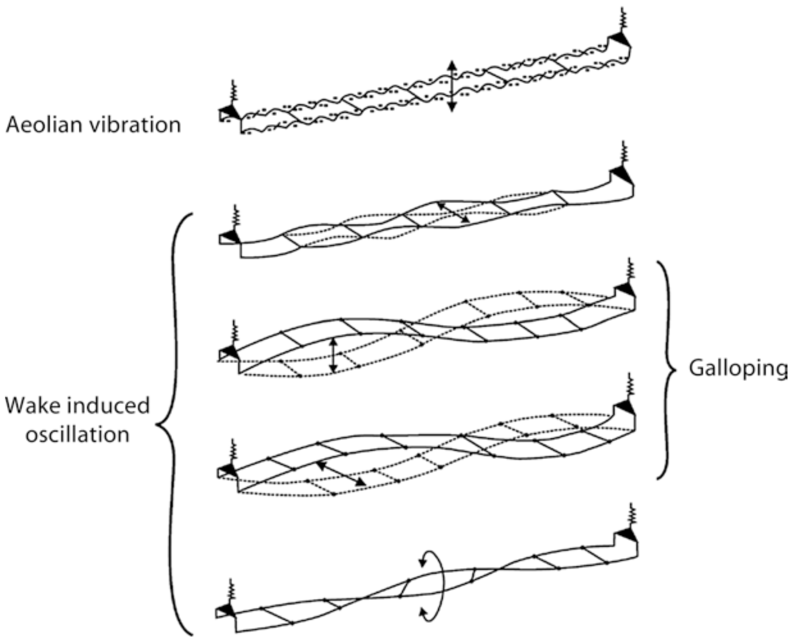


Figure 10.1 Wind-induced conductor motions.

result of reducing the tendency toward instability. Although the levels of all the conductor motions decrease with the increase of the wind turbulence, it has been observed that galloping is the least sensitive to this effect.

10.3.2 Aeolian vibration

Aeolian vibration is a small amplitude and relatively high frequency movement of the conductor induced by the wind and takes its name from the aeolian harp (Figure 10.2), an instrument devised by the ancient civilizations. Rabbinic records report that King David used to hang his harp over his bed where it emitted a melodic chord in the midnight breeze.

It has been known for a long time that the primary cause of aeolian vibrations is the alternate shedding of wind-induced vortices from the top and the bottom of the leeward side of the conductor. This is known as “Von Karman effect” after the scientist who first (1912) developed a theoretical explanation of the phenomenon.

10.3.2.1 Cause and Effects

The detachment of vortices creates an alternating pressure unbalance, which generates forces able to move the conductor up and down at right angles to the direction of air flow (Figure 10.3).

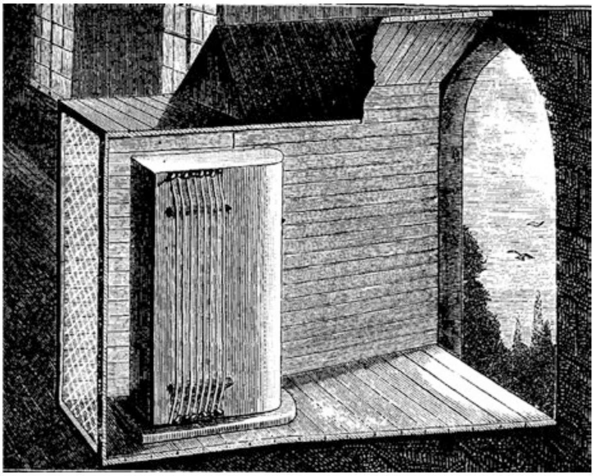


Figure 10.2 Aeolian harp.

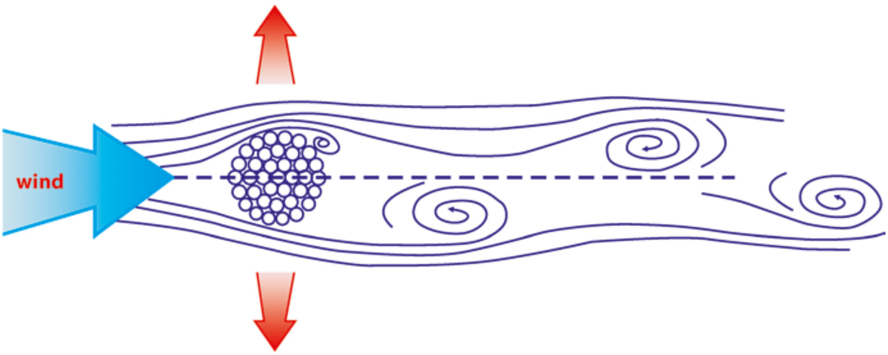


Figure 10.3 Von Karman effect on an overhead conductor.

The frequency of these forces is a function of wind velocity and conductor diameter and when this corresponds approximately to the frequency of a vibration mode of the span, the conductor tends to vibrate with many loops in a vertical plane.

Aeolian vibration is generated by moderate wind in the range 0.8 to 7 m/s. In very flat areas the upper limit can be higher. Typical aeolian vibration frequencies lie between 4 and 120 Hz and the antinode amplitude rarely exceeds the conductor diameter. The frequency is given approximately by the Strouhal formula:

$$f = S\frac{V}{D} \tag{10.1}$$

where

V is the wind velocity (m/s)
D is the conductor diameter (m)
S is the Strouhal Number.

The Strouhal Number varies only slightly within the range of Reynolds numbers typical of transmission line conductors and relevant wind conditions (EPRI 2009). A value of 0.185 is generally considered as a good average value.

Formula (10.1) indicates that the lowest vibration frequencies will be found for large conductor diameters and low wind velocity, whereas the highest vibration frequencies are found for small conductor diameters and relatively high wind velocities.

Once the aeolian vibration has been established at a certain frequency, variations of the wind speed in a relatively large interval (0.9 m/s < V < 1.3 m/s) do not change its value. This is referred as the "locking-in effect" and is due to the fact that, in a certain range of wind speed variation, the conductor is able to synchronize the vortex shedding on the natural frequency at which it is vibrating (Eq. 10.1).

Considering the Strouhal formula and the wind velocities able to excite aeolian vibration, it is possible to define the range of potentially harmful vibration frequencies of any conductor size.

Aeolian vibration takes the form of vibration waves travelling back and forth in a span. Waves travelling in opposite directions superimpose on each other, tending to form standing waves.

A vibrating conductor span contains several, usually many, standing wave loops (Figure 10.1a), with nodes and antinodes, the loop length ranging from below 1 m (high frequency vibration) up to 30 m and more (low frequency vibration). The relationship between frequency and wave length (the loop length is half the wave length) is given by the following formula:

$$f = \frac{1}{\lambda}\sqrt{\frac{T}{m}} \tag{10.2}$$

where

f is the vibration frequency
λ is the wave length (m)
T is the conductor tension (N)
m is the mass per metre of the conductor (kg/m).

The formula (10.2) does not take into account the conductor stiffness but can be considered sufficiently accurate for most of the practical uses.

At the points where the conductor is secured to fittings, that are possible points of reflection of the travelling waves, the bending strain resulting from aeolian vibrations may be sufficiently large to cause fatigue failures of conductor strands. Typical failure locations are: at suspension clamps, deadend clamps, splices, clamps of spacers and vibration dampers, warning devices and anti-galloping devices. Among these locations, the most critical is at the suspension clamp because of its rigidity in the direction of aeolian vibrations (mainly vertical) and the cumulative static stress due to conductor curvature, tensile load and clamping effect. All the other fittings show a certain degree of mobility, at least at low vibration frequencies, but poorly designed units, especially spacers and dampers, may produce strand failures at their location or may fail themselves under vibrations. Strand failures usually occur either in the outer layer where there is contact between conductor and clamps, or in the inner layers at the crossover points of the strands, and sometimes lead to a complete breakage of the conductor.

In overhead conductors, fatigue failure of strands is the most common form of damage resulting from aeolian vibrations. Conductor fatigue may also result from galloping and subspan oscillation, even if this is not the main problem associated with these motions.

Fatigue failures are characterized by transverse fracture planes without deformation of the wire near the fracture area (Figure 10.4).

Another problem related to conductor vibration is the loosening of clamps of fittings such as spacers, dampers, warning devices, etc. Loosening of spacer clamps causes serious damage to the conductor (Figure 10.5). In fact, initially, the movement of the loose clamp causes abrasion on the conductor surface, and then increasing looseness allows hammering between the conductor and the clamp that leads to complete failure of the conductor. Initial loosening is often due to poor control of clamp bolt tightness. Field observations indicate that spacer clamp loosening is mainly produced by subspan oscillation. Loosening of vibration damper clamps is less critical for the integrity of the conductor as it leads only to the progressive slipping of the units along the conductor toward the middle of the span.

Fittings whose natural vibration frequencies fall in the range of conductor vibration frequency can be put in resonance by the conductor vibration, even if it is mitigated by suitable dampers, and may fail due to fatigue (Figure 10.6).

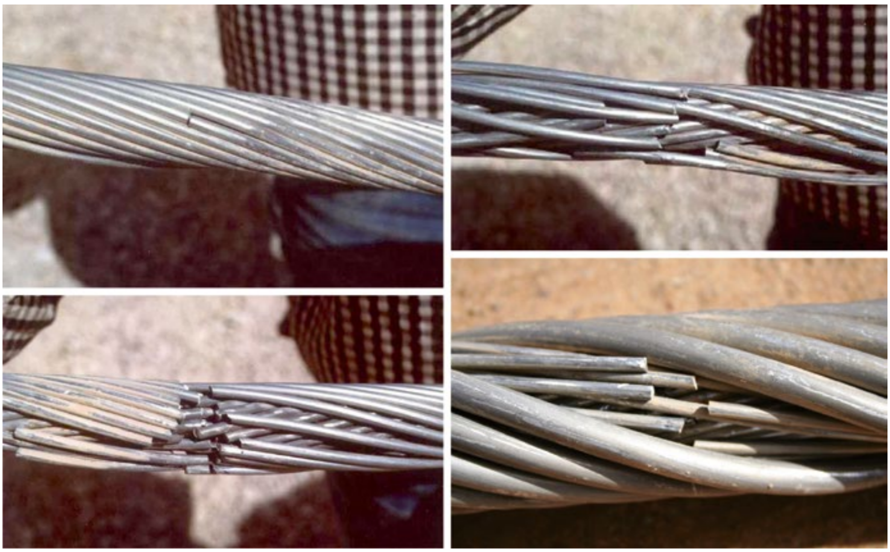
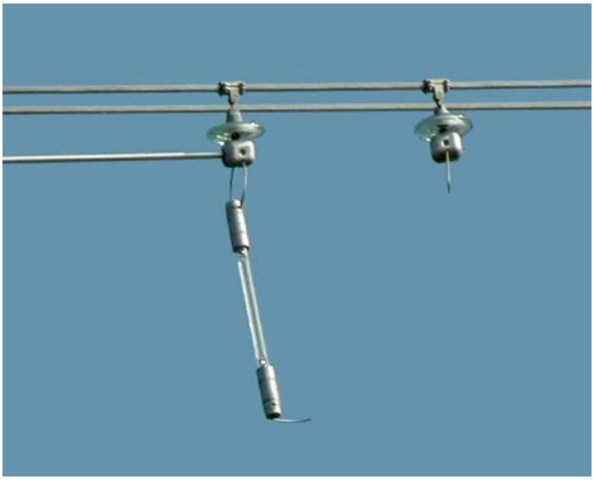


Figure 10.4 Strand failures due to aeolian vibration.

Figure 10.5 Wear and failure of conductor strands due to spacer clamp loosening.

Figure 10.6 Night warning device, with a natural frequency around 20 Hz, broken by fatigue due to conductor vibration.



Bundled conductors are less sensitive to aeolian vibration than single conductors, but still subject to fatigue failures if not protected with an appropriate damping system. Moreover, problems can be accentuated by the presence of a greater number of clamps.

Several methods are commonly used for the assessment of vibration severity on overhead transmission line conductors. A comprehensive review of the assessment methods is given in Section 10.3.2.13.

Aeolian vibration can sometimes affect transmission system components other than conductors and fittings, such as tower members, stay cables, station bus bars, insulator strings and related hardware. Moreover, aeolian vibration may generate acoustic noises.

The levels of conductor vibration may be expressed using different quantities. The most common are:

- The antinodal vibration amplitude y_{max} that is the maximum amplitude of vibration of a free loop in the span (Figure 10.7)
- The free span vibration angle β that is related to y_{max} as follows:

$$\beta = \frac{2\pi}{\lambda} y_{max} = 2\pi \ f y_{max} \sqrt{\frac{m}{T}} \tag{10.3}$$

- The bending amplitude y_b which is conventionally defined as the peak to peak amplitude measured 89 mm from the last point of contact between the conductor and the clamp. In the last decades y_b has played a dominating role as the quantity being recorded in vibration field tests.
- The bending stress σ_a or strain ε_a referred to the outer layer of the conductor, as representative of the stress conditions of the conductor as a whole, although internal stresses may be higher. These quantities have the maximum values at the points where the conductor is secured by fittings especially at span extremities.
- The vibration parameter fy_{max} is the product of the free loop amplitude of vibrations y_{max} by the frequency f. It has been used as a reference parameter for a number of conductor fatigue tests.

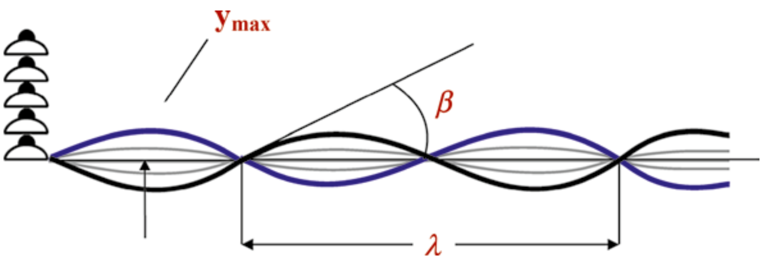


Figure 10.7 Some quantities used to describe aeolian vibration.

10.3.2.2 Energy Balance Principle

At design stage it is of great interest to anticipate the vibration behaviour of the line conductors and shield wires in order to verify the need of additional damping and to define, when necessary, the most suitable damping system to be applied. In a laminar wind and in wind with a given turbulence, the vibration level, of an undamped conductor, can be estimated by using the Energy Balance Principle EBP (Cigré 1998) that is based on the knowledge of:

- Energy E_W (or power P_W) imparted to the conductor by the wind,
- Energy E_C (or power P_C) dissipated by the vibrating conductor.

The EPB can be expressed by the following equation:

$$E_W = E_C \tag{10.4}$$

In most of the transmission lines the conductor self-damping mechanism is insufficient to control the levels of vibration within limits that do not produce accumulation of damaging fatigue cycles. Therefore additional damping elements shall be considered and the EBP equation becomes:

$$E_W = E_C + E_D \tag{10.5}$$

where E_D is the energy dissipated by the dampers. Several damping devices have been developed for single and bundled conductors. They have been presented in Chapter 9.

The EPB works in the frequency domain: in its simplest form, one mode of vibration at a time is considered and the computed steady state solutions corresponding to the maximum vibration amplitude which could be excited on that conductor at that frequency. Transient effects like those due to wind turbulence cannot be taken into account. Some advanced analyses consider the statistical distribution of the wind on the conductor, either in time (Diana et al. 1993) or in the frequency domain (Noiseux et al. 1986; Rawlins 1983). Even if some approximation is present, the straightforward EPB is considered acceptable for engineering applications and a number of computer programs have been written based on, to be implemented on a personal computer.

10.3.2.3 Wind Power Input

Vortex shedding excitation is a very complex aeroelastic phenomenon. Much research has been carried out on the subject, not only in air but also in water and other fluids. Several researchers have been concerned about the wind energy imparted to an overhead conductor and how to obtain quantitative expressions of it. If attention is focused on the energy introduced by a laminar wind to a vibrating conductor model, it is possible to define the maximum wind energy as a function of the non-dimensional amplitude of vibration *A/D* where *A* is the antinode amplitude of vibration and *D* is the conductor diameter. Several empirical functions available in literature have been obtained mainly by means of wind tunnel tests. Most of them can be brought into the form:

$$P_W = f^3 D^4 fnc\left(\frac{A}{D}\right) \tag{10.6}$$

Where

P_W is the wind power imparted to a unit length of conductor (W/m)
f is the vibration frequency related to wind velocity through the Strouhal formula (Hz) fnc(A/D) is the reduced power function (Ws^3/m^5).

Figure 10.8 illustrates some of these functions; the dispersion among the results collected by the various researchers may be due to several causes (Cigré 1998) including: the different characteristics of the wind tunnels, the different test parameters and the use of rigid rods or flexible models to simulate the conductor. The difference in term of maximum non-dimensional amplitude A/D reached by the various researchers in their wind tunnel tests is due to different Scruton numbers used. Scruton number represents the ratio between damping and aerodynamic forces and is defined as $Sc = 4\pi\delta m/\rho D^2$, where δ is the logarithmic decrement, m is the conductor mass per unit length and ρ is the fluid density.

It can be observed that Diana & Falco are the researchers who made the wind tunnel tests, reaching the maximum vibration amplitude ($A/D = 0.8$) attributed to the lowest Scruton number. Transmission line conductors can be characterized by very low Scruton numbers and vibration amplitudes can reach one conductor diameter.

In order to evaluate which of the different wind power input curves best fit reality, comparisons between experimental and theoretical results of aeolian vibration

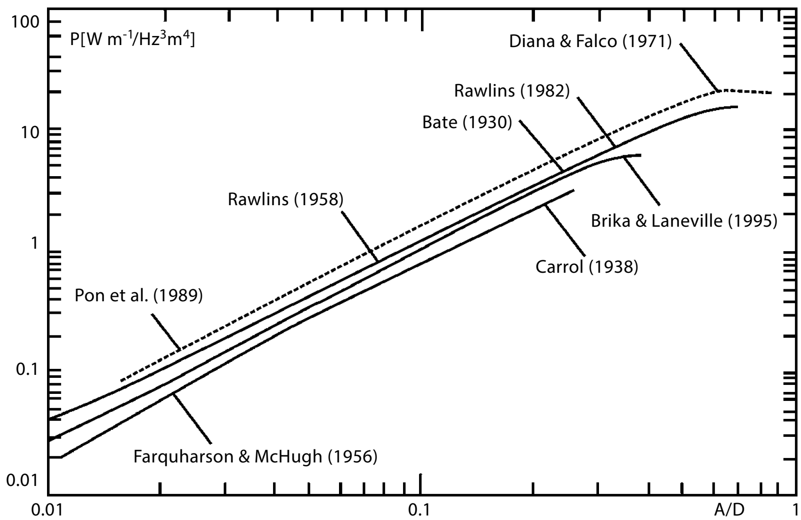


Figure 10.8 Wind power imparted to a vibrating cylinder versus non-dimensional amplitude *A/D*, obtained by different researchers (Brika and Laneville 1995).

levels can be performed. Theoretical results should be obtained by EBP, once the conductor self-damping has been assessed by means of laboratory tests.

The statistic distribution of wind speed is typically represented by an asymmetric bell shaped curve or histogram that is interpreted using the Weibull and Rayleigh probabilistic models with parameters evaluated case by case according to the experimental data. In different places, the distribution of the wind velocities will present the same skewed shape but with different mode and extension, as shown in Figure 10.9.

Effect of Turbulence in the Wind Power Input

The wind power functions from different sources, given in Figure 10.8, were evaluated based on wind tunnel tests in the laminar flow condition. In the natural wind, at the lower layers of the atmosphere, there is always certain turbulence. This has the effect of reducing the power imparted to the conductor by the wind, and consequently also the vibration level is reduced. Hence, it is important to account for this effect in the numerical experiments.

Turbulence intensity at any particular field location is strongly influenced by the local terrain, and especially the nature of the ground cover. Obstacles to wind flow, such as trees and buildings and even blades of grass, shed vortices somehow as conductors do. These vortices determine the turbulent component of the wind. Naturally, large obstacles shed large vortices increasing the turbulence intensity, while small obstacles, with their small and short-lived vortices, result in low intensity turbulence. However, very large obstacles such as hills, ridges and mountains do not cause turbulence as understood here, rather, they shape the flow to conform to these gross orographic features. For example, valleys may funnel the wind, increasing its speed and actually reducing its turbulence intensity. Field

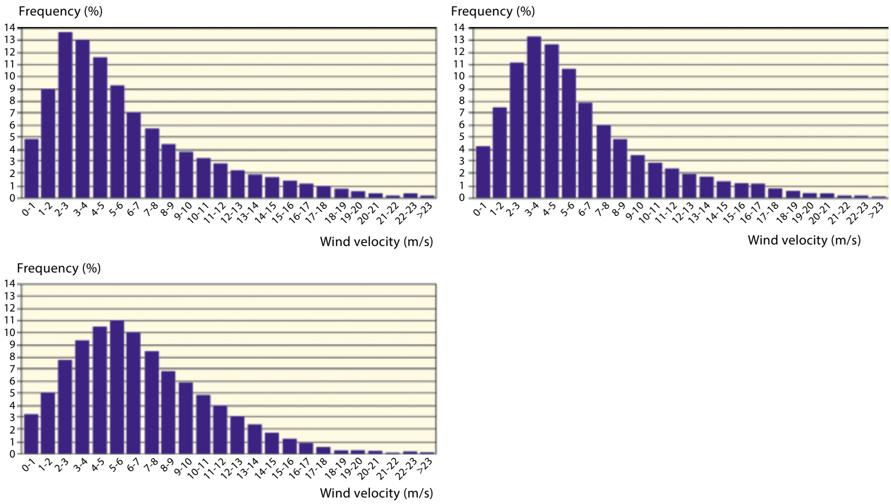


Figure 10.9 Examples of wind speed distribution in three places with different climate and environmental conditions.

measurements have yielded tables of typical values of intensity found in various classes of ground cover. The values in Table 10.1 pertain to elevation above ground of 10 metres. Tables with more finely-divided classifications are available. For example, (Wieringa 1992) provides twice as many.

The intensities given in these tables (expressed as the ratio between the rms value of the variation and the average wind speed) are typically measured during strong winds. Light to moderate winds, say up to 8 or 10 m/s (hourly average), show a great deal of dispersion caused by the effects of the buoyancy acquired by parcels of air that are in contact with the surface when they are heated or cooled by the ground. Heating causes these parcels to rise, churning the atmosphere as they do, resulting in increased turbulence. Cooling, on the other hand, causes the atmosphere to stratify, with the cool layer sticking to the ground and blocking the movement of surface-generated turbulence upward. Because of these effects, turbulence intensity during the light-to-moderate winds associated with aeolian vibration can be much larger, or significantly smaller than the values reported in Table 10.1 as shown in Figure 10.10.

For example, in rural areas, at very low wind speed, intensity can be as high as 0.50 or as low as 0.07, depending upon whether the ground surface is warmer or colder than the air.

Table 10.1 Typical values of turbulence intensity for different terrain conditions

Terrain	Turbulence Intensity
Open sea; large stretches of open water	0.11
Rural areas; open country with few, low, obstacles	0.18
Low-density built-up areas; small town; suburbs; open woodland with small trees	0.25
Town and city centres with high density of buildings; broken country with tall trees	0.35

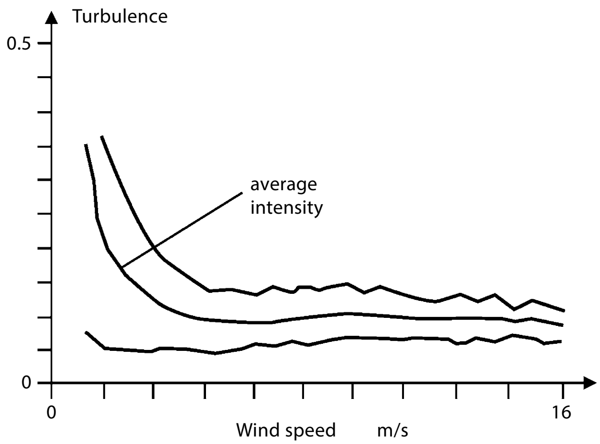


Figure 10.10 Intensity of turbulence vs. mean wind velocity (Kraus and Hagedorn 1991).

Maximum power is transferred when wind speed causes a Strouhal frequency of vortex shedding that is close to the frequency at which the conductor is vibrating (Rawlins 1993). Due to the travelling-wave nature of conductor vibration, the conductor's vibration frequency, or frequency spectrum, is the same all along the span. If the wind speed is not constant all along the span, there must be parts of the span where maximum power transfer does not occur, and total wind power input must be less than would occur in perfectly uniform wind. Fluctuations in wind speed with time - gustiness - also reduce wind power input, because the vibration of the span cannot change frequency fast enough to follow short-term wind speed variations. Both the span-wise variations (spatial turbulence) and the gustiness (time turbulence) are reflections of turbulence in the wind structure.

The spatial turbulence of the wind determines, quite often, the simultaneous excitation of two or more slightly different vibration frequencies in different places of the span. The overlapping of these vibrations generates beats which results in a continuous variation of the vibration amplitude at any vibrating point of the span as shown in Figure 10.11.

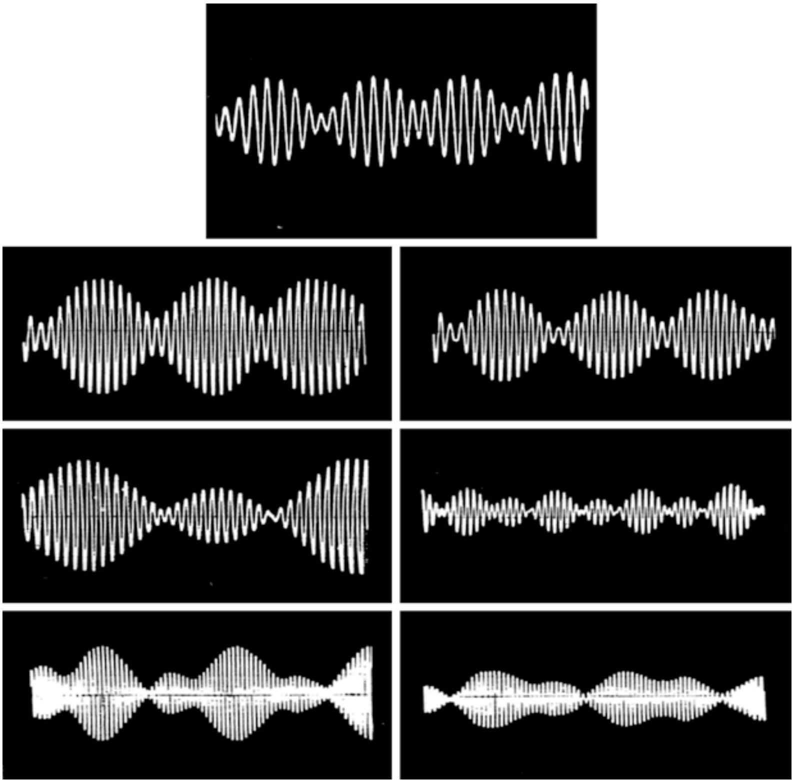


Figure 10.11 Records of natural aeolian vibrations.

To evaluate the energy introduced by the wind in the turbulent regime, an analytical model that allows to simulate the turbulence phenomenon was developed using wind tunnel tests together with a variable wind velocity model (Diana and Gasparetto 1980). This made it possible to obtain a series of curves of the energy introduced by the wind in a single conductor, as a function of the turbulence level (Diana et al. 1979).

The energy obtained in this way is shown in Figure 10.12 where *W/m* is the mean power measured per unit length, *d* is the conductor diameter, f is the frequency and *U/D* is the non-dimensional vibration amplitude (Diana et al. 1982).

In the case of bundles, the vortex shedding mechanism is markedly different from the one present in the case of single conductors (Diana et al. 1976; Curami and Gasparetto 1981).

The experimental research done in the wind tunnel and the analytical model developed made it possible to obtain the energy introduced by the wind in the case of a pair of conductors, one in the wake of the other, on the assumption of laminar wind. This energy is given in Figure 10.13 (curve b). To obtain, for the bundles, the energy introduced by the wind for different turbulence conditions, the energy of the bundle in the laminar case has been reduced in the same ratio as for the single conductor (Figure 10.13 curves c and d).

10.3.2.4 Conductor self-damping

Conductor self-damping is a physical characteristic of the conductor that defines its capacity to dissipate energy internally while vibrating. For conventional stranded conductors, energy dissipation can be attributed mostly to frictional damping, due

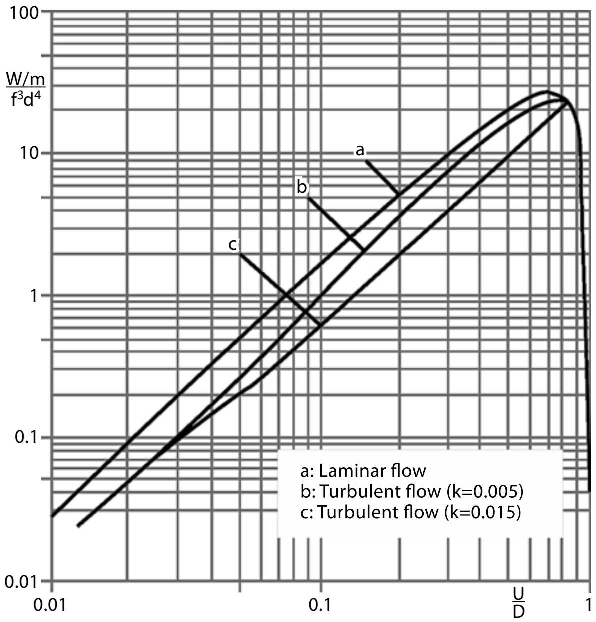


Figure 10.12 Single conductor. Wind power functions.

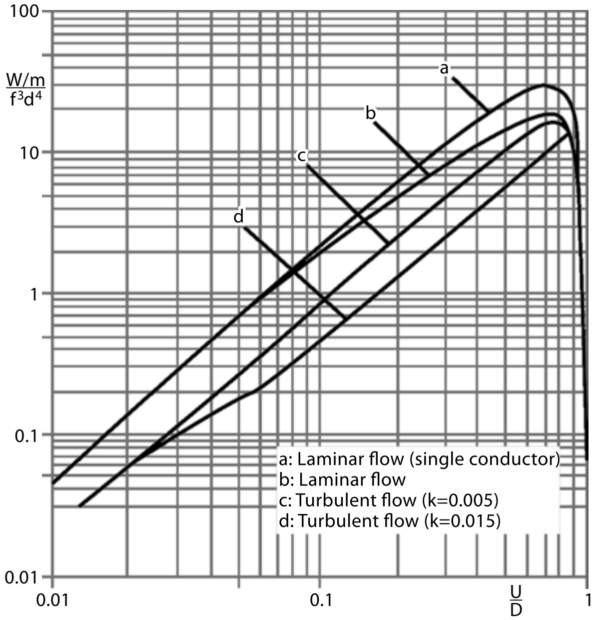


Figure 10.13 Bundled conductors. Wind power function.

to small relative movements between overlapping individual wires, as the conductor flexes with the vibration wave shape.

Conductor self-damping is generally not specified by the manufacturer and can be determined through measurements performed on a laboratory test span (Figure 10.14).

A "Guide on conductor self-damping measurements" (IEEE 1978) had been prepared jointly by IEEE Task Force on Conductor Vibration and Cigré SC22 WG01, to promote uniformity in measuring procedures. The Guide has been published by IEEE as Std. 563-1978 and also in Electra (Cigré 1979b).

The Cigré TB titled "State of the Art for Testing Self-Damping Characteristics of Conductors for Overhead Lines" (Cigré 2011b), prepared by WG B2.25, describes the current methodologies, including apparatus, procedures and accuracies, for the measurement of conductor self-damping and for the data reduction formats. In addition, some basic guidance is provided to inform the potential user of the strengths and weaknesses of each given method.

The IEC Std 62567 titled "Overhead Lines. Methods for Testing Self-damping Characteristics of Conductors" (IEC 2013) has been published in 2013 on the basis of a proposal presented by Cigré WG B2.25.

Conductor Self-Damping Measurements

Three main methods for conductor self-damping measurements are recognized in the above documents. The first two, which are the most used, are referred to as "forced vibration methods" and the third as "free vibration method".

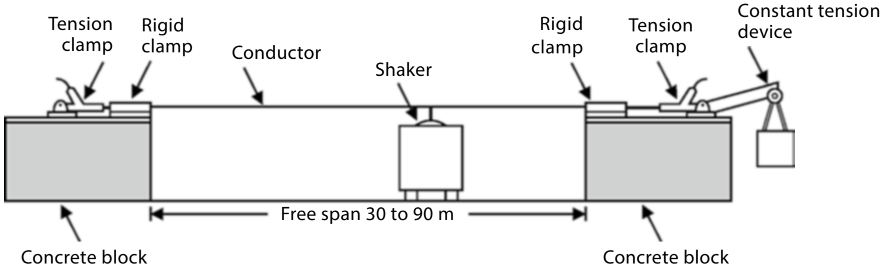


Figure 10.14 Laboratory test span for conductor self-damping measurements.

The first forced vibration method is the "Power Method" in which the conductor is forced into resonant vibrations, at a number of tunable harmonics, and the total power dissipated by the vibrating conductor is obtained by the measurement of the force and acceleration (or velocity or displacement) imparted to the test span at the point of attachment to the shaker. The power method is simple and requires a limited number of measurement points. However, all the extraneous dissipation, at span extremities and at the forcing point, is part of the total calculation of the conductor self-damping and special care must, therefore, be devoted to reduce all these extraneous loss sources or to account for them.

At each test frequency, the power dissipated by the conductor can be calculated by means of the following equation:

$$P_c = \frac{1}{4\pi f} F A \sin\theta_a \tag{10.7}$$

The second forced vibration method, known as the "Inverse Standing Wave Ratio" method (ISWR), determines the power dissipation characteristics of a conductor by the measurement of antinodal and nodal amplitudes on the span, for a number of tunable harmonics, where the inverse standing wave ratio is given by the ratio of nodal and antinodal amplitudes. Performing two measurements in two different loops, the dissipation relates to the considered portion of the conductor only; therefore, the estimated self-damping value is not affected by the extraneous losses at the span ends and shaker-conductor connection.

At each test frequency, the total power dissipated by the conductor can be calculated from the following equation:

$$P_c = \sqrt{Tm}\,\frac{V_n^2 a_n}{2Y_n} \tag{10.8}$$

where

$\sqrt{Tm}$ is the wave or characteristic impedance (at very high frequencies this may be modified due to the effect of the stiffness of the conductor).
$Vn = \omega Yn$ is the vibration velocity at the nth antinode

$S_n = \frac{a_n}{Y_n}$ is the inverse standing wave ratio ISWR at the n^{th} loop.

The main problems that this method presents are the correct estimation of the node positions and the measurement of the node amplitude of vibration which may have a very small value in the order of a few micrometers.

The free vibration method is named "Decay Method" and determines the power dissipation characteristics of a conductor by the measurement, at a number of tunable harmonics, of the decay rate of the amplitude of motion of a span following a period of forced vibration at a natural frequency and fixed test amplitude. The rate of decay is a function of the system losses.

At each test frequency, the logarithmic decrement can be calculated by the following equation:

$$\delta = \frac{1}{n_c} \ln \frac{Y_a}{Y_z} \tag{10.9}$$

where

δ = logarithmic decrement
n_c = number of vibration cycles between the two cycles considered
Y_a = single antinode amplitude of the first cycle considered
Y_z = single antinode amplitude of the last cycle considered

The power P dissipated by the conductor can be determined from the following equation:

$$P_c = \frac{1}{2} f m V_{\partial}^2 L \delta \tag{10.10}$$

where V_a is the antinode velocity at the initial constant antinode amplitude.

If a lightly damped system ($h<<1$), such as a stranded overhead conductor, is left free to vibrate from a forced resonance condition, it undergoes a transient decay of oscillation similar to the one reported in Figure 10.15.

This method, if correctly employed, can give an estimation of the values of the self-damping in a large range of vibration amplitudes in one trial. Moreover, it is quick and easy, requiring, in its simplest form, just one transducer measuring the decay. However, as in the Power method, all the extraneous dissipation is part of the total calculation of the conductor self–damping. Therefore it is necessary to minimize all these extraneous loss sources or accounting for them. When this is not possible the use of the ISWR method is recommended.

The decay can be affected by the method used to disconnect the driving force as any additional disturbance of the conductor causes other vibration modes to be generated. With proper precautions, the shaker force can be stopped inducing a minimal disturbing impulse into the system. The TB (Cigré 2011) describes the methods normally used to terminate the forced vibration of the test span.

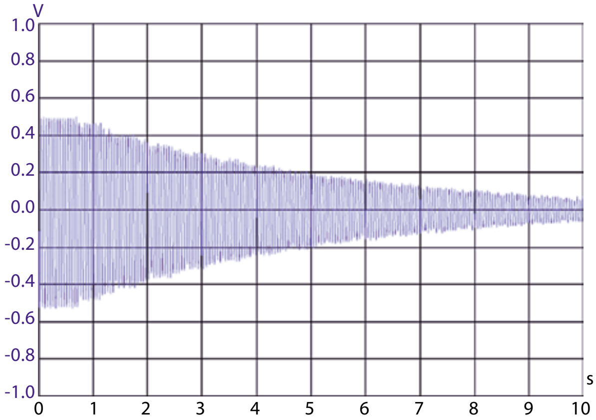


Figure 10.15 A decay trace of a 264-AL3/34-ST1A conductor tensioned at 20 % RTS.

Laboratory Test Spans

Several laboratories around the world have performed conductor self-damping measurements but large disparities in self-damping predictions have been found among the results supplied by the various laboratories. The probable causes of these disparities are listed in the Cigré TB 482 (Cigré 2011b).

The laboratory test spans for conductor self-damping measurements are built indoor and are generally 30–50 m long. In a few cases, longer spans up to 90 m have been built.

The test spans are strung between two massive blocks generally made of steel reinforced concrete and preferably common or solidly connected with the concrete floor (Figure 10.16).

The test span should have the capability of maintaining a constant conductor tension. Hydraulic and pneumatic cylinders, springs, threaded bars and pivotal balance beams have been used successfully.

Square faced rigid clamps are used to ensure that energy losses do not occur beyond the extremities of the free span. The vibration exciter is generally an electrodynamic shaker. Hydraulic actuators are also used. Modal shakers having a light armature can be used to excite the conductor with minimal distortion of the natural mode shape and to produce virtually zero stiffness and zero damping in the direction of the movement.

The most common position of the shaker is at one span extremity within the end vibration loops of the span.

The armature of the shaker can be connected to the test span either rigidly or by the use of a flexible fixture (Figure 10.17).

The shaker connection is instrumented for force and vibration level measurements. The latter one is generally made using accelerometers but also velocity transducers and displacement transducers can be used. Miniature accelerometers are most commonly used for measurements of node and antinode amplitudes (Figure 10.18).

Figure 10.16 Laboratory test span, 85 m long, at VRTC, KwaZulu-Natal University, Durban, South Africa.

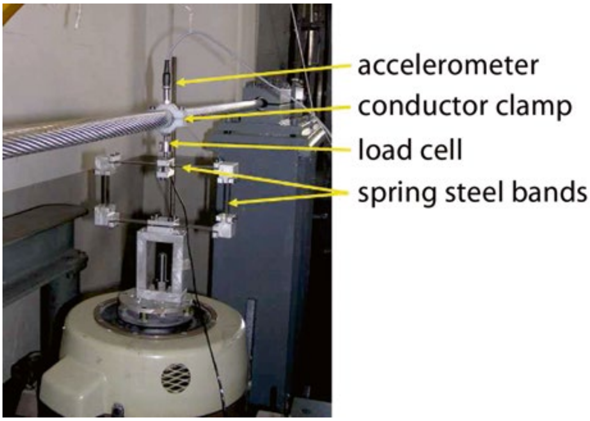


Figure 10.17 Example of flexible connection between shaker and conductor (Courtesy ISELFA).

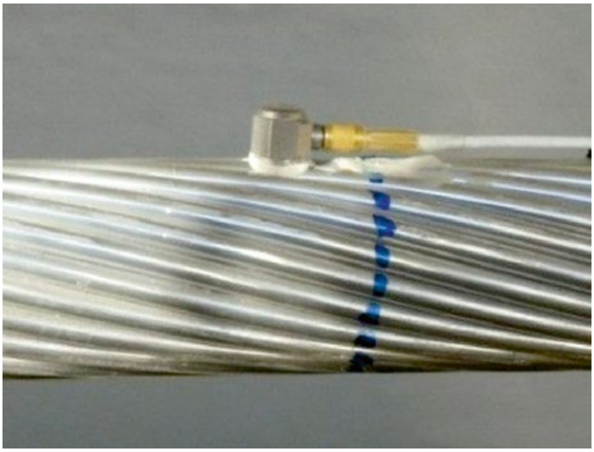


Figure 10.18 Miniature accelerometer used for conductor self-damping tests (Courtesy ISELFA).

Contactless displacement transducers (laser or eddy current based) have also been used with small and light conductors.

An example of the test span equipment for the conductor self-damping measurements, fully equipped to perform the measurements with the methods outlined (Cigré 2011), is shown in Figure 10.19.

Data Reduction and Elaboration

It is customary to fit self-damping data to empirical equations that are thought to model the self-damping phenomenon. This is done to facilitate energy balance calculations and to provide a basis for extrapolating the measurements beyond the ranges covered in the laboratory tests. Ability to extrapolate is important since limits on measurement accuracy effectively prevent obtaining useable data at the lower vibration frequencies, yet these may be the frequencies where greatest fatigue stresses occur.

Data measured in the laboratory span are generally expressed empirically through a power law:

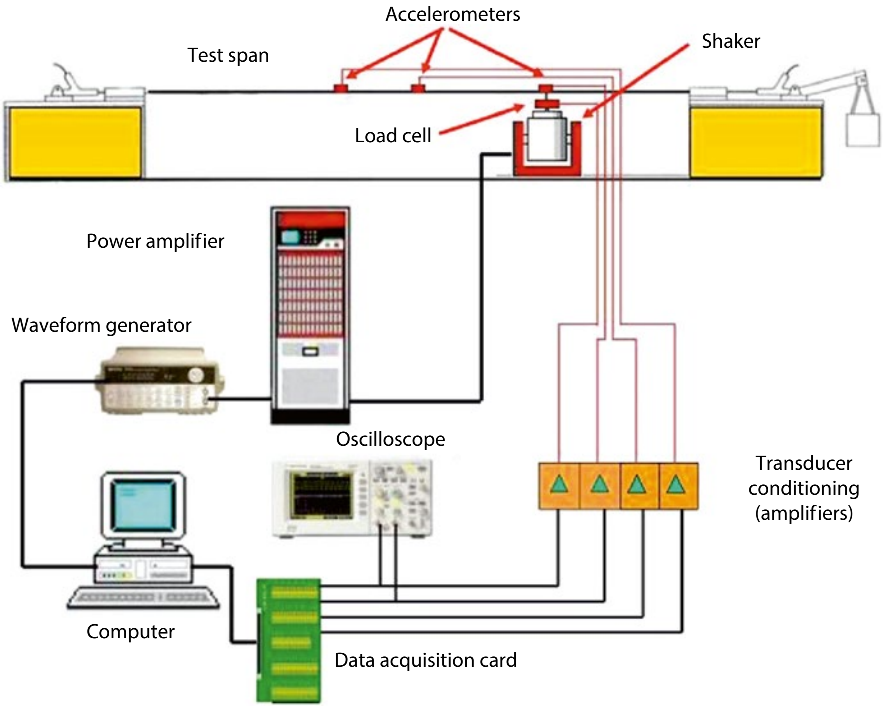


Figure 10.19 Test span equipment for the conductor self-damping measurements.

$$\frac{P}{L} = k\frac{Y_{\max}^{l} f^{m}}{T^{n}} \tag{10.11}$$

where *P/L* describes the power per unit length dissipated by the conductor, k is a factor of proportionality, Y_{max} is the antinode amplitude of vibration, f is the frequency of vibration, T is the conductor tension, while l, m and n are the amplitude, frequency and tension exponents, respectively. Using the above empirical rule, self-damping determined in laboratory spans could be extrapolated to actual much longer spans.

The damping properties of some conductors, such as ADSS, gap conductors, etc. can not be expressed by the above formula and require other interpolating functions to be defined as the best fit of the measurement data (Cigada et al. 1998).

Table 10.2 from (Cigré 1998) summarizes the exponents obtained by a number of investigators for Equation (10.11), together with the method of measurement used, the test span length, span end conditions and number of conductors and tensions tested.

The power method for conductor self-damping measurements on laboratory test spans with rigidly fixed extremities produces empirical rules with an amplitude exponent close to 2.0 and a frequency exponent close to 4.0, in comparison to about 2.4 to 2.5 and 5.5, respectively, for the ISWR method and PT method with pivoted extremities.

Such differences in the above exponent values, together with those in the k factor of proportionality, may lead to large differences in the predicted self-damping values. It, thus appears, that, the major disparities among conductor self-damping values reported by different laboratories are mainly related to end span effects (Hardy and Leblond 1993; Tavano et al. 1994).

The documents (IEEE 1978; Cigré 1979, 2011) and (IEC 2013) recommend to present the measurement results in diagrams showing the power dissipated per conductor unit length, as a function of the ratio of the antinode displacement amplitude $Y_{\max}$ to conductor diameter D for each frequency f and tensile load T (Figure 10.20).

10.3.2.5 Effect of Tension on Conductor Vibration

There are several motives for controlling overhead conductor tension at the design stage.

One of the most obvious reasons is to ensure that maximum tension resulting from the assumed most severe climatic loading does not exceed the conductor allowable tension. At the opposite end, it may be required to limit minimum tension while the conductor is operating at maximum temperature so that line clearance is not violated. A third motive, which should not be disregarded, is to restrict conductor susceptibility to harmful conductor vibrations.

Stranded conductors get more vulnerable to aeolian vibrations as tension is increased. This is true for all conductor systems whether they are used *in solo* or in bundles and whether they are fitted or not with damping and/or spacing devices.

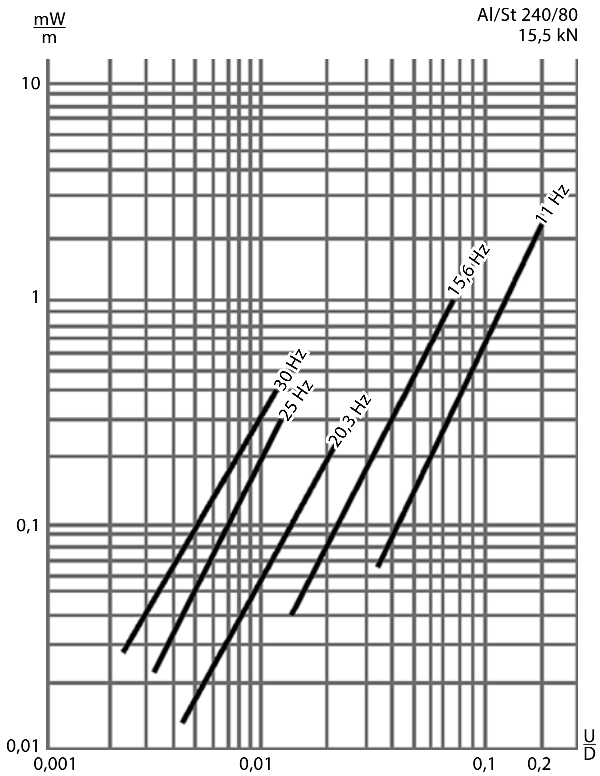
If the tension is increased, the self-damping of the conductor is reduced accordingly because the conductor tends to behave more as a solid beam rather than a

Table 10.2 Comparison of Conductor Self-damping Empirical Parameters

Investigators	l	m	n	Method	End Conditions	Span length (m)	Number of conductors × number of tensions
Tompkins et al. (1956)	2.3-2.6	5.0-6.0	1.9(1)	ISWR	N.A.	36	1 × 2
Claren and Diana (1969b)	2.0	4.0	2.5;3.0;1.5	PT	M.B.	46	3 × 3
Seppä (1971), Noiseux (1991)	2.5	5.75	2.8	ISWR	N.A.	36	1 × 8
Rawlins (1983)	2.2	5.4		ISWR	N.A.	36	1 × 1
Lab. A (Cigré 22.01 1989)	2.0	4.0		PT	M.B.	46	1 × 1
Lab. B (Cigré 22.01 1989)	2.2	5.2		PT	P.E.	30	1 × 1
Lab. C (Cigré 22.01 1989)	2.44	5.5		ISWR	N.A.	36	1 × 1
Kraus and Hagedorn (1991)	2.47	5.38	2.80	PT	P.E.	30	1 × ?
Noiseux (1991)(2)	2.44	5.63	2.76	ISWR	N.A.	63	7 × 4
Tavano (1988)	1.9-2.3	3.8-4.2		PT	M.B.	92	4 × 1
Möcks and Schmidt (1989)	2.45	5.38	2.4	PT	P.E.	30	16 × 3
Mechanical Laboratory Politecnico di Milano (2000)	2.43	5.5	2	ISWR	P.E.	46	4 × 2

ISWR: Inverse Standing Wave Method
PT: Power Method
N.A.: Non applicable
M.B.: Massive block
P.E.: Pivoted Extremity
(1): extrapolated
(2): Data corrected for aerodynamic damping

Figure 10.20 Example of diagram of the power dissipated by a conductor ($U = Y_{max}$).



stranded cable, reducing, during vibration, the micro movements between elementary wires that is the mechanism through which the conductor dissipates energy.

Therefore, there is a need to set an upper limit to conductor unloaded tension that may prevail for a significant period of time.

Cigré TB 273 titled "Overhead Conductors safe Design Tension with Respect to Aeolian Vibration" (Cigré 2005a) deals with this important issue. First, it provides a critical examination of the EDS (Every Day Stress, expressed as percentage of the Rated Tensile Strength RTS) concept which was put forward in 1960 by Cigré SC6 with the intent to provide guidance on the maximum allowed tension with respect to aeolian vibrations. It is noted, for example, that the 18 % EDS value which was proposed as safe for ACSR conductors did lead to fatigue failures in a significant number of cases, thus motivating further investigation. Accordingly, one of the first and most important tasks of Cigré was to question the relevance of the EDS as conductor tension parameter. On account of its improved ability to rate conductor self-damping capacity, on the one hand, and to generalise results as widely as possible, on the other hand, it was resolved to adopt parameter H/w, the ratio between the tensile load H and conductor weight w per unit length. As stated in Cigré TB 273, this tension refers to initial horizontal tension before any significant wind and ice loading and before creep, at the average temperature of the coldest month.

Another parameter of prime importance is wind turbulence since it affects to a great extent the aeolian power imparted to vibrating conductors. This is scrutinised in the brochure insofar as it relates to roughness of the terrain crossed by the lines.

The method proposed by Cigré TB 273 makes use of the *H*/*w* parameter as an index of vibration susceptibility and the quantity *LD*/*m*, the ratio of the product of span length *L* and conductor diameter *D* to conductor mass *m* per unit length, as an index of the span dimensions. In other words, *LD*/*m*, expressed in m^3/kg, is a parameter that describes the quantity of material in the span.

A diagram, shown in Figure 10.21, valid for single unarmored, unprotected conductors of the most common types, defines, for four different terrain (hence wind turbulence) conditions, three different areas:

- The Safe Design Zone No Damping, where no additional damping is required
- The Safe Design Zone Span-end Damping. where additional damping at span extremities is required generally provided by Stockbridge type vibration dampers
- The Special application Zone, where a special additional damping system should be foreseen.

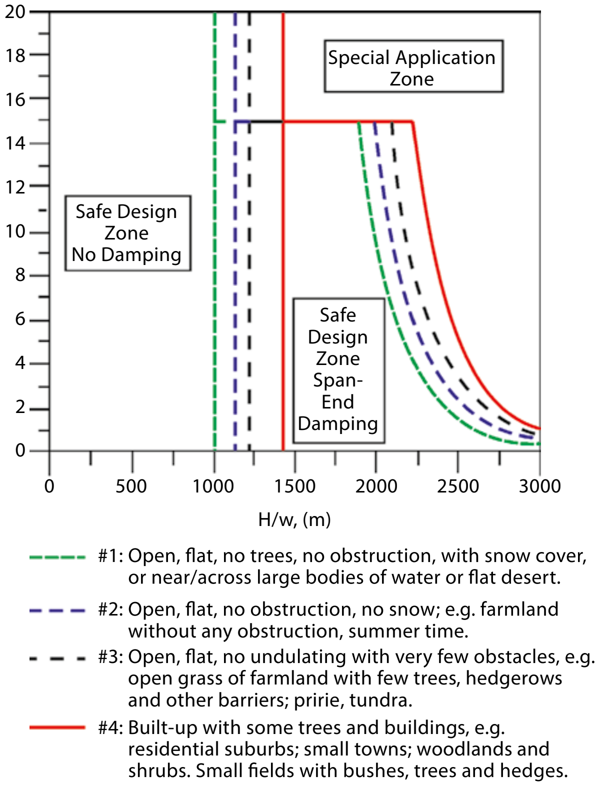


Figure 10.21 Recommended safe design tension for single aluminium based conductors.

Cigré TB 273 deals also with bundled conductors, particularly, twin horizontal bundles, triple apex-down bundles and quad horizontal bundles made up of conventional stranded conductors fitted either with damping spacers or non-damping spacers or a combination of non-damping spacers and span-end Stockbridge-type dampers. The methodologies that were used to arrive at safe design tension for each one of a number of bundled conductor systems are purely empirical relying on field experience gathered on 91 bundled conductor lines erected in North America and full scale test line data available in the literature.

The same classification criteria used for single conductors are applied to bundled conductors giving the following diagrams:

Figure 10.22 shows the Safe Design Zones and the Special Application zone for twin bundles that do not require additional damping.

Figure 10.23 shows the Safe Design Zones and the Special Application zone for twin bundles equipped with spacers and vibration dampers.

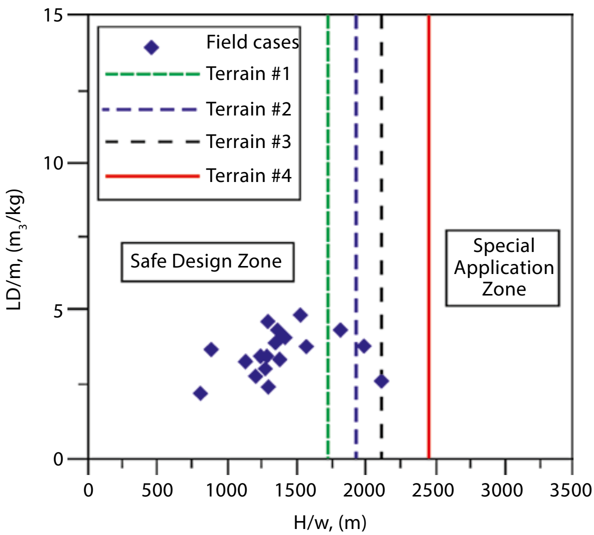
Figure 10.24 shows the Safe Design Zones and the Special Application zone for triple and quad bundles with spacers and vibration dampers or with spacer dampers only.

The Task Force recommendations for single and bundled aluminium based conductors are summarised in Table 6.3 of Cigré TB 273, in the form of simple algebraic expressions, each one associated to a specific conductor system and to one out of four terrain categories.

10.3.2.6 Vibration Levels

To determine the behaviour of single and bundled conductors when subjected to aeolian vibration, use is made of analytical models in which the vibration amplitudes are obtained by equating, for each own frequency, the energy introduced by the

Figure 10.22 Twin bundles with no additional damping.



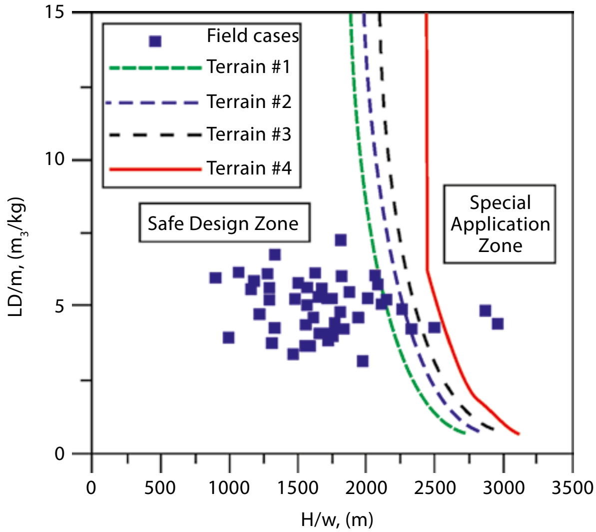


Figure 10.23 Twin bundles with spacers and vibration dampers.

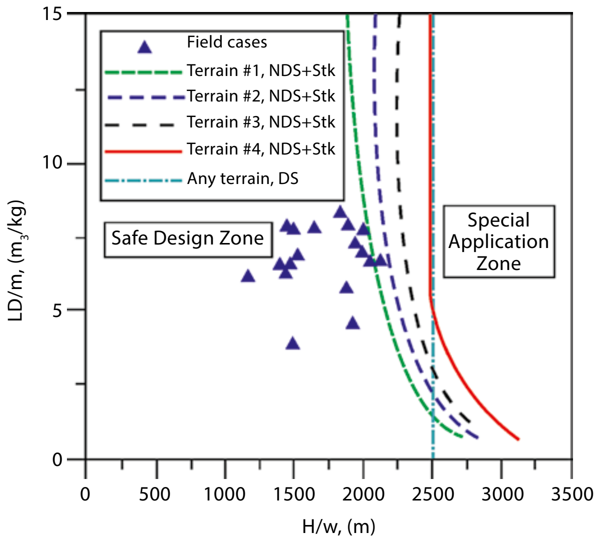


Figure 10.24 Triple and quad bundles with spacers and vibration dampers and any bundle with spacer dampers.

wind and the energy dissipated by the conductor-spacer-damper system (Claren et al. 1974).

The energy dissipated is calculated on the basis of the conductor, spacer and damper characteristic; as regards the energy introduced by the wind, however, it is necessary to distinguish between various cases.

For single conductors, if it is assumed that the wind speed is constant and that there is therefore no turbulence, uses is made of the energy measured in a wind tunnel (Diana and Falco 1971).

The wind turbulence can also be taken into account, using the wind power functions illustrated in Figures 10.12 and 10.13 and in (Noiseux et al. 1986; Rawlins 1983).

The effect of tension variation on the vibration amplitudes of a medium size conductor is shown in Figure 10.25 for four different values of the EDS and a constant wind turbulence of 5 %. The vertical red dot lines encompass the vibration range calculated using the Strouhal formula (10.1) for wind velocities between 1–7 m/s. The following should be noted:

- Increasing the vibration frequency, the vibration amplitude decreases
- Increasing the conductor tension the vibration amplitudes increase
- Establishing a safety limit for the antinode vibration amplitude, it can be noted that, for lower tensions, the range of vibration frequencies exceeding this limit is reduced, which means that the additional damping is required only for a smaller frequency range. Starting from the curve of the vibration amplitude relevant to an EDS of 20 % RTS and 5 % turbulence, Figure 10.26 shows how the vibration amplitudes vary with increasing turbulence. The effect is more pronounced at higher vibration frequencies.

10.3.2.7 Fatigue Endurance Capability of Conductor/Clamp Systems

Introduction

Fatigue endurance capability of conductor/clamp systems is another important parameter taken into consideration at the design stage of a transmission line. It remains an important factor when comes the time to assess the residual service life of a particular transmission line.

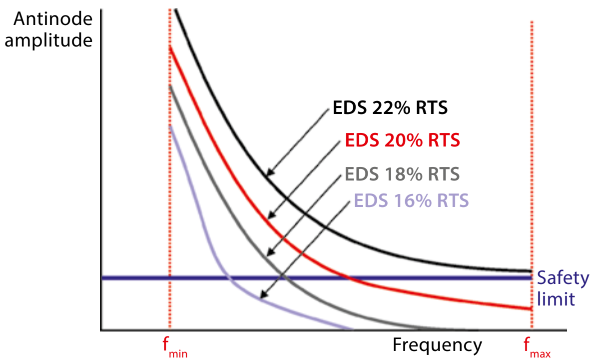


Figure 10.25 Effect of tension variations on vibration amplitude.

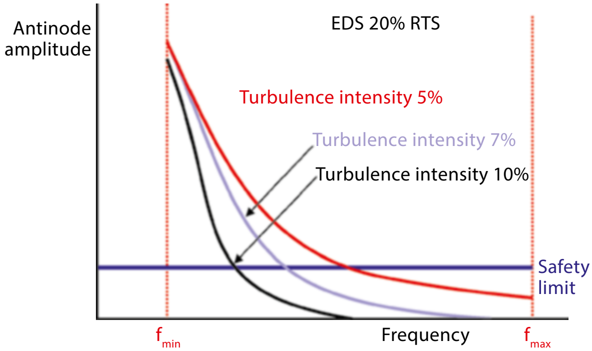


Figure 10.26 Effect of wind turbulence variations on vibration amplitude.

The fundamental cause of conductor fatigue failures is the cyclic bending stress imposed by aeolian vibrations. At singular points of the conductor where motion is constrained against transverse vibration, more frequently at suspension clamps, but also at spacer, dampers and hardware clamps, bending causes the strands of the conductor to slip relative to each other. The friction forces combined with the relative motion cause fretting at interstrand and clamp contacts. Once an initial crack is induced from the fretting mark surface, it may propogate, leading to the rupture of the wire and eventually to the complete breaking of a conductor.

Even though the presence of fretting in conductor fatigue is a well known phenomenon, fretting fatigue is not understood enough yet to allow the prediction of the life of a conductor-clamp system by the solution of a mathematical model when knowing the mechanical and physical properties of the wires. The standard method of evaluation is still based on experimental tests on a case by case basis (Cigré 2007).

Mechanism of Fretting Fatigue

Fretting fatigue is a contact damage phenomenon that takes place when a structural component experiences surface microslip associated with small-scale oscillatory motion on the order of 20–100 μm. This phenomenon is often responsible for unexpected fatigue failures and limits component life in aeronautical and automotive structures and common industrial machinery such as steam and gas turbines, cables, bolted plates, shaft keys and bearings.

A vast amount of research work has been published on fretting fatigue. Fretting is complex (Vincent et al. 1992; Waterhouse 1992; Hoeppner 1994; Mutoh 1995) since it is influenced by a number of factors including the normal contact load, the amplitude of relative slip, friction coefficient, surface conditions, contact materials and environment. The fretting fatigue process is also recognized as the result from the interaction between wear, corrosive and fatigue phenomena driven by both the microslip at the contact surface and cyclic local stresses.

In particular, the mechanism of fretting damage of aluminium material involves several stages of evolution (Hoeppner 1994). At the beginning, a surface oxide film is removed and, then, bare surfaces in contact start to rub against each other. At the same time, the surfaces tend also to adhere to each other forming weld junctions which will be broken by the subsequent relative movement. This process produces the accumulation of wear dust between the surfaces. Surface plastic deformation, change in surface chemistry as well as formation of aluminium oxide and wear product tend to increase with the fretting cycles.

The thin and brittle layer of aluminium oxide consists in an $Al(OH)_3$ structure. As this oxide is more voluminous and harder than the aluminium metal itself, it may provoke nucleation of grain-size cracks with the help of contact stresses. Initiation of surface microcracks is then unavoidable. If the slip amplitudes are large enough the small cracks will be worn preventing their propagation and contributing to create more fret debris. That is a typical fretting wear mechanism. But if the microcracks can propagate below the oxide surface into the bulk material, a fretting fatigue process is generated. As the crack grows deeper the influence of the bulk stresses predominates until the complete fatigue failure of the component occurs.

The effect of wind excitation on overhead electrical conductors has been studied for a long time (Varney 1926; Nefzger 1933) and more recently the effect of fretting fatigue has been recognized. In 1968, (Fricke and Rawlins 1968) highlighted the importance of fretting in vibration of overhead conductors. The conductor wire failures were examined from lines in service and from laboratory tests and showed that fatigue cracks originated through fretting marks in all cases. Poffenberger and Komenda (1971) identified some of the complexities involved in fatigue mechanism. They also understood that the calculation of the flexural stiffness implied the consideration of the situation represented by some wires acting individually and other wires remaining locked together.

Analysis of a large number of fatigue breaks from field and laboratory tests have been done by many authors (Moecks 1970; Dulhunty 1971) confirming that the fretting scars were the crack starting points.

In EPRI's reference book, Rawlins (1979) reviewed various ways of relating fatigue of conductors to measurable vibration data, illustrated by some of the available data and field results. In 1979, Cigré Working Group 04 of Study Committee 22 presented recommendations for the evaluation of the fatigue strength of transmission line conductors (Cigré 1979a). It established graphically that any fretting decreases the fatigue strength of metals drastically, using a comparison of S-N curves of single wires with those of conductors. Figure 10.27 shows the S-N curves for aluminium alloy wires (4) that result as the most fatigue resistant, for the pure aluminium wires (3) that are less resistant and for the whole conductors that lay in the shaded area (2) and present the lower fatigue resistance due to the fretting phenomenon. This failure zone was defined by Cigré WG 22-04 on the basis of the data collected from a large number of laboratory fatigue tests on conductors. The lower limit (1) of this area is called Safe Border Line and is considered as a "universal" fatigue curve that can be used for conventional aluminium based conductors when the specific actual S-N curves are not available.

In 1981, (Ramey and Townsend 1981) stated that fretting is the single most important parameter in fixing strand break locations. It is also a major parameter in determining the number of cycles at a given amplitude level to cause these breaks.

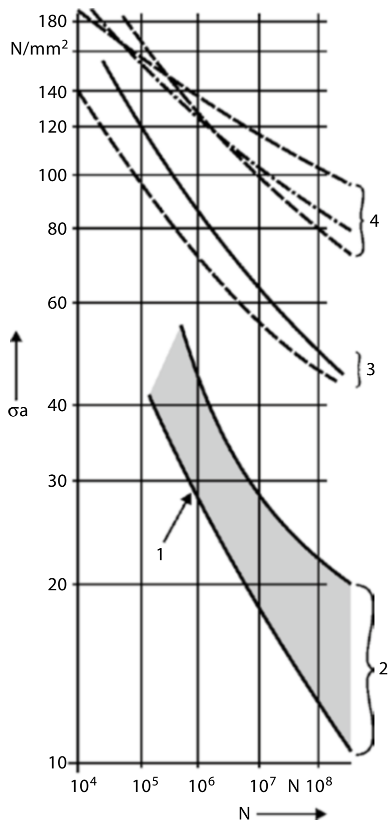


Figure 10.27 S-N curves (Wöehler curves) for individual wires and for stranded conductors. *1* Safe border line. *2* Aluminium based conductors. *3* Pure aluminium individual wires. *4* Aluminium alloy individual wires.

In a guide for endurance tests of conductors inside clamps, written by Cigré Working Group 04 of Study Committee 22 (Cigré 1985), it is explained that fretting occurs between the wires of adjacent layers of the conductor and between the conductor external wires in direct contact with the line accessories.

Subsequently, (Cardou et al. 1990, 1994) presented several ACSR conductor fatigue test results at spacer and suspension clamps. A Cigré report (Cigré 1998) again stated the basic principles of the fretting mechanism in the stranded cables and its dangerous effect on the fatigue process in transmission line conductor.

Many bending fatigue tests, with different types of clamps, have been performed on several types of ACSR conductors in GREMCA's laboratories. Clamp systems and lubricant have been studied more specifically (Zhou et al. 1995, 1996). The clamp design has a strong influence, in its vicinity, on wire-wire and wire-clamp contact conditions. It appears that the mixed fretting regime may be reduced drastically for spacer clamp with pre-formed rods and elastomeric cushions. The application of a lubricant can increase the conductor service lifetime as fretting crack nucleation can be delayed.

A state of the art on the effect of fretting fatigue on the endurance capability of conductors has recently been presented in a report prepared by GREMCA at Laval

University (Dalpé et al. 2003). An update of present knowledge is reported in Cigré TB 332 (2007a) and Cigré TB 429 (2010).

The IEC Std.62568 (IEC 2014) has been prepared based on a proposal by Cigré WG B2.25 with the scope of providing test procedures to measure the fatigue characteristics of conductor associated to metallic clamps. The standard is expected to be published in October 2014.

Laboratory Determination of Fatigue Endurance

Background

Clamp hardware is an important factor in the evaluation of fatigue endurance of a conductor subjected to aeolian vibrations. For an endurance assessment as well as for an improvement of clamp design, fatigue tests are advantageous. The exact modelling of the actual phenomenon is indeed a complicated matter. The failures originate at inter-layer strand contacts or at contacts between the outer strands and the line accessories where conditions for fretting are present. The definition of a more appropriate model than the one presently proposed to represent the actual phenomenon remains to be completed. It is thus still opportune to remind not only that *fatigue characteristics of conductors must be determined by fatigue tests of conductors themselves* (Rawlins 1979), but also that these tests should be conducted with clamps having similar characteristics to those of the conductor/clamp system being characterized (Cigré 1985) and that *to arrive at comparable results in different laboratories an agreement on important test parameters and on a uniform method is necessary.*

Laboratory Conditions

Different systems have been developed to replicate conductor motion (Elton et al. 1959; Goudreau et al. 2003; Cardou et al. 1994; Philipps et al. 1972), each presenting specific advantages. However, a test bench of the resonance type imposing a conductor motion in a vertical plane should be preferred (Figure 10.28).

The active length of the conductor specimen should be at least 5 m between the clamp and the point of excitation, to assure a good distribution of the load within the strands at the test end, where the clamp is held in a position to reproduce the static

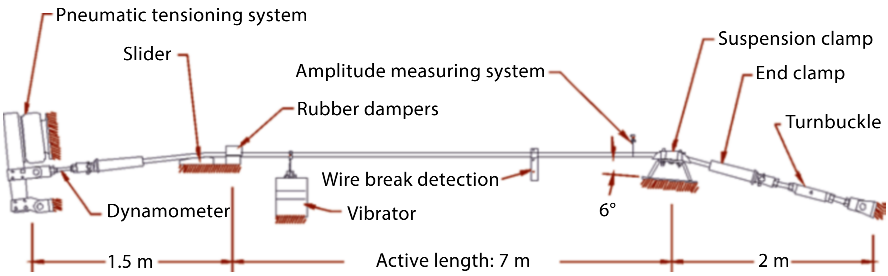


Figure 10.28 Typical resonance fatigue test bench (Cigré 1998).

bending angle of the conductor. For instance, it is typically 5 to 10 degrees for suspension clamps, and zero degrees for spacer clamps. The minimum distance between the clamp under test and the back dead-end of the conductor should be at least 2 m to ensure adequate homogeneity of the load distribution in the conductor strands. That section of the conductor experiences no motion.

If the clamp is held in a fixed position, it results in a simpler test procedure as it avoids the difficulties associated to the dynamic response of a rocking clamp and the ensuing complex motion that remains to be adequately interpreted (Cardou et al. 1990).

At the other end of the test bench, a suitable tensioning device assures a constant load (within ±2.5 %) during the tests. A dynamometer is introduced to continuously monitor the tension applied or to verify its value periodically. The level of the tension in the conductor should be representative of the actual prevailing line conditions, (Cigré 1985) the objective being the reproduction of similar mean static stress in the system. However, this parameter seems to have little effect on the S-N relationships given a conductor and its supporting clamp according to (Rawlins 1979) but it is a question that was never really settled. The actual knowledge of the fretting phenomenon and of the conditions of contact favouring micro-welds and crack initiation, however, suggest the need for adequate control of a constant tension during a test campaign.

An electro-dynamic shaker can be conveniently used to impose conductor vibration in the system. Most tests are carried out at constant amplitude and frequency. A frequency in the range of 10 to 60 Hz fits best the field experiences and thus the reproduction of the actual field conditions. Frequencies normally chosen, within that range, are those corresponding to a resonant mode of the tensioned-conductor system, because it simplifies the achievement of the requirement of conductor excitation at given constant amplitudes for long duration tests.

A strand failure detector (Rawlins 1979) consisting of a small beam attached to the conductor that amplifies its relaxation in torsion when a strand failure occurs, is extensively used (Cloutier et al. 1999) in consideration that failures regularly occur in inner-layer strands and cannot be simply detected by visual inspection.

The detector provides a step signal that can be correlated to the number of cycles applied (Figure 10.28).

Test Parameters

In such tests, the fatigue life of the conductor is determined as a function of some measure of vibration intensity. The stresses or stress combinations that would characterize the conditions favouring strand failures are not easily accessible to direct measurement. Several measures of vibration have been employed: the vibration angle β, the dynamic strain in an outer-layer strand in the vicinity of the clamp, the free-loop amplitude of vibration y_{max} and the bending amplitude Y_b. The latter is the most widely used parameter for measurement of vibration in the field and it is recommended to use it as well in laboratory tests to avoid being obliged to introduce the conversion of this bending amplitude into any of the other parameters. That conversion depends strongly on the proper choice of the bending stiffness of the actual conductor (Rawlins 1979). However, it is advisable to also measure the free loop amplitude *ymax* to facilitate the correlation of the test results of conductors supported with clamps of different configuration. Results from tests on one conductor size are not necessarily applicable to all the others of the same size (Fig. 10.29).

The assumption that there is some idealised strain or stress that can be calculated from vibration amplitude and that correlates well enough with conductor fatigue life has given the engineer a useful tool to overcome the complexity of the problem and find results that are reliable enough to be usefully applied.

The cycles to failure N is intended to refer to failure of the first strand (Rawlins 1979). However, in Cigré (1985) one can read that *three broken wires or 10 % of the aluminium wires – whatever is smaller – should be used as the damage criterion in respect of the relationship between the stress amplitude and the number of cycles*. In practice, it is not a problem to indicate clearly what situation one refers to when reporting test results. Due consideration should be given to that point when comparing results from different laboratories.

Tests should be carried out with different values of the vibration parameters to obtain fatigue endurance curves (the so-called S-N curves or Wöhler curves). Those curves also provide a value for an endurance limit, i.e. the amplitude of bending that a particular clamp-conductor combination will endure almost indefinitely. The endurance limits are evaluated, as currently accepted for aluminium, at 500 megacycles. In practice a test is interrupted when three failures are observed or when 500 megacycles are reached. Three samples per level of vibration amplitude is a mere minimum, and four levels barely define the S-N curve appropriately.

Figure 10.29 Resonance type test benches, GREMCA's laboratories.

Analysis of Test Results

The most common form to present conductor fatigue test results is the logarithmic fatigue endurance curve mentioned previously as the S-N curve. It is possible to superpose, on the same graph, points indicating the first, second, third and *n*th strand failures for a series of tests. It then shows the dispersion of the results and certain particular anomalies when, for instances, an early first failure occurs but is not followed by a second one within the 500 Mcycles duration of the test.

To assist in the interpretation of available data on fatigue endurance of a certain conductor/clamp system, a statistical analysis (Hardy and Leblond 2001) was presented that led to the determination of various S-N curves on a sound probabilistic basis. It confirmed that data dispersion was *so large as to rule out precision in the prediction of conductor fatigue life*.

Cigré TB (Cigré 2010) gives a representation of typical results obtained from fatigue tests conducted on resonance type test benches. It shows the differences encountered when testing conductors of different geometry such as one, two or three-layer ACSR. As an example, Figures 10.30 and 10.31 give the results of the stresses calculated as a function of Y_b and fy_{max} respectively, for a three layers ACSR conductor.

Calculation of Idealized Stresses

Simple Analytical Representation of the Fatigue Phenomenon

The conductor/clamp system may be simply represented as a cantilever beam supported in a square face block. Although this model is not exact, because the conductor

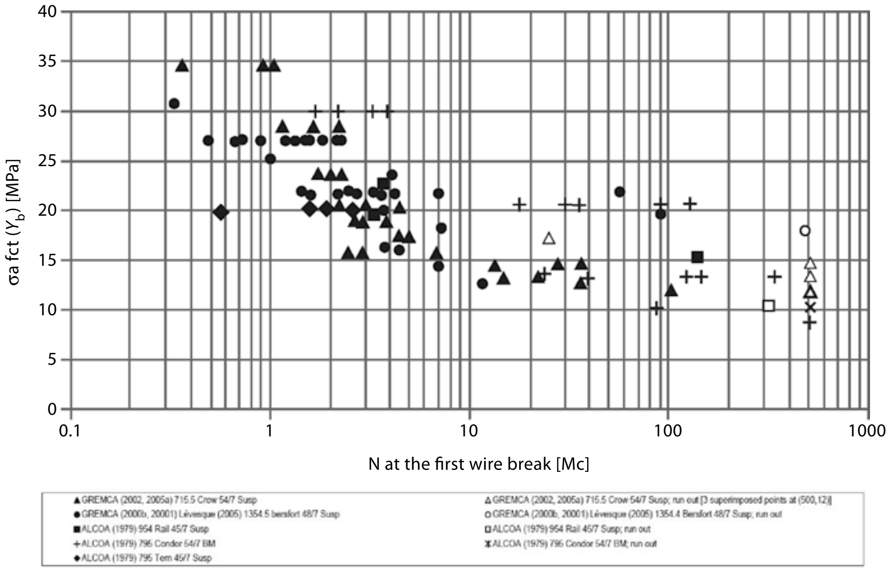


Figure 10.30 Typical results from fatigue tests on three-layer ACSR as a function of Y_b.

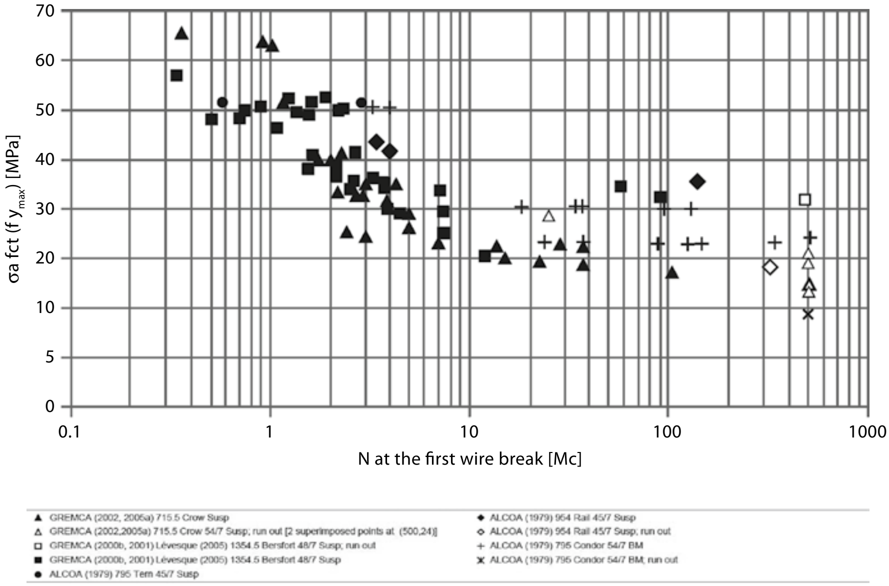


Figure 10.31 Typical results from fatigue tests on three-layer ACSR as a function of fy_{max}.

fatigue is caused by inter wire fretting and not by bending of the wire only, it gives the engineer some useful tools to correctly monitor different aspects of the fatigue endurance capability of conductor clamp/systems. Figures 10.32 and 10.33 illustrate clearly why the bending amplitude method may be valid for conductors fitted with solid metallic clamps, but invalid for conductors in cushioned clamps. In the latter case, it is not possible to locate a precise position for an equivalent plane for the last point of contact (LPC).

Idealized Bending Stress σ_a (Y_b)

Because of the complexity of the bending process of a conductor under tension as described above, a simplified model has been developed (Poffenberger and Swart 1965) and is, since then, almost exclusively and extensively used in order to calculate "idealized" conductor stresses. These are used as a sort of "figure-of-merit" or reference stresses, in order to compare the vibration intensity of different conductors, as determined by bending amplitude measurements in the field, and also to put them in perspective with the so-called safe stress limits or fatigue endurance limits (accumulated stress or S/N (Wöhler) curves) (Figure 20.27) (Cigré 1995), as a comparison which enables a statement about the conductor endurance capability.

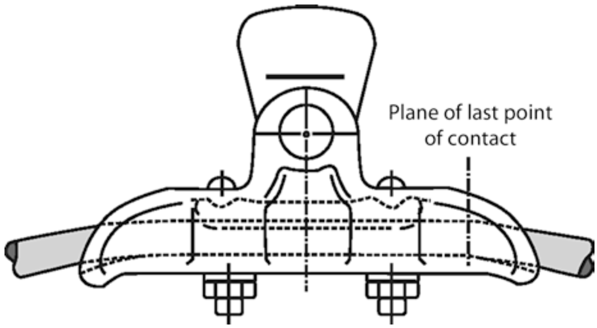
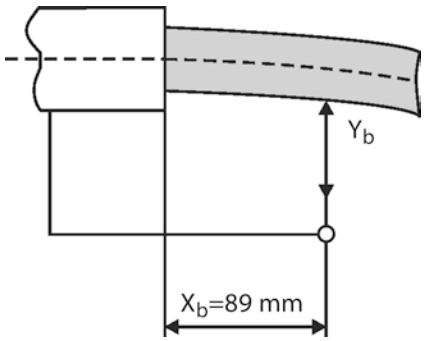


Figure 10.32 Conductor supported in a typical short metallic clamp.

Figure 10.33 Bending model of a conductor supported in a square face block.



From the model shown in Figure 10.33 Poffenberger and Swart proposed the calculation of an idealized bending stress $\sigma_a(Y_b)$ in the top-most outer-layer strand of the conductor, in the plane of the last point of contact:

$$\sigma_a\left(Y_b\right) = \frac{E_a\, d\, p^2}{4\left(e^{-px} - 1 + px\right)} Y_b \tag{10.12}$$

where:

Y_b: bending amplitude (m peak-to-peak)
E_a: Young's modulus of elasticity of outer-layer wire material (N/m^2)
d: diameter of outer layer wire (m)
$p = (T/EI_{min})^{1/2}$
T: conductor tension at average temperature during test period (N)
EI_{min}: sum of flexural rigidities of individual wires in the cable (N m^2)
x: distance from the point of measurement to the last point of contact between the clamp and the conductor (m).

In Equation (1) the *idealized bending stress* is expressed as a function of the bending amplitude Y_b.

Idealized Dynamic Stress $\sigma_a(Y_b)$

However in certain circumstances, the parameter $f\,y_{max}$ could be a more practical parameter. Figure 10.34 shows the case of a standing wave vibration with rigidly fixed supporting clamp at the left end of section (a).

In that case, the *idealized dynamic stress* σ_a can be expressed as a function of $f\,y_{\max}$:

$$\sigma_a\left(f\,y_{\max}\right) = \pi\,d\,E_a\sqrt{\frac{m}{EI}}f\,y_{\max} \qquad (10.13)$$

where:

E_a: Young's modulus of elasticity of outer-layer wire material (N/m^2)
d: diameter of outer layer wire (m)
f: frequency of the motion (Hz)
$y_{\max}$: free loop amplitude (m zero-peak)
m: conductor mass per unit length (kg/m)
EI_{min}: sum of flexural rigidities of individual wires in the cable (N m^2)

The reader must be warned that the idealized bending stresses $\sigma_a(Y_b)$ and $\sigma_a(f\,y_{max})$ do not have the same value and do not correspond to the stress that would be measured on the conductor wire but as stated above shall be considered as a mere figure-of-merit.

The Poffenberger-Swart approach assumes that the vibrating conductor near the clamp acts as a fixed cantilever beam under tension, with an imposed deflection (half the bending amplitude) at the free end. The bending stiffness of this beam is taken as the sum of the bending stiffness of the individual wires which are considered to be parallel, EI_{min}, i.e. with the assumption "wires loose", no interstrand friction. The so-called Poffenberger-Swart (PS) formula which ultimately relates (measured) bending amplitudes with (calculated) wire stresses in the outer conductor, has been a valuable tool for the assessment of vibration severity of overhead line conductors for more than 30 years. Because of its relatively easy and straightforward application, it has been adopted by practically all researchers in this field and has become the *de facto* standard for the calculation of a "nominal" conductor stress on the outer layer for a given (measured) bending amplitude. Because of this "standardization", its main contribution has been to enable comparative statements, very valuable if not absolutely exact, on the effects of a certain vibration level to the mechanical safety level, limit stress, of a conductor.

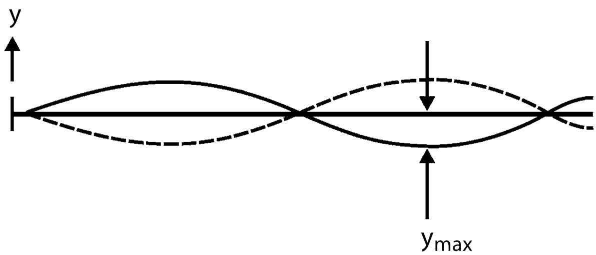


Figure 10.34 Free loop amplitude $y_{\max}$.

Since the very beginning of the introduction of this formula, there has been a certain "uneasiness" of its "universal" application, i.e. without considering the approximations underlying its development. In particular for small vibration amplitudes – which in the field accumulate the highest number of cycles and have thus a significant effect on conductor endurance – even Poffenberger and Swart mentioned, in the closure of their seminal paper, that there is a "cloud" of uncertainty in this region.

The main reason for this statement has been that one would expect intuitively, that for small bending amplitudes, the individual strands of the conductor would "stick" together, and thus the conductor would behave as a "solid rod", responding to the bending load with its maximum bending stiffness. This should lead theoretically in significant higher stresses in the wires for small bending amplitudes, than those predicted by the PS formula (Papailiou 1995, 1997). With increasing bending amplitudes more and more wires slip, the conductor bending stiffness comes closer to EI_{min} and thus the PS formula becomes a good approximation for the wire stresses in the outer layer. Figure 10.35 shows the bending stress versus bending amplitude as calculated according to the PS formula and the bending stress versus bending amplitude in accordance with the "stick–slip" theory.

There have been various approaches to overcome this problem, such as using empirical factors to the bending stiffness etc., but none of them achieved wide acceptance. Also there have been some publications (Lanteigne et al. 1986; Ramey 1987) presenting strain measurement results on conductors not in good agreement with the PS formula, but again, they remained largely unnoticed.

Fatigue Endurance Limits and Data Base

Fatigue test data are available for only a small fraction of the conductor sizes and types that are in use, and such data are expensive to acquire. Endurance limits based on the bending amplitude Y_b are available (EPRI 2009) for: 74 ACSR conductors, 4 steel conductors (7 strands) and 2 AAAC conductors (7 strands). A general bending amplitude limit for ACSR conductors is proposed at 0.23 mm. Bending stress/strain endurance limits for aluminium based conductors are provided by different sources.

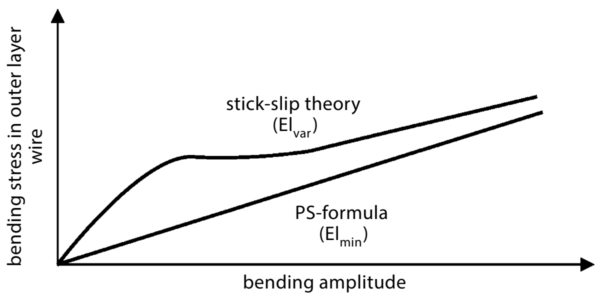


Figure 10.35 Bending stress in outer layer wires as a function of bending amplitude.

Originally, (IEEE 1966) suggested an endurance limit of 150-200 microstrain (με) peak to peak. With accumulating experience these limits were considered too conservative and values up to 300 με peak to peak have been adopted by utility's specifications.

EPRI (2009) suggests for multi-layer ACSR conductors a bending stress endurance limit of 8.5 MPa which correspond to a bending strain of 247με peak to peak. For multi-layer AAAC conductors, EPRI suggests a more conservative limit of 5.7 MPa which correspond to a bending strain of 165με peak to peak.

A bending stress/stain endurance limit can be derived from the Cigré Safe Border Line considered asymptotic at 5×10^8 cycles. This value corresponds to 9.09 MPa and to a bending strain of 264 με peak to peak.

The limits are valid *only* for conductors with round aluminium strands in conventional suspension clamps with and without armour rods (Figure 10.36).

No specific values are available for other conductors and conductor/clamp combinations.

10.3.2.8 Behaviour of Single Conductors with Dampers

Vibration dampers for single conductors have been extensively treated in Chapter 9. The most common of them is the Stockbridge damper that have been used on transmission lines for the past 90 years (Figure 10.37). A damper function is to reduce the vibration levels in all location in the span below the endurance limits established for the specific conductor.

It is well known that, if the conductor tension (or, more precisely, the ratio between tension and cable unit weight H/w) exceeds certain limit values, aeolian vibrations may cause serious conductor and fitting damage. This problem has been dealt with in (Cigré TB 273 2005a) in which the H/w limit values for various types of undamped conductors and wind turbulence conditions are defined. These H/w limits are generally exceeded on transmission lines and then suitable dampers are needed to protect conductors, as it is a well established practice.

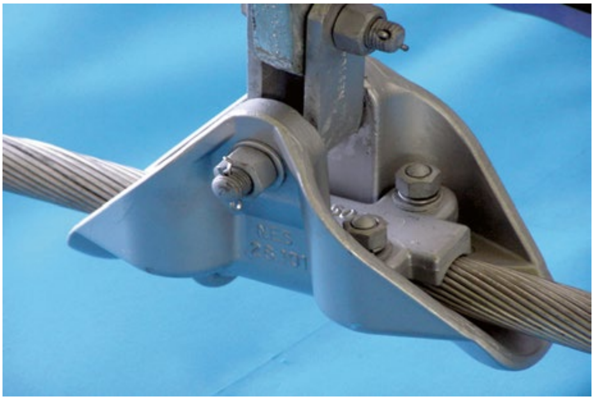


Figure 10.36 Conventional metal to metal suspension clamp.

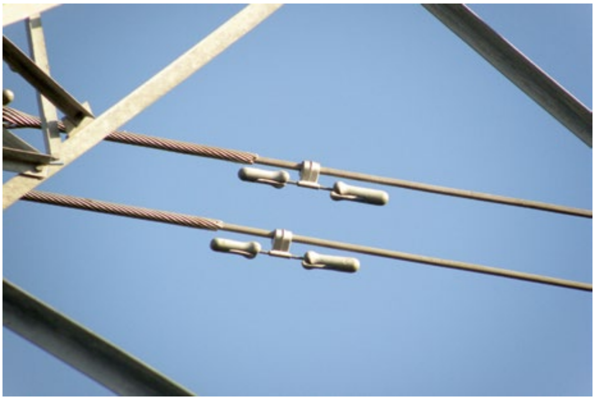


Figure 10.37 Stockbridge type vibration dampers.

While designing a new transmission line it is important to know how much additional damping is needed to control aeolian vibration within safe levels. To this purpose, various researchers have developed computation methods – based on the energy balance principle (EBP) – to predict the aeolian vibration level of a single conductor and or a conductor plus damper and to define the damping system most suitable for the different cases: these methods are based on the knowledge of the damper dynamic characteristics as measured on a shaker (IEC 1998). The evaluation of the computation methods, through direct comparison between analytical and experimental data is reported in 10.3.2.10.

Another method is to assess the efficiency of a damping system using a laboratory test span where the conductor and dampers are installed. The conductor is usually excited using an electrodynamic shaker. This method reproduces the interaction between the conductor and damper and is thus more accurate but it is more costly and is more time consuming than the analytical approach.

10.3.2.9 Vibration Damper Positioning

On free spans, i.e. in spans where there are no reflection points, such as warning devices, or other heavy items, vibration dampers are normally applied at span extremities. Other position criteria called in-span damping are considered only in very special cases. For normal spans, under non critical wind conditions, one damper per span can generally provide adequate protection. However, it is a good engineering practice to install at least two dampers per span (one at each extremity) to introduce a suitable safety factor. In fact, if for any reason (manufacturing defects, wrong location, clamp loosening, etc.) the single damper did not work properly, the entire span would be left unprotected.

Correct positioning is essential for the performance of vibration dampers, like Stockbridge dampers and elastomeric dampers, as they do not work properly if they are located close to a nodal point at anty vibration frequency. On the other hand, positioning is not critical for spiral dampers as they are long enough to envelop a vibrating portion of the conductor. A suitable location point, that never become a nodal point in the whole range of aeolian vibration for a specific conductor size, is generally considered to be at 70-80 % of the first loop length of the vibration frequency corresponding to the maximum wind velocity considered. This is a suitable position for a vibration damper and its distance from the last pint of contact between the conductor and the suspension clamp can be calculated starting from the equation of the wave length:

$$\lambda = \frac{1}{f}\sqrt{\frac{T}{m}} \tag{10.14}$$

where

λ = wave length (m)
f = vibration frequency (Hz)
T = conductor tension (N)
m = conductor mass per metre (kg/m)

The equation of the loop length is as follows:

$$\frac{\lambda}{2} = \frac{1}{2f}\sqrt{\frac{T}{m}} \tag{10.15}$$

The damper position can be calculated from the following equation

$$x = k\frac{1}{2f_{\max}}\sqrt{\frac{T}{m}} \tag{10.16}$$

where

x = damper position (m)
f_{max} = maximum vibration frequency
k = variable between 0 and 1, giving damper position as a fraction of the minimum loop length at f_{max} (generally taken between 0.7-0.8).

Considering the Strouhal formula:

$$f = 0.185\frac{v}{d} \tag{10.17}$$

where

f = vibration frequency (Hz)
v = maximum wind velocity (m/s)
d = conductor diameter (m)

equation (10.16) can be written as follows:

$$x = k\frac{d}{0.37v}\sqrt{\frac{T}{m}} \tag{10.18}$$

If the maximum wind speed of 7 m/s is considered, the installation point at 80 % of the corresponding vibration loop ($k = 0.8$), can be calculated as follows:

$$x = 0.31d\sqrt{\frac{T}{M}} \tag{10.19}$$

therefore

$$x = 0.00031d\sqrt{\frac{T}{M}} \tag{10.20}$$

when d is expressed in millimeters.

For any other value of maximum wind speed to be considered v_X, x, in equation 10.19 and 10.20 shall be multiplied by $7/v_X$.

Obviously, the above procedure, although generally applicable, is rather approximate since it does not consider the conductor bending stiffness and cannot take into account the presence of armour rods and the influence of the damper on the vibration profile of the conductor. Moreover, the optimum positioning of the damper should consider its dynamic performance. For example, a damper that responds weakly at low vibration frequencies can work better if located at a longer distance from the end clamp; vice versa, installing the damper closer to the end clamp, the performance at higher frequencies will be improved. Computer calculations based on EBP are generally used by the manufacturers to determine the optimum positioning of their dampers as well as to establish the number of units per span.

In spans, to be equipped with two dampers, the best solution is to apply one damper per span extremity rather than placing both dampers at one extremity only. The dampers are generally positioned at the same distance from the span extremities, although sometimes a different spacing can help to cover a wider frequency range (Figure 10.38).

For tension-suspension spans, when using only one damper, the damper should be placed at the suspension extremity.

When two damper per span extremity are deemed necessary, the position of the second damper, is generally taken at a distance from the first damper equal to 80-100 % of the distance x.

Tension clamps are less critical then suspension clamps, especially at low frequencies where the clamp can follow the conductor motion and the conductor at the clamp mouth is not subjected to bending stress. The installation of a vibration damper at a tension clamp, as well as near other fittings such as warning spheres and other devices that show a degree of mobility at lower frequencies, is generally made using the same criteria as for the suspension clamps.

Modern vibration dampers of Stockbridge type are asymmetric having two masses of different weight and different arm lengths. The installation of these dampers is generally performed with no consideration about the orientation of the masses. In fact, the difference of the damper performance with different orientation of the masses is supposed to be negligible (EPRI 2009).

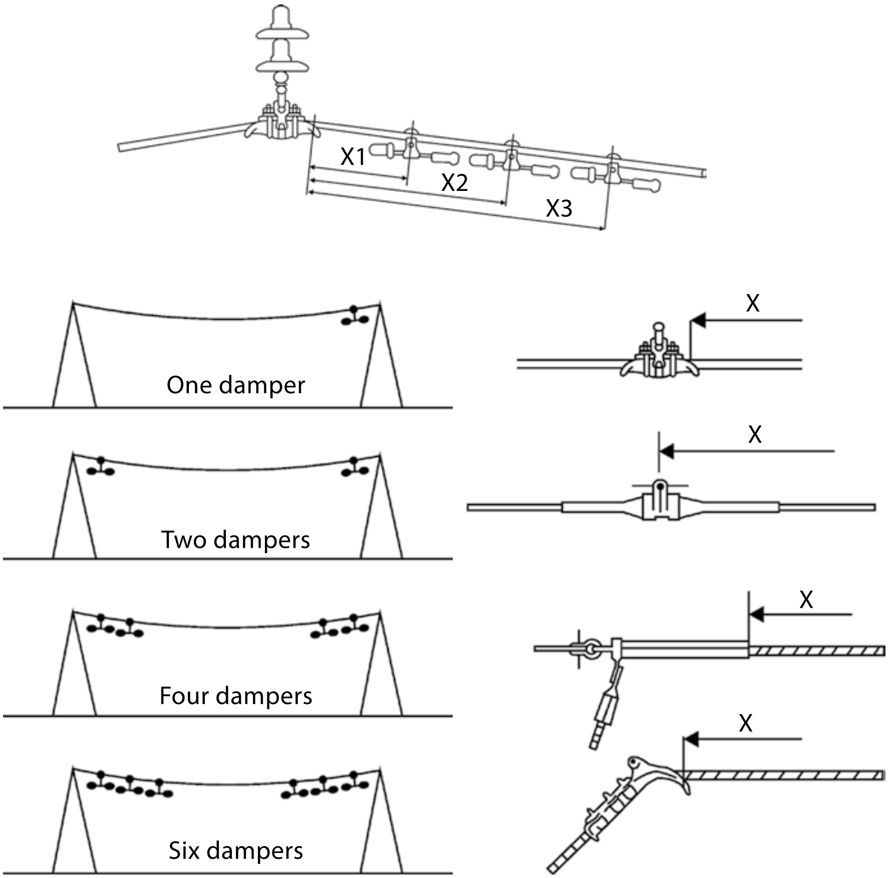


Figure 10.38 Distribution of vibration dampers per span and datum point for positioning measurements (Courtesy Damp).

10.3.2.10 Modelling of Aeolian Vibration for Single Conductors

Study Committee 22 of Cigré (1998a) proposed and evaluated an analytical approach to be used to investigate alternatives in the design or re-design process of conductor with respect to aeolian vibrations. The study was done in four parts: first the wind power input was defined by means of experimental data, hence the self damping of a single conductor was identified, then by means of EBP approaches, the behaviour of the conductor with respect to aeolian vibrations was predicted and numerical and experimental data were compared.

Subsequently a detailed analysis of the effect of uncertainties in conductor self-damping and wind power on conductor response was carried out.

The main outcome was that EBP approach is able to provide a good estimate of the frequency range and of the distribution of vibration amplitudes with frequency.

Further, if the assumed ranges of uncertainties in wind power functions and self damping models are realistic, then the range of uncertainty in EBP predictions of vibration amplitude is about 50 %.

A further study (Cigré 2005c) compared several computation methods with results obtained on an experimental span, to predict the aeolian vibration level of a conductor plus damper. This allowed the selection of suitable damping. These methods use the damper dynamic characteristics as measured on a shaker. Several dampers, of the same type as the one installed on the test line, were tested on the shaker but not the same sample. The comparison between analytical and experimental results was probably affected by this additional source of uncertainty.

As a result of this benchmark, considerable variability in the output of EBP models can be found and there is not always perfect agreement between numerical and experimental data. This is also due to the steady state or stationary condition assumed in the analytical approach; in fact vibration is a result of a complex interaction between the conductor and the turbulent wind, usually with many frequencies simultaneously excited, rarely reaching a steady state or stationary condition. Moreover, the boundary condition can modify the conductor deflection shape significantly, and, consequently, the energy dissipated by the damper.

However it can be concluded that methods based on the EBP and shaker-based technology can provide a useful tool for designing damping systems for the protection of single conductors against aeolian vibrations. However, it should be used with circumspection and be supplemented by references to field experience.

Finally, the effectiveness of the EBP methods was analyzed for the design and/or verification of the damping system of long single conductor spans strung at relatively high tensile load, such as crossings, which need more than one damper per span extremity to be effectively damped against aeolian vibration (Cigré 2011a). An analytical-analytical benchmark was carried out: the amplitudes predicted by the various available models applied to a certain test case were compared against each other; furthermore, a second benchmark was carried out where the amplitudes predicted by analytical model were compared to amplitudes actually measured in a field test. The benchmark concluded that the use of the EBP approach based on the shaker-based technology does not fully take into account the complexity of such long single conductor spans.

Future research work is needed to improve the EBP technology, which generally produces a safe design of the damping system. Future work is also needed to better understand the effect of turbulence and mean wind speed variation, together with a better simulation of the mechanical system, to reproduce tensile load variations and multi-frequency excitation.

10.3.2.11 Bundle Conductors

In the last forty years, due to the advent of Extra High Voltage and Ultra High Voltage Overhead Transmission Lines (EHV and UHV OHTL) bundles of two, three, four, six and eight sub-conductors, with spacing ranging between 300 and 600 mm were gradually introduced in place of single conductors to guarantee electrical performance (EPRI 2009).

Depending on the nominal voltage of the line, different bundle geometries were developed (Figure 10.39) and suitable spacing devices were distributed along the spans to maintain the sub-conductor separation within the design limits under all conditions of normal service.

At the beginning, rigid spacers were installed to maintain the subconductor separation but failures of the subconductor strands were found at the spacer clamps. The cause was attributed to the entrapment between the spacers of the vibration that could not be mitigated by the dampers located at the span extremities. In addition, sustained oscillations, now referred to as wake induced oscillations, were observed on bundles and one of these: subspan oscillation, was considered as a potentially dangerous phenomenon (see Section 10.3.3). To safely accommodate these motions, flexible spacers were used and later damping elements were introduced into the spacers that became spacer dampers and the vibration dampers at span extremities were eliminated except for special cases.

Classification of Bundle Spacers

The characteristics of the various types of spacers for bundled conductors are reviewed in Chapter 9. Here, the fundamental differences between rigid, flexible and damping spacers are described for a better understanding of the bundle response to wind action.

Spacer Damper

The term "spacer damper" applies to spacing devices whose inertial, elastic and damping properties are specifically defined to control, within safe limits, the levels of sub-conductor motions induced by the wind. The term "spacer damper system" identifies the complex of spacer damper units installed on the line together with the relevant in-span distribution scheme.

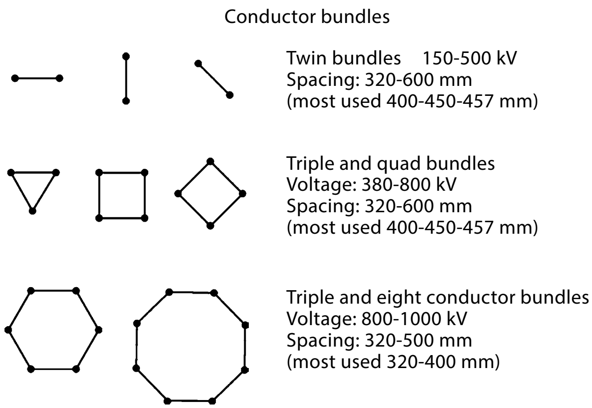


Figure 10.39 Types of bundles.

The damping mechanism of the spacer dampers is based on the dissipation of a certain amount of the sub-conductor vibration energy by means of the resilient material (generally elastomer bushes) contained into the articulations (Figure 10.40). To do that, the spacer damper arms must rotate to allow the resilient material to absorb energy by deformation.

Flexible Spacer

The flexible spacer is designed to maintain the nominal spacing between subconductors while allowing subconductor relative motions, during the normal operations of the line. Elastic properties are incorporated to ensure that the spacer will restore the bundle's nominal configuration when the external loads are removed. The spacer is equipped with elastomeric bushes or other flexible mean, but no damping properties are included.

Rigid Spacers

Rigid spacers do not allow any relative movement of the bundle subconductors at their location. They are no longer used on tensioned spans but on jumper loops and slack spans only.

Bundle Response to Wind Action

Although a bundle would appear simply composed of a number of single conductors, its dynamic response to exciting forces is substantially different from that of the single conductor, due to the forces that are developed by the spacers under the sub-conductor motion.

A single conductor is free to vibrate in any plane passing through its longitudinal axis. The orientation of this plane depends on the direction of the exciting forces. Aeolian vibrations of a single conductor, for instance, develop in a vertical plane since the direction of the relevant exciting forces is substantially vertical.

In a bundle, however, as a result of the mechanical connections existing between the sub-conductors due to the spacers, the motion of the sub-conductors at resonance must always be such that the vectorial summation of all the forces, applied to

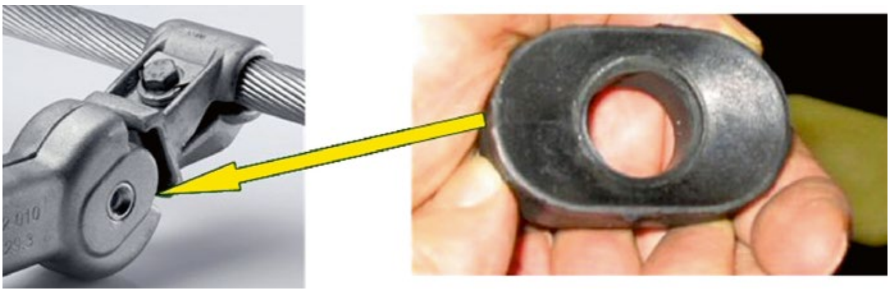


Figure 10.40 Spacer damper articulation (Courtesy Pfisterer-Sefag).

the spacers by the sub-conductors, results in the spacers being in a condition of dynamic equilibrium. Consequently the planes, along which the harmonic motion at resonance of the sub-conductors may occur, are established by the spacer characteristics and bundle geometry.

For an imaginary weightless spacer, with purely elastic response, Figure 10.41 illustrates the typical directions of sub-conductor motions (natural modes), as seen from any bundle cross-section (Claren et al. 1974). In particular any bundle of n sub-conductors equipped with identical spacers will have 2n groups of natural modes and hence an infinity of natural mode shapes, but each modal shape belonging to a group will have the same plane of vibrations of the sub-conductors when the inertial forces of the spacer are neglected.

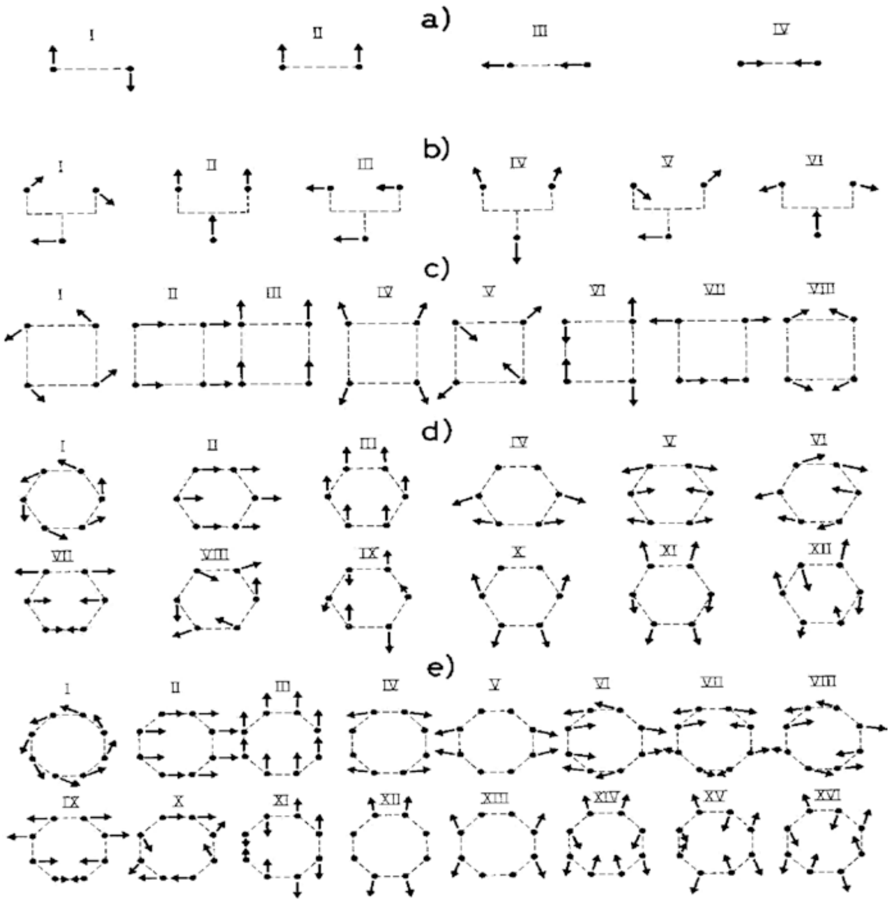


Figure 10.41 Groups of natural vibration modes: (**a**) two conductor bundle (**b**) three conductor bundle (**c**) four conductor bundle (**d**) six conductor bundle (**e**) eight conductor bundle (Claren et al. 1974).

A real spacer is not weightless and its masses will react producing inertia forces when subjected to harmonic motions. If the masses are directly and rigidly connected to the sub-conductors, such as the clamps, the inertia forces will simply be of opposite sign to the elastic forces and consequently the planes of oscillation will not be modified. If the masses are, instead, suspended from the sub-conductors through an elastic medium such as, for example, the central frame, their effect will modify not only the value but also the direction of the spacer elastic forces, and thus will modify the planes of oscillation in respect to those shown in Figure 10.42. It is not possible to generalize in this case typical modes as illustrated for a pure elastic spacer, as the effects of the inertia forces depend not only on their location on the spacer but also on the vibration frequency. However, true bundle motions can be considered as the result of a vectorial combination of a number of natural modes, the contribution of each depending on the spacer design and the frequency of oscillation.

Another fundamental difference between the response at resonance of a single conductor and the response of a bundle equipped with spacers is that, for a single conductor, the antinode amplitudes are practically the same all along the span, while for a bundle, quite often, the antinode vibration amplitudes of each sub-span differ from those in another sub-span. This phenomenon is greatly influenced by the forces that the spacers impart to the sub-conductor as a reaction to the bundle motion, and by the distribution of the spacers along the span.

Whilst, on a single conductor the maximum bending stress will always be found at the span ends for any frequency, on a bundle it will be found at locations that may be different for each frequency, due to the sub-span effect; therefore, damping devices installed only at the span extremity cannot reduce the vibrations of the whole span for all the vibration modes, as it is possible for single conductor.

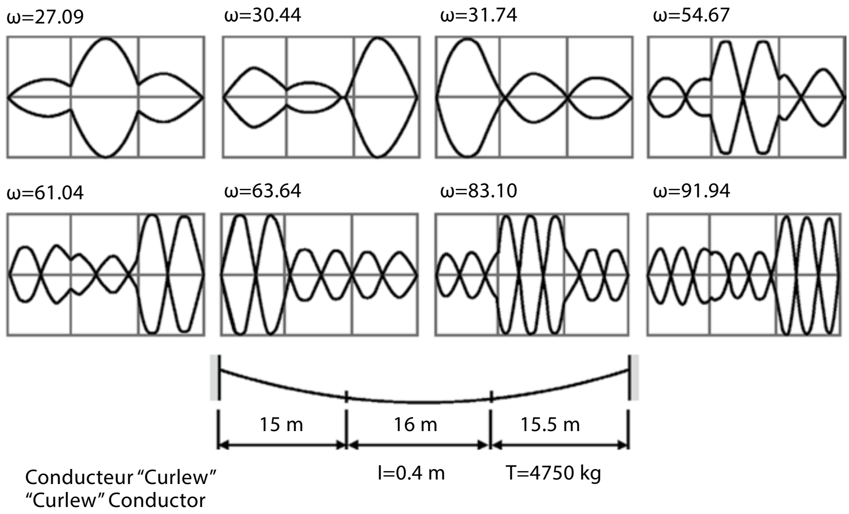


Figure 10.42 Example of natural shape along the span in a two conductors bundle (Claren et al. 1974).

The above justifies the application of spacer dampers which allow the presence of a damping action in each sub-span.

On single conductors, the span extremities can be effectively protected by vibration dampers attached near the suspension or tension clamps. On bundled conductors, the span extremities can also be protected by local vibration dampers but the vibration levels within the sub-spans will depend on the bundle geometry and the mass and flexibility of the spacers. Single vibration dampers, on each of the sub-conductors at each span end, have performed satisfactorily provided suitable flexibility has been incorporated into the spacers to minimize the entrapment of vibration inside the subspan. Spacer dampers alone have, in general, performed well, except for twin bundles, while rigid spacers, even with separate vibration dampers, have given rise to conductor fatigue failures.

The optimisation of the type and the position of the spacers on a span is made with respect to problems of wind excited vibrations: mainly instability phenomena (sub-span oscillations) and aeolian vibrations; other phenomena taken into account are ice galloping, bundle twisting due to ice loads and short circuit forces.

For aeolian vibration, the parameter of interest is mainly the type and number of spacers, whilst their location is not so important. Because of the wave length values involved in this phenomenon, tolerances allowed in spacer positioning (generally ±1 m) make sub-span lengths automatically different, one from another. As a result, whatever the spacing, it is practically impossible that, for any mode of vibration of the conductor, all the spacers are at nodes of the deflected shape and give no contribution to the energy dissipation. The optimisation of the spacer location with respect to aeolian vibrations is not useful: it is much more important to optimise the spacer type and its characteristics (stiffness and damping of the elastic elements, geometry and inertia of the parts).

In the case of subspan oscillation the parameters of interest are the location of the spacers along the span (ratio between the lengths of two adjacent sub-spans) and the maximum sub-span length as discussed in details in Section 10.3.3.4.

Vibration Behaviour of a Horizontal Twin Bundle

It has been illustrated that the resonant bundle motion is defined by the planes on which the sub-conductor motion occurs and by the antinodal amplitude occurring in each sub-span. All these characteristics depend from the direction and amplitude of the forces that the spacer develops simultaneously on all the sub-conductors under resonant conditions. It will be noted, for example, that for motions I, II and III, such as illustrated in Figure 10.41, for all type of bundles no relative movement between sub-conductors exists, while, for all the other motions, the relative movements between the sub-conductors will cause an elastic reaction with respect to the spacer frame. Modes I, II and III are called “bulk” or “rigid” modes and do not produce spacer arm rotation.

The ability of a spacer damper to control the bundle vibrations is also related to the capacity of the main frame to develop inertia forces able to combine bulk modes, where no damping effect can be produced, with one or more of the other natural modes, which can cause spacer arm rotation and consequently dissipation of energy.

However, in bundles of three subconductors and above, the presence of a bulk mode is unlikely as there are always relative movements between sub-conductors at spacer damper locations. This is due to the fact that the sub-conductors vibrate at slightly different frequencies and with different phase and amplitude.

The relative movements between sub-conductors produce rotation of the spacer damper arms allowing the articulations to dissipate energy.

In twin bundles, on the contrary, aeolian vibration does not produce relative movements between sub-conductors at spacer damper location. In fact, any difference in vibration frequency, phase and amplitude between the two sub-conductors always results in a bulk rotation and vertical translation of the bundle that cannot determine the rotation of the spacer damper arms. In these cases, the main frame of the spacer damper should develop inertial forces able to produce arm rotations and consequently dissipation of energy as shown in Figure 10.43.

However, at low vibration frequencies the spacer damper frame develops only small inertial forces that may not be sufficient to produce a suitable arm rotation. In this case, the spacer dampers may be unable to dissipate the amount of energy needed to mitigate the vibration levels of the conductors within safe limits. On the other hand, the mass and the moment of inertia of the spacer damper frame cannot be increased, above a certain limit, to achieve the required inertial reaction, for technical and economical reasons. Considering the above, it is clear that, when a consistent damping effect is required on a twin bundle, the spacer dampers are unable to control the levels of aeolian vibrations, at least at low frequencies, and a different solution must be used.

When spacer dampers alone are not suitable, the best solution is to apply non-rigid spacer (semirigid, flexible or articulated) together with vibration dampers at span extremities.

The spacers should be light in order to prevent entrapment of vibration within the sub-spans and to allow the vibration to run freely toward the span ends where it will be mitigated by the vibration dampers.

For any specific twin bundle configuration, computer simulations or field vibration measurements will clarify whether spacer dampers alone are sufficient to control aeolian vibration or spacers and separate vibration dampers should be considered.

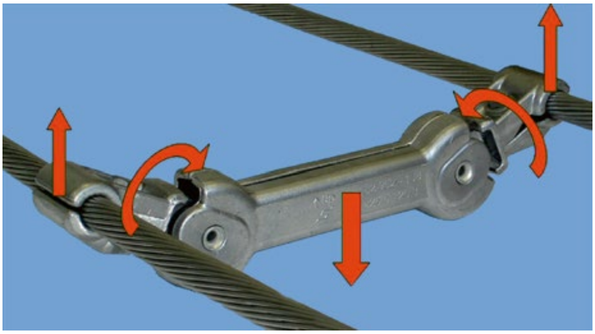


Figure 10.43 Inertial reaction of the spacer frame.

Vibration Behaviour of a Vertical Twin Bundle

As reported in Section 10.3.4, single conductors are less sensitive to galloping than bundled conductors, as single conductors are more prone to rotate under ice accretion which gives to the ice deposit a profile more aerodynamically stable. Thus, one solution to mitigate galloping on twin bundles is to remove the spacers in order to allow the free rotation of the conductors under ice accretion. However, without spacers, the sub-conductors of the horizontal twin bundle will be subjected to collision due to wind buffeting and electrodynamic forces. This can be prevented in two ways:

- installing special spacers called “hoop spacers” shown in Figure 10.44.
- changing the arrangement of the subconductors from horizontal alignment to vertical or diagonal alignment.

Hoop spacers are connected to one subconductor or the other alternatively. They do not link the subconductors, that are free to rotate, but can prevent collision between them.

Hoop spacers do not have any damping capacity and the aeolian vibrations are controlled by vibration dampers installed at span extremities on both subconductors.

On twin bundles in which the subconductors are vertically or diagonally arranged, the spacers are removed and the aeolian vibration are controlled by vibration dampers installed at span extremities on both subconductors (Figure 10.45).

However, on unspacered bundles, at load current conditions, electromagnetic attraction between subconductors may cause a reduction of the spacing or collapse which results in increasing the strength of the electrical field. This produces excessive audible noise levels and, in case several spans are involved, a significant increase of line impedance with consequent effects on both the power flow and the performance of the line protections (Leppers and Lillien 1982; Adami et al. 1983). In these cases, a minimum number of spacers should be used. If only one spacer at midspan is required, a rigid or semirigid spacer can be considered suitable, provided vibration dampers are installed at both span extremities in order to protect the two subspans against aeolian vibration.

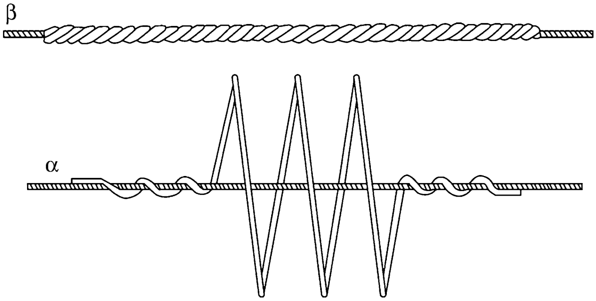


Figure 10.44 Hoop spacer.

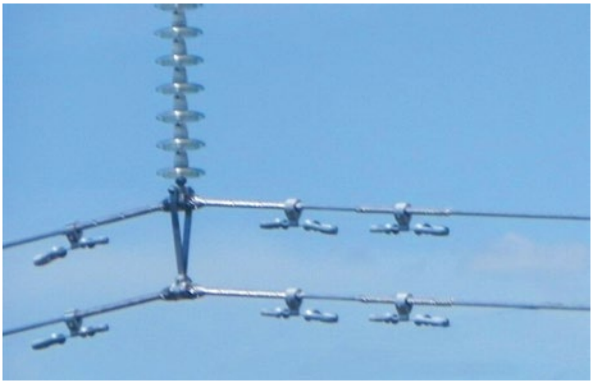


Figure 10.45 Vibration dampers on a vertical twin bundle.

If more than one spacer is necessary, it should be considered that rigid or semirigid spacers divide the span in a number of subspans in which aeolian vibration can be easily entrapped and cannot be mitigated by the vibration damper installed at span extremities. In these cases, flexible spacers or spacer dampers suitable for this bundle configuration are required.

Recent experience with vertical twin bundles, equipped with two or more semirigid spacers and vibration dampers at span ends only, has shown failures of the conductors at spacer locations.

Modelling of Aeolian Vibration for Bundled Conductors

It has been shown in Section 10.3.2.9 that analytical methods based on the Energy Balance Principle and a shaker-based technology can provide a useful design tool for damping systems that protect a single conductor against aeolian vibration.

In order to evaluate the effectiveness of the available methods for the design and/or verification of the damping system of conductor bundle spans with respect to aeolian vibrations, an analysis of the available technology and two benchmarks: an analytical-analytical benchmark and an analytical-experimental one have been carried out within Cigré WG B2.46.

The comparison between the analytical results produced by the different available models and the experimental ones helped to understand the limitations and the usefulness of the approaches considered.

Field tests on a 500 m quad bundle span equipped with ACSR Drake conductor and spacer-dampers have been selected as test case both for the analytical-analytical and analytical-experimental benchmark. The selected case has an H/w parameter around 2000 m.

The study was carried out by comparing the results of EBP based calculations coming from two sources describing three different studies (Cigré TB 273 2005a; Claren et al. 1971). The studies differ in the wind power input functions, self-damping models, and the modelling of the effects of wind turbulence (Cigré to be published).

In order to provide comparable results and highlight the main differences in the models, the same energy input from the wind and the same dissipated energy for the conductors have been introduced in the analytical-analytical benchmark. Moreover, the same tensile load is applied on the conductors of the bundle. Good agreement between the results of the different models were obtained.

In the analytical-experimental benchmark the models are used to identify the strain amplitudes at the suspension clamp to be compared with the experimental results.

In addition to the two benchmarks, a sensitivity analysis has been carried out to identify the impact that tension differential and variable turbulence can have on aeolian vibration. It was observed that a non negligible impact can be seen, however it is not straightforward knowing the real value to assign to the turbulence and to the tension differentials when the bundle behaviour for aeolian vibrations must be analysed.

One of the most important results of these two benchmarks is that the computed vibrations have a very similar trend even if some differences in the models are present.

As far as the experimental-numerical benchmark, the numerical results appear to be generally conservative at low frequencies.

However it is needed to point out that, generally, when dealing with twin bundles, numerical results appear to be less conservative compared to the experimental data (Cigré 2005a; Belloli et al. 2003).

10.3.2.12 Vibration of Tower Members

Wind induced motions of the conductors may induce resonances in structural elements, which may result in fatigue failures. Vibration of tower members can originate also from direct aeolian excitation. However, for structural members with T, L and circular cross section, self-excited aeolian vibration may occur only for slenderness ratio (calculated for bending in the plane of vibration) greater than 250 (Carpena and Diana 1971). Member vibration may also result from forces associated with galloping and wake induced oscillations of the conductors. The remedy can consist of the application of dampers (Havard and Perry 2003) or in the stiffening of the vibrating elements.

10.3.2.13 Assessment of Aeolian Vibration Severity

General

Among the various wind induced motions, (EPRI 2009) vibrations are the most recurrent and the most dangerous for the integrity of conductors and other line components. In overhead conductors, fatigue failure of strands is the most common form of damage resulting from aeolian vibrations (Figure 10.4). Conductor fatigue may also result from galloping and subspan oscillation, but is not the main problem associated with those motions.

For this reason, great efforts are devoted to the assessment of aeolian vibration severity. Five main methods are available for this task:

- Computer analysis of the conductor vibrations
- Field vibration tests on outdoor experimental spans
- Vibration test on laboratory spans

- Vibration measurements on actual lines
- Conductor inspections on actual lines.

Each method offers its own contribution to the total picture. Although they are inter-related, their limitations and concepts are somewhat different.

Computer Analysis of Conductor Vibrations

The most comprehensive medium to predict the vibration behaviour of a conductor is the computer simulation performed by means of specific computer programs (Figure 10.46). Other methods based on abacus, diagrams and nomographs can only provide qualitative information. For example, the procedure proposed in the Cigré TB "Safe Design Tension with Respect to Aeolian Vibration" (Cigré TB 273 2005a) can usefully determine whether additional damping is required or not but cannot provide data about the damping system to apply.

Computer analysis (Claren et al. 1974; Cigré 1998a), is mainly used during the design of the line to anticipate the performance of single and bundled conductors under aeolian vibration and to determine, when necessary, the characteristics of the damping system to be applied on the conductors.

Outdoor Experimental Spans

Outdoor experimental spans, exposed to natural wind, have been built in several countries world-wide for research purposes and for the comparative evaluation of conductor damping systems proposed for important projects (Cloutier et al. 1974; Houle et al. 1987). Some test stations have been used also for the evaluation of new damping systems and for the assessment of the vibration behaviour of new line configurations (Figure 10.47).

These test stations represent the most accurate mean for the investigation of vibration phenomena as they can be extensively instrumented with recording and monitoring systems. However, the considerable costs involved can be afforded only

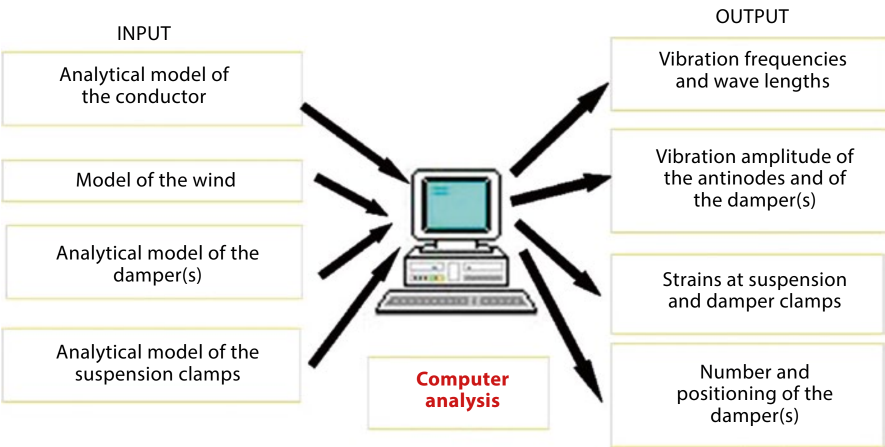


Figure 10.46 Computer analysis of a single conductor plus damper(s).

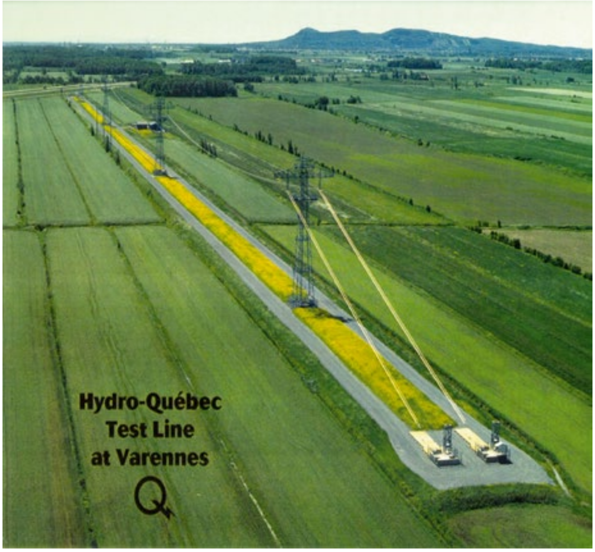


Figure 10.47 Outdoor test station of IREQ, Canada.

by government financed Power Authorities and Research Institutes or justified by some major transmission project.

Laboratory Spans

Vibrat+ion tests on indoor laboratory spans, generally 30 to 90 m long, can provide important information on the conductor dynamic characteristics such as self-damping (Cigré TB 482 2011b) and dynamic bending stiffness. Moreover extensive tests are performed to assess the fatigue behaviour of various conductor–clamp systems (Cigré TB 429 2010) and effectiveness of vibration dampers (IEEE 1993) (Figure 10.48).

Vibration Measurements on Actual Lines

Vibration measurements on overhead lines are commonly performed as a final acceptance test of the conductor damping system, at the end of the line construction, and, on lines in operation, for assessment of vibration intensity of the conductors. Measurements of aeolian vibration on operating lines have been made in different ways using a variety of instruments that can be classified into four groups:

- Vibration detectors
- Generic transducers
- Optical vibration monitoring devices
- Specific vibration recorders (bending amplitude recorders).

Conductor vibration recorders, such as Zenith and Servis recorders and Jacquet counters, used in the period 1950÷70, were mere vibration detectors able to provide a quite rough relative index of vibration activity.

Generic transducers like accelerometers, velocity pick-up, displacement transducers, anemometer and thermometers, connected to grounded data acquisition

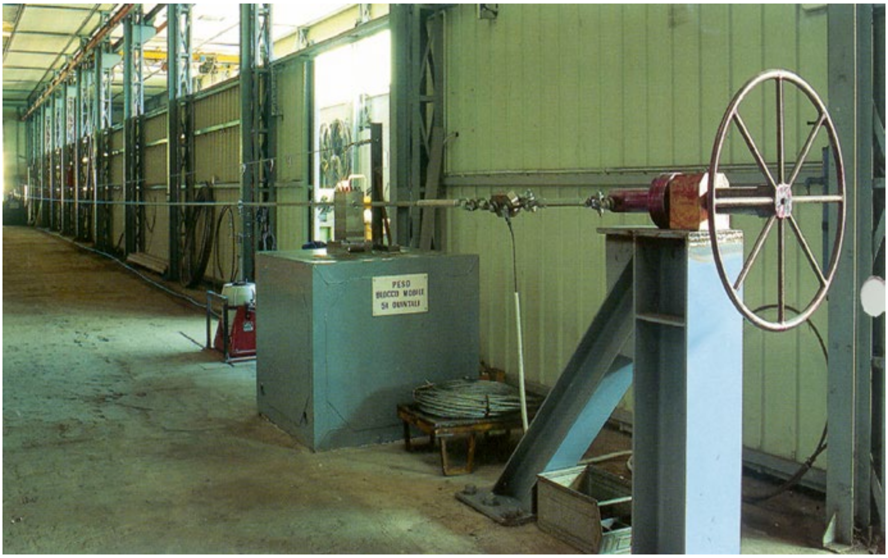


Figure 10.48 Laboratory test span (Courtesy Cariboni).

systems are normally used in outdoor test stations. In the past, they have also been used to assess the vibration severity on several operating lines (Diana et al. 1982).

Optical devices have been used to assess overhead conductor vibration and oscillation. Two systems are known so far: Opto-electronic recorders and Laser recorders. The first consists of an electro-optical camera equipped with a telephoto lens that is directed at the vibrating object from the ground. The camera transforms the vibration images into electrical signals which frequency spectrum and time history can be displayed on an oscilloscope and stored in a computer. The second consists of ground equipment emitting a low power laser beam directed to a "scotchlite" target installed on the conductor. The laser light reflected by the target returns to the instrument carrying the vibration data that are analysed and stored. Vibrations of amplitude from 50 micron to 7 m in the frequency range 0-150 Hz can be measured.

Bending Amplitude Method

The direct method to evaluate the conductor vibration severity is the measurement of the conductor bending strain at the suspension clamp mouth that is the most stressed point in a span, performed by means of strain gauges (Buckner et al. 1968; Hard 1958; Steider 1959). In this way, the data can be directly correlated with the fatigue curves of conductors that are expressed in stress–strain versus number of cycles to failure. This technique, used for a limited period of time at the beginning of this type of investigation, was abandoned in favour of methods more suitable for field application.

In 1964, Edwards and Boyd (1964) proposed the use of an easily measurable vibration amplitude called "bending amplitude" as a parameter directly related to the bending strain at the mouth of the suspension clamp. This practice had already been used successfully by Ontario Hydro for some 25 years and the same authors presented the first live-line recorder suitable for these measurements. Bending amplitude (Y_b) was defined as the total displacement peak to peak of the conductor, relative to the suspension clamp, measured at a point 3.5 inches (89 mm) from the last point of contact between the clamp and the conductor (Figure 10.49). This distance was chosen to provide a detectable displacement in the vibrating conductor, in the zone whose shape, is governed by the stiffness effect alone and not by the inertial forces acting in the vibration loops.

In 1966, The IEEE Task Force on the Standardization of Conductor Vibration Measurements recommended the bending amplitude method (IEEE 1966) as a practical method of assessing the severity of fatigue exposure of overhead conductors in all conventional suspension clamps. A simple but approximate equation was suggested to convert the bending amplitude into bending strain, and an evaluation criterion was proposed.

Later, Poffenberger and Swart (1965) formulated the dynamic deflection field of the conductor in the vicinity of a fixed clamp and provided an idealized relation to convert the bending amplitude into bending stress in the outer layer strands at the mouth of the suspension clamp.

An alternative method to the IEEE procedure, known as the "inverted bending amplitude" method was proposed (Hardy et al. 1981; Hardy and Brunelle 1991) together with a relevant measuring device usable with suspension clamps allowing access for the probe on the conductor surface. The measured inverted bending amplitude can be converted to either bending amplitude or bending stress by means of the Poffenberger and Swart theory, in order to express the measurement results in accordance with the IEEE Standardization.

The Cigré WG 22-04 recommended, in 1979, an approximate method to determine the lifetime of aluminium based conductors under the effect of aeolian vibration (Cigré 1979a). The method makes use of the bending stresses derived from the measured bending amplitudes and, based on the Palmgren-Miner's theory, permits the estimation of the life expectancy (before the first strand fatigue failure) of conductor subjected to complex bending strain spectra.

In 1995, another Cigré document (Cigré 1995) was published to provide a comprehensive guide to vibration measurements on overhead conductors performed by means of bending amplitude recorders.

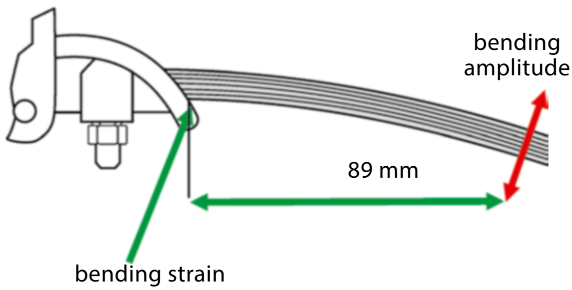


Figure 10.49 Bending Amplitude and bending strain.

IEEE has published a "Guide for Aeolian Vibration Field Measurements of Overhead Conductors" (IEEE 2006) as an update of the paper (IEEE 1966) that standardized this technique.

The bending amplitude is easier to measure than the bending strains at the clamp mouth. In a number of cases, the bending amplitude can be converted into an idealized bending strain using the Poffenberger and Swart (P&S) formula. In other cases, the conversion factor can be determined by means of laboratory tests.

Bending Amplitude Recorders

The commercial bending amplitude recorders are specific live line devices designed to perform vibration measurements, in accordance with IEEE recommendation (Figure 10.50). They are installed on the suspension clamps, with the only exception of the inverted bending amplitude recorder to be fixed on to the conductor, where it senses the motion directly above the last point of contact between the conductor and the clamp.

The recorders can be classified into two categories: analog and digital. The analog recorders are the oldest and no longer available on the market, however, a number of units may be still in operation. They can provide the time history of the conductor vibration that is an interesting information but the relevant data require time-consuming transfer for tabulation.

Digital recorders are microprocessor based, self-contained devices that use built-in memory storage. They can be connected to a computer, equipped with utility software, for the set-up of the parameters and functions, before the measurements, and for

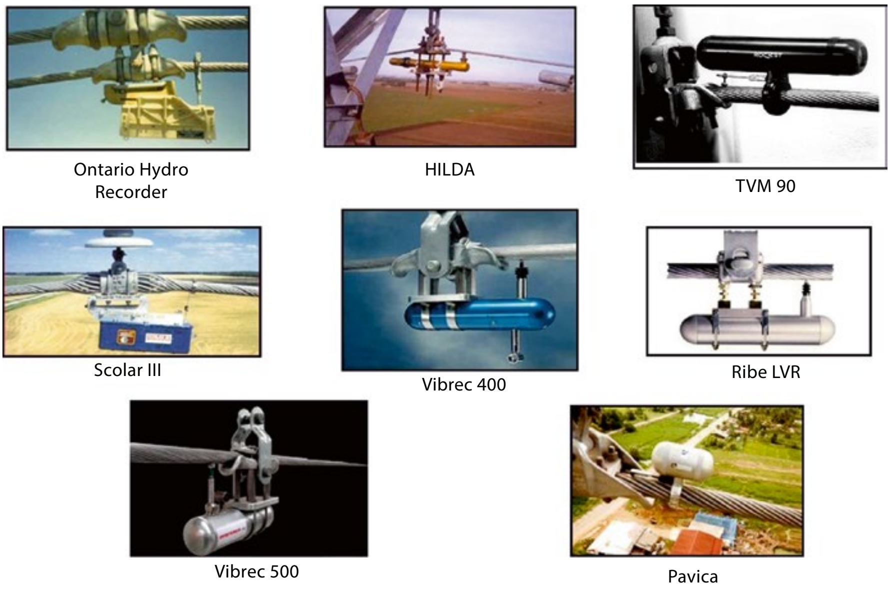


Figure 10.50 Vibration recorders used on transmission lines in the last 50 years. Only the last two are still available on the market.

the read out, display, elaboration and print of measured data, after the test session. The vibration sensor can be a blade equipped with strain gauges or a LVDT displacement transducer or a linear encoder. The instruments are battery powered and their autonomy ranges from three weeks to more than one year depending on the recorder type, the duration and frequency of the sample period and the environmental temperature. Some recorders are equipped with an anemometer and a temperature sensor.

Data Sampling and Reduction

It has been common practice, since early application of the bending amplitude method, to perform measurements for a few second at regular intervals. The first analog recorder was timed to be active for 1 second every 15 minutes. Digital recorders allow setting up different sample periods and waiting periods. Currently, the most used intervals are 10 seconds recording every 15 minutes.

The digital recorders reduce the analog signal, produced by the vibration transducer, in digital form. Then the frequency and the amplitude of the vibration cycles are measured and stored in a memory matrix. The matrix contains a number of frequency classes and amplitude classes (typically 10×21, 32×32 or 64×64) forming "cells" in which, each amplitude/frequency combination is stored as a single event.

Some digital recorders consider the highest amplitude and the average frequency of each sample period; others count the amplitude and frequency of each individual cycle recorded. Due to the typical shape of the aeolian vibration amplitude (Figure 10.11), the results obtained with these two procedures can be rather different, especially when used for the evaluation of the conductor lifetime.

Data relevant to temperature and wind speed, where available, are stored in separate arrays.

Although originally recommended for conventional metal to metal suspension clamps, the bending amplitude method has been applied to elastomer lined clamps and clamps with helical rod attachments. Measurements of dynamic bending amplitude are also performed on clamps of other fittings (dampers, spacers, warning spheres) using lightweight recorders.

Some suspension clamp do not allow to maintain the "lever arm", i.e. the distance between the sensor tip position (or the recorder position in the case of the inverted bending amplitude recorder) and the last point of contact between conductor and the suspension clamp, at the nominal distance of 89 mm. In these cases, the measured vibration amplitudes can be converted to the corresponding bending amplitudes or bending strains using the Poffenberger and Swart theory and considering the actual length of the lever arm. Digital recorders can perform these conversions during the automatic data elaboration.

Test Locations

Many utilities require that a final check of the efficiency of the conductor damping system should be performed on a new line before commissioning. In these cases, one or two spans with the greatest exposure to the vibration-inducing wind, that can be considered representative of the whole line are selected and equipped with vibration recorders. The selection criteria consider the longest spans with the tallest towers stretched in open flat areas with low and sparse obstacles where the presence of wind transversal to the line is expected. Long spans such as crossing spans with special conductors strung at higher tensile loads are tested individually.

The test duration depends on the purpose of the measurements. The original (IEEE 1966) paper proposes a minimum period of two weeks to pick up the maximum bending amplitude. Experience demonstrated that that period is too short and generally a minimum test period of one month is required. However, the test cannot be considered conclusive until the whole range of wind speeds that can excite aeolian vibration is recorded and therefore wind velocity measurements should be associated with vibration measurements and the test period extended if necessary. Moreover, when the wind and terrain conditions change seasonally, measurements should be repeated at each season or performed under the most severe environmental conditions which correspond, generally, to the period of the year where the temperature is lower and the conductor tension reaches its maximum.

Installation of the Vibration Recorders

The installation of the vibration recorders is performed or witnessed by an experienced engineer. In most of the cases, the engineer instructs linemen, at ground level, using a conductor-clamp assembly. Generally, the installation and removal of the recorders on operating lines are made during an outage of few hours. In some cases, the operations are made on energized lines using hot sticks or the bare-hand technique (Figure 10.51). An outage may not be required for installations on shield wires.

When available, the use of the automatic start/stop function of the recorder is preferable since it makes the linemen task easier and prevents the recording of the conductor movements during the installation and retrieval operations.

Measurements at Clamps Other than Conventional Suspension Clamps

The bending amplitude method has been established for conventional metal to metal and bell shaped suspension clamps (IEEE 1966). Other clamp types such as elastomer lined clamps and clamps with helical rod attachments do not behave like metallic clamps, and for them the relationship between bending amplitude and bending strains

Figure 10.51 Installation of a vibration recorder on a live line.

should be determined by laboratory vibration tests. For clamps incorporating elastomeric inserts the Cigré (1995) guide suggests, for practical reasons, to use the Poffenberger and Swart formula, considering the centre line of the suspension as the point of maximum dynamic bending stress, pending a more specific analysis of these supports.

Dangerous dynamic bending strains can occur, also, at the edge of clamps of other fittings such as dampers, spacers, warning devices and at the extremities of armour rods. Measurements of dynamic bending amplitudes at these clamps are not as simple as measurements at a suspension clamp. They require light recorders or a different measurement approach. Moreover the fatigue endurance limits of the specific conductor/clamp combination as well as the relationship between bending amplitude and bending strain, if required, have to be determined by laboratory tests.

Measurements Inaccuracies

In bending amplitude measurements, there are several possible sources of measurement inaccuracies that should be duly considered and possibly reduced to a tolerable value (EPRI 2009). Measurement errors can arise from the instrument performance as well as from the recorder attachments to the suspension clamps. Imprecision can be determined by the inaccurate measurement of the recorder lever arm or by an incorrect adjustment of the sensor rest position. Moreover, the mass and moment of inertia of the recorder and relevant holders may influence the bending amplitude measurements as discussed in several papers (Krispin 1992, 1993; Heics and Havard 1993; Sunkle et al. 1995). The influence is greater with small conductors, high vibration frequency and large additional inertia. To minimize this phenomenon, recorders with a seperate vibration sensor are also available for small conductors (on dead lines) and shield wires.

The memory matrix of the recorders shows, quite often, entries at frequencies below the minimum aeolian vibration frequency calculated using the Strouhal formula (10.1). These data may exhibit high amplitudes but a limited number of cycles. They are mainly due to vertical components of not sustained transverse oscillations of the cable or movements of the linemen along the conductors and they have generally no influence on the calculation of conductor lifetime. Instead, they are discarded, when exceeding the maximum allowable bending amplitude (or strain), if this criterion is used for the evaluation of vibration severity.

Reliability of Bending Amplitude Measurements

Regarding the reliability of these measurements, the following should be considered.

The inherent concept is to take for a few weeks, on one or few spans, samples of the conductor vibrations. In general, the measurements are performed for about ten seconds every fifteen minutes for a period of one month. This means that information is collected for 1.1 % of the test period only, which covers about 0.002 % of the transmission line life. Such information is supposed to establish:

- If the conductors under tests, in the spans where measurements have been made, will face or not fatigue risks during their expected service life (30÷50 years).
- If the conclusion drawn for those conductors and spans can be extended to all the other spans of the line.

It must be pointed out that, to achieve reliable conclusions, it is necessary that the vibration samples taken do really represent, at least, the predominant conditions that will exist during the service life of the line. Therefore, the correct choice of the test locations, test periods and test duration is of primary importance.

Evaluation Criteria
The following criteria are commonly used to assess the vibration severity on transmission line conductors:

- IEEE maximum allowable bending strain
- EPRI endurance limits
- Cigré WG 22-04 method.

The IEEE (1966) paper provided, for the aluminium-based conductors, a general evaluation criterion based on a maximum allowable bending strain. A value of 150 μinch/inch (microstrains) peak to peak was given as a conservative value and it was suggested that maximum strains of the order of 200 microstrains peak to peak might well prove to be safe. These limits demonstrated, with accumulating experience, to be rather conservative. However, many utilities, in different countries, adopt this criterion, prescribing a bending strain varying between 150 and 300 microstrains peak to peak, as the acceptance limit for the damping systems of new lines.

For the conversion of the measured bending amplitude into bending stress, or strain, the Poffenberger and Swart formula (10.12) although approximated, (the accuracy of the conversion is influenced by the difficulty to predict the actual dynamic bending stiffness of the various conductors) can be usefully employed for combinations of conductors and conventional metallic suspension clamps, without reinforcing rods. In all the other cases, the conversion factor should be better determined through laboratory tests or provided by the fitting suppliers.

The EPRI (2009) book and the IEEE (2006) guide provide the values of the bending amplitude and bending stress that can be endured indefinitely by ACSR conductors and few other type of overhead cables. These values, defined as "endurance limits" as reported in Section 10.3.2.7.6 (Subsection "Fatigue endurance limits and data base"), can be applied to conductors with conventional metallic suspension clamps, with and without reinforcing rods. In particular, the bending amplitude endurance limits allow a direct evaluation of the recorded data, making unnecessary the conversion between bending amplitude and bending stress.

The evaluation of the conductor fatigue danger based on the maximum allowable bending amplitude or strain may be considered excessively cautious. In fact, these limits can be exceeded up to a certain level and for a limited number of times with no practical effect on the conductor endurance. To reduce the severity of the method, some concessions are granted. For example, the following empirical limits are widely used (IEEE 2006):

The bending amplitude may exceed the endurance limit for no more than 5 % of the total cycles.

No more that 1 % of the cycles may exceed 1.5 times the endurance limit.

No cycles may exceed 2 times the endurance limit.

The method for the evaluation of the lifetime of aluminium based conductors (Cigré 1979a) has been implemented in the utility software supplied with some digital recorders. The bending amplitude data, stored in the recorder memory matrix, are converted into bending stresses, and used to define the curve of the stresses accumulated by the conductor in one year of service. The curve shows, for each stress level "σ_i", the number of cycles "n_i" to be expected in one year (Figure 10.52).

Using the Palmgren-Miner's theory about accumulative damage on structure subjected to alternating stresses, the above curve is scaled against a "universal" S-N curve known as "safe border line" (or with the S-N curve of the specific conductor) showing for each stress level "σ_i" the number of cycles "N_i" that can be endured by the conductor without strand failures.

The partial damage at each stress level "σ_i" is determined from the ratio n_i/N_i. Supposing that the damage accumulation is linear and not influenced by the order in which the different stresses occur, the conductor damage in one year would be:

$$D_{\text{year}} = \sum_{1}^{i} \frac{n_i}{N_i} \tag{10.21}$$

and the lifetime "L", in years, of the conductor will be:

$$L = \frac{1}{\sum_{1}^{i} \frac{n_i}{N_i}} \tag{10.22}$$

The conductor lifetime estimation appears to present a useful measure of the condition of the support point that was tested. However, considering the remarkable

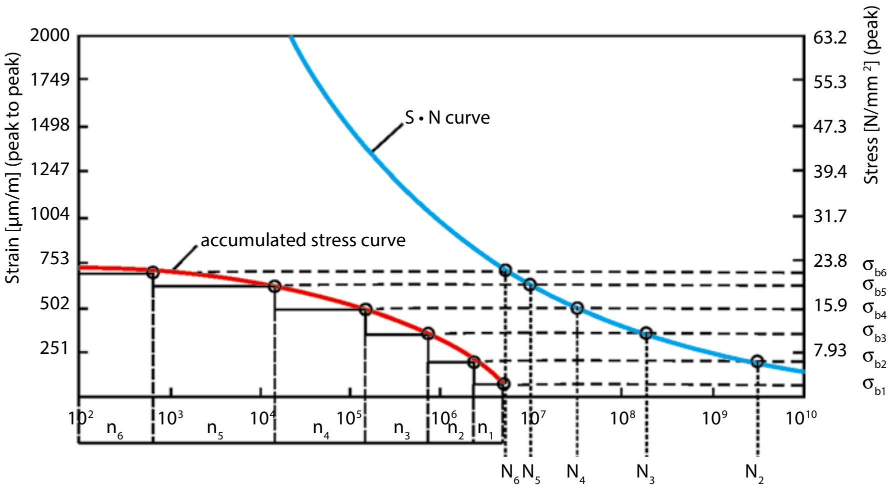


Figure 10.52 Fatigue S-N curve of a aluminium based conductor (*blue line*) and the accumulated stress curve of the same (*red line*).

scatter in conductor fatigue characteristics and the uncertainties of the underlying Miner's Rule as applied to stranded conductors, conductor life expectancy should be considered to have only qualitative significance.

Survey on the Evaluation Criteria

A survey on the evaluation criteria adopted by the industry for the assessment of vibration severity on transmission line conductors was performed reviewing 80 Technical Specifications issued by the main Utilities worldwide in the past 40 years (EPRI 2009).

The survey shows that, for the evaluation of the vibration severity:

- 59 % of the Specifications adopt the bending strain as endurance limit
- 16 % adopt the bending amplitude endurance limits proposed by EPRI and IEEE
- 6 % adopt the Cigré method for the evaluation of the lifetime
- 19 % do not specify any criterion.

Among the Utilities adopting the bending strain endurance limits:

- 27 % prescribe 150 micro strains peak to peak
- 18 % prescribe 200 micro strains peak to peak
- 4 % prescribe 247 micro strains peak to peak (corresponding to a bending stress of 8.5 MPa)
- 51 % prescribe 300 microstrains peak to peak.

It was evident during the survey that, in the industry, evaluation criteria of vibration severity are frequently prescribed with no consideration of whether the relevant reference limits available in literature are applicable or not to a specific conductor clamp combination. For example, endurance limits for aluminium based conductors in metallic clamps have been adopted for steel shield wires or OPGW or for measurements taken at the spacer clamps.

Laboratory tests should be performed to determine the actual endurance limits of a conductor/clamp system when no specifications are available.

Conductor Inspections on Actual Lines

Some inspection procedures are available to assess strand failure or to estimate whether a strand may eventually fatique during the economic life of the conductor. The most common are:

- Visual inspection of conductor and fittings
- Radiographic inspection
- Thermographic inspection
- Electro-magnetic-acoustic inspection.

The need to apply one of these procedures may be indicated by certain "early warnings".

Generic information about excessive vibration levels on an overhead transmission line can be gathered by means of line-crew reports about conductor or structure vibrations or visible damage or looseness of hardware components, cross-arm members and conductor fittings. Strand failures of Stockbridge damper messenger cables and loss of damper weights are amongst the warning signs but can also indicate a poor unit design, or the result of galloping, or the consequence of severe aeolian vibration on conductor covered with hoarfrost or ice.

Black spots on the surface of the conductors may indicate severe vibrations. If the spots consists of fret debris of black aluminium oxide they can be an important sign of imminent conductor fatigue, as they demonstrate that there has been some fretting consumption of aluminium wires in the inner layers, as a consequence of severe conductor vibration.

Failure of hardware components, having natural frequencies in the range of aeolian vibrations, can occur for excessive conductor vibration although it can be produced by the damped residual vibrations that are easily endured by the conductor. Hardware components that show signs of chafing or rotation may provide evidence that vibration had occurred.

Visual inspection of the conductors is appropriate when there is strong or specific evidence that damage has occurred, but cannot be performed systematically during periodic maintenance or line survey. In any case, strand failures may be difficult to detect, as they occur near the last point of contact between conductor and clamp. For example, failures at suspension clamps generally occur on the lower side of the conductor that is inside the clamp mouth. Reliable inspections require that the conductor be separated from the clamp. When armour rods or elastomer-lined clamps with helical rods are used, the search for strand failures requires the removal of these components (Figure 10.4). In any case, this technique allows the detection of outer-layer damage only and thus may overlook evidence of excessive vibration severity. In fact, aluminium based conductors, having more than one layer of aluminium strands, may show the first strand failures either in the outer layer or in the layer below (Cigré TB 332 2007a). According to laboratory tests, the first failures are more likely to happen in the inner layers so that when outer layer strand failures are observed the extension of the damage may be already large and the corrective actions late.

Radiographic inspection can give some results, but it is not a common practice since it is costly and rather complex. Moreover, the interpretation of the radiographs is sometimes difficult and the failure detection may be not completely reliable especially on bimetallic conductors. This technique, however, has been used also on energized lines, in cases where inner strand failures were considered likely to have been occurred.

Thermographic inspection is not suitable for the early detection of strand failure as the failure of few strands in the vicinity of a suspension or tension clamp, will not increase the temperature of the conductor appreciably.

Electro-magnetic-acoustic inspection performed using test devices that can move along the spans has been developed for the evaluation of the corrosion conditions of ACSR steel cores and can be also used for the detection of strand failures.

10.3.3 Wake – Induced Oscillations: Subspan Oscillations

10.3.3.1 Introduction

Wake-induced oscillation encompasses several types of motion, observed in conductor bundles that are caused by the aerodynamic shielding of leeward-lying conductors by windward conductors.

Among several type of wake induced oscillations (EPRI 2009) subspan oscillations are the most dramatic and the most frequently reported and it is the motion that designers are confronted nowadays with greatest conflict between sources of information and modelling. In fact, even through subspan oscillation is a well known phenomenon in transmission lines (EPRI 2009; Cigré to be published) only recently, operators become more sensitive to the problem as subspan oscillations have occurred in several lines. For example, some new quad bundled OHTL built in Saudi Arabia showed significant subspan oscillations, causing sub-conductors and spacer-dampers damage. These oscillations were mainly stirred by the terrain configuration (desert) and the high probability of medium-high wind speeds (Diana et al. 2013a, b).

The phenomenon has been widely studied from the analytical and experimental point of view: experimental studies have been carried out both in wind tunnels and on experimental lines (EPRI 2009; Cigré to be published; Diana et al. 2013a, b). Moreover different numerical models have been developed along the years: from those of Simpson (1971), Ikegami et al. (1971), Diana et al. (1974), Ko (1973), and Tsui (1975) based variously on a two degrees of freedom model of the system, up to models based on finite element approach and the transfer matrix approach (Claren et al. 1974; Rawlins 1974, 1976, 1977).

This section provides both a background on subspan oscillations to permit line designers to make the best use of the state-of-the-art and experimental data, then describes a benchmark on the mostly used model for studying the phenomenon with the aim to provide a useful instrument to prevent or limit the problem.

The analysis of the natural modes of conductor bundles has been discussed in a number of papers (Diana and Massa 1969; Claren et al. 1971), and a method based on the Transfer Matrix approach is proposed that is able to provide the resonant frequencies, which can be excited during subspan oscillations. Moreover the knowledge of resonant frequencies and modes allow for the calculation of the modal shape of the whole span.

10.3.3.2 Types of Motion and Mechanisms of Subspan Oscillations

Wake induced oscillation occurs on conductor bundles and is due to the effect of the wake produced by the windward conductors on the leeward ones.

The mechanism of subspan oscillation takes the form of one or two loops between adjacent spacers in a span, with nodes at or near the spacers. The trajectories of individual sub-conductors are elliptical, and windward-leeward pairs of sub-conductors often move approximately in phase opposition (Figure 10.53).

A typical oscillation shape for a quad bundle is shown in Figure 10.54: the sub-conductor motion is elliptical and is the result of the combination of an essentially horizontal or torsional mode of vibration of the bundle with a vertical one.

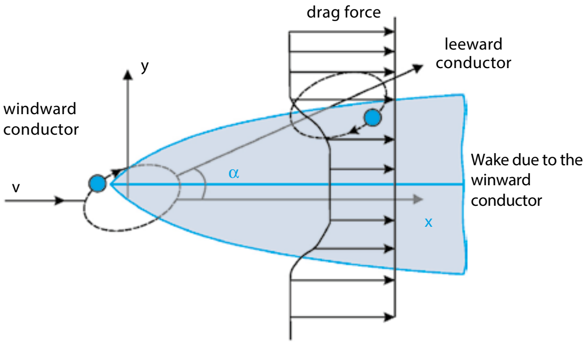


Figure 10.53 Leeward conductor in the wake of the windward one. Drag force distribution and type of motion.

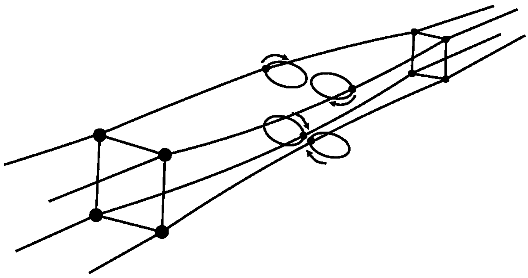


Figure 10.54 Example of Subspan oscillation (EPRI 2009).

The subspan mode is one of the most dramatic and one of the most frequently reported. However, several other types of motion can be found under the definition of wake induced oscillations: torsional motion (rolling), a horizontal motion (snaking) and a vertical motion (galloping) (Figure 10.55). These less common motions do not affect generally the integrity and the operation of a transmission line and mitigation methods are not considered necessary.

In the subspan mode, the elliptical orbits traced by the conductors usually have their major axes horizontal and the motions can be easily seen from the ground. Large amplitudes in the rolling mode happened to be detected, if the observer is not directly under the bundle, hence many instances of the rolling mode are reported as subspan mode.

In the subspan mode, both subconductors in a windward-leeward pair usually participate in the motion, the leeward having the higher amplitude. Not all pairs in a bundle necessarily participate to the same degree. For example, in a four-conductor square bundle, the upper or lower pair may have greater amplitude than the other.

The frequencies of the subspan mode are associated with loop lengths determined by subspan lengths, and are well approximated by the fundamentals or harmonics of the subspan. They are however in the range of a few Hertz.

The motion is caused by the field of aerodynamic forces, which originate from the leeward conductor. In fact, the force field is non-conservative and may cause a

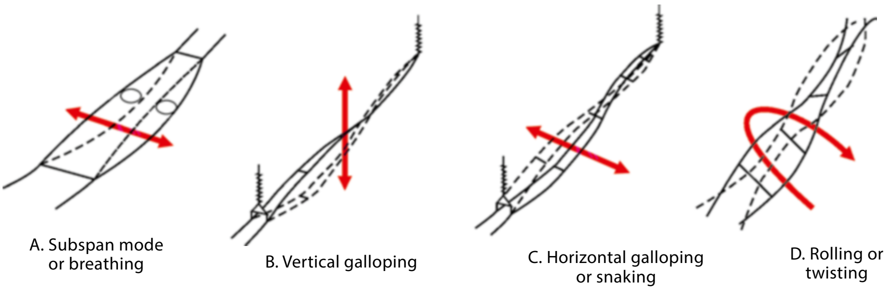


Figure 10.55 Wake induced motions (EPRI 2009).

flutter type of instability where the horizontal and vertical mode frequencies, initially different, become equal.

The instability phenomenon occurs for wind speeds in the range between approximately 8 and 20 m/s, as a function of the bundle parameters. Amplitudes of vibration may be as high as to cause sub-conductors clashing and, in any case, the oscillations are associated with strains on the subconductors at the spacer clamps and forces on the spacer arms that may lead to subconductor wire damage and spacer clamp loosening (St-Louis et al. 1990, 1993; Hoffmann and Tunstall 2003; Sarkinen and Wiitala 1969).

A distinctive feature of subspan oscillations is the distribution of the energy of motion within the span. In order to have a complete knowledge of this mechanism it is important to evaluate the bundle modes, which could be excited by any external force. The knowledge of the bundle deformation in any of its modes makes it possible to estimate the kinetic and potential energies of the system, which, in conjunction with the damping energies, allow the identification of the system response to any exciting force.

10.3.3.3 Parameters which Affect Subspan Oscillations and Protection Methods

Several parameters can have an influence on wake induced oscillation and in particular on sub-span oscillation, and the most important are summarized below.

The main parameters are the location and the line design. The location appears to exert an influence because of the recurrence of significant winds and of the effect of local terrain upon the smoothness of wind flow over the lines (Rawlins 1974).

Aside from location or terrain, several design parameters and structural variables influence the susceptibility to subspan oscillations.

The conductor tension impacts directly on the frequency of any natural vibration mode. The value of frequency of any natural vibration mode is priportional to the square root of tension divided by mass, as reported in Equation (10.2). In the case of subspan oscillation the relationship assumes the following form:

$$f = \frac{n}{2l}\sqrt{\frac{T}{m}} \tag{10.23}$$

where n is the subspan oscillation mode, that is generally 1 or 2, and l is the subspan length.

The distance between windward and leeward sub-conductors and the angle of attack, or tilt, of the bundle, are important parameters affecting the behaviour of the bundle. They have a strong impact on the sensitivity to subspan oscillations. The strength and character of the aerodynamic shielding of leeward conductors by windward ones vary with the position of the leeward conductor in the windward's wake (Wardlaw et al. 1973; Giordana 1972; EPRI 2009). The effects of a/d, which expresses the separation between windward and leeward conductor, (a) in term of subconductor diameter (d), arise because of the diffusion of this wake as it moves downstream. Moreover it is common to have a certain degree of tilt in a bundle after the mounting of a line, due to differences in tension and creep of subconductors.

Additionally, it is well known that the aerodynamic instability leading to sub-span oscillations can be considered inversely proportional to the horizontal separation between sub-conductors. The ratio between conductor spacing and diameter of about twelve has resulted in significant oscillations whereas with ratios of eighteen and twenty, the incidence appears to be greatly reduced. Quad diamond bundles where only two sub-conductors are horizontally aligned and spaced of the diagonal of the square have shown very low sensitivity to the phenomenon.

Type, number, and positioning of spacing devices according to EPRI (1979) affect, as well, the susceptibility to oscillation, influencing the sub-span mode. In general, the use of more spacers, hence shorter average subspan length, reduces the incidence of subspan oscillation by increasing the threshold wind velocity (Champa et al. 1973; Mohajery 1976; EPRI 2009). Independently of this, use of patterns of unequal subspan lengths within a span also raises threshold wind velocity. Such patterns are referred to as "subspan staggering schemes." The effectiveness of any particular staggering scheme depends, in at least some cases, upon the characteristics of the spacer being employed (Cloutier et al. 1974; EPRI 2009).

Also the conductor surfaces have been demonstrated in wind tunnel tests to have an important impact on the aerodynamic field forces (Counihan 1963; Ikegami et al. 1971; EPRI 1979; Diana et al. 2013b).

Based on the knowledge of the parameters that impact on the susceptibility of bundles to subspan oscillations several basic approaches have been applied in operating lines.

If bundle separation, or a/d ratio, is usually determined by electrical considerations, the bundle tilt represents a degree of freedom in the building of a transmission line. It is then possible to have bundles tilted enough to remove leeward conductors from windward conductor wakes, hence reducing or eliminating the wake forces, and preventing all modes of wake-induced oscillation (Diana et al. 1974; Rawlins 1974). Unfortunately such a countermeasure requires the perfect knowledge of the wind direction and the static rotation of the bundle need to be carefully adopted in order not to have negative effects.

It is common to have a static rotation of the bundle due to the possible presence of differential creep in the subconductors and/or the bundle assembly and difficulties in the correct stringing of the subconductors may arise in windy locations.

The use of systems of unequal subspan lengths represents another protection method against the subspan mode of wake-induced oscillation, in conjunction with damping spacers or non-damping spacers. The effectiveness of these staggered sub-span systems (Hearnshaw 1973; Alnutt et al. 1980; Cigré TB 277 2005b; EPRI 2009; Van Dyke et al. 1997) is well supported by data from tests on full-sized test spans.

10.3.3.4 Number and Location of Spacers

There is a general agreement that the minimum wind speed required for instability to occur increases with the natural frequency of oscillations. Since the natural frequency of a sub-span tends to be inversely proportional to its length, by shortening the sub-spans, the minimum wind speed, at which the oscillations can occur, increases. This is advantageous for two reasons; first because the oscillation amplitude decreases with the increase of the frequency; second because according to the wind distribution (Figure 10.9) higher wind speeds have lower occurrence.

Considering all the parameters influencing sub-span oscillations, it is clear that the number and position of spacer dampers (Figure 10.56) play an important role as they directly change the subspan length.

Firstly it is important to state that the optimisation of the type and the position of the spacers in a span is made with respect to problems of wind-excited vibrations and also to control bundle twisting due to ice loads.

In the case of subspan oscillations, the parameters of interest are the location of the spacers along the span (ratio between the lengths of two adjacent subspans), the bundle configuration and the maximum sub-span length. Even if the type of spacer has some influence on the phenomenon and is important for the prevention of damage caused by sub-span oscillation to the conductors, the spacer location remains paramount.

Spacing is very important because sub-span oscillation is an instability phenomenon resulting from the coupling between two types of vibration mode of the bundle, one having a horizontal component of motion and one having a vertical component. Most commonly, the vertical component is provided by torsional modes of the bundle.

Torsional modal frequencies are mainly influenced by the overall span length and, to some extent, by the end conditions; the horizontal modal frequencies are mainly controlled by the sub-span lengths.

Figure 10.56 Spacer damper distribution on a hexagonal bundle.

A change in the values of the subspan lengths produces a change in the horizontal modal frequencies and thence in the coupling between the modes: so the problem can be controlled to some extent.

It is recognized that a span divided into equal subspans is more easily subjected to oscillation than a span divided into unequal sub-spans. This is because the equal sub-span length defines a horizontal frequency for which all the sub-spans vibrate at the same time, with a vibration mode which can easily be coupled to a torsional mode.

Some common modes of sub-span oscillation for quad bundles involve a combination of horizontal and vertical modes: these are less influenced by unequal sub-spans since both frequencies depend on sub-span length.

The instability mechanism is complex as it depends, in general, on the horizontal and torsional modal frequencies which are initially different (in structural terms) and are made equal by the wind action, thus giving rise to a typical flutter-type instability.

Given a span length with a certain number of spacers, the ratio between the lengths of adjacent sub-spans must be optimised. If this sub-span ratio is much lower than unity, adjacent sub-span lengths are very unequal and the long sub- spans may be unstable at relatively low wind speeds. This is especially the case for very long spans with many torsional modes in the frequency range of sub-span oscillation. In any case, long sub-spans are unsafe because, as the length increases, not only does the frequency decrease - together with the critical wind-speed for instability - but the associated vibration amplitude increases.

A sub-span ratio around 0.85 to 0.9 is generally agreed (literature, experimental tests and analytical simulations) to be the optimum solution (Hearnshaw 1974).

Regarding the end sub-spans, these are generally shorter than the others. A good value for the ratio between the lengths of an end sub-span and the adjacent one is between 0.55 and 0.65. Short end sub-spans (25 to 45 m) prevent subspan oscillation at span extremities which can damage the insulator hardware and increase the bundle torsional stiffness with two main advantages: a partial contribution to detuning bundle torsional and vertical modes of vibration, and a reduction in the risk of static, torsional collapse under ice loading and strong wind.

All configurations of bundles experience sub-conductor oscillation to a greater or a lesser degree.

The maximum sub-span length depends on the wind speed and on the type of terrain typical of the site. It is also dependent on the oscillation amplitude allowed by the specifications issued for the specific project.

Analytical simulations and measurements on real spans lead to a limit on the maximum sub-span length. This limit is related to specific conditions: for instance, with a ratio between bundle separation and conductor diameter of the order of 10 to 17 (with ratios of 12 or below being the most critical) and a site characterised by medium/high wind speeds (>20 to 25 m/s), this value should be around 65 m.

In non-severe conditions maximum sub-span lengths around 80 m have been used without problems.

It is not easy to set a general specification: knowledge of the wind statistics typical of the site, combined with the parameters set for the project, assist in selecting the correct solution.

Together with the subspan length the spacer damper helps in controlling subspan oscillations if proper characteristics are chosen. The control could be achieved with different solutions such as spacer dampers, non rigid spacers or a combination of twin articulated spacers (Russian configuration).

10.3.3.5 Methods for the Assessment of Subspan Oscillations

Experimental investigations of subspan oscillation are very useful in order to deeply understand the nature of the phenomenon itself and to evaluate the main parameters involved.

Over the years several experimental campaigns were carried out both in the field and in Wind Tunnels or laboratories. In the following, a summary of the main outcome obtained by means of field and laboratory tests is provided with particular attention to recent development achieved in this tecnology.

Field Tests

Testing of full-sized bundles for wake-induced behaviour in natural conditions has been carried out on a number of occasions by operating utilities and others. Such tests are of value in providing the basis for deciding whether to provide protection in new or in existing lines and, if so, how extensively and of what type (EPRI 2009). Moreover, they can be used to optimise new line designs so to avoid subspan oscillation. Several testing systems and methods can be normally employed and have been tested in the past. They fall generally into two groups as regards the type of data provided:

- damage-oriented methods designed to understand the type and entity of damage;
- motion-oriented methods designed to provide information, with differing levels of detail, on the occurrence and magnitudes of oscillation, on the modes involved and sometimes on the wind conditions that cause them.

The aim of this section is to briefly describe the motion-oriented methods identifying their weakness and their strenght. The main idea is to provide experimental knowledge and data that will be used to develop and validate analytical and numerical tools. Eventually, those tools might be used to validate the performance of bundles regarding subspan oscillations at a design stage.

Visual Inspection

This method is fully based, as the name suggests, on the visual evaluation of the bundle behaviour.

It provides data on the modes of oscillation involved, their approximate amplitudes, and the meteorological conditions that cause them. Moreover, if inspections are frequent enough, the percentage of time that motion occurs (incidence of motion) can be estimated.

The method foresees the establishment of test sections in lines, and provision for periodic inspection of these sections by trained observers (EPRI 1979; Rissone et al. 1968; Winkleman 1974). A test section may comprise an entire line, or exposed sections of it.

Unfortunately such a method is not completely objective in fact it relies completely on the training given to observers and by the design of the report form used, and only a qualitative knowledge can be achieved. (EPRI 2009). Data quality is improved when video cameras are used, possibly in conjunction with hand held anemometers.

Deformation Gages

An approximate detection of the maximum oscillation amplitude has been performed using the so called "deformation gauges" that are shaped rings made of soft-drawn aluminium wires (Figure 10.57), which were generally installed in the middle of the longest subspans. The diameter of the ring is equal to the maximum allowed subspan oscillation, generally 50 % of the nominal spacing. When the spacing becomes less than that, the soft wire is deformed by an amount indicative of the maximum oscillation occurred. Sometimes, the deformation gauges are installed at ¼ of the subspans in such a way that large-amplitude wake-induced oscillation, in both the first and second subspan mode, can be detected.

Even if this is a fairly low cost method due to the fact that the cost of application is almost entirely that of the labour of installation, some limitation are present:

- only the maximum amplitude that exceeds some threshold is determined;
- they are susceptible to deformation by causes other than wake-induced oscillation or subspan—e.g. ice galloping, ice shedding, transit of linesmen on the line, etc.

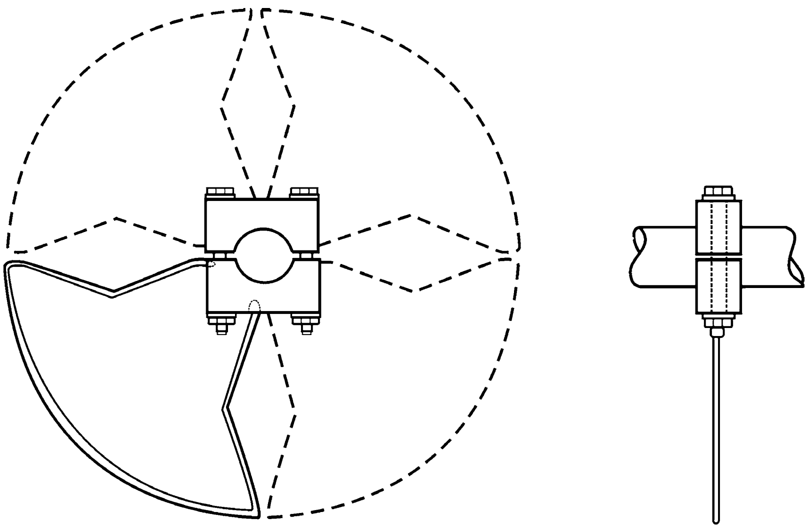


Figure 10.57 Deformation gage for subspan oscillation detection.

Automatic Camera Systems

This method implies cameras that record wake-induced motions of bundles by taking motion pictures of spans automatically. It provides a view of bundle motions over about half the length of the span being tested. Its primary advantage is that mode types that occur can be determined and their amplitudes estimated, and these can be correlated with wind conditions including, in some systems, turbulence content. However, data analysis is time consuming.

Sub-span Oscillation Recorder

Subspan oscillation has been studied extensively in outdoor test laboratories, but to a lesser extent on actual lines for lack of live-line recorders. Vibration recorders designed for aeolian vibration measurements have been used for subspan oscillation testing. For this purpose, the recorders were installed on the line, generally on the clamp of a spacer with the vibration sensor in horizontal position. The instruments were able to measure the horizontal bending amplitude giving information about the fatigue accumulation at the clamp but not the oscillation amplitude.

A new subspan oscillation recorder is now available (Figure 10.58). It is able to perform the field measurements required by some major technical specifications as acceptance test of the bundle spacing system. Moreover, it can be used to collect data on subspan oscillation of actual bundles, for creating a data base and for a better understanding of the variables involved which will improve the mathematical model and the computer simulation of the phenomenon.

The vibration recorder is a microprocessor based, battery powered measurement device.

The hardware of the vibration recorder is practically the same of that of an aeolian vibration recorder, with the exception of the displacement transducer. which comprises a measuring steel wire that can be extended up to 762 mm (30 inches). Thus, the measurement range of subspan oscillation is ± 381 mm. The transducer is connected to the recorder main frame through a 30 m cable.

Figure 10.58 Subspan vibration recorder.

An automatic START/STOP function is available for fixing the date of beginning and end of measurements. The system can store the frequency and amplitude of each oscillation cycle in digital form, moreover a time history reconstruction of the most significant recordings is also available.

At a post processing stage, for any position of the displacement transducer along the span, it is possible to calculate the antinode amplitude of the recorded oscillations. The recorder is designed for application on live lines. The Corona performance of the instrument has been considered in two ways: avoid Corona emission at the maximum line voltage, be insensitive to Corona present on the line.

Dedicated Test Lines

This can be considered the most comprehensive way to study subspan oscillation at full scale. Several test lines and spans are available and have been used in the past.

Among the test lines used for such investigations were Hydro-Québec's Magdalen Islands Test Line (Cloutier et al. 1974) now moved to Varenne near Montreal, Canada, ENEL's (Italy) test span at Pradarena Pass, and Bonneville Power's Moro Test Line. The important characteristics that those installations require in order to provide efficient and reliable results are:

- High incidence of strong winds nearly perpendicular to the lines
- Means for controlling and quickly changing tilts of bundle spans
- Extensive instrumentation
- On-site staff.

The frequent occurrence of strong winds permits rapid exploration of the range of wind velocities likely to be of interest in connection with operating lines. The ability to change tilts quickly allows the most instable bundle positions and the effect of their variations to be determined.

Normally these lines are composed of a few tiltable spans equipped with sophisticated support instrumentation, such as motion sensors, meteorological equipment, and television monitors. The rapid flow of test data requires a highly specialised on-site staff.

Test lines are especially suitable for evaluation of oscillation protection schemes intended for later application in operating lines, since the test lines permit exploration of the ranges of wind velocity and bundle tilts that can be expected to occur in operating lines.

Laboratory Tests

Subspan oscillation has been demonstrated to be a very complex mode of motion, mainly dependent on the effect of aerodynamic forces. Moreover these forces are functions of position of the leeward conductor in the wake, Reynolds number, bundle angle, conductor surface roughness and stranding, as well as free stream air turbulence and humidity. An understanding of the complexity of the aerodynamic forces can be obtained by testing bundles in a wind tunnel and measuring the aerodynamic force fields for different value of the parameters affecting it. Laboratory tests are suitable for such a study due to the ability to keep several parameters under control at a time.

Tests carried out by Wardlaw et al. (1973) allowed the identification of the maximum lift and minimum drag coefficients with downstream position for a typical stranded conductor. Besides this Ikegami et al. (1971) showed the variation of the drag coefficient of a typical stranded conductor with change in wind speed, demonstrating that the drag coefficient can not be considered constant with speed (EPRI 2009).

In spite of these investigations some questions are still unresolved. That is: normally the aerodynamic forces acting on the leeward conductor are identified through static measurements in the wind tunnel, as a function of the relative position between the windward and the leeward conductors. The quasi-steady theory (QST) (Zdravkovich 1997), generally used to describe the phenomenon, accounts for the motion effect, introducing the relative velocity of the two conductors with respect to the approaching flow and using the static aerodynamic coefficients measured in wind tunnel. This approach generally holds for very high reduced velocities:

$$U_r = \frac{U}{fI} \tag{10.24}$$

where f is the oscillation frequency, U the wind speed and I a characteristic dimension which in case of subspan could be the bundle separation. Then one of the issues of the present research is to verify if the QST is adequate to reproduce the phenomenon for values of reduced velocity Ur characteristic of the subspan oscillations.

Another important issue is the effect of Reynolds number, already pointed out by Ikegami et al. (1971) but never analysed in detail: considering the range of wind speeds U of interest to subspan oscillation and the conductor diameters D, Reynolds number ($Re = U \cdot D/\nu$) is between $2 \cdot 10^4$ to $1 \cdot 10^5$. For stranded conductors, i.e. rough cylinders, these values are close to the critical zone characterized by the negative slope of the drag force versus Re (Zdravkovich 1997, 2003).

Recently, adding to the existing experimental knowledge, an extensive experimental campaign was performed in the Politecnico di Milano wind tunnel on smooth and rough cylinders moved along elliptical orbits to reproduce the subspan oscillation (Diana et al. 2013b; Cigré to be published) with the aim to clarify the above issues. Tests were carried out changing frequency and amplitude of motion, wind velocity and cylinders separation. Different reduced velocities and Reynolds numbers were tested. The first output of the research showed that the Reynolds number is very important because the conductors during subspan oscillations can operate around the critical range of the drag coefficient (see Figure 10.59).

In order to underline the importance of Reynolds number, Figure 10.60 shows the variation with speed (i.e. with Reynolds number) of the overall bundle energy, assessed during wind tunnel tests (Diana et al. 2013b; Cigré to be published): the smooth (continuous line) and stranded conductors (dashed line) are compared in the same diagram. The energies reported in Figure 10.60a as a function of the conductor

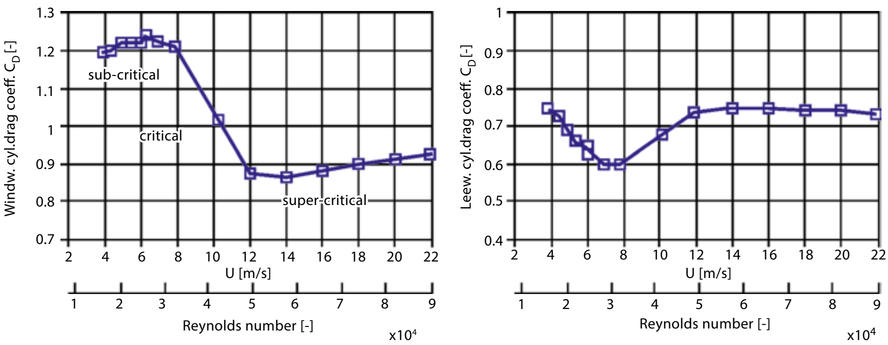


Figure 10.59 Drag coefficient on windward (*left*) and leeward (*right*) conductors.

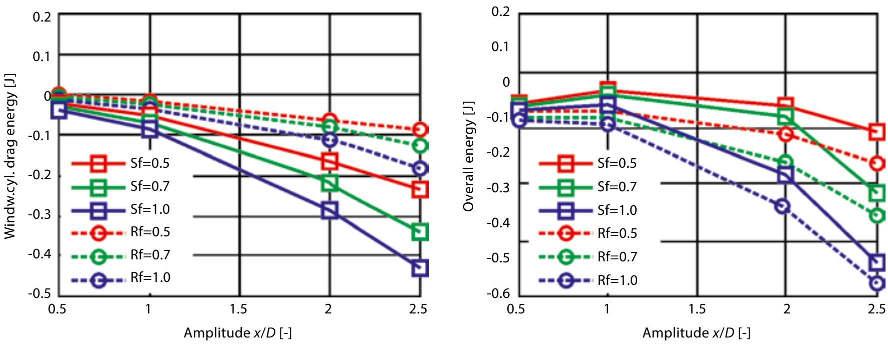


Figure 10.60 Tested frequencies and at different wind speeds: dashed line stranded conductor (Rf) and continuous line smooth conductor (Sf) (separation 15 diameters, angle = 3°.

oscillation amplitude and frequency of motion, show substantial differences depending on the surface roughness. Notably, at low speed the energy of the stranded conductor is greater than that of the smooth cylinder: the windward stranded conductor dissipated less energy than the smooth one while the downstream cylinders introduce the same energy. Whereas, at increasing wind speed the overall energy for smooth cylinders becomes higher due to the lower energy introduced by the leeward stranded conductor.

It can be concluded that the static tests in a wind tunnel, carried out to identify the aerodynamic coefficients on the leeward conductor must be made on rough cylinders, covering the critical and supercritical range of the drag coefficient (Figure 10.60).

The laboratory tests also allow verification of the quasi-steady theory (QST), mentioned above. For this, a comparison between numerical and experimental results is required. In fact all the models, presently available, rely on the use of the QST in order to reproduce the wind force field.

Diana et al. (2013b; Cigré to be published) carried out this comparison, replicating by means of their model, properly updated with the effect of Reynolds numbers and the experimental tests carried out in the wind tunnel.

Figure 10.61 shows a comparison between experimental and numerical results in terms of total energy on conductors as a function of the dynamic amplitude *x*/*D* for test cases representative of conductor behavior during subspan oscillations for three tested frequencies (0.5, 0.7 and 1 Hz) and two different wind speeds i.e. 10 m/s and 15 m/s. The numerical results are reported with lighter colors while the experimental outputs are represented with darker lines. Results show a good agreement both at a speed of 10 m/s ($Re = 4 \times 10^4$), and at the higher wind speed of 15 m/s ($Re = 6 \times 10^4$). Hence it can be concluded that the results support the validity of the quasi-steady theory.

In conclusion, the experiments in the laboratory, confirmed the validity of the QST and highlighted the importance of Reynolds number effects on the behavior of the bundles, and it can be considered as a useful approach for detailed study of subspan oscillations.

10.3.3.6 Review and Benchmark Evaluation of Existing Modelling Techniques for Subspan Oscillations

In this section a review of the existing modelling techniques is proposed to provide a general overview of the modelling options the designer can have in order to control and prevent subspan oscillation at an early stage of line design. Subsequently a benchmark carried out within WG B2.46 of Cigré is reported to highlight the drawbacks and advantages of several modelling approaches.

The first analytical models developed to understand the cause of subspan oscillations are those of Simpson (1970), Ikegami et al. (1971), Giordana (1972), Ko (1973) and Tsui (1975). These are all two degrees of freedom (2DOF) models (Figure 10.62) – the motion of the leeward conductor is studied along the x and y directions, the windward conductor being still.

The linearized QST is employed and the drag and lift coefficients on the leeward conductor are deduced from static measurements in wind tunnel, as a function of the relative position of the leeward conductor with respect to the windward one (see Figure 10.63 taken from Diana et al. (1974)).

Such models are linear and clearly simplify the structural behaviour of the bundle sub-conductors, taking it back to a two degrees of freedom system in which the leeward conductor is the only one moving. Even if very simple, these models are able to show how the subspan oscillations are caused by an instability phenomenon due to the non-conservative field of forces which is generated on the leeward conductor by the wake of the windward conductor. It is a flutter type instability with two different frequencies along the x and y planes, which become equal due to the effect of the force field. This field is non-conservative and then can introduce energy into the system, justifying the observed instability. Unfortunately they are not suitable to compute the oscillation amplitudes in a real span, because the latter greatly depend on the complex modes of vibration of the bundle and on the non-linear effects of the field of forces, which are not taken into account there.

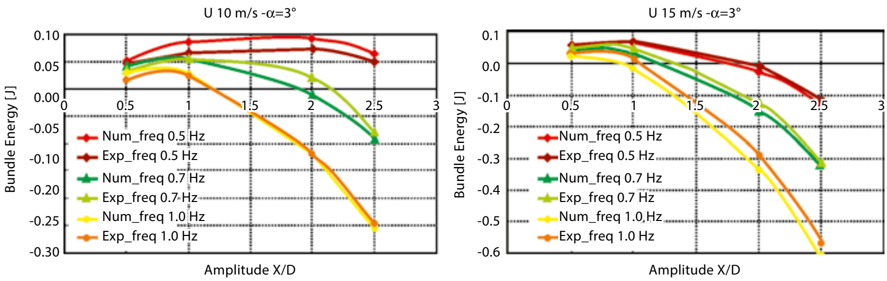
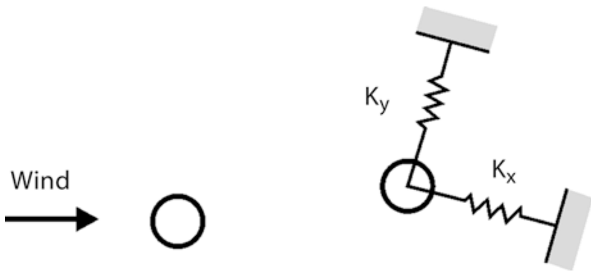


Figure 10.61 Stranded conductor energy with respect to *x*/*D* amplitude for the three frequencies. Experimental – numerical comparison. Due to the model scale, *f*=0.5 Hz corresponds to f=1 Hz full scale.

Figure 10.62 Two degrees of freedom model schematisation.



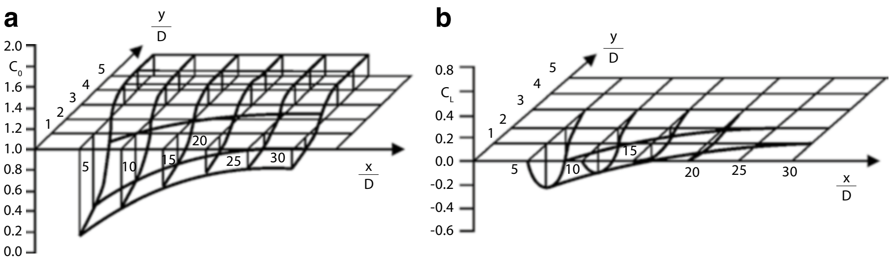


Figure 10.63 Aerodynamic coefficients from wind tunnel measurements as functions of bundle geometry.

More complex model are the one developed by Rawlins and described in Diana et al. (1974), Claren et al. (1974), Rawlins (1974, 1976, 1977) and Cigré (to be published). where, the bundle dynamics is taken into account using the transfer matrix method. However the aerodynamic forces are still reproduced through the QST with a linear approach.

Nowadays several models rely on the Finite Element Approach (FEA) which allows for the reproduction of the bundle dynamics and for the application of the aerodynamic forces to each sub-conductor using the QST with a non linear approach (Snegovskiy and Lilien 2010).

In this approach, the conductors of the bundle are modelled with a number of simple elements governed by ordinary, rather than partial, differential equations. Equations of motion of the bundle systems may then be cast as a set of simultaneous ordinary differential equations.

In theory, finite element methods can be made to yield results that come arbitrarily close to the exact behaviour of the bundle. How close depends upon the type of element employed, and how finely the bundle is divided into elements. The choice of type of element and mesh size is important, because use of too few or too simple elements may lead to inaccurate results, while use of too many elements or of types that are too sophisticated leads to unmanageably large matrices and prohibitive computational expense (Snegovskiy and Lilien 2010; Vinogradov 2003). The first papers showing the application of this approach date back to 1977 (Curami et al. 1977).

However, FEM analyses in the time domain are not always a practical tool for subspan oscillation simulation also because of the computation time required to obtain results. To overcome these problems, Diana and Gasparetto (1972; Diana et al. 1974) developed an energy based method, that firstly evaluates the natural frequencies and vibration modes of the bundles, then identifies the modes showing a predominant horizontal and vertical component and selects those in the oscillation frequency range 0.5-3 Hz, which is typical of subspan oscillation. Subsequently, within the selected modes, the ones which could be coupled by the aerodynamic forces to give rise to subspan oscillation oscillations are chosen.

Once the types of modes that can be coupled are defined, the elliptical motion of the conductors typical of flutter instability is reproduced.

All the models developed up to now rely on the Quasi Steady Theory (QST). This approach generally holds for very high “reduced velocities” *Ur*. Another important issue is the Reynolds number (Re) effect.

In fact for stranded conductors, i.e. rough cylinders, with typical values of conductor diameter and wind speed involved in subspan oscillations, Re may be close to the critical zone (EPRI 2009). Hence the Re number could significantly affect the phenomenon, due to the non-negligible variations of the drag coefficient with Re itself (Champa et al. 1977; Diana et al. 2013a) as mentioned in Section 10.3.3.5.

Considering the several types of models and approaches used to replicate the subspan motions existing in literature, within WG B2.46 a benchmark using the different type of models at disposal for subspan oscillation studies was carried out. The numerical results were compared with measurements on the IREQ Varennes test span equipped with a quad bundle of ACSR Bersimis conductors and spacer-dampers (Cigré to be published). In the following the main results achieved are reported.

From the beginning the benchmark pointed out that the models using FEM can give rise, at wind velocities between 10 and 20 m/s, as reported in detail in Snegovskiy and Lilien (2010), to an instability of the whole span at very low frequency, also called galloping or snaking motion. This instability is predominant and this approach is generally not able to reproduce subspan oscillation. However a full description of the results obtained by the FEM model is reported in (Lilien 2010).

Figure 10.64 (benchmark result) shows the comparison in terms of peak to peak horizontal oscillation amplitude as a function of mean wind speed, corresponding to the most critical subspan registered during tests.

The results from the Energy Based (EB) models are reported in blue, the results from the Finite Difference (FD) model in green and the results from the Finite Element model (FEA) in black, while the experimental points are represented in red.

It is possible to observe that the EB and FD models correctly replicate the trend of the oscillation peak to peak values, (Cigré to be published).

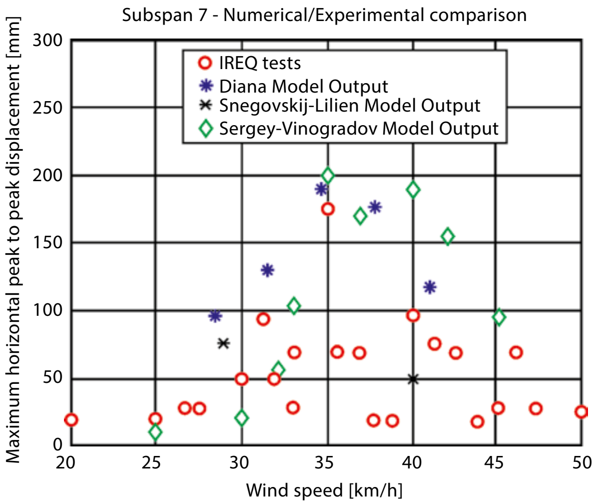
As it can be seen the range of instability is well reproduced by the numerical model, and the computed amplitudes of subspan oscillations are very close to the measured values, confirming the validity of the numerical model improved by the results of the recent research.

As a conclusion from the benchmark, it indicates that wake induced vibration is a complex vibration of bundle conductors. However, both simple and advanced modelling methods can be used. In particular a complex FEM model was applied with success but it requires a very cumbersome analysis which is very dependent on certain details.

Methods based on modal analysis and the energy balance approach seem to be more useful tools for practical applications.

Moreover the benchmark (Cigré to be published), indicates that: a numerical model based on the EB approach and on sophisticated wind tunnel tests to identify the aerodynamic parameters seems a useful tool for analyzing the subspan oscillation phenomenon. Moreover, models based on the finite difference method an the explicit scheme of system equations, if calibrated properly, seem to be able to reproduce the phenomenon..However, more research and validation are still required before it may be used to predict subspan oscillation amplitudes.

Figure 10.64 Benchmark result. Experimental and numerical comparison.



10.3.4 Conductor Galloping

10.3.4.1 Introduction

Of all the wind induced motions of overhead transmission line conductors or other suspended cables, galloping is the most noticeable and spectacular. The resulting damage can be equally dramatic and very costly, with broken conductors and fittings, damaged tower components and even whole towers collapsing! The consequential economic and social costs of power loss to whole areas can also be very considerable.

Galloping is an oscillation of single or bundled conductors due to wind action on an ice or wet snow accretion on the conductors, although there are recorded instances of non-ice galloping arising from the conductor profile presented to the wind.

Galloping may be characterized as follows:

- A thin ice accretion is generally required to obtain galloping. One to two millimetres of ice is sufficient on one side of the conductor. Sometimes, the ice accretion on the conductor is so thin that it cannot be seen from the ground.
- Frequencies are generally from 0.08 to 3 Hz. Higher galloping frequencies may occur but at lower amplitudes.
- Maximum galloping amplitude may exceed the conductor sag and amplitudes larger than 10 m have been observed.
- A minimum wind velocity is required to obtain galloping and the threshold value is approximately 25 km/h.
- Damage may occur within one to 48 hours due to large dynamic loads and/or fatigue on conductors, hardware and accessories, insulators and towers.

Galloping of iced conductors has been a design and operating problem for electric utilities since the early 1900s. Over the years, it has been the subject of numerous investigations and research programs, resulting in a better understanding of galloping mechanisms and in the development of devices and procedures to combat its effects. However, the EPRI Reference Book, "Wind-Induced Conductor Motions," (EPRI 1979) commented:

> "Progress, both in analytical attack on the problem and in development of countermeasures, has been slow. Forty-five years after publication of Den Hartog's analysis, important questions remain as to which variables and mechanisms are significant, and validation of theories of galloping is still not satisfactory. No practical protection method has been developed that is recognized as fully reliable."

Later advances fall in several categories. Of particular importance is the development of several countermeasures that appear to be reliable enough to find common usage on operating lines. These include the conductor construction known as "T2" in which two conventional conductors are twisted together; airflow "spoilers" which impart a figure-8 outline to the conductor span over part of its length. Other devices, showing promise in development programs, include torsional dampers for use on bundled conductors. Although they are not a recent development, interphase spacers have found increasing use and acceptance in recent decades.

Advances have also occurred in guides for the design of electrical clearances to accommodate galloping motions without flashovers. Several independent analyses of a large data bank of galloping observations have yielded improved guides to maximum expected amplitudes; and a systematic study of films of galloping events has provided better definition of the shapes of galloping orbits.

Although the accumulation of field observations has markedly slowed since 1980, methods of obtaining data from the field have improved. First, Cigré WG11 (Cigré 2000) has issued a document standardizing the acquisition and reporting of such observations. Second, and more significantly, there has been a proliferation of instrumented test lines and test sites where much more comprehensive information on natural galloping has been acquired. This information is of critical importance in developing and validating analytical models of galloping mechanisms.

There has been increasing success in simulating, in the computer, actually observed galloping behaviour in field test spans and, even more so, the measured behaviour in dynamic wind tunnel tests.

A fully satisfactory analytical attack depends upon reliable data on the aerodynamic characteristics of the ice shapes that actually occur on overhead lines and cause galloping. Galloping technology remains deficient in this area. Although a few samples of such ice shapes have been obtained and evaluated in wind tunnel tests, there is as yet no case where such a shape, with its aerodynamic characteristics, can be associated with an actual galloping event. There are several cases where the association between such characteristics and actual galloping has been established for artificial shapes, but the relationship between these shapes and actual icing deposits is not completely clear because of differences in surface texture and the degree of uniformity along the conductor. A 1988 paper remarked (Rawlins and Pohlman 1988):

> "… Galloping technology seems to divide naturally into a mainly meteorological segment which is inherently random, and a basically deterministic segment that is driven by … the first segment. The pivot between the two segments is … (aerodynamic) information on ice shapes. The deterministic segment cannot be exploited without a fund of data at this pivot."

It should be added that the deterministic segment cannot even be *validated* without data at this pivot.

10.3.4.2 Causes of Conductor Galloping

Galloping is a large amplitude (several metres), low frequency (fraction of Hz), wind-induced oscillation. In the vast majority of cases, an ice accretion is present on the conductor: this has the effect of modifying the conductor's cross-sectional shape such that it becomes aerodynamically and/or aeroelastically unstable (Blevins 1990; Den Hartog 1932; Edwards and Madeyski 1956; Koutselos and Tunstall 1988; Lilien and Ponthot 1988; Lilien and Dubois 1988; Nakamura 1980; Nigol and Buchan 1981; Rawlins and Pohlman 1988; Richardson et al. 1963; Tunstall and Koutselos 1988) (Figures 10.65 and 10.66).

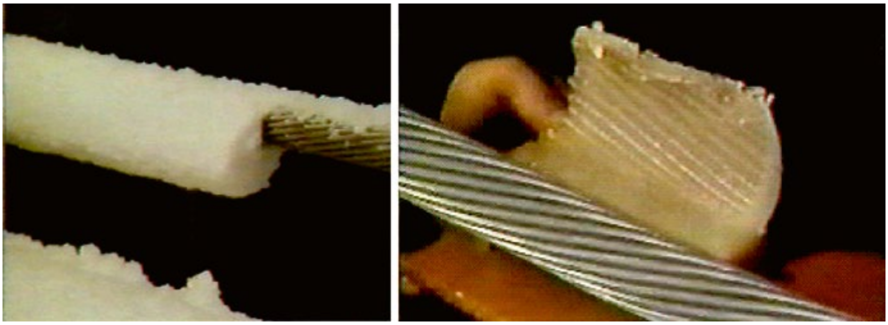
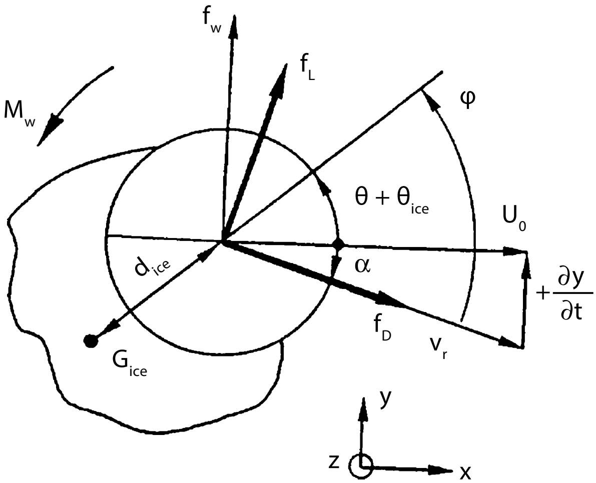


Figure 10.65 Typical ice shapes as observed on power lines, closely following to galloping events.

Figure 10.66 Aerodynamic forces acting on an iced conductor. U_0 is the horizontal wind velocity.



The relative wind velocity, taking into account conductor vertical velocity, is indicated by v_r. Drag force f_D, lift force f_L and pitching moment M_W can thus be obtained on such an asymmetric shape. Compared to v_r direction, the position of ice (its centre of gravity) is defined by φ, the angle of attack. This one is influenced by conductor rotation (torsion) and conductor vertical velocity. f_D, f_L and M_W depend on the angle of attack as detailed in equation (10.25) and shown on Figure 10.67 for a particular ice shape.

Ice eccentricity ε is defined as: ε = maximum ice thickness/d/2 where d is the conductor diameter.

Equations (10.25) are the definition of aerodynamic drag f_D and lift forces f_L (N/m) as well as pitching moment M_W (Nm/m) per unit length. ρ_{air} is the air density

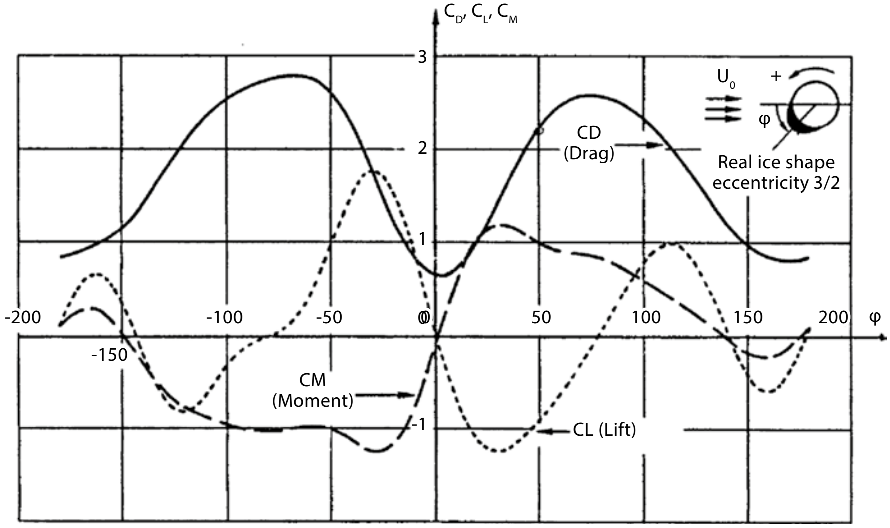


Figure 10.67 Typical aerodynamic lift, drag and moment versus angle of attack. Ice thickness 24 mm over a subconductor diameter of 32.4 mm. These coefficients are wind velocity independent in the range of galloping. (0° angle of attack when ice is facing the wind). LIFT positive upwards; Pitching moment and angle of attack positive anti-clockwise. Zero angle when ice is facing the wind and in horizontal position. Major similarities exist between different ice thicknesses and in general for any typical shapes, but this is not valid for very thin ice thickness.

(about 1.2 kg/m^3), v_r is the relative wind velocity (m/s) and d the conductor diameter (m) (without ice). φ is the angle of attack (abscissa of Figure 10.67).

$$
\begin{aligned}
&f_D = k_D v_r^2 C_D(\varphi) \qquad && f_L = k_D v_r^2 C_L(\varphi) \\
&k_D = \frac{1}{2}\rho_{air} d && k_M = \frac{1}{2}\rho_{air} d^2 \\
&M_w = k_M v_r^2 C_M(\varphi) &&
\end{aligned}
\tag{10.25}
$$

When the aerodynamic coefficients are such that the conductor is unstable, it may extract energy from the wind as it starts to move, allowing the amplitude of the motion to grow. The final amplitude is limited by the balance between the energy extracted and the energy dissipated during a cycle of motion.

Thus, galloping is NOT a forced oscillation, it is a self-excited phenomenon. It may (and does) occur during both ‘steady’ and turbulent winds.

An aerodynamic instability can arise when the aerodynamic lift and drag acting on the iced conductor, as functions of angle of attack of the wind, provide negative aerodynamic damping. This negative aerodynamic damping generally increases in magnitude as the wind velocity increases so that, at some critical velocity, the sum of the aerodynamic damping and mechanical damping in the conductor system becomes zero. Unstable motion can then develop, usually in the vertical direction (Den Hartog 1932).

An aeroelastic instability is much more complex and will always involve more than one type of conductor motion (degree of freedom) - typically vertical and torsional motion - whereas an aerodynamic instability may involve only one. The aeroelastic instability is only possible because of a strong interaction between the aerodynamic properties of an iced conductor, as functions of angle of attack, and the structural properties of the iced conductor system. Bundled conductor systems are particularly susceptible to aeroelastic instability because their natural frequencies in vertical, horizontal and torsional motion tend to be very close together. This is true for any number of loops and there is no easy design means available for separating them. A change in effective angle of attack of the iced conductor - induced, for example, by vertical motion - leads to changes in all three aerodynamic forces (see Figure 10.66). Because of the close proximity of the natural frequencies in a bundle, the vertical motion is then readily coupled to horizontal and torsional motion. Of these, vertical-torsional coupling is usually the most significant and can lead to some spectacular galloping of conductor bundles.

The gravitational moment provided by the eccentricity of the ice and the aerodynamic moment characteristic of an iced conductor can have a strong effect on the conductor's torsional stiffness - and, hence, torsional frequency. This can lead to a convergence of the vertical and torsional frequencies, even for single conductors where these frequencies are otherwise well separated. An aeroelastic instability may then ensue.

Finally, it should be noted that most theoretical studies of galloping employ wind tunnel data that have been measured for winds perpendicular to the conductor axis. The complexity of fluid flow is such that these data may not be reliably used for studies involving non-perpendicular (yawed) winds by resolving the data into components perpendicular and longitudinal to the conductor since the aerodynamic coefficients of the conductor may be completely different (Van Dyke and Laneville 2004).

10.3.4.3 Mechanism of Conductor Galloping

Basic Physics of Galloping on Overhead Lines

A body immersed in a moving fluid experiences lift and drag forces which act through a point in the body known as the aerodynamic centre. In general, this will not be the same point as the centre of gravity and, a priori, its position will not be known (Binder 1962; Blevins 1990; Davison 1939). As the movement of the body in response to the fluid flow is restricted by the boundary conditions - for example, a conductor tensioned between towers - it is generally more convenient to consider the forces and moments acting at a known location, typically the shear centre in the case of a conductor. This requires the introduction of an aerodynamic pitching moment about the new location. The evaluation of lift, drag and pitching moment is usually done in a wind tunnel on a fixed, rigid cylinder on which the ice shape has been reproduced (Bokaian and Geoola 1982; Chabart and Lilien 1998; Koutselos and Tunstall 1986, 1988; Nakamura 1980). However, there is still some concern about the evaluation of such forces and moments on a fixed wind tunnel model (quasi-steady approach) rather than a moving one. The quasi-steady hypothesis will be discussed later and its limitations clearly pointed out. All existing simulation models are based on the quasi-steady approach.

For the sake of simplicity, we will discuss only pure vertical plus torsion movement. No horizontal movement is taken into account.

In Figure 10.66 shows a representation of the cross-section of an iced conductor. The conductor, subject to a wind, U_0, is shown at a time, t, during vertical + torsional motion. Aerodynamic forces, f_L, and f_D, and moment, M_W, act at the shear centre. The conductor is assumed to move vertically upwards with a positive vertical speed. The initial ice position is θ_{ice} and θ is the actual rotation of the conductor; φ is the so-called "angle of attack" and is positive anticlockwise. The drag force, f_D, is oriented in the direction of the relative wind speed, v_r (the combination of U_0 and the conductor's vertical speed). The lift force, f_L, is perpendicular to the drag force and positive upwards. The pitching moment is positive anticlockwise.

Figure 10.68 shows the drag and derivatives with respect to φ of the lift and pitching moment for an assumed ice shape. The regions where the lift curve derivative crosses the drag curve are regions of possible Den Hartog instability (see equation 10.34). It is remarkable that a small variation in the ice shape leading to a slightly asymmetric lift curve results in a Den Hartog instability region around −50° but not at +50°.

$$\begin{gathered} f_D = k_D v_r^2 C_D(\varphi) \quad f_L = k_D v_r^2 C_L(\varphi) \\ k_D = \frac{1}{2}\rho_{air} d \quad k_M = \frac{1}{2}\rho_{air} d^2 \\ M_w = k_M v_r^2 C_M(\varphi) \end{gathered} \tag{10.26}$$

C_D as well as C_L and C_M derivatives are given by the measured values as shown in Figure 10.68 evaluated during wind tunnel testing.

To evaluate possible instabilities, the vertical force acting on the (moving vertically and torsionaly) conductor is calculated as follows (noting that α is negative):

$$f_w = f_L \cos\alpha + f_D \sin\alpha \tag{10.27}$$

Where f_L is the lift force (proportional to the lift coefficient C_L given in Figure 10.68 and depending on the angle of attack φ, as shown in equation 10.26) and f_D is the drag force:

$$\varphi = \theta_{ice} + \theta - \alpha \tag{10.28}$$

where

φ = total angle of attack to consider

θ_{ice} = initial ice position on the conductor (ice accretion angle)

θ = extra rotational component of the conductor (or the bundle) due to acting forces (pitching moment, inverse pendulum effect, inertial effect) in the dynamic movement

α = the part of the angle of attack which is due to vertical movement

Instability occurs in a vertical movement if a perturbation in the vertical movement (thus creating a vertical speed) would see a change in applied force which would amplify the movement. For example, a positive vertical speed would generate an increase of vertical net force in the same direction, in other terms:

$$\Delta f_w > 0 \quad \text{unstable} \tag{10.29}$$

$$\Delta f_w < 0 \quad \text{stable} \tag{10.30}$$

To establish the variation of the force, we will make the simplified hypothesis that the drag coefficient is constant and also note that the angle α is very small.

$$\Delta f_w = \Delta f_L + f_D \Delta\alpha \quad \Delta\alpha = -\frac{\Delta\dot{y}}{U_0} \tag{10.31}$$

$$\Delta f_L = k_D \frac{\partial C_L}{\partial\varphi}\Delta\varphi = k_D \frac{\partial C_L}{\partial\varphi}(\Delta\theta - \Delta\alpha) \tag{10.32}$$

$$\Delta f_w = k_D \left[C_D \Delta\alpha + \frac{\partial C_L}{\partial\varphi}(\Delta\theta - \Delta\alpha) \right] \tag{10.33}$$

So that instability criteria are predictable. Noting that Δα is negative for an upward movement, instability depends on the torsional behaviour. Two cases have to be considered.

Case 1: no torsion (infinitely rigid)

$$\begin{aligned} &\Delta\vartheta = 0 \rightarrow C_D - \frac{\partial C_L}{\partial\varphi} > 0 \quad (\text{also noted } C_D - C_{L\alpha} > 0) \\ &\rightarrow \text{the system is stable} \end{aligned} \tag{10.34a}$$

$$\begin{aligned} &\Delta\vartheta = 0 \rightarrow C_D - \frac{\partial C_L}{\partial\varphi} < 0 \quad (\text{also noted } C_D - C_{L\alpha} < 0) \\ &\rightarrow \text{the system is unstable} \end{aligned} \tag{10.34b}$$

Therefore the system may be unstable only for $C_{L\alpha}>0$ and larger than C_D. This is the classical Den Hartog criterion (Den Hartog 1932). The unstable range of attack may be derived from Figure 10.68, drawn with lift derivative: It may occur when the C_D curve crosses the $C_{L\alpha}$ curve (dotted line). Thus, only one narrow zone around –50° and another one around 180° may be unstable according to the Den Hartog criterion.

That criterion (Equation 10.34) is often presented with a "+" instead of a "–". That is simply because of the sign convention chosen for clockwise or anti-clockwise angle of attack.

This criterion does not take into account conductor torsion. But, as we know, the torsion on overhead line conductors cannot be assumed to be zero, in fact a several hundred metre beam with a diameter of a few centimetre is obviously not rigid in

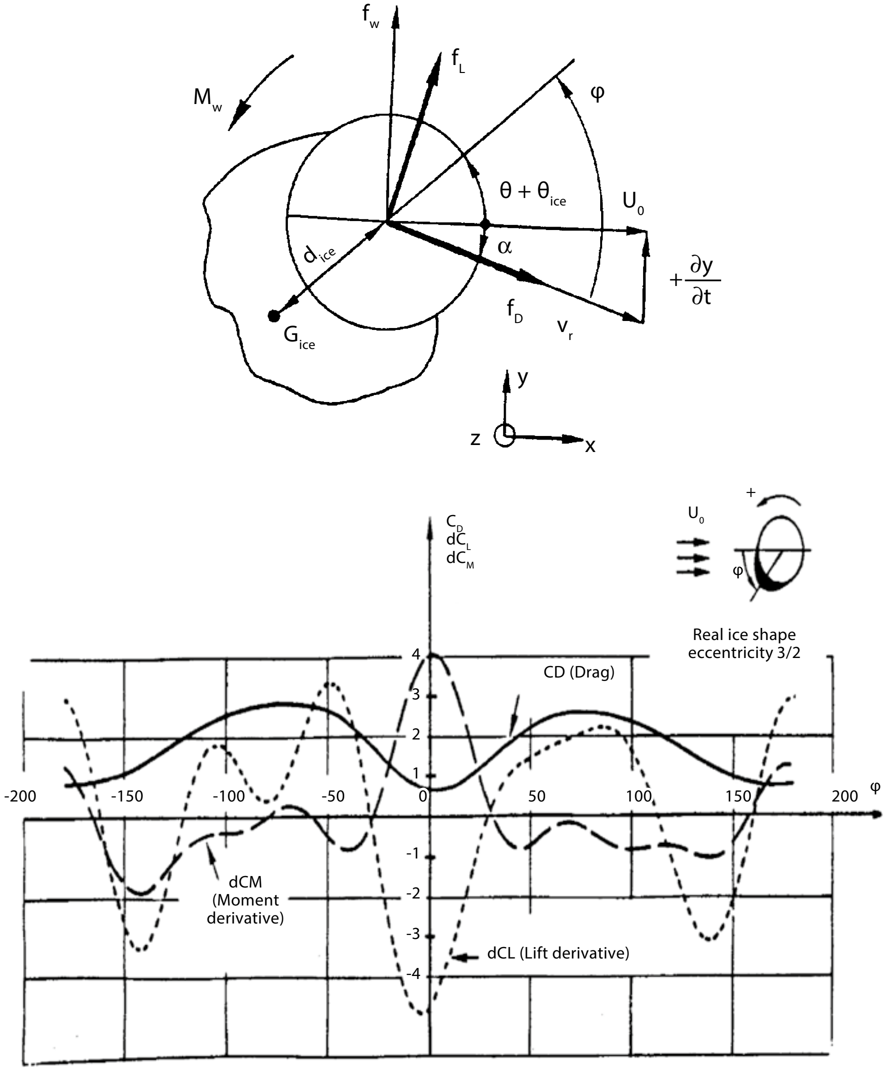


Figure 10.68 Aerodynamic Characteristics of an Iced Conductor.

torsion. A lot of investigations have been done in the literature on the subject, mainly by Nigol and Havard (Nigol and Clarke 1974; Nigol et al. 1977; Nigol and Buchan 1981) and Lilien and Wang (Lilien et al. 1989, 1994; Wang and Lilien 1998), which covered, both single and bundle conductors.

For bundle conductors, the torsional stiffness depends on the mechanical tension in the sub-conductors and the spacing in the bundle as well as the number of sub-conductors and the spacers used. Bundle conductor torsional stiffness (several thousand of Nm^2) is two orders of magnitude larger than that of a single conductor (from tenths to some hundreds of N m^2). However, bundles have a resonance between the vertical and torsional mode, which is not there for single conductors where the frequency ratio is about 3 to 10 (the torsional frequency being higher than the vertical one). This induces a completely different behaviour but in both cases, torsion during dynamic movement is easy to obtain.

Thus, a second case has to be considered; the most frequent one.

Case 2: torsion occurs

$$\Delta\theta \neq 0 \tag{10.35}$$

In the presence of torsion, at least two cases must be considered:

- $\Delta\theta$ in phase with the vertical velocity (the case of single conductor)
- $\Delta\theta = -k\ \Delta\alpha$
- The criterion does not change compared to the Den Hartog criterion but the derivative of lift is increased by the coupling.
- $CD - CL_{\alpha}\,(k+1) \leq 0$ The system is unstable As above, for torsion to be in phase with velocity requires a forced movement with no inertial effects. This would need a large difference between vertical and torsional frequencies, which will be possible only for single conductors with a very thin ice deposit.
- $\Delta\theta$ in opposite phase with the vertical velocity (may be one particular case of bundles) The criterion is completely modified. Instability may occur even if ∂CL <0. In this case the phase shift (vertical/torsion) play an important role, this last being strongly related to torsional damping and the proximity of resonance. This last case is called "coupled flutter" or simply "flutter" galloping for electrical engineering.
- This expands the range of instabilities to include *completely different mechanisms, as the derivative of lift no longer needs to be negative as is the case for the Den-Hartog instability criterion.*
- These galloping cases are considered as "aeroelastic" (and not aerodynamic) as structural data (like the ratio vertical/torsional frequencies, inertial effect, torsional stiffness, damping) may interact strongly in the phenomenon. Not only aerodynamic properties (= lift, drag and moment aerodynamic curves) are important but also structural data play a major role.

Of course, many other situations are also possible (torsion not in phase with vertical velocity).

Discussion

These developments may easily become more complex by introducing horizontal movement, limit cycle frequency (which is close to the vertical one but not equal), etc. These can be managed by a computer but experts have not found significant discrepancies with the theory explained above. Some new kinds of instability (horizontal/torsion) may occur but the physics remain similar.

If both kinds of instability (Den Hartog and flutter type galloping) are theoretically possible, very few ice shapes can produce Den Hartog instabilities. There are many discussions in the literature about that (Chabart and Lilien 1998; Chadha 1974a, b; Davison 1939; Den Hartog 1932; Diana et al. 1991; Dubois et al. 1991; Edwards and Madeyski 1956; Hunt and Richard 1969; Keutgen 1999; Lilien and Dubois 1988; Nakamura 1980; Nigol and Buchan 1981; Novak 1972; Otsuki and Kajita 1975; Ottens 1980; Parkinson 1971; Richardson 1979; Richardson et al. 1963; Wang 1996). The few ice shapes producing aerodynamic properties in agreement with Den Hartog are some very thin ones (Chadha 1974; Tunstall and Koutselos 1988) (a very few mm thickness), such cases are unstable in a very narrow range of angle of attack (near zero °) which would lead to limited amplitudes, but increasing linearly with the wind speed (using a simplified approach).

There is another case of Den Hartog galloping possible on any arrangement: angle of attack close to 180° (see Figure 10.68). It means that the wind would have to reverse its direction between the icing period and the galloping period which occurs seldom, even if few cases have been recorded in the literature.

Bundle conductor configurations have a natural collapse of vertical and torsional frequencies as explained in the literature (Lilien and Dubois 1988). The collapse depends on wind speed and ice position. Such arrangements are obviously more prone to gallop under the second type of instability (flutter type).

Nevertheless there are still some concerns on single conductor. Some experts (i) would support the fact that torsional frequency (about 3 to 8 times the vertical frequency without wind or ice) may drop to resonance due to ice and wind. Some others (ii) do not agree with such theory which supposes that ice shape remains on the same position, independently of the wind speed level. The latter could not find any collapse of the frequencies for single conductor arrangements, taking into account that the actual ice shape position cannot be maintained in a position which would be statically unstable.

The first theory (i) may allow coupled flutter on single conductor while the second (ii) would not.

The basic theory behind galloping is at the origin of retrofit methods. See Section 10.3.4.5.

The following sections will describe some aerodynamic aspects of the phenomenon, to better understand the physics behind the Den-Hartog galloping, and to estimate validity of some hypoteses. It will also explain basic differences between some other aerodynamic phenomena and galloping.

Remark

Aerodynamicists and aeroelasticians, in general, have adopted the Den Hartog type instability as the definition of 'galloping' - in essence, a one-degree-of-freedom (dof) motion. Other forms of instability involving two or more dofs are classified as flutter, a term coming from the original aircraft wing, aeroelasticity studies and subsequently applied to suspension bridge decks, etc. However, as far as the overhead line world - and Cigré - is concerned, the term 'galloping', covers all forms of large amplitude, low frequency oscillation, caused other than by turbulent buffeting.

It is a term that conveys the visual impact of what lines do and it therefore includes vertical-torsional flutter, as well as the Den Hartog instability.

10.3.4.4 Ice and Snow Deposit

Galloping requires moderate to strong wind at an angle greater than about 45° to the line, a deposit of ice or rime upon the conductor lending it suitable aerodynamic characteristics, and positioning of that ice deposit (angle of attack) such as to favour aerodynamic instability. The ice, wet snow or rime deposit has to have strong adhesion to the conductor.

The types of ice and snow that may accrete on conductors are rime ice, glaze ice, frost, dry snow and wet snow (Poots 1996). Rime is an ice deposit caused by the impaction of supercooled droplets and their freezing onto a substrate. When air temperature is well below 0 °C, supercooled droplets possessing small momentum will freeze upon hitting the substrate, creating air pockets between them in the process. This type of deposit is known as *soft rime*. When the droplets possess greater momentum, or the freezing time is greater, a denser structure known as *hard rime* is formed. *Glaze* ice will form when the droplet freezing time is sufficiently long to let a film of water form on the accreting surface. The latter type of ice accretion has the highest density and the strongest adherence to conductors. *Frost* is formed when water vapour in the air sublimates on a substrate of temperature below 0 °C. Ice load due to frost is insignificant and rare. *Dry snow* has low density and accretes at sub-freezing temperatures. Dry snow rarely accumulates and only when wind speed is very low, below 2 m/s. *Wet snow* accretion is observed when air temperature is between 0 °C and 3 °C, and may occur under any wind speed. Wet snow is made up of a matrix held together by capillary forces and ice bonding. The adhesion of wet snow to conductors may be strong, and its accretion may be quick, causing its liquid water content to increase to such a level that the aerodynamic and gravitational forces eventually overcome the internal cohesive forces (Admirat et al. 1988). Above this level the snow sleeve breaks up and means no further danger for the transmission line.

The relation between accretion type and air temperature and wind speed, is shown in Figure 10.69 (based on (Tattelman and Gringorten 1973; Sakamoto 2000)).

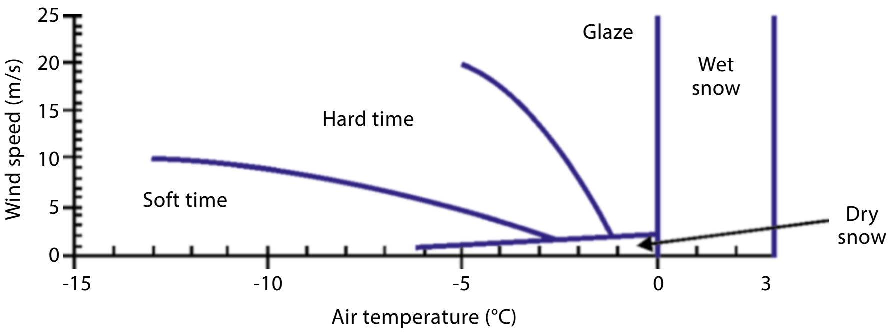


Figure 10.69 Relation between ice accretion type and some meteorological conditions.

Formation of ice and snow on conductors may come from cloud droplets, raindrops, snow or water vapour. Cloud droplets are a constitutive part of fog, while raindrops and snowflakes are associated with freezing rain and snow falls, respectively.

A classification of icing forms has been proposed in Cigré TB 179, by a Cigré working group (Cigré 2000). They divided icing into six different types.

Precipitation icing:

- (1) Glaze, density 0.7 to 0.9, also called "blue ice", is due to freezing rain, is pure solid ice, and has very strong adhesion. It sometimes forms icicles, and occurs in a temperature inversion situation. Accretion temperature conditions are −1 °C to −5 °C.
- (2) Wet snow, density 0.1 to 0.85, forms various shapes dependent on wind velocity and torsional stiffness of the conductor. Depending on temperature, wet snow may easily slip off or if there is a temperature drop after accretion, it may have very strong adhesion. Accretion temperature conditions are +0.5 °C to +2 °C.
- (3) Dry snow, density 0.05 to 0.1, is a very light pack of regular snow, which is easily removed by shaking the conductor.

In-cloud icing:

- (1) Glaze due to super cooled cloud/fog droplets (similar to precipitation icing).
- (2) Hard rime, density 0.3 to 0.7, has a homogenous structure and forms a pennant shape against the wind on stiff objects but forms as a more or less cylindrical coating on conductors with strong adhesion.
- (3) Soft rime, density 0.15 to 0.3, has a granular "cauliflower-like" structure, creating a pennant shape on any profile, with very light adhesion.

Hard rime and glaze deposits are tenacious enough, and have sufficient strength and elasticity, that galloping motions do not dislodge them.

Wind-driven wet snow may pack onto the windward sides of conductors, forming a hard, tenacious deposit with a fairly sharp leading edge. The resulting ice shape may permit galloping.

The torsional rigidity of the cable has a direct influence on ice shape as shown in Figure 10.70. Increasing wind speeds may result in thicker and broader ice mass in the windward direction and, consequently, in a significant ice-load growth. Figure 10.71 shows the simulated ice accumulations obtained by applying varied wind speeds while maintaining the other conditions constant.

Conductors with any noncircular cross-section are prone to galloping. Principally, both the lift and drag coefficients determine if galloping will occur. These coefficients basically depend on shape, angle of attack, and Reynolds number. For any noncircular cross-section, there exist angle of attack ranges where galloping may occur. These ranges and the minimum wind speed which initiates galloping, however, vary to a great extent with the shape of the cross-section (Blevins 1990).

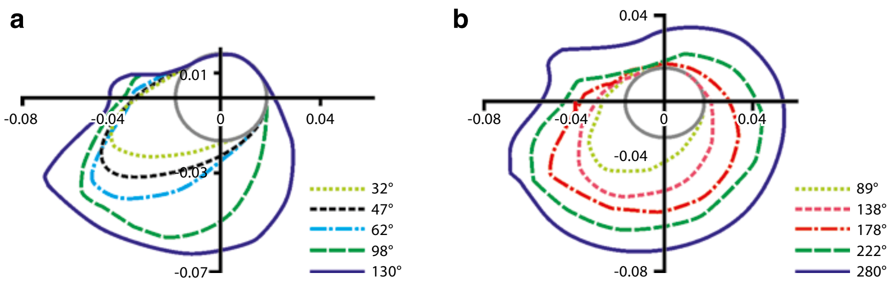


Figure 10.70 Simulated ice shapes for cables with finite torsional rigidity (Adapted from Fu and Farzaneh (2006)) (Parameters: diameter 0.035 m, duration 180 min, temperature −15 °C) (**a**) Predicted ice shapes for a rigid cable (torsional rigidity: 100 Nm_2). (**b**) Predicted ice shapes for a soft cable (torsional rigidity: 351 Nm^2)

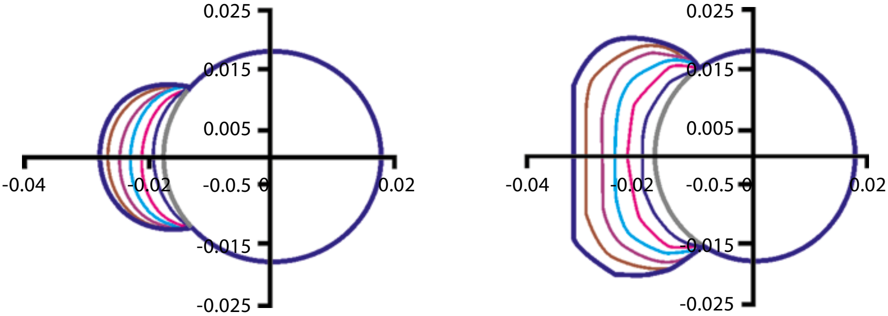


Figure 10.71 Comparison of ice shapes (based on Lozowski et al. (1983)) (**a**) Case 1: air speed 5 m/s. (**b**) Case 2: air speed 10 m/s.

10.3.4.5 Countermeasures against Galloping

There are three main classes of countermeasure employed against galloping:

- Making lines tolerant of galloping through ruggedness in design, provision of increased phase clearances or controlling the mode of galloping with interphase ties.
- Interfering with the galloping mechanisms to prevent galloping from building up or from attaining high amplitudes.
- Removal of ice or preventing its formation on conductors.
  - The complexity of galloping is such that control techniques cannot be adequately tested in the laboratory and must be evaluated in the field on trial lines. This testing takes years and may be inconclusive.
  - Analytical tools and field test lines with artificial ice are useful in evaluation of galloping risk and appropriate design methods.

- No control method can guarantee it will prevent galloping under all conditions.
- Interphase spacers virtually ensure galloping faults will not occur, but do not necessarily prevent galloping. Their usage is growing and their design is undergoing further development.
- Mechanical dampers to stop vertical motion are still being pursued but to only a very limited extent.
- Torsional devices, which either detune or increase torsional damping or both, are being pursued and actively evaluated.
- Techniques which disrupt either the uniformity of ice accretion by presenting a varying conductor cross-section or the uniformity of the aerodynamics by inducing conductor rotation are being actively pursued.
- Methods of ice removal or prevention are not widely used as specific anti-galloping practices.
- Despacering or using rotating-clamp spacers is still used extensively in a number of parts of Europe subject to wet snow accretions.
- For bundled conductors, the influence of the design of suspension and anchoring dead-end arrangements on the torsional characteristics of the bundle and on the occurrence of vertical/torsional flutter type galloping has been recognized.

Increased Clearance

A database of 166 observations of galloping on single, twin, triple and quad bundle lines has been analyzed. The database is sufficiently detailed to define the variation of maximum amplitudes of galloping motion for single conductors in 50 to 450 m spans, and for twin and quad bundles in 200 to 450 m spans. Conventional design expectations are exceeded, for maximum galloping motions on short spans, and through the existence of single loop galloping on long spans.

The Cigré TFG experts have approved the next formulas estimating the maximum galloping motions for spans without galloping controls. The best fit numerical model for single conductors uses the peak-to-peak galloping amplitude over conductor diameter versus "conductor span parameter", the conductor diameter over the sag. The best-fit model for bundle conductors also uses the peak-to-peak galloping amplitude over subconductor diameter as a function of the "conductor span parameter".

The following proposal has been deduced from cases in the following range of data:

- sag/span ratio in the range 1-5 %
- conductor diameter 10-50 mm
- single and bundle conductors (two different formulas)
- span length 50-450 m.

More details of the database are presented in Lilien and Havard (2000).

The approach employs the *reduced amplitude*, which is the ratio of peak-to-peak galloping amplitude (*Apk-pk*) over conductor diameter (d), both in m:

$$\frac{A_{pk\text{-}pk}}{d} \tag{10.36}$$

This reduced amplitude has a range between 0 and 500.

The conductor *span parameter* is a combination of the catenary parameter with the ratio of conductor diameter (d) over the square of the span length (*L*), which can also be expressed as the ratio of conductor diameter over the sag (*f*). The conductor span parameter is dimensionless:

$$\text{Conductor span parameter}: 100\frac{Td}{mgL^2} = \frac{100d}{8f} \tag{10.37}$$

With tension in N, mass in kg/m, span length, sag and diameter in m, the conductor span parameter is in the range:

- For single conductor: 0 to 1
- For bundle conductor: 0 to 0.12.

The observed values of galloping amplitude have been completed by simulated cases to fill missing zones of observation.

For single conductors, the fitted curve to the maximum amplitude over conductor diameter, which is included in Figure 10.72, is given by:

$$\frac{A_{pk\text{-}pk}}{d} = 80\ln\frac{8f}{50d} \tag{10.38}$$

This is valid only in the 0–1 range of the conductor span parameter, which corresponds to the data base range.

The observed values (all for wind speed lower than 10 m/s) are completed by many simulations coming from different aerodynamic curves (4 different) and for wind speed covering up to 15 m/s, means bigger than in observed cases.

As the difference between observed and calculated galloping amplitude for bundle conductors is much larger than on single conductor, more observations would be needed, especially for higher wind speed before presenting a definitive curve of maximum amplitude.

Actually, we will recommend the fitted curve based on observed data only.

For bundle conductors, the corresponding fitted curve, which is reproduced in Figure 10.73 as the estimated maximum, is given by the denominator γ factor and could be 300 or 500 following the chosen curve fit on Figure 10.73.

$$\frac{A_{pk\text{-}pk}}{d} = 170\ln\frac{8f}{\gamma d} = 170\ln\frac{8f}{500d} \tag{10.39}$$

This is valid in the range 0-0.15 of the conductor span parameter.

It may be noted that the expressions have the same form, but single conductors have from less than one up to about 2.5 times larger values of galloping amplitude/diameter for values of the conductor span parameter between 0.015 and 0.10.

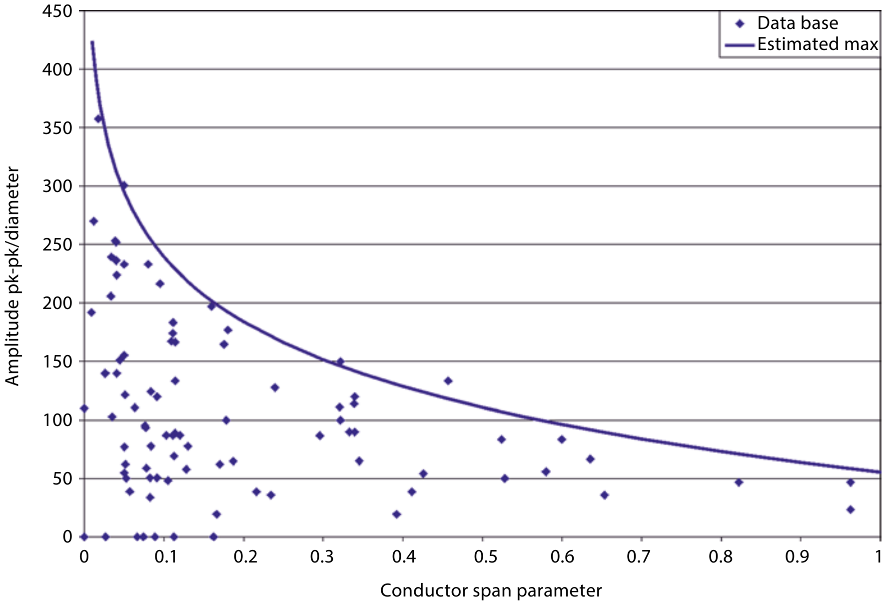


Figure 10.72 Variation of observed maximum peak-to-peak galloping amplitude/diameter on single conductors as a function of the conductor span parameter (defined in equation (10.37)).

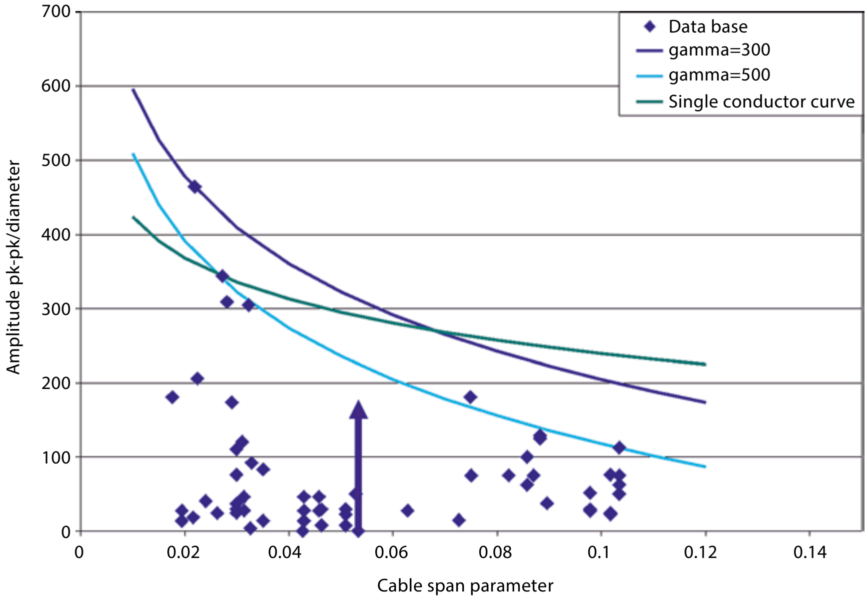


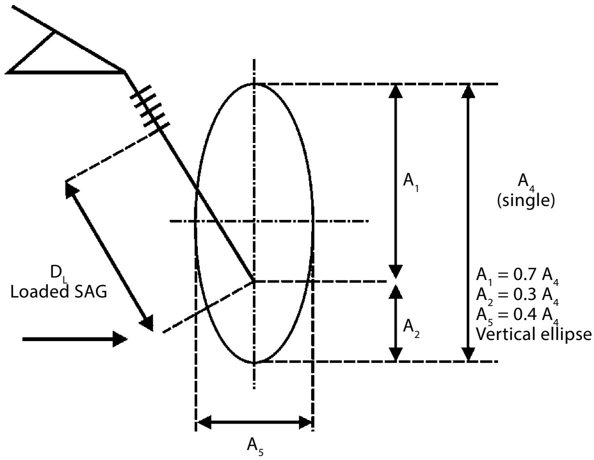
Figure 10.73 Variation of observed maximum peak-to-peak galloping amplitude/conductor diameter on bundle conductors as a function of the conductor span parameter (defined in equation (10.37). Gamma is defined in equation (10.39).

It should be noted that the observed galloping amplitude on single conductors can reach up to 5 times the unloaded sag. In the context of distribution line conductor spans and sag, this indicates much larger galloping motions than conventionally considered in design (Dienne et al. 1985). Also the data show a significant number of single loop galloping events on long spans, which is at variance with the above design guide.

The observed galloping amplitude on bundle conductor was limited to the unloaded sag in the observed cases.

A more detailed analysis of that database is available in Lilien and Havard (2000) (Figure 10.74 and Figure 10.75).

Figure 10.74 Proposed ellipse for clearance design against galloping for power lines.



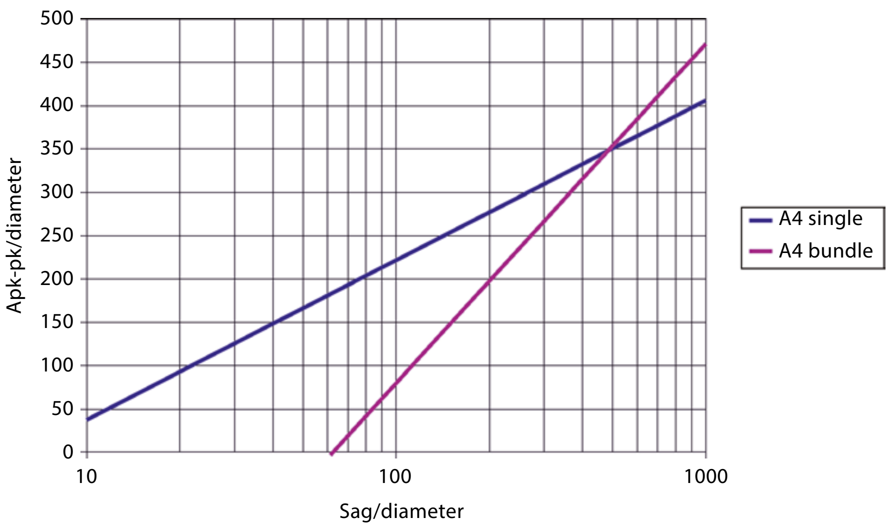


Figure 10.75 Proposed curves for galloping maximum peak-to-peak amplitude (all data in metres).

Range of Application for Curves of Maximum Galloping Amplitude

Span length between 30 m and 500 m

Sag/span ratio between 0.5 % and 5 %

Diameter of the conductor between 0.01 m and 0.05 m

Data were obtained from 166 field observations and complementary simulations.

Data were only based on classical bundle designs (symmetric 2, 3 and 4 bundle conductor up to 0.6 m bundle diameter). The maximum design wind speed against galloping was taken as 15 m/s.

Only realistic data were considered, curves are not applicable to extreme designs such as a bundle with conductor diameter 0.01 m and 1 m sag.

This approach cannot be easily compared to BPA curves (Winkelman 1974) or any other approach because of the dependence on the conductor diameter and the sag. Nevertheless we may apply both methods in a given case.

A multi-span 400 kV line, with span length close to 350 m, and having a twin bundle (45 cm bundle diameter). Initial loaded sag about 8 m (sag/span ratio 2.3 %)

Evaluation following BPA curves:

A4 = about 70 % of the sag = 5.6 m

Evaluation following Cigré method (using diameter data):

A4 = 10 m (diameter 32 mm); 8.5 m (diameter 22 mm), 5.6 m (diameter 11 mm)

Evaluation following KEMA method (KEMA 1998; Rhebergen 1999)

A4 = 8.5 m

Actually, a line in Belgium that was analyzed has a 32 mm conductor.

More observation data are needed which would include conductor diameter to validate the new approach. The proposed approach is valid for single conductor lines but needs more information for bundle conductors, as stated in Rawlins (1979). The bundle curve reproduced here is based on the field data augmented by numerous added data from simulation for wind speed up to 15 m/s because the data base observations were mainly limited to 10 m/s.

Anti-Galloping Devices

An overview of existing techniques is provided in Table 10.3.

In-span hardware, including galloping control devices and aircraft warning markers, are concentrated masses, which can act as reflection points of traveling waves of aeolian vibration. This vibration due to wind can occur in the sections of the conductors or overhead ground wires between the in-span devices and these sections of the span are isolated from any vibration damping systems, which are most often applied to the ends of spans. For spans of conductors with low tension this does not cause any problems. However, extra precautions are needed for spans with

Table 10.3 Overview of existing countermeasure against galloping

NO	DEVICE NAME	APPL'N	WEATHER CONDITION		LINE CONSTRUCTION			COMMENTS
			Glaze	Wet snow	Dist'n	Single trans'n	Bundle	
1	Rigid Interphase Spacer	Widely used	Yes	Yes	Yes	Yes	Yes	Prevents flashovers, reduced galloping motions
2	Flexible Interphase Spacer	Widely used	Yes	Yes	Yes	Yes	Yes	Prevents flashovers, reduced galloping motions
3	Air Flow Spoiler	Widely used	Yes		Yes	Yes	Yes	Covers 25 % of span Limited by voltage Extensive field evaluation
4	Eccentric Weights& Rotating Clamp Spacers	Used in Japan	No	Yes	No	Yes	Yes	Three per single span One per spacer per subconductor
5	AR Twister	Used in USA	Yes		Yes	Yes	Yes	Two per span
6	AR Windamper	Used in USA	Yes		Yes	Yes	Yes	Two per span
7	Aerodynamic Galloping Controller (AGC)				Yes	Yes		Number based on analysis
8	Torsional Control Device (TCD)	Used in Japan		Yes	No		Yes	Two per span
9	Galloping Control Device (GCD)	Used in Japan		Yes	No		Yes	Two per span 3 or 4 per span. Uses armor rods if tension is high. Most extensive field evaluations.
10	Detuning Pendulum	Widely used	Yes		Yes	Yes	Yes	Few cases have been reported where detuning pendulums increased galloping amplitude.
11	Torsional Damper and Detuner (TDD)	Experimental	Yes	Yes	No	No	Yes	2 or 3 per span

tensions approaching the safe tension limits with no dampers (Cigré 1999). The precautions required are to reduce the stress concentrations at the metal clamps attaching the hardware to the conductors. Two alternatives for reducing these stresses are installing armor rods under the metal clamps or replacing the metal clamps with elastomer lined clamps (Van Dyke et al. 1995). A further option is to add vibration dampers within each subspan between the in-span hardware.

A second aspect requiring caution applies to galloping control devices based on the control of torsional motions. These are custom designed based on the parameters of the conductor span. They are designed to ensure that the torsional natural frequency, after adding the devices and a chosen amount of ice and wind, falls within a range necessary for the proper function of the control device. The caution required for this is that the actual parameters of the line need to be known, and that may necessitate a line survey to confirm that the line is installed according to the design. In particular the tension of the conductors has been found to deviate from the as designed values, especially in regions where ice loads have occurred increasing the sag, or where repairs have been made in the spans. There are ratios of torsional to vertical oscillation frequency that make a span more likely to gallop. Consequently, it is possible to misapply the devices if they are designed with the wrong input parameters, or if the resonant behavior is not avoided by proper choice of device dimensions. It is therefore highly recommended that the design of galloping controls be carried out by experienced practitioners.

Another way to prevent galloping is to remove or prevent ice accretion on the conductors. Table 10.4 (Cigré 2000) enumerates de-icing and antiicing techniques.

10.3.4.6 Assessment of Galloping

Galloping Amplitude and Fatigue Damage Criterion

A methodology to estimate maximum galloping amplitude has already been described in section 7.2.1.

Measurements on a full scale test line (Van Dyke and Laneville 2005) have shown that during galloping events, $f\,y_{\max}$, which is a fatigue indicator of conductor vibration, may reach amplitudes as high as 1.2 mm/s peak. Knowing that ACSR's endurance limit is 0.12 m/s peak (Rawlins 1979), this shows that conductors can be severely stressed by galloping. Fortunately, such conditions happen seldom and the number of cumulated cycles may not be sufficient to damage the conductors. Consequently, the possible hazard associated with those events must be evaluated on a probability basis.

Dynamic Load on Towers due to Galloping

There have been several valuable studies of dynamic loads due to galloping, including measurements on site. The differences existing between dead-end cases and multi-span cases must be recognized (Anjo et al. 1974; Krishnasamy 1984; Cigré 1989; Havard 2002; Keutgen 1999; Lilien and Ponthot 1988; Lilien 1991; Lilien et al. 1994; Wang 1996).

Table 10.4 Ice removal systems

Type		Technical Features			Industrial Use		
No.	Name(Ref)	Description	Action Mode	Installation	Conditions	Extent	Countries*
2.4.1.	Systems Moving along the Line	Moving conductor heater or snow scraper	lee removal by heat or by scraping			High	Norway USA Japan Canada Sweden Russia
2.4.2	lee Melting by High Electrical Current	Heating conductors by Joule effect Heating overhead ground wires by Joule effect Routingthe load current of bundled conductors through only one of the conductors by using special commutators	Total/partial metting of ice Total/partial metting of ice Total/partial metting of ice	Three-phase short-circuit Additional switching units and bus bars Load cel! detects initiation of icing; operator increases line current to melt ice Insulators and a.c. or d.c. sources Insulation of spacers and yoke plates and addition of special commutators directly on power line without reference to ground	Forbundled conductors power lines.	15 to 140 km 30,000 km Small Demonstrated on a 12.4 km loop using two ground wires 1 to 50 km by modules, under investigation	Canada Russia Tasmania Canada Canada

2.4.3.	LowCurie PointAJloy [15, 25, 26]	Wrapping the conductor with a layer of aluminum wires which has a core of speciallow Curie point alloy (close to 0 °C} (Figure 11)	At temperatures below the Curie point, the layer works as a short circuited, single tum, transformer: heating arises and icemelts. Athigher temperatures the lasses are negligible	UK method used aluminum sleeves: Discontinued because of weight. Japanese method uses special wire: weight about 0.5 kg/m	Consideration must be given to the additional mass	Medium, Decreasing	Japan
2.4.4.	Snow-resistant Rings [15]	Plastic rings around the conductors (Figure 12)	Stops the snow sliding along the strands; snow drops off	Clipped on	Does not prevent galloping with small ice accretions	Medium (for snow limitation)	Japan
2.4.5.	Anti-twist Counterweight [16]	Pendulum clamped below the conductor (Figure 13)	Prevents conductor twisting, avoiding large cylindrical ice accretion	Clamping with armour rods	Contributes to wing-shaped ice accretion: may lead to galloping	High (for snow limitation)	Japan France: No galloping observed- to prevent overload only.
2.4.6.	Electrodynamic Method: Impulse voltage	High voltage impulse generator connected to the conductors	Electrodynantic shocks between strands, break:ing ice deposits	From the nearest substation	Mainly for freezing rain	Proposed concept	Belgium
2.4.7	Electrodynantic Method: Impulse current	High current impulse in two para!le! insulated strands of the cable	lee break:ing by Electrodynantic repulsion between strands	Fixed or transportable impulse source, specially made cable or insulated strands added on existing cables	For freezing rain	Demonstrated ona260m length of OPGW	Canada

* Not Exhaustive

Tension changes are generally considered by reference to a given tension value at appropriate temperature (so called here after "initial static value"), wind speed and ice load (static). Ice load during galloping has been considered as limited in most of the cases. Thus the tension with no ice load can be used as initial value before galloping. Wind speed is not considered in that reference value and temperature is chosen at 0 °C. Of course particular locations have to be considered with different hypothesis.

The following equation predicts to the maximum theoretical value of tension reached for one-loop galloping in a dead-end arrangement with peak to peak amplitude equal to the sag (neglect tower stiffness) ($\Delta y_s = y_{s0}/2$)

$$\Delta T = K_{ev} \frac{\pi^2 N_s}{4L} \sum_s \left(2y_{s0} + \Delta y_s\right) \Delta y_s \tag{10.40}$$

Which would be equal to 1.2 times the initial static value. Such a value has in fact been observed.

In all reported cases, the following *tension variation* has been observed:

Dead end spans: up to 1.2 times the value without wind

Suspension spans: up to 1.7 times the value without wind

When the variation is very large, the movement may slightly surpass the sag level, as can be seen in some videos, and the tension may be completely relaxed at the upper position. But more often the tension is not relaxed in multi-span arrangement, even during extremely high amplitude galloping, also the tension in the conductor reflects the length changes of the whole section, which is never relaxed in all spans except may be in some dead-end spans.

Suspension insulators have to sustain large vertical loads, but they are also subjected to dynamic horizontal loading (due to tension variation in the span). The tensioned insulators have a specific eigenfrequency which may be excited by these horizontal excitations. Such effects may lead in dramatic insulator movement.

The above evaluations can be summarized:

- The longitudinal loads on tension towers, during galloping events may reach 2.2 times the load existing without wind (but with ice). Ref. (Havard 2002) shows available measurements in the literature on such tension variations (peak-peak/static) and observed factors up to 2.2 on "standard" high voltage lines. But for short span lengths (80 m long) in Iceland some extreme cases occurred reaching a factor of 2.8 on test spans.
- The vertical load on crossarms (and thus applied to the suspension insulators) due to galloping may reach 2.7 times the load without wind. The same reference cited above has also analysed such loads and found dynamic peak factors always lower than 2.
- As there is no reason for synchronism or asynchronism of galloping loads in each phases, extreme dynamic loads may be reached at different times. So that tension towers with two circuit in a vertical arrangement may be submitted to torsional loads induced by a quasi-relaxation on one circuit and the maximum values in each phases of the second circuit.

As a conclusion on dynamic load factors, we would recommend, in the absence of detailed simulation able to point out particular cases, to choose the following design values:

- dead end spans: tension variation during galloping: from 0 to 2.2 times the static value (with ice, no wind);
- suspension spans: vertical load: from 0 to 2 times the static value.

The risk of tension tower torsion has to be analysed as well as the risk in suspension towers related to unbalanced vertical loads between the left and the right hand side of the towers (triangle arrangement or double circuit).

10.3.4.7 Cost and Damages caused by Galloping

Galloping is not just a spectacular and annoying phenomenon: in some cases it may have very costly consequences. The costs associated with galloping events can be due to damaged components requiring inspection and repair or to the consequences of repeated power interruptions. Costs may range from very low to extremely high, depending on the circumstances of each case.

There are also costs related to the prevention of galloping. Increased conductor clearances and the use of anti-galloping devices generate direct costs whilst investments in studies, research and development also have to be considered. This section will show that galloping can have a serious cost impact and what aspects should be considered.

Costs Related to Galloping Events

DAMAGE REPAIR

Galloping does not necessarily damage transmission line components and most of the time it does not. When it occurs however, damage may range from minor, such as conductor strand burn (which is quite common), to extreme, such as line collapse as the result of conductor breakage or dynamic overload. The repair costs will vary greatly depending on the extent of the damage. Repair of broken conductor strands may cost a few thousand dollars for easily accessed lines. For lines in remote area or those that are not easily accessible, such as river crossings, special techniques may have to be used such as helicopter work. Costs would then increase significantly. Although rare, line collapses due to galloping have occurred. As an example, galloping has been observed to have triggered a cascade failure of a section of a HV line during the 1998 ice storm that affected the north east of North America. Another case was reported in 1997 when two 120 kV towers collapsed due to a conductor breakage under galloping conditions. Costs range from less than 100 k$ for the two towers to millions of $ for the EHV line cascade in 1998. Experience from Russia shows that tower collapse can cost 50 k$ per tower for 110-220 kV lines, whilst repairing one suspension insulator string can cost 2-4 k$.

INSPECTION

A galloping event causing the repeated trip-out of lines may require an emergency inspection to identify the cause and apply remedial measures. This has to be done in bad weather at unpredictable moments. Otherwise, depending on the utility's practices, an inspection of the lines that galloped may have to be performed to detect any damage. This may be done either by a ground crew or by helicopter. The costs may not appear significant if this work is considered as part of the normal tasks of the maintenance crews. However, as the work is often unplanned, it may introduce additional costs.

Loss of Revenue

Most of the time, line trip-out due to galloping will be of short duration with negligible effect on the utility's revenues. In some cases, repeated flashovers will cause the automatic protection systems to open the circuit until the cause of the fault is identified and repaired. A real loss of revenues will result if there is no alternate route to supply the customer and the cost of galloping may then be significant. As an example, in a recent galloping event a loss of 200 MW for 2 hours was reported. Depending on energy costs, this represents a significant amount of revenue.

System Reliability and Quality of Service

There is no doubt that many utilities are increasingly concerned about the impact of galloping on system reliability and the quality of service but establishing the cost of galloping with regards to those factors is problematic. There may be no direct costs, as customers will seldom get compensation for a short duration power failure. However, transmission system owners may sustain significant costs if the system operator has to call up more expensive generation to maintain system security. Indirect costs may certainly be important; for example, it may be necessary to have a backup line for important industrial customers, such as aluminium smelters. There may also be a risk of losing hi-tech customers who are very sensitive to power quality.

Social Impacts of Outages due to Galloping

Impact on Utility Image

All unscheduled interruptions in supply to customers result in adverse publicity. The extent of the adverse publicity will be influenced by a number of factors: for example, the number of customers affected, the duration of the failure and the time of the year when the failure occurs. If the outages are frequent and last for long periods during the winter season, the utility can expect adverse publicity from the national media. This may adversely influence public confidence in the company and also the share values for public limited companies. However, there can be a positive side to failures in that increased public awareness of the importance and vulnerability of transmission systems can be used to help justify investments in maintenance or in the application of countermeasures.

Impact on Hospitals

Outages caused by galloping are normally short, but even short outages can be critical in hospitals. Most countries require that hospitals have backup power supplies in case of power outages, so the impact on hospitals should be limited. If the back-up power supply fails, it is more likely that public criticism will be directed at the hospitals rather than at the utility involved.

Impact on Production Industry

Some types of industry are very sensitive to both power outages and power quality. Heavy industries, like aluminium smelters, may have huge start up costs if a long outage causes the cessation of production. Other industries, like paper mills, require good power quality to avoid interruptions in production. In some countries, the utilities have to pay compensation to industrial costumers for the power that has not been supplied. The compensation rate will depend on the type of industry. Examples from Norway for other types of failures show that a short outage lasting for few minutes can cost more than 100,000 US$ and an outage to an aluminium smelter could cost the power utility about 150,000 US$ per hour. In this case, compensation costs could easily be much larger than the costs of repairing damage to towers and line components if the outage were to last for several hours.

If production industries have too many interruptions in their power supplies, they will evaluate alternative on-site power sources such as gas turbines to avoid power outages. This will result in loss of income for the power utility.

Impact on Population Confidence and Safety

Outages will always have a negative impact on confidence in the utility, especially among the affected customers. Normally the customers will not know or care about the reason behind the failures that occur and they are unlikely to have any knowledge of the phenomenon of conductor galloping. People living in the vicinity of galloping lines may observe the phenomena and be concerned about damage to property or person due to broken conductors or falling towers. This may, in turn, result in questions being raised about the professional competence of the utility.

When a line gallops severely and for a significant period of time, the failure of a component is always a possibility. In this case, measures may have to be taken to keep people away from the galloping line. Such a situation happened when a 4-conductor bundle line passing over a highway was experiencing galloping and the traffic had to be stopped for a few hours. In another case, during the 1998 ice storm in Canada, access to the Montreal city area was closed because a twin bundle line was galloping.

Costs Related to Prevention of Galloping

Design Criteria

It has been the practice in many utilities to increase conductor clearances in order to minimise the risks of flashovers between conductors. Different approaches have been used, generally based on the theoretical shape and size of the galloping conductors' trajectory. Although more realistic clearance requirements have been made possible by field observations, this approach is costly because it is usually applied to complete sections of lines, assuming that galloping can happen anywhere. The actual cost of this approach can only be established for each specific case. In fact, conductor clearances are also dictated by other considerations, such as live-line maintenance, so that the potential impact of galloping may be reduced. Nevertheless, any additional clearance due to galloping means higher towers and higher mechanical loads, leading to heavier and costlier towers and foundations.

Anti-galloping Devices

Anti-galloping devices can be retrofitted on existing lines that experience galloping. This situation is the most common and the easiest to manage because the field experience exists to justify the decision. These devices can also be used on new lines as part of a design approach to prevent galloping. In these cases, the galloping experience of other lines in the same area can be taken into account. However, in cases where there is no other line in the area and the concern about galloping is based on an evaluation of the terrain conditions and climatic data, then the decision is difficult. A cost comparison between increasing the clearances and using anti-galloping devices must be made.

In addition to the cost of purchasing and installing the devices, the maintenance costs have to be considered because each piece of equipment installed on conductors may be a source of problems in the future. For example, the device itself may become defective or create damage to the conductor due to the effect of aeolian vibration. Experience has shown that inappropriate devices may cause more damage than the benefits they provide. A serious situation was experienced in 1993 when multiple conductor breakages occurred at the attachment points of anti-galloping devices on a 120 kV line. This was due to aeolian vibration entrapment between the devices. Thousands of people were left without an electrical supply for nearly two weeks during the cold season. Conductors had to be replaced on many km of lines. Data on the actual cost of this event are not available, but it was certainly in the order of millions of dollars.

Research and Studies

Because galloping exists and has created concerns among utilities for nearly 75 years, considerable expenditure has been made on field observations, studies and the research and development of counter measures. The efforts dedicated to this phenomenon have varied widely with time but even today, hundreds of thousands dollars, if not millions, are invested every year to better understand the galloping phenomenon and develop efficient means for the protection of transmission lines against it.

10.3.5 Conclusions

Among the wind induced conductor motions the most dangerous is aeolian vibration, for the following reasons:

- Occurrences can be on almost any transmission line at any time
- It is the most recurrent phenomenon: the wind velocities able to excite aeolian vibration (1÷7 m/s) have the higher occurence as shown in the asymmetrical distributions of wind speeds in Figure 10.9.
- There is a fast accumulation of fatigue cycles: the aeolian vibration frequencies are within 4 and 120 Hz
- It causes dynamic bending strains. The bending angle is higher than any other conductor motion.

Subspan oscillation frequency is in the range 0.7-3 Hz and can hardly produce strand fatigue failures since the accumulation of fatigue cycles is slow and the conductor stress at spacer damper clamps is generally moderate. In addition, the high wind speeds able to excite the phenomenon have a lower percentage of presence.

- Nevertheless, subspan oscillation can cause spacer clamp loosening when the clamp locking system is somehow ineffective or absent. The looseness of the spacer clamps determines conductor strand failures due to the abrasion and hammering between the clamp body and the conductor (Figure 10.76). Large subspan oscillation may produce sub-conductor clashing in the middle of sub-spans and when excited on the end subspans can produce wear in suspension hardware.

Galloping is a relative rare event on any given line span or section because of the combination of weather conditions that is required for its occurrence. Galloping duration is typically of few hours, associated with the passage of a weather front. The main problems that arise are usually associated with the phases of a line approaching each other such that an electrical flashover occurs. This leads to a line outage, potential loss of supply and may damage the conductor by local melting of the outer layer strands. In a few cases, repeated damage has caused conductor failure. In rare cases, galloping can continue over several days. In these events, substantial mechanical damage may be sustained, such as conductor and jumper failure, insulator string parting, breakage of spacers and dampers, loss and fatigue of tower bolts and even fatigue of major tower steelwork.

10.4 Non Sustained Conductor Motions

10.4.1 Introduction

Non sustained motions of the transmission line conductors can be due to from several different transient phenomena. The most common and potentially armful are:

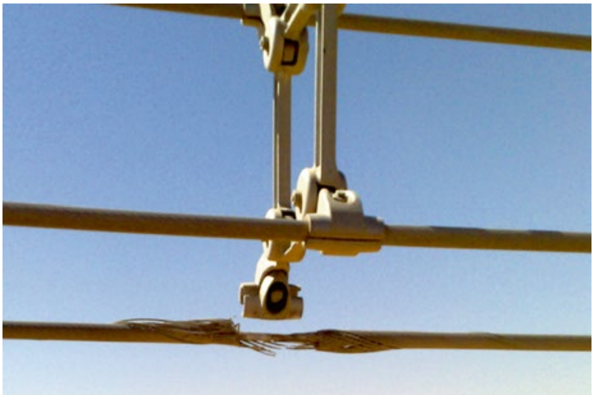


Figure 10.76 Spacer clamp loosening and consequent conductor damage.

- Short circuits on conductor bundles
- Corona vibration
- Bundle rolling
- Ice and snow shedding
- Wind gust response
- Earthquakes

The level of danger and the mechanical effect of the above phenomena are discussed in this section.

10.4.2 Short-circuit Forces in Power Lines

10.4.2.1 Introduction

Short-circuit currents in power lines induce electromagnetic forces acting on the conductors. The forces generated by short-circuit forces are very important for high-voltage bundle conductor lines, medium-voltage distribution lines, where spacer compression forces and interphase spacings are significantly affected by them.

Manuzio (1965) did the pioneering analytical and experimental work on short-circuit current effects in transmission-line bundles.

Short-circuit mechanical design loads have been a subject of significant importance for transmission line and substation design for many years, and numerous papers, technical brochures and standards have been published (Manuzio 1965; Hoshino 1970; Havard et al. 1986; Cigré 1996; Cigré 2002; IEC 1993, 1996; Lillien and Papailiou 2000). Under short-circuit forces, there are some similarities and some differences between the behavior of flexible bus in substations and power lines.

For both the power lines and substations, the electromagnetic forces are similar in their origin and shapes because they come from short-circuit current (IEC 1988). Nevertheless, as listed below, there are some major differences between short-circuit effects on substation bus systems and power lines:

- Power lines are subjected to short-circuit current intensity, which is only a fraction of the level met in substation bus systems. The short-circuit level is dependent on short-circuit location, because longer lengths of lines mean larger impedance and lower short-circuit level. The level also depends on power station location and network configuration.
- Power line circuit configuration may not be a horizontal or vertical arrangement, thus inducing other spatial components of the forces than in bus systems, and the movement may be quite different.
- Power lines have much longer spans and thus much larger sags than flexible bus and rigid bus. This induces a very low basic swing frequency of the power line span (a fraction of one Hz). Therefore the oscillating components of the force at the network frequency (and its double) have negligible action on power lines.
- Power line phase spacings are much larger than those in substations, and this has a dramatic reduction effect on forces between phases.

- Bundle conductors in power lines have much larger subspans than in substations, and bundle diameter is often larger, too. Sometimes very large bundle diameter and a large number of subconductors are used compared to bundled substation flexible bus. This has significant effects on the phenomenon because long subspans reduce the effect of bundle collapse upon the tension in the sub-conductors during short circuit conditions. Figure 10.77 demonstrates the distortion of the subconductors of a quad bundle around a flexible spacer during a short-circuit, known as the pinch effect, which causes the tension increase.
- Due to differences in structure height and stiffness, power line towers have significantly lower fundamental natural frequencies than substation structures. One result is that the substation structures are more likely to respond dynamically to the sudden increase in tension that results from the pinch effect.
- Power line design load includes severe wind action and in some cases heavy ice loads acting on much larger spans than in substations. Therefore design loads due to short circuits may be of the same order as design wind and ice loads in substations, but much less in transmission lines.

Bundle Conductor Lines

For bundle conductor lines, during a fault, the subconductors of the bundle move closer to each other due to strong attraction forces because of the very short distance between subconductors (Figure 10.77).

Detailed discussions of this phenomenon were given by Manuzio and Hoshino (Manuzio 1965; Hoshino 1970).

From their initial rest position, the subconductors move towards each other, remaining more or less parallel in most of the subspan, except close to the spacer (Figures 10.77 and Figure 10.78). After first impact, which for power lines is typically around 40 to 100 ms after fault inception, there is a rapid propagation of the wave in the noncontact zone near the spacers, sequence c-d-e of Figure 10.78. The inward slope of the subconductors at the spacer results in a component of subconductor tension that tends to compress the spacer. This compressive force, or "pinch,"

Figure 10.77 Example of quad bundle before and during short-circuit test at 50 kA, showing distortion of the subconductors. One flexible spacer at mid-span (Courtesy Pfisterer/Sefag).

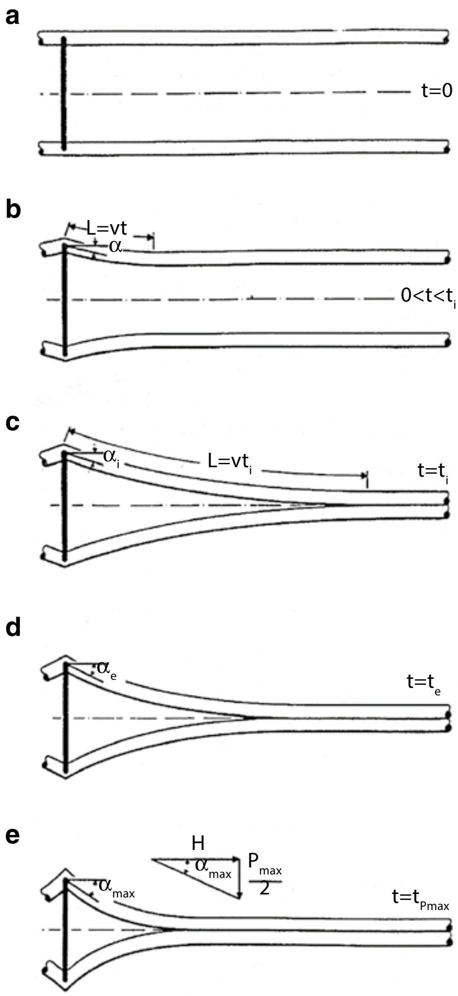


Figure 10.78 Attraction of subconductors of a bundle at a spacer during a short-circuit (Manuzio 1965).

while it is associated primarily with the change in angle, can be further increased by the rise in tension in the subconductors due to bundle collapse. This jump results from the fact that subconductor length in the collapsed condition is greater than in the normal condition.

The pinch is maximum when the wave propagation stops towards the spacer, position e in Figure 10.78. The triangle of collapse then performs oscillations through positions d-c-d-e-d-c-e-d-c and so on as long as electromagnetic force is still on, but with decreasing amplitude. If the short circuit is long enough, the pinch oscillations result in a "permanent" oscillating force, sensibly lower than peak value, typically 50 %.

During the fault, the spacer is strongly compressed. The compression is related to maximum pinch force in the conductor and the angle between the spacer and the subconductor.

The subconductor movements occur at very high acceleration. For example, a 40 kA fault on a twin bundle of 620 mm^2 conductor, with a separation of 40 cm, may have acceleration up to several tens of g, depending on the instantaneous current value. Spacers are subjected to compression forces; and these instantaneous compression loads can be very high.

Upward movement of the whole span follows the rapid contraction of the bundle and reduces the conductor tension, but does not reduce the maximum forces on the spacers occurring during initial impact.

Interphase Effects and Distribution Lines

Fault currents produce an impulse tending to make the separate phases of a circuit swing away from each other, independently of whether the phases are bundled. The impulse that causes this lasts only as long as the fault, so it is brief relative to the fundamental period of the span. The momentum from the impulse carries the phases outward for a certain distance before their tension arrests and reverses the motion. They then swing inward. This inward swing may be large enough to cause cable contact and even permanent wrap-up at the middle of the span. For double-circuit towers, the circuit subjected to the short circuit could force its phases to come in contact with another circuit, thus causing outages on both circuits. There may also be sag increases, up to several times the initial sag in distribution lines, due to heating effects under short circuit, which may significantly affect the amplitude of movements.

Even though the inward swing could be short of interphase contact, if the phase spacing is less than the critical flashover distance, and the inward swing occurs at the time that voltage is restored by automatic reclosure, there will be a second fault.

Very large movements may be seen on distribution lines. Figure 10.79 shows the motion produced during full-scale testing on an actual line. This is from an actual three-phase short-circuit test on a 15-kV distribution line near Liège, Belgium (Lilien and Vercheval 1987). The photo shows an instantaneous position of the conductors taken during the test. The fault current level was 3 kA. The reduction in phase spacing may be particularly dramatic on medium-voltage lines, even if the short-circuit level is much lower.

10.4.2.2 Fault Currents and Interphase Forces

A short-circuit current wave shape is consists of an ac component and a decaying dc component due to the offset of the current at the instant of the fault. The ac component generally is of constant amplitude for the duration of the fault, and although the system through which the fault passes is multimesh, it can usually be assigned a single “global” time constant for the decay of the dc component. In high-voltage lines, and even more in low-voltage lines, because the ratio X/R, reactance to resistance, is much less at low-voltage level, the global time constant of the system

Figure 10.79 Instantaneous position of the conductors taken during three-phase short-circuit test on 15-kV distribution line near Liège (Lilien and Vercheval 1987).

"τ" is rather low, typically 20 to 80 ms, compared to substations where it is typically 70 to 200 ms.

$$
\begin{aligned}
i_1(t) &= \sqrt{2}I_{rms}\left(\sin(\omega t+\phi)-e^{-\frac{t}{\tau}}\sin(\phi)\right)\\
i_2(t) &= \sqrt{2}I_{rms}\left(\sin\left(\omega t+\phi-\frac{2\pi}{3}\right)-e^{-\frac{t}{\tau}}\sin\left(\phi-\frac{2\pi}{3}\right)\right)\\
i_3(t) &= \sqrt{2}I_{rms}\left(\sin\left(\omega t+\phi+\frac{2\pi}{3}\right)-e^{-\frac{t}{\tau}}\sin\left(\phi+\frac{2\pi}{3}\right)\right)
\end{aligned}
\tag{10.41}
$$

Where

I_{rms} is the root-mean-square value of the short-circuit current (A).
$\omega = 2\pi f$ is the network pulsation (rad/s) equal to 314 rad/s in Europe and 377 rad/s in the United States.
τ is the network time constant (= L/R) at the location of the fault (s).
ϕ is an angle depending on the time of fault occurrence in the voltage oscillation (rad). Asymmetry is very dependent on ϕ. In the case of a two-phase fault, it is possible to have no asymmetry if $\phi = 0$ rad.

According to the basic physics of electromagnetism for a three- or a two-phase arrangement, there is always a repulsion force between phases from each other. For a single-phase fault, only one current is involved. In the case of bundle conductors, it is generally considered that the short-circuit current is equally divided among all subconductors. The force acting between subconductors of the same phase is an attractive force, as discussed in Section 10.4.2.3.

In the general case of parallel conductors, the force, *Fn(t)* in N/m, applied on each of the phases can be expressed by:

$$F_1(t) = \frac{\mu_0}{2\pi} x \left(-\frac{i_1(t).i_2(t)}{a} - \frac{i_1(t).i_3(t)}{2a} \right)$$
$$F_2(t) = \frac{\mu_0}{2\pi} x \left(\frac{i_1(t).i_2(t)}{a} - \frac{i_2(t).i_3(t)}{a} \right) \tag{10.42}$$
$$F_3(t) = \frac{\mu_0}{2\pi} x \left(\frac{i_1(t).i_3(t)}{2a} + \frac{i_2(t).i_3(t)}{a} \right)$$

Where

μ_0 is the vacuum magnetic permeability = $4\pi 10^{-7}$ H/m.
a is the interphase distance (m).

The force, being due to current flow, very much depends on phase shift between currents. It generally includes:

- Pseudo-continuous dc component, with a time-constant decay,
- Continuous dc component, sometimes, and
- Two oscillating ac components, one at network frequency, with a time-constant decay, and one at the double of the network frequency, which is not damped.

In the case of a two-phase fault, the force is proportional to the square of the current. Thus it always has the same direction—that is, a repulsion between the two faulted phases.

In the case of a three-phase fault, it is much more complex. In flat-phase configuration, illustrated by the top view of Figure 10.80, the middle phase has a zero mean value, and at least one of the outer phases has forces similar to those generated by a two-phase fault (Figure 10.71 *left*).

The same location in a network gives two different values of current for three- or two-phase faults with a ratio 0.866 between them. For example, a 34.8 kA three-phase fault would give a 30.1 kA two-phase fault at the same location. Therefore, a three-phase fault has to be considered for estimation of design forces.

Figures 10.80 (*top*) and Figures 10.81 give examples of currents and forces on horizontal, or purely vertical, arrangements. In the case of an equilateral triangular arrangement, Figure 10.80 (*bottom*), the forces are similar on all three phases, similar to the force on phase 1 for the horizontal arrangement.

Figures 10.81 shows the currents and forces applied to each phase during a three-phase fault with an asymmetry chosen to create the maximum *peak force on one outer phase* as calculated using Equation 10.42. This is for a horizontal or vertical arrangement of the circuit. The fault current is 34.8 kA rms with peak currents of 90.4, 79.2, and 61.2 kA. The time constant is 70 ms, and the short-circuit duration is 0.245 seconds. The current frequency is 50 Hz. The loads shown are per unit length for a = 6 m clearance between phases. The repulsion peak load on phase 1 is 228 N/m. (ϕ = 1.39 rad). The signs convention is positive in the directions shown in the upper diagram in Figure 10.80.

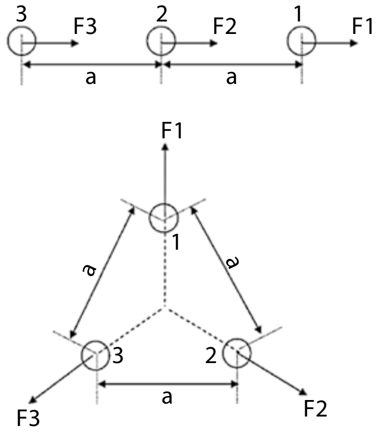


Figure 10.80 Two different geometric arrangements for a three-phase circuit and the electromagnetic force reference directions on each phase corresponding to Equation 10.42. The numbers 1, 2, and 3 are phase numbers.

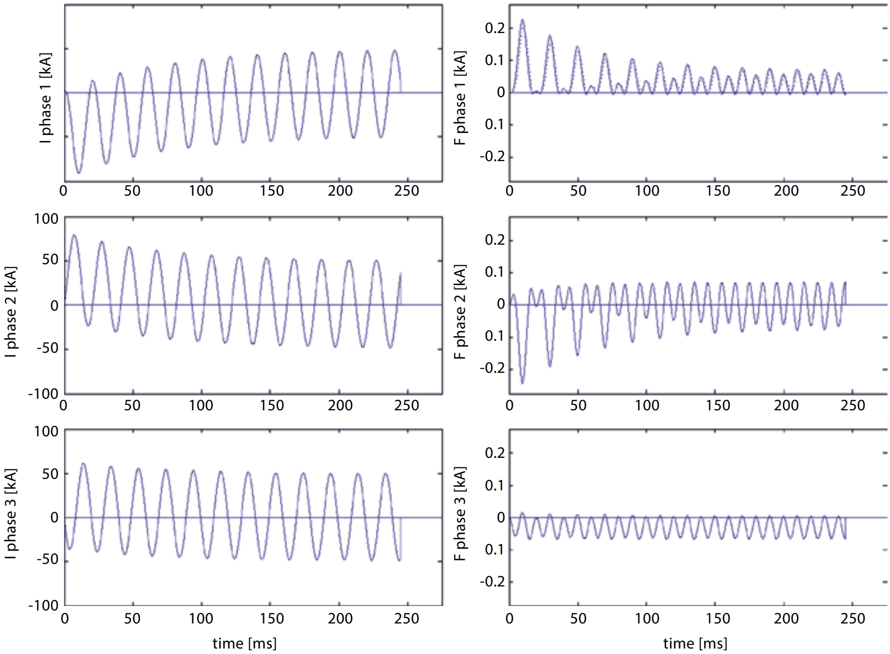


Figure 10.81 Example of calculated three-phase short-circuit current wave shape and corresponding loads on a horizontal or vertical circuit arrangement.

But the time dependence of the forces is very different on the outer phases compared to middle phase. On the outer phases, the force is unidirectional and has a significant continuous component. On phase 2, the continuous component is zero (except during the asymmetrical part of the wave).

It must be noted that the level of the peak force, about 200 N/m in Figure 10.81, is far greater than the conductor weight and is proportional to the square of the current. But the continuous component is much lower, about 30 N/m in this case, as shown later. Under actual short-circuit levels and clearances, it is closer to the conductor weight, but acts, in most cases, in the other direction. See upper right panel in Figure 10.81.

Thus the interphase effects, for the case of horizontal or purely vertical arrangement only, may be summarized as:

- The design force on the horizontal or vertical three-phase arrangement is the force due to a three-phase fault considering the outer phase with appropriate asymmetry. Taking into account the fact that only the continuous dc component has to be considered, the force on an outer phase can be approximated by Equation 10.43. This is the horizontal repulsion force for the horizontal arrangement, or the vertical repulsion force for the vertical arrangement:

$$F = \frac{0.2}{a} I_3^2 \left(0.75 + 1.61 e^{-2t/\tau}\right) \tag{10.43}$$

- Where
  a is the interphase distance (m).
  I_3 the rms three-phase fault at that location (kA).
  τ is the network time constant at that location (s).
  t is time (s).
- The forces considered above cannot be directly applied to structure design loads, because the structural response to these loads has to be taken into account.

The continuous dc component acting after the short transient during the asymmetrical period of the current is obtained by using t = infinity in Equation 10.43. For example, in Figure 10.81, the continuous dc component after transient is given by:

$$F = \frac{0.2}{6} 34.8^2 x 0.75 = 30.3 \tag{10.44}$$

10.4.2.3 Behavior of Bundle Conductors under Short Circuits

Detailed behavior of bundle conductors under short circuit is most easily illustrated through short-circuit tests in actual bundles. Some results from a program of tests at the Veiki substation in Hungary are used here for that purpose (Lillien and Papailiou 2000).

The systematic single-phase fault tests on twin conductors were performed in the 1990s on a power line with a double deadended span, with a length of 60 m, with the following characteristics (Figure 10.82):

Span length	60 m
Sub conductor type	ACSR CONDOR (455 mm², ϕ = 210.4.7 mm, 1.52 kg/m, UTS 125 kN)
Spacing	0.457 m
Current	35 kA (90 kA peak), Time constant 33 ms
Duration	0.17 to 0.2 s
Sagging tensions	15, 25, or 35 kN (per subconductor)

Figure 10.82 Test arrangement applying short circuits to a 60-m span length with one spacer at mid-span (Lilien and Papailiou 2000).

All cases are single-phase faults; the return path is through the ground Supporting structure:

Stiffness:	about 8.5 10^6 N/m
First eigen frequency:	about 14 Hz

Figure 10.83 shows installation of rigid spacers and measurement points (bold lines) for the 60-m subspan (Figure 10.83 *top*) and 30-m subspan (Figure 10.83 *bottom*). For the 30-m subspan, two spacers were installed close to each other so as to receive half the contribution. The installation of measurement is such that actual load for spacers in power lines would be twice the measured value.

The following oscillograms were recorded (Figure 10.84). On the left hand side, the 60-m span length results are presented, and on the right-hand side, the 30-m span length results are presented. It should be noted that the actual "pinch" occurs during the first approximately 0.2 seconds, while the fault current is on, and that the other "spikes" in the records arise from subsequent motion of the bundle.

After the short circuit, the subconductors separate from each other during a long transient, with wave propagation along each Subspan. During that transient, significant tensile forces (the opposite of compression) are applied on the spacers, the level of which reach about 50 % of the maximum compression load. In spite of their smaller magnitude, the effect of these tension forces on the spacer must be considered separately, because some spacer attachments are not as strong in tension as they are in compression. A particular example is the attachment using an open or "saddle" clamp, with helical rods to capture the subconductor. These loads are repeated with every passage of the wave up and down the span. Note the shorter repetition time in the 30-m span. These loads decay very slowly, so that many repeated such loads have to be taken into account.

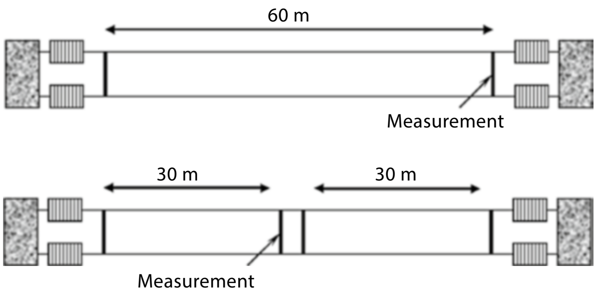


Figure 10.83 Two test span arrangements for spacer compression tests (Lilien and Papailiou 2000).

The graphs in Figure 10.84 show the effect of gradually increasing initial tension before the fault from 15 kN (12.5 % EDS) to 35 kN (28 % EDS). The effect on propagation speed can be seen in the after short-circuit peaks, but the influence on maximum pinch is limited in actual range, as predicted by Manuzio (the pinch being proportional to the square root of the tension), and it is particularly valid for long subspans, as used in power lines and as validated by Manuzio's test arrangements (Manuzio 1965).

In case of spring-type dampers, which could be compressed by the pinch, there could be a large increase of these tensile loads acting on spacer attachment as the relaxation of energy stored in spring compression during short-circuit is released after the end of the short circuit.

Depending on the configurations of the spacer and spacer dampers, the short-circuit forces could cause large bending moment in the conductor and the elements of the spacer.

In these tests, limited to one-phase fault, there is no interphase effect but, due to the increment in tension caused by the pinch, the whole phase jumps up after short-circuit inception and falls down afterwards. This behavior induces some tension changes in the conductors, as can be seen in Figures 10.85 and 10.86. It is notable that the pinch effect (the first peak during the fault in the first 0.18 s) in the conductor has a smaller tension rise than that which occurs, at 0.9 seconds, as the phase falls. In both cases, the latter is limited to 1.8 times the initial static sagging tension.

Subspan Length Effect

Bundle pinch is very much related to subspan length. There exists a critical subspan length under which no contact is possible and over which contact occurs on a significant part of the subspan. Of course, that length depends on short-circuit level and some other parameters. That critical value corresponds to extreme loading (for pinch effect in substations (El Adnani 1987; Lilien and El Adnani 1986)). For the power lines with typical subspan lengths, subconductors experience contact in all cases except in jumpers.

Subconductor Separation Effect

A closer bundle spacing results in a smaller increment in subconductor tension. In fact, initial electromagnetic force are stronger, but the tension increment is generated by conductor deformation into the triangles of Figure 10.78 after contact, and

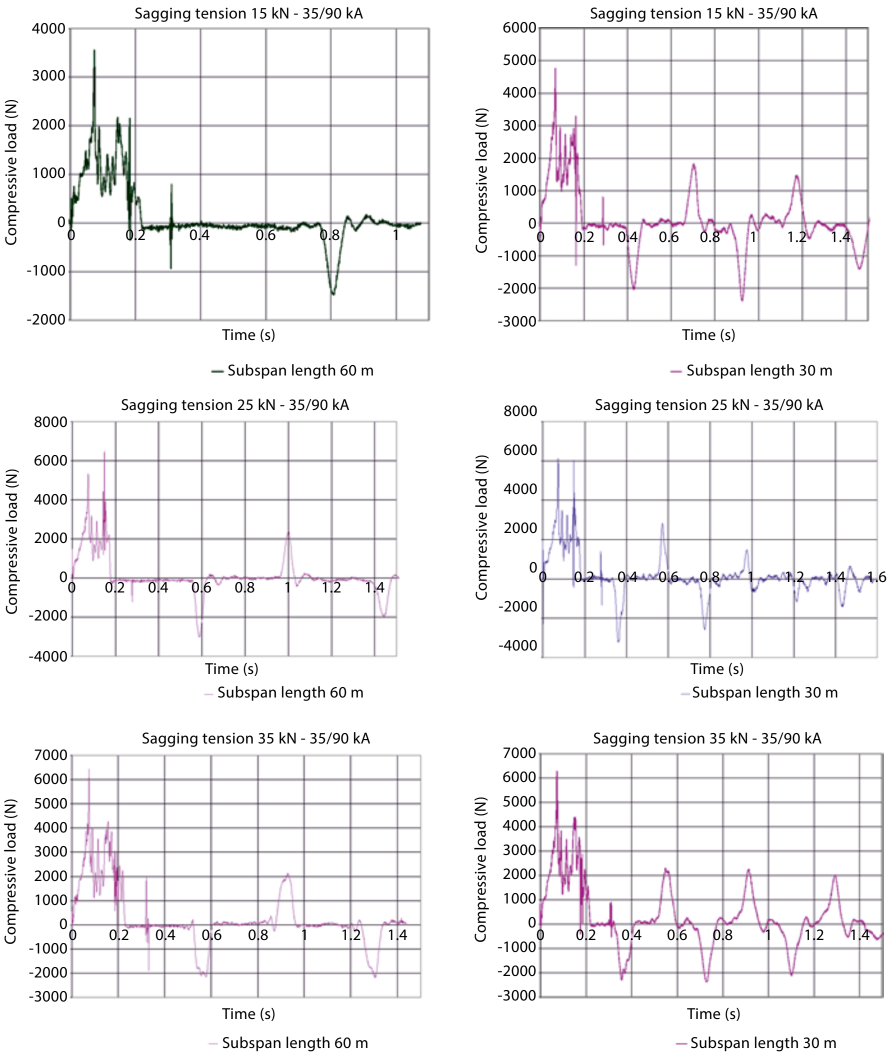


Figure 10.84 Typical tests results on spacer compression on 60-m and 30-m subspan length, at 35 kA on twin-bundle line 2x Condor, with different sagging tensions. Half of the compression is given. The drawings are covering short-circuit and significant after short-circuit time to better see the wave propagation effects after the end of the short circuit (Courtesy Pfisterer/Sefag).

most of deformation is located in those triangles. Smaller conductor separation thus leads to less deformation in that area. At the limit, if conductors are in contact all along the span, there is no increment in tension.

10.4.2.4 Interphase Effects under Short Circuits

Maximum Tensile Loads during Movement of the Phases

Figure 10.87 shows a typical response of a bundle conductor two-phase fault in a horizontal arrangement (Cigré 1996). Both cable tension versus time (Figure 10.87 *left*)

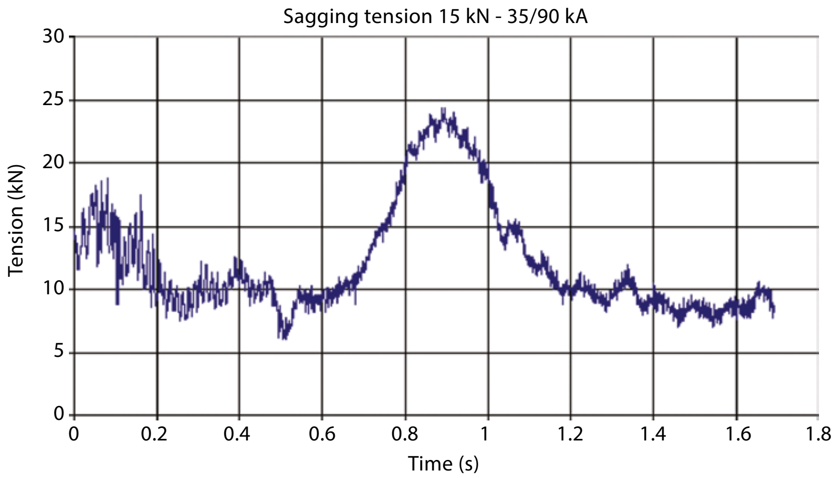


Figure 10.85 Typical tension oscillogram in one subconductor during and after the fault, for the 60-m span length configuration (15 kN initial). Irms 35 kA (peak 90 kA), 0.18 s (Courtesy Pfisterer/Sefag).

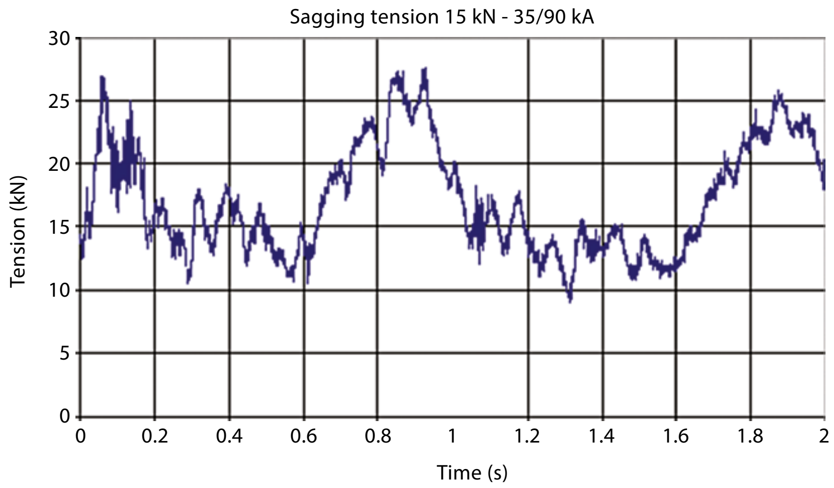


Figure 10.86 Typical tension oscillogram in one subconductor during and after the fault for the 2×30-m span length configuration (15 kN initial). Irms 35 kA (peak 90 kA), 0.18 s (Courtesy Pfisterer/Sefag).

and phase movement in a vertical plane at mid-span (Figure 10.87 *right*) are shown. On the cable tension curve, three maxima (and their corresponding time on the abscissa) have been indicated, which is discussed below. On the phase movement curve at mid-span, the curve has been marked by dots every 0.1 s to get an idea of the cable speed, and in particular to show that the short circuit ends before there is significant movement of the phase.

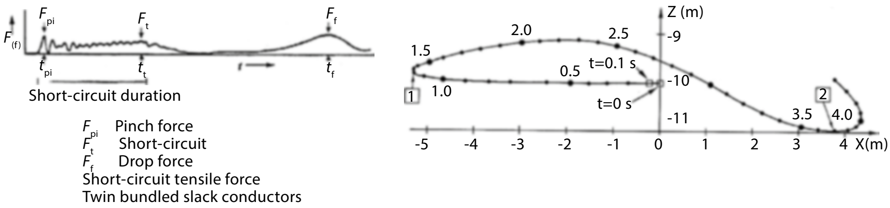


Figure 10.87 *Left*: Tensile force (*left*) time evolution of a typical twin-bundle span during two-phase short circuit between horizontal phases. Three maxima: F_{pi} at time t_{pi} (so-called pinch effect, due to bundle collapse), F_t at time t_t (the maximum of the force due to maximum swing of the span represented by circle point 1 on the right figure), and F_f at time t_f (the maximum of the force due to cable drop represented by circle 2 in the *right* figure. Typically, $t_{pi}=40$ ms, $t_t=1.2$ s and $t_f=4$ s. *Right:* Movement of one phase (*right*) in a vertical plane at mid-span (*X* and *Z* are the two orthogonal axes taken in the vertical plane at mid-span, perpendicular to the cable. *Z* is vertical, −10 m is the initial point showing sag, and *X* is horizontal and transverse to the cable). Such movement has been calculated for a two-phase fault of 63 kA (duration 0.1 s end of short circuit being noted on the figure) on a 2×570 mm² ASTER on a 400-m span length (sag 10 m) (Lilien and Dal Maso 1990).

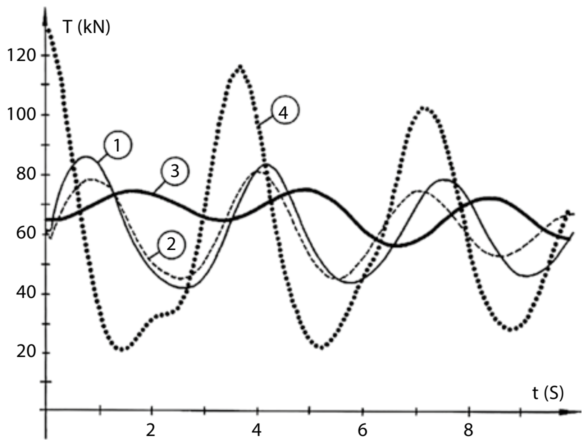


Figure 10.88 Simulated longitudinal loads applied on attachment point on a cross arm on a "Beaubourg" tower (the circuit configuration is shown by points T, R, and S in Figure 10.89) for loading conditions (Lilien and Dal Maso 1990): *1* three-phase fault of 72.3 kA. *2* two-phase fault of 63 kA. *3* initial wind of 60 km/h followed by a gust at 100 km/h for 5 seconds on a quarter of the span. *4* shedding of ice sleeve of 6 kg/m

Typical maximum loads (Figures 10.87 and 10.88) that could influence design appear when total energy (including a large input during short circuit) has to be mainly transformed to deformation energy.

Peak design load could occur under the following three conditions:

- Maximum swing-out F_t (at time t_t in Figure 10.87 left and square 1 in Figure 10.87 right): very little kinetic energy (cable speed close to zero) and potential energy with reference to gravity, so that a large part is converted in deformation energy, that is, increase of tension. In power lines, t_t occurs always after the end of the short circuit (the cable position at the end of the short circuit (0.1 s) is indicated in Figure 10.87 right).
- Maximum F_f at the extreme of downward motion (at time t_f in Figure 10.87 left and square 2 in Figure 10.87 right): generally more critical because of a loss of potential energy of gravity due to the cable position at that moment. t_f always occurs after the end of the short circuit.
- The pinch effect F_{pi} (at a very short time after short-circuit inception at t_{pi}). The pinch effect only occurs with bundle conductors, when subconductors come close to each other: t_{pi} always occurs during short circuit.

It is interesting to compare the level of these loads with typical overhead line design loads related to wind or ice problem. Figure 10.87 shows results of such a case calculated by simulation on a typical 400-kV overhead line configuration. Figure 10.88 shows cable tension versus time in different dynamic loading conditions, as explained in the legend. It can be seen that cable tensions due to short-circuit currents are significantly smaller than other causes such as ice shedding.

Reduction in Phase Spacing

After the initial outward swing, the phases move towards each other. For the case illustrated in Figure 10.87, this inward movement exceeds 4 m per phase. That means a phase-spacing reduction of more than 8 m. Other cases are shown in Figures 10.89 and 10.90 (only the rectangular envelope of the movement is given) for different configurations and short-circuit level.

The timing of this inward swing may be such that the phase spacing is less than the critical flashover distance at the time that voltage is restored by automatic reclosure. That would induce a second fault with the dramatic consequence of a lock-out circuit breaker operation, with all its consequences (power outage).

Distribution Lines

As mentioned earlier, very large movements may be seen on distribution lines (Figure 10.79). Figure 10.91 shows a case of two circuits on the tower, where the faulted circuit forces some of its phases to get in contact with the second (healthy) circuit, inducing a fault in the other circuit so that both circuits trip out.

How to estimate the required interphase spacing is discussed further in Section 10.4.2.5 (Equation 10.50).

10.4.2.5 Estimation of Design Loads

The most critical effects on power lines are:

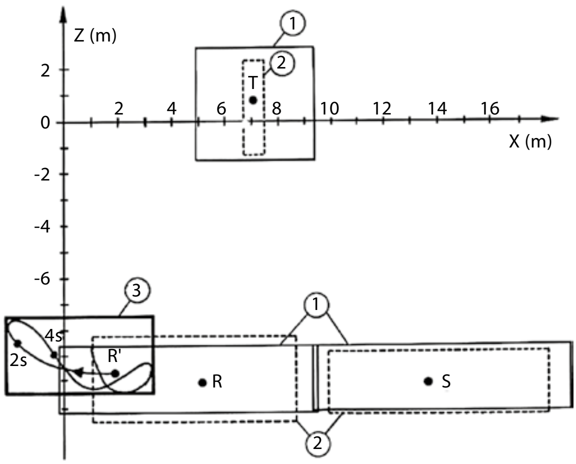
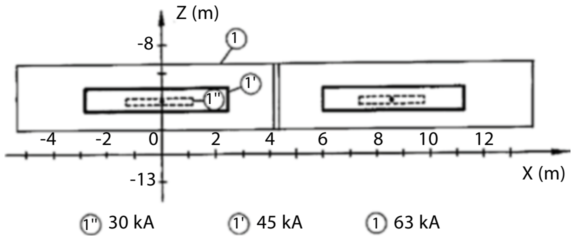


Figure 10.89 Calculated envelopes of phase-conductor movements for three types of loading conditions on a "Beaubourg" tower (the figure is drawn in a vertical plane located at mid-span: R, S, and T are their phase locations in still conditions) (Lilien and Dal Maso 1990): *1* two-phase short-circuit 63 kA either RT, RS, or TS. *2* three-phase short-circuit 72.3 kA. *3* initial wind speed of 60 km/h followed by a wind gust at 100 km/h during 5 s on a quarter of the span.

Figure 10.90 Calculated envelope of phase-conductor movements for two-phase faults of different rms amplitude (Lilien and Dal Maso 1990).



- For bundle conductors: spacer compression (Equation 10.45).
- For power lines in general, but particularly for distribution lines: reduction in phase spacing (Equation 10.50 for high-voltage line).
- To a much lesser extent, and generally having negligible effect compared to other kind of loading: tension increase generating longitudinal and transverse loads (Equation 10.49 for longitudinal load due to interphase effect).

The loads under no. 3 above due to short circuits should be considered by line designers by including them in the loading schedule for structures. Since there are three ways to have one phase fault, three to have a two-phase fault, and one to have a three-phase fault, there may be seven different loading conditions. They must, of course, be taken separately, since these events cannot occur simultaneously.

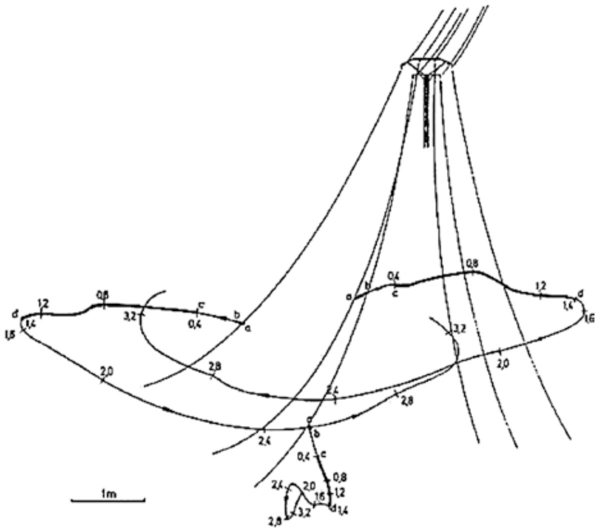


Figure 10.91 Three-phase short-circuit on 15-kV line (*left circuit*), with autoreclosure. a = fault inception, b = 0.1 s, end of the first fault, c = 0.4 s, time of reclosing, and d = 1.4 s end of the second fault and definitive removal of the voltage on the line. Short-circuit of 2700 A on a 165-m span length, conductor 93.3 mm^2 AAAC (Lilien and Vercheval 1987).

Advanced calculation methods (Lilien 1983; El Adnani 1987; Wendt et al. 1996; Declercq 1998; Stein et al. 2000) may be used for any situation.

Bundle Conductors in Transmission Lines

Manuzio developed a simple method for spacer compression effect in bundle conductors (Manuzio 1965).

$$F_c = kI\sqrt{F_{st}\log_{10}\left(s/\phi_s\right)} \tag{10.45}$$

Where:

F_{st} is initial sagging tension for each subconductor (N).
k is a correction factor depending on the number of subconductors.
k_{twin} = 1.510.4.
$k_{tripple}$ = 1.44.
k_{quad} = 1.210.4.

I is the rms short-circuit value/phase (kA). s is the bundle diameter, related to subconductor separation "a_s" by the formula (n = number of subconductors):

$$s = \frac{a_s}{\sin\left(180°/n\right)} \tag{10.46}$$

ϕ_s is the subconductor diameter (m).

Example:
Consider a case of a short circuit of 35 kA (rms/phase) acting on a twin ACSR Condor (210.4.7 mm diameter) conductor with 0.457 m conductor separation, tensioned at 25 kN/subconductor. Equation 10.45 gives a spacer compression force of:

$$\begin{aligned} F_c &= 1.57x35\sqrt{25000x\log_{10}\left(0.457/0.0277\right)} \\ &= 9586N \end{aligned} \tag{10.47}$$

However, in the analysis by Manuzio (1965), short-circuit current asymmetry was neglected.

That has been taken into account in IEC 60865 (IEC 1993, 1994) for evaluating the maximum tension in the conductor during fault. But IEC 60865 gives no recommendation for spacer compression.

Other methods to estimate spacer compression forces have been proposed (Hoshino 1970; Pon et al. 1993; Lilien and Papailiou 2000). Some tests performed in Canada (Pon et al. 1993) on spacer dampers for power-line-estimated spacer-compression design load up to 20 kN for typical configurations and anticipated short-circuit levels.

Manuzio's method can be safely applied to faults with maximum asymmetry through a correction factor of 25 % (multiply all k factors by 1.25). In fact, Manuzio's method is very simple to apply compared to other methods. It may not be accurate enough for use with respect to substation flexible bus.

Alternatively, if we define F_{pi} (as shown in Figure 10.87) as the maximum tensile load in one subconductor during the bundle pinch, another best fit would be to use Manuzio method (without correction factor), but using F_{pi} pinch value instead of initial static pull. F_{pi} can be evaluated by IEC 60865 method.

F_{pi} increases linearly (and not with the square) with short-circuit current. That is because a stronger short-circuit current will increase contact length, thus reducing acting parts of the conductors.

Note: In the use of IEC method 60865 to evaluate Fpi, there is a need to introduce the so-called "supporting structure stiffness." In this application, that stiffness is not simply the static stiffness of supporting structure, but must take into account insulator chain movement during the first tens of milliseconds of the fault to arrive at an equivalent stiffness (which in fact would permit evaluation of span end movement, from short-circuit inception up to the maximum pinch value, after about 40 to 90 ms. An heuristic evaluation indicates that a good estimate for such equivalent stiffness may be to consider in most of the practical cases a value of 10^5 N/m.

Despacering as a Means to Limit Pinch Effect

Despacering (removal of spacers) is an antigalloping measure (see Section 4.5) for some power lines. It has been used up to the 245-kV level for twin bundles of limited diameter. In such cases, the bundle is turned in vertical or slightly oblique position, and conductor separation is increased compared to a spacered bundle. Moreover, it has been recommended to use larger subconductor spacing at the middle of the span (compared to end of the span)—for example, 0.6 m at ends and 0.8 m at mid-span.

Such configurations may suffer from the “kissing or sticking” phenomenon under high electrical load, because electromagnetic forces also act under load current. At such current levels, nevertheless, the electrostatic repulsion (due to voltage) cannot be neglected. It can be shown that, at surge impedance loading (SIL), equilibrium exists between attraction and repulsion forces. Power flows are often several times (up to four times) the SIL, so that attraction forces are generally stronger than repulsion. One of the major problems of such configurations is linked to possible sticking of the subconductors following a perturbation. As electromagnetic forces depend on distances, there exists a distance under which the subconductors always come together and stick together, and it is very difficult to separate them without opening the circuit. Sticking induces large permanent noise and increase in Corona. To avoid such problems, line designers have developed several proposals like the “hoop” spacer.

Under short circuit, these configurations result in clashing between subconductors and, as “sub-span” length (= span length in this case) is very large, there is little increment in tension. But, in the case of hoop spacers or similar, the conductor clashing destroys these light spacers beyond a certain level of short-circuit current.

Interphase Effects: Estimation of Tension Increase and Reduction in Phase Spacing

The following discussion pertains to the case of horizontal/vertical configuration and neglects temperature heating effects (Lilien and Dal Maso 1990). Only one span is considered.

a = interphase distance (m).
m = mass per unit of length of one phase (kg/m).
I_{rms} = root mean square of the three phase short-circuit current/phase (kA).
τ = time constant of the short-circuit asymmetric component decay (s).
t_{cc} = duration of the fault (= time of first fault + time of second fault if auto-reclosing) (s).
L = span length (m).
T_{st} = phase conductor static tension before the fault condition (N).
EA/L = conductor extensional stiffness (product of Young modulus times cross section divided by span length) (N/m).
K = tower stiffness (N/m) (order of amplitude 10^5 N/m).
f = initial sag (m).
R = maximum displacement (m).

- The energy imparted to the conductor is given by:

$$E_0 = \frac{1}{2} m \left[\frac{0.2 I_{rms}^2 \left(t_{cc} + \tau \right)}{am} \right]^2 \frac{3L}{4} \left(\text{Joules} \right) \tag{10.48}$$

- The maximum tension in the conductor during movements:

$$T_{\max} = \sqrt{T_{st}^2 + \frac{2E_0}{\frac{L}{EA} + \frac{2}{K}}} \tag{10.49}$$

- The maximum displacement of one phase (zero to peak):

$$R^2 = \left(f + \frac{E_0}{\frac{2}{3} mgL} \right)^2 - f^2 \tag{10.50}$$

That maximum may be observed in the case when the conductors are moving away from each other. But phase spacings can be critical when the phases move back towards each other, in which case there is generally lower displacement (say, 80 % of the separation movement). In this case, the clearances may be reduced (the most dramatic case being a two-phase fault) by $2 \times 0.8 \times R$ or $1.6 \times R$.

The combined values of T_{max} and R result in a transverse load on the suspension tower in the case of a horizontal arrangement, for example.

There is very limited experimental validation of these formulas, because full-scale tests on power lines have not been conducted.

It must be noted that advanced methods (finite elements) can be used to evaluate these effects (details are given in Cigré TB 214 (Cigré 2002).

It is estimated that these formulas give results with 20 % precision on the conservative side.

Example:

For example, consider the following:

Short-circuit current at 63 kA during 100 ms (with time constant 60 ms) on a twin ASTER 570 mm² ($m = 2 \times 1.55 = 3.1$ kg/m) with interphase distance $a = 8.5$ m, span length of 400 m and initial sagging tension of $2 \times 31000 = 62000$ N:

Energy imparted to the conductor using Equation 10.48:

$$E_0 = \frac{1}{2} m \left[\frac{0.2 I_{rms}^2 \left(t_{cc} + \tau \right)}{am} \right]^2 \frac{3L}{4} = \frac{1}{2} 3.1 \left[\frac{0.2 \times 63^2 \left(0.100 + 0.060 \right)}{8.5 \times 3.1} \right]^2 \frac{3 \times 400}{4} = 10803 \text{Joules} \tag{10.51}$$

With conductor Young modulus $= 5.6 \times 10^{10}$ N/m² and tower stiffness of $K = 5 \times 10^5$ N/m, the maximum conductor tension is calculated as:

$$T_{\max} = \sqrt{62000^2 + \frac{2 \times 10803}{\left(\frac{400}{2 \times 5.610^{10} \times 57010^{-6}} + \frac{2}{510^5} \right)}} = 77127 \text{ Newton} \tag{10.52}$$

Assuming an initial sag of 9.8 m, the maximum displacement of one phase is:

$$R^2 = \left(f + \frac{E_0}{\frac{2}{3} mgL} \right)^2 - f^2 =$$

$$\left(9.8 + \frac{10803}{\frac{2}{3} 3.1x9.81x400} \right)^2 \qquad (10.53)$$

$$-9.8^2 = 27.99 \text{means}\, \mathrm{R} = 5.2\mathrm{m}$$

Thus the reduction in phase spacing is $2 \times 0.8 \times 5.2 = 8.32$ m.

It means that the remaining clearance is $8.5 - 8.3 = 0.2$ m.

For the same case at 45 kA, the results are:

$E_0 = 2812$ Joules
$T_{max} = 66270$ N
Remaining clearance = 4.3 m

It can be noted that that energy varies as the fourth power of the short-circuit current.

This is due to the fact that short-circuit forces vary with the square of the current, so the speed of the conductor at the end of the short-circuit also varies with the square of the current, and energy in the system varies with the square of that speed.

10.4.2.6 Interphase Spacers as a Mean to Limit Clearances Problem Linked with Short Circuit

Interphase spacers have been proposed to solve the phase-clearance problem during short circuits (Declercq 1998). Experience has shown that appropriate installation of such devices may effectively maintain appropriate clearances since conductor movement is restricted at some location in the span.

A major challenge is defining the design load on these interphase spacers. Tests can be performed. Advanced calculation methods may also help to define these loads. Interphase spacers may be subjected to bending stresses induced by conductor movements.

10.4.2.7 Short Circuit Forces on Bundled Jumper Loops and Slack Spans

Jumper loops are installed in tension towers to electrically connect the conductors of the adjacent spans. On bundled lines, the jumper loops have, generally, the same configuration as the spans, but are subjected to a much lower tension. Jumper loops can also assume different configurations aiming to optimize tower dimensions; one of the most common is the reduction of the bundle spacing, for example from 400 mm to 200 mm, in order to increase the clearance between the jumper and the tower.

Jumper loops are not subjected to wind induced conductor motions such as aeolian vibration and sub-span oscillations. For this reason, no vibration dampers and spacer dampers are required and rigid spacers can be installed to maintain the design spacing between the sub-conductors. However, it is common practice to install the same spacers or spacer dampers used on the line spans, unless the bundle configuration changes or counterweighted spacers are required to reduce swing of the jumper loop under wind pressure.

The so-called "Sticking Effect" may happen on jumper loops of a transmission line whose switch-gears are equipped with an automatic re-closing system operating under fault conditions.

The current flow produces attractive forces between the sub-conductors but under normal service conditions, only a minor sub-conductor deflection occurs and the sub-conductors remain well separated.

Under short circuit conditions, there are strongly increased attraction forces that deflect the sub-conductors, which rapidly clash. The sub-conductors come into contact with the exception of short lengths around the spacers and at loop extremities which, for this reason, are subjected to compressive forces generally of the order of. 1-2 kN.

On line spans, when the fault is cleared, the elastic forces due to the high tensile load in the conductor (besides gravity) are quite sufficient to restore the design configuration of the bundle after some inertial oscillations that apply to the spacers decreasing tension and compression forces.

On jumper loops, as a consequence of the low tensile load, when the switchgears open the circuit, the small elastic forces may not be able to move the sub-conductors apart sufficiently before the automatic re-closing system restores the normal line current. In this case, the reduced distance between the sub-conductors increases the attractive forces and the sub-conductors remain stuck together even with the normal line current (Lilien and Papailiou 2000).

The usual way to prevent this occurrence is to place spacers at a short distance from each other, in order to reduce the attractive forces and increase the elastic ones.

In bundled jumper loops, the installation of a spacer every 4-5 m is generally sufficient to prevent the sticking effect. In any case, calculation of the optimum distance of the spacers can be made using the algorithms provided by the Manuzio (1965) paper and considering the nominal current and the maximum short circuit current of the line, the loop geometry, the sub-conductor characteristics and mechanical tension.

Slack spans that are tensioned at low values may experience the same sticking effect as the jumper loops.

10.4.3 Corona Vibration

EHV and UHV transmission lines are designed to minimize Corona emissions and their negative effects. This is achieved by choosing the conductor size or by the use of bundled conductors in order to keep the surface voltage gradient below 15 kV/cm.

Corona intensity increases by one or two orders of magnitude in adverse weather conditions, especially under rain but also in the presence of wet snow and fog. The main factor is the formation of water drops on the lower part of the conductors that locally increases the electric field gradient. Corona can generate several phenomena such as power losses (PL), electromagnetic interference (RI), audible noise (AN) and conductor vibration (CIV). The latter is characterized by a vibration amplitude generally less than 100 mm, and a frequency lower than 10 Hz (Edwards and Boyd 1965; Newell et al. 1968) and Lemanxzyk et al. (1975) and has been observed in still air or in the presence of light wind. Strong wind may induce conductor vibration due to vortex shedding but it prevents Corona vibration as it eliminates the water drops hanging below the conductors.

The Corona-induced vibration of power line conductors are mainly caused by the variation of the electrostatic forces between the conductor and the ground, generated by the recurrent shielding effect of Corona-space charge in the vicinity of the hanging water drops (Farzaneh 1986).

The frequency of the Corona induced vibrations falls into the lower range of the aeolian vibration excited by the wind on the most common phase conductor sizes. Hence, they can be easily controlled by the conductor damping systems, i.e. vibration dampers and/or spacer dampers.

For the above reasons damage due to Corona vibration has never been reported and this phenomenon has raised more academic interest than consideration by transmission line engineers. However, it seems that CIV has the effect of increasing the frequency and the degree of dicturbance of the Corona acoustic noise.

10.4.4 Bundled Conductor Rolling

When the subconductors of a bundle are subjected to differential load (uneven ice deposits, ice drops, different tension, different wind pressure, etc.), there is a tendency of the bundle to twist about its axis. Ideally, it would be desirable for the restoring torque to be so great as to limit bundle twisting to a negligible amount, but in practice, this situation could be achieved only by the use of large number of spacers or very high line tensions. The former situation is costly and increases the number of points of the conductor where clamps are attached, that are points of possible mechanical wear. Alternatively, increasing the line tension demands stronger tower structures, renders the system more sensitive to aeolian vibration and is limited by other conditions such as ice accretion and wind loads. The answer must therefore lie in a compromise between the correct choice of the number of spacers, their in-span distribution and a suitable spacer design.

The primary task of spacers and spacer dampers is to maintain subconductor spacing within any prescribed limits under all condition of service, excluding short circuit. They can also provide additional torsional stiffness to restore the bundle to its normal position after the application of a torsional moment. Although flexibility in a spacer may be beneficial for the control of aeolian vibration it tends to reduce the torsional stiffness of the bundle. The technique of including arm rotation stops in the design of flexible and damping spacers counteracts this problem and in addition protects the articulations during short circuit. Any tendency of the bundle to twist by more than a critical amount will put the spacer articulations against their stops and the torsional stiffness of the bundle will be accordingly restored thereby retaining its torsional stability. However, the full torsional stiffness will not be realized if any rotation of the subconductors occurs inside the spacer clamps.

The restoring torque of the bundle is also affected by the position of the spacer centre of gravity and by the length of the articulated spacer arms. In most designs, the barycentre of the spacer coincides with the geometric centre of the bundle, but when it does not, then the restoring torque can be reduced or increased, depending on the amount of twist which has taken place. Such offset designs cannot be ruled out since they do occur in practice especially for twin and triple spacers. The net effect on the bundle restoring torque is, however, usually small compared with that of the conductor tension and spacer stiffness. On the other hand, short spacer arms can substantially improve the torsional stability of the bundle.

It has been shown that the bundle torsional stiffness increases as the subspan lengths decrease especially those of the end subspans. Bearing this in mind, it may be necessary to use short end subspans, particularly in areas where high wind speeds or heavy icing conditions are experienced. In the latter conditions the longest spans are at greater risk and the torsional stability can be enhanced by increasing the number of spacers. This is not in conflict with the requirements for controlling wake-induced oscillations. There are clear indications that long spans are more sensitive to subspan oscillation and that oscillation amplitudes can be reduced by shortening the subspan lengths in a staggered distribution scheme.

The need to control the torsional stability of the bundle conductors has been firstly recognized in Sweden (Jancke et al. 1955) under severe ice loading conditions. Tests were performed on a quad conductor bundle in a 420 m span. Since then, several experimental and analytical research programs were conducted in Japan (Munakata et al. 1963), in Canada (Nigol et al. 1977) and in Belgium (Wang and Lilien 1998). In early 1970s, on the Saint Lawrence River crossing, some quad bundled conductors equipped with flexible spacers became permanently twisted during a period of heavy ice accretion (St-Louis et al. 1990).

The results of the theoretical and experimental researches, although they did not reach a consensus about the optimum distribution criteria for spacers and spacer dampers, could agree with the requirements already presented in relation to clamp grip, short subspans, short spacer arms and arm rotation stops.

It may be impossible to obtain bundle stability in all circumstances, however, if the above requirements are satisfied the restoring torque will be in most cases sufficient to bring the bundle back to its original position after the removal of the ice deposit.

10.4.5 Ice and Snow Shedding

10.4.5.1 General

Ice and snow deposit along an overhead conductor can shed spontaneously as result of melting, mechanical breaking and sublimation or any combination of these.

Sudden shedding of large portions of ice/snow sleeves may result in high amplitude oscillations that can produce damage at the supporting structures and flashovers between phase conductors and between phase conductors and shield wires (Morgan and Swift 1964; Su and Hu 1988; Roshan Fekr and McClure 1998). When ice/snow load is suddenly released the conductor springs upward. If during the transient the clearance between phase conductors or between conductor and shield wire is reduced, below the minimum dielectric distance, flashover and short circuits may occur. In the most severe cases, i.e. the dropping of a heavy sleeve from a long portion of the conductor may generate high transient forces that could damage the structure. In addition, the insulator string may flip over the tower cross arm causing a permanent fault.

However, in most cases, ice/snow shedding from overhead conductors occurs in relatively small chunks along the spans that do not generate structural damage or large insulator string motions but can still cause flashovers and short circuits (Figure 10.92).

The main condition for removal of ice or snow by melting is that the ice or snow surface temperature has to be above 0 °C. Mass reduction by melting consists of two phases. In the first phase, simple melting takes place, which is associated with a low shedding rate. The second phase is characterized by the drop of ice or snow chunks, and a much higher shedding rate. Only the external surface of the ice or snow accretions is affected by the air temperature in the first phase, while the metal surface of the conductor also heats up the accretions in the second phase. This temperature increase produces a liquid layer or decreases the adhesion between the ice or snow and the cable. When the adhesion becomes too weak to compensate for the aerodynamic and gravitational forces involved, ice or snow chunks may eventually drop.

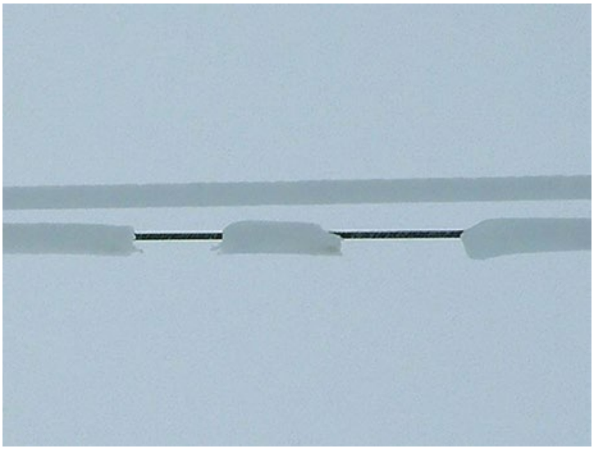


Figure 10.92 Snow shedding in small chunks.

Ice or snow shedding by mechanical breakage is a consequence of adhesive or cohesive failure of the accretion. Since both static and dynamic loads may induce mechanical breakage, the following factors exert an influence on this mass reduction mechanism: wind velocity, air temperature, and ice or snow load and strength. Ice or snow shedding by mechanical breakage usually occurs at temperatures below 0 °C. The most important factor in the breakage of the ice at such temperatures is the deformation in the cable due to aerodynamic forces. Thus, the meteorological factor that has the greatest influence is wind velocity during the shedding event.

Sublimation is a slow process that occurs at the ice surface and does not cause ice and snow drops from the ground wires and conductors.

Of the three mass reduction processes discussed, mechanical breakage is the most damaging for lines because it happens in most cases of ice or snow drop and usually has a high shedding rate.

10.4.5.2 Protection Methods

At the design stage, increased conductor spacing can be considered to reduce the occurrence/probability of flashover although this will not reduce the amplitude of conductor oscillations during the ice/snow shedding transient.

Ice removal techniques are described in Table 10.4. Ice melting is the thermal de-icing technique applicable for large scale ice/snow removal from line conductors. The heating of ice-covered line conductors by electrical current is considered as the most efficient engineering approach to remove ice/snow deposits. However it requires a great amount of energy as generally a current higher than the nominal line current is required. Moreover, the circulation of this current may accelerate the ageing of the conductor splices and connections by overheating.

The most common protection method is the use of interphase spacers which in conjunction with the bundle spacers or spacer dampers can control the distance between the conductor phases and the subconductors of the same phase.

A preliminary study has been performed on the prevention of ice shedding by the method of installing interphase spacers. Simulation results showed that the method was helpful to the mitigation of ice shedding. Further studies also point out that two spacers at mid span, where ice sheds from between the ice-shedding phase and the other two phases separately, are recommended for short spans, while for longer spans, three spacers with one at mid span and the other two positioned at the one quarter and three quarter are recommended to be installed. The rod diameter of the spacer has little effect, however, care must be taken not to damage the insulator core because of the compression forces that may be induced. Those forces are proportional to the conductor diameter and expected ice accretion weight.

10.4.5.3 Static Phase Approach

Most double circuit line phases are vertically or quasi-vertically aligned. An ice or snow deposit unequally distributed along the phases produces interphase spacing below the minimum dielectric distance and consequently causes flashovers and short circuits of the line. This may happen for example when the sag of an upper conductor loaded with ice increases and the lower conductor is not equally loaded because for example ice shedding has occured. Bundle conductors are particularly sensitive to this phenomenon because they may be covered by a snow or ice sleeve that bridges the subconductors. In this case, even considering that the deposit may have a low density, such as, for example, soft rime that is typical of elevated sites, the interphase spacing can be critically reduced.

10.4.6 Wind Gust Response (Tunstall 1997)

The turbulence in natural wind modulates the drag force acting on the conductors which respond as tuned systems to this random excitation in motions termed "buffeting". Since the spectrum of turbulence in the natural wind has most of its energy at very low frequencies, the response of the conductor is in its lowest frequency transverse modes. Buffeting response cannot be overlooked in gusty winds on account of the high flexibility of the transmission line. Since the characteristics of gust response are totally different from those of galloping, the methods to control or minimize them would be different for rational design of phase clearance and smooth operation of transmission lines. It is therefore necessary to know the wind turbulence effect on wind induced phenomena and to identify gust responses by processing field data. This response is of interest because it may affect the operating clearance between phases and between phases and adjacent structures and may result in flashovers.

The calculation of the response can be carried out if the cross spectra describing the covariance of the turbulence as a function of separation along the span and frequency are available. Alternatively, recordings of turbulent wind speeds at a succession of points along the span can be used as input to a discretized theoretical model of a span.

National codes usually provide adequate guidance to the line designer to predict the clearances required for most spans of overhead lines, (IEC 1991) but very long spans in mountainous environmental require in-depth consideration. Moreover, data may not be available for more extreme wind conditions which may lead to the worst effects of wind gusts that are the flashovers, but these are fortunately very rare events.

The full understanding of this aspect represents a gap in the technology, which is usually covered by conservative design criteria. Consequently, we can assume that present design criteria duly consider the prevention of excessive swing out and conductors clashing except under special conditions, as for example overhead lines built on sloping terrains where there will be a significant upward component of the wind forces (EPRI 2009).

Another consideration, however, is the horizontal separation required between phases to avoid phase-to-phase contact which could potentially arise from the differences in turbulent response between two phases. This is generally of no concern in normal spans but, it may be significant for exceptionally long spans or in case of compact lines.

Smooth surface conductors offer the opportunity to reduce the gust response since they may have lower critical and transcritical values of the drag coefficient C_D at the design wind condition.

10.4.7 Earthquake

Earthquaks are is a sudden release of energy in the earth's crust, usually caused by movement along geologic fault plane or by volcanic activity and resulting in the generation of seismic waves which may be destructive. The vast majority of earthquakes do not last for more than few seconds and the horizontal acceleration is in the range 0.05-0.5 g. In rare and particular circumstances only, disastrous motions can have acceleration of more than 1 g and last for a longer time.

The natural frequencies of normal towers, that are nominally rigid, and those of the conductors, are generally detuned, thus no seismic force can be transmitted from line supporting structures to the conductors and vice versa. However, tall towers of long crossing spans and high voltage tubular poles are more flexible and the natural frequencies are closer to the conductor frequencies. In these cases conductors may transmit to the towers additional longitudinal loads especially in tension-tension spans (CENELEC 2001).

Besides soil deformation, earthquake induced vibration can generate liquefaction of saturated sandy soil, that than loses strength and stiffness and can no longer support weights causing buildings or other objects on the surface to sink or fall over; earthquake can also produce landslides on unstable slopes. These earthquake effects may cause tower dislocation as well as damage and large relative displacement of the foundations that in turn may damage the line structures. Cases of tower failure have been reported on a few occasions, as well as cases of conductor failure requiring the application of joints, but in general, transmission lines demonstrate a very low sensitivity to earthquake and the designers do not pay much attention to this phenomenon unless the transmission line has strategic importance and must be provided with high reliability. In these cases, design solutions to mitigate the effect of earthquake should be considered and a post-earthquake procedure should be established in order to recover service as fast as possible. In the design codes, very little information is given about anti-seismic criteria for transmission lines (EPRI 2009). The IEC Std. 60826 (IEC 2003) does not consider seismic loads on transmission lines. However, computer simulations based on finite element calculation are available for transmission line designers (Clough and Penzier 1993). On the other hand, substations are more vulnerable and are carefully designed in order to resist earthquakes.

10.5 Highlights

Wind induced conductor motion can be classified, in three main categories: aeolian vibration, wake induced oscillation and conductor galloping.

10.5.1 Aeolian Vibration

Aeolian vibration (Figure 10.93) is the most common and the most dangerous for the conductor integrity. It is generated by the alternate detachment of wind induced

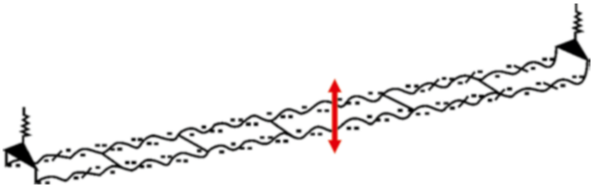


Figure 10.93 Aeolian vibration.

vortices from the top and bottom sides of the conductor. These produce an alternating pressure unbalance, inducing the conductor to move up and down at right angles to the direction of airflow. Typical aeolian vibration parameters are:

- Range of wind speeds: 1 to 7 m/s
- Maximum amplitude peak to peak: generally not higher than the conductor diameter
- Vibration frequency range: 4 to 120 Hz
- Minimum wave length: 1.5 to 2 m.

Aeolian vibration can be mitigated by the use of vibration dampers and, on bundled conductors, spacer dampers.

10.5.2 Wake Induced Oscillations

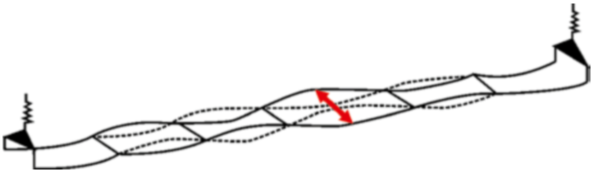
The phenomena known by the collective term "wake induced oscillations" are typical of bundled conductors with at least two sub-conductors horizontally aligned. The oscillations are generated by the aerodynamic instability of the leeward sub-conductor of the bundle as it moves in the wake of the windward one. Among various motions induced by the wake effect, the most common and potentially dangerous is the so called "subspan oscillation" that is an anti-phase oscillation of two subconductors horizontally aligned with one or two loops in a subspan (Figure 10.94). It can be mitigated by an appropriate distribution of the spacers along the conductor bundles. The motions occur in moderate to strong wind in the range of 7 to 18 m/s. The maximum amplitude can reach the subconductor spacing and the frequency is in the range: 0.7÷3 Hz.

Typically, it is a quite localized phenomenon with significant motions occurring in a few subspan of a few spans of a transmission line.

10.5.3 Energy Balance Principle

The vibration level of an overhead conductor is generally estimated by using the Energy Balance Principle (EBP) between the energy EW imparted to the conductor by the wind and the energy E_C dissipated by the vibrating conductor with or without additional damping.

Figure 10.94 Subspan oscillation.



The energy/power introduced by the wind in an overhead conductor has been measured in wind tunnels by several researchers and a number of empirical functions are available in literature.

The energy dissipated by the conductors, as well as the damping properties of the vibration dampers and spacer dampers can be evaluated through laboratory tests.

10.5.4 Galloping

Galloping usually occurs in moderate and strong winds. It is a predominantly vertical oscillation (Figure 10.95) resulting from the cross-section of the conductor having unstable aerodynamic characteristics most commonly caused by asymmetrical ice deposit. The frequencies associated with full-span galloping are typically 0.1 to 0.75 Hz with amplitudes of the same order of the conductor sag and mode shapes having one, two or three loops per span.

It is generally considered that bundled conductors are more prone to galloping under icing conditions than single conductors. Several antigalloping methods and devices have been designed and operated in the last 70 years.

10.5.5 Fatigue

Conductor fatigue and its resulting consequence, the breaking of conductor strands, is mainly due to a phenomenon known as fretting fatigue, in locations on the conductor where its motion is restrained, e.g. suspension clamps, spacer clamps or damper clamps.

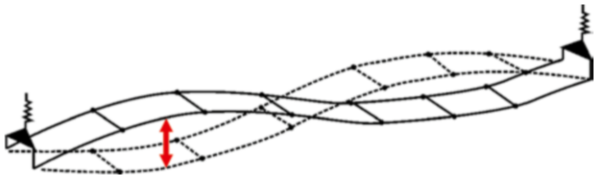
Fatigue behaviour of conductors cannot simply be calculated from the fatigue characteristics of the materials used and the stresses that occur but must be determined by fatigue tests conducted on specific conductor/clamp systems reproducing as closely as possible the field loading conditions.

Fatigue test data are available for only a small fraction of the conductor sizes and types and clamp desigs that are in use, and such data is expensive to acquire.

10.5.6 Assessment of Vibration Severity

Four main methods are commonly used for the assessment of vibration severity on overhead transmission line conductors:

Figure 10.95 Galloping.



- Computer analysis of the conductor vibrations
- Field vibration tests on outdoor experimental spans
- Vibration test on laboratory spans
- Vibration measurements on actual lines
- Conductor inspections on actual lines.

Each method offers its own contribution to the total picture. Although they are inter-related, their limitations and concepts are somewhat different.

Sophisticated computer programs and modern live line recorders dedicated to aeolian vibration and subspan oscillation phenomena are used.

10.5.7 Other Conductor Motions

In the design of overhead transmission lines, conductor motions other than sustained vibrations and oscillations induced by the wind should be duly considered in order to safeguard the lines against their harmful effects. They are:

Short Circuit

Affects mainly the conductor bundles in which, under short circuit conditions, the subconductors are driven rapidly toward the geometric center of the bundle by strong attractive forces and they generally clash. When the fault is cleared by the line protection relays the subconductors to spring apart and oscillate about their normal position.

Bundle Conductor Rolling

Severe and unequal ice accretions may produce bundle rolling of more than 180° with no spontaneous return to the untwisted position. Suitable spacer damper designs and short end subspans can increase the bundle torsional stability and prevent the phenomenon.

Ice and Snow Shedding

Sudden ice or snow shedding from overhead conductors may result in high-amplitude vertical oscillations. Consequences could be: conductor damage, violation of inter-phase and ground clearance causing short circuit, damage to towers, insulators, hardware and excessive sag. Increased conductor spacing and the use of inter-phase spacers are common remedies. De-icing and anti-icing procedures and devices are also available.

Gust Response
Wind speed varies rapidly due to turbulence and gustiness. Present line design practices are generally adequate to avoid excessive swing-out and conductor clashing under transverse strong winds. However, in sloping terrains of hills and mountains significant upward forces are developed by the wind and may produce conductor clashing.

Earthquakes
Transmission lines have low sensitivity to earthquakes. Differential foundation settlements may cause damage to towers and conductors

Corona Vibrations
Corona induced vibrations of conductors occur under rain, wet snow and heavy fog, with light wind or in still air for conductor surface voltage gradients above 15 kV/cm. Protection methods include normal vibration dampers and control of voltage gradient at the design stage. Typical amplitudes of the order of 100 mm and frequencies around 10 Hz have been recorded.

10.6 Outlook

The science and technology of wind induced motions, the relevant diagnostic procedures and the mitigation systems are well established and can guarantee satisfactory solutions to all the design and operation problems encountered on normal transmission lines.

However, the evolution of the transmission line technique has introduced new conductors (thermal resistant, OPGW, ADSS, etc.), new bundle configurations (expanded, hexagonal and octagonal bundles) and higher nominal voltages (above 1000 kV). The performance and effect on conductor vibration of these innovations are yet to be established through laboratory tests and field experience.

Regarding new conductors, self-damping characteristics and fatigue endurance need to be determined and measured. This is possible only through laboratory tests. Unfortunately, these tests are expensive and time consuming and the accumulation of a data base is slow.

Some new conductors such as, for example, gap conductors and ADSS may have different self-damping mechanisms in respect to conventional conductors and different test procedures and data reduction may be required. Moreover, it is possible that thermal resistant conductors could exhibit different self-damping properties at different working temperatures. Laboratory tests aimed to cover these aspect are bound to be longer and more complex.

The analytical models used for predicting the vibration behaviour of conductors with and without additional damping systems are continuously reviewed and enhancements are expected in the future for a better correspondence with the actual phenomena and with the new line configurations.

Regarding the diagnostic procedures and devices, monitoring instruments are under development to be able to provide real time information required for better use of the existing lines.

Acoustic/magnetic devices for the detection of conductor steel core corrosion and strand failures are being studied to improve their sensitivity and to make the installation and operation easier.

Then next step in the evolution of vibration recorders would be lighter instruments permanently installed on transmission line conductors and connected via GSM (Global System for Mobile Communication) to a monitoring centre.

Galloping does not yet have operationally acceptable solutions which cover all circumstances. The efforts dedicated to this phenomenon have varied widely with time but even today, hundreds of thousands dollars, if not millions, are invested every year to better understand the galloping phenomenon and develop efficient means for the protection of transmission lines against it.

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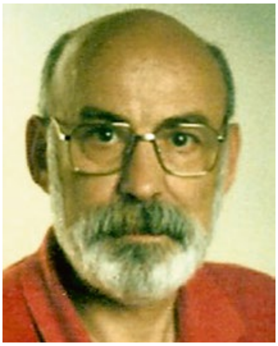

Umberto Cosmai is an international independent consultant with more than 50 years of experience in overhead transmission lines. He worked for ENEL as laboratory engineer and researcher for 23 years, then he joined the company DAMP, as technical director, where he designed vibration-damping systems for overhead transmission lines up to 1000 kV, including special projects for long rivers and channel crossings. He performed educational activity and authored several national and international papers and three books. He also co-authored the book titled "Wind Induced Conductor Motion" edited by EPRI Palo Alto CA (USA). He presented seminars on overhead conductor vibrations and performed field vibration measurements in 30 Countries worldwide. He is member of TC11 WG09 of IEC and chairman of Cigré WG B2.25. For Cigré he authored two Tutorials, ten papers and co-authored five Technical Brochures. In 2012, he received the Cigré Technical Committee Award for his contribution to the work of SC B2

Pierre Van Dyke has B.Eng., Master Certificate in Project Management, M.A.Sc. and Ph.D. degrees. He is currently Senior Research Scientist at Hydro-Quebec Research Institute (IREQ) as well as Associate Professor at Sherbrooke University, Associate Professor at Quebec University in Chicoutimi (UQAC), IEEE editor PES Transactions on Power Delivery and Convenor of Cigré TAG 06 'Mechanical behaviour of conductors and fittings'. He is author or co-author of more than 50 papers and two books. He has designed aeolian vibration dampers, interphase spacers and suspension clamps and performs R&D and consulting on aeolian vibrations, wake-induced oscillations, conductor galloping, and climatic loads on overhead transmission lines using a full scale test line, a laboratory test span, and fatigue test spans among other facilities.

Laura Mazzola is born in Milan (Italy) on 3rd April 1980. She graduated in Mechanical Engeneering at Politecnico di Milano, on April 2005. From January 2006 to December 2008 she attended the PhD School in Mechanical Engineering at Politecnico di Milano. At present she is temporary assistant Professor at Dipartimento di Meccanica Politecnico di Milano. Her research activity is focused on railway vehicles and cable dynamics, in particular train track interaction, vehicle stability, safety and comfort. She is author of more than 40 papers piublished in journals and conferences.

Jean-Louis Lillien PhD., is the head of the unit Transmission and Distribution of Electrical Energy at the Montefiore Institute of Technology, University of Liège, Belgium. He has over 35 years experience solving the electrical and mechanical engineering problems of power systems. His work involves analysis of problems in "cable dynamics" in general and on overhead power lines in particular. His major activities were devoted to (i) vibrations on transmission lines, in particular galloping, including its control (ii) large movements of cables, like short-circuit (both in substations and power lines), (iii) health monitoring of power lines (sag and vibrations) and last, but not least (iv) low-frequency electric and magnetic field effects on human beings. Jean-Louis is a long-time active member of IEEE and Cigré, where he has served as convenor of several task forces of Cigré study committee B2, "overhead lines" and B3 "substations". He has published over 110 technical papers in peer reviewed publications.

Insulators

11

Frank Schmuck and Konstantin O. Papailiou

Contents

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F. Schmuck (✉)
Malters, Switzerland
e-mail: frank.schmuck@pfisterer.com

K.O. Papailiou

K.O. Papailiou (ed.), *Overhead Lines*, CIGRE Green Books,
DOI 10.1007/978-3-319-31747-2_11

11.1 Introduction

In this chapter, line insulators are covered from the perspective of Cigré work and related activities. In principle, it is to differentiate into conventional insulator technology, which includes glass and porcelain cap and pin insulator as well as porcelain longrod insulators and into polymeric insulator technology. When considering higher distribution and transmission voltages level, the concept of the composite insulator is used, where different materials contribute to the insulator function in accordance to the relevant material properties (fibre reinforced plastic rod (FRP) for force function, housing as environmental protection, both for electrical function).

Conventional insulators have been installed since the 19th century. First IEC standards for them became available from the fifties of the 20th century, some examples are:

- IEC (60)075 "IEC specification for porcelain insulators for overhead lines with a nominal voltage of 1 000 volts and upwards" – 1st Edition in 1955 (P-IEC (60)075 Ed. 1 1955),
- IEC (60)087 "IEC specification for glass insulators for overhead lines with a nominal voltage of 1000 Volts and upwards" – 1st Edition in 1957 (P-IEC (60)087 Ed. 1 1957),
- *IEC (60)120 "Recommendations for ball and socket couplings of string insulator units" - 1st Edition in 1960* (P-IEC (60)120 Ed. 1 1960),
- IEC (60)213 "Tests on solid-core insulators for overhead electric traction lines with a voltage greater than 1 000 V" – 1st Edition in 1966 (P-IEC (60)213 Ed. 1 1966),
- *IEC (60)305 "Characteristics of string insulator units of the cap and pin type" – 1st Edition in 1969* (P-IEC (60)305 Ed. 1 1969),
- *IEC (60)372 "Locking devices for ball and socket couplings of string insulator units" – 1st Edition in 1971* (P-IEC (60)372 Ed. 1 1971),
- *IEC 60(383) "Tests on insulators of ceramic material or glass for overhead lines with a nominal voltage greater than 1 000 V" - 1st Edition in 1972* (P-IEC 60(383) Ed. 1 1972),
- *IEC (60)433 "Characteristics of string insulator units of the long rod type" – 1st Edition in 1973* (P-IEC (60)433 Ed. 1 1973),
- *IEC (60)471 "Dimensions of clevis and tongue couplings of string insulator units – 1st Edition in 1977* (P-IEC (60)471 Ed. 1 1977),
- *IEC 60672-1 "Specification for ceramic and glass insulating materials - Part 1: Definitions and classification" 1st Edition in 1980* (P-IEC (60)672-1 Ed. 1 1980); *IEC 60672-2 "Specification for ceramic and glass insulating materials - Part 2: Methods of test" - 1st Edition in 1980* (P-IEC (60)672-2 Ed. 1 1980); *IEC 60672-3 "Specification for ceramic and glass insulating materials - Part 3: Individual materials" – 1st Edition in 1984* (P-IEC (60)672-3 Ed. 1 1984).

The standards shown in italic characters are still in use, of course in a more advanced edition and some of them apply to composite insulators as well. In view of this situation it is obvious that conventional insulators are recognized as "matured technology" and Cigré was not dealing much with corresponding topics during the last years.

In contrast to, basic concepts of polymeric insulators including monolithic designs made of structural materials such as Epoxy were developed in the 1950's, when the first standards for conventional insulators were already launched (see above). And considering the transmission voltage level > 100 kV, the technology of composite insulators was taken seriously into account not before the 1970's. This was also initiated by major progresses in both material development of FRP and housing materials as well as manufacture techniques of complete assembled insulators, which includes processes of housing application and end fitting attachment. At their period of introduction, composite insulators were recognised as very specialised sometimes "exotic" products. They were rather expensive owing to the low numbers in which they were produced often with non-standardised semi-finished products and were thus limited to special applications, for example in areas with extreme pollution or vandalism. As it is typical for new developments, there were hardly any standards or long-term operational experience available, and design errors sometimes resulted in corresponding failures. Well known examples for this lack of knowledge were sealing problems in general or in particular as it was especially identified on Teflon-housed insulators, which had no bond between housing and rod. The interface between housing and rod was filled with grease and when the grease disappeared after a relatively short operational time, the insulator failed by so-named flashunder, rod tracking or brittle fracture caused by moisture ingress (Cojan et al. 1980; Weihe et al. 1980; Bauer et al.1980).

Since then, the composite insulator technology has been continuously developed as a quality alternative with improved service properties to porcelain and glass insulators. And in the meantime it has acquired a positive reputation attributed to good operational experience in global applications and accordingly high production numbers. Worth to mention that the today's technical state-of-the-art of the composite insulator technology can be attributed to important pioneering work that was spent by few international manufacturers and interested users, who recognised the application potential of composite insulators and took the risk for early network installations to gain outdoor experience. Research institutions have been deeply participating in the identification and understanding the dynamic interactions between the housing material and the surrounding environment and the deduction of models for this behaviour.

In the context of outstanding work and contributions in the field of composite insulators on behalf of the industry as well as for Cigré and IEC, Dr. Claude de Tourreil (Figure 11.1) must be mentioned. He worked many years with a pioneering manufacturer of composite insulators, performed fundamental investigations with utilities and as long-term convenor of the Cigré Working Group (WG) Insulators, he compiled this knowledge for the first relevant documents dealing with technical requirement of composite insulators.

Today it is well accepted that together with correct design (which includes shed profile and material composition) a durable hydrophobic housing effect has

Figure 11.1 Claude de Tourreil, long-term convenor of Cigré's Working Group on Insulators.

virtually eradicated the need for cleaning maintenance. This increased level of understanding alongside growing production numbers has also led to optimisation and automation of production processes so that high quality can be provided at an attractive cost (economies of scale). Overall, there is remarkable engineering knowledge available to design composite insulators as a save and in some properties outperforming alternative to glass and porcelain insulators. However, some trends are obvious that purely economic considerations bear the risk for less product redundancy.

Taking the situation about conventional and polymeric insulators into consideration, the chapter looks mostly into Cigré subjects of composite insulators and it is structured as follows:

- Status of IEC standardization for conventional and polymeric insulators,
- Overview on selected Cigré contributions for composite insulators,
- Excerpt presentations of these contributions structured into contributions for materials (end fittings, rod and housing) and performance/behaviour of completely assembled insulators and insulator strings or sets.

References or benchmarking to the behaviour of conventional insulators are provided when appropriate.

11.2 Composite Insulator Product Generations, the Demand for and Status of Standarized Tests

In the 1950's characterising the early days of the polymeric insulator developments, structural materials for one-material-insulations and the replacement of grease, which was applied as mitigation measure for hydrophilic insulator surfaces under high pollution, by more surface-sticking coatings were the main focus areas of the work. Meanwhile, the basic concept of the composite insulator was developed in the

1960's. This concept consists of a combination of different materials, which perform different duties in the function of the insulator, relating to their particular strength and properties.

The composite insulator technology has undergone the various development phases and standardization stages, which are typically recognized to be associated with technical products. The composite insulators manufactured today, often also known as third-generation or third-generation plus composite insulators, are characterised by high-grade components with a long-term history of use. In 1991, a relation between insulator generation, semi-finished material components and insulator development was described, which is still valid today (Gorur and Orbeck 1991):

- 1st Generation 1955-1970:
  Development of dry band and arc-resistant polymeric materials and corresponding test methods to prove this property,
- 2nd Generation 1971-1984:
  Discovery and evaluation of the hydrophobic behaviour of polymeric surfaces for insulations, starting with the use of silicone grease applied to porcelain surfaces,
- 3rd Generation 1985-today:
  Fundamental investigations on the interaction between (dynamic) material properties in relation to the service behaviour, introduction of test procedures and product standards.

With the increasing use of composite insulators, there was a need for standards to ensure product quality and, in particular, substitutability in comparison to the well established conventional technologies (cap and pin or longrod insulator, glass or porcelain, etc.).

Cigré made an important key contribution in this regard when its WG 22.10 formulated minimum material and test requirements for composite insulators in a comprehensive study, which was published in 1983 (Cigré WG 22.10 1983). Then, this document served as basis for the product standard IEC (6)1109 (P-IEC 61109 Ed. 1 1992), which was issued in 1992. In the meantime, many years of service experience are available with composite insulators, which have been qualified in accordance with this first standard and the validity of its test methods and philosophies has been successfully verified. Hence, it was a logical result that the test methods and philosophies of this first standard were pursued in subsequent standards. It is worth to mention that also these standards are subject to defined maintenance cycles within IEC to allow for new material developments, advanced field experiences etc. As is the case with many standards, however, "only" minimum requirements are defined, but the on-site conditions may demand rules that are more stringent.

The various needs for insulator testing can be classified as shown in Figure 11.2. *Material Evaluation* tests are specifically used to quantify certain properties (for polymeric material: erosion resistance, hydrophobic behaviour, etc; for ceramic and glass materials: bulk density, apparent porosity, glass transition temperature, etc.). It is a proven practise for material tests that simple test specimen geometries are used

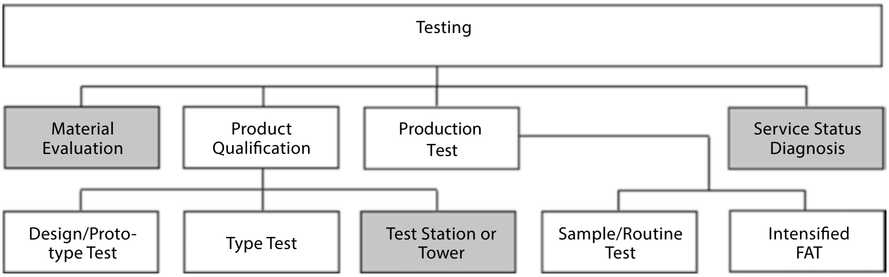


Figure 11.2 Classification example of insulator testing.

to prevent an impacting superimposition of material properties and shape of test specimen. These tests are assigned to develop new materials and, thanks to their simplicity and the high level of automation that can be achieved, they are also used for in-process quality assurance procedures during manufacture.

For the *Product Qualification* tests, a differentiation can be made into *Design Tests* (also known as prototype tests in the American literature) and *Type Tests* (named design tests in the American literature) in accordance with applicable product standards. When compared against a sole *Material Evaluation*, the design testing is more complex because both material properties and geometry influence are evaluated on short composite insulator specimens, which are functionally complete insulators. A type test is usually conducted on insulators in their original size; certain tests must already be performed involving insulator string or set elements (e.g. corona rings or power arc protective devices). The current version of IEC 61109 (2008) permits an interpolation of the lightning withstand voltage, withstand switching surge voltage and power frequency withstand voltage values if the striking distances of the insulators describing the points of the interpolation range does not exceed a factor of 1.5. Some power utilities and researcher has been employed *Test Stations* or *Test Towers* (Cigré WG B2.03 2007; Sklenicka and Zeman 2001; Riquel et al. 1996; Vlastos and Sorqvist 1997) to correlate the results from accelerated ageing tests in the laboratory (mostly in design test scale) with the results of natural weathering and simultaneous stressing of full scale specimens. Often, these special installations are at locations that are subjected to accelerated ageing as a result of high pollution stresses (see also Section 11.4.2.1).

Production Tests can be differentiated into *Sample Tests* and *Intensified Factory Acceptance tests*. The first are also a kind of product qualification in the sense of confirmation of guaranteed product properties. Here, it is necessary to verify the conformity of a batch; design tests and type tests are generally concluded at this time.

Intensified Acceptance Tests are used if some uncertainty surrounds a batch's conformity to the order specification (Schmuck et al. 2010) and can be part of a factory acceptance test (FAT). The applied tests are selected specifically to the uncertainty(ies) identified and are overall more stringent as the sample tests normally undertaken and are targeted at the additional evaluation of specific material properties.

The *Service Status Diagnosis* qualifies and/or quantifies the current status of all line equipments. In terms of insulators, the diagnosis may come to a conclusion that a detailed evaluation of an insulator vintage is required in service, which applies to conventional and polymeric insulators. Examples of such evaluations are shown for conventional insulators in Cigré WG B2.03 (2006) and polymeric insulators in Cigré WG B2.21 (2011, 2013).

The subjects of boxes shaded will be discussed more in detail, when the Cigré contributions will be shown.

In Figure 11.3, the IEC standards for polymeric and conventional line insulators are comparatively displayed (Papailiou and Schmuck 2012). It is obvious that a comparable structure was introduced for both starting with *Material Selection Tests* and ending with Standards for *Insulator Sets*, which are practically independent from the insulator technology used.

The *Material selection for composite insulators* as per IEC 62039 (2007), which was published in 2007, is based on the contributions of Cigré Working Group D1.14, which were published as Cigré TB 255 (Cigré WG D1.14 2004). The standard

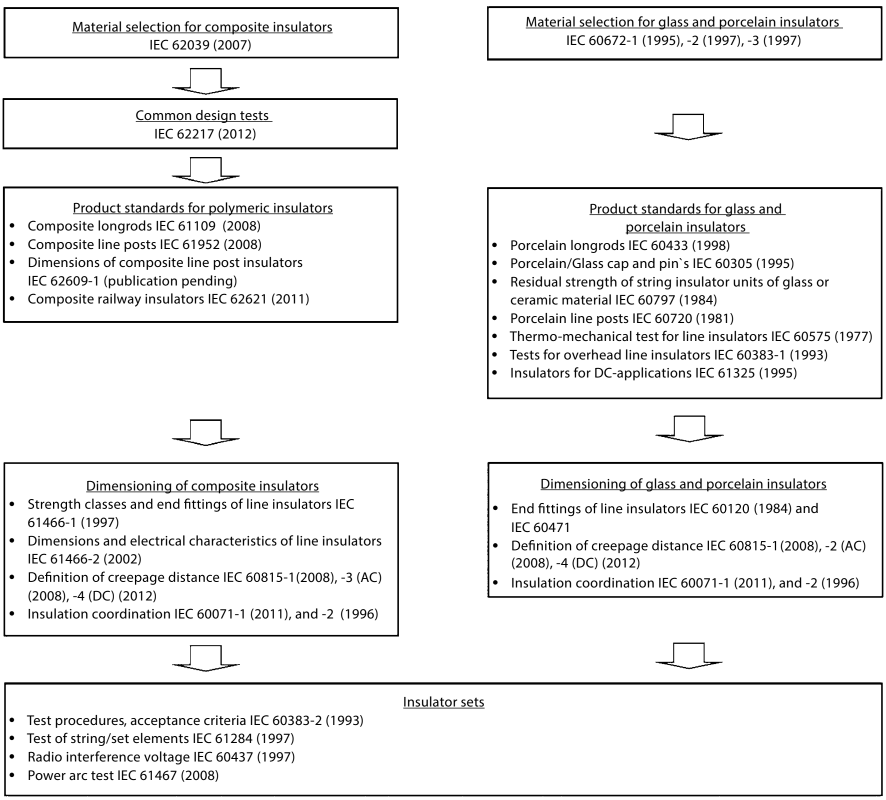


Figure 11.3 IEC standards for polymeric and conventional insulators used in lines (Papailiou and Schmuck 2012).

specifies twelve important material properties and provides information about their minimum requirements.

Where information was available, standardized test methods are given. Equivalent standards exist for conventional insulator materials with the parts of IEC 60672. In IEC 62039 reference is made to other standards to test certain material properties. With the development of polymeric materials for outdoor applications, many material tests were introduced aiming in the evaluation of the erosion and tracking resistance.

Examples are the Inclined Plane Test (IEC 60587 2007), a rotating wheel dip test (IEC 61302 1995), a resistance test to (dry) high-voltage, low-current arc discharges (IEC 61621 1997). Also, in the past, a simple method for the determination of so-named comparative tracking indices of solid insulating materials was employed (IEC 60112 2004). However, the high erosion resistance of today's insulating material cannot be sufficiently differentiated by this test method (Bärsch et al. 1997). A test that determines the resistance of polymeric surfaces to corona discharges is available with IEC 60343 (1991). However, it is preferable to evaluate other influencing factors (e.g. simultaneous tensile stress) during this test (Ma et al. 2010), when such additional stresses are representative for the application.

The *Common design tests* were introduced, because composite insulators share similarities (especially different interfaces due to the design concept) despite various end applications such as line, apparatus or station insulators. IEC 62217 provides a full description of certain tests to be verified.

Important notes to Ed. 1 and 2 of IEC 62217 issued in 2005 and 2012 respectively: Ed. 1 included three different tracking and erosion tests. The continuous salt fog test with a duration of 1000 hours, was defined in the main chapter as mandatory test and two alternative (additional) test were given in the annexes, which are a multi-stress test over 5000 hours and a tracking wheel test (this tracking wheel test is different to the wheel test of IEC 61302, the last is a sole material test). An international study of the usage and effectiveness of all three tests was undertaken by WG 12 of IEC TC 36. The results of the study showed clearly that only the 1000 hour salt fog test was used for all insulator types and was more economical to perform. In view of this result, IEC TC 36 decided to include the 1000 hour salt fog test as the only standardized ageing test in IEC 62217 revised. Furthermore, the 5000 hour multi-stress test and the tracking wheel test procedures were moved to a standalone IEC standard (IEC 62730 2012) in order to keep the information of these test methods and parameters for research or other purposes. Two further precisions were introduced in Ed. 2, which are the use of the Xenon arc test as only UV test basing on the work of Cigré's D1.14 TB 488 (2012a) and the specification of flammability material tests and acceptance criteria in accordance to application and voltage class basing on Cigré's D1.14 TB 489 (2012b).

The respective *Product standards* give general rules for design and manufacture of insulators. Discussing it for composite line insulators, they apply to composite suspension/tension and post insulators consisting of a load-bearing cylindrical insulating solid core consisting of fibres – usually glass – in a resin based matrix, a polymeric housing covering the insulating core and end fittings permanently attached to the insulating core. The scope of these standards are the definition of commonly agreed terms, the prescription of test methods for design (under reference to

IEC 62217), type, sample and routine tests and the stipulation of acceptance criteria for the tests mentioned. The product standards do not include requirements for the choice of insulators for specific operating conditions.

Such requirements are covered by the standards mentioned under *Dimensioning of composite insulators*, where end fittings in accordance to the nominal force rating, striking and creepage distances are selected for the in-situ conditions of the application.

When evaluating *Insulator sets*, the set of tests is equal to sets built with conventional insulators or composite insulators. The aim here is to value the behavior of the entire system, which comprises one or more insulators and metallic string/set elements.

With respect to pollution tests, IEC 60507 (2013) and IEC 61245 (1993) are used for AC and DC tests on conventional insulators respectively. In the past and to some extent, both were also used to test composite insulators. Due to the hydrophobic effect of composite insulators, especially with silicone rubber housing, the results can differ greatly. For this reason, Cigré Working Group C4.303 was developing a test method that can also be used for composite insulators. The proposed test method was approved in international Round Robin Tests and their results were published in Cigré TB 555 (2013).

11.3 Selected Contributions by Cigré for Insulators and Insulator Sets, and in particular Composite Insulators

In the following section, relevant publications in ELECTRA or issued as TB of Cigré WG's dealing with insulator subjects are shown. The presentation follows the principle as per Table 11.1. The *Working Group* and the *Title* provide the main information of the corresponding document, *Date of Publication* is the time of being published either as ELECTRA publication or TB. In the case of a TB, typically a short summarizing introduction of it is then published in ELECTRA. This introduction is not considered in the table. *Reference* refers to the Section References of this document. *Contribution for* describes in which field of IEC standardisation work or further Cigré work the results the document were used. *Main result discussed in chapter* makes reference to the corresponding section of this document, when the content and main results are displayed in more detail.

11.3.1 Insulator Groups 22.03, 22.10, B2.03, B2.21

In the following Table 11.2, selected documents of Cigré WG's, which dealt with insulator themes, are shown in chronological order.

Table 11.1 Principle of presentation of contributions in ELECTRA or Cigré TB

Working Group	Title	Date of publication	Reference
Contribution for		Main result discussed in section	

Table 11.2 Overview on Cigré publications dealing with insulator topics

WG 22.03	**Study and Conclusions from the Results of the Enquiry on Insulators. Report on Conditions of the Use**	1979	Cigré WG 22.03 (1979)
Selection criteria and manufacture improvement of conventional insulators such as IEC's 60433 and 60305		See also 11.4.1.1	
WG 22.03	**Study and Conclusions from the Results of the Enquiry on Insulators: Information on Damages**	1981	Cigré WG 22.03 (1981)
Survey on experiences and failures with information for manufacturer and utilities, impact on selection and test criteria – IEC's 60433, 60305 and 61284, is end of life predictable?		See also 11.4.1.1	
WG 22.10	**Technical Basis for minimal Requirement for Composite Insulators**	1983	Cigré WG 22.10 (1983)
Fundament for IEC (6)1109 and further standards		See also 11.2	
WG 22.03	**Worldwide Service Experience with HV Composite Insulators**	1990	Cigré WG 22.03 (1990)
Selection criteria and manufacture improvement of polymeric insulators and standards such as IEC's 61109, 62039 and 60815-3		See also 11.4.1.2	
WG 22.03	**Prospective Devices for Insulator Sets (HV and EHV Transmission Overhead Lines)**	1991	Cigré WG 22.03 (1991)
Insulator set design in terms of power arc protection and power arc testing, IEC's 61284 and 61467		See also 11.4.4.3	
WG 22.03	**Comparative electric Field Calculations and Measurements on High Voltage Insulators**	1992	Cigré WG 22.03 (1992a)
Insulator set design in terms of corona protection, IEC's 61284 and 60437			
WG 22.03	**Use of Stress Control Rings on Composite Insulators**	1992	Cigré WG 22.03 (1992b)
Composite insulator set design in terms of corona protection, IEC's 61284 and 60437,		See also 11.4.4.2	
WG 22.03	**Guide for the Identification of Brittle Fracture of Composite Insulators FRP Rod**	1992	Cigré WG 22.03 (1992c)
Contribution for IEC's 62039 and 62662 (IEC TR 62662 Ed1: Guidance for production & testing and diagnostics of polymer insulators with respect to brittle fracture of core materials 2010)		See also 11.4.3.2	
WG 22.03	**Analysis of the Replies to the Questionnaire concerning the Use of high mechanical Performance Insulators**	1993	Cigré WG 22.03 (1993)
Selection criteria and manufacture improvement of conventional insulators and standards such as IEC 60433 and 60305		See also 11.4.1.1	

(continued)

Table 11.2 (continued)

WG 22.03	**Service Performance of Composite Insulators used on HVDC Lines**	1995	Cigré WG 22.03 (1995)
Selection criteria and manufacture improvement of polymeric insulators and standards such as IEC's 61109, 62039 and 60815-4			
WG 22.03	**Review of "In-service diagnostic Testing" of Composite Insulators**	1996	Cigré WG 22.03 (1996a)
Selection criteria and manufacture improvement of polymeric insulators and standards such as IEC's 61109, application of live line work		See also 11.4.2.2	
WG 22.03	**Cantilever Load Performance of Composite Line Post Insulators**	1996	Cigré WG 22.03 (1996b)
Contribution for IEC 61952 and IEC 62231		See also 11.4.4.4	
WG 22.03	**Worldwide Service Experience with HV Composite Insulators**	2000	Cigré WG 22.03 (2000a)
Selection criteria and manufacture improvement of polymeric insulators and standards such as IEC's 61109, 62039 and 60815-3		See also 11.4.1.2	
WG 22.03	**Dynamic Bending Tests of Composite Line Post Insulators**	2000	Cigré WG 22.03 (2000b)
Contributions for IEC 61952 and IEC 62231		See also 11.4.4.4	
WG 22.03	**Composite Insulator Handling Guide**	2001	Cigré WG 22.03 (2001)
Contribution for all composite insulator product standards			
WG 22.03	**Guide for the Evaluation of Composite Line Post Insulators subjected to combined Mechanical Loads**	2002	Cigré WG 22.03 (2002)
Contribution for IEC 61952 and IEC 62231		See also 11.4.4.4	
WG B2.03	**Brittle Fractures of Composite Insulators - Field Experience, Occurrence and Risk Assessment**	2004	Cigré WG B2.03 (2004a)
Contribution for IEC's 62039 and 62662		See also 11.4.3.2	
WG B2.03	**Brittle Fractures of Composite Insulators - Failure Mode Chemistry**	2004	Cigré WG B2.03 (2004b)
Contributions for IEC's 62039 and 62662		See also 11.4.3.2	
WG B2.03	**Use of corona Rings to Control the Electrical Field along Transmission Line Composite Insulators**	2005	Cigré WG B2.03 (2005)
Composite insulator set design in terms of corona protection, IEC's 61284 and 60437,		See also 11.4.4.2	

(continued)

Table 11.2 (continued)

WG B2.03	**Guide for the Assessment of old Cap & Pin and Long-Rod Transmission Line Insulators made of Porcelain or Glass: What to Check And When to Replace**	2006	Cigré WG B2.03 (2006)
Selection criteria and manufacture improvement of conventional insulators and standards such as IEC's 60433 and 60305, is end of life predicable?		See also 11.4.1.1	
WG B2.03, B2.11, B2.12	**Considerations relating to the Use of High Temperature Conductors**	2007	Cigré WG B2.03, B2.11, B2.11 (2007)
Insulator set design for high temperature conductor, testing as per IEC 61284		See also 11.4.4.3	
WG B2.03	**Guide for The Establishment of naturally polluted Insulator Testing Stations**	2007	Cigré WG B2.03 (2007)
Selection of ageing tests such as in IEC's 62217 and 62730, material screening tests as per IEC 62039, contribution to IEC 60815		See also 11.4.2.1	
WG B2.21	**On the Use of Power Arc Protection Devices for Composite Insulators on Transmission Lines**	2008	Cigré WG B2.21 (2008)
Insulator set design in terms of power arc protection and power arc testing, IEC's 61284 and 61467 as well as IEC 61109		See also 11.4.4.3	
WG B2.21	**Investigation of different Liquid Solutions for Dye Penetration Tests used in Standard IEC 62217 for Design and Routine Testing**	2010	Cigré WG B2.21 (2010)
Contribution for Revision of IEC 62217		See also 11.4.3.2	
WG B2.21	**Guide for the Assessment of Composite Insulators in the Laboratory after their Removal from Service**	2011	Cigré WG B2.21 (2011)
Tool for approval of selection criteria and manufacture rules of polymeric insulators and standards such as IEC's 61109, 61952, 62039 and 60815-3		See also 11.4.1.2	
WG B2.21	**Assessment of in-service Composite Insulators by using Diagnostic Tools**	2013	Cigré WG B2.21 (2013)
Selection criteria and manufacture improvement of polymeric insulators such as IEC's 61109, contribution to Live working standard IEC 61472 (IEC 61472 Ed. 3 2013)		See also 11.4.2.2	

11.3.2 Material Groups D1.14, D1.27

In the following Table 11.3, selected documents of Cigré WG's, which have been in charge with themes of materials and test methods for polymeric insulators, are shown in chronological order. As in the table before, if a TB is announced by a short summary in ELECTRA, this summary is not displayed.

Table 11.3 Overview on publications in ELECTRA or as Cigré TB by WG's dealing with material properties and related test methods of composite insulators

WG D1.14	**Material Properties for non-ceramic Outdoor Insulation**	2004	Cigré WG D1.14 (2004)
Fundament for IEC 62039		See also 11.2	
WG D1.14	**Evaluation of dynamic Hydrophobicity Properties of polymeric Materials for non-ceramic Outdoor Insulation – Retention and Transfer of Hydrophobicity.**	2010	Cigré WG D1.14 (2010)
Contributions for IEC's 62039 and IEC 60815 (Judgement of Hydrophobicity Transfer Materials (HTM))		See also 11.4.3.3	
WG D1.14	**Important Material Properties of RTV Silicone Rubber Insulator Coatings**	2011	Cigré WG D1.14 (2011)
Contribution for IEC's 62039 and 62217			
WG D1.14	**Resistance to Weathering and UV Radiation of polymeric Materials for Outdoor Insulation**	2012	Cigré WG D1.14 (2012a)
Contribution for IEC's 62039 and 62217			
WG D1.14	**Requirements on Testing Flammability of polymeric Materials for Outdoor Insulation.**	2012	Cigré WG D1.14 (2012b)
Contribution for IEC's 62039 and 62217			
(WG D1.14)*	**Effects of Long Term corona and Humidity Exposure of Silicone Rubber Based Housing Materials**	2013	Bi et al. (2013)
Contribution for IEC's 62039 and 62217		See also 11.4.4.2	
WG D1.27	**Retention of Hydrophobicity under DC Voltage Stress Evaluation with the Dynamic Drop Test**	2014	Hergert et al. (2014)
Contribution for IEC's 62039, 62217 and 60815-4		See also 11.4.3.3	
WG D1.27	**Fingerprinting of Polymeric Insulating Materials for outdoor use**	2014	Cigre WG D1.27 (2014)
Contribution for utility specifications		See also 11.4.3.3	
WG D1.27	**Feasibility Study for a DC Tracking & Erosion Test**	2015	Cigre WG D1.27 (2015)
Selection of materials for DC applications		See also 11.4.3.3	

*Results are also basing on the work of D1.14, results were not published so far.

11.3.3 Task Force Groups of SC 33 (Power System Co-ordination) dealing with Insulator Pollution Aspects

In the following Table 11.4, insulator-relevant documents published as ELECTRA paper or TB by Task Force (TF) Groups dealing with pollution aspects of insulations within the former SC 33 are shown.

Table 11.4 Overview on publications in ELECTRA or as Cigré TB by Task Force Groups TF 33.04

TF 33.04.01	**Polluted Insulators: A Review of current Knowledge**	2000	Cigré TF 33.04.01 (2000)
Contributions to IEC 60815		See also 11.4.4.1	
TF 33.04.02	**Failure of Cap and Pin Insulators subjected to HVDC**	1994	Cigré TF 33.04.02 (1994)
Contributions for material optimization as per IEC's 60672, 60305		See also 11.4.1.1	
TF 33.04.03	**Insulator Pollution Monitoring**	1994	Cigré TF 33.04.03 (1994)
Contributions to IEC 60815		See also 11.4.2.1	
TF 33.04.07	**Natural and artificial Ageing and Pollution Testing of polymeric Insulators**	1999	Cigré TF 33.04.07 (1999)
Selection of ageing tests such as in IEC's 62217 and 62730, material screening tests as per IEC 62039, contribution to IEC 60815			
TF 33.04.09	**Influence of Ice and Snow on the Flashover Performance of Outdoor Insulators. Part I : Effects of Ice**	1999	Cigré TF 33.04.09 (1999)
Contributions to IEC 60815		See also 11.4.4.1	
TF 33.04.09	**Influence of Ice and Snow on the Flashover Performance of Outdoor Insulators. Part 2 : Effects of Snow**	2000	Cigré TF 33.04.09 (2000)
Contributions to IEC 60815		See also 11.4.4.1	

11.3.4 Contributions by WG's of SC C4 - System Technical Performance - in Terms of Insulator Selection and Testing

In the following Table 11.5, insulator-relevant TB published by C4 WG's are shown.

11.4 Cigré Publications Reflecting the Status Quo of Insulators, in Particular Composite Insulators

11.4.1 Information on Surveys, Reliability, Failures

11.4.1.1 Conventional Insulators

In accordance to IEC 60383-1, overhead line string insulators are divided into two classes according to their design, so-named Class A and Class B insulators (Figure 11.4). For Class A applies that the length of the shortest puncture path through the solid insulating material is at least equal to half the arcing distance. A long rod insulator with external fittings is an example for. Class B insulators have

Table 11.5 Overview on Cigré TB by WG's C4.303 and C4.306

WG C4.303	**Outdoor Insulation in polluted Conditions: Guidelines for Selection and Dimensioning - Part 1: General principles and the AC case**	2008	Cigré WG C4.303 (2008)
Contribution for IEC 60815-1, -2 and -3		See also 11.4.4.1	
WG C4.303	**Outdoor Insulation in Polluted Conditions: Guidelines for Selection and Dimensioning - Part 2: The DC Case**	2012	Cigré WG C4.303 (2012)
Contribution for IEC 60815-4		See also 11.4.4.1	
WG C4.303	**Artificial Pollution Test for Polymer Insulators - Results of Round Robin Test**	2013	Cigré WG C4.303 (2013)
Contributions to IEC 60815		See also 11.4.4.1	
WG C4.306	**Insulation Coordination for UHV AC Systems**	2013	Cigré WG C4.306 (2013)
Contribution for application guide IEC 60071-2 for UHV			

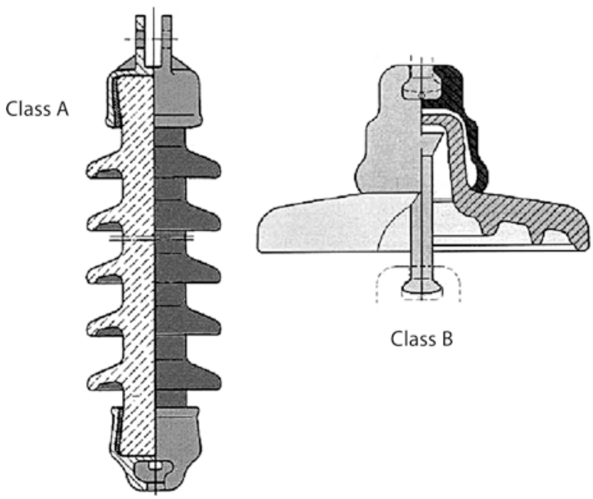


Figure 11.4 Principle of longrod (introduced in 1955) and cap and pin insulators (introduced in 1914).

the length of the shortest puncture path through solid insulating material, which is less than half the arcing distance. A cap and pin insulator is a typical example for.

These different constructive principle designs result in different damage modes. In the case of glass cap and pin insulators, the presence of any defect in the glass leads to a shattering of the insulator shell and only the stub remains in the string (Figure 11.5 - left). The service experience has shown that the string can still perform its mechanical functions as there is practically no reduction in the mechanical

Figure 11.5 Broken shell of glass cap and pin insulators (*left*) and puncture paths inside a porcelain insulator cap (*right*) (Mishra et al. 2006).

strength of the stubs. In terms of the electrical function, the flashover voltage of the glass stubs is significantly reduced as compared to intact glass insulators due to reduced striking distance, an external flashover will occur all the time without the risk of internal arcing or stub short-circuiting. For this reason, utilities permit a number of shattered shells in a glass string before replacement. This “user-friendly” failure mode is recognized as advantage of glass cap and pin insulators because of the easiness of identification from the ground without the need of additional tools.

In contrast to, defects in porcelain cap and pin insulators cannot be that easily detected since they appear between the metal cap and pin, thus they are not visible from outside. The experience has shown that ageing processes can cause these defects, which can be a puncture (Figure 11.5 - right) or cement growth. Such defects can cause a significant reduction in the mechanical and electrical strength of the units affected. Furthermore, pre-arcs, e.g. initiated by pollution or lightning or switching surge, travelling externally along sound insulators in the string will be transferred as internal fault/short-circuit into defective units. This can cause thermal stresses separating the porcelain from the hardware, resulting in an insulator failure and in the case of a single string a conductor drop. But also under normal voltage operation, a reduced life time can be anticipated for strings with punctured units as the remaining healthy units are subjected to higher electric stress. Investigations (Rawat and Gorur 2008) on the failure reasons have demonstrated that punctured insulators have a different micro structure in comparison to sound units. As major differences, defects in the porcelain micro structure were identified which were a higher porosity and a large number of micro cracks, the last caused by the presence of numerous large quartz crystals. Such inhomogeneities create a high electric field thus initiating and propagating the breakdown channel.

The various failure/ageing mechanisms of porcelain and glass cap and pin insulators result in different mechanical values when measuring the ultimate failing loads (Figure 11.6). The failure loads were normalized to their respective

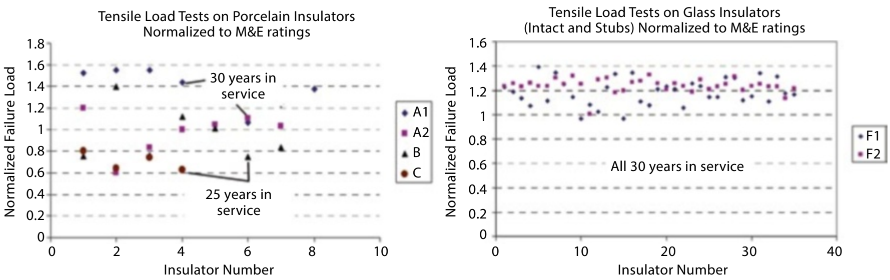


Figure 11.6 Normalized ultimate load of porcelain cap and pin insulators (*left*) and of glass cap and pin insulators (*right*) (Mishra et al. 2006).

nominal force ratings. For the porcelain cap and pin insulators, it was found that some units failed far below their ratings. In some cases the reduction in mechanical strength was almost 40 %, which is considered to be relevant for the string reliability. Furthermore, the high variability of failure loads indicates that different ageing stages are present. The results found for A2, B and C would call for replacement.

The first patent of porcelain longrod insulators is dated in year 1942 (Verschmutzungsarmer keramischer Langstab-Isolator 1942) and they have been widely utilized since the mid-fifties of the last century. Porcelain longrod insulators have been recognized to be superior because of their higher ultimate strength and the higher flexibility of shed designs to take pollution countermeasures into account. The reduced number of metal fittings was an additional advantage, because a porcelain longod is not punctureable. Power arc protection is required, if the network supplies sufficient energy to damage insulator sheds (Figure 11.7) or the shank in a fault situation. The product development has solved the problems of the early days, which were mainly characterized by (Frese and Pohlmann 1999):

- The material grade C-110 (quartz porcelain) could originate porous insulator cores with varying thermal expansion coefficient over the diameter of the rod. This was eliminated by the change to higher strength C-120 (alumina porcelain).
- Portland or sulphur cements were substituted by more ductile lead-antimony cementing to prevent stress enhancement in the interface between porcelain body and steel cap (since approximately 1972).
- Use of ultrasonic measurements for quality control (since 1957).
- Careful rounding of the cone end to avoid multiple-cone fractures (Figure 11.7 – right).
- Introduction of impact tests in mechanical routine testing.

The improvement of the porcelain longrod insulator technology is also reflected by comparative measurements on insulators, when being new and after a service time up to 35 years (Table 11.6). In 1999 the following failure rates were published for a particular network (Frese and Pohlmann 1999):

Figure 11.7 Power arc damage to porcelain longrod (*left*) (Cigré WG B2.21 2008) and cone breakage due to stress enhancement by non-rounded cone in the interface between porcelain and steel cap (*right*) (Cigré WG B2.03 2006).

Table 11.6 Ultimate tensile force in kN of porcelain longrods (Frese and Pohlmann 1999)

		Time in service in years				
Manufacturer	New state	20	25	30	35	Material composition
Modern type of porcelain composition made from 1964 to 1966						
A	243	221			225	Pure alumina
B	180	167			176	Quartz porcelain with some alumina
C	184	186			213	Pure alumina
D	183	161			150	Alumina with some quartz
E	183	178			159	Pure quartz porcelain
Old type of porcelain insulators made in 1959						
F	137	81	78	62		Pure quartz porcelain

- Modern type of longrod insulator: 1.14×10^{-6} annual failure rate (defined as failures divided by service years).
- Old type of longrod: $4.2\ldots8.3 \times 10^{-6}$.

In the year 1998, the question was addressed by utilities to Cigré WG B2.03, after what service period conventional insulators should be replaced. A general answer on such a request is not possible without the inspection of the respective network and the insulators installed there. This is due to the different damage modes described above as well as the various generations and possible quality variations of the early insulator vintages. For these reasons, the WG launched a test program, in which more than 1000 insulators of cap and pin as well as longrod types were investigated. The operating period of the longrod insulators lay between 29 and 45 years with an average of 37 years and for the cap and pin insulators between 11 and 39 years with an average of 25 years. The test description and presentation of results formed the content of the Cigré TB 306 (2006), which was published in 2006. Many tests were conducted, including electrical tests for porcelain cap and pin insulators as well as inspection/measurement of the insulator end fittings. This applies especially for cap and pin insulators, because often the pin became the weak part in tensile testing due to corrosion.

The mechanical testing was found to be of central importance. When ever it was possible, three test series were analyzed (Figure 11.8). The failing load of the insulators was measured in their status as received, after a thermo-mechanical test as standardized in IEC 60383-1 and the results compared with the measurement of new insulators, when these data were available. The results of Figure 11.8 serve as reference scenario and can be concluded as follows:

- All failing load lines are to the right of the SFL (Specified Failing Load).
- The individual measurements have normal dispersion.
- The insulators of this transmission line fulfil the standard requirements of all three measurements (erection of the line, as-received after × years of service and after the TMP-test).

An important empirically result was identified: If any of the SFL curves show a high scatter in particular after the TMP test, this can be an indicator for serious problems. It was recommended to perform re-testing either immediately or within a short period relatively to the actual age of the insulators. Such an example is shown in Figure 11.9: After the TMP test, the failure risk is about 35 % with a certain likelihood of further strength reduction, when temperature changes occur in service (damage accumulation). Worth to mention that the test campaign could unambiguously identify insulator vintages that exhibit a strength reduction due to the manufacturing/design fault as shown in Figure 11.7 (right).

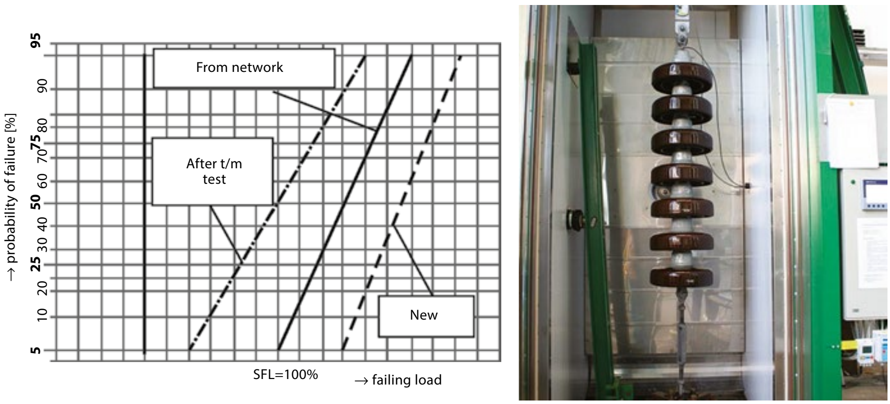


Figure 11.8 Failing load test analysis (*left*) and view into the test chamber of the thermo-mechanical performance test (TMP test) as per IEC 60383-1 (*right*) (Cigré WG B2.03 2006).

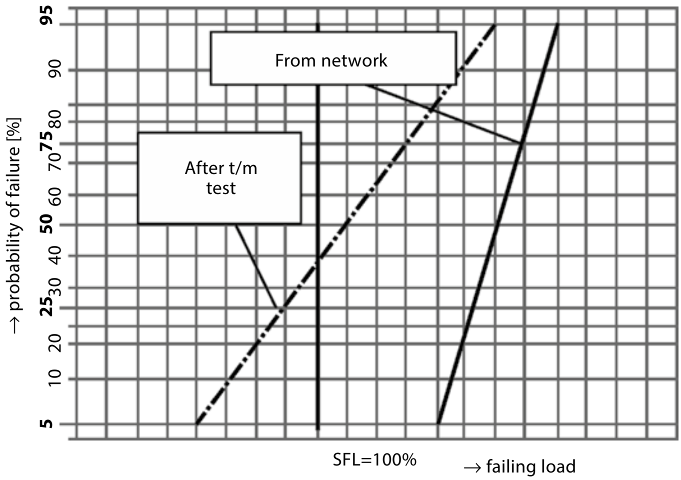


Figure 11.9 Failing load test analysis of an insulator vintage which suffered from ageing (Cigré WG B2.03 2006).

In the following, a brief summary of further Cigré documents is provided. In 1979, Cigré WG 03 of SC 22 published the results of a survey about the real conditions of use and the respective behaviour of conventional insulators (Cigré WG 22.03 1979). The purpose of the document was the exchange of service information among utilities and the identification of improvement potentials for manufacturer. The survey included 72 lines operated in 20 countries resulting in 6’270 km transmission line length covered with 72’400 insulator strings equipped with around 1.5 million insulators. It was found that in Western Europe most of the insulator strings were equipped with power arc protection devices on both ends meanwhile in Canada, USA and USSR not. An important aspect was identified in terms of safety factors: For normal in-situ conditions, average safety factors (related to the nominal tensile force) of 6…33 with minimum safety factors of 3.2…20 were calculated. For exceptional in-situ conditions, average safety factors (related to the nominal tensile force) of 3.5…10 with minimum safety factors of 1.6…9.1 were calculated. Taking into consideration that the on-top safety margin between nominal tensile force and ultimate failing load includes another 30…50 % to be added, the WG summarized that an optimisation of the design and choice of insulator types is appropriate. Also a change from risk of failure basing on factors to a probabilistic concept of safety was recommended. In 1981, a supplementing document was published about the information on insulator damages (Cigré WG 22.03 1981). A number of 48 reports were received, displaying 213 partial or full insulator failures. Their share was as follows that 39 reports to cap and pin insulators and 9 to porcelain long-rod insulators. The results can be summarized as shown in Table 11.7.

In year 1993, Cigré WG 03 of SC 33 published the results of a survey about field experiences with high mechanical performance insulators (Cigré WG 22.03 1993). Overall 54 replies were received from 20 countries and only insulators with a

Table 11.7 Failure rates of different conventional insulator types (Cigré WG 22.03 1981)

Country	Insulator type	Period of consideration	Failures	Insulator number considered	Failure rate	Remark
France	Glass cap and pin	1964-1973	23	34’939’000 (Insulators × years)	0.66×10^{-6}	No broken string since 25 years of record
Australia	Porcelain cap and pin	1964-1974	7	10’934’783 (Insulators × years)	0.64×10^{-6}	Different force classes covered
Sweden	Cap and pin made of porcelain (P) or glass (G)	1967-1971		Depending on the type: 9…61’754 (P) 30…21’511 (G)	0… 0.02 per 100 P-units inspected, 0…0.0012 per 100 G-units inspected	Inspection campaign to identify punctured units, oldest P-units were manufactured in 1914, oldest G-units in 1948
Germany	Porcelain longrod	1964-1974	5 (110 kV network)	7’577’404 (Insulators × years)	0.66×10^{-6}	
Austria			10 (110 kV network)	587’180 (Insulators × years)	17.3×10^{-6}	Failure due to inappropriate power arc protection
Switzerland			2 (110 kV network)	1’014’582 (Insulators × years)	1.85×10^{-6}	

nominal force rating > 200 kN were considered. The annual failing rates reported were up to 2 % for porcelain cap and pin, < $10^{-3}\ldots10^{-4}$ for glass cap and pin and < 10^{-6} for porcelain longrods.

An interesting survey was published by TF 33.04.02 in 1994 about the failure of cap and pin insulators installed in HVDC lines (Cigré TF 33.04.02 1994). Porcelain cap and pin insulators failed mostly by pin corrosion, when the sacrificial sleeve was made of a zinc alloy instead of pure zinc. Under heavy pollution, an additional coating of the pin by a polymer improved the performance. No failures by thermal runaway were found. In the case of glass cap and pin insulators, the minimisation of inhomogeneities and inclusions in the glass body as well as the increase of the glass bulk resistivity to 10^{17} Ωm, which is by two orders higher than for AC were found a key factors for a reliable operation. Further additional tests were proposed by IEC for cap and pin insulators to be used under HVDC (ion migration test, thermal runaway test, bulk resistance test etc.).

A study published in the UK in 1986 (Maddock et al. 1986) showed for porcelain cap and pin insulators from the 420 kV network and after a service time of 15…20 years, a failure rate of 2 % for suspension and 0.6 % for tension units. The failures were cracks in the porcelain body causing breakdown or high leakage current at few kV test voltage.

11.4.1.2 Composite Insulators

The various causes of insulator failures in the USA and their percentage of occurrence are shown in Figure 11.10 (EPRI Database 2011). By 2011, a total number of 315 failures had arisen for an estimated 3 million installations of composite insulator. This results in a cumulative failure rate of 0.0105 %. Under the arbitrary assumption that composite insulators are in service since 1981 and their number increased

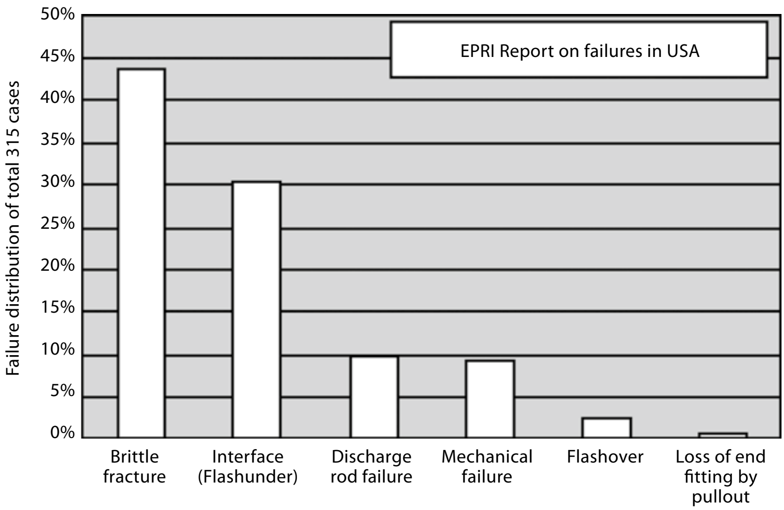


Figure 11.10 Causes of failure for composite insulators in the USA (EPRI Database 2011).

lineary in 30 years, a failure rate of 7×10^{-6} can be calculated. This number appears high in comparison to cap and pin (glass and porcelain) and porcelain longrod insulators, however three aspects have to be taken into consideration:

- The utilities in the USA were pioneering the introduction of composite insulators. Hence, the statistic also contains information about first-generation insulators, installed in the eighties, which were particularly prone to brittle fracture failure and to flashunder in the case of insufficient adhesion in the interface between rod and housing.
- The values of conventional insulators refer to individual units, thus a 420 kV single suspension string would be built of 21 cap and pin insulators or 3 porcelain longrod insulators. So, the failure rates of the individual units have to be multiplied correspondingly.
- Different failure criterions in terms of insulator replacement apply: Often, glass cap and pin insulators with a broken shed remain in the insulator string if a certain quantity is not exceeded. On the other hand, a composite insulator damaged in accordance with a criterion defining its end of life must be replaced quickly.

Brittle fractures are the main reason for failures and their typical appearance is shown in Figure 11.11. This situation has resulted in extensive analyses and researches (see also Section 11.4.3.2). As an internationally accepted state-of-the-art technology, glass fibres and impregnation methods that facilitate the production of electrically high-grade, acid-resistant rods were introduced. Today, the use of E-CR-fibres is a recognised standard for composite insulators that are subjected to permanent tensile loads (suspension and tension insulators). In this context, IEC 62662, published in 2010, can serve as a useful guide when assessing the risk of insulators, which belong to an older vintage equipped without acid-resistant rod. In this technical report of IEC, failure mode and effects analysis (FMEA) is used to assess those

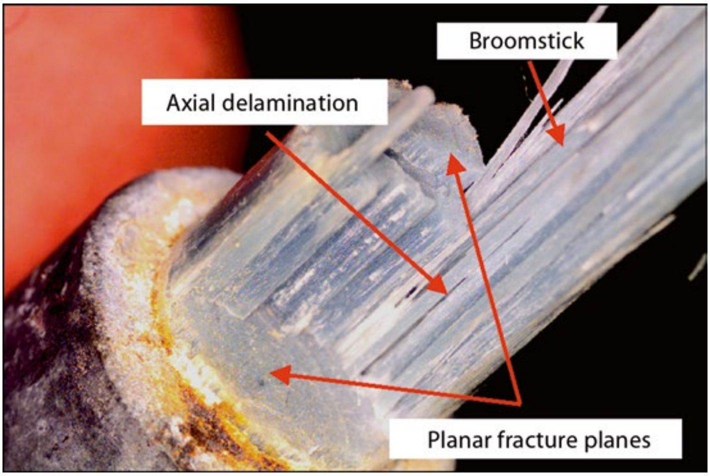


Figure 11.11 Visual appearance of a brittle fracture failure (Cigré WG B2.21 2013).

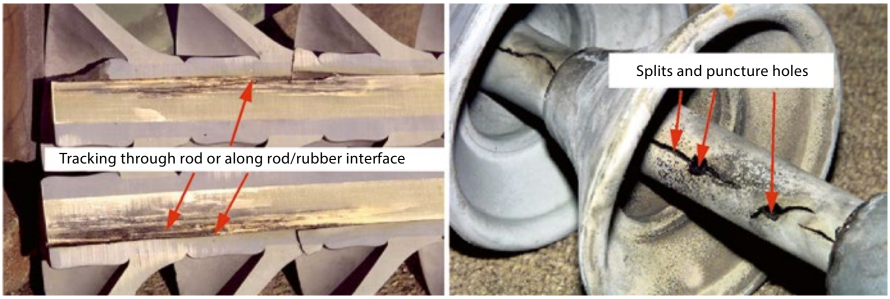


Figure 11.12 Two halves of a dissected composite insulator that has failed due to a flashunder (*left*) and the external appearance of such a failure mode (*right*) (Cigré WG B2.21 2013).

factors that make the entire insulator design or string design vulnerable to brittle fractures and provides quantitative figures for a risk estimation on basis of the overall insulator and string design.

The second most frequent failure is the flash-under, which is characterised by partial or full formation of conductive traces in the rod or the interface between rod and housing and partial punctures of the housing toward the atmosphere surrounding (Figure 11.12). Such failures can occur, when the rod is not "electrically graded" or when moisture can ingress in the interface between rod and housing.

Both failures are displayed because they are also the main causes of a Cigré survey, published in year 2000 by WG B2.03 (Cigré WG 22.03 2000a).

The questionnaire of the survey also enquired about the approximate time in service of the insulators under consideration and derived corresponding comparative figures. The index of service experience is calculated in such a way that the quantity of a particular type of insulator is multiplied by its service time and the values obtained are standardised to 1'000 insulators/year. The lower values from the first survey (Cigré WG 22.03 1990) are provided in brackets. To relate the figures shown, the three aspects mentioned in the beginning of this section apply here too.

The following survey from China provides an interesting supplement to the previously shown surveys, the information was taken from an article presented in 2011 (Zhicheng et al. 2011). An impressive number of composite insulators have been deployed in the Chinese electrification programmes. The total number was estimated to be approx. 2.2 million at the end of 2006. When compared with the root cause analysis performed by the Electric Power Research Institute (EPRI) (Figure 11.10), the percentage of failures caused by ageing or a brittle fracture is rather similar (Figure 11.13). This may be due to the fact that the EPRI analysis makes another differentiation in terms of failure causes and a brittle fracture caused by ageing is only recorded cumulatively. Furthermore, more stringent environmental rules apply in the USA. Therefore, the effect of ageing caused by industrial pollution is expected to become more significant in China. The percentage of faults resulting from a product defect is considered as a critical quality indicator. This is technically somehow in contradiction to the low percentage of failures caused by installation faults, which

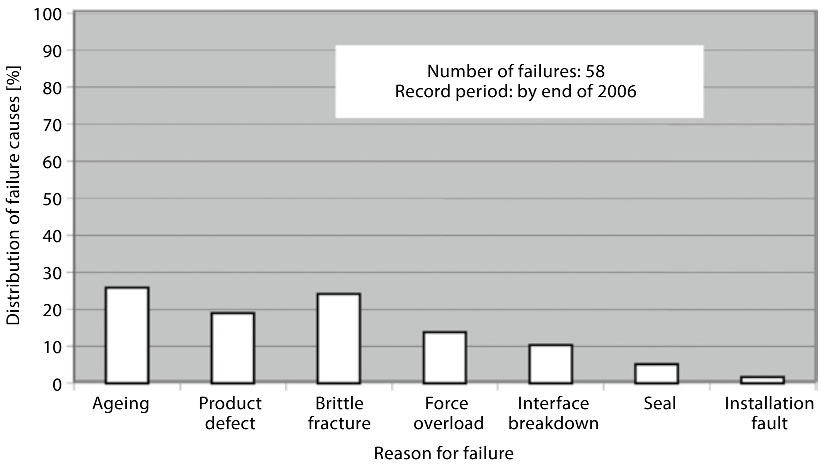


Figure 11.13 Failure causes of composite insulators reported from China (Zhicheng et al. 2011).

Table 11.8 Results of the Cigré survey (Cigré WG 22.03 2000a)

Analysis	Service voltage [kV]				Total
	<200	200…<300	300…<500	500	
No. of insulators recorded in the survey	456’835	174’482	59’446	1’413	692’176
Failures reported	105	28	107	3	243
Index of service experience k in 1000					
insulators × year (previous survey figures)	2’991 (160)	1’102 (42)	558 (81)	28 (9)	4’679
Failure rate related to insulator years	35×10^{-6}	25×10^{-6}	191×10^{-6}	107×10^{-6}	52×10^{-6}
Cumulative failure rate in %	0.023	0.016	0.18	0.21	0.035

can positively be attributed to the provision of appropriate training for the installation teams. Overall, the cumulative failure rate is 0.0026 %, which is substantially lower in comparison to the EPRI and Cigré studies. It should be noted that China started later with the composite insulator technology, thus the two other studies also include numerous first-generation composite insulators, which may have a higher potential for failure, because of design weakness of the early days (Table 11.8).

Is the composite insulator technology technically matured, are composite insulators reliable and safe? A critical analysis of composite insulator failures leads to following main reasons:

- Cost pressures become more and more the dominating factor,
- Inadequate specification for on-site conditions by the user, consultant or trader,

- Design errors by insulator or/and string manufacturer,
- Lack of knowledge,
- Commercially stimulated abdication of testing (design, type) in accordance to standards,
- Installation faults.

In view of the facts that in the meantime a level of standards is available for composite insulators, which is equivalent to conventional insulators and with test philosophies proven by service experiences, such problems are not caused by the technically matured composite insulator technique and the question above can be answered with a distinct **YES**, if fundamental technical rules are considered. Cigré TB 545 (2013) provides a respective statement that the reliability of today's generation of composite insulators, manufactured in accordance with the latest technology, including a tight quality control and traceability, is on par with that of ceramic insulators. It is important to mention that this level of reliability can only be reached, if the following is provided:

+ Correct Insulator and String Design

- Force rating and correct creepage distance in accordance with the in-situ conditions,
- Manufacture of housing materials with lasting hydrophobic effect and a high erosion and tracking resistance (typically Silicone Rubber with ATH filler),
- Use of E-CR-glass in terms of a low seed boron-free E-glass to prevent brittle fracture,
- Correct corona protection of the composite insulator set with consideration given to the water droplet corona phenomenon (Cigré WG B2.03 2005; IEEE Taskforce on Electric Fields and Composite Insulators 2008),
- Combined corona and power arc protection in terms of co-ordination, if determined by the network parameters (Cigré WG B2.21 2008),

+ Quality assurance including prove of insulator and string design:

- Only installation of design-tested and type-tested units, or units for which the performance can be interpolated from proven and existing designs.
- Established quality assurance system of the manufacturer e.g. ISO 9001: 2015.

+ Correct Handling and Installation on Site

The very general statement can be given: In the past and for their 1st and 2nd generations, the risk of a composite insulator failure was determined by a lack of knowledge in application and manufacture, limited service experience and the absence of product standards. Today, this information is available; thus many failures are mostly cost driven (see reasons mentioned above). Commercially it has been proven that the pay-back period (life-cycle cost) of composite insulators is often shorter in comparison to conventional insulators, especially when the latter have to be washed or coated.

11.4.2 Field Evaluation and in-service Diagnostic Methods

11.4.2.1 Test Stations and Reference Measurements

Cigré WG B2.03 published in 2007 a TB 333 entitled "Guide for the Establishment of naturally polluted Insulator Testing Stations" (Cigré WG B2.03 2007). The aim of this document is to serve as a general guide for the establishment of natural test stations, facilitating the overall comparison of various insulator designs, the exploration of particular aspects of insulator performance and/or the selection of the most appropriate insulation for a particular application. The guide was authored largely based on practical experience with test stations in South Africa, in particular the Koeberg test station, which was commissioned in 1974. In view of this, the guide relates specifically to insulators intended for AC applications, however general aspects are applicable to DC stations as well. High voltage outdoor insulators are important components of electrical transmission and distribution networks, despite their commercial value is only in the order of up 5 % of erection costs of a transmission line. The selection of the correct insulator type is thus most decisive to ensure a secure supply of energy. With the introduction of the composite insulator technology, the aspects of testing of insulators in order to identify those designs and materials which will provide satisfactory long-term performance for a particular application became more challenging. Regardless a high level of standardization to qualify composite insulators, the combination of many variable environmental in-situ parameters is practically impossible to artificially simulate and, moreover, to accelerate. For critical in the sense of special applications (for example special pollution), the complement of laboratory test results by outdoor tests is desirable (IEEE Taskforce on Electric Fields and Composite Insulators 2008). In view of the above, the evaluation of insulator performance in naturally polluted outdoor test stations is becoming an attractive technical approach. In comparison to laboratory ageing tests, a longer test duration is typical and the correct interpretation of the results requires the consideration of test data, which should be gathered in a way to describe the environmental and stress conditions comprehensively. In this respect, it has been approved that a combination of simultaneous measurements of electrical and meteorological data is successful.

The typical aims of an outdoor test station can be one or more of the following:

- Simultaneous comparison the performance of insulators of different designs, which includes housing profile and housing materials and from different manufacturers,
- Verification of dimensional rules of insulators for a particular environment or application,
- Identification of possible weaknesses or failure mechanisms of an insulator design,
- Estimation of the life expectancy of various insulators,
- Qualification test for potential suppliers (Important note: If an insulator passes the test, its material properties should be described by fingerprint methods as reference),
- Investigation of mitigation measures of conventional insulators such as washing, greasing, silicone rubber coating, shed extenders, etc.

Figure 11.14 Permanent insulator research stations at Koeberg and Sasolburg, South Africa (Cigré WG B2.03 2007).

Figure 11.15 Test tower (*left*) and example of a mobile test station (*right*) installed close to the sea for acceleration purposes (Cigré WG B2.03 2007).

A clear rule has been proven to be valid: When insulators are tested for qualification as approved supplier, the standard design tests of the applicable product standards have to be passed first. Test stations can be permanent tests stations for research and product qualification purposes (Figure 11.14), online-stations, in-service test structures such as test towers or mobile test stations (Figure 11.15).

Often the question is raised whether the results from different test stations could be compared for one particular insulator specimen. This can be complicated because of the potentially significant differences in the climatic conditions, pollution types and sources to which the test specimens are exposed, the different voltage sources and measuring equipment. To make results comparable, some standardization of the measurement techniques and philosophies is helpful. In this regard, the following recommendations can be provided:

- The assessment and definition of the pollution severity needs to be equal at all stations to be compared. For example, insulators with inert surface such as identical glass discs and porcelain longrods should be used for ESDD and NSDD measurements. These reference strings can have 25 mm/kV (related to U_m) specific creepage distance and/or 31 mm/kV for heavily polluted sites.

- The use of directional dust deposit gauges can assist in the description of the test site severity. Details can be found in IEC 60815-1.
- In addition to any other current measurements made, the absolute value of the maximum peak amplitude of the leakage current on each test specimen should be logged for each 10 minute interval. This easily accessible value can serve as a basic comparison of insulator performance and should be foreseen for the reference strings as well.
- Meteorological data simultaneously measured to the leakage current must include the average relative humidity, average wind speed and accumulated rainfall for each 10 minute interval. Wind measurements should be taken at a height of 10 meters.
- Visual inspection reports, including detailed images, describing the state of the insulators should be prepared every three months.

11.4.2.2 In-service Diagnostic Methods

The overall inspection and assessment of transmission lines, which includes insulators, insulator sets, conductors, dampers as well as towers, foundations etc., are well established philosophies in terms of line maintenance. Cigré WG 22.03 and B2.21 published two documents on this topic, in 1996 an ELECTRA paper entitled "Review of "In-service diagnostic Testing" of Composite Insulators" (Cigré WG 22.03 1996a) and in 2013 the Cigré TB 545 "Assessment of inservice Composite Insulators by using Diagnostic Tools" (Cigré WG B2.21 2013). Cigré TB is an updating analysis of the situation seventeen years after the publication of the ELECTRA paper and the experiences of both utilities and laboratories worldwide were taken into consideration. It can be shown that the diagnostic tools that were first introduced in the 1990's have been further developed and that if correctly used, these tools can provide sufficient information to evaluate the status of an insulator (conventional and composite). Aspects of Live Line Work (LLW) were covered by examples, on how the diagnostic tools can be employed for the determination of critical electrical or mechanical defects to identify potential risks of insulators. Cigré TB 545 refers also to the Cigré TB 481 "Guide for the Assessment of Composite Insulators in the Laboratory after their Removal from Service" (Cigré WG B2.21 2011), because in the latter damages of composite insulators are shown as visual reference to catalogue ageing effects also in terms of their risk. A clear statement can be given that there is definitive no individual "best" diagnostic tool and method, often a combination of different tools and methods has given good practices and experiences and this philosophy has been successfully implemented across the electrical industry. The principles behind the tools or procedures can be displayed as follows:

- Visual inspection and hydrophobicity assessment,
- Infrared (IR) thermography,
- Ultra-violet (UV) detection,
- Combined IR- and UV-measurements (Multicam)
- E-field measurements,
- High frequency high voltage measurement tool (new principle).

Visual inspection and IR/UV methods can be used both from the ground and from the air. Usually a classical helicopter is used for aerial inspections; recently many small remote-controlled devices such as mini-helicopters, drones or airships were tested. Despite the fact that the basic diagnostic technique principles are rather similar as in (Cigré WG 22.03 1996a), improvements like new, easy-to-use camera systems, have been introduced, making diagnostics less sophisticated today. Furthermore, R&D activities have created references resulting in better methods for the interpretation of the measurements, which was a bottleneck in the past.

Acoustic emission is not anymore or only very limited used under laboratory conditions and for this reason, it does not receive further consideration as diagnostic principle.

In terms of pollution, advanced pollution diagnostic using antennas or sensors or even using satellite records are considered to be still in the R&D state. They were not selected as part of Cigré TB 545, because being a status description of the external surface of the insulator housing, which is visually easily to inspect.

From the principles, especially UV and IR have shown their potential to serve as tools not only used to inspect insulators but to assess the range of line components, which are under high voltage.

In some countries, an important issue limits a wider application of composite insulators especially for higher transmission voltage levels: It is the challenge to assess their conditions in service and especially before the application of LLW techniques for the replacement or repair of insulators, insulator strings or dampers or to repair the conductor. In particular, LLW on overhead lines equipped with composite insulators was only recently introduced in IEC 61472, in its Ed. 3 published in 2013 (IEC 61472 Ed. 3 2013).

In the following, the principles are briefly described. *Visual inspection including hydrophobicity assessment* is presently the most commonly used inspection technique. It can be employed remotely from a long distance as well as through close-up visual inspections. Binoculars or telescopes are used to perform remote visual inspections. A number of practical guides for visual inspection are available from Cigré, EPRI and STRI (Swedish Transmission Research Institute). The guides typically include detailed descriptions of different types of possible defects with carefully selected colour photographic examples, enabling field personnel to quickly locate the photograph(s) and definition(s) of interest with respect to insulator deterioration and/or damages (see also Cigré TB 481). In particular, it is important to define the seriousness or criticalness of a damage/defect, thus enabling required actions to be taken. For a defect classification prior LLW, a more simple inspection approach is applicable as only conductive (see as example Figure 11.12) or semi-conductive defects are recognised as being critical. This assumption is valid for the well-agreed rule that LLW is only permitted under dry weather conditions. While visual inspection allows most of the outside defects to be detected, internal defects, which might lead to flashunder, cannot be observed. Furthermore, visual inspection can generally provide qualitative indication of further damages, which can be better quantified using the other diagnostic methods examined in the following sections. While inspecting the insulator, it is worth evaluating its "global"

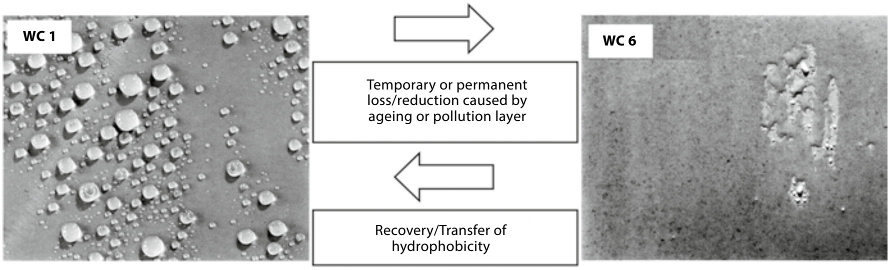


Figure 11.16 Examples of reference photos of the wettability classes and direction of dynamic behaviour of hydrophobicity change.

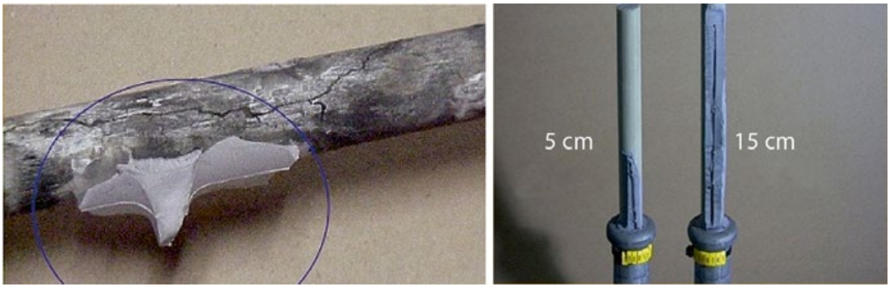


Figure 11.17 Examples of internal defects investigated - *left*: tracking mark and *right*: channel with low conductive but high permittivity moisture (Cigré WG B2.21 2013).

hydrophobicity. This applies only if the housing material is classified as hydrophobic and in the case of a polluted surface, it exhibits the property of hydrophobicity transfer such as silicone rubber. The spraying method (IEC 62073 (IEC TS 62073 Ed. 2 2016), Method C) has proven to be a simple applicable test; reference photos (Figure 11.16) are used to determine the wettability class (WC 1-7) in this standard. After spraying, the surface wetting is qualitatively compared. The reference photos are based on a hydrophobicity classification guide, which was introduced by STRI in 1992. A loss of hydrophobicity is not necessarily a sign of a severe damage, however if unevenly distributed it can be an indicator for frequent corona activity and associated internal interface or rod damages.

The *infrared (IR) thermography* detects the thermal emission of a local heating. This means for a defective insulator that a current is flowing along a faulty part of the insulator, characterised by relatively high conductivity in comparison to the intact neighbouring insulating material. Example would be in the presence of tracking or other semi-conductive paths as shown in Figure 11.12 and Figure 11.17.

The development of compact cameras, characterized by high sensitivity and excellent field handling has provided a fast and reliable tool to inspect the insulators. An example of defect detection by IR is shown in Figure 11.18. The method is particularly sensitive to defects developing between the housing and the core,

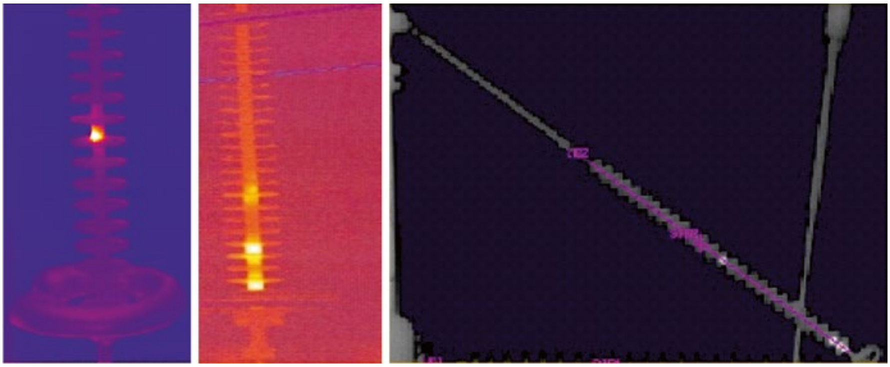


Figure 11.18 Examples of clear IR detection of internal conductive defects, from left-to-right: in laboratory; at test station; in service (Cigré WG B2.21 2013).

leading possibly to a flashunder. In this case, the fault current is ohmic and passing through the defective zone causing a significant temperature increase. The effect can be found when the tracking affects large parts of the insulator or when sufficient conductivity is present along the insulator axis. This could be by moisture ingress in the interface or by full wetting (WC 6 or 7 in Figure 11.16) of insulator parts that is not yet damaged. A distinct limitation must be mentioned for the IR measurements - they are not suitable to detect conductive or semi-conductive defects developing on only a small section of the insulator while its remaining part are still healthy and characterised by high resistivity. This is especially true if the measurements are made in low humidity conditions. In such a situation, corona is more likely to occur on the tip of the defect. Because corona is more associated with capacitive couplings, very low ohmic current are expected, thus leading to a very limited temperature increase that is hardly detectable in service. So, corona measurements are also an important principle, as discussed in the following.

For the *ultraviolet (UV) detection*, different techniques are available for day and night measurements. In daylight conditions, the localisation of corona activity constitutes an interesting technical challenge, because of the other UV sources. Thus, for daylight corona cameras, the diagnostic indicator considered is the emission generated by the defects in the UVc range (i. e. with wavelength in the range 240 … 280 nm), because at this bandwidth the solar light is filtered by the atmosphere (Figure 11.19 left).

The corona appears as clouds or blobs in the camera (Figure 11.19 – right (Papailiou and Schmuck 2012)). The corona emission intensity is difficult to calculate by using the number of pulses of light emission, because of the influence of the gain adjustments and environmental conditions. Furthermore, the intensity of corona cannot be directly related to the severity of damage but the position and source of corona can be identified unambiguously. Some utilities apply a day inspection, followed by a night vision inspection on those corona positions identified as critical to gather information that is more detailed. Specialists or training is

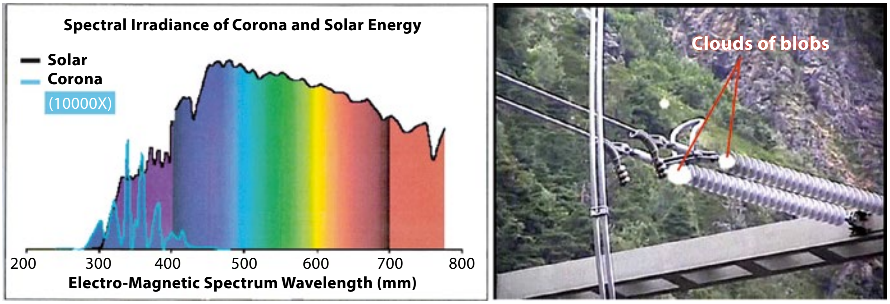


Figure 11.19 Bandwidth used by daylight corona cameras (*left*) and the appearance of corona as camera image (*right*), measurement on a 245 kV tension string without correct corona protection.

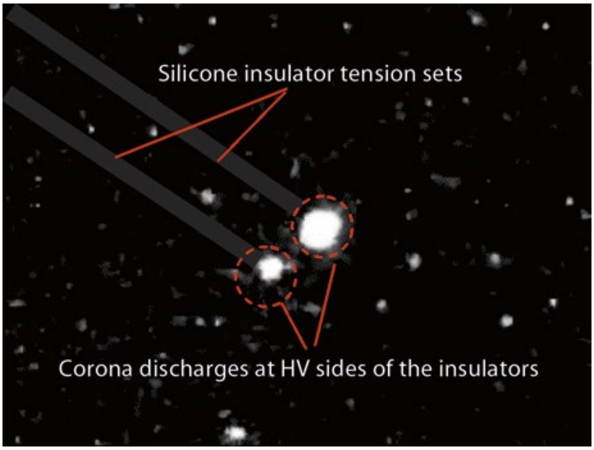


Figure 11.20 Example of a night vision measurement (525 kV tension insulators without correct corona protection at the high voltage end fittings (Papailiou and Schmuck 2012)).

recommended to interpret the results correctly. The example of a night vision measurement is shown in Figure 11.20. This type of camera works on the principle of image intensification and is configured to receive a mixture of wavelengths in-between 230 … 450 nm that are typical for corona discharges. For this reason, measurements can only be taken in darkness (see also the situation at daylight described in Figure 11.19 – left).

In the meantime, very portable cameras became available, which are developed as combined "*multi-cameras*". They can provide UV, IR and visual observations with one instrument. This particular type of camera consists of three different detector paths each having its own unique set of filters and lenses. As the ultraviolet image (daylight concept) reveals only the active sources of corona, it has to be projected onto the visual image in order to determine its geometrical location. This overlay is achieved by aligning the optical axes of the ultraviolet and visible channels to one optical centre line. The two fields of views are identical. Although a similar optical alignment concept was considered for the IR channel, it has not been

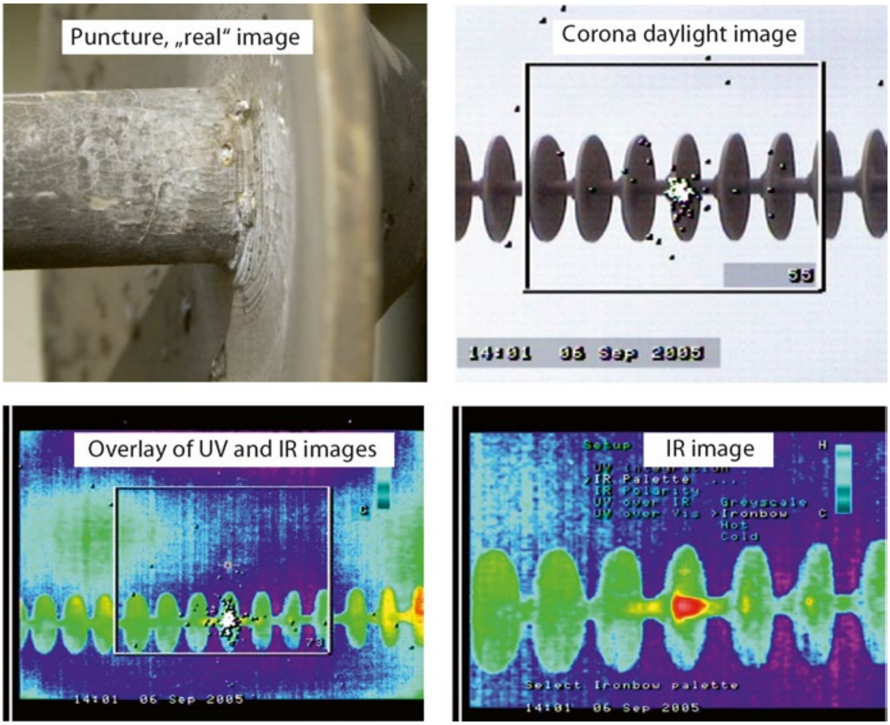


Figure 11.21 Multi-cam images taken of a composite insulator with puncture damage (Cigré WG B2.21 2013).

executed in the current camera generation for reasons of performance and manufacturing cost. It is also not required for the image recognition as the IR image radiates sufficient energy to form a recognisable scene. However, it is possible for scene recordings at an infinite distance to overlay the corona discharge image onto the infrared image.

An example of a successful fault identification is shown in Figure 11.21. The photos exhibit a good correlation between the IR image of heating that occurred as a result of the damage (leakage current flow), and the UV discharges; i. e. both of these displayed in the exact area of damage occurrence. The development of the multi-cam principle is an interesting tool for damage diagnosis that takes the different failure modes and as a result of, corona or heat into consideration. However, the sensitiveness of specialist corona (especially night vision cameras) or IR cameras was not the purpose to be achieved. The use of the multicam for diagnostics offers new ways of result interpretation by only one measurement. A simplified matrix was introduced by Cigré WG B2.21 and is shown in Figure 11.22. A high corona activity (left top) can be easily identified on metallic parts that have a sharp contour. This can happen by design faults or as a result of a power arc, when melting of steel parts establish an undesirable corona source. Such corona discharges are typically

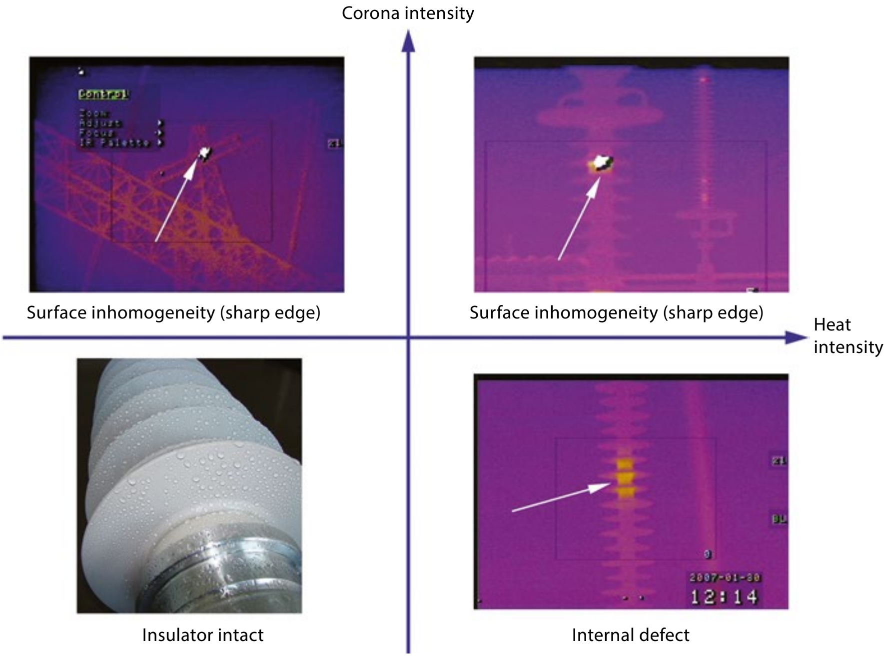


Figure 11.22 Possible matrix for failure mode interpretation of multi-cam measurements (Cigré WG B2.21 2013).

accompanied by low heat generation. In contrast to this scenario, the occurrence of dry band arcing (right top) causes both corona and heat emission, because the dry band currents are in the range of a few mA. The most critical case is a conductive interface defect (right bottom). Due to its conductive nature, no sufficient voltage difference occurs to form an external partial discharge.

E-field (EF) measurements were intentionally developed in the past to inspect cap and pin insulators made of porcelain because of their puncture failure mode (see also Section 11.4.1.1). This measuring principle applies to composite insulators as well, if a composite insulator is electrically defective, the electric field changes in the vicinity of the defective area with a high likelihood. Thus, it was a logic development to adapt the basis version used for cap and pin insulators to a portable, in-service and manually-operated diagnostic EF probe for composite insulators. In the meantime, the diagnostic probe is commercially available, it has been tested in laboratory and in service to be technically suitable (Figure 11.23). The principle of operation is based on the measurement and recording of the axial electric field along the insulator generated by the power frequency voltage of the network.

The EF probe can easily be used by skilled personnel also prior LLW. Defects that generate a distortion of the EF (i. e. conductive or semi-conductive defects) can be detected by comparing the EF pattern (Figure 11.24) obtained on the defective

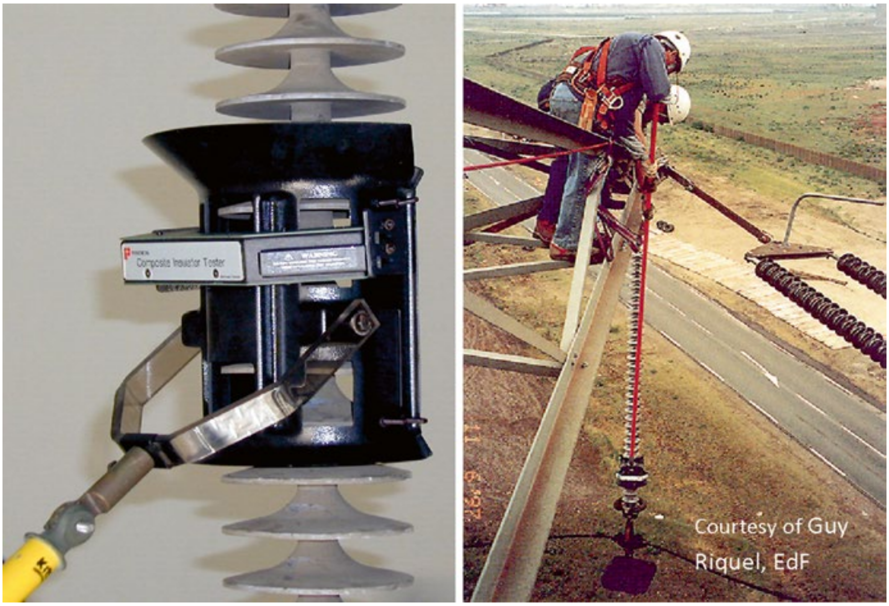


Figure 11.23 Diagnostic field probe developed for composite insulators used under laboratory and field conditions (Cigré WG B2.21 2013).

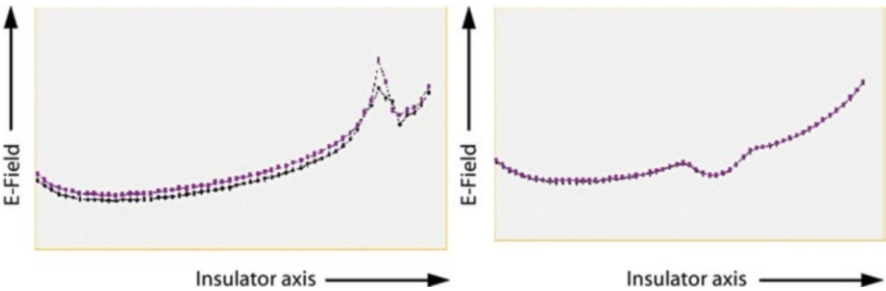


Figure 11.24 Laboratory examples of EF probe application on a 420 kV insulator - *left*: defect at the fitting; *right*: defect in the middle axis (Cigré WG B2.21 2013).

insulator with a reference fingerprint obtained on a sound insulator of the same type. Experience proved that the EF probe that provides an instantaneous GO/NOGO visual and audible indication of a defective composite insulator is a great aid.

Some empirical considerations on the EF probe measurements: Apart from being very sensitive, the advantage of the method lies on its ability to detect size and location of a defect. However, the method is quite demanding in terms of the time/cost and expertise required and thus it is not economical to scan an entire overhead line. It was identified as very effective measure to ensure the safety of LLW on insulators

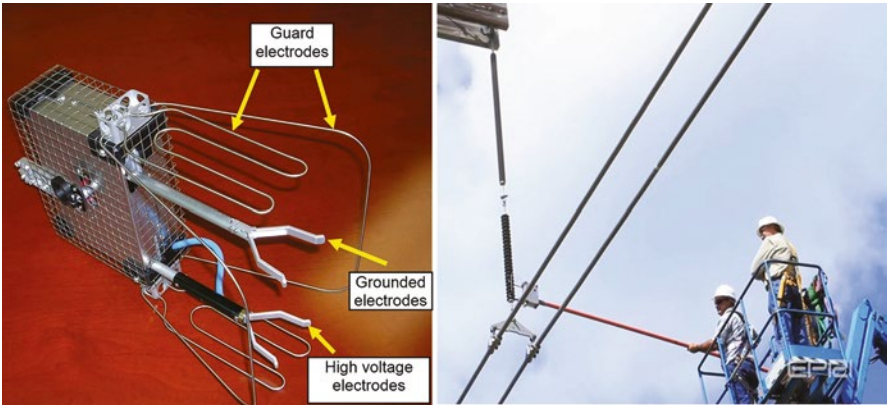


Figure 11.25 High frequency/high voltage tool showing high voltage electrode, grounded electrode and guard electrodes (*left*) and its use in a LLW situation (*right*) (Cigré WG B2.21 2013).

specifically installed in the spans subjected to LLW. A constrain was identified that the EF probe may not detect low severity level defects near the end fitting, especially when the electric field is shielded by a corona ring. Thus, this does not allow measurements closer than approximately 15 cm from the end fitting with corona rings. Also, the atmospheric humidity during EF probe measurements must be recorded, because it can be very influential. If an insulator is covered by a hygroscopic pollution layer, this situation must be taken into consideration when taking the reference measurement and analysing the results. Otherwise a misinterpretation of the results is possible causing a replacement campaign, which would not be needed as a result of EF measurements performed under dry conditions.

The principle of a *probe* that brings its own *high frequency and high voltage field* along is a current development of EPRI. The tool is applied to the insulator using a hotstick and has two spring-loaded electrodes separated by approximately six inches (152 mm – adjustable depending on the insulator design) as shown in Figure 11.25 (left).

The electrodes are pushed up against the sheath of the insulator, and a high frequency-high voltage is applied between the electrodes. The unit applies the voltage and start a measurement when the force applied back through the spring-loaded electrodes triggers this. The capacitive voltage coupled to a sensor imbedded in the grounded electrode is measured as well as the resonance frequency that the high voltage supply resonances at and the current loading in the high voltage supply. All of these values are analysed and the probe informs the user whether the six-inch section tested has any conductive, or semi-conductive, or high dielectric constant properties that would be an indicator for electrical compromising. One of the objectives of the tool is to provide the worker with a simple decision on a go/no go (green/red light) indication of the section of insulator being tested without requiring interpretation or accounting for differences between configurations, insulator designs and worksites. So far, prototypes of the tools are presently being tested by utilities in the United States, Canada and Australia. After these field trials, the tool is expected to be available commercially. Considerable effort has been made to make the tool light and field-rugged and successful testing up to 345 kV has been completed. At 500 kV the length of the hotstick results in high mechanical cantilever loads for the operator. In view of this, EPRI considers the development of a robot, which can take the tool as a payload together with other inspection technologies in near future.

11.4.3 Material Components of Composite Insulators

The basic idea of the composite insulator concept consists in the combination of different materials, which overtake different duties in the insulator function corresponding to their particular strength and properties (Figure 11.26). The insulator end fittings are typically made of metal, such as forged steel or aluminium. For line insulators, a high degree of standardisation has been achieved for the insulator end fittings with the objective of an easy substitution of existing conventional insulators by composite solutions. The glass fibre reinforced resin rod is responsible for bearing the mechanical loads, which can be tension, bending or compression, or a combination of all three, depending on the application and load scenarios. Materials for the housing are as manifold as the corresponding methods of manufacturing. However, there are unambiguous performance trends as a result of the existing

Figure 11.26 Material components and interfaces illustrated for a typical composite insulator.

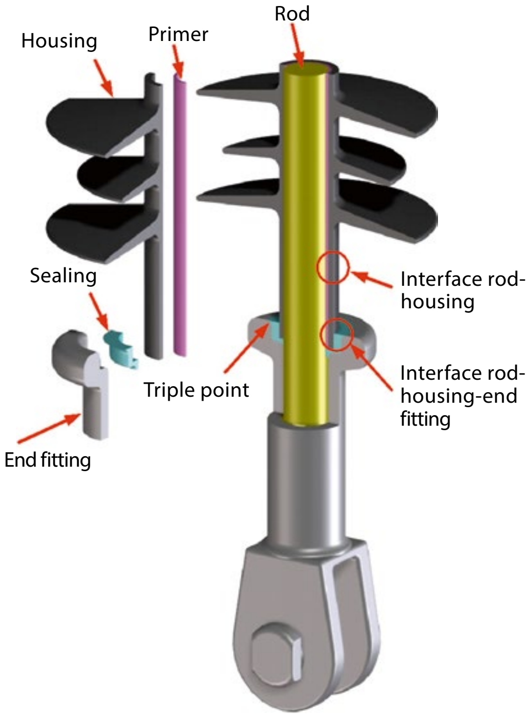


Figure 11.27 Insulator end fitting types.

service experience especially under harsh environmental conditions, which places a high ageing resistant Silicone Rubber with durable hydrophobic surface properties as housing material of the first choice. Main Silicone Rubber grades are: RTV-2 and LSR, which are two component liquid systems without ageing enhancement by aluminium trihydrate (ATH), and HTV, which is a high viscosity grade with ATH.

A distinctive characteristic of composite insulators is the many interface areas, which can be classified as microscopic or macroscopic interface. They need to be considered in accordance with the relevant applicable test philosophies in each case. Macroscopic interface areas form between the rod and the insulator housing or between the rod and the end fitting, for example, while microscopic interface areas form, for example, between the glass fibres, their sizes and the resin matrix when manufacturing rods or between the axial and radial vulcanising points when manufacturing the insulator housing. All of these interface areas are important for the reliable operation of a composite insulator. Special care is required for the sealing system, because this interface area forms often the so-named triple point, hence it can be subjected to high electrical stress.

11.4.3.1 Insulator End Fittings

Typical end fitting configurations are shown in Figure 11.27. Dimensions are in accordance with the applicable standards of IEC, intentionally introduced for conventional insulators in the past. IEC 60120, IEC 60471 or IEC 61466 as well as equivalent ANSI are today standardized up to 550 kN. The steel end fittings are hot dip galvanized and the galvanizing thickness follows the recommendations of IEC 60383. Enhanced thickness for heavily corrosive in-situ conditions such as desert, coastal areas, tunnels or DC applications can be provided on request. DC application can require an additional sacrificial sleeve made of pure zinc. Overall, there are no distinct Cigré activities for the component *insulator end fitting*.

11.4.3.2 Rod

The rod consists of glass-fibres which are impregnated by resin by one of the different processes deployed in the manufacture of rods for composite solid core insulators:

- Vertical impregnation while using the capillary effect,
- Special lay-in techniques,

- Pultrusion process,
- Combined pultrusion and winding process (pull-winding).

The pultrusion process is the most widely used process because it is economical and ensures high levels of productivity. Over the years of application, the pultrusion process has achieved a high degree of maturity and rods of high quality can be manufactured. This is also attributed to in-process developments such as partial vacuum impregnation, microwave heating, automated resin component dosing systems etc. For the behaviour of the finally assembled composite insulator, not only the intrinsic properties of the rod but also the complex interactions between the end fitting designs and crimp process are further key factors for the attainable ultimate failing load, its variation and the type of failure mode.

As impregnation carrier, the following thermosetting plastics, which are also available under generic names, are used as resin systems:

- Epoxy resin,
- Vinylester resin,
- Unsaturated polyester resin,
- Blends of the resin systems mentioned.

The choice of resin and its heat treatment have an important influence to mechanical and physical rod properties such as breaking strain and glass transition temperature (T_g). As example, if the co-ordination of the breaking strain is inaccurate and the value of the epoxy resin is lower than that of the glass fibre, the composite material behaves similar to a pure resin and fails prematurely; the tensile strength of the glass fibre is not used. The glass transition temperature in terms of a maximum temperature describes a threshold that when it is exceeded the rod becomes softened. In Cigré TB 255 and IEC 62039 - both defining minimum material requirements, based on practical experience and the physical mechanism of a glass transition, a safety margin of 15 K is defined between T_g and the maximum permitted, continuously operating temperature T_{max}. Today, a T_g range of 110…160 °C is introduced for composite insulator rods. The latter value is then beneficial in operational service if the insulator string/set design is not designed for power arc protection function (only corona protection) and the fault current of the power arc can flow over the insulator fitting (see also Figure 11.57).

For the processing of the housing, when high temperature vulcanising elastomers are used, a high T_g is advantageous for preventing rod deformation in the injection mould causing rod eccentricity.

The glass fibres as reinforcing material used rods are manufactured by pulling from the glass melt as individual glass filaments and, without any additional intermediate step (assembly), they are wound directly in parallel, without twisting, onto bobbins. This is known as "direct roving". Rovings used in rod manufacture can be differentiated by follows:

- Fibre diameters,
- Sizings (coatings with protective layers, or combined protective layers with adhesive agents),
- Tex numbers.
- Level of corrosion resistance.

The *fibre diameter* is reciprocally proportional to the breaking strain of the fibre and in general not only valid for the application of insulators, the (tensile) strength of a glass fibre structure is always higher in comparison to an equivalent solid glass structure. This is due to the following effects:

- When the fibre is pulled out from the glass melt, the outside of the fibre cools faster than the inside; internal stresses that occur in the fibre and increase its tensile strength must be overcome in addition to the fracture. This principle is also used in the manufacture of tempered glass, named "toughened glass" for glass cap and pin insulators for example.
- Statistically, the glass fibre is accredited with a lower imperfection density, which also increases its tensile strength.
- If a crack occurs in a fibre, it does not propagate to adjacent fibres.

The *sizings* can have a complex chemistry and improve multifunctionally the rod manufacture by a protection against abrasion, enhanced sliding ability of the filaments in order to prevent crippling, a reduction in electrostatic charges, an improved spreading behaviour of resin on the fibre surface during the impregnation process and a defined chemical bond between the resin matrix and glass fibre.

The *tex number* is a unit of measurement for the thread count and describes the length mass. So, a tex number 9'600 means a roving with a weight of 9.6 g/m. Tex numbers between 4'400 and 9'600 are rather common for rod pultrusion. For larger diameters so-named assembled rovings may be used to reduce the number of glass bobbins.

As shown in Section 11.4.1.2, the number of insulator failures by brittle fractures is high in the EPRI and Cigré surveys. Thus, the property of corrosion resistance of the glass fibre to acid, in particular, became an important property and the respective effects were extensively investigated (Cigré WG 22.03 1992c; Cigré WG B2.03 2004a, b; Armentrout et al. 2004; Kuhl 2001; Phillips et al. 2009; Kumosa et al. 2005a, b, c; Chughtai et al. 2004; Liang et al. 2000, 2010). A distinction is nowadays commonly used between two types of glass fibres, namely E-Glass, which was developed in 1938, and the more corrosion-resistant E-CR-Glass. Both names are of generic nature, which means they represent product lines having certain properties in common, but may nevertheless differ in details from manufacturer to manufacturer. At the start of the 1980's, an acid-resistant E-CR-Glass was patented under the name ECRGlas© (Patent US 000004199364A 1980; Owens/Corning Fiberglass 1991). Its glass composition was intentionally not introduced to improve the acid resistance of composite insulator rods but borne out of a commercial consideration whereby more stringent environmental regulations demanded a reduction in fluorine and boron emissions during the glass melting process. The availability of

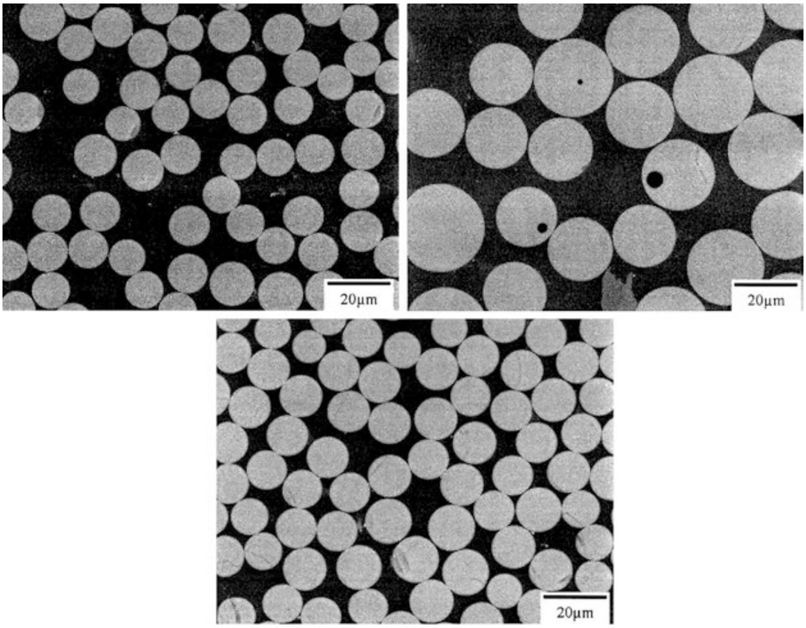


Figure 11.28 SEM exposure of E-Glass (*left*), of „normal" E-CR-Glass (*middle*) and of seed-free E-CR-Glass (*right*) (Armentrout et al. 2004).

ECRGlas© established a high ageing resistance within a pH range of ≤ 3; within the pH range 4–12, there is effectively no measurable differences between E-CR-Glass and E-Glass. Since measurements taken after corona or partial discharges have recorded pH values of 0, the use of corrosion-resistant glass fibres can reduce the risk of a brittle fracture occurring. In terms of product development, the E-CR-Glass from the early years had, when compared to E-Glass, a significant functional disadvantage: The modified composition with reduced fluorine and boron could show the phenomenon that increased quantities of non-dissolved gases accumulated in the melt. If, as a result of the melt viscosity, these gas bubbles did not reach the melt surface and then they were extracted in the spinnerets. As a negative result, the filaments could contain relatively long seeds. Respective images of scanning electron microscope (SEM) showing rods with different glass fibres are shown in Figure 11.28 (left and middle). The diameters of the E-CR-Glass fibres are greater and have hollow spaces (capillaries - seeds). Studies on rods that have an identical resin system, but either E-Glass or E-CR-Glass fibres with seeds, have shown that the dielectric strength is already reduced significantly without further stressing (e.g. immersion in water). This effect is intensified when capillary condensation occurs or when the rods is exposed to water.

The today's situation can be summarized as follows: Thanks to a rise in demand for E-CR-Glass fibres and a growing market acceptance for composite insulators, the glass composition and glass melting processes were further optimised and today,

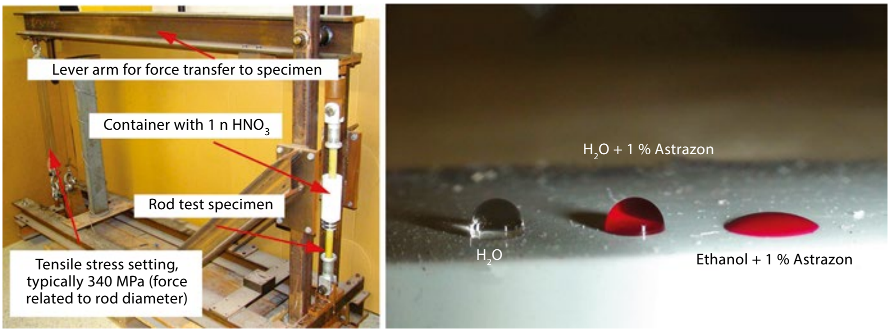


Figure 11.29 Classical brittle fracture test whereby an acid attack and tensile load occur simultaneously (*left* (Papailiou ad Schmuck 2012)) and principle of different spreading behaviour of the test solution components in the dye penetration test (*right* (Cigré WG B2.21 2010)).

it is possible to manufacture corrosion-resistant glass fibres with a very low seed count. Such glass fibres are also known as boron-free low-seed E-Glass fibres. Figure 11.29 (right) shows an example for and they are considered as the technical state-of-the-art. In terms of testing, the manufacturer and user of composite insulators can refer to well accepted and long-term proven test methods (Figure 11.29), which are an acid withstand test as per Cigré TB 255/IEC 62039 and a test for the diagnosis of seeds as per IEC 62217. Both tests are easy to perform and are used as quality assurance test during manufacture as well.

Very much of importance: Brittle fractures are often caused by poor insulator string design of certain manufacturers especially in terms of permanent corona (see also Section 11.4.4.2), hence, a certain degree of uncertainty has arisen on this subject. As mentioned above, assistance can be provided in such cases by the recently published IEC 62662, which uses failure mode and effects analysis (FMEA) to describe influencing parameters that are relevant for brittle fracturing of insulators, and can provide support during a risk assessment.

Some important progress in the understanding of the solely mechanical failure mode of composite insulators was achieved and found the way into the current product standard. This can be summarized as follows: In the first edition of IEC 61109 (1992), three tests were defined to ascertain the mechanical strength of composite insulators. It is also noted that the tensile strength of composite insulators decreases over time; this decrease can be assumed to be linear with the duration of load application. This is shown in a graph by the straight line *a* in Figure 11.30 (left). The value F_{Br} represents the average failing load of three test specimens established in an ultimate tensile test (performed as 1 min test). The standard also requires that the slope of the straight line *a* must not exceed 8 % per decade. This is to be checked by a 96 h test of further three test specimens at a value of 60 % of the average failing load F_{Br} previously determined. The term specified mechanical load (SML) has been also introduced in the standard. It is defined as the load which, after a 96 h test at 70 % of the specified mechanical load of the insulator (specified by the manufacturer), is retained in a subsequent 1 min tensile test, and is to be determined in the

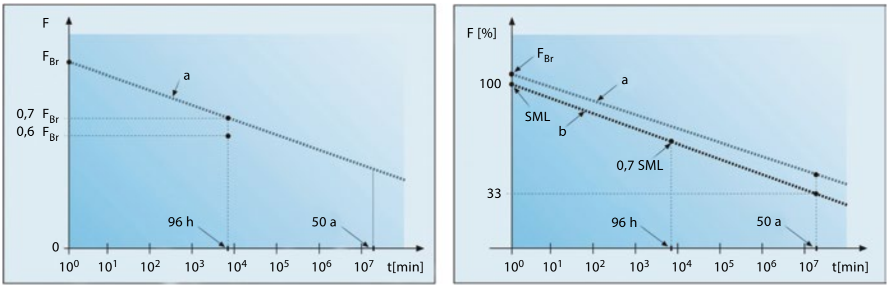


Figure 11.30 Determining of the load-time curve “a” of a composite insulator (*left*) and its specified mechanical load (SML - *right*) according to the first edition of IEC 61109.

type test (Figure 11.30 - right). The SML is the nominal load of a composite insulator and commonly understood as withstand load. Thus, there must be a safety margin to the lowest ultimate failing load, which is not determined in the standard, however a safety margin value of 20 % is well introduced. Lastly, a routine test named routine mechanical load (RML) is provided, which is at least 50 % of the specified mechanical load and it has be applied to all insulators prior to delivery. Due to the relative novelty of the composite insulator technology during the creation of the first edition of IEC 61109, the depiction of Figure 11.30 in terms of the expected mechanical long-term behaviour of composite insulators was misleading, irritated users and often led to redundant over-dimensioning. The uncertainty of the real behaviour was caused by two reasons of interpretation:

- Firstly, the linear fall of the withstand load curve in the standard implies that the failing load of a composite insulator decreases continuously over time. It ignores that such a behaviour would only occur and be describable by this curve, when the insulator is loaded continuously by a high specific tensile load (fairly above the every day stress).
- Secondly, the undefined linear fall of the curve suggests that the tensile strength of a composite insulator would fall practically to zero after a finite, even if rather long, operational period. It opened the door for an absurd interpretation that a composite insulator which has been stored without any mechanical force would fall into pieces at some point in the future.

Quite some work was spent in the experimental and physical considerations to correct this view, by the introduction of a mechanical model for the long-term behaviour of composite insulators subjected to tensile loads, as detailed hereinafter.

The mechanical behaviour, and in particular the time-dependent failure mechanism, of an FRP rod subjected to continued tensile load can be explained qualitatively as follows: Since the resin matrix of the rod should have a higher breaking strain than the glass, it can “stretch” considerably, but in contrast the glass fibres are hardly able to undergo plastic deformation (brittle material – breaking strain 2.2…4.8 %). Thus, the load is taken over practically completely by the glass fibres

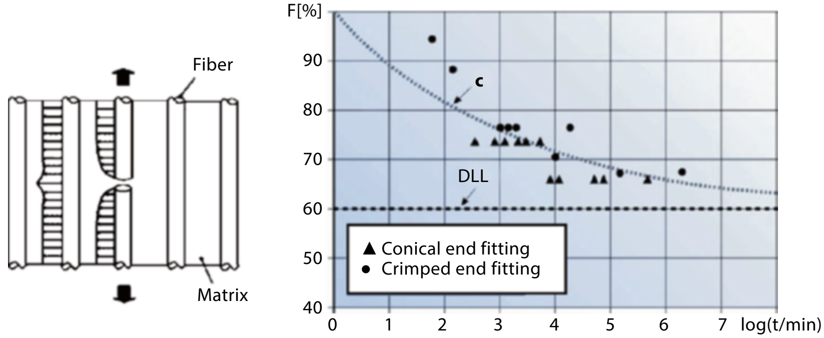


Figure 11.31 Simplified model of load transfer processes in the fibres of an FRP rod under axial load (*left*) and IREQ test results of static long-term behaviour of insulators from various manufacturers (*right*) (de Tourreil et al. 1988).

more or less immediately after application of the external tensile load. But, it must be taken into account that the properties of the individual glass fibres vary widely in a random manner. There are approximately 800’000 individual glass fibres in the cross-section of an FRP rod of 16 mm diameter. And they cannot have the same individual tensile strengths. Additionally, the individual fibre cross-section A_F, and to a certain extent the modulus of elasticity E of the fibres also vary from fibre to fibre. So the tensile load applied to the FRP rod thus being distributed over the individual fibres in accordance with the tensile stiffnesses DS of said fibres ($DS = E \times A_F$). That means the greater the stiffness of a fibre, the more load it must bear, and since the tensile strength of an individual fibre is subject to a certain level of random scattering, some weaker glass fibres will break. The time-dependent failure mechanism of the FRP rod, which is particularly interesting in this instance, is based on the load transfer from the broken fibres to adjacent fibres (see model in Figure 11.31 - left).

The simplified model considers as follows:

- When a glass fibre breaks at a certain load, the resin matrix enveloping the glass fibre distributes the axial load to the cylindrical surfaces to the left and to the right of the breaking point by shear stress. The break therefore going “unnoticed” at said cylindrical surface from a certain distance from the area of the break.
- Secondly, the matrix transfers the original load from the broken fibre to the healthy adjacent fibres, which are thus loaded increasingly, which in turn results in these adjacent fibres being stressed to a greater extent as before.

However, since the adhesion between glass fibres and resin matrix is subject to relaxation, this leads to a decrease in the “load transfer capability” of the fibre matrix composite over time, especially as the interface between fibre and resin matrix is loaded. The load which could still be borne by the broken fibres is increasingly transferred completely to the healthy fibres, which will also fail by the same mechanism after a certain period of time until all fibres, and therefore the FRP rod, have broken. It makes sense that the higher the load, the more fibres will break over a rather short period of time and the quicker the described relaxation processes will occur. But there is an important threshold named damage limit load (DLL) which describes, if the overall initial load lies below a certain limit, for example the limit value for the first fibre breakages, then hardly any fibres will break on the basis of this model, even if the load is applied to the insulator for an "infinite" period of time. Conservative estimations indicate that this damage limit load can be set at least at 50…60 % of the specified mechanical load. These considerations are only true for the failure mechanism of the rod, without consideration of the fitting and its attachment to the rod. This model was confirmed by a number of independent tests which showed that the permanent load curve of suitably designed composite insulators is not linear (Paris et al. 1994), contrary to the illustration in Figure 11.30 - right. As shown in Figure 11.31 (right), which displays the results of tests having been carried out by IREQ in the 1980's (de Tourreil et al. 1988), it can be seen that the measured curves fall relatively steeply at the start, but asymptotically approach a lower threshold value of the damage limit load after a relatively long period of time. This means that a composite insulator retains a significant proportion of its original failing load F_{Br} for an "infinite" period of time as mentioned before. In the case of these IREQ tests, F is the failing load normalised to the 1 min value, and t is the time until failure in minutes and the dashed straight line indicates the DLL (damage limit load) at 60 %. This theory has been confirmed by practical experience later on. De Tourreil (1994) reported for insulators which had been in operation for 12 years, no significant difference in the 1 min average failing loads (M_{av}) from the failing load of the same insulator family when being tested as new. Later results (Ammann et al. 2008) of mechanical tests on 132 kV and 400 kV insulators after more than 20 years in operation also confirmed these findings. The further understanding of the physical processes during tensile loading of composite insulators as well as the extensive tests and positive operational experience were taken into account, when the IEC 61109 was revised and its 2nd Edition published in 2008:

- A 96 h test as a design test to determine the "position" of the load-time curve of the insulator (value pair D1 and D2),
- A limit load test as a type test to establish the limit load once the insulator has been loaded for 96 h by a constant load of 0.7 SML (value pair T1 and T2) (Figure 11.32).

The design test establishes M_{av} and thus the starting point of the load-time curve of the insulator under consideration. This value marks with its 60 % value also the minimal limit load below which, according to the statements above, no mechanical damage to the insulator should occur (test at 0.60 M_{av} for 96 h).

Some more explanation on this choice of test parameters: Taking into account the practical capabilities of testing laboratories, the test period of 96 h was selected because it lies in the "middle" of the logarithmic time scale of 1 min to 50 years. The load was defined by 60 % M_{av} because, in the case of three test specimens which passed this 96 h test at $0.60 \times M_{av}$, there is a 90 % probability that the average failing

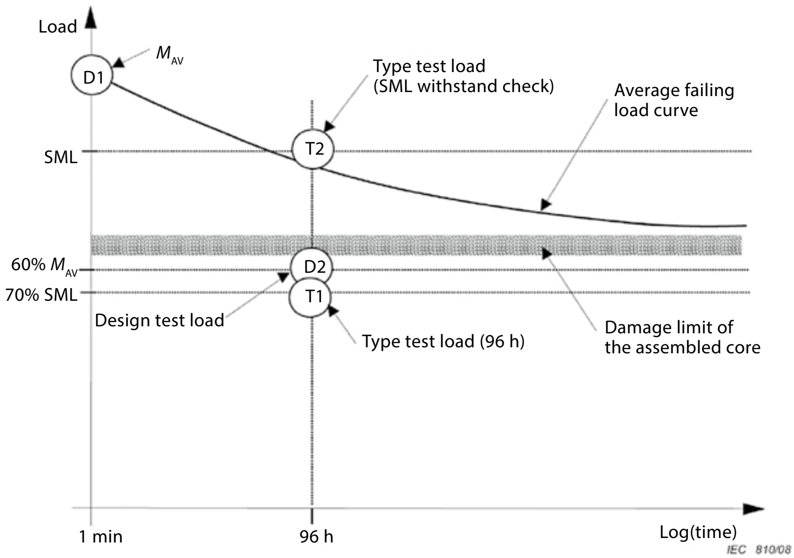


Figure 11.32 Relation of test loads in IEC 61109, Ed. 2, 2008.

load at 96 h will be at least $0.70 \times M_{av}$. This results from the assumed Gaussian distribution for three test specimens:

$$M_{96} - 1.82\ \sigma_M \tag{11.1}$$

where M_{96} is the average 96 h failing load and σ_M is the standard deviation.

If the rather conservative value for the standard deviation of $\sigma_M = 0.08$ is used, it follows that

$$0.7 \times M_{96}\ \left(1 - 1.82 \times 0.08\right) = 0.60 \times M_{av} \tag{11.2}$$

thus justifying the assumption of 0.60 M_{av}.

Some general application considerations: The rod manufacture by pultrusion permits the production of endless rods. In view of this, a rod length is today chosen in accordance to the insulator length of a particular project or the transportation logistics (length of container, stock area etc.). For the rod diameter there exists a direct correlation to the application. Insulators used as suspension or tension units are mainly designed for tensile loads. Typically, the crimp interface between insulator end fitting and rod is adjusted to be the predetermined failing point when the ultimate failing load is exceeded. The intrinsic tensile strength of the rod is only used to some extend. In the early days, relatively large rod diameters or low ratios between nominal force and rod diameter were dominating, which caused a higher fault redundancy. Under consideration of costs and the increased knowledge, nowadays typical relations between rod diameter and nominal forces exist as shown in Table 11.9.

Table 11.9 Rod diameter and typical related nominal force

Rod diameter in mm	Specified mechanical load in kN
16 … 18	70 … 160
24	210 … 320
32	500
50	1’000

For post applications, the rod diameter is determined by bending and compression force loadings. Such applications are for lines often used to realize compact appearances by means of single line posts or insulated cross arms. So far, rod diameters up to 130 mm are commercially available, larger diameters are under development. With this availability, rods have entered applications, which were technically solved by means of tubular solutions. So, post insulator solutions are in service up to 800 kV HVDC (Papailiou et al. 2010) and solutions for 765 kV insulated cross arms were successfully tested (Lakhapati et al. 2014).

11.4.3.3 Polymeric Housing

The kind of polymeric housings is as manifold as the number of publications. In the early days of product development, many materials were tried. In the meantime, the service experience and development of process technologies have acknowledged the importance of silicone rubber as generic material family. Since material properties can be adjusted in accordance to their operational relevance and their processability, the availability of corresponding test methods was very decisive also to verify new product developments in back-to-back tests with materials well proven in service since many years. In this context, IEC 62039, which was published in 2007 and basing on Cigré TB 255 from 2004, describes, for the very first time, key material properties and the minimum requirements for polymeric insulating materials for outdoor insulation systems. For convenience, the relevant properties and respective tests were excerpted for Table 11.10. The shown comparison is reduced to the properties of composite insulators, whereas the standard also describes the material properties of 1-component insulating, so-named structural systems. Twelve properties have been identified. Standardised test methods and minimum requirements where available for eight of them. For the remaining four properties, test methods and minimum requirements are under consideration of the further Cigré work.

The following considerations will mainly focus on silicone rubber, some statements apply to other elastomeric housing materials as well. The recipe of a housing material is determined by the desired outdoor performance and the process properties. From these prospects, the process pressure required to fill a mould cavity with the housing material of a certain viscosity becomes a dominating factor. In the case of solid silicone rubber (so-named HTV), “classic” processes known from the rubber industry are used, which, owing to the simultaneous presence of high pressure (up to 1’500 bar) and a high temperature (approx. 200 °C when manufacturing composite insulators). Because of the relatively high volumes of injected material, this technology is very challenging and requires detailed special knowledge. In the

Table 11.10 Material properties for composite insulators, minimum requirements for and respective test methods

Property	Minimum requirement: Housing material	Minimum requirement: Core	Standard	Remark
Resistance to erosion and tracking	1 A 3.5	-	IEC 60587 (2007)	
Resistance to ozone and corona	x	-	In progress	e.g., IEC 60343 (1991; Bi et al. 2013), but an evaluation of further influencing factors (elongation) is recommended.
Resistance to chemical and physical degradation by water	Immersion in boiling water for 100 hours followed by 1-minute voltage withstand test at 12 kV_{rms} (AC) without a breakdown or flashover, current during voltage test ≤ 1 mA		IEC 62217 (2012)	This test is called the water diffusion test and provides sufficient information about material suitability.
	Optionally, measurement of dissipation factor tan δ after 50 days of water immersion at 50 °C - threshold tan $\delta < 0.2$		IEC 60250 (1969)	This test gives additional information about possible ageing mechanisms.
Tear strength	>6 N/mm^2	-	ISO 34 (2010)	DIN 53504 (2009) is applied as well
Volume resistivity	> 10^{10} Ωm			IEC 60093 (1980)
Breakdown strength (electrical)	10 kV/mm		IEC 60243-1 (1998)	IEC 60243-3 (2001) for impulse voltage test
Resistance to chemical attack		96-hour test involving simultaneous mechanical (340 MPa) and chemical (1 N HNO_3) stresses without failure	IEC 62039	Only applicable for acid-resistant core material
Resistance to weathering and UV	x		IEC 62217 with reference to ISO 4892-2 (2010)	The second edition of IEC 62217 has only the stress with Xenon lamp radiation (ISO 4892-2).

(continued)

Table 11.10 (continued)

Property	Minimum requirement		Standard	Remark
	Housing material	Core		
Resistance to flammability	x		IEC 62217, with reference to IEC 60695-11-10 (2003)	V0, V1 or HB40-25 mm is to be proven depending on the application and nominal voltage; V0 is the highest class.
Arc resistance	>180 s		IEC 61621 (2003)	
Glass transition temperature		$T_g > T_{max} + 15$ K	IEC 61006 (2004)	T_{max} = maximum temperature in service
Resistance of hydrophobicity	x		In progress	Only for polymeric materials, which have permanent intrinsic and dynamic hydrophobic properties.
Transfer of hydrophobicity	x		In progress	

case of low viscosity silicone rubber (so-named LSR or RTV), more easy-to-use mix and dosing equipment is used in a low pressure process whereby the viscosity pre-defined by the equipment must not be exceeded.

This difference significantly determines the composition of the usable silicone rubber in terms of recipe for outdoor-relevant properties: While high pressure injection moulding machines can, with some adjustments, also process liquid silicone, it is not possible for mix and dosing equipment to process solid silicone rubber in low pressure processes. The addition of active fillers (e.g., the addition of ATH (Patent DE 2650363 C2 1976)) can significantly increase the ageing resistance of silicone rubber to thermal decomposition initiated as a result of thermal-ionised partial discharges such as pre-arcs (stabilised by a pollution layer) over dry zones. For the ATH quantity required, however, the resulting increase in viscosity can only be processed by high pressure injection moulding machines designed to process highly viscous materials from the outset.

In the literature (Cherney et al. 1999), a dual protective mechanism for silicone rubber has been introduced as result of laboratory and service experience, which is characterized by both hydrophobicity and a low propensity to form conductive tracking. If, however, there is a loss of hydrophobicity, and stable pre-arcs across dry bands occur, fed by the pollution layer and carrying currents in the mA range, thermal decomposition of silicone rubber may commence, which often has the pattern of damage associated with distinct bulk erosion. The respective decomposition products have a high SiO_2 content and form a brittle structure (Figure 11.33) that looses adhesion from the surface of the insulating material and easily detaches under

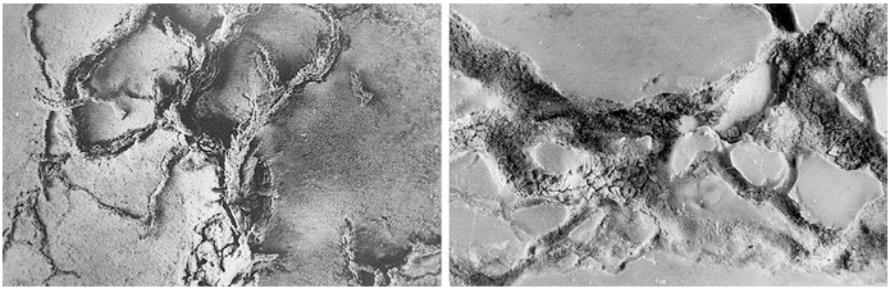


Figure 11.33 Decomposition products (*left*) on a silicone rubber surface (SR without ATH-filler) and damage pattern caused by bulk erosion (*right*) (Papailiou and Schmuck 2012).

mechanical force. The remaining "canyon" is not subject to any self-healing (as transfer of hydrophobicity can be seen) and can result in preferential adsorption of the pollution layer or, in the next humidification phase, in a pollution layer that is higher than on the surrounding smooth surface. In the worst case, both result in further cumulative damage; the bulk erosion worsens despite the low intrinsic conductivity of the direct decomposition products. Moreover, it is possible to expose the core material (rod, tube, etc.) whose surface is to be classified as being non-resistant to outdoor conditions. And in the case of E-glass rods, a failure by brittle fracture has a high likelihood.

For the reasons mentioned and under corresponding in-situ stresses, hydrophobicity as solely protective mechanism is inadequate to ensure successful operation without intensive damage to the silicone surface. This is especially true if the environment calls for a high pollution class, which is often accompanied by multiple, temporary losses of hydrophobicity. In addition to the „classical" pollution, further severities of the environmental conditions can accelerate critically the loss of hydrophobicity. These include, for example, mold growth (especially when humid conditions during insulator stock-keeping has kicked off this growth), algae growth, hygroscopic pollution layers (Schmuck and Bärsch 1993; Schmuck and Ramm 1991; Winter and Bärsch 2006; Neumann 2003; Gubanski et al. 2005, 2006; Fernando et al. 2006, 2010; Bärsch and Kuhl 1999).

As mentioned above, fillers are used in polymeric materials to increase erosion resistance. The most popular filler is aluminium trihydrate (ATH), which is one of the world's most important mineral-based flame retardants and was patented for the first time in 1909 by Fritz Hofmann. ATH can undergo single-stage or two-stage decomposition, when being subjected to heat (Figure 11.34).

Under atmospheric standard pressure, and as of approx. 180-200 °C, ATH is converted directly into Al_2O_3 without the intermediate stage of boehmite formation AlO(OH) (single-stage decomposition). A two-stage decomposition occurs if a high temperature and high pressure occur simultaneously. This situation may arise during the thermal decomposition of particles if the surface is spontaneously converted into Al_2O_3. The internal $Al(OH_3)$ then experiences conditions conducive to the formation of AlO(OH), which does not enter the second decomposition stage until higher

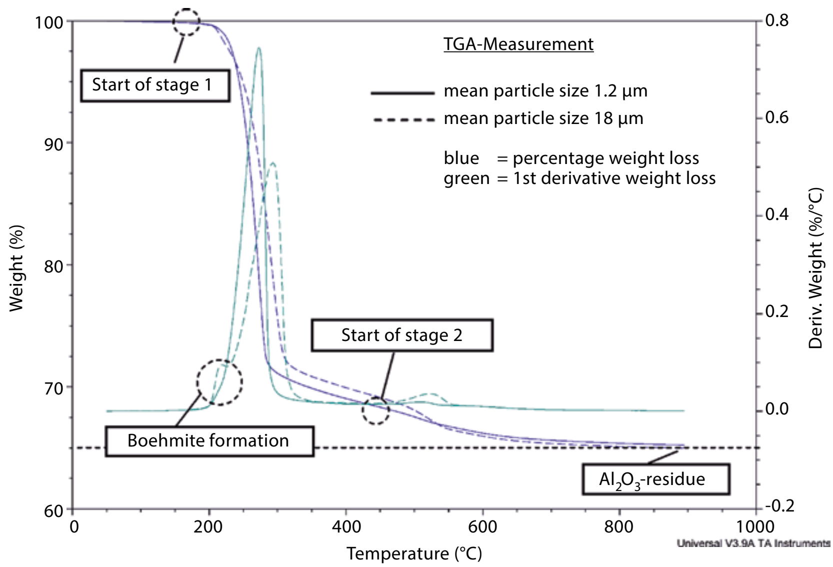


Figure 11.34 Thermographic analysis (TGA) of two-stage thermal decomposition of ATH (Papailiou and Schmuck 2012).

temperatures are reached. The particle size determines the quantity of boehmite formed. Larger particles have a more enclosed volume, while smaller particles have a larger surface to volume ratio. In other words, larger particles form more boehmite.

These decompositions can be described by equations as follows and more details can be found in (Papailiou and Schmuck 2012):

Single-stage decomposition

$$2\ \mathrm{Al(OH)_3} \rightarrow \mathrm{Al_2O_3} + 3\ \mathrm{H_2O} \quad \text{as of } 180 \quad 200^\circ\mathrm{C} \tag{11.3}$$

Two-stage decomposition

$$\mathrm{Al(OH)_3} \rightarrow \mathrm{AlO(OH)} + \mathrm{H_2O} \quad \text{as of } 180 \quad 200^\circ\mathrm{C} \tag{11.4}$$

$$2\ \mathrm{AlO(OH)} \rightarrow \mathrm{Al_2O_3} + \mathrm{H_2O} \quad \text{as of } 450 \quad 560^\circ\mathrm{C} \tag{11.5}$$

The effect of ATH as a flame retardant for increasing resistance to partial discharges or power arcs in a filled elastomer is more complex. The following mechanisms are effective alone or simultaneously (Kumagai and Yoshimura 2001; Schmidt et al. 2010; Kautschuk Gummi Kunststoffe 2006):

- Substitution of polymer as a thermally decomposable material fraction,
- Use of ATH to increase the thermal capacity (i.e. more thermal energy must be supplied to facilitate the thermal decomposition of the polymer),
- Endothermic ATH decomposition (i.e. discharge of energy from the surface),
- Use of nascent steam to cool the surface,

- Effect of steam to "dilute" flammable gases and to displace oxygen required for oxidation purposes,
- Reduction in the formation of flammable cyclic oligomers with a low flash point (e.g., $(SiO(CH_3)_2)_3$, which has a flash point of 135 °C) in silicone rubber.

Moreover, the effect of increased thermal conductivity as a result of adding ATH is not to neglect: A commercially available HTV system filled with ATH (overall weight: approx. 50 % ATH) has a thermal conductivity of 0.5 W/mK, while an RTV system that has not been filled with ATH has only 0.2 W/mK. This property is relevant from an ageing perspective in order to dissipate the temperature rise at the partial discharge (PD) roots (Meyer et al. 2004a, b).

In view of the relevance of ATH for the increase of the erosion and tracking resistance, the effects of its addition were comprehensively summarized in Papailiou and Schmuck (2012). The results presented there are a selection of results provided in the literature and based on the own investigations with various silicone rubber grades. Qualitatively, the results display the development trend associated with a particular material modification; quantitatively, they apply only to the chosen test conditions and test specimens. The results also confirm a well accepted state of knowledge that solely adding a certain quantity of ATH or other fillers does not serve to the purpose of an overall material optimization. Rather, the entire system (polymer, fillers, the treatment of fillers, etc.) needs to be balanced in relation to all relevant properties.

In view of the Cigré and IEC work, the different outdoor-relevant properties of a polymeric material can be evaluated with one or more test methods. Many tests are solely material tests with the purpose to investigate material properties on simple specimen geometry without any influence by a complex insulator shape. From an insulation perspective in service, however, their long-term behaviour is determined from the complex interaction between the materials used, the geometric design of the insulator housing (e.g. shed distances and shed overhang), the manufacturing process (parting line or mould line) and the overall insulator string design (for example sufficient corona protection). Consequently, the use of suitable materials that have been optimised for the intended purpose is a necessary but by no means a sufficient condition for ensuring reliable operational behaviour. Some examples for the test of relevant material properties are displayed in the following sections.

Erosion and Tracking Resistance under AC Stress

The erosion and tracking resistance is the most tested property because comparatively simple methods in the form of the Inclined Plane Test, salt fog test or wheel test are available to test it. And in the early days of polymeric outdoor materials, this property was in the main focus because the value-added performance by hydrophobicity was not discovered yet.

Due to the high pressure method required to process HTV solid silicone rubber for housings, ATH in the required quantity (depending on the formulation) can almost always be added to the housing material. The Inclined Plane Test also reveals the differences shown in Figure 11.35. The erosion rate of each specimen is

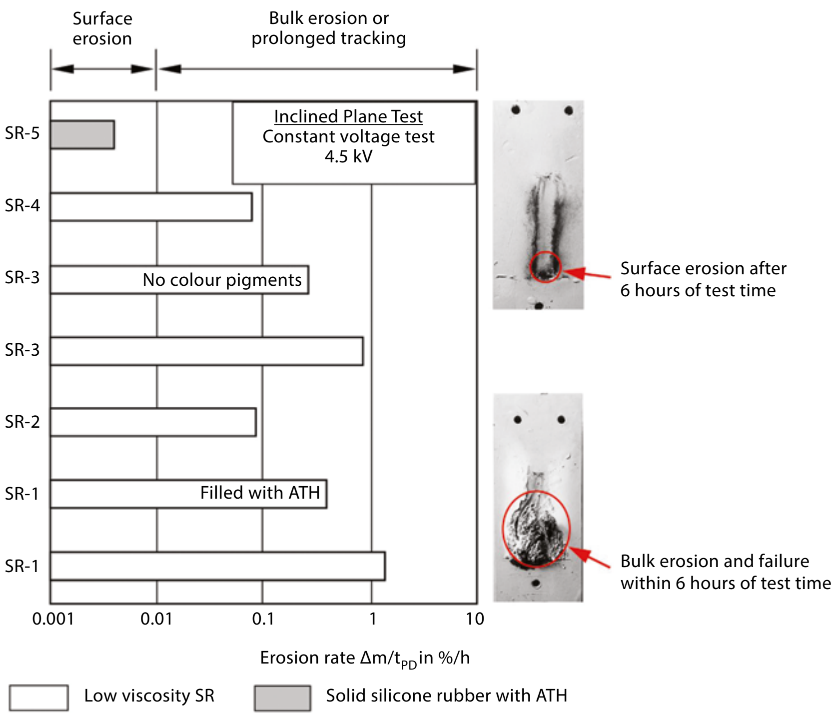


Figure 11.35 Increase of erosion resistance as a result of adding ATH (Büchner et al. 1996, 1997).

calculated as quotient of its erosive weight loss (a possible mass increase by water uptake during test should be corrected) divided by its real exposure time to PD-activity. This procedure considers that in the case of no PD (e.g., caused by a diversion of the electrolyte), a specimen is not stressed and can pass the test more easily.

In the case of SR-1 (unfilled RTV grade), the erosion rate can be lowered by adding ATH. However, the material is so highly viscous that processing in the form of low pressure cavity casting is no longer possible. SR-3 is an LSR grade and illustrates an example whereby the addition of an unsuitable colour pigment can increase the erosion rate. SR-2 (RTV grade) and SR-4 (LSR grade) are commercially available systems without the addition of ATH that are castable and, with a suitable formulation, achieve a lower erosion rate than, for example, SR-1 with ATH. This can occur, for example, by adding suitable additives such as TiO_2 or a surplus platinum catalyst. The low erosion rate associated with SR-5, a commercially available HTV with approx. 48 % ATH, is not achieved with the low viscosity systems tested under these conditions. The behaviour of SR-1 confirms that the quantity of ATH needed to deploy the flame-retardant effect must always be tailored to the carrier material and coordinated with the contribution of other additives. It is well proven that by adding ATH, a polymeric material can also achieve a significant increase in erosion resistance up to 6 kV in the Inclined Plane Test. The required quantity of ATH depends on how the entire system is formulated. Preferably, it should be determined through systematic tests on an adequate sample size (Ansorge et al. 2012). The surface modification of ATH has a positive effect on erosion resistance and the dynamic of hydrophobicity.

Erosion and Tracking Resistance under DC Stress

For AC applications, the Inclined Plane Test based on IEC 60587 is widely used and permits the comparison of materials intended for outdoor insulation under controlled electrical stress. It is commonly agreed that the material ranking achieved with this test is especially relevant for the service performance of an insulation, when the hydrophobicity becomes lost and the second protective mechanism is required. The experience of a corresponding test operated under DC is rather limited and not specified within IEC. Currently a DC tracking and erosion test of composite outdoor insulation materials is only required in a Chinese Standard for 500 kV DC long rod composite insulators (Electric Power Industry Standard of the People's Republic of China , DL/T 810-2002). This can be attributed to the fact that with increasing use of energy transmission by high voltage direct current (HVDC) up to 800 kV, new milestones in energy transmission have been reached in some countries. From the perspective of materials testing, the situation also poses the question, whether the material ranking of AC stressing is transferable to DC stressing. This subject is currently under consideration by Cigré WG D1.27.

First exploratory tests do apparently not confirm a comparable material ranking for AC and DC stresses (Cigré WG D1.27 2014). These tests were independently performed as Round Robin Tests with three families of materials (Figure 11.36). Material A is a structural material typically used mostly for distribution applications. Material B is a castable Silicone Rubber with no added filler to improve its erosion resistance. Material C is a HTV Silicone Rubber with ATH filler. For material A, practically all tests under DC-stress resulted in failure with a conductive path causing an excess of the 60 mA current criterion. If materials B and C failed then by a different failure mode as material A did. Materials B and C failed only by erosion and not by excess of the current criterion. Beside the different failure mechanism, it was measured that the test time required for this erosion failure to occur was always much longer than to fail by tracking for material A. The lower failure susceptibly of material C is attributed to the ATH content, which improves the tracking and erosion resistance for AC and DC stress. If the trend of this first test will be confirmed in further comparative tests, the use of DC tests will be an important and needed supplement to AC tests.

The following aspects can be derived from the currently available, mostly empirical knowledge (Cigré WG D1.27 2014; Heger et al. 2010; Rowland et al. 2011):

- The erosion rate or failure rate for the same testing parameters is higher under DC stressing than under AC stressing.

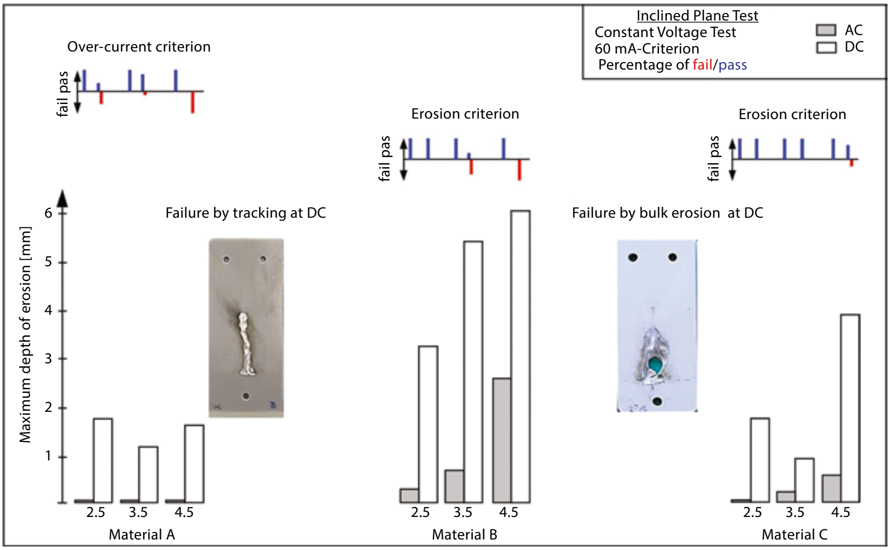


Figure 11.36 Results of AC and DC Inclined Plane Tests performed on three different material families (Cigré WG D1.27 2014).

- In the case of tested insulating materials commercially used for overhead transmission line insulators, a trend whereby the positive polarity results in a higher stress is evident.
- The effect of ATH to improve erosion resistance is higher for DC than for AC with the tendency the more filler the lower the erosion.
- Secondary effects due to the absence of a change in polarity were identified for certain materials, which resulted in the formation of conductive tracks and the premature triggering of the over-current criterion or heavy erosion. Hence, damage appearances were found differing from AC and DC stresses.
- The impact of electrode corrosion must be taken into consideration as possible stress enhancement.

Dynamic Properties of Hydrophobicity (Retention, Recovery and Transfer)
Since the recognition of hydrophobic effects more than 30 years ago, the behaviour of polymeric insulations was studied under real service conditions and laboratory test. Most of the polymeric materials behave hydrophobic when being new and without pollution. However, the field experience has shown so far that only silicone rubber has a significant recovery and transfer of hydrophobicity as well. How is this considered in standards to take design advantage by a lasting hydrophobicity? Since 2008, when the Technical Standard IEC 60815-3 was published, the hydrophobicity has been discussed for two design aspects in this document:

- Creepage distance in comparison to permanently hydrophilic materials,
- Influence to housing diameter.

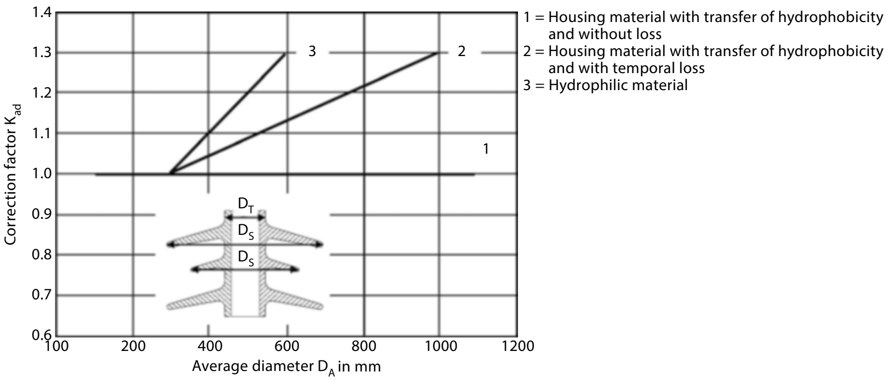


Figure 11.37 Correction factor versus average diameter as per IEC 60815-3: 2008.

The discussion on creepage reduction for permanently hydrophobic insulators is rather qualitative. Both smaller average diameter and hydrophobic behaviour especially when talking about line applications, can lead to the conclusion that in principle and solely from a pollution withstand or flashover point of view a reduced creepage distance may be used for such insulators. However, compared to traditional insulating materials, polymer materials are more susceptible to degradation by the environment, electric fields and arc activity which may, in certain conditions, reduce insulator pollution performance or lifetime. Therefore, in many cases, it is advisable to employ the same creepage distance as recommended for equivalent porcelain and glass insulators used under the same service conditions and accept improved pollution performance as additional redundancy and thus, avoid degradation or flashover problems. This is well accepted in the meantime as empirical "design rule" and especially true when keeping in mind the low cost savings for a shorter creepage distance for line insulators.

Quite a different situation is faced for large hollow core insulators used for apparatuses. Such insulation is typically in a station and so easier accessible for inspection and maintenance. The influence of the diameter in relation to a demand for increased creepage distance was introduced with the previous standard IEC (60)815, published in 1986 in a way that correction factors of 1…1.2 had to be applied for the creepage distance required, when an average diameter of 300 mm was exceeded. The new standard IEC 60815-3 has higher factors (see Figure 11.37), which is attributed to the development of transmission technology towards ultra high voltage classes. The first time it is differentiated between housings with permanent hydrophobic behaviour, temporal loss of hydrophobicity and hydrophilic surface behaviour. For the first case, no correction has to be applied, which can play a vital role for cost, especially when considering apparatuses for 800 kV and above.

However, IEC 60815-3 does not describe test procedures and values, when a (polymeric) material falls into category 1, 2 or 3. Here, Cigré TB 442 WG D1.14 is a helpful tool, because a test to quantify the hydrophobicity transfer is described as well as tests for the retention and recovery. The data base on Round Robin Test and

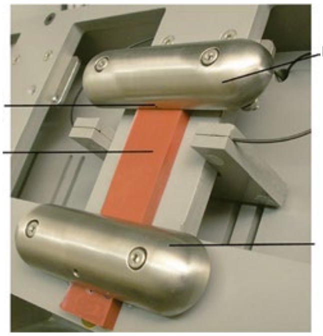


Figure 11.38 Set-up of the Dynamic Drop Test for evaluating the retention of hydrophobicity.

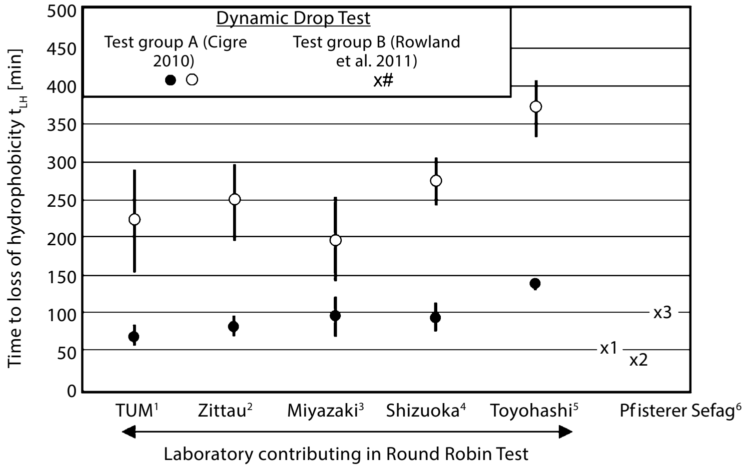
this subject under work to provide sufficient information for an IEC standard, especially in terms of material classification.

About the current status, the following information can be given: The *retention of hydrophobicity* can be tested with principle methods aiming in the evaluation of erosion and tracking resistance. The principles of fog testing and wheel testing belong to these methods. In contrast to their use as tracking and erosion test, the test parameters are chosen in such a way that it is possible to distinguish between the early ageing phases (identification of hydrophobicity loss and not tracking/erosion) of various materials. The test specimens, which are typically cylindrical or rotationally symmetrical, must be manufactured in such a way that there is no (axial) mould line. Such a mould line can work as a "mechanical water carrier" and shorten the time to failure. Are different materials tested comparatively, the surface roughness of the specimens must be in the same order of magnitude. However, these tests have disadvantages: In the wheel test, each specimen has a drip edge in an unidirectional direction of rotation. If this drip edge coincides with random increases in roughness, there is a greater variation among the measurement results. The (salt) fog test is technically more complex, has less acceleration than the wheel test under the same conditions (Papailiou and Schmuck 2012) and is therefore more costly and time-consuming. In order to use more simple geometric test specimens, to make the test easier with the option for test automation within the scope of routine quality control, a test method called Dynamic Drop Test (DDT) (Cigré WG D1.14 2010; Bärsch 2003; Cervinka et al. 2008) was proposed (Figure 11.38). It can for example, be integrated into the set-up of an Inclined Plane Test device.

The test principle was evaluated by a Round Robin Test and the results found that the time until a loss of hydrophobicity was experienced showed good correlation in 4 of the 5 laboratories and only one laboratory measured higher values that differed on average (Figure 11.39).

The test parameters defined for the Round Robin Test were originated in the systematic fundamental analyses of various influencing factors (Cervinka et al. 2008) and shown in the table of Figure 11.39.

Beside the good reproducibility of the test, the results have shown that the acceleration associated with evaluating hydrophobicity is higher in comparison to a salt



Test parameter	Test group A	Test group B
Specimen inclination relative to horizontal line [°]	60	45
Creepage distance [mm]	50	50
Electrolyte conductivity [mS/cm]	1.5 ± 0.2	1.5 ± 0.2
Flow rate [ml/min]	1.0 ± 0.2	1.0 ± 0.2
Voltage [kV]	o = 4.0 ● = 5.0	x = 5.5
Material	RTV-Silicone Rubber	x1 = RTV-Silicone Rubber x2 = HTV- Silicone Rubber with silanised ATH x3 = Base polymer (gum)
Criterion for failure I [mA]	2 ± 0.5 for 4 ± 0.5 s	2 ± 0.5 for 4 ± 0.5 s

1 = TU Munich (Germany), 2 = HTWS Zittau (Germany), 3 = University of Miyazaki (Japan), 4 = Shizuoka University (Japan), 5 = Toyohashi University of Technology (Japan), 6 = PFISTERER SEFAG (Switzerland)

Figure 11.39 DDT results from different laboratories, AC measurement (Cigré WG D1.14 2010; Ansorge et al. 2010; Papailiou and Schmuck 2012).

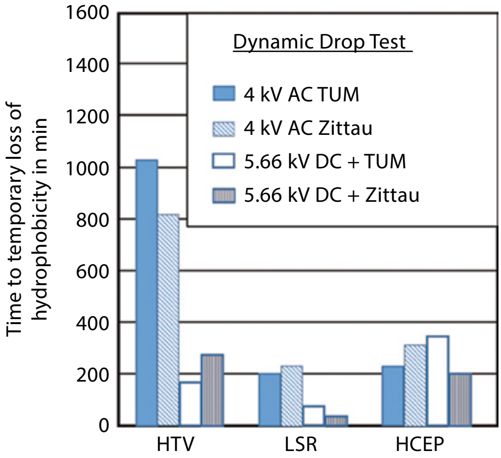
fog test or wheel test. In other words, less time is involved. This finding and the simplicity of the test specimens make it possible to also take measurements in a statistically needed volume (e.g. 10–20 test specimens), which improves the expressiveness of the test. And thanks to the test easiness, no special skills are needed which opens the test for the purpose of quality assurance within production. Storing test specimens under defined conditions before the test commences contributes towards good reproducibility of the measurement results.

Within Cigré WG D1.27 (Hergert et al. 2014), the subject was further investigated for DC stress using the Dynamic Drop Test. The general reproducibility of the test set-up from AC but adopted for DC was investigated at two German universities. The tests were conducted using 4 kV AC_{rms} voltage and a positive DC voltage with a magnitude of 5.66 kV (equal the peak value of 4 kV AC). The results of both universities show that there are no significant differences between the two laboratories. Different materials or material families can be distinguished. The surface roughness is one of the major factors of influence on the test results. The general dependency on the roughness for the materials investigated should be verified for other materials. The test is important in the context of evaluation of the overall hydrophobicity of a polymeric material.

The "hydrophobing" of pollution layers on the surface of the insulating material - named *hydrophobicity transfer* - is a proven and operation-relevant unique characteristic of composite insulators with silicone rubber housing and is due to the migration of low molecular weight (LMW) chains. This property was described in 1981 as a possible explanation for the return of hydrophobicity (Lee and Homan 1981) whereby, at that time, there was still no distinction, within recovery, between the reorientation of methyl groups and an LMW transfer. The potential of this property was recognized in terms of less maintenance meaning operational line costs and in the following years this property was specifically analysed by using electron spectroscopy for chemical analysis (ESCA) (Gorur et al. 1986, 1988) and other test methods. The result of which was that, after a series of ageing tests and a specific rest phase, the quantity of silicone in the carbon pollution layers applied for diagnostic purposes increased again. Later on, this effect was also extensively analysed for RTV coatings (Kim et al. 1982). In terms of visual and haptic appearance, the hydrophobicity transfer causes more adhesion of the pollution layer to the silicone rubber surface. Often seen in reality and not only as an ideal scenario, this increased "stickiness" is an indicator for a LMW transfer and a better hydrophobicity than the surface without a pollution layer can be exhibited (Ansorge et al. 2008). If the hydrophobicity transfer can take effect, it is not necessary to clean the insulators while they are in service, even under critical operating conditions (e.g. in tunnels (Kocher 1993) or in arid conditions (AI-Hamoudi 2008; Munteanu 1994)). The further systematic analyses on this phenomenon involving laboratory pollution layers of different thicknesses were published in 1989 (Kindersberger and Kuhl 1989). The authors revealed that, in order to reproducibly apply an artificial pollution layer to hydrophobic and rubber-elastic surfaces, it is necessary to comply with certain rules. A summary of this work was published in Cigré TB 442 in 2010 following many years of work and the research has still being continued (Figure 11.40).

Beside the contact angle measurement of polluted surfaces and after the positive experiences with the DDT for the evaluation of the retention of hydrophobicity, its principle was evaluated to quantify the hydrophobicity transfer (Papailiou and Schmuck 2012). Having identical test conditions to Figure 11.39, the surface of the test specimens was treated differently. A dry pollution layer was applied using a paint-brush or a soft sponge; compressed air is then used to lightly blow off the excess pollution layer. There was a complete loss of hydrophobicity immediately after the pollution layer has been applied (Figure 11.41 - left). To prevent influence by previous measurements, a test specimen was only used once for each measurement. The silicone rubber plates yet to be tested were stored in a desiccator in order to control, in a defined manner, the effect of the ambient humidity on the transfer process.

Figure 11.40 Time to temporary hydrophobicity loss found for the DDT at DC for different materials (63 % quantiles and 95 % confidence intervals of Weibull distribution, 8 specimens measured for each bar) (Hergert et al. 2014).



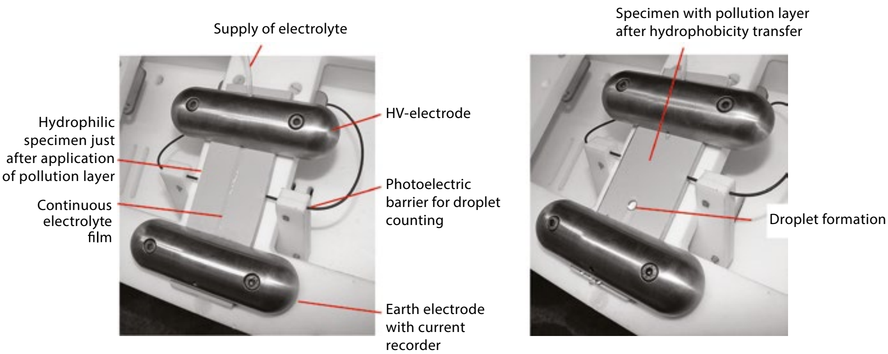


Figure 11.41 A loss of hydrophobicity after applying a dry pollution layer in the DDT (*left*) and return of hydrophobicity by transfer and subsequent storage after pollution application (Papailiou and Schmuck 2012).

After a certain time of storage, a recovery of hydrophobicity was observed by the hydrophobicity transfer (Figure 11.41 - right). Initial quantitative measures have shown that, as expected, the type of dry pollution layer has a major effect on the transfer time (Figure 11.42). The Sicron© used is a quartz powder that is ground to a grain size of 9 µm (iron-free). The shape of the curve progression, which correlates to the duration of loss of hydrophobicity measurement directly with the transfer intensity, corresponds to the increase in contact angles in other measurement campaigns. In contrast to the measurement concerning the static contact angle, it should be noted, as a result of using rolling droplets in the evaluation, the dynamic receding contact angle is better reproduced (see also Figure 11.41 - right) and thus there is better correlation with the efficacy of the hydrophobicity transfer because of the electrolytic pollution layer starts to flow. The test was repeated using commercially available Kaolin (60 % of the particle size ≤ 2 µm). Kaolin is a hydrated aluminium

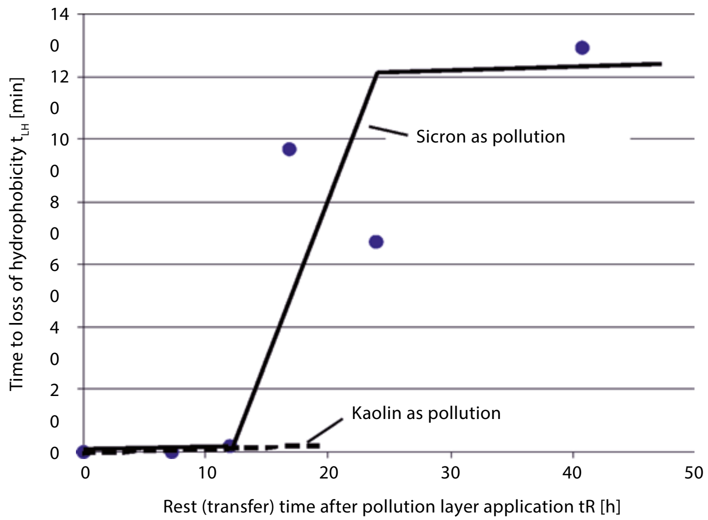


Figure 11.42 A longer time to hydrophobicity loss as a result of the hydrophobicity transfer.

silicate with the chemical formula Al_2O_3 $2SiO_2$ $2H_2O$. Depending on the particle size, its specific surface is between 10 and 40 m^2/g. In contrast to Sicron©, a hydrophobicity transfer during the analysis period (200 h) was barely detectable when Kaolin was used.

These initial results show that the Inclined Plane Test principle also has the diagnostic potential to evaluate properties of the hydrophobicity. Other systematic and fundamental analyses are required, in particular, to establish and apply the pollution layer in a reproducible manner.

Briefly summarizing: The section *Material Components of Composite Insulators* shows in context with the status of IEC test standards in Figure 11.3 that, from a design perspective, some detailed tests apply to one insulator technology only. In the case of composite insulators, for example, interface areas are frequently evaluated. Nowadays, the standards for composite insulators have reached a level that provides both the manufacturer and user with great support when designing reliable, long-lasting components. It is worth to be mentioned that this is only possible because the standards are subject to revision at specified intervals, thus enabling them to adapt to the latest technology as well as any new service experiences. The range of tests that can be conducted on housing and rod materials and composite insulators has been expanded considerably. The evaluation of the erosion and tracking resistance continues to be extremely important, especially when one considers the growing use of HVDC applications. Progress was achieved that new test methods were systematically evaluated in order to make it possible to quantify the dynamic hydrophobicity as value-adding property of polymeric insulating materials. The idea for a simple but reproducible test method is mainly associated with the Inclined Plane Test principle because this easy method from the process and manufacture of specimens point of view is of equal interest from both a development and quality assurance perspective. While Cigré SC B2 is more focusing on the overall function of an insulator/insulator set, the work of Cigré SC D1 provides important results and basic findings for the test methods to be applied and the selection of suitable easy-to-use devices. Overall, there are sufficient test methods available for reliable ageing-resistant products.

11.4.4 A Selection of Topics on the Dimensioning of polymeric Insulators and Insulator Sets

11.4.4.1 Creepage Distance

There are a number of important documents by Cigré TF 33.04.01 (2000), TF 33.04.03 (1994), and C4.303 (Cigré WG C4.303 2008, 2012), which are looking into the subject of creepage distance. In service the outdoor insulation should withstand all voltage and environmental stresses that may occur. The pollution performance of an insulation is one important component of the overall insulation coordination design, which determines especially for DC application mainly the insulator length. In the past and recognized for decades, the conventional materials glass and porcelain were the only available options. Service experience combined with intensive research led to a good understanding of the flashover mechanisms and the design of the insulation could be adopted to perform satisfactory in many situations. However, there remained a significant number of in-situ conditions with high severity of pollution often combined with low likelihood of rain occurrence, which caused unstable service performance. With the development of polymer materials, options to glass and porcelain became available with the possibility of improved performance in these situations by both different insulator shape and surface behaviour against pollution. It has been part of the learning curve with composite insulator technology that the failure mechanisms, and the processes which led to them, were very different to conventional insulators. Thus, research and analysis of service experience has been triggered lasting by today. The first document (Cigré TF 33.04.01 2000) was published in 2000, which accumulates broad information about the performance of glass, porcelain and polymeric insulators. Basing on this document, Cigré SC C4 continued to provide a guide for the selection and dimension of outdoor insulations under consideration of the wide variety of housing materials and insulator types and the levels of performance requested for the strategic importance of the line or station under consideration. A main key for the guide is a performance-based methodology considering field and laboratory experiences. An important note: During the time of compiling the documents, a close liaison has been established with IEC TC 36 WG 11, which has been responsible for the rewriting of IEC 60815, "Selection and dimensioning of high-voltage insulators for polluted conditions". At the end of the day, two important documents were published, covering the AC (Cigré WG C4.303 2008) and the DC (Cigré WG C4.303 2012) case of outdoor insulations. For the purpose of convenience, the general

Conventional insulators
Most common mechanism for insulation failure is pollution flashover, extensively researched and fairly well understood.

In critical pollution zone, an adequate pollution performance can be impossible to achieve without additional mitigative measures.

For vertically mounted post and barrel insulators, there is a general trend relating specific length to average diameter for a given voltage and pollution severity.

Under AC. stressing, the pollution flashover performance of suspension insulators is essentially linear with string length for voltages up to 700 kV and is only moderately non-linear for higher voltages. Post insulators seem to be more non-linear than the corresponding case for cap and pin ones.

The effect of mounting angle to the vertical depends upon the type of insulator. For suspension insulators, improvement occurs as this angle increases. When large diameter insulators are horizontally mounted the performance is much inferior to those for corresponding vertical cases.

The flashover strength at cold switch-on can be at least 40 % less than that for continuous energization.

In desert regions, flashover can be a problem even for USCD values of 90 mm/kV.

Snow and ice can substantially decrease the flashover performance when icicles or snow span most of the insulator. The probability of flashover at operating voltage is very high during the melting stage.

Hollow insulators or shells may have a lower flashover performance than that of comparable solid insulators; this is due to the influence of both the electric field and heat from internal components.

At a given surface stress at flashover, the critical pollution severity under DC energization is much less (maybe a factor 10) than that under AC stressing.

By using semi-conducting glaze to achieve a continuous leakage current of about 1 mA, sufficient heating of the insulator surface is achieved to keep it essentially dry in dew or fog - thereby greatly increasing the pollution flashover performance compared with that of a normally glazed insulator. Problems still with cold switch-on remain and rapid deterioration in severe pollution. Semi-conducting glaze is not recommended for DC insulators.

Polymeric insulators
Service experience has demonstrated that the performance of polymeric insulators is excellent if they have been properly dimensioned and the correct materials are used (3^{rd} generation).

Failure of polymeric insulators using silicone rubber for the sheath and shed material is usually mechanical as a result of damage to the reinforced glass fibre core. It is important, therefore, to design the insulator so that the integrity of the material covering the core is maintained under all operating conditions. Great improvements were achieved by the use of E-CR fibres.

The pollution flashover performance of some polymeric materials - especially silicone rubber - is generally superior to that of glass or porcelain. In contrast, epoxy resin rapidly degrades from its new - hydrophobic - condition such that its flashover strength can be somewhat inferior to that of ceramic materials, especially when tracking occurs.

Some types of discharge activity (e.g. corona or sparking) at or near the surface may cause severe degradation of the material, thereby exposing the core to mechanical degradation and also reducing the flashover performance. Such discharges may be minimised or prevented by having the correct design of the complete string/set.

Figure 11.43 Comparison of insulator technology performance under AC outdoor conditions (Cigré WG C4.303 2008).

review of insulator characteristics can be summarized from the AC case as shown in Figure 11.43. Traditionally the selection and dimensioning of insulation for outdoor use has largely been based on creepage distance alone. This principle cannot be applied anymore and can be substituted by:

- Pollution flashover performance is determined by many factors other than axial length or creepage length. The nature and accumulation of the contaminants, the effect of natural washing and the physical characteristics of the surface discharges all play a part.
- For all insulators, the specific length needs to be increased as the pollution severity increases following a power law.

The document on DC cases covers the trend of using HVDC more and more as alternative to AC transmission over long distances. With the expectations on modern networks in terms of costs, reliability etc, Cigré WG C4.303 reviewed and analysed the practice and experience available for a service duration of up to 50 years. The guide published in 2012 (Cigré WG C4.303 2012) is an important tool for the selection of an outdoor insulation under consideration of modern HVDC system requirements, environmental conditions and modern insulator technology. In HVAC systems, switching and lightning performance are the dominant factors with a main impact to the

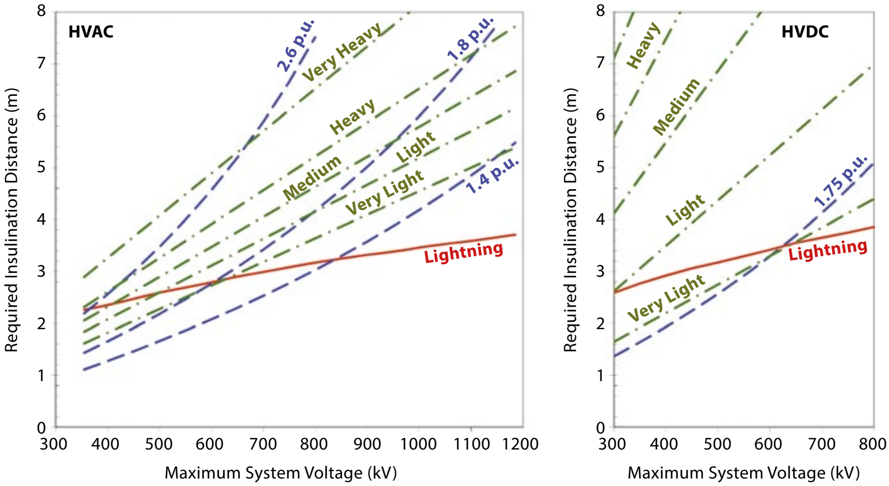


Figure 11.44 A comparison of the indicative insulation distance requirements for switching (*blue*), lightning (*red*) and pollution (*green*) for HVAC and HVDC systems (Cigré WG C4.303 2012).

overall length of insulation. Under HVDC, the insulator length is mostly determined by the creepage length demand (Figure 11.44). This is due to the difference to AC that the static electrostatic field along the length of an insulator, in conjunction with the prevailing wind, lead to a continuous build-up of pollutants on the insulator surface which may, typically, range between 1–4 times, but possibly as high as 10 times! more severe than that on comparable HVAC insulation in the same environment. The situation becomes worse by the fact that the leakage current in the pollution does not experience natural current zeros and as a result, the dry band arcing is very aggressive.

Thus, the accurate assessment of site severity is, therefore, critically important as starting point for any insulation design. The guide provides a range of options for doing this, starting with data from insulators energised at HVDC through information from insulators energised at HVAC to a survey of likely pollution sources, coupled with wind and rain data. The site severity is determined in terms of both the concentration of salts (ESDD) which contribute to electrical conduction and the concentration of non-soluble material (NSDD) which contributes to water retention, both well known from the AC case. One value of the document is the analysis of publications related to large number of HVDC sites around the world and the presentation of a range of correction factors for adjusting site severity information from HVAC insulation or from the analysis of source, wind and rain conditions to determine the HVDC site severity. This is important for cases, when an assessment of the site severity using energized HVDC insulators cannot be achieved. As final stage, different engineering options are proposed:

- Most desirable is the validation of the chosen insulator design under the in-situ conditions and at DC stress.

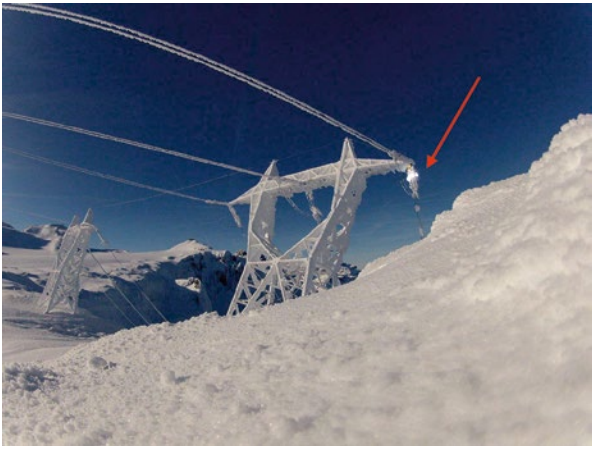


Figure 11.45 Snow flashover across the tension set of a 420 kV line.

- If not applicable for various reasons, the use of laboratory test simulating representative conditions can be taken into account.
- If none of these is applicable, the experiences around the world documented in the guide can be used in a plausibility approach.

For all three options applies that the need and application of maintenance and palliative measures should already be considered at the design stage.

Snow and ice are a special pollution and can substantially decrease the flashover performance when icicles or snow cover most of the insulator. This applies to conventional and composite insulator technology as well. The probability of flashover at operating voltage is very high during the melting stage (Figure 11.45).

Cigré TF 33.04.09 published in 1999 (Cigré TF 33.04.09 1999) and 2000 (Cigré TF 33.04.09 2000) two documents with a description of the associated phenomena and possible solutions. A specialist book covering comprehensively this matter was published by IEEE in 2009 being entitled "Insulators for Icing and Polluted Environments". The latter comprises many practical experiences with respective solutions as well as describes failure mechanisms. Thus, if problems by ice and snow occur, this book will probably give an answer.

11.4.4.2 Corona Protection

The protections against corona and power arc are still important aspects with relevance for the in-service reliability. Due to the broad variety of composite insulator designs, standardization is difficult and individual solutions dominate the market. The experience has shown that problems can occur, if insulators are inappropriately designed, manufacture defects occur or insulator string/set components are insufficiently coordinated or incompatible to each other. Reasons for such a situation can be price pressure, missing product knowledge in comparison to the conventional technique, invalid tender specifications or a commercially stimulated abdication of

Figure 11.46 Scale comparison between a porcelain longrod, a cap and pin and a composite insulator (Papailiou and Schmuck 2012).

the suitability verification by simulation or practical test. It is obvious that in such cases the problems are not caused by the technically matured composite insulator technique. Composite line insulators installed as longrod insulators in suspension or tension applications have the known and visually appreciated smaller silhouette in comparison to porcelain longrods or cap and pin insulators. The slenderness of the composite longrods results in smaller fitting diameters, a comparison is shown in Figure 11.46. All insulators displayed are rated for 120 kN nominal tensile load, the porcelain longrod has a shank diameter of approx. 65 mm, while the composite insulator has a rod diameter of only 16 mm, which corresponds to a shank diameter of approx. 23 mm. The dimension of the insulator end fittings differ respectively, which makes it necessary to protect the insulator against corona at lower transmission voltages in comparison to conventional insulators. If an insulator string/set is insufficiently designed for the application and in-situ conditions, corona occurrence at voltage levels as low as 115 kV was identified by field measurements. Thus, a correct design of the composite insulator and its metallic string elements is critically important to prevent failures.

The corona protection is often coordinated with the power arc protection (see also Section 11.4.4.3) for applications, which require it. This can lead to the scenarios as shown in Figure 11.47. The insulator set is only equipped with corona protection (1). The insulator set has both corona and arc protection, but two suppliers (2). In both cases, the corona protection is integral part of the insulator design and typically supplied by the insulator manufacturer. Case 3 describes the situation that corona and power arc protection are combined and the complete insulator string/set is supplied by one manufacturer. The last scenario provides the advantage that the overall responsibility to meet the specified data is unambiguously with only one supplier. This scenario is often used for transmission lines of strategic relevance.

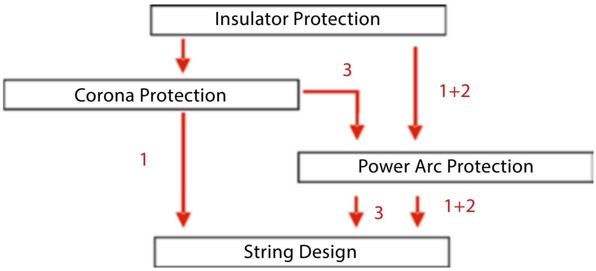


Figure 11.47 Insulator string/set design with different responsibility of the individual components.

corona discharges are undesirable side effects in energy transmission. If the transmission voltage increases, there are introduced design measures to limit the occurrence of corona discharges with multi-conductor systems and corona protection devices on insulator strings. Very general, the following negative effects are associated with corona:

- Energy loss,
- Acoustic interferences (under dry conditions and during rainfall),
- Electromagnetic interferences,
- Luminous effects,
- Ozone formation,
- Damage to string components and insulator housing.

In this section, the focus is on potential risk for string/set elements and insulator housing and can be summarised and evaluated as follows:

- If a continuous corona occurs at the insulator fitting or at string elements close to the insulator, it can cause permanent damage to the insulator housing and seal.
- Major damage mechanisms include changes to the surface of the insulating material caused by UV radiation and a chemical attack resulting from the formation of radicals or acid.
- A reduction in hydrophobicity as a result of water droplet corona can also occur while complying with the empirical threshold values for field stress and the high-grade hydrophobic properties of the insulator housing. Based on outdoor experiences with most of the silicone rubber grades, this reduction is deemed to be temporary and therefore not functionally relevant.

The effects of corona discharges on polymeric insulating material surfaces are extremely complex (Figure 11.48) because, under outdoor conditions, in particular, there is no inert atmosphere. Instead, additional secondary reactions occur with oxygen, nitrogen and water. The changes to silicone rubber surfaces and the effect on hydrophobicity as a result of UV, corona discharges, immersion in water and dry zone discharges are described extensively in the literature, a summary is provided in Papailiou and Schmuck (2012). In terms of field service, the main differences

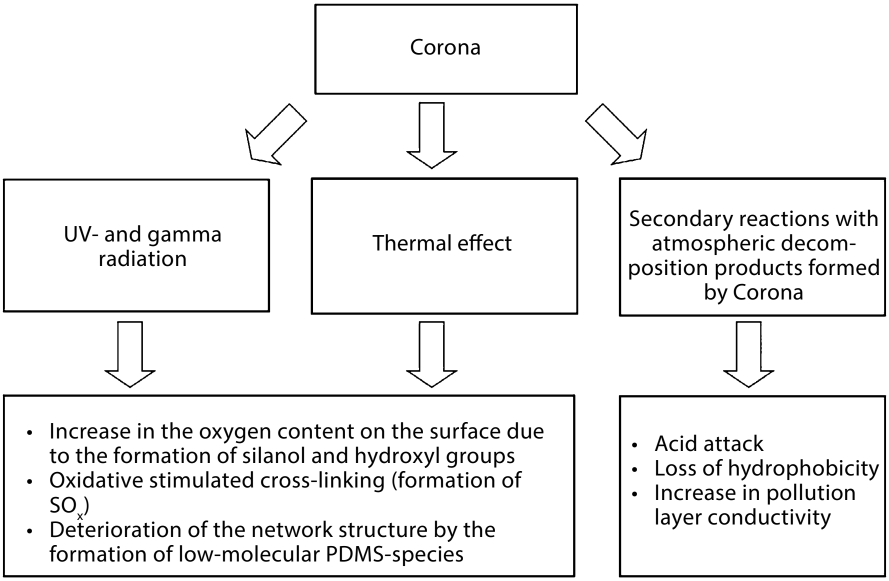


Figure 11.48 Effects of corona discharges on the example of silicone rubber (Papailiou and Schmuck 2012).

Table 11.11 Comparison of insulator types in terms of pollution behaviour and corona effects (Papailiou and Schmuck 2012)

Characteristics of a composite insulator set compared to an equivalent conventional insulator set	Effect on Pollution performance	corona
Smaller diameter of shank/housing	Improved	Negligible
Smaller diameter of end fitting	Negligible	The rim diameter of the insulator end fitting is to design carefully and corona rings must be installed at 200 kV onwards or even at lower voltages in the case of critical designs or environmental conditions.
Longer distance between conductor bundle and end fitting rim	Minor effect	The entire insulator set must be coordinated and type-tested (medium to major effect in the case of extended fittings with no corona protection).
Hydrophobicity	Enhanced	Phenomenon of water droplet corona

between a conventional insulator set and a composite insulator set can be contrasted as shown in Table 11.11 from the perspectives of the effect on pollution behaviour and corona effects.

The smaller diameters and longer insulator fittings (for technical reasons) compared to conventional insulators, and the optimisations performed today due to cost restraints, call for a critical evaluation of the corona protection design for composite insulators. So far no application guide in terms of an IEC standard exists and the following simplified rules from 1992 (Cigré WG 22.03 1992b) were often applied:

- corona rings must be used on the high voltage side as of 220 kV; they must also be used at lower voltages if a rather small shank diameter of the composite insulator is used or the in-situ pollution needs special care.
- If uncertainty surrounds the behaviour (today's simulation processes and computing capacity were not available in 1992), corona tests that simulate the insulator arrangement (suspension configuration, tension configuration or insulated cross arm) in accordance with the on-site conditions must be performed.

In terms of standards, IEC 61109 1st Edition 1992 has been referring to IEC 60437 (RIV Testing) and IEC 61284 1st Edition 1995 to RIV and corona testing of string elements (Hardware).

A clear statement is possible here: If these "matured" but simple rules would have been followed all the time, the number of service problems would have been significantly smaller. Some practical examples:

525 kV Double Tension Set

In Figure 11.20, problems arose, because the corona rings were forgotten during the string installation due to the lack of knowledge of the installation crews with the new "composite insulator" technology. The 525 kV strings shown here have since been retrofitted with corona rings. And some of them with this particular service history have been withdrawn from the network in order to undergo a detailed inspection programme.

245 kV - Double Tension String at a Station Entry

This example of Figure 11.49 shows images of a day-time UV-detection camera in a 245 kV European substation. This camera system typically displays corona discharges as integral "measurement clouds" (see also 11.4.2.2). It is clearly seen in this case, the string design was not adapted to the voltage level. The upward-oriented racket has the only function as a power arc protective fitting, which, due to its position and geometry, is unable to provide complete corona protection of the insulators. Consequently, after an average service time of just over one year, there was considerable damage to the galvanised layer and specifically performance-relevant to the sealing system. Furthermore, despite the low level of pollution in the zone of installation, an intensive grey colour was visible on the first shank section as a result of oxidation-stimulated cross-linking, which caused SiO_x to form on the silicone rubber surface. The position of the damage on each outward facing area of the fittings on the left and right insulator is due to the fact that the field-controlling effect of the racket is at its lowest at these locations. The insulators were retrofitted with corona rings including the withdrawal of few damaged insulators. Unfortunately, a detailed analysis of the seals affected showed a real risk of further cumulative damage even

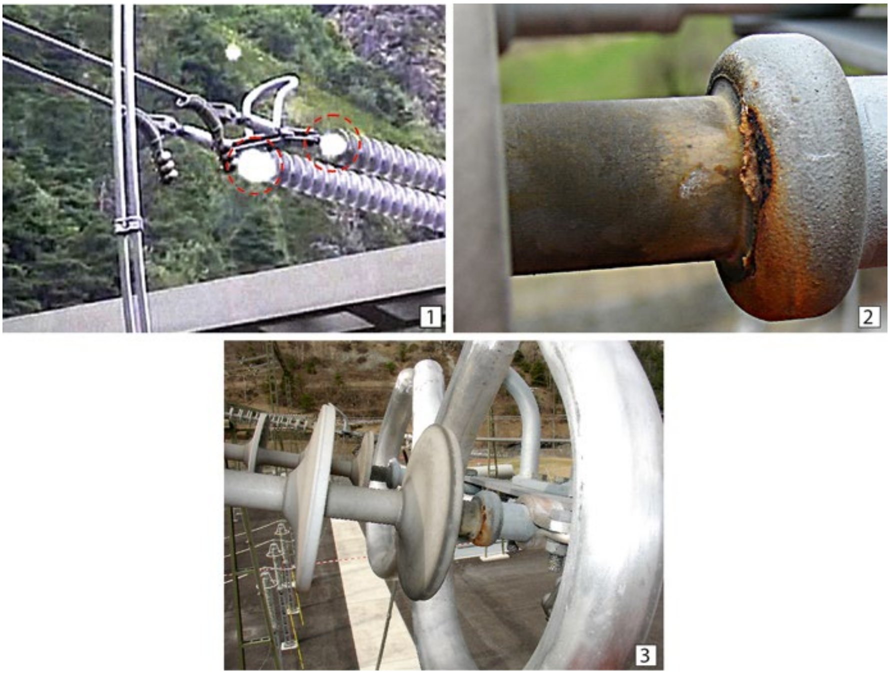


Figure 11.49 (1) - Photograph taken using a day-time UV detection camera, (2) - Damage to the galvanizing layer and seal, (3) - Retrofitting of corona rings, damage cannot be rectified (Papailiou and Schmuck 2012).

with the late installation of corona rings. For this reason, all of the composite insulators were replaced and the string design was adapted. In this case, the individual insulator set components had not been tendered as a packaged solution, nor was a comprehensive type test performed, which would have easily identified the design errors.

Examples for 115/138/145 kV - Various Insulator Sets

The so-called distribution level often involves already service voltages ≤ 145 kV, the cost pressures are particularly high. Figure 11.50 shows a 145 kV composite insulator during a type test in a complete set with single conductor. At these voltage levels, often corona and/or arc protective fittings are usually dispensed. In this example, it was established that, as a result of a fault that occurred during the manufacture of the composite insulator, the sealing knife edge of the injection mould caused sharp-edged damage to the galvanised layer of the metal fitting on the insulator, and the demand for corona freedom at 1.15 times the value of the phase to earth voltage was not fulfilled. While, in this particular example, it was still possible to eliminate the cause of the fault by smoothing the insulator end fittings prior to delivery and installation, it is often costly to identify such faulty designs when the insulator is in

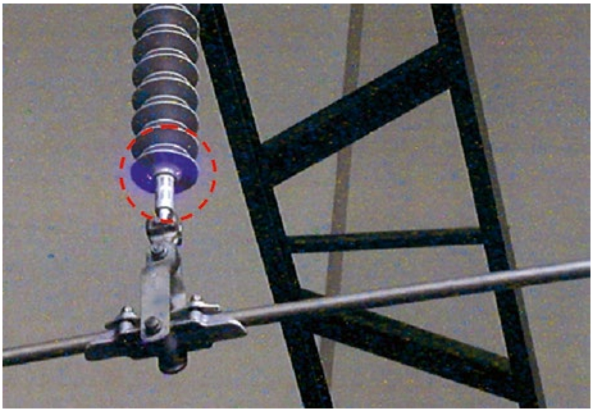


Figure 11.50 Sharp-edged damage to the galvanising layer by manufacture problem creates source of corona.

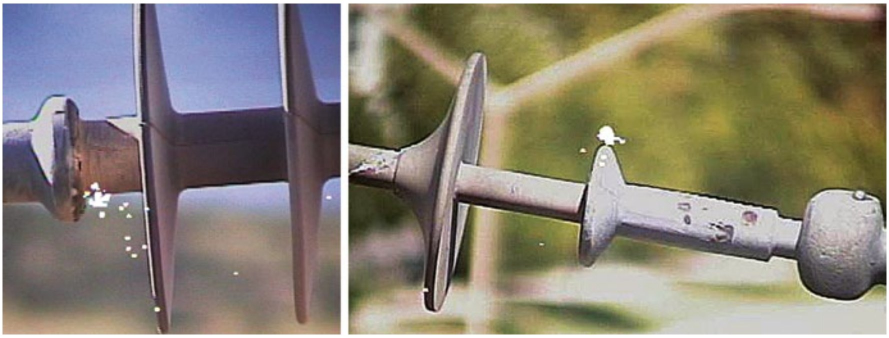


Figure 11.51 Examples of permanent corona discharges in the US network at 115…138 kV.

service. Furthermore, this process may require special diagnostic and replacement programmes. In light of failures involving certain insulator designs in some applications (dead end towers, in particular), the EPRI in the United States launched a programme that used a day-time UV detection camera to examine various string installations in five EVU's (Phillips et al. 2009). The results were unexpectedly bad because the general rule is that all supplied or similarly constructed insulators or insulator strings are type-tested and, if important changes are necessary (e.g. to optimise costs), a further type test is performed to verify their suitability. So, many examples were found of permanent corona discharges due to inappropriate insulator string/set design (Figure 11.51).

Beside the demand to prevent the "classical sources of corona" within a string, which can be easily measured, there is a special difference between conventional and permanently hydrophobic insulators (Figure 11.52). Special for the latter the phenomenon of water droplet corona that occurs at considerably lower field stresses must be taken into account when designing an insulator or string. Water droplet corona is caused by the difference in permittivity of air (value of 1) and water (value of 80).

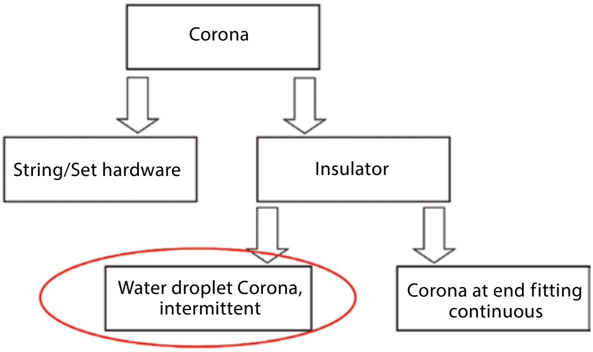


Figure 11.52 Possible sources of corona.

A summary is provided in Papailiou and Schmuck (2012). From a risk perspective, a continuous corona at the insulator end fitting must be regarded as the most critical case because it has a lasting permanent effect, not only during periods of humidification, and may cause material damage in a short time of service (see also Figure 11.49). The following are empirically found examples of some key reasons for the occurrence of an intermittent water droplet corona or continuous corona at the fitting:

- A reduction in the rim diameter at the fitting,
- A lower field-homogenising effect of the conductor bundle in the case of an extended fitting, especially if there is no additional corona protection,
- No type tests performed for the entire string; design errors not detected,
- No overall responsibility because various suppliers are involved in the manufacture of the insulator and the hardware components of the insulator set; corona protection not adjusted to the components,
- No correction for installations over 1’000 m in height,
- A reduced fault tolerance for the insulator fitting in relation to production-related variations in surface roughness in the galvanisation (zinc layer) process.

Are there non-standardized empirical threshold values for corona prevention supplementing Cigré rules and IEC standards? Cigré TB 284 explicitly does not provide any threshold values for permitted field stresses on the insulating material and hardware components. The permitted insulating surface field stress range for AC stressing, in order to prevent water droplet corona, is described in the literature on the basis of model testing and tests on silicone insulators up to 500 kV, and lies between 4 kV/cm and 7.5 kV/cm (IEEE Taskforce on Electric Fields and Composite Insulators 2008; Phillips et al. 1999; Braunsberger et al. 2004; Nixon et al. 1998; Swift 1993; Windmar 1994). An IEEE publication from 2008 contains a summary of simulations, service experiences involving various manufacturers, model testing

Table 11.12 Empirical threshold values for composite insulators (and composite insulator sets) in AC-applications (IEEE Taskforce on Electric Fields and Composite Insulators 2008)

Occurrence of corona	Duration	Part of the insulator set	Threshold of highest field stress [kV/cm]	Verification by Test under dry conditions	Simulation under dry conditions
Dry conditions	Continuous	corona ring or combined corona/arc protection ring, insulator end fitting	$\leq 17^{**} \ldots 21$	x	x
Moist conditions	Intermittent	Insulator shank housing	≤ 4.5 for a length ≤ 10 mm	-	x
Moist conditions	Intermittent	Seal*	3.5	-	x
Dry and moist conditions	Continuous/intermittent	In the insulator (rod, housing and the interface between the two)	≤ 30	-	x

Explanatory note: * For designs without an embedded fitting (non-overmould)

** Highly-corrosive environment

and materials testing and may be recognized as important guiding document for this subject (IEEE Taskforce on Electric Fields and Composite Insulators 2008). The aforementioned permitted field stress range can be extended to include other parts of an insulator string/set (Table 11.12).

The value 17 kV/cm was obtained from local experiences in Canada where, after 20 years in service, the corona inception voltage can fall by 20 % due to corrosion of the surface of hardware components (Phillips et al. 2009).

A recently finished paper (Phillips et al. 2014) summarizes comprehensively current experiences and results from the field as well as laboratory tests and the recommendations were slightly reformulated:

- Along the insulator sheath, the E-field should not exceed 4.2 kV/cm over a distance of more than 10 mm.
- For non-overmoulded designs, where the end fitting seal is exposed and a particularly vulnerable area a more stringent protection from high E-fields is to define. Considering that hydrophobicity loss may occur on SIR insulators where the E-field exceeds about 0.35 kV/mm an additional requirement is formulated: The E-field on the end fitting seal should not exceed 3.5 kV/cm.

In Papailiou and Schmuck (2012), composite insulators of a 420 kV network with a HTV silicone rubber housing but manufactured using different production processes were evaluated. It was one of the goals to correlate the electrical field stress values of Table 11.12 with the field stresses in service and possible changes found after 10 years. An electric field stress up to 8 kV/cm was found on the shank exceeding the recommendation of the threshold of 4.2 kV/cm. However, no critical changes or damages were found. It was concluded that high-grade insulating materials ensure safe operation even when the threshold value for water droplet corona is exceeded. This does not apply to insulator sets that are subjected to a continuous corona discharge.

To summarize briefly this section: By observing some simple and well-known rules, it is possible to prevent the occurrence of corona discharges on composite insulators or metal components of the insulator string/sets. Well service-proven current standards and introduced in the past for conventional insulator sets are applicable insofar as the occurrence of a continuous corona at hardware components or at the insulator end fitting can be tested directly. The phenomenon of water droplet corona, which depends on numerous factors, should be given special consideration in the case of hydrophobic composite insulators. The composite insulator design (i.e. the material chosen, the stability of the sealing system, etc.) and the stresses that occurs at the service location can play a significant role here. Not standardized in any standard yet, the threshold value 4.2 kV/cm is basing on field experience and laboratory measurements. It can be regarded as a conservative in the sense of safe recommendation, especially in view of the current trend whereby cost pressures are resulting in further developments with a lower fault tolerance.

11.4.4.3 Power Arc Protection

Various factors determine whether or not power arc protective fittings need to be used in an insulator string/set. Among them, network parameters such as the current value, duration and frequency of occurrence of a power arc are very influential. However, the basic set-up of the insulator string plays a significant role too. In this respect, it is to differentiate between the cap and pin design and the longrod design, because they behave differently when there is a power arc and therefore influence the philosophy of power arc protection. Composite insulators have a longrod design. Unlike porcelain longrod insulators, however, they have the distinctive feature of being able to be manufactured in one piece without any intermediate fittings, even for the highest voltage levels. As a result of this classification, many “power arc” experiences and rules associated with porcelain longrod insulators also apply to composite longrods. As shown in Section 11.4.4.2, the slenderness of the composite longrods results in smaller end fitting diameters, which makes it necessary to protect the insulator against corona at lower transmission voltages. This duty is often taken by aluminium ring constructions, which are almost unable to handle a power arc situation. This section will look into relevant design criteria for power arc protective fittings while considering the current practice of porcelain longrods as well as the many years of experience with string components and silicone composite insulators, all of which shaped the content of the Cigré TB 365 (2008). As reported in Cigré WG 22.03 (1991), the majority of AC electric HV and EHV overhead lines (operating at a maximum voltage greater than 100 kV) are equipped with protective devices (horns, rackets or rings). Some utilities (especially in Europe and Japan) have a systematic policy to use protective devices, which are mainly used to protect line conductors and insulator sets from power arcs. In this case, lines are equipped with these devices throughout irrespective of the voltage. Other utilities such as in USA, Canada or the former USSR have variations in their policies, depending especially on voltage level. The use increases with higher voltages in order to minimize radio interference due to corona effects and to improve the voltage distribution among the insulator sets. These findings of the past are still valid today.

A power arc can occur over an insulator or insulator string/set or between conductors for the following reasons:

- Inner or outer overvoltage (i.e. as a result of a surge caused by switching operations or lightning),
- Pollution flashover,
- Sufficient bridging of the striking distance by animals (either by direct contact or indirect contact through “bird streamers”),
- Electrical insulator failure (flashunder, dielectric breakdown, etc.),
- Conductor approach as a result of wind or galloping after ice shedding,
- Reduced electrical strength of air if fires occur below an overhead transmission line.

Flashovers followed by a power arc caused by a), c), e) and f) are mainly determined by air clearances and depend either marginally or not at all on the insulator technology used. In contrast to, the pollution flashover is heavily influenced by the insulator technology: Composite insulators have a smaller mean diameter and, in the case of housing materials with a lasting hydrophobic effect, they have a higher insulation strength than conventional insulators when pollution occurs. An electrical insulator failure can occur with cap and pin insulators (especially porcelain cap and pin insulators – see Section 11.4.1.1). It can also occur as an interface flashover or after prolonged tracking in the case of low-grade composite insulators (see Section 11.4.1.2).

The principle differences between corona and power arc protection devices can be contrasted as shown in Table 11.13.

In the following, design rules for power arc protection devices are presented.

Material

In the situation of a power arc, steel is superior in its behaviour in comparison to aluminium. At first, this can be attributed to the different melting points, which are 1’500 °C vs. 620 °C. Secondly, the arc movement rate on a steel fitting is 50 % higher than on a respective aluminium fitting. In other words, the damage-inducing combination of a slow movement rate and a low melting point occurs with aluminium and can cause holes to form in the profile (Figure 11.53 - left). Thirdly, if aluminium is ignited, the heat of combustion is five times higher than when steel is ignited. The thermal radiation is also more intensive. In the case of solutions that

Table 11.13 Differences between corona and power arc protection

	corona protection	corona and power arc protection often combined
Material	Majority made of aluminium, bent or cast	Steel, bent or cast, galvanized
Purpose of the shape	Optimization of electrical field	Optimization of electrical field and guidance of the arc to the end burning point
Attachment in the insulator string/set	Often direct attachment to the end fitting of the insulator	Direct attachment to the end fitting of the insulator in view cases however, not recommended

Figure 11.53 Power arc damage to an aluminium corona ring (*left*), aluminium corona collar (*middle*) and intensive thermal deterioration of the polymeric housing due to the aluminium combustion (Cigré WG B2.21 2008).

involve mounting aluminium rings close to the insulator fitting (Figure 11.53 - middle), considerable damage to the insulating material may occur if the direction of the power arc is unstable (Figure 11.53 - right).

Interestingly and fourthly, the better thermal conductivity of aluminium is quite detrimental because being combined with the low melting point. So, the critical temperature is quickly transferred to the inside of the profile and deformities may occur. The negative effect of this combination of properties was confirmed in a power arc test where the melting loss for aluminium electrodes was four to five times higher under the same conditions (Möcks 1982). It was also observed that material abrasion was not only oxidative but also occurred as metal vapour, which can deposit itself on insulators of adjacent strings as a permanently conductive layer.

Fault Current Density

In addition to the thermal effect of the power arc, the heat-generating effect of the fault current in the string elements is another important design criterion, when a reliable power arc protection is to design. Electro-magnetically determined, small ring electrode diameters are beneficial to the migration speed of the arc root. Tests involving steel electrodes and arc currents of 1 kA for an electrode distance of 25 mm have led to the empirical relationship $v \sim d^{-x}$ (with $x = 0.66$ for the current of 1 kA) (Gönenc 1960). The larger the diameter d (or ring height), the more likely the migration speed v is hindered by inverting current flow lines, which supply the

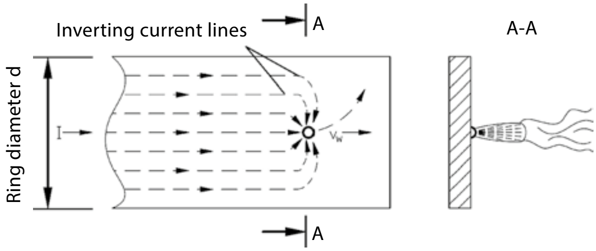


Figure 11.54 Influence of inverting current lines on flat electrodes.

power arc in the opposite direction of its migration (Figure 11.54). In this context, it is worth mentioning that corona rings manufactured from aluminium have a comparatively large diameter for an optimization of the electrical field. The aforementioned material "shortcomings" of aluminium in the case of a power arc are further intensified as a result of the reduced migration speed.

Out of the desire for a small diameter, however, physical limits are set from the perspective of combined corona protection and the permitted ampacity of the steel cross-section. The current flow through a steel cross-section results in a temperature rise to which the corrosion-protecting zinc layer on the surface is exposed. Zinc has a melting point of 440 °C, which restricts the permitted temperature rise. For a standardised current density of 1 second and an ambient temperature of 35 °C, this produces a value of 70 A/mm^2, which increases the temperature of the fitting to 400 °C, if the fault current flows through a cross-section of the fitting. (Note: The current density is without taking the skin effect into consideration.) For this reason, the following two current densities for string components are defined in the German standards, in particular (EN 50341-3-4 2011), and have proven their worth for many years:

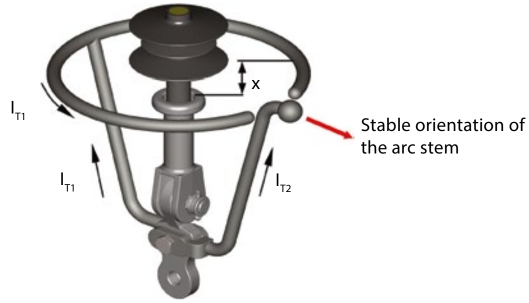
- String/set components that participate directly in transmitting the load should not exceed a fault current density of 70 A/mm^2 over a period of 1 s. These include shackles, eyes, and so on.
- String/set components that do not contribute directly to the load transmission should not exceed a fault current density of 80 A/mm^2 over a period of 1 s. These include power arc protective fittings, for example.

Resulting geometrical Design of Power Arc Protecting Devices

Key criteria for power arc protecting fittings irrespective of the insulator technology used can be summarized as follows, possibly including corona function (supplemented by Figure 11.55):

- Use of galvanised steel,
- Use of the smallest possible diameter in terms of corona protection for the ring electrode,
- An open ring at the end burning point,
- Unidirectional power arc supply for both the ring and end burning point,

Figure 11.55 Example of an open ring design with defined end burning point.



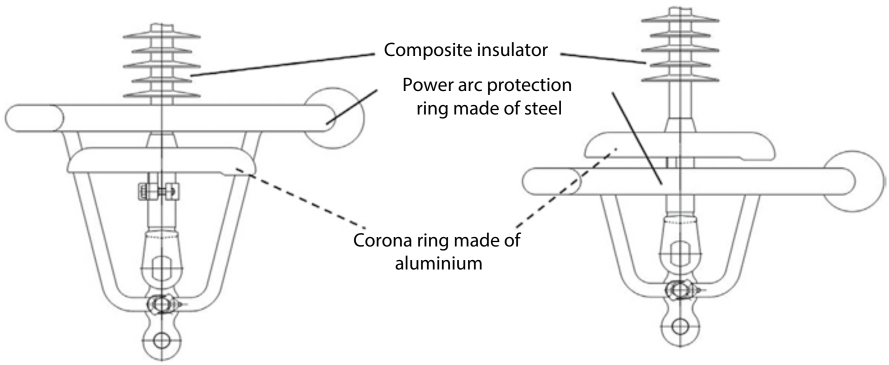


Figure 11.56 Coordination between corona and power arc protection - correct (*left*), – incorrect (*right*).

- Guidance of the power arc through recesses at the end burning point in the case of high short-circuit currents,
- Dimensioning of the end burning point from the perspective of corona behaviour and the expected power arc energy,
- Use of open rings as a replacement without opening the complete string.

The dimension x is the variable to optimize the electrical field stress at the first shank (see also Section 11.4.4.2).

Coordination of corona and Power Arc Protection, if not combined

Due to the wide range of production processes and solutions for the sealing system, etc., the ring design for corona protection is not standardised for composite insulators. For this reason, it has been established as common understanding that the composite insulator must be delivered with corona protection that has been tailored to its needs (one or two rings). If the insulator with corona ring(s) and the string/set elements are procured separately, it is critically important to coordinate corona and power arc protection. An example of correct coordination is shown in Figure 11.56 (left) whereby the power arc protective fitting is moved forward to shorten the striking distance and to take over a power arc relatively quickly. Since the aluminium corona ring does not have to guide the power arc until it is extinguished, it can be mounted directly onto the composite insulator fitting. An example of incorrect coordination, which can be critical to operations, is shown in Figure 11.56 (right). Such a situation can occur, for example, if a relatively small rod diameter is chosen in order to save costs, the crimp interface has to be extended and the power arc ring already exist with a given height.

This results in a longer composite insulator fitting and causes the corona ring on the insulator fitting to be moved. If this is positioned over the power arc protective fitting (as shown in the example), it is unlikely that it will take over the power arc. The aluminium corona ring will have to carry the power arc until it is extinguished and, depending on the power arc parameters, it may be thermally destroyed as a result of unsuitable material properties (see also Figure 11.53). Such a situation can be avoided by tendering and purchasing of complete insulator strings/sets with a defined performance responsibility.

Disadvantage of direct Attachment of Power Arc Protective Fittings onto Composite Insulator End Fittings

In individual cases, the power arc protective fittings are frequently not mounted onto intermediate fittings but directly onto the composite insulator end fittings. This solution has already been used in porcelain longrod insulators, but solely for small fault currents in the distribution network. This also applies to composite longrod insulators (Figure 11.57 - left). If, as in the example shown, a ring with end burning point is used to take over a power arc quickly and to facilitate corona protection, an adequate effect is ensured from the perspective of power arc protection.

The fault current flows directly over the composite insulator end fitting which has some limitations and resulting into possible disadvantages:

- If an end fitting with ball would be used, depending on the ball diameter (in accordance with IEC 60120), the 1-second residual current is restricted to the following values: 16 mm for 14 kA and 20 mm for 22 kA in order to adhere to the criterion of 70 A/mm^2.
- The fault current may cause the temperature of the insulator fitting to rise, which, in turn, can cause the glass transition temperature of the rod to be exceeded. In this case, compression between the rod and fitting diminishes and the tensile strength is also reduced after cooling down to ambient conditions. Tests involving a specific type of glass fibre rod, impregnated with epoxy resin and a glass transition temperature (Tg) of 110 °C, have shown that a temperature rise to 120 °C can result in a 20 % reduction of insulator tensile strength.
- The position of the ring is not clearly defined and requires precise instructions for the installation team.
- If conductor vibrations occur, the ring may loosen due to the gravitational force and move downwards if the tightening torque of the screws was not defined and was therefore too low.

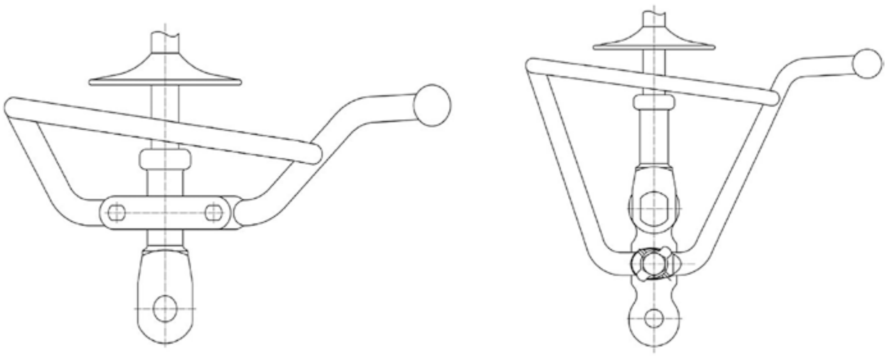


Figure 11.57 Composite insulator with a directly mounted power arc protecting ring (*left*) and with an intermediate fitting for its mounting (*right*).

If the fault currents are high, and to avoid incorrect installations, the most reliable solution is to use intermediate fittings to explicitly mount the power arc protective fitting at a pre-defined position (Figure 11.57 - right). Consequently, the fault current does not flow directly over the composite insulator fitting. For such a solution, tensile tests conducted after power arc tests on these designs have confirmed that there is no critical heat transfer from the intermediate fitting to the composite insulator fitting in terms of tensile force reduction quantified above. This is also in line with tests conducted for Cigré TB 331, which is a common document of Cigré WG B2.03, B2.11, B2.12 (2007). By these tests it could be demonstrated that, at a conductor temperature of 200 °C and higher, the temperature of the composite insulator fittings rises by only 30 K when compared with the ambient temperature. The smaller shed diameter of composite insulators in comparison to cap and pin insulators, and the longer length of the crimped end fitting, counteract positively large increases in temperature. However, since the wide range of string designs exists in the field, which were unable to be simulated in this test, a corresponding check is recommended when using high temperature conductors. This recommendation applies to both conventional and composite insulators.

Power Arc Testing

The first standard in relation to conducting power arc tests on insulator strings was published in 1997 (1st Ed. of IEC 61467). Up until that time, a short circuit test was frequently specified as a way to qualify insulator strings that short-circuited the flashover path at a low resistance. The short circuiting was by means of a cable with a sufficient cross-section, thus no power arc occurred. But with the availability of a respective standard, the behaviour of an insulator string can be evaluated in terms of possible multi-effects caused by a power arc test for which IEC 61467 provides good guidance. This includes the following aspects:

- Forces of the magnetic fields and effects of the current density on the entire insulator string,

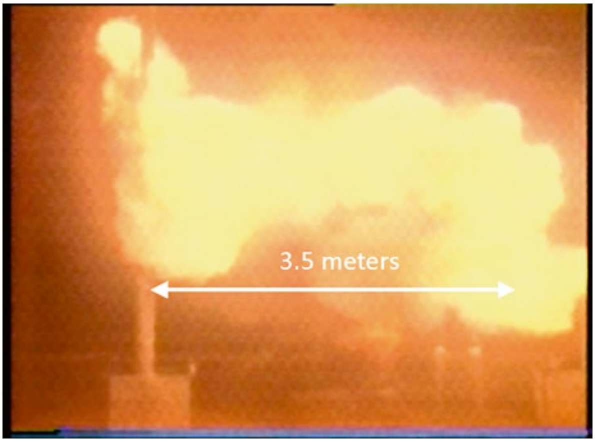


Figure 11.58 Power arc over a post insulator of a 420 kV isolated cross arm (30 kA) (Papailiou and Schmuck 2012).

- Formation of the power arc (Figure 11.58),
- Movement of arc stems,
- Thermal effect of the power arc on the insulator and metallic string components.

The standard IEC 61467 uses various test scenarios to consider the different installation positions in an overhead transmission line. Recommendations are provided for different combinations of the short-circuit current, time of short circuit and installation location in order to simulate typical network conditions (e.g. response time of network protection). Other than these, specific in-situ real-life network conditions can be simulated by using modified values. Experience has shown that smaller short-circuit current values cause less mobile power arcs and when typically tested with a longer short-circuit time, they can have a more damaging effect. After the power arc test, diagnostic tests are performed, which involve a visual inspection in accordance with certain criteria, a mechanical test and, in the case of cap and pin insulators, an electrical test to prove for puncture.

In Cigré TB 365 (2008), a comparison of power arc effects to conventional and composite insulators was provided and showed that both may be damaged in such a situation if they are not protected in accordance with the relevant operating conditions. This particularly applies to the thermal effect on load-transmitting metal fittings (e.g. thermal damage to a ball). However there are also differences, which mainly lie in the behaviour of the insulating material. Polymeric materials do not suffer from fractures or oxidative decomposition if the composition is correct (flame-retardant fillers or additions). From an operational behaviour perspective, and on the basis of many years of experience, other differences have emerged, which are presented in the comparison of Table 11.14.

A brief summary of this section: A power arc can be a critical event for conventional and composite insulators. However, by well introduced measures it can be controlled. The rules valid many years for porcelain longrods can be applied to composite insulators as well, because both share the longrod concept. In addition to

Table 11.14 Probability of occurrence and effects of power arcs to conventional and polymeric insulators (Cigré WG B2.21 2008)

	Porcelain longrod Glass or porcelain cap and pin insulator	Composite insulator (longrod)
Probability of occurrence of a pollution flashover[1)]	High	Low, for a hydrophobic surface effect[2)] and due to a smaller diameter
Probability of occurrence of an overvoltage-caused flashover.	In the first approach: same for an identical striking distance, power arc in the shortest air clearance or the sum total	
Thermal damage to the insulator if the power arc is poorly guided[3)].	Insulator may tear or split	No tears or splits, no significant abrasion of materials that have a high thermal and erosion resistance[4)]
Effect on the mechanical insulator function when the power arc is poorly controlled.	Loss of mechanical strength if the attachment to the fitting (cement) is thermally degraded and experiences an irreversible reduction in strength or if the (longrod) insulator fractures	If the attachment to the power arc protective fitting is unsuitable, the fault current flows over the insulator fitting or, if there is no power arc protection, the crimp connection may lose some of its strength when the rod's T_G is exceeded[5)].
Effect on the electrical insulator function when the power arc is poorly guided.	A reduction in the withstand values for the flashover voltage if the striking distance or creepage distance is shortened as a result of sheds that have been destroyed.	Damage to the seal and housing critical[6)], inappropriate housing materials can form conductive residues.

Explanatory notes:
1) Assuming that pollution flashovers may occur
2) If there is a hydrophobic effect (recovery, transfer, etc.)
3) The duration, stability and intensity of the power arc are damaging factors.
4) Critical is damage to the seal at the triple junction or exposure of the rod to environment (Fig. 11.59- left).
5) Polymers that are filled with ATH and with the flame classification V0 (IEC 60695-11-10) (Fig. 11.59 - right)
6) Glass transition temperature

the key criteria shown in Figure 11.55, the following aspects can be mentioned in relation to power arc protection for composite insulators:

- Depending on the design and installation situation concerning the composite insulator, corona protection must be provided as of 145–245 kV. This generally involves ring-shaped aluminium profiles. Since corona protection especially made of aluminium is not resistant to power arcs, it must be coordinated with power arc protection made of steel components.

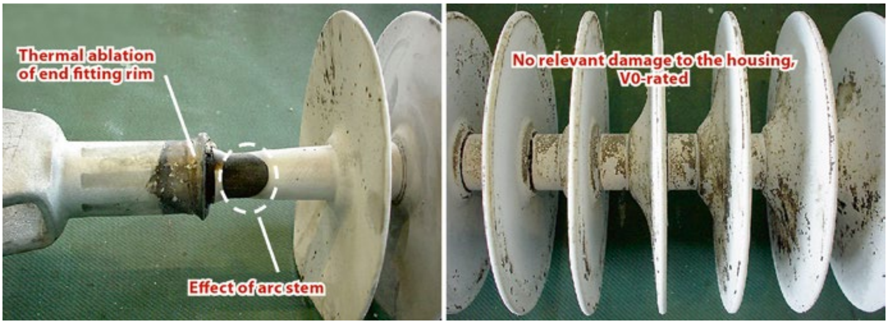


Figure 11.59 Defunctionalised seal and molten end fitting rim on the HV side (*left*), no damage to the housing part (*right*).

- "Packet solutions" in the form of entire strings/set including insulators are recommended whereby corona and power arc protection are combined with a steel fitting.
- Generally, it is not possible to fit composite insulators with power arc protective fittings that are used for conventional insulators; this is due to the different fitting lengths and the requisite corona protection.
- Due to a limited ampacity, power arc protective fittings can only be mounted directly onto the composite insulator fitting if the fault currents are small.
- The proven values for the permitted current density in the event of a fault (namely 70 A/mm^2 and 80 A/mm^2) are valid irrespective of the insulator technology used and therefore are also valid for composite insulators.

All in all, the more than thirty years of service experience with composite insulators, showing a lasting hydrophobic effect, has shown that the probability of a pollution flashover occurring has been reduced significantly and the power arc protective fitting rarely has to provide any protection. However, overvoltage flashovers must be taken into consideration for example in zones of high isokeraunic level.

11.4.4.4 Polymeric Post Insulators and Insulated Cross Arm Arrangements

Polymeric Post Insulators

In contrast to composite long rods, composite post insulators are subjected mainly to loads which act perpendicular to the longitudinal axis of the insulator and thus produce bending stresses over the cross section of the insulator. These bending stresses reach their maximum value at the point at which the FRP rod is fixed in the metal fitting attaching the support structure of a steel lattice tower, a tubular steel or concrete pole, or the platform in a pole-mounted substation. As a result of this bending load, composite post insulators use FRP rods of substantially greater diameter compared to composite long rods. Whereas a diameter of approximately 32 mm (1.5 inches) is almost always sufficient for composite long rods (see also Table 11.9), composite post insulators require FRP rods having a diameter of up to 130 mm (5 inches) in some applications. Larger diameters are under development.

The mechanical behaviour of composite post insulators under bending loads will be discussed in greater detail hereinafter, paying particular attention to the failure mode and development over the years of test procedures for such insulators. Although insulators are generally primarily designed for static loads and are tested in this respect, in line applications vibration loads can occur and the behaviour of post insulators has been tested extensively with regard to such dynamic loads.

Bending Loads

The mechanical behaviour of composite post insulators was extensively investigated by Cigré WG B2.03 to understand the mechanisms and to provide information on suitable test methods for respective product standards. From 1996 to 2002, there were three respective documents published in ELECTRA (Cigré WG 22.03 1996b, 2000b, 2002). An important technical approach was the adoption of the model of damage limit, which was successfully introduced for composite longrod insulators (see Section 11.4.3.2). This was a logical step, because as in the case of composite longrod insulators, the FRP rod is ductile, which is why there is no physical separation of the insulating body in the event of mechanical failure of the insulator as it is known with porcelain insulators. Thus, in the case of a well designed but failing composite post insulator, there is no risk of a catastrophic line dropping. This behaviour is also described as *safe failure mode* (Schmuck and Papailiou 2000) and it applies only for the use of FRP rods. Post solutions which have a resin rod without axial glass fibre reinforcement or are a hybrid with a porcelain rod inside, will fail "conventionally" by part separation (Papailiou and Schmuck 2012).

However, this positive behaviour from the line safety point of view also means that the "failure load" cannot be defined so clearly. In particular, the FRP rod of the insulator may be damaged before noticeable change to the bending behaviour of the insulator occurs. This sort of damage can be caused by microcracks in the FRP material, it might not influence the short-term behaviour of the insulator, but may have a negative impact on its service life, since partial microcracks can further develop size-wise and discharges may be triggered then resulting in a negative impact on the electrical (and ultimately mechanical) strength of the material. It was therefore important to develop a test method in order to establish the mechanical loads at which this special failure modes start to form in the FRP rod. The used damage limit concept, which was presented for the first time in (Dumora et al. 1990), builds on the observation that FRP exhibits considerable creep as soon as it has been subjected to a constant load. In the case of composite post insulators subjected to bending load, this leads over time to a noticeable increase in their maximum deflection. To better understand this phenomenon, 1 m long FRP rods measuring 63 mm in diameter (2.5 inches) and in this case a composite post insulators before application of the silicone housing were subject purely to bending load for a period lasting a few weeks. The change *Df* of the deflection was measured over time *t*. If the measurement results are plotted in semi-logarithmically scale (Figure 11.60 - left) there are a family of curves which obey the following formula:

$$\mathrm{Df} = \mathrm{A} \log \mathrm{t}. \tag{11.6}$$

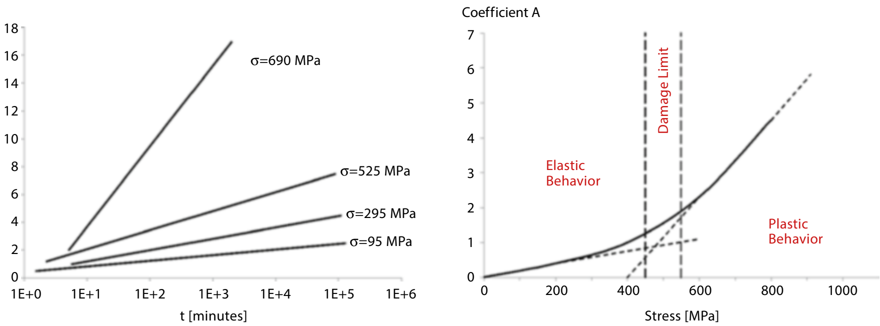


Figure 11.60 Change in deflection over time with bending stress as a parameter (*left*) and creep coefficient over bending stress (*right*) (Dumora et al. 1990).

The values of the coefficient *A* thus established are plotted in Figure 11.60 - right. The inclination of the respective curve changes with (nominal) bending stresses of approximately 500 MPa, calculated at the point of fixing. In the lower stress range, the FRP rod returns to its initial position after a certain relaxation time. For bending stresses above 500 MPa, the creep coefficient A exhibits non-linear behaviour. This means that greater loads (but in any case still below the failing load of approximately 800 MPa) lead to failure of the FRP rod within a few days.

If these insulators are relieved after a few hours, their deflection indeed noticeably subsides, but they retain a permanent deformation, which is dependent on the magnitude and duration of the load applied. To summarise, under just bending load (and at ambient temperature), FRP rods, and therefore composite post insulators, exhibit similar behaviour to a ductile, metal material, that is to say there is purely elastic deformation at lower loads and quasi-plastic deformation at higher loads. The bending stress which separates these two ranges is called the damage limit stress.

This concept was adopted within Cigré WG 22.03, with the objective of developing a workable test method (Cigré WG 22.03 1996b). A number of tests were carried out on different types of insulators for this purpose. In order to better compare the different types of insulators tested, the results were presented according to the nominal bending stress σ, which can be illustrated using the known formula of a beam fixed at one end:

$$\sigma = \frac{F_b\, l}{\sigma d^3 / 32} \tag{11.7}$$

σ = maximum tensile or compressive stress
F_b = external load (bending)
l = bending length
d = rod diameter

This is a permissible compromise for comparison purposes, because the state of stress in a bent insulator is much too complex to be illustrated by the simple formula above. In the first series of tests, the damage limit was established both by measuring the change in deflection over time, and by visual inspection of the surface of the rod for cracks, which is why the test insulators were manufactured without a silicone housing. For a better reproducibility and test comparability, all insulator manufacturers participating in the test provided insulators of equal dimensions, which were catalogued as follows:

- Short insulators having 45 mm rod diameter and 0.3 m bending length,
- Long insulators having 63 mm rod diameter and 1.2 m bending length.

These tests were carried out using the methods as described above. Over the course of these (non-destructive) methods, the parameter *Df*/log *t* (where *t* lasts from 0 to 240 h) is established as a result of 10 days of maximum continuous application of a constant bending load, and the damage limit is determined therefrom. Being without housing, the surface of the FRP rods was easily to inspect for visible damage once the load had been relieved. The damage limits thus established in line with Figure 11.60 – right are presented by the curves of Figure 11.61. It can be seen that, with values between 325 MPa and 425 MPa, the damage limits for short insulators are lower than for most long insulators, which have values between 475 and 600 MPa. Cracks on the surface of the rod were observed at bending stresses above 400 MPa and up to 450 MPa, indicating a delamination (first ply failure) of the composite material. In most cases, there was good correlation with the measurements established for change in deflection and the occurrence of delamination - no damage to the rod surfaces were identified below the damage limits.

In the second series of tests, commercially available insulators which had already been provided with a silicone housing were examined. There were involved two rod diameters of 45 and 63 mm, and the bending length was between 0.41 and 0.71 m. The insulators were installed and subjected to bending loads as they are subjected to in

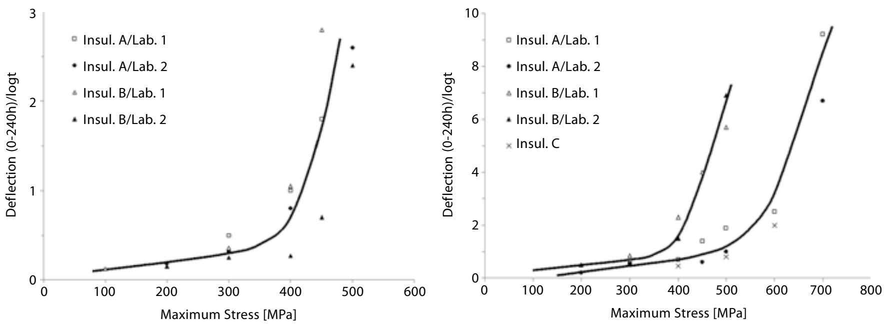


Figure 11.61 Deflection over the maximum bending stress for "short" insulators (*left*) and for "long" insulators (Cigré WG 22.03 1996b).

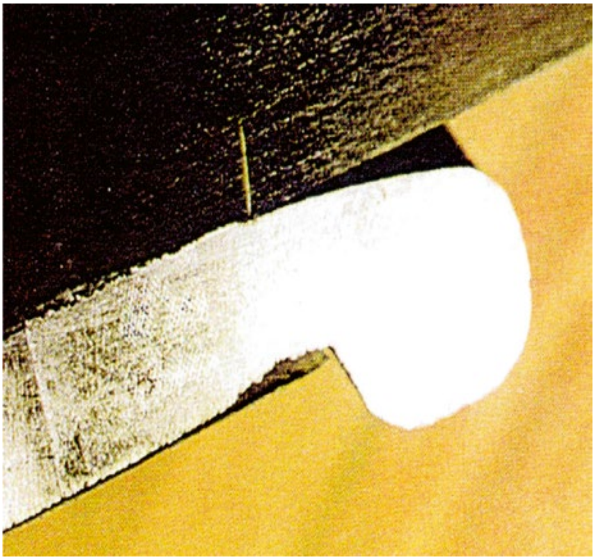


Figure 11.62 Crack on the compressed side of the rod.

service. After 4.5 days, the load was relieved and the FRP rod, including metal fitting, was carefully cut open along the plane defined by the rod axis and the direction of load. The interface was polished and examined for the presence of cracks. The test results for the insulators having a silicone housing clearly showed that both types of rod (having a diameter measuring 45 or 63 mm) were damaged below the previously established damage limit. The first cracks are almost perpendicular to the longitudinal axis of the FRP rod and are located on the compressed side of the rod, almost exactly at the point where the metal fitting ceases to contact the rod (Figure 11.62). The physical background of these cracks is a stress enhancement and further explained in (Papailiou and Schmuck 2012). An easy way for prevention is the introduction of an entry radius, which follows the rod deflexion. An interesting effect was found: whilst an insulator without a silicone housing exhibited such cracks on the compression side at 400 MPa, no cracks were formed in two similar insulators with overmoulded silicone rubber housing, up to 500 MPa. This indicates the positive effect in a sense of partial stress reduction by the effect of heat during injection moulding and covering housing.

The findings detailed above can be summarised as follows:

- The maximum bending load of a composite post insulator during operation is defined as the bending load which can be applied to the insulator without any damage to the FRP rod. This value is design-dependent and to establish by the respective manufacturer of the insulator.
- If composite post insulators experience bending loads above the maximum bending load (see above), cracks will start to form in the FRP rod, more specifically in the vicinity of the base end fitting and before it is possible to detect any external signs in the mechanical behaviour of the insulator. These cracks can be found as a result of an axial dissection or acoustic emission technique.

- With the exception of "long" post insulators, the failure begins on the compression side, just within the base end fitting. In long post insulators however, longitudinal delamination (typically in the neutral zone) of the FRP rod may occur beforehand.

These findings have been implemented in international regulations as design tests such as the standards IEC 61952 or 62213. In view of the Cigré findings, the following terms for test loads were introduced:

- The Specified Cantilever Load (SCL) is the bending load during testing which an insulator can *withstand* at the conductor side. This value is specified by the manufacturer and is understood as a withstand value and not failing value.
- The Cantilever Failing Load (CFL) is the maximum load which is achieved during testing of the insulator; it should be all time higher than the SCL also taking into account the scatter of failing of individual insulators tested.
- The Maximum Design Cantilever Load (MDCL) is the load above which damage to the core is initiated and which is the limit load for the loads occurring during operation. The MDCL is specified by the manufacturer on the basis of the above-mentioned IEC Standards. The associated test procedure is briefly described in the following. As "rule of thumb", the MDCL is normally approximately 25 % below the DLL (Damage Limit Load) of a particular design.

For the determination of MDCL, three insulators provided with the standard end or special fittings if used are to be tested by the manufacturer. The total length of the insulators must correspond to 15…18 times the core diameter unless the manufacturer does not possess equipment suitable for the manufacture of insulators of this length. In such a case, the insulator length must be as close as possible to the range stipulated above. The base end fitting must be fixed rigidly during this test. The insulator is gradually loaded up to $1.1 \times$MDCL at ambient temperature of 20 ± 10 °C. The test load is maintained for 96 h. The load application is at the conductor attachment point of the head end fitting, perpendicular to the direction of the conductor, and perpendicular to the core of each insulator. It has been found useful that the deflection of the insulator at the point of the load application is recorded at 24, 48, 72 and 96 hours in order to provide additional, useful information. After the 96 hours, the following steps are necessary once the load has been removed:

- Visual inspection of the base end fitting for cracks or permanent deformation,
- Measurement of residual deflection.

Then, each insulator is cut in two at a distance of approximately 50 mm from the base end fitting at an angle of 90° to the axis of the core, then the bottom fitting is cut into two halves in the longitudinal direction in the plane in which the bending load was previously applied. The dissected interfaces have to be smoothed using an abrasive cloth (particle size 180). The interface halves are then inspected visually for cracks and delamination. Dye penetration testing is then carried out in

Figure 11.63 Post insulator dissected, no cracks, "test passed": left halve without dye, right halve with dye (Papailiou and Schmuck 2012).

accordance with ISO 3452 in order to detect any cracks at the interfaces. Failure while the load is applied, cracks, permanent deformation or defective threads in the end fitting, or the presence of cracks or delamination in the rod of a test specimen constitutes a failure of the test. The dye penetration test is also used in other product standards and very suitable for "discovering" fine cracks. The test specimen in Figure 11.63 has passed the test, whereas the test specimen in Figure 11.62 has clearly failed.

Often the question was raised, whether the values of MDCL, SCL and CFL can be achieved by one test, which is shorter than the 96 hour MDCL test standardized. Due to the key role of the MDCL determination for faultless operation of the composite post insulator, a simple short-time test was investigated by extensive testing. It could be demonstrated that the load deflection curve is suitable for establishing the MDCL (Schmuck et al. 2008). In practice, it is thus sufficient to determine the MDCL from the slope increase in the load deflection curve, that is to say the point at which the non-linearity of the curve starts (Figure 11.64). The cantilever failing load (CFL) can also be established by continuing this relatively simple test until failure of the insulator.

Combined Loads

So far, the post insulators subjected to a single bending load were considered. However, line post insulators are often stressed to bending in the vertical and horizontal directions, and sometimes also to compression in the axial direction. The vertical bending load (V in Figure 11.65) is primarily caused by conductor weight, whilst the longitudinal load (T) is primarily caused by conductor tension. Axial compression loads (H), and also tensile loads (Z), are produced by the wind perpendicular to line direction, and in the case of angle towers by the angular force caused

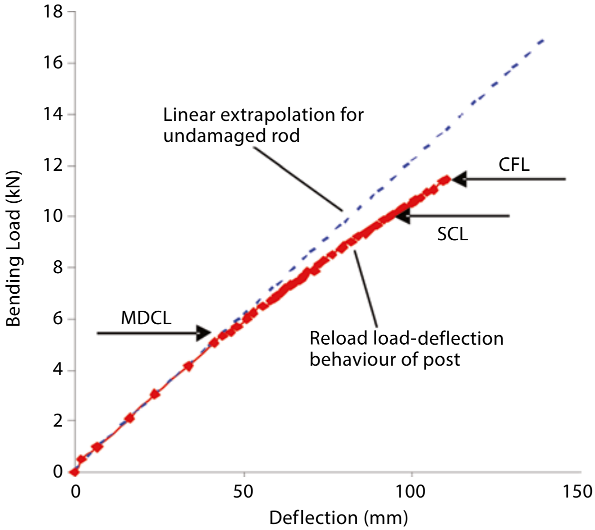


Figure 11.64 Load vs. deflection diagram for determining the MDCL, SCL and CFL in the case of a 38 mm post insulator.

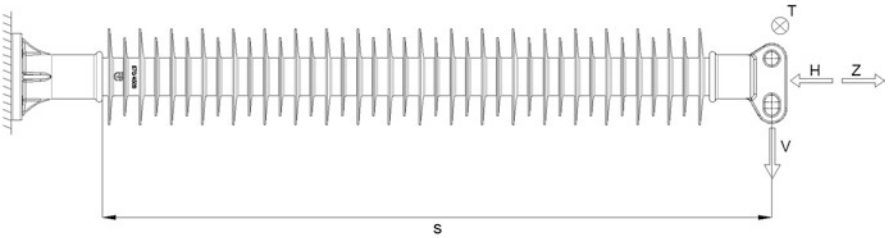


Figure 11.65 Load occurrence of a horizontal post insulator.

by the change in line direction. Ultimately, all of these forces have to be taken into consideration when selecting a suitable insulator. In practice, this occurs by the use of load diagrams so-named application curves. As it is shown later, there are simple analytical formulas for line post insulators, and they can be used with satisfactory results up to a maximum deflection of approximately 10 % of the length of the insulator. Computer simulations have to be used for greater deflections.

For a correct choice a composite post insulator, the user must consider the line data and operating conditions to determine the loads at the head fitting of the insulator in the vertical, longitudinal and axial directions. Local rules call for factors of safety, which take into account uncertainties when determining these loads. Having these information, the manufacturer of the post insulator, who has determined the permissible maximum mechanical stress of the insulator by MDCL testing, must control which combinations of these loads could occur and that the stress limits are not exceeded within the combinations. This is reflected by the application curves which are actually based primarily on the mechanical properties of the FRP rod. However, it may also be that the end fittings, in particular the base end fitting, are the limiting factor for a specific application. In the following examples, the shaded areas in the diagrams indicate that the strength of the fittings has been exceeded.

The following calculations (Cigré WG 22.03 1996b) are based on the assumptions below (see also Figure 11.65):

- Both metal fittings of the insulator are assumed to be completely rigid. The same assumption also applies to the tower or pole to which the insulator is fixed. The loads are applied at a point at the head fitting of the insulator, arranged in line with the axis of the insulator.
- *V* is the vertical load; it is applied in the direction of gravity but is not necessarily perpendicular to the axis of the insulator.
- *T* is the longitudinal load; it is applied perpendicular to both the vertical load and the axis of the insulator.
- *H* and *Z* are transverse loads. *H* is a compression load which acts perpendicular to the axis of the tower, whereas *Z* is a tensile load (for the insulator) directed away from the tower.
- σ is the maximum allowable tensile or compressive stress (assuming there is no prior damage to the FRP rod) at the neck of the base end footing produced by any combination of all above loads and calculated by the formula $\sigma = M/W$.

As described above, the value of σ is largely dependent on the material properties of the FRP rod, but also on the crimping method and on the rod diameter. For the examples, a conservative value of $\sigma = 400$ MPa was selected for a rod diameter of $D = 63$ mm. *E* is the modulus of elasticity of the FRP rod with a value of E = 37 GPa. The lever arm s is the distance between the head fitting of the line-side fitting of the insulator (point of load application) to the point at which the FRP rod enters the base end fitting. This lever arm is normalised to be s = 1’000 mm in all the examples. The examples of the application curves were created both analytically and by computer calculations, the results being practically identical. Two cases were taken into consideration: Fully horizontal orientation of the post and an inclination of 15° to the horizontal axis.

The left diagram of Figure 11.66 uses the following equations:

Compression case

$$M_H = \sqrt{\frac{\left(V^2 + T^2\right)EI}{H}} \tan\left(s\sqrt{\frac{H}{EI}}\right) \tag{11.8}$$

Tension case

$$M_Z = \sqrt{\frac{\left(V^2 + T^2\right)EI}{Z}} \tanh\left(s\sqrt{\frac{Z}{EI}}\right) \tag{11.9}$$

whereby the moment of inertia of the FRP rod is calculated by

$$1 = \pi\ D^4 / 64 \tag{11.10}$$

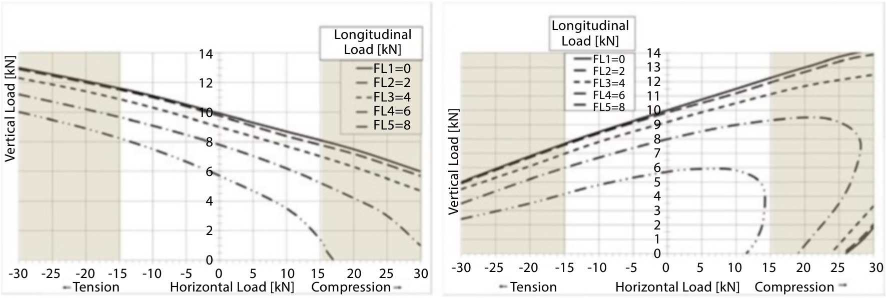


Figure 11.66 Analytically generated application curves for a horizontal post insulator, (*left*) and for a horizontal post insulator with 15° inclination (*right*).

The stress on the FRP rod can therefore be calculated as follows:

$$\sigma = \frac{M_{H/Z}}{W} \tag{11.11}$$

In the right diagram of Figure 11.66 the inclination must be considered, which leads to the following equations:

In this case, the above formulas were adapted as follows (dashed variables are the loads in the global coordinate system, whilst un-dashed variables are the loads based on the coordinate system of the insulator).

$$V = H' \cdot \sin(\beta) + V' \cdot \cos(\beta) \tag{11.12}$$

$$\mathrm{H} = H' \cdot \cos(\beta) + V' \cdot \sin(\beta) \tag{11.13}$$

$$\mathrm{Z} = Z' \cdot \cos(\beta) + V' \cdot \sin(\beta) \tag{11.14}$$

Computer simulation was performed by means of finite element calculation for these load cases. An advantage is that the program not only calculates the stresses along the insulator, but also the deflection of the insulator. As already mentioned, since there is practically no difference between the load diagrams created using analytical formulas and those created using computer simulation, the computer simulation is not further implemented.

Important to note that the calculations of Figure 11.66 were confirmed by laboratory tests. The maximum deflection of the insulator calculated by computer simulation was used as a comparison parameter. Four different combined loads from V, H or Z were applied for each of four axial loads L, a total of 16 load situations being tested overall. The loads were selected in such a way that their vector sum produced a maximum stress of $\sigma = 320$ MPa, which is slightly lower than the damage limit established before. The difference between measured and calculated deflections was 4.1 % on average, with a maximum value of 15 % (Cigré WG 22.03 1996b).

Dynamic Loads

Cigré WG 22.03 decided to also examine the behaviour of FRP rods under dynamic loads, because they are present in each line such as wind-induced vibrations and ice shedding, in addition to static loads primarily caused by the conductor weight and by wind. Such dynamic loads may lead to material fatigue, even if the stresses generated thereby remain below the static damage limit determined before. In turn it calls into question whether the purely static test for determining the damage limit is sufficient. The results will be discussed hereinafter (Cigré WG 22.03 2000b).

The test specimens were taken from two different types of insulator which were similar to the insulators used for the static tests. One type had no housing so as to facilitate a visual inspection of the surface of the rod during the dynamic tests. These insulators had a rod diameter of 63 mm, crimped base end fittings and a bending length of 1.2 m. The second types of insulators were completed with their housing. They also had a 63 mm FRP rod with crimped base end fittings, but were slightly longer at 1.4 m. The test specimens were mounted and loaded as they supposedly are during operation, i.e. a static load was first applied and this was then superimposed a cyclic load, as shown in Figure 11.67.

The peak load (static+cyclic) was selected in such a way that the total stress thus calculated remained below the static damage limit of the rod (this damage limit was calculated to be approximately 400 MPa). One load cycle lasted approximately 9 s, whereby the 10^6 load cycles deemed to be necessary lasted approximately 4 months. The load amplitudes were selected in such a way that they corresponded to the actual loads during operation for typical 45–138 kV lines in which such post insulators are primarily used. So, the static loads were between 25 and 80 kN, and the dynamic loads were between 6 and 60 kN (peak to peak). The ambient temperature was set between 18 and 28 °C during the test. In most cases, two insulators were tested for each load level. At the end of the tests the insulators were examined for the presence of any damage (delamination, cracks, or both). The test results can be summarised as follows:

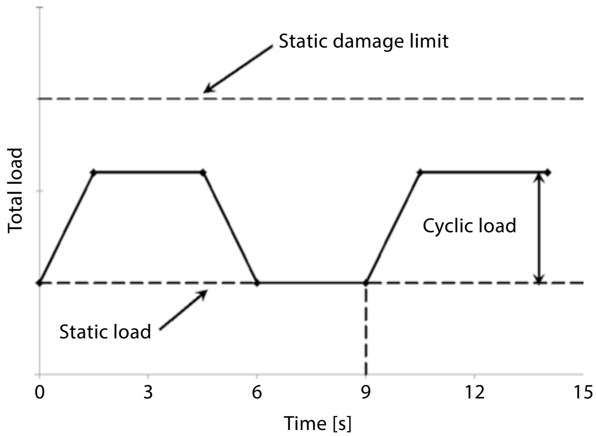


Figure 11.67 Load cycle for the dynamic tests.

- No damage could be determined with peak stresses in the rod up to 270 MPa (corresponding to a bending load of 37 kN (static) and 18.5 kN (dynamic).
- Damage was only determined at peak stresses in the rod above 390 MPa (corresponding to a bending load of 80 kN (static) and 18.5 kN (dynamic).
- Additional tests are recommended for determining the behaviour of the insulators in the range between 300 and 400 MPa.

To summarise, it is found that, except for quite specific cases in which the dynamic load exceeds 30 % of the static load, it is not necessary to establish a new test to examine, specifically, the dynamic load behaviour of composite post insulators. The test based on the MDCL concept, described before and employed in the product standards, should be sufficient to cover both static and dynamic load situations.

Insulated Cross Arm Arrangements

The concept of insulated cross arms is a well accepted solutions for future new lines for minimizing their impact by compacting such as for the use of existing corridors for voltage upgrade, reduced Right of Way (ROW) in forest or city sections, construction of lines along the highways or on the central verge of the highways. The installation of new or the voltage up-grade of existing transmission lines through urban areas is often a special challenge in respect to constraints of ROW aspects, regarding the threshold values of audible noise, radio interference, electrical and magnetic field determined by the local rules and authorities and to aesthetic impact. Compact line arrangements are well accepted solutions to solve such situations (Hoffmann et al. 2010; Soerensen et al. 2010; Lee et al. 2010; Hoekstra et al. 2010). The first installations of compact lines were reported for the 70's from Canada (Havard et al. 1991) and Greece (Voyazakis 1988), at these days still using porcelain insulators. With the progress in the composite insulator technology, optimized solutions were developed (Paris et al. 1991) and the introduction of composite interface phase spacers (see also Section 11.4.4.5) additionally to insulated cross arms was considered for further line compaction (Karaday et al. 1991). Compact line installations are typical tailor-made solutions, which were always accompanied by the development of appropriate computer simulation models (Kennon 1991; Baker et al. 1982). The available design knowledge and field experience was summarized in an IEEE guide, published in 2008 (Baker et al. 2008). In 1998, the first 420 kV compact line section was erected in Switzerland (Ammann et al. 1998). This line required a high buckling load resistance of the post. Due to the size limitation of the available diameter rods at this time, a solution with a single hollow core was preferred instead of using two parallel rods. The experiences from testing and later from service with this first generation has triggered further developments of the concept, and today the 3+ generation is available with single, high strength rods of larger diameters up to 130 mm, larger diameters are under development (Schmuck et al. 2004; George et al. 2007; Papailiou and Schmuck 2011; Papailiou et al. 2013). In terms of attachment to the pole or the tower, it is differentiated into braced line post (rigid) or horizontal Vee (pivoted) (Baker 2013). Rigid solutions with double posts and non-circular post cross section are in field trials (Rowland 2013).

The existing experience with compact line is thoroughly positive. This can also be attributed to the redundancy aspect, since a braced line post or horizontal Vee is

Table 11.15 Pros and cons of compact lines with braced line post or horizontal Vee arrangements (Lakhapati et al. 2014)

Pros	Cons
Less ROW consumption, cost savings in property required and time needed for permissions	Often but not necessarily shorter span lengths
Cost savings for tower and foundation construction because of smaller bending moments due to the shorter isolated cross arms compared to conventional steel lattice cross arms	Increased RIV or corona level possible because of shorter distances between phase conductors, if conductor configuration is inappropriate and/or inadequate hardware is installed.
Aesthetically pleasing tower configurations possible (landmark art concept)	More demanding conductor stringing process
Reduced electro-magnetic field at ground /21, 22/	Live-line-work can be an issue for double circuit towers.
Higher power transfer capacity because of lower surge impedance /18/	Mechanical stability problems, when the number of horizontal Vees becomes too high in relation to in-situ wind scenarios.
Fail-safe redundancy because of the use of two insulators.	Braced line posts or horizontal Vees are not a commodity and so more costly to conventional strings but additional costs are negligible concerning to the savings.

a string of at least two insulators. Furthermore, the non-brittle nature of a large-diameter composite post provides additional safety in the case of a failing bracing longrod. The pros and cons result from by the experience and can be summarized as shown in Table 11.15. It has been shown in various projects that the "Cons" can be solved by individual engineering solutions having a close cooperation between utility, line designer, tower and insulator manufacturer and architect. For example, in 1998 when the 420 kV line with compact section in Switzerland was erected, no installation rules existed for the insulated cross arm made of composite material and silicone rubber housing on which the linesman should not walk on. The easy solution was the pre-assembly of the insulated cross arm on the ground and the temporal attachment of aluminium frames during installation and conductor stringing (Ammann et al. 1998). In another example, the tubular poles had a modular structure and the insulated cross arms were preassembled on the ground and fixed to the tower segments, in order to simplify the erection process with considerable cost savings in comparison to a lattice tower (George et al. 2007).

When comparing braced line post and horizontal Vee arrangements, their main difference lies in the fact that, in the case of a rigid connection, the post insulator also has to withstand forces in line direction, since its rigid fixing, does not allow any rotation (Figure 11.68). The loads which act on an insulated cross arm, are vertical loads V from the conductor, and, if present from ice, horizontal loads H from the wind and again if present from angular pull, and longitudinal loads T, possibly from non-uniform conductor tension in the adjacent spans or from a conductor break (exceptional load – extremely rare).

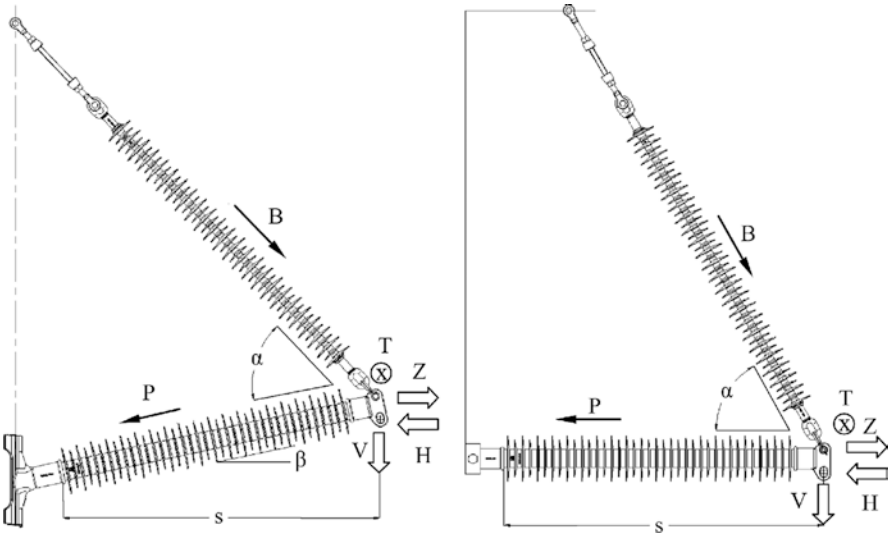


Figure 11.68 Schematic view of a braced line post (rigid – *left*) and a horizontal Vee (pivoted – *right*).

In both cases, rigid or pivoted, the vertical loads are largely taken up by the brace, irrespective of the angle α between the brace and post. By contrast, horizontal loads, when acting in compression, stress the post in buckling. The insulator forces, that is to say the force P on the post and the force B on the brace, are calculated relatively easily using the following formulas (assuming $T = 0$):

$$P = H\frac{\cos(\varphi + \vartheta)}{\sin(a)} + V\frac{\sin(\varphi + \vartheta)}{\sin(a)} \tag{11.15}$$

$$B = H\left[\frac{\cos(a)}{\sin(a)}\cos(\varphi + \vartheta) - \sin(\varphi + \vartheta)\right] + V\left[\frac{\cos(a)}{\sin(a)}\sin(\varphi - \vartheta) + \cos(\varphi + \vartheta)\right] \tag{11.16}$$

The load in line direction T only needs to be taken into consideration in the case of a rigid connection, but may be the decisive factor in the dimensioning of the cross arm. In addition to the use of high-strength posts, the use of a bottom fitting having a fail-safe base and suspension of the line using a load release clamp may also be of use. Should the post of an insulated cross arm fail nevertheless, there should follow no cascade, since the failing load of the remaining, healthy brace (composite longrod) is normally sufficient to prevent the risk of line release. If in doubt, a double tension string with composite longrods as the string is used.

Table 11.16 Technical ranking of post solutions in a cross arm arrangement (Lakhapati et al. 2014)

Property/characteristics	Single post	Composite hollow core	Hybrid post*	Double single post
Weight	1	2	3	2
Pollution performance	1	2	2	3**
Torsion and buckling strength	3	2	1	2
Brittleness (vandalism resistance, shock load behaviour)	1	1	3	1
Technical demand in insulator manufacturing	1	3***	1	1

1 = best, 3 = worst, * = fully covered by silicone rubber housing, ** lower flashover values as a single post because of possible proximity effect, *** internal space requires filler

In terms of post buckling of horizontal Vees, the resulting compression force becomes the main design parameter of the insulated cross arm. The E-Modulus of a glass-fibre reinforced rod is approximately half of the value of an equivalent porcelain insulator. Hence, the composite rod starts with an elastic buckling at lower values than the porcelain equivalent, however without the risk of a breakage. So, depending on the post insulator length and magnitude of the compression force, different solutions exist long posts and high forces:

- Single post made of a massive core,
- Composite hollow core,
- Hybrid post,
- Double single post, both as massive cores,
- Post with non-circular cross section.

The solutions 1) - 4) are compared in Table 11.16 in regard to their different properties/characteristics. The use of a single post is the preferred technical solution, however if the forces are too high for the rod diameter available, one of the other solutions has to be considered. Positive experience is available with hollow core insulators, when their internal space is filled in a way that no cracks are formed in the interface between the filler and the internal tube wall and the filler itself is free of partial discharges (Ammann et al. 1998). This becomes the critical part of the production process, especially when large dimensions are required as for voltage applications higher than 420 kV. In the case of a double single post, its flashover value under pollution conditions will be smaller in comparison to a single unit, because the power arc can develop on both units. However, if a housing material with hydrophobicity transfer mechanism such as silicone rubber is employed, this situation is not very likely.

Rigid Insulated Cross Arms – Braced Line Post

Since in insulated cross arms having long posts and for lines of higher voltage significant deformations often occur, it is recommended to carry out a numerical simulation

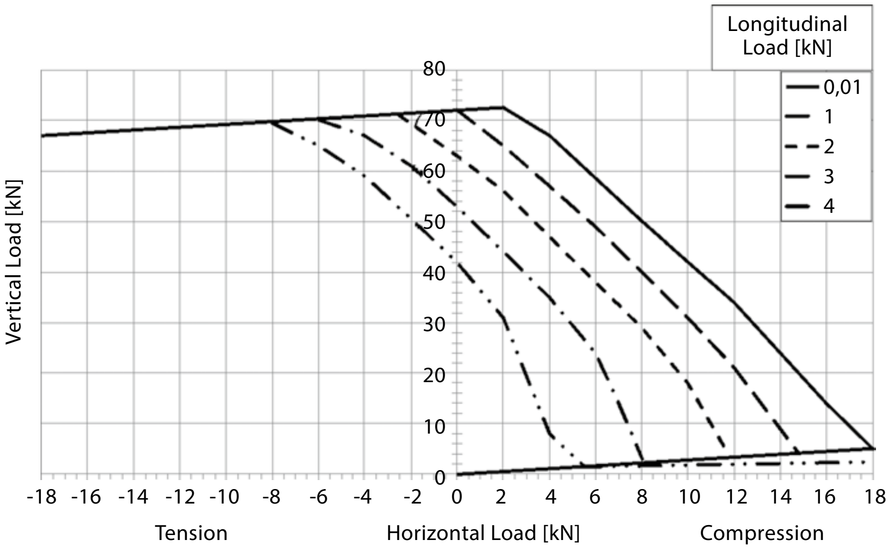


Figure 11.69 Loading diagram for a rigid isolated cross arm (Cigré WG 22.03 2002).

for the dimensioning of rigid insulated cross arms. For example, Cigré WG 22.03 used a FEM calculation program to generate application curves as presented in the case of line post insulators in Section 11.4.4.4.1. This will be discussed briefly hereinafter (Cigré WG 22.03 2002). For these calculations, it was assumed that all three forces ideally act at one point at the tip of the cross arm. The inclination angle of the 63 mm post was 15° and its length 2’000 mm. The coupling angle of the 16 mm brace to the tower was 45°. The brace being assumed to be pivoted at either end, in contrast to the post, which was fixed in a rigid manner to the tower. The corresponding loading diagrams are illustrated in Figure 11.69. The load of the brace should not be negative (compression) so as to prevent a buckling of the brace leading to contact between the metal fittings of the two insulators; the latter is inadmissible and could give rise to RIV disturbances. With the horizontal angle of the post insulator of 15° as used in this case, this condition leads to the inequality: $V > H \tan 15°$. In this diagram, the lower straight line corresponds to the equality $V = H \tan 15°$, that is to say the brace is not loaded along this line, or in other words the insulated cross arm should not “work” below this line. The upper straight line in the diagram extends parallel to the lower straight line and corresponds to the maximum allowable tensile load of the brace. The results of the calculation were checked by measuring the deflection of the tips of the cross arm for nine different load situations. The average value of the deviation between the measured and calculated deflection was 8.1 %, with a maximum value of 15 % and a standard deviation of 4 %, which can be considered to be in relatively good correlation.

Pivoted Insulated Cross Arms – Horizontal Vee

This is the most commonly used arrangement, in particular for higher voltages, since it has a high level of mechanical strength and is also fault-tolerant. The static calculation of the pivoted insulated cross arm is similar to the calculation just described for rigid cross arms. The external loads which act on the tip of the cross arm in the horizontal and vertical direction (Figure 11.68 - right) are first decomposed into their respective components in the direction of the brace and of the post. With the assumption of an equilibrium of forces in the longitudinal (line) direction ($T = 0$) and with the same notation as in Figure 11.68, the loads B for the brace and P for the post are given from the two equations 11.15 and 11.16. The composite longrod in the brace is typically loaded purely by tension and can be dimensioned relatively easily. By contrast, the post is loaded by compression and, since it is articulated at both ends in this case can be calculated as a Euler buckling beam with the maximum tolerable compression load. However, when calculating the buckling it must be noted, that by the practically unavoidable eccentric application of the compression load (Figure 11.70 - left), the post insulator is additionally subjected to bending. The negative influence of this eccentricity can result to higher loads achieved from the conventional buckling formula. A considerable reduction of the measured failing load compared to the theoretical buckling load can be seen. One possibility for reducing this harmful additional bending load is the use of special fittings, for example the so-called "boomerang" (Figure 11.70 – right).

In practice, the unavoidable friction in the many joints of the cross arm is also to be taken into consideration, since these may have a considerable effect on the mechanical behaviour of the cross arm. Due to all these uncertainties, it is recommended that such insulated cross arms also be subjected to mechanical testing as a whole in addition to the type tests as stipulated in the various IEC Standards, some of which are unfortunately based only on the individual components (insulators) of the cross arm. In such

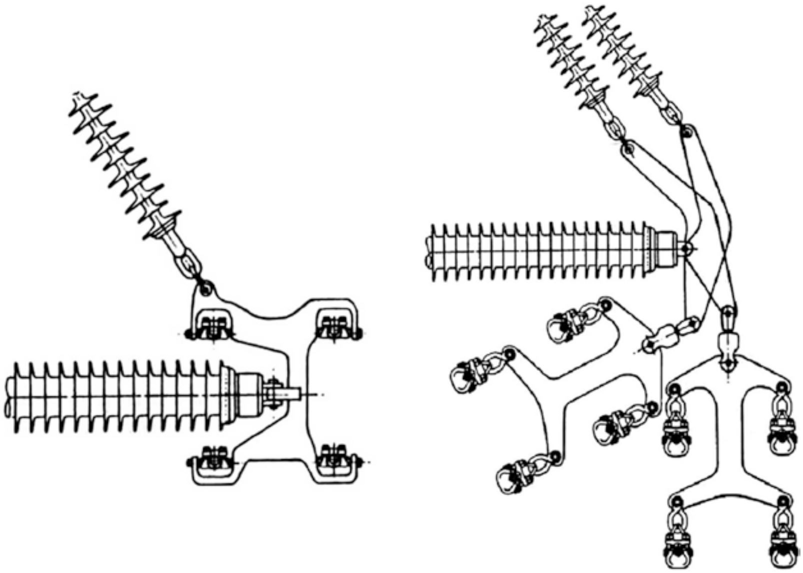


Figure 11.70 Eccentric application of compression load via the conductor fitting in a quad bundle (*left*) and boomerang fitting ensures a central application of load (Paris et al. 1991).

Figure 11.71 Swiss 420 kV horizontal Vee, commissioned in 1998 (*left*), DEWA's 420 kV horizontal Vee, commissioned in 2007 (*middle*) and the Dutch 420 kV horizontal Vee solution of TenneT, commissioned in 2011 (*right*).

Figure 11.72 Winter situation at the highest European 420 kV line across the Alps (*left*) and introduction of interphase spacers to prevent conductor drop by ice shedding (*right*).

a mechanical test, the insulated cross arm should withstand the maximum allowable loads without permanent deformation or other damage (George et al. 2007).

Important aspects of cross arms are dynamic loads for both pivoted and rigid as well as stability for pivoted ones. More information on these subjects can be found summarized in (Papailiou and Schmuck 2012).

Some examples of installations are shown in Figure 11.71.

11.4.4.5 Interphase Spacers

As discussed previously, line compaction is primarily based on the principle of minimising interphase spacing. As a result of this, and also since the interphase spacings are somewhat smaller than those encountered in the case of normal overhead transmission lines, there is greater risk of interphase flashover for a compact design when two conductors of different phases move closer to one another, for example as a result of wind, ice shedding or short circuit. Interphase spacers (IPS) are used to avoid this (Figure 11.72). In the last few years, increased use of composite interphase spacers has been made possible due to the generally massive advances made in the development and acceptance of composite insulators. In this application, it has thus been possible to utilise the specific properties of composite technology, such as low weight, high flexibility and excellent hydrophobicity to name just a few.

A comprehensive summary of the current state-of-the-art of interphase spacers is provided in (Papailiou and Schmuck 2012) also under consideration of respective Cigré documents (Cigré WG 22.11 1992; Cigré TF B2.11.06 2007).

11.5 Outlook

Composite insulators for outdoor applications cannot be compacted in a way as known from capsulated or fully solid insulation systems, because the surrounding air determines the insulator length to meet the flashover withstand values as per insulation coordination or the creepage distance (dominates for DC). But this will not limit further innovations for the composite insulator technology as shown below as examples. An overall "warning" should be permitted. The positive development of the composite insulator technology has caused the impression that they are a commodity. The authors are not in line with this opinion because a line drop by a down-falling insulator of any technology by manufacturing fault or inappropriate specification has a high risk for damages to infrastructure and humans. This involves also the fact that purely commercial considerations result in cost savings, many times without being long-term proven, and providing a zero redundancy of the component.

11.5.1 Technology of Manufacture

The technology of manufacture determines significantly the costs and quality of the individual unit. Since the steadily growing acceptance of the advantages of composite insulators, the order volumes increased significantly and made a combination of high degree of automation and simultaneous flexibility desirable. Innovative solutions to mould the housing were developed (example Automated Continuous Injection Moulding – ACIM (Papailiou and Schmuck 2012)), which also provides advantages in service in comparison to conventional injection moulding. More material developments are expected for an increased efficiency and more failure redundancy during manufacture.

11.5.2 Applications

The development of insulated cross arms up to 765 kV was successfully finished and for applications of 800 kV HVDC as well as 1200 kV AC, composite insulators made as single unit are available.

In some areas, the impact of birds remains a topic. While the bird streamer can be prevented by measures on the tower cross arm, the direct attack and housing damages need the intensive analysis of the species attacking and a response by corresponding design of the overall insulator set.

11.5.3 Tests for Material and Insulator Selection

DC applications cause a different pollution distribution on an insulator surface as known and well describable for AC. Is there a loss of hydrophobicity in a way that thermo-ionized partial discharges are formed, the risk for a material deterioration is critically to evaluate. In view of this, the availability of test methods for DC and the answer whether any ranking by means of AC tests can be transferred to DC are important subjects to achieve reliable products for DC applications as they are introduced for AC in the meantime. This is relevant for both manufacturer of the composite insulator and its user.

11.5.4 Material Development

Biogenic pollution layers can occur without having a direct performance impact rather being an aesthetic issue. Often, an improper insulator stock can be the cause. The introduction of respective inhibitors, which have a broadband effect, but do not influence negatively manufacture processes and have no risk during manufacture and installation to the humans is close.

The use of particles that provide a micro-varistor characteristic to the polymeric surface has been investigated and positive effects especially under humid pollution shown. But the higher costs and process requirements are in a mismatch to the added value for a composite insulator with permanent hydrophobic behaviour.

11.5.5 Insulator Diagnostic

Conventional insulators have been used longer in the network as composite insulators. As a result, more service statistics is available with conventional insulators. Unfortunately, many composite insulator faults are still caused by missing knowledge of manufacturer newcomers, inappropriate technical project specification etc. For both conventional and composite insulator well established diagnostic methods do exist, which are under continues advancement. Current editions of live-line-work standards do consider networks with composite insulators now.

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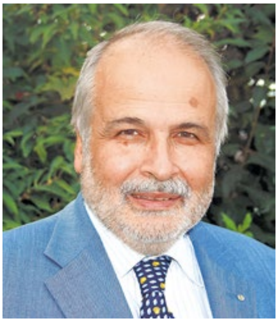
Frank Schmuck studied for his MSc degree at the University of Applied Sciences in Zittau, specialising in high-voltage insulating technology, before going on to earn his doctorate degree. In 2012, he received his post doctoral qualification as lecturer (Dr. Ing. habil.) from the technical University of Dresden. From 1992 to 1994 he was a scientific assistant at the Technology Centre North at Rheinmetall AG (Germany), before becoming Product Manager and Head of Development for epoxy resin-reinforced electrical components and composite hollow core insulators from 1994 to 1998 at Cellpack (Switzerland), Field of Advanced Composites. Since 1998 he has been employed by PFISTERER SEFAG, since 2009 in the capacity of Head of Development and Technology of the Centre of Competence for Overhead Transmission Lines and for OEM Products. Since 1994 he has been involved in international Cigré and IEC working groups, and since 2006 he has been the Convenor of the Cigré working group for insulators. Since the beginning of 2012 he is also Chairman of the Swiss Technical Committee 36, Insulators. He has more than 70 publications in professional journals of Cigré and the IEEE, and since 2007 he has been a columnist for the international insulator magazine “Insulator News and Market Report”. In 2012/2013 he co-authored the book Silicone Composite Insulators, which was released at the German publisher Springer in German and English languages. A Chinese version will be available soon.



Konstantin O. Papailiou studied electrical engineering at the Braunschweig University of Technology and civil engineering at the University of Stuttgart. He received his doctorate degree from the Swiss Federal Institute of Technology (ETH) Zurich and his post doctoral qualification as lecturer (Dr.-Ing. habil.) from the Technical University of Dresden. Until his retirement at the end of 2011 he was CEO of the Pfisterer Group in Winterbach (Germany), a company he has served for more than 25 years. He has held various honorary positions in Technical Bodies and Standard Associations, being presently Chairman of the Cigré Study Committee "Overhead Lines" (SC B2). He has published numerous papers in professional journals as well as coauthored two reference books, the EPRI Transmission Line Reference Book - "Wind -Induced Conductor Motion" and "Silicone Composite Insulators". He is also active in power engineering education, teaching Master's level courses on "High Voltage Transmission Lines" at the University of Stuttgart and the Technical University of Dresden.

Supports

12

João B.G.F. Silva, Andreas Fuchs, Georgel Gheorghita,
Jan P.M. van Tilburg, and Ruy C.R. Menezes

Contents

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J.B.G.F. Silva (✉)
Belo Horizonte, MG, Brazil
e-mail: jbfdsilva.sabn@gmail.com

A. Fuchs • G. Gheorghita • J.P.M. van Tilburg • R.C.R. Menezes

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12.1 Introduction

This Chapter intends to cover the aspects related to the design, test and fabrication of the structures used as support for the Overhead Transmission Lines.

The supports are essential elements on the universe or the Overhead Lines. Their importance can be understood by the functions they exert on the transmission line system. Besides being responsible to support all the loads coming from the cables, they are also in charge of keeping the electrical clearances between the conductors and the grounding parts, as well as to maintain the phase-to-phase and phase-shield wire distances. They also need to be strong enough to absorb the conductor tension in the anchorage/terminal towers guarantying, thus, the existence of the angles and/or the end of the lines.

From the reliability point of view, it is important to highlight the role played by the supports on the reliability analysis of the Overhead Lines. According to IEC 60826 Standard (IEC 60826 Standard Design Criteria of Overhead Transmission Lines), the suspension tower should be designed as to be the "weakest link" of the system, being thus, the first element to fail. This consideration means, in other words, that the line reliability is directly linked with the mechanical strengths of the supports.

As far as the environmental impact of the Overhead Lines is concerned, again the supports are in evidence since they are the most visible elements in the landscape.

As a consequence, they need to be treated more and more as aesthetic element having their visual aspect improved.

The content of this chapter is organized in the following way: Section 12.2 will describe the different types of supports classified according to their function in the line, circuit dispositions, structural types, shapes, formats, etc. The acting loadings on the structures are treated in Section 12.3, while Sections 12.4 and 12.5 are dedicated to the support calculations.

Information related to the drawing detailing practices and fabrication processes are given in Section 12.6. Section 12.7 will treat issues regarding to the full scale prototype test practices and acceptance criteria currently adopted.

In Section 12.8, special structures are shown; The environmental aspects of the transmission lines supports are treated in Section 12.9, discussing their impacts in the landscape and describing the measures recently adopted around the world to mitigate them.

Closing the subject, Section 12.10 will cover aspects related to the life of the structures, their aging process, and techniques usually adopted for repairs.

12.2 Types of Supports

The Overhead Line Supports can be classified according to different characteristics, or criteria. Generally these classifications are: regarding to their function in the line, number of circuits, line voltages, structural characteristics or types, structural modeling, shapes, formats, used materials, etc.

12.2.1 Regarding Function in the Line

It is common that a line, reasonably long, is composed by the following types of supports:

- Suspension or tangent towers: those which main function is just to suspend or support the conductors in alignment or small line angles (e.g., 1°, 2°, 3°) (Figure 12.1). Lines relatively long (around 500 kms or more) use to have two or three different suspension towers classified according to their wind spans (e.g., 500 m, 600 m, 700 m) and weight span (e.g., 600 m, 700 m, 800 m).
- Angle towers: those which the main function is to keep the line angles. It is common the use of suspension towers for small angles (up to 5°), while for bigger ones (above 10°), is more practical the use of angle/tension towers.
- Anchorage or tension towers: those used to anchorage the conductors and ground wires on them, supporting their tensions. They are currently designed to support all the cable tensions and also the big line angles (e.g., 30°, 45°, 60°) (Figure 12.2).
- Dead end or terminal towers: as described by the name, these towers are used to segment the line in intermediate or final substations.

Figure 12.1 765 kV Suspension tower.

12.2.2 Number of Circuits/Phase Arrangements/Tower Top Geometry

As far as the number of circuits and the phase arrangements are concerned, the towers can be classified as single circuit horizontal (flat) configuration, delta configuration, inverted delta or double vertical circuit, double delta circuit (Danubio type) or even triple, quadruple circuits, etc. (see Figures 12.3 and 12.4).

12.2.3 Structural Types, Structural Modeling

According to the structural modeling, the towers can be classified as self-supported or guyed (Figure 12.5). They can also be from the latticed type, or formed by box sections like poles, as can be seen in Figure 12.6.

Figure 12.2 500 kV Anchorage Tower.

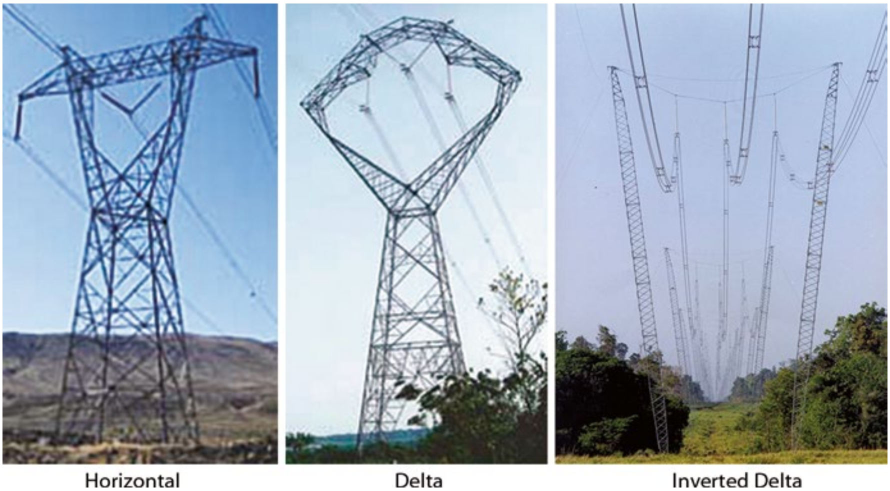


Figure 12.3 Single circuit Horizontal and Delta configuration supports.

12.2.4 Formats, Aspects, Shapes

Looking at the whole structures, they still can be named as pyramidal trunk (Christmas tree), Delta type, "Cat face", "Raquet", "Monopoles", Guyed V, Portal type, Cross-rope suspension (CRS) etc., according to their aspects or formats, basically as a result of the phase arrangements and/or circuits dispositions (see Figure 12.7).

Double Vertical circuits Double Delta circuits

Figure 12.4 Double circuits supports.

Figure 12.5 Self-Supported and Guyed towers.

12.2.5 Material Used

The Overhead Lines Supports can be fabricated by steel, concrete or wood. The use of one or other material type depends on the local availability of that material, market conditions and, also, on technical limitations. Usually for lower voltages levels, wood and concrete can be feasible and more economical, while for higher levels the steel is predominant (Figures 12.8 and 12.9). For ultra high voltage lines, the latticed steel supports are, nowadays, the unique solution adopted.

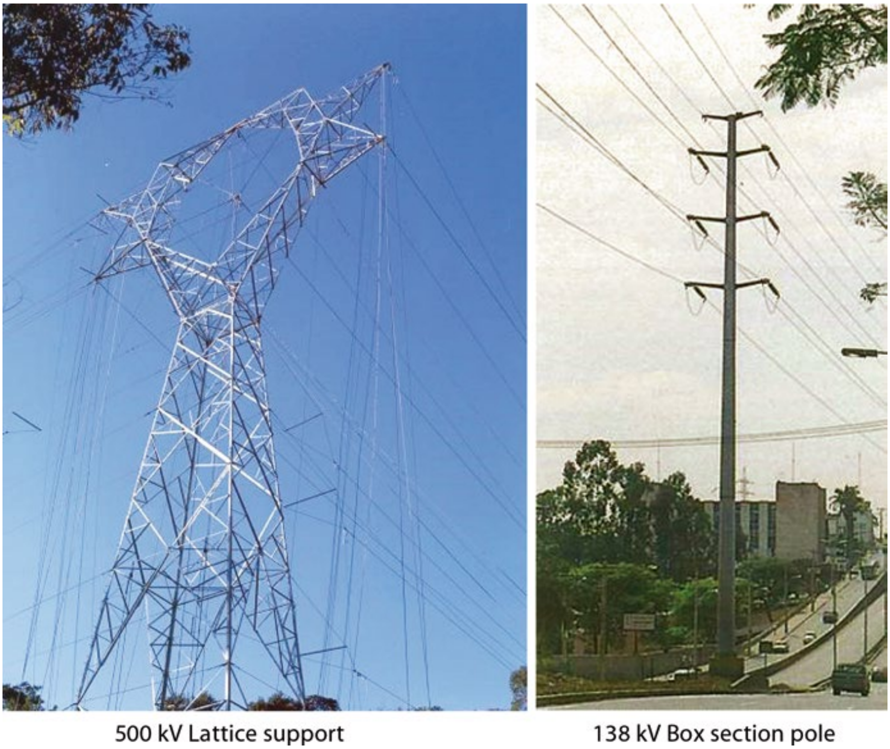


Figure 12.6 Latticed and Box Section Supports.

12.3 Design Loadings

12.3.1 Design Philosophy

During the 90's, there was a great change in the adopted philosophy for the overhead transmission lines designs. The criteria that had been currently used, changed from the so called "deterministic approach" to the "RBD - reliability based design" or "probabilistic based method". By that time, considerable amount of meteorological data like ambient air temperature, wind velocity, lightning, etc., had already been accumulated by many utilities, enough to sustain a probabilistic approach based on data bank.

The IEC 60826 Standard (IEC 60826 Standard Design Criteria of Overhead Transmission Lines) issued during this period, establishes interesting premises for the design of high voltage overhead lines. The design, as proposed, must fulfill reliability, security and safety requirements. Reliability requirements aim to ensure that lines can withstand the defined climatic limit loads, that can basically be treated by using probabilistic approaches, such as wind, ice, ice and wind and the loads derived from these events. It is usual to associate them to a return period T. Security requirements correspond to special loads and/or measures intended to reduce risk of

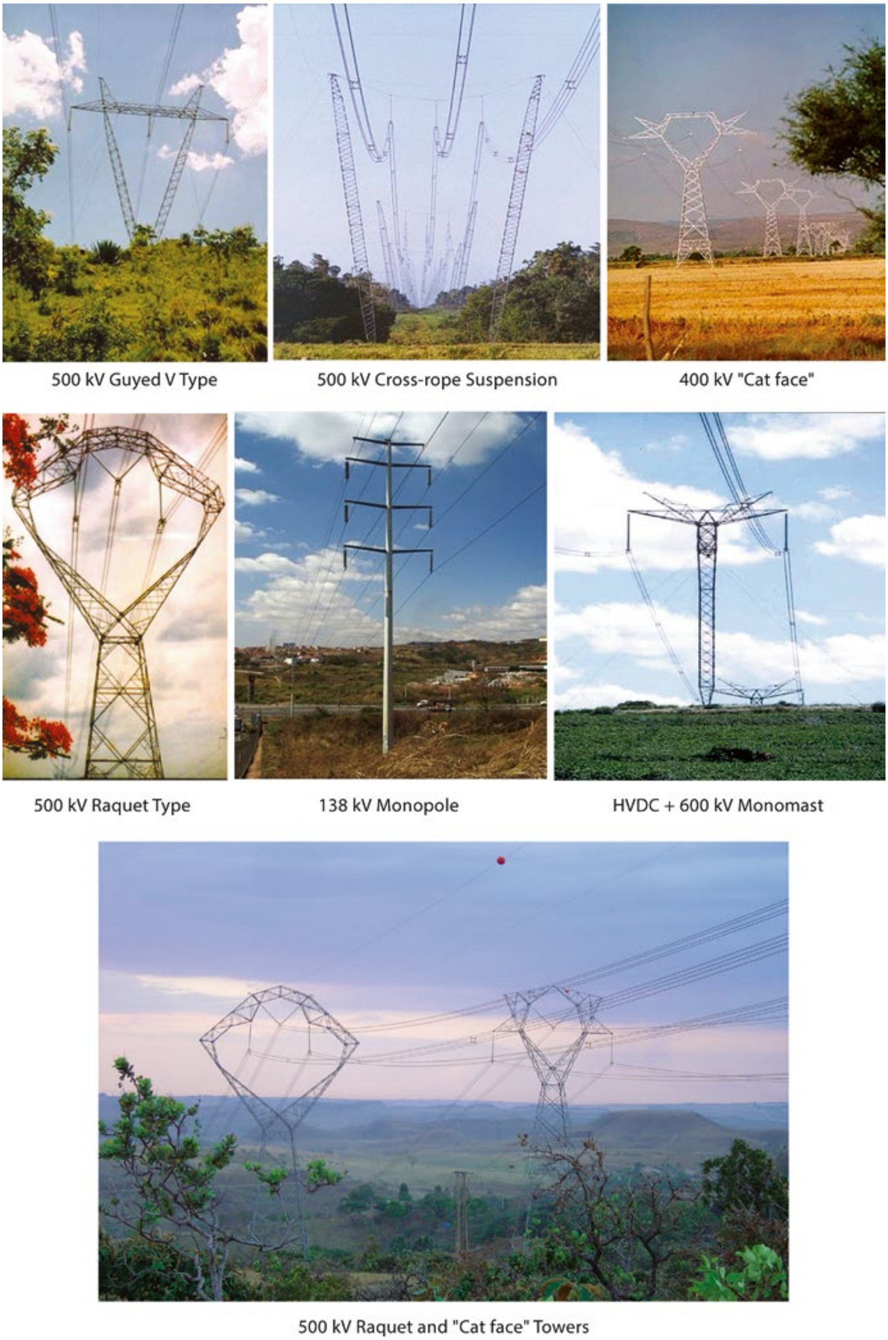


Figure 12.7 Different formats and shapes of supports.

Figure 12.8 Concrete Supports.

Figure 12.9 Wood OHL Supports.

uncontrollable progressive (or cascading) failures. Safety requirements consist of special loads for which line components have to be designed, to ensure that construction and maintenance operations do not pose additional safety hazards to people.

Among the reliability requirements, and with direct impact on the support designs, it deserves to be mentioned:

- The lines are classified according to their target reliability within the system. These reliability levels were linked to a wind velocity associated to an adopted return period (e.g., 50, 150, 500 years).
- Establishment of a "preferential sequence of failure" or "failure coordination", where is defined that the so called "suspension tower", the most numerous one in the line, should be designed as to be the weakest link of the transmission line system. The other towers, as well as the other line components (conductors, shield wires, insulators, foundations, etc), should be designed stronger enough to have their probability of failure lower. According to IEC 60826 (IEC 60826 Standard Design Criteria of Overhead Transmission Lines), so, the general strength equation is given by:

$$\gamma_U Q_T < \Phi_R R_C$$

where:

Q_T = Design loading referred to a returned period T (or/with specific load factors)
γ_u = Use factor coefficient
R_C = Characteristic strength of the structures, assessed by calculations and/or calibrated by loading test and/or professional experience
Φ_R = "Strength factor" to be used in the design and evaluated as function of the statistical distribution of support strength.

Simplifying the concept and the understanding, one can say that load effects must be increased according to their uncertainties and the support strengths should be reduced in accordance with their accuracy grades.

Taking the distribution curves for load effects and strengths and adopting, an "exclusion limit" of 10 %, as recommended by IEC 60826 (IEC 60826 Standard Design Criteria of Overhead Transmission Lines) for the design of the supports, the probabilistic design approach may be illustrated by Figure 12.10.

From the probabilistic perspective, an exclusion limit of 10 % is proposed to account for the uncertainty arising from the strength. Thus, one can right, $R_{10\%} = \Phi_R R_C$ and $\gamma_u Q_T \leq R_{10\%}$

For the correct application of the probabilistic based method, it is extremely important to know the "statistical distribution of support strengths", the mean value and the respective standard deviation. Aiming to improve the knowledge for a better definition of this function, Cigré has conducted many important researches during

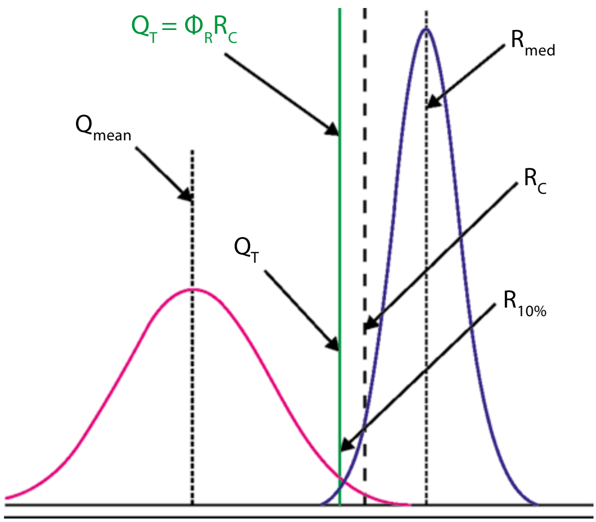


Figure 12.10 IEC 60826 reliability based design philosophy.

the last 20 years. Among them, it deserves to be mentioned the publications Paschen et al. (1988) and Riera et al. (1990), where mathematical/statistical treatments were made over sets of full scale prototype test results, leading to strength statistical distributions, well fitted by log-normal curves, and having in the case of article (Riera et al. 1990) a mean value of 104.6 % and a standard deviation of 8.51 % for lattice suspension towers. Taking into consideration the specified exclusion limit of 10 %, the "strength factor" value of $\Phi_R = 0.93$ may be calculated for this case. For other type of supports, like anchor, heavy angle, dead-end, considered as having greater dispersion in their design, values of 0.90 and/or even 0.85, have been deterministically adopted by the industry in some countries.

As above said, during the last years, Cigré has devoted many researches for better understanding and calibrating Φ_R values. The influence of the methods, tools and techniques used in the support designs, as well as the impact of the structural modeling adopted, the material property dispersions and the accuracy of the fabrication and erection procedures have been investigated and are published, as can be seen in (An experiment to measure the variation in lattice tower strength due to local design practice 1991; Variability of the mechanical properties of materials for transmission line steel towers 2000; Diaphragms in lattice steel towers 2001; Statistical analysis of structural data of transmission line steel towers 2005; On the failure load of transmission line steel towers considering uncertainties arising from manufacturing & erection processes; Influence of the hyperstatic modeling on the behavior of transmission line lattice structures 2009; The effect of fabrication and erection tolerances on the strength of lattice steel transmission towers 2010; Investigation on the structural interaction between transmission line towers and foundations 2009), as listed in Section 11.

12.3.2 Loadings

Loads acting on overhead line supports result from actions coming from the components (conductors, shield wires, insulator strings, guy wires), besides those acting directly to them like wind loads and dead-weights. To be easily treated in the structural analysis, these loads are decomposed in vertical and horizontal components, these ones, being transverse or longitudinal, as referred to the transmission line axes. From the design point of view, it is necessary to identify critical load combinations that can act during the supports lifetime.

As vertical loads, always acting, there are the cable tensions decomposed in vertical axis, the insulators weights, the dead load of the support and eventually the weights coming from snow and/or ice. It is also important to consider construction loads coming from the tower erection and conductor stringing works. They can also be representative in terms of load effects to some structural members, requiring special attachment points in some cases.

Transverse horizontal loads (orthogonal to the line direction) are basically due to wind action on the conductors, insulator strings and supports, as well as the cable tensions decomposed in transversal axis, which is very significant in case of angle towers.

As far as longitudinal loads are concerned, they result from cable tensions decomposed in longitudinal axis, arising from conductors and shield wires, acting on the anchor and/or dead end towers. Loads due to broken wires (longitudinal unbalance) also should be considered and are important specially for designing suspension supports. Loads arising from longitudinal or oblique winds should also be taken into account.

12.3.2.1 Loads Associated to Design Requirements

Such loads must be evaluated keeping in mind the premises and requirements above mentioned.

Therefore, to fulfill reliability requirements, loads which show a random nature (as wind velocity and ice accretion or a combination of them) are addressed in a probabilistic approach. Some of other loads acting simultaneously may be treated in a deterministic format due to their low variability (e.g.,: dead load).

To address requirements to the line security is necessary to carefully consider some loading conditions that may eventually trigger various types of failures. Loads involving storms of large footprints are likely to trigger multiple failures of weak components, while more localized consequences are expected when accidents happen in normal operational conditions. Typical loading cases aiming to fulfill such requirements are due to broken wires (conductors and shield wires). For those cases, semi-probabilistic approaches are appropriated. In traditional design practices, these loads on transmission lines have been represented by conductor failure (conductor breakage load or unbalanced residual static load (RSL)) occurring in normal operational conditions. Although conductor breakages or failures of conductor attachment hardware are rather uncommon in normal conditions, their likelihood is increased in severe weather conditions and their consequences will obviously differ. This highlights the importance of these considerations as they will influence the

Figure 12.11 Workers on the support during tower erection.

choice of security measures in the specific context of each utility. Other exceptional loads that are defined as climatic or natural loads in excess of design loads can also be specified using a reliability analysis approach.

From the safety requirement perspective, there are some operations during construction and maintenance works that a failure of a line component may cause injury or even losses of human lives. Therefore, such events cannot be treated under a probabilistic model, and are usually regulated by National Codes and/or practical regulations to fulfill minimum safety requirements, being the supports calculated under deterministic approaches. As IEC 60826 (IEC 60826 Standard Design Criteria of Overhead Transmission Lines) establishes, system stress under these loadings shall not exceed the damage limit, and the strength of the supports shall be verified either by testing or by reliable calculation methods. Typical loadings are due to erection of supports, construction stringing and sagging, longitudinal and vertical loads on temporary dead-end supports. As the consequences may involve injury or loss of life, special attention is also needed whether the loads are of static or dynamic nature, with or without the presence of workers on the support (Figure 12.11). All the following figures must be one number more.

12.3.2.2 Loading Cases

The structures are designed to withstand many different loading combinations (loadings cases or loading hypothesis) that can occur during their lifetime. It is a common practice, in the industry, to take into account at least the following loading hypothesis in the calculation of the supports:

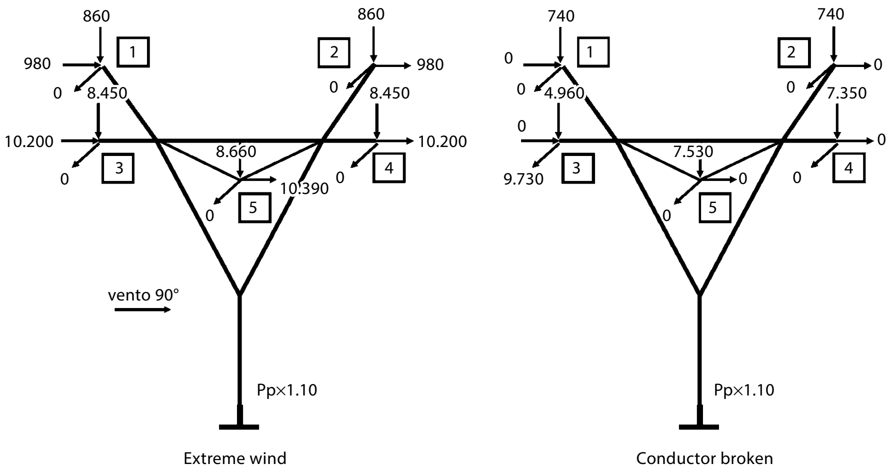


Figure 12.12 Loading cases.

- Extreme wind
- Ice and associated wind
- Only ice
- Shield wire broken
- Conductor broken (one conductor/phase at any point)
- Anti-cascading
- Construction and maintenance operations.

The loads are combined into "loading trees" like it is shown in Figure 12.12.

In the majority of the countries, loadings are calculated according to standards (or national codes) and, after considering the requirements above discussed, they are considered as "ultimate loads", not being necessary to apply any other additional safety factor. However, the concept of "partial safety factor" (Comparison of general industry practices for lattice tower design and detailing, Cigré 2009) is also applied especially in some European countries.

Usually, the most difficult loads to be evaluated, are the wind loads, not only for their correct characterization of intensities, but specially for their dynamic nature that may be dependent of the type of storm. Most of the codes have methods to appropriately consider synoptic winds but still do not have appropriate methodologies to care of other wind types (e.g. thunderstorms).

12.3.3 Static and Dynamic Loads

Loadings from wind and broken conductors on a transmission line support are clearly of dynamic nature. To be complete and consistent, the dynamic nature of such loadings has to be evaluated in both sides of the design equation: in the load effect side and in the member strength side.

There are many initiatives around the world aiming to model the dynamic effect of the wind on the towers, as well as, the impact of the broken wires. Menezes et al. (2012) and Leticia et al. (2009), have modeled the dynamic loading, such as wind and the breakage of wires, and numerically obtained the response of the supports in terms of member forces (Figure 12.13). McClure et al (Mechanical security of overhead lines- containing cascading failures and mitigating their effects 2012) has modeled the load due the breakage of wires and compared it to field measurements (Figure 12.14). From these references, what can be seen is that supports and cables work together for the absorption of those loads and their dynamic effects.

The industry, however, has addressed these cases considering them as static loadings. From the practical point of view, and for the purpose of tower calculations, wind loads as well as broken wires effects are treated as "equivalent static loadings".

Because the important part of the frequency spectrum of a broken conductor load is significantly higher than that of most transmission line tower natural frequencies, this load would only be felt on the tower as an impulsive load. After the transient part is damped, the tower would then be loaded with the residual load of the conductor tension (Figure 12.14).

By this way, aiming to take into account the dynamic impacts of occurrence of broken wires, what is normally done is to load the supports with the "residual static loads" (RSL), applying a dynamic impact factor to compensate the "peak dynamic load" effect.

Therefore, utilities have used two different approaches to address this type of loading event. For towers to resist the full impulse load a dynamic impact factor is applied to the conductor tension and this load is applied as a static load in the calculations. In a transmission line system the behaviour of an individual tower to a broken conductor event can be influenced by the unbroken conductor phases, the overhead ground-line, and the deflection of the adjacent towers.

An option against the detrimental effects of a broken conductor is to install controlled sliding clamps.

A controlled sliding clamp is made of a body in which rests the conductor and of a cover (see Figure 12.15). This cover is installed over the conductor by means of a system the pressure of which can be adjusted to make it possible to carry out the calibration of the load that causes the conductor to slide through the clamp. More details can be found in Chapter 5, page 44 ff.

12.4 Structural Modeling

12.4.1 Structural systems

As mentioned in Section 12.3, from the structural system point of view, the supports can be from self-supported or guyed types, in this last case, when they combine rigid bars with flexible elements needed to keep their equilibrium (Figure 12.5).

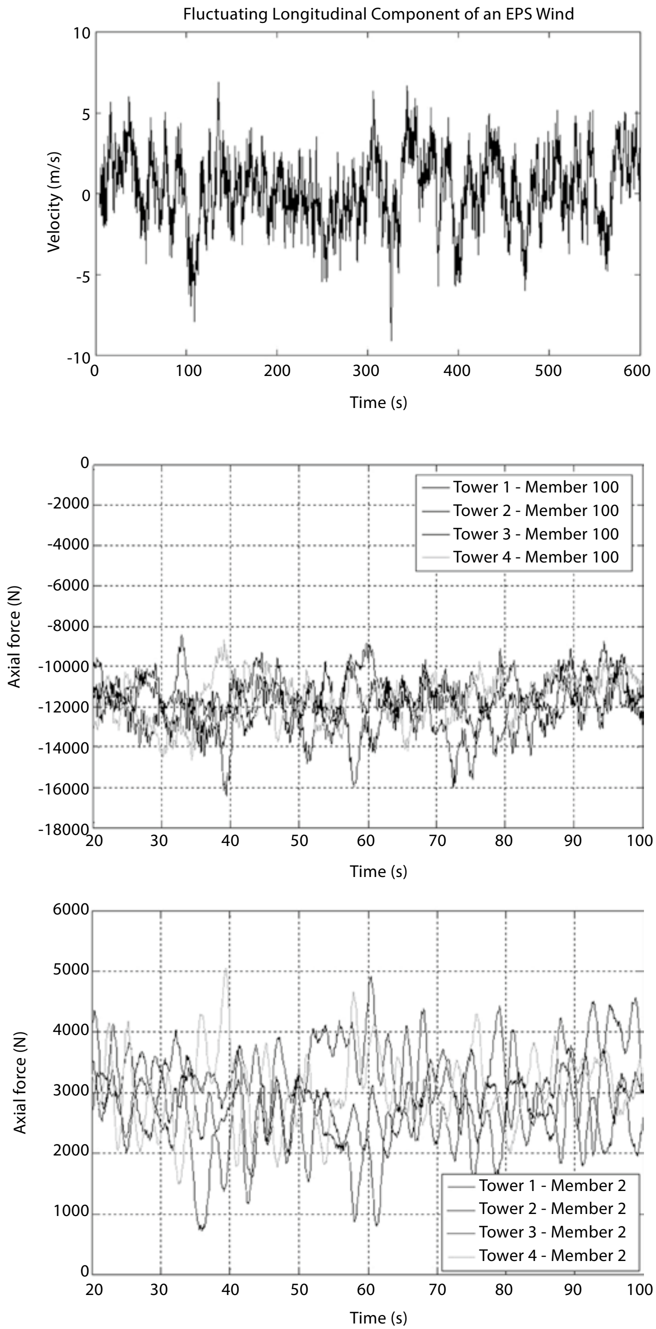
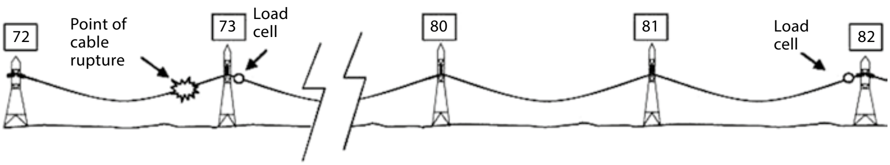
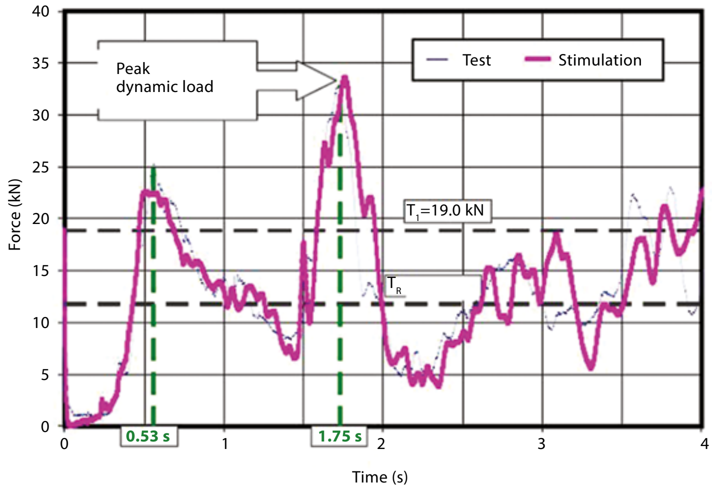


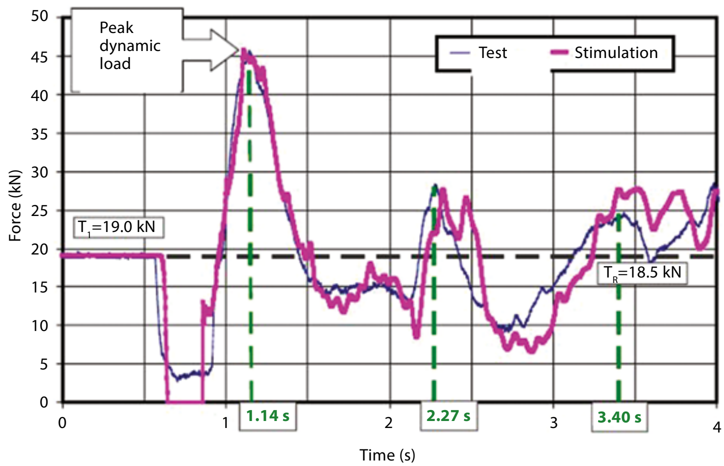
Figure 12.13 Simulated wind velocity and axial forces in main and diagonal members of a crossing tower GTS due to EPS wind load.



Broken donductor test on Saint-Luc-de-Vincennes 230 kV line
(Cigré Report B2-308, Vincent et al., 2004)



a) Conductor tension at Tower 73 (Initial 19.0 kN; Peak dynamic 33 kN; Residual 12.5 kN)



a) Conductor tension at Tower 82 (Initial 19.0 kN; Peak dynamic 45 kN; Residual 18.5 kN)
Measured vs. Predicted dynamic conductor tension on Saint-Luc-de-Vincennes
230 kV line (Cigré Paris Session 2004 Report B2-308, Vincent et al., 2004)

Figure 12.14 Modeled load due to a broken conductor and field measurements.

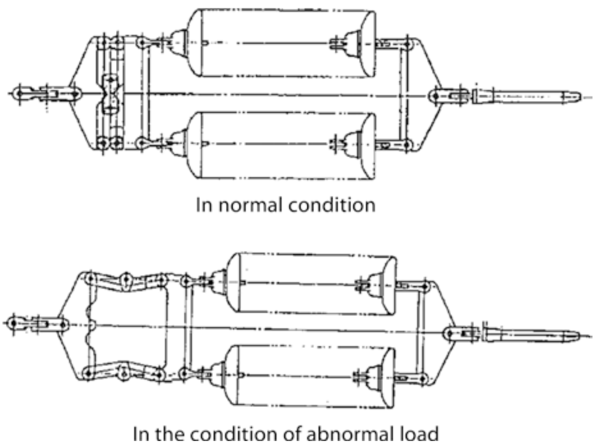


Figure 12.15 Elongating LCD type.

Usually, heavy-loaded supports (anchor, heavy angles, dead-end) of a line are of the self-supported type, being guyed towers more used as suspension structures. Section 8 gives more details of these structures.

In addition to that, the supports can also be shaped/formed by box sections, like poles, or constructed using, the concept of trusses (Figure 12.6).

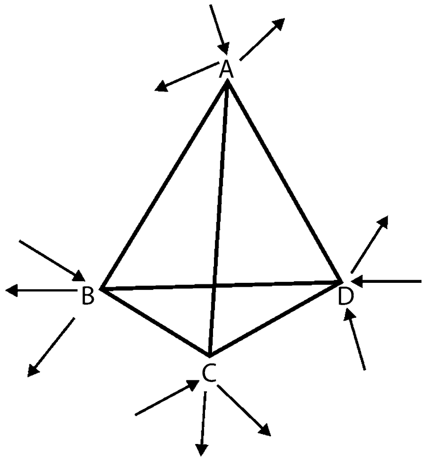
In lower voltage level lines, the supports can still be in wood or concrete poles with gross cross sections. As the line voltage level increases, the use of lattice tower become predominant. This fact is basically due to the excellent strength capacity of the lattice structures when large structural dimensions are needed to accommodate the phase arrangements as well as the insulator string swings. It is also important to point out the logistics involved in transportation and erection of the supports, that, in the case of lattice supports, is tremendously simpler since they can be sent to site location disassembled.

12.4.2 Structural Modeling

The lattice solutions currently used in OHL structures are, are from the spatial truss type, here named as "incomplete" or "imperfect", since they are not formed by "spatial rigid nodes" like the edges of a tetrahedron as shown in Figure 12.16.

The three-dimensional truss normally used can have some "pseudo-unstable" nodes, that are carefully carefully studied to support loads that are very well defined in terms of application point, direction and plane of action (vertical, horizontal transverse or longitudinal). In other words, the structures are well proposed and designed to support "well defined" load systems (not generic loads). The structural model here used is from the "tension-compression" system type (or "composite truss"), forming lattice panels juxtaposed (or combined).

Figure 12.16 Spatial rigid nodes.



This system is made up of diagonal cross bracings, being shear forces equally. Shear is equally distributed between the two diagonals of each panel, one in compression and the other in tension. Both diagonals are designed for compression and tension in order to permit reversal of externally applied shear. The diagonal braces are connected at their cross points, since the shear effect is carried by both members and the critical length is approximately half that of a corresponding single web system. This system is used for large and small towers and can be economically adopted throughout the shaft except in the lower panels, where bracing portal systems can, sometimes, be more suitable.

Thus, at the end, the spatial truss obtained is exactly a three dimensional lattice structure formed by the combination of panels of individual plane trusses, supporting loads on their planes or in parallel (or quasi), as shown in Figure 12.18.

In order to guarantee a good structural performance and to obtain predictable results, it is recommended to pay attention on some particular aspects of those uncommon structures:

- All loads must be applied on their nodes. If for any reason, a new load is to be supported by the structure, a new node shall be created, modifying, thus, the original proposal.
- It is always recommended to use "horizontal struts" in nodes where a load exists. This will create a better distribution of shear loads on the diagonals of the panel (see the effect of load P_1 and P_2 in Figure 12.17).
- In some cross sections on those "imperfect spatial trusses", special diaphragms are necessary to guarantee the overall structural behavior, as reported by the proposed in the relevant Cigré TB 196 (Diaphragms in lattice steel towers 2001).
- All attention should be paid in order to confirm that, in each panel, tension and compressive diagonals receive the same load effect with opposite signals, giving to the tension diagonal capacity to brace the compressive one as diagonal as can be seen in Figure 12.19.

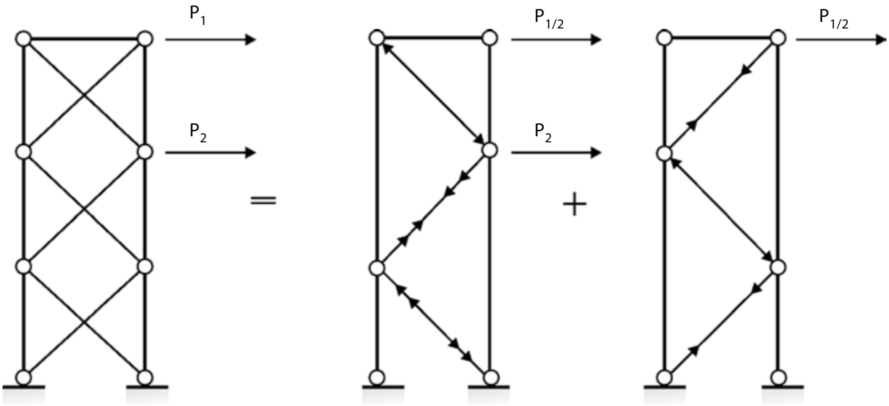
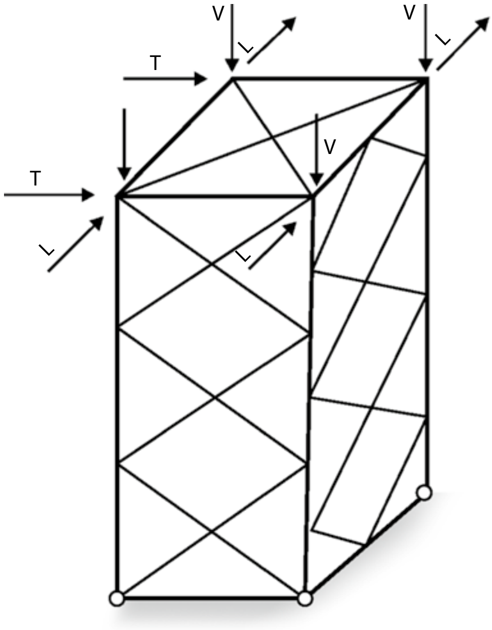


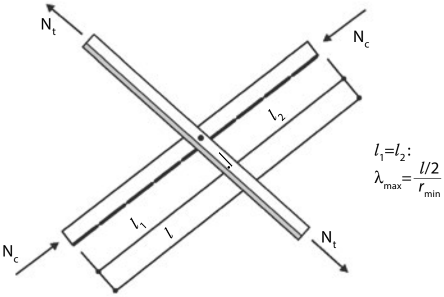
Figure 12.17 Tension-compression system. Load distribution on diagonals.

Figure 12.18 "Incomplete" 3-D lattice structure.



12.4.3 Structural Analysis

The method of analysis for transmission line towers has advanced quite a lot since the first towers have been designed. In the beginning the transmission line engineer used graphical analysis developed to a professional art for application to three dimensional space truss towers. With the introduction of the computer, mainframe computer analysis capabilities using structural matrix algorithms were developed.



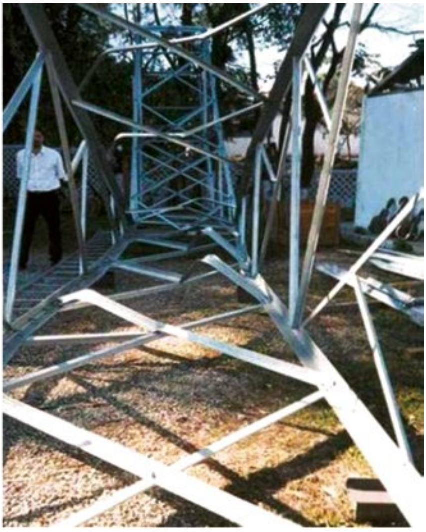


Figure 12.19 "Tension-compression" system behavior. Failure node during test.

As described in the last item, the standard of practice for analysis of lattice steel transmission line towers is a three-dimensional truss analysis. The structural computer model is based on the tension and compression behavior of the individual tower members, i.e. on a truss model. These tower analysis programs are based on linear elastic structural performance, whereby members are assumed to be axially loaded and to have pinned connections. The member forces determined from the computer model are compared to the allowable member capacities. In special cases, a three-dimensional frame model may be required to provide necessary information on the member forces, including bending moments.

In survey carried out by Cigré (An experiment to measure the variation in lattice tower strength due to local design practice 1991) and according to (ASCE 10–97 2000), the structural analyses model more used around the world is the 3-D truss analysis. Good results have been reported using linear analysis methodology for the self-supported lattice OHL supports.

For more deformable structures, like the guyed towers or poles, non linear analysis are currently required.

There are many well known softwares based on "Finite Element Method - FEM", available in the market appropriate for the design of the transmission line supports, such as TOWER, OPSTAR, SAPS, ANSYS, etc. It is extremely important that the software to be used have a friendly approach and the specialized for OHL Structures, facilitating the inputs and organizing accordingly the outputs. Otherwise design activities of OHL supports can become extremely complex in terms of pre and post processing and consequently become unviable for commercial purpose.

A good example that can be reported is the software named "TOWER", developed by Power Line Systems Inc. that works together with the PLS-CADD, the most used software around the world for towers spotting. The main characteristics of the "TOWER" software are:

- Specialized program for the analysis and design of steel latticed supports of overhead lines and substations;
- Easy information input through interactive menus;
- Linear and nonlinear finite element analysis options;
- Databases of steel angles, rounds, bolts, guys, etc.
- Automatic generation of joints and members by symmetries and interpolations
- Automated mast generation;
- Steel angles and rounds modeled either as truss, beam or tension-only elements
- Guys are modeled as exact cable elements;
- Automatic calculation of tower dead weight, ice, and wind loads as well as drag coefficients;
- Automatic design checks according to many codes;
- Design summaries printed for each group of members;
- Easy to interpret text, spreadsheet and graphics design summaries;
- Automatic determination of allowable wind and weight spans;
- Automatic determination of interaction diagrams between allowable wind and weight spans;
- Capability to batch run multiple tower configurations and consolidate the results;
- Automated optimum angle member size selection and bolt quantity determination;
- Tool for interactive angle member sizing and bolt quantity determination;
- Capability to model foundation displacements. Can optionally model foundation stiffness;
- Directly link to line design program PLS-CADD.

Figure 12.20 illustrates the input data, showing the generation of the here called "primary nodes" and "secondary nodes".

Due to the three dimensional characteristic of the overhead line structures, the inherent symmetry in their geometry, as well as to avoid complexity in calculations, it is important to create the concept of the so called "bar groups". Those are groups of structural elements that, for optimization purposes, should be designed using the same profile and connections (see Figure 12.21).

12.4.4 Advanced Tools and Techniques

With the maturity of the transmission tower engineering profession and the advances in computer analytical solution power, the transmission engineer can now push the margin of analysis beyond the simple truss model. The uses of the simple truss model is still the main analysis tool of the transmission engineer, but advanced tools for evaluating the performance of space truss towers, including effects other than simple truss action, are now being utilized. As an example, three advanced transmission tower analysis computer programs will be briefly described:

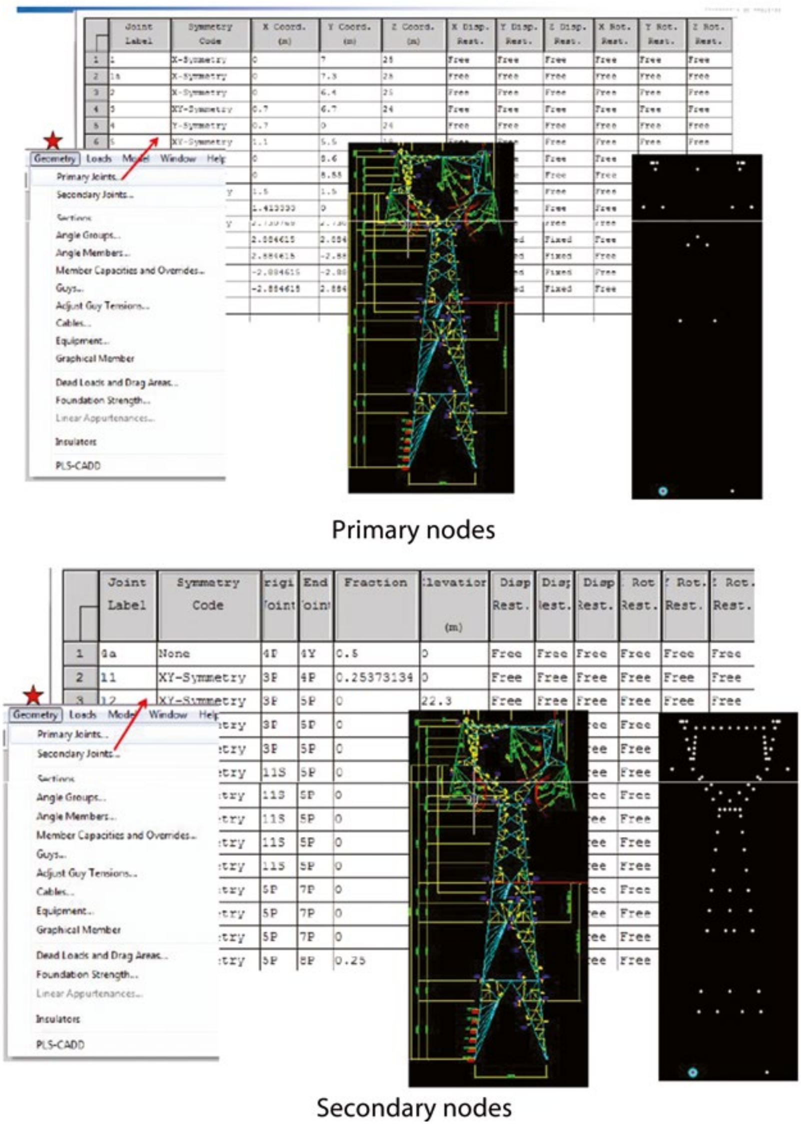


Figure 12.20 "Primary nodes" and "Secondary nodes" by software "Tower".

AK TOWER Program: AK TOWER is a finite element computer program that uses geometric and material nonlinear analysis to simulate the ultimate structural behavior of lattice transmission towers (Albermani 1992). The program has been calibrated with results from full-scale tower tests with good accuracy both in terms of failure load and failure mode. It is capable of accurately predicting tower capacity under static load cases by progressively detecting buckling and yielding in various parts of the structure until collapse. The software has been used by electricity

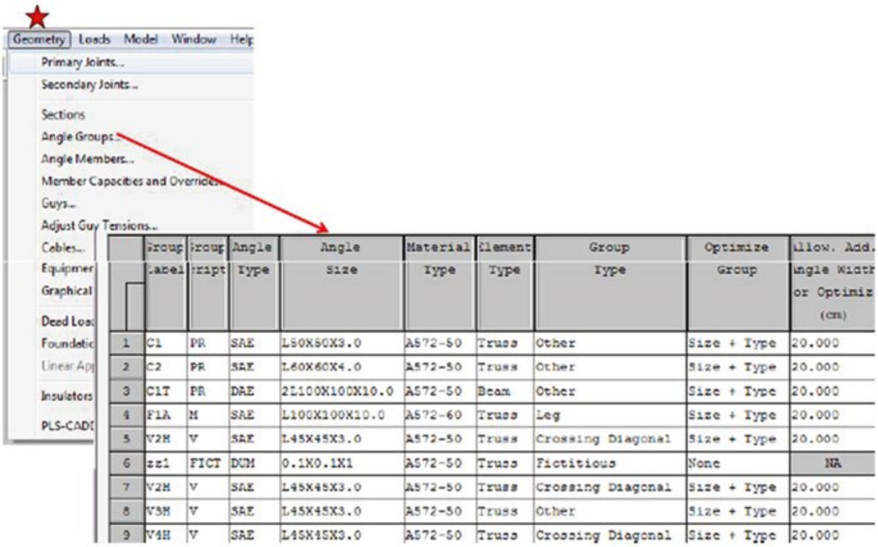


Figure 12.21 Group of bars.

utilities to verify new tower design and reduce or eliminate the need for full-scale tower testing. The structure is modeled as an assembly of general thin-walled beam-columns, trusses, and cable nonlinear elements.

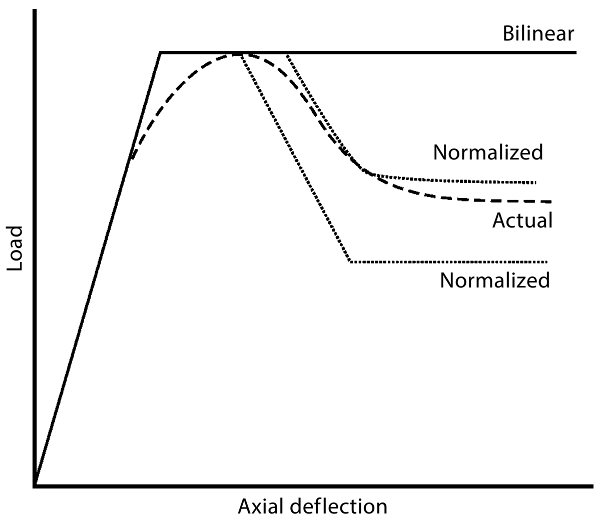
MORENA Program: MOdular REliability aNAlysis – is a computer program that can be used to study the variability of the strength of transmission line towers. The program main modules are:

- Statistical analysis of data: perform standard statistical analysis including distribution fitting and correlation evaluation;
- Random samples generation: generate sets of random samples following established distribution, including correlated variables;
- Probability of failure calculations: estimate probability of failure for explicit or implicit limit state functions using advanced Monte Carlo Simulation procedures;
- Finite Element Analysis: in case of an implicit limit state function such as the response of a structure, perform classical finite element analysis (FEM) including standard linear or full nonlinear analysis (geometric and material nonlinearities) up to failure.

MORENA manages information which is stored and allows the user to call modules for specific purposes by means of commands written in the input file. The user has special commands to perform “loops”, “jumps” and tests. It can be deduced, that within this concept, the FEM analysis is just a step to get a response for a limit state function in a reliability analysis. Therefore, the complexity of such a step is up to the user and, within a modular concept it can be improved as much as possible and desired. Laboratory testing of individual tower members (Menezes 1990), full-scale experimental tests of strength capacity of transmission line towers under lateral loads (Menezes 1988; Riera et al. 1990) and an extensive survey of the field performance of transmission lines in Southern and Central Brazil (Menezes 1988) provides data for strength variation evaluation of transmission line towers. This type of information permits: (a) Evaluation of the capacity of numerical procedures for nonlinear structural analysis to predict the carrying capacity of steel towers under lateral loading; (b) Evaluation of the capacity of reliability models to determine the failure probability of transmission lines towers and (c) comparison of the calculated probability of failure with field experience.

LIMIT Program: The Bonneville Power Administration (BPA) and Portland State University (PSU) developed a computer program called LIMIT. LIMIT performs a first-order non-linear analysis accounting for individual member post-buckling performance of lattice steel transmission towers. A direct iteration, Secant Method (Kempner 1990), procedure is used to account for non-linear member behavior. The analysis results can be used to determine the failure "collapse" load mechanism, and the member load flow at failure. The LIMIT analysis uses individual member post-buckling performance curves to track the member load after it reaches and exceeds its calculated compression capacity. Two options are used to model the post-buckling member performance: bilinear and normalized (empirical) curves. Normalized member performance curves were developed from actual tests of angle steel members (Bathon 1990, Huntley 1991). The LIMIT program has 29 normalized curves that can be used to represent the post-buckling member performance of steel angles (equal, unequal, and double angles). Both the bilinear and normalized curves assume linear behavior to the member compression capacity as shown in the Figure 12.22.

Figure 12.22 Member Performance Curves.



The LIMIT program provides three post-buckling analysis methods: Deterministic, Probabilistic, and Capacity Variations analysis. The deterministic analysis, referred to as LIMIT, provides a collapse load capacity based on individual member capacities determined from minimum yield strength, actual member yield strength, and/or observed member behavior. Probability based analysis can provide a design tool that accounts for variation in parameters which can affect member capacities, such as yield strength, connection eccentricity, engineer judgment, etc. A probabilistic analysis generates a set of randomly distributed member capacity. LIMIT provides two simplified probabilistic analysis options: LIMIT/PBA and LIMIT/CVA. The LIMIT/PBA, Probability-Based-Analysis, option varies member capacities based on selected yield strength distributions. The LIMIT/CVA - *Capacity Variation Analysis* option varies member capacities based on user selected +/− percentage variation about a calculated "base" member capacity.

Both PBA and CVA use the Monte Carlo technique to randomly vary member capacities. The first order non-linear post-buckling analysis is repeated using the random member capacity variation to obtain the tower collapse load distribution.

12.5 Calculation and Dimensioning

12.5.1 Materials and Standards

Supports for transmission lines are designed and fabricated according to different standards and practices. National or international standards are currently used, as well as local codes, guidelines or simply utilities' specifications. Cigré TB "Comparison of General Industry Practices for Lattice Tower Design and Detailing" (2009) gives a clear picture on that. According to document (An experiment to measure the variation in lattice tower strength due to local design practice 1991), ASCE 10-97(ASCE 10–97 2000) is the most used standard around the world for design of OHL supports.

12.5.1.1 Profiles

Profiles to be used in the fabrication of overhead lines lattice supports (mostly angles and plates) shall be shaped by means of hot-rolling or cold-forming processes, as per ASCE 10-97(ASCE 10–97: Design of lattice steel transmission structures 2000) or EN 50341–1:2012 – European CENELEC Standard (7.2.3) (CENELEC – EN 50341–1 2012) and EN 10025 European CENELEC Standard (7.2.3) (CENELEC EN 10025) (Figure 12.23).

The steels specified for the fabrication of those profiles shall be of the low carbon steel types, which present good resistance and ductility to guarantee strength and workability (ASCE 10–97 2000). As examples, as per ASTM standard (ASTM American Society for testing and materials):

- Structural steel: ASTM A36.

Figure 12.23 Raw material – Steel angles stock.

- High-strength low-alloy structural steel: ASTM A242.
- Structural steel with 42.000 psi (290 N/mm^2) minimum yield point: A529.
- Hot-rolled carbon steel sheet and strip, structural quality: ASTM A570.
- High-strength low-alloy structural Columbium-Vanadium steels of structural quality: A572.
- High-strength low-alloy structural steel with 50,000 psi (345 N/mm^2) minimum yield point to 4-in. thick: A588.
- Steel sheet and strip, hot-rolled and cold-rolled, high-strength low-alloy with improved corrosion resistance: ASTM A606.
- Steel sheet and strip, hot-rolled and cold-rolled high-strength low-alloy, Columbium or Vanadium, or both, hot-rolled and cold-rolled: ASTM A607.

12.5.1.2 Bolts

There are many standards and specifications for bolts around the world. According to Cigré TB (2009), however, the most used types types in the transmission line industry are ASTM A394 (ASTM-A394 2000), ISO 898–1 (ISO 898 1 Internacional Standard Organization) and CENELEC 5.8.1 (CENELEC – EN 50341–1 2012).

According to ASCE 10–97 Standard (ASCE 10–97 2000), bolts should be as per ASTM A394:

Type "0"

Low or medium carbon steel, zinc-coated (hot dip):

$$f_u = 510.0 \ \text{N/mm}^2$$
$$f_v = 380.5 \ \text{N/mm}^2 \left(\text{for the thread}\right)$$
$$f_v = 316.5 \ \text{N/mm}^2 \left(\text{for the body}\right)$$

Type "1"

Medium carbon steel, with heat treatment, zinc-coated (hot dip):

$$f_u = 827.5 \ \ N/mm^2$$
$$f_v = 513.0 \ \ N/mm^2 \left(\text{thread and body}\right)$$

Type "2"

Low carbon martensilic steel, zinc-coated (hot dip):

$$f_u = 827.5 \ \ N/mm^2$$
$$f_v = 513.0 \ \ N/mm^2 \left(\text{thread and body}\right)$$

Type "3"

Corrosion resistant steel, with heat treatment:

$$f_u = 827.5 \ \ N/mm^2$$
$$f_v = 513.0 \ \ N/mm^2 \left(\text{thread and body}\right)$$

where:

f_u = ultimate tensile strength of bolt
f_v = allowable shear stress

According to ISO 898–1 (ISO 898 1 Internacional Standard Organization):

Class 5.8 (low or medium carbon steel, zinc-coated):

$$f_u = 520 \ \ N/mm^2$$
$$f_v = \ \ 381 \ \ N/mm^2 \left(\text{for the thread}\right)$$
$$f_v = \ \ 322 \ \ N/mm^2 \left(\text{for the body}\right)$$

Class 8.8 (medium carbon steel, with heat treatment, zinc-coated):

$$f_u = 800 \ \ N/mm^2 \left(\text{diameter} \le 16\text{mm}\right)$$
$$f_u = 830 \ \ N/mm^2 \left(\text{diameter} > 16\text{mm}\right)$$
$$f_v = 496 \ \ N/mm^2 \left(\text{thread and body, diameter} \le 16\text{mm}\right)$$
$$f_v = 515 \ \ N/mm^2 \left(\text{thread and body, diameter} > 16\text{mm}\right)$$

12.5.1.3 Metallic Poles

The steel used in the fabrication of poles are currently from the high strength low alloy carbon types. Yield stress (Fy) and ultimate tensile stress (Fv) are around 3.500 kgf/cm^2 (355 N/mm^2) and 4.500 kgf/cm^2 (490 … 630 N/mm^2) respectively, values that can vary according to the thickness of the plates.

12.5.1.4 Concrete and Wood Poles

Standards for concrete and/or wood poles vary quite a lot depending on utility specification, national standards or local conditions such as materials, labor work or wood quantities.

12.5.2 Lattice Towers

Once the external loads acting on the support are determined and the structural analysis has been carried out, one proceeds with an analysis of the forces in all the members with a view to fixing up their sizes. Since axial force is the only force for a truss element, the member has to be designed for either compression or tension. When there are multiple load conditions, certain members may be subjected to both compressive and tension forces under different loading conditions. Reversal of loads may also induce alternate nature of forces; hence these members are to be designed for both compression and tension. The total force acting on any individual member under the normal condition and also under the broken-wire condition is considered as “ultimate force” and the dimensioning is done aiming to ensure that the values are within the permissible ultimate strength of the particular steel used. In some countries, the concept of “partial safety factor” also needs to be taken into account.

It shall be verified that bracing systems have adequate stiffness to prevent local instability of any parts. Bending moments due to normal eccentricities are treated in item 12.5.2.2 of buckling cases. If the continuity of a member is considered, the consequent secondary bending stresses may generally be neglected.

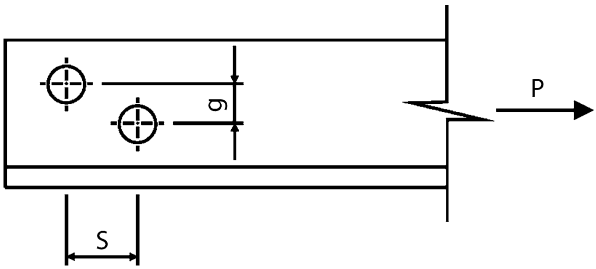
According to Cigré TB (2009), the most used standards around the world for design and calculation of lattice steel supports for overhead lines are ASCE 10–97 (ASCE 10–97 2000) and European CENELECs EN 50341–1:2001 (CENELEC – EN 50341–1 2012), EN 50341–3:2001 (CENELEC - EN 50341–3 2001) and EN 1993–1:2003 (EN 1993). In this section, emphasis will be given mainly to ASCE 10–97.

12.5.2.1 Design of Tension Members

According to ASCE 10–97 Standard (ASCE 10–97 2000), the tensile stress on a tension member is calculated as follows (Figure 12.24):

s - distance between holes in the direction parallel to the direction of the force
g - distance between holes in the direction perpendicular to the direction of the force.

Figure 12.24 Tension members design.



Concentric Loads

$$f_t = P / A_n \leq f_y$$

f_t - tensile stress on net area
f_y - yield strength of the material
P - force transmitted by the bolt

$$A_n = A_g - n\ d_0\ t + [\Sigma(s^2/4\,g)]\ t$$

s - distance between holes in the direction parallel to the axial force
g - distance between holes in the direction perpendicular to the axial force
A_n - net cross section area
A_g - gross cross section area
n - number of holes
t - plate thickness
d_0 - hole diameter.

Eccentric Loads: Angle Members Connected by One Leg

$$f_t = P / A_e \leq f_y$$
$$A_e = 0.9\ A_n$$

A_e - effective cross section area

PS: For unequal leg angles, connected by the shorter leg, the free leg shall be considered as having the same width as the shorter leg.

Eccentric Loads: Other Sections
Members shall be proportioned for axial tension and bending.

Threaded rods:

$$f_t = P / A_s \leq f_y$$

A_s - core section at the thread.

12.5.2.2 Design of Compression Members

According to ASCE 10–97 Standard (ASCE 10–97 2000), the compression stress is calculated as follows:

Allowable Compression Stress on the Gross Cross-Sectional Area (N/mm2):

$$f_a = \left[1 - 0.5\ \left((kL/i)/C_c\right)^2\right] f_y \quad \text{if}\left(kL/i\right) \le C_c$$

$$f_a = \pi^2 E/\left(kL/i\right)^2 \quad \text{if}\left(kL/i\right) > C_c$$

$$\text{with } C_c = \left[\left(2\pi^2 E\right)/f_y\right]^{1/2}$$

where:

f_y - yield strength (N/mm^2)
E - modulus of elasticity (N/mm^2)
L - unbraced length
i - radius of gyration corresponding to the buckling axis
k - effective buckling length coefficient (See Clauses 11.1 and 11.2).

Local and Torsional Buckling
For hot rolled steel members with the types of cross-section commonly used for compression members, the relevant buckling mode is generally *flexural* buckling. In some cases *torsional*, *flexuraltorsional* or *local buckling modes may govern*. Local bucking and purely torsional bucking are identical if the angle has equal legs and is simply supported and free to warp at each end; furthermore, the critical stress for torsional-flexural bucking is only slightly smaller than the critical stress for purely flexural buckling, and for this reason such members have been customarily checked only for flexural and local buckling (Figure 12.25).

- For ASCE 10-97(2000) f_y shall be replaced with f_{cr}.
- For EN 50341-1(CENELEC – EN 50341–1 2012) b and A shall be replaced with b_{eff} and A_{eff}.
- For ECCS 39 (Recommendations for angles in lattice transmission towers 1985) f_y shall be replaced with f_{cr}.

$$\left(w/t\right)_{lim} = 670.8/\left(f_y\right)^{1/2}$$

If $(w/t) < (w/t)_{lim}$ then the previous formulas for f_a apply without any change (Figure 12.26).

$$\text{If } 670.8/\left(f_y\right)^{1/2} \le \left(w/t\right) \le 1207.4/\left(f_y\right)^{1/2}$$

Then the allowable compression stress f_a shall be the value given by the previous expressions with f_y replaced by f_{cr} given by:

$$f_{cr} = \{[1.677 - 0.677\ \left[\left(w/t\right)/\left(w/t\right)_{lim}\right]\}\ f_y$$

$$\text{If } \quad \left(w/t\right) > 1207.4/\left(f_y\right)^{1/2}$$

$$f_{cr} = 668086/\left(w/t\right)^2$$

where (Figure 12.26):

w - flat width of the member
t - thickness of the member
b - nominal width of the member
R - rolling radius

Figure 12.25 Diagonals buckling during test. (See the bracing provided by the tension diagonals)

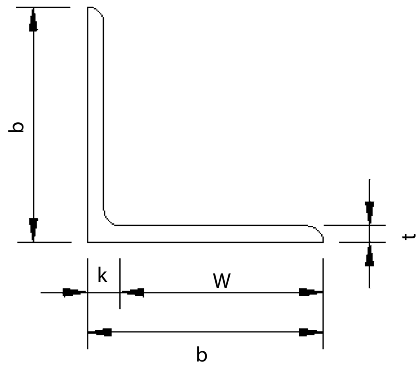


Figure 12.26 Determination of w/t ratios.

$$k = R + t$$
$$w = b - k$$

Note: The provisions of this section are only applicable for 90° angles.

Buckling Lengths

According to ASCE 10–97 Standard (2000), Effective buckling lengths for end restraints and eccentricities are modelled as following:

PRIMARY BRACING MEMBERS (EXCLUDING MAIN LEGS, CHORDS AND REDUNDANT MEMBERS)

Curve 1 - members with concentric load at both ends of the unsupported panel

$$kL / i = L / i \quad 0 \le L / i \le 120$$
$$(\text{according to ASCE Eq.3.7 5})$$

Curve 2 - members with concentric load at one end and normal framing eccentricity at the other end of the unsupported panel

$$kL / i = 30 + 0.75\ (L / i)$$
$$0 \le L / i \le 120\ (\text{according to ASCE Eq.3.7 6})$$

(*) To qualify a member for partial joint restraint the following rules are recommended (BPA criteria):

a - the member shall be connected with at least two bolts
b - the connection shall be detailed to minimize eccentricity
c - the relative stiffness (I/L) of the member must be appreciably less than one or more other members attached to the same joint. This is required for each plane of buckling being considered. To provide restraint the joint itself must be relatively stiffer than the member to which it is providing restraint. The stiffness of the joint is a function of the stiffness of the other members attached to the joint.

Curve 3 - members with normal framing eccentricities at both ends of the unsupported panel

$$kL / i = 60 + 0.5\ (L / i)$$
$$0 \le L / i \le 120\ (\text{according to ASCE Eq.3.7 7})$$

Curve 4 - members unrestrained against rotation at both ends of the unsupported panel

$$kL / i = L / i \quad 120 \le L / i \le 200$$
$$(\text{according to ASCE Eq.3.7 8})$$

Curve 5 - members partially restrained against rotation at one end of the unsupported panel

$$kL/i = 28.6 + 0.762(L/i)$$
$$120 \leq L/i \leq 225(*)(\text{according to ASCE Eq.3.7 } 9)$$

Curve 6 - members partially restrained against rotation at both ends of the unsupported panel

$$kL/i = 46.2 + 0.615(L/i)$$
$$120 \leq L/i \leq 250(*)(\text{according to ASCE Eq.3.7 } 10)$$

REDUNDANT MEMBERS

$$kL/i = L/i \quad 0 \quad \leq L/i \leq 120$$
$$(\text{according to ASCE Eq.3.7 } 11)$$

Curve 4 - members unrestrained against rotation at both ends of the unsupported panel

$$kL/i = L/i \quad 120 \leq L/i \leq 250$$
$$(\text{according to ASCE Eq.3.7 } 12)$$

Curve 5 - members partially restrained against rotation at one end of the unsupported panel

$$kL/i = 28.6 + 0.762(L/i) \quad 120 \leq L/i \leq 290$$
$$(\text{according to ASCE Eq.3.7 } 13)$$

Curve 6 - members partially restrained against rotation at both ends of the unsupported panel

$$kL/i = 46.2 + 0.615(L/i)$$
$$120 \leq L/i \leq 330 \ (\text{according to ASCE Eq.3.7 } 14)$$

Buckling Length for Different Bracing Types

MAIN MEMBERS BOLTED IN BOTH FACES AT CONNECTIONS:
As per ASCE 10–97 Standard (2000),

$$kL/i = L/i \quad 0 \leq L/i \leq 150$$
$$(\text{according to ASCE Eq.3.7 } 4)$$

For main members of equal angles, having no change in member force between panels, designed with staggered bracing, the controlling L/i ratio shall be as shown in the Figure 12.28, 12.29 and 12.30 here below:

- Leg Members with Symmetrical Bracing (Figure 12.27)
- Leg Members Controlled by (2 L/3)/i_{zz} (Figure 12.28)
- Leg Members Controlled by (1.2 L)/i_{xx} (Figure 12.29)
- Leg Members Controlled by (1.2 L)/i_{xx} (Figure 12.30).

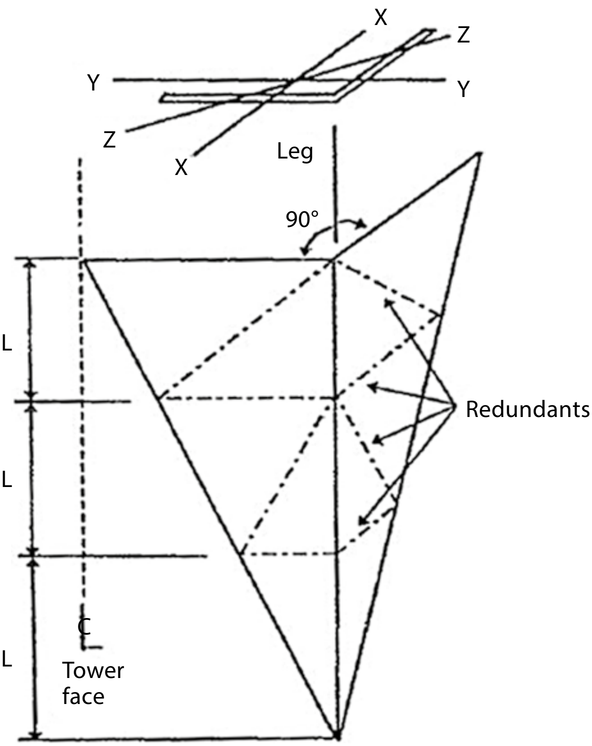


Figure 12.27 Leg Members with Symmetrical Bracing.

Diagonals and Bracing Members

ASCE10-97(Annex B) (ASCE 10–97 2000) and EUROPEAN CENELEC Standard (J.62 J.6.3) (EN 1993) provide various slenderness ratios $\lambda = kL/i$ applicable to all types of bracings (single, cross and multiple bracing with or without redundant members, k-bracing etc), as well as the appropriate bucking length and bucking axis.

Slenderness Ratio Limits

According to ASCE 10–97 Standard (2000),

Leg members and chords	$L/i \leq 150$
Primary bracing members	$L/i \leq 200$
Redundant members	$L/i \leq 250$
Tension-hanger members	$L/i \leq 375$
Tension-only members	$300 \leq L/i \leq 500$
Web-member – multiple lattices	Not specified
Horizontal edge members	Not specified

Cross bracing diagonals where the loads are equally or almost equally split into tension-compression system shall be dimensioned considering the centre of the

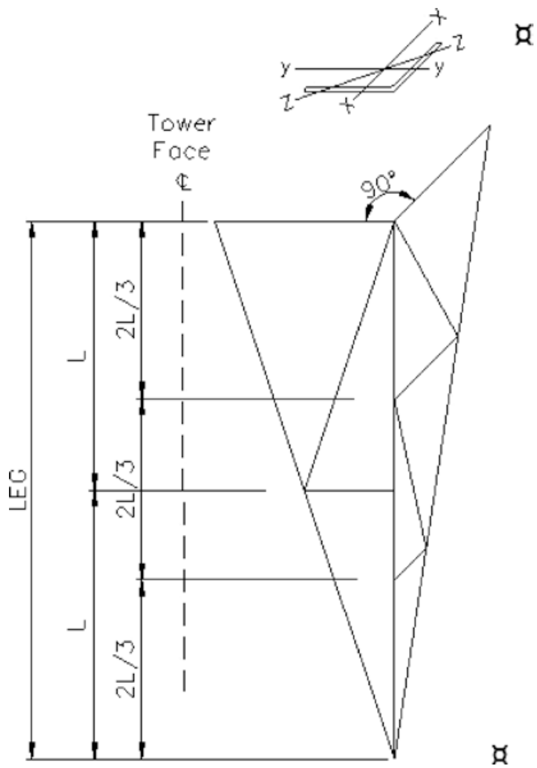


Figure 12.28 Leg members effective buckling lengths (a). Leg members shall be supported in both faces at the same elevation level every four panels.

cross as a point of restraint for both transverse to and in the plane of the bracing (Figure 12.31). Furthermore, the bracings shall have an effective maximum slenderness of 250 when considering the whole length.

Design of Redundant Members

Redundant (or secondary) members are installed on the overhead line lattice supports, basically for the function of bracing the loaded bars (leg members, chords, primary members). Even not having calculated loads, they must be rigid enough to guarantee efficient support against buckling. For this reason, it is recommended to attribute to the redundant members, hypothetical loads which magnitude are, usually, percentages of the loads of the supported members.

As per ASCE 10–97 Standard (2000),

The magnitude of the load in the redundant member can vary from 1.0 to 2.5 % of the load in the supported member.

Design of Members Acting only under Tension

It is a current practice that some very long members are installed only under tension to provide better assembly and overall rigidity.

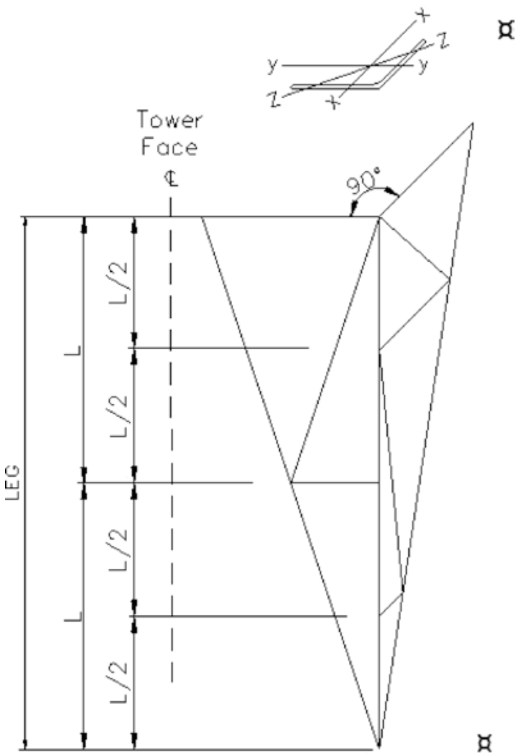


Figure 12.29 Leg members effective buckling lengths (b). Leg members shall be supported in both faces at the same elevation level every four panels.

According to ASCE 10–97 Standard (2000),

Connections should be detailed with at least two bolts to make assembling easier.

Reductions in length shall be as specified per Table 12.1.

Design of Members Subjected to Bending and Axial Force

As per ASCE 10–97 Standard (2000),

Members subject to both bending and axial tension shall satisfy the following formula:

$$\left(P / P_a\right) + \left(M_x / M_{ax}\right) + \left(M_y / M_{ay}\right) \le 1$$

where:

P - axial tension

P_a - allowable axial tension

M_x, M_y - moments about x- and y-axis, respectively

M_{ax}, M_{ay} - allowable moments about the x- and y-axis, respectively, as defined in previous section.

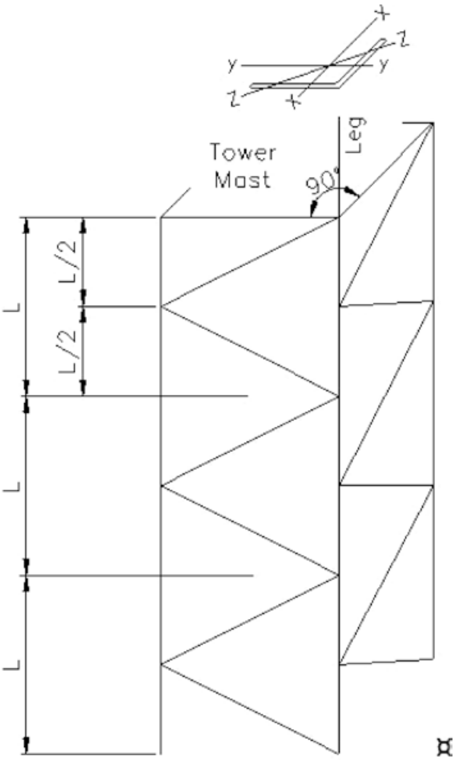


Figure 12.30 Leg of tower mast effective buckling lengths. For these configurations some rolling of the leg will occur. Eccentricities at leg splices shall be minimised. The thicker leg sections shall be properly butt spliced. The controlling L/r values shown shall be used with k =1.

Figure 12.31 Diagonals buckling.

$$M_{ax} = W_x \ f_y$$
$$M_{ay} = W_x \ f_y$$

where:

W_x, W_y - x and y-axis section modulus, respectively
f_y - yield strength

Table 12.1 ASCE 10–97
Tension members detailing

Standard ASCE 10-97	
Length (mm)	Reduction (mm)
$L \leq 4600$	3.2
$L > 4600$	3.2 + 1.6 (*)

(*) for each additional of 3100 mm or fraction

Members subjected to bending and axial compression shall be designed to satisfy the following equations:

$$(P / P_a) + C_m (M_x / M_{ax})[1/(1 - P/P_{ex})] + C_m (M_y / M_{ay})[1/(1 - P/P_{ex})] \leq 1$$

$$(P / P_a) + (M_x / M_{ax}) + (M_y / M_{ay}) \leq 1$$

where:

P - Axial compression
P_a - Allowable axial compression according to item 10

$$P_{ex} = \pi^2 E\ I_x / (k_x\ L_k)^2$$
$$P_{ey} = \pi^2 E\ I_y / (k_y\ L_y)^2$$

where:

I_x - moment of inertia about x-axis
I_y - moment of inertia about y-axis
$k_x\ L_x$, $k_y\ L_y$ - the effective lengths in the corresponding planes of bending
M_x, M_y - the moment about the x- and y-axes respectively, see Notes below;
M_{ax}, M_{ay} - the allowable moments about the x- and y-axis respectively, see explanation below

$$C_m = 0.6 - 0.4\ M_1 / M_2$$

The last equation is for restrained members with no lateral displacements of one end relative to the other, and with no transverse loads in the plane of bending (linear diagram of moments), being M_1/M_2 is the ratio between the smaller and the larger end moments in plane of bending. M_1/M_2 is positive when bending is in reverse curvature and negative when it is in single curvature (Figure 12.32).

$C_m = 1.0$ for members with unrestrained ends, and with no transverse loads between supports

$C_m = 0.85$ if the ends are restrained and there are transverse loads between supports

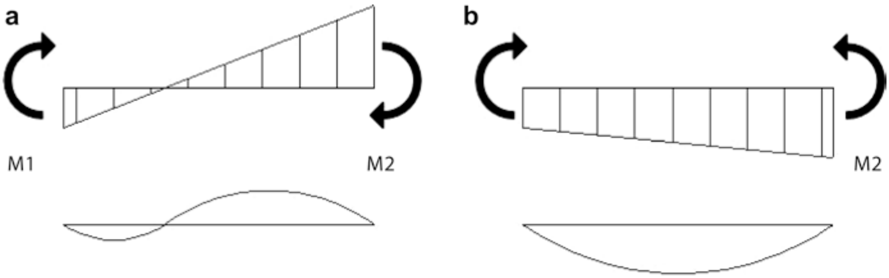


Figure 12.32 Lateral buckling moments.

For Laterally Supported Beams:

$$M_{ax} = W_x \ f_y$$

$$M_{ay} = W_x \ f_y$$

where:

W_x, W_y - x and y-axis section modulus respectively based on the gross section or on the reduced section (when applicable);
f_y - yield strength

For Laterally Unsupported Beams:

Verify lateral buckling according to paragraphs 4.14.4 and 4.14.8 of the ASCE Manual 52 – 1989 or 3.14.4 and 3.14.8 of Standard ASCE 10–97.

Notes:

M_x and M_y are determined as below:

a) If there are transverse loads between points of support (in the plane of bending):

M_x and M_y in the first equation above are the maximum moments between these points, which in the second are the larger of moments at these points;

b) If there are no transverse loads between points of support (in the plane of bending):

M_x and M_y in both equations above are the larger of the values of M_x and M_y at these points.

12.5.2.3 Design of Bolted Connections

The minimum distances bolt to bolt and bolt to the edges of a member have an impact on the capacity of the connection and on the ease of assembly (Figure 12.33). As example, according to ASCE 10–97 Standard (2000), distances vary according to the allowable shear and bearing stresses adopted and can be reduced when those stresses are reduced (see Section 6, item 6.1.4).

As per EN 50341–1:2001 - European CENELEC Standard (J.11) (2012), distances vary according to the allowable shear and bearing stresses. Distances are not specified for inclined directions.

Figure 12.33 Leg members connections.

Shear
According to ASCE 10–97 (2000) and ASTM-A394 (2000),

Type "0"
Low or medium carbon steel, zinc-coated (hot dip):

$$f_v = 380.5 \ \mathrm{N/mm^2} \ (\text{for the thread})$$
$$f_v = 316.5 \ \mathrm{N/mm^2} \ (\text{for the body})$$

Type "1", "2" and "3"

$$f_v = 513 \ \mathrm{N/mm^2} \ (\text{thread and body})$$

f_v - allowable shear stress

Bolts that have no specified shear strength:

$$f_v = 0.62 \ f_u \ (\text{thread or body})$$

f_u - ultimate tensile strength of the bolt

The minimum shear force shall be evaluated multiplying the effective area (root cross-section area at the thread or gross cross-section area at the body) by the corresponding allowable shear stress.

The cross-section area at the root thread is based on the core diameter (ANSI)

According to EN 50341–1:2001 - European CENELEC Standard (J.11.1), If the shear plane passes through the unthreaded portion of the bolt:

$$F_{v,Rd} = 0.6 \quad f_u \ A / \gamma_{Mb}$$

If the shear plane passes through the threaded portion of the bolt for classes 4.6, 5.6, 6.6, 8.8:

$$F_{v,Rd} = 0.6 \quad f_u \quad A_s / \gamma_{Mb}$$

If the shear plane passes through the threaded portion of the bolt for classes 4.8, 5.8, 6.8, 10.9:

$$F_{v,Rd} = 0.5 \quad f_u \quad A_s / \gamma_{Mb}$$

A - cross section area of the bolt
A_s - tensile stress area of the bolt
$F_{v,Rd}$ - shear resistance per shear plane
γ_{Mb} - partial factor for resistance of bolted connections
f_u - ultimate tensile strength of the bolt

Tension
According to ASCE 10–97 (2000) and ASTM-A394 (2000):

Type "0"
Low or medium carbon steel, zinc-coated (hot dip):

$$f_v = 316.5 \text{ N/mm}^2 \left(\text{for the body}\right)$$

Type "1", "2" and "3"

$$f_v = 513 \text{ N/mm}^2 \left(\text{thread and body}\right)$$

f_v - allowable shear stress

Bolts that have no specified proof-load stress

$$f_t = 0.6 \ f_u \quad \text{over the net area } \left(A_s\right) \text{ of the bolt}$$

f_u - ultimate tensile strength of the bolt

Net stress areas for bolts in tension (Table 12.2):
Bolts in inches: $A_s = (\pi/4)\,[d - (0.974/n_t)]^2$

Table 12.2 Net areas for tension bolts

D	n_t	A_s (cm^2)	d	p (mm)	A_s (cm^2)
1/2″	13	0.915	M12	1.75	0.843
5/8″	11	1.450	M14	2.00	1.154
3/4″	10	2.155	M16	2.00	1,567
7/8″	9	2.979	M20	2.50	2.448
1″	8	3.908	M24	3.00	3.525

Metric bolts: $A_s = (\pi/4)\ [d - 0.9382\ p]^2$
where:

d - nominal diameter of the bolt
n_t - number of threads per inch
p - pitch of thread

Combined Shear and Tension
As per ASCE 10–97 Standard (2000),

$$f_t(v) = f_t\ \left[1 - (f_{cv} / f_v)^2\right]^{1/2}$$

where:

f_t - design tensile stress under tension only (item 8.2.2)
f_v - design shear stress under shear only (item 8.2.1)
f_{cv} - computed shear stress on effective area (thread or body)
$f_t(v)$ - design tensile stress when bolts are subject to combined shear and tension. The combined tensile and shear stresses shall be taken at the same cross section in the bolt, either in the threaded or the unthreaded portion.

Bearing
According to ASCE 10–97 Standard (2000),

$$f_P \leq 1.5\ f_u$$

f_u - ultimate tensile strength of plate or bolt
f_p - ultimate bearing stress.

12.5.3 Metallic Poles

The most attractive solution for urban or suburban OHL towers has been the monopole supports. They have been extensively used in all over the world, having adaptations and characteristics according to local necessities.

There are many reasons for the extensive use of monopoles as the main aesthetic solution. Among them it can be noteworthy: the simplicity, the slenderness, the low visual impact, the elegance, the beauty and the reduced area for settlement. As a summary, they are attractive solutions having appropriate painting system to fit them into special environmental circumstances (Figure 12.34). Section 12.9 gives more details about the use of aesthetic solutions for overhead line supports.

From the structural analysis point of view, it is important to observe that the monopoles are very flexible structures with high level of elastic deformation (up to 5 % of the pole height or even more) especially when compared with similar latticed towers. For this reason, it is recommended that the calculations should be carried out through

Monopole Support, Brazil   Aesthetic Pole, Japan   Compact Plus - Top insulated Support, Sweden

Figure 12.34 Monopole Solutions.

"physical and geometric non linear" analysis. Second order effects, may be of great relevance in the case of structural analysis for monopoles. To limit pole top deflection, however, can be very expensive. Therefore, aiming to reach both aesthetic and economic targets, it is suggested to verify the pole top deformation at the following stages:

- at EDS condition: maximum top deformation equal or smaller than 1.5 to 2 % of the pole height,
- at ultimate stage: 4 to 5 % of the pole height.

Figure 12.35 illustrates how deformable are the monopoles during prototype tests.

12.5.4 Concrete Poles

12.5.4.1 Design Methods

Concrete poles were initially developed to meet the expanding need of a supporting structure on streets, highways and area lighting, stadium lighting, traffic signals etc, and for overhead power transmission and distribution (Figures 12.36 and 12.37).

Later on, the quality of concrete was improved being possible to extend the utilization of concrete towers as support for high voltage transmission lines or wind turbine.

Generally, the lifetime of a concrete pole is in range of 50 years. This life can be increased using special protections of surfaces, or special reinforcing material, like high-corrosion resistant types, or free-corrosion or composite types.

The design methods cover pole reinforcing as material and forms, concrete, or special concrete material and pole as technical and functional requirements.

Figure 12.35 Pole deflections during Tests.

Figure 12.36 110 kV Concrete Pole.

The selection of materials and design methods is subject of optimization, thus it is directly reflected in the costs. This part depends on marketing and is solved separately. The other aspects such condition as the controlling of longitudinal cracking and the limitation of pole deflection during bending are considered generally requirements of production and thus solved by factory procedures. Interfaces with metallic materials for crossarms shall be designed based on steel lattice tower design methodologies.

Figure 12.37 Concrete Pole.

Figure 12.38 Pole structure for 110 kV line.

Depending on the requirements, concrete poles can be installed as self-supported, Figure 12.38, or guyed structure.

12.5.4.2 Standard and Practices

The basic design requirements can follow "safety factors method" or "ultimate design state" method. Both methods are standardized in many countries, based on local experiences and type tests. The full scale test shall be carried out to determine the load resistance, deflections and width of cracks.

12.5.5 Wooden Poles

12.5.5.1 Design Methods

Wood poles are composed of a naturally grown biological material which exhibits inconsistent material properties throughout the length of the pole. These inconsistencies, which have a direct impact on strength, are knots, checks, shakes and splits.

Wood poles are susceptible to rot and decay over the design life of the structure. Wood poles normally have less strength at the end of their service lives than when they were originally placed in service that required specific safety factors or partial material factors.

Moreover, insects and animal attacks can significantly decrease the load carrying capacity of the wood pole well before the end of the anticipated service life. To keep the safety level, the standards specify higher safety factors when compared to concrete or steel poles. As an example, NESC requires the wood pole to have a strength that is 60 % higher than the prestressed concrete pole; EN recommends that design should take into account the very probable loss of strength that will occur over the service life of the pole.

12.5.5.2 Standard and Practices

The basic design requirements can follow “safety factors method” or “ultimate design state” method.

In case of “ultimate design state” method, the internal forces and moments in any transverse section of the structure shall be determined using linear elastic global analysis.

12.6 Detailing Drawings and Fabrication Process

The works with transmission line lattice supports are unique when compared with those employed in other metallic construction types, as bridges, roofs or buildings. At least two characteristics make them different and specialized: the extensive use of bolted connections on small web angle profiles and the great number of equal pieces to be produced (sometimes reaching millions of units), which requires series production in “numeric controlled machines” (CNC). This means, in other words, that lattice supports fabrication is a specific business, requiring its own design and detailing professionals, as well as expert production working teams.

Metallic, concrete and wood poles also demand specialized construction works. This is particularly true when the line voltage increases due to the high level of loads involved and the required support heights.

12.6.1 Lattice Supports

12.6.1.1 Detailing Drawings

As mentioned above, the preparation of latticed tower detailing drawings is not a simple task. It requires expertise and qualification of the involved personnel. Profiles are almost a hundred percent angles having “reduced legs” to accommodate one or

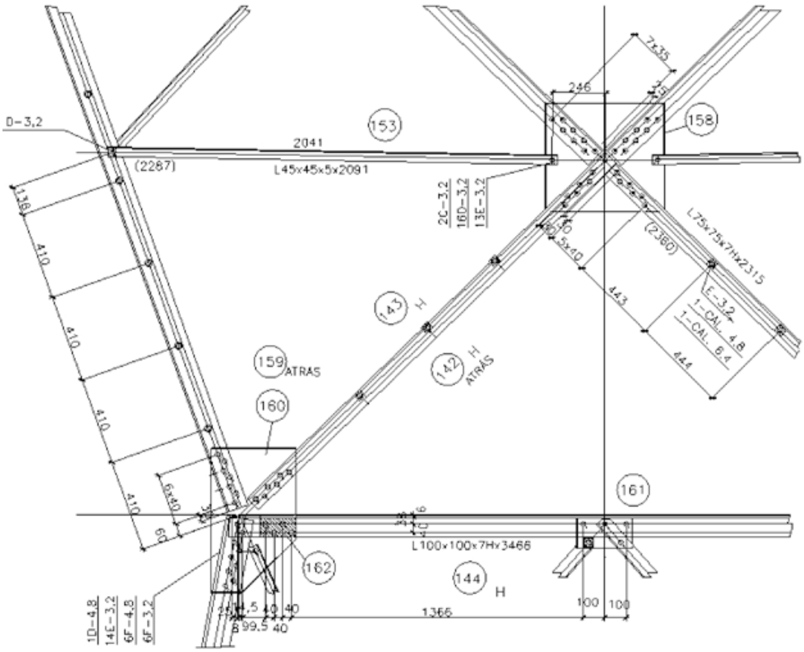


Figure 12.39 Typical lattice tower drawing.

more bolts. Furthermore, the most important premise to be observed in the detailing practices is trying to guarantee the "original structural figure", creating the nodes through the crossing of bar axis at the same point. Figures 12.39 and 12.40 are typical OHL lattice support detail drawings.

As a design premise, structural bars must be only submitted to axial forces (tension and/or compression). To assure this, joints must be designed and detailed as much as possible without eccentricities. Figures 12.41 and 12.42 show correct and incorrect detailing practices.

12.6.1.2 Bolts

Lattice OHL supports are normally modelled and calculated as "pin-jointed truss structures", being the bolt the key structural connection element. In the majority of the cases, tower bolts are submitted to shear forces. To cope with this function, those bolts are normally detailed having a "not threaded part" on the length, to avoid the coincidence of shear plane with the threaded section.

As shown in Figure 12.43, the unthreaded length of the bolts must be long enough to accommodate all the pieces to be connected (length equal to the sum of bar thicknesses). On the other hand, the threaded part is defined according to the bolt diameter, having lengths enough to permit the installation and tightening of the washers, nuts and eventually "locking devices" when specified.

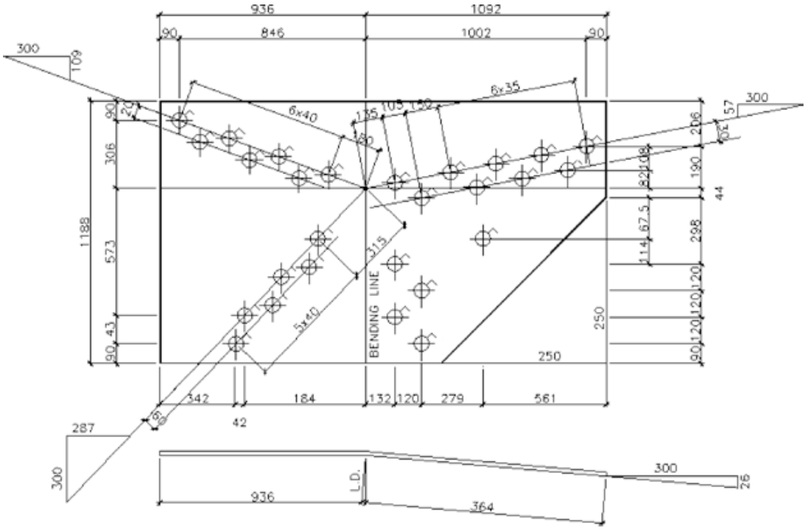
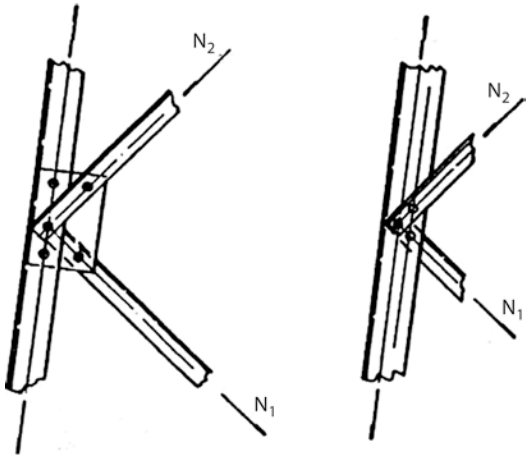


Figure 12.40 Typical gusset plate detailing.

Figure 12.41 Correct Detailing.



12.6.1.3 Nuts, Washers and Locking Devices

Nuts are essential elements on the bolted connections, being responsible for the tightening procedure itself. As per Cigré TB (2009), nut specifications (materials) are according to ASTM A 563 (ASCE 10–97) (ASTM-A563 2000), EUROCODE 3 EN 1993-1-1 (EN 1993) and EN 10025 (EN50341-1) (CENELEC – EN 50341–1 2012) or ISO 898–2 (ISO 898 1 Internacional Standard Organization) (Figure 12.44).

Plane washers are currently used in the lattice tower bolted connections, aiming to protect the galvanized surfaces during the tightening operation, and for better forces distribution on the pieces. According to the above mentioned Cigré TB (2009), washers are normally circular and specified by ASTM A 283 (ASTM-A283

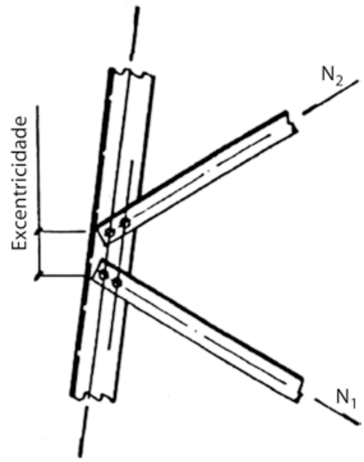


Figure 12.42 Detailing with eccentricities.

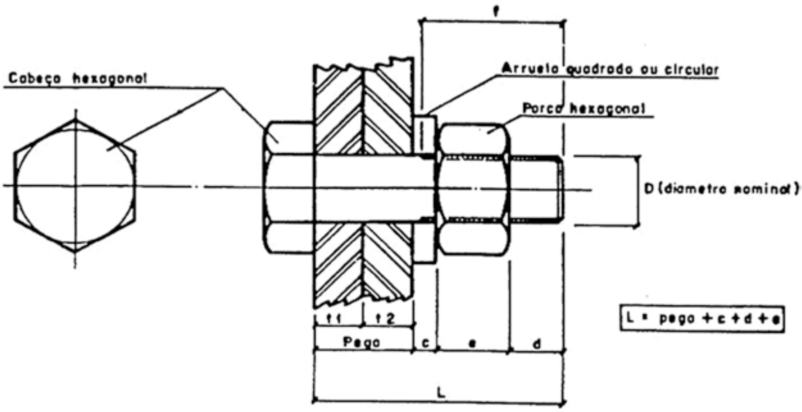


Figure 12.43 Tower bolts detailing.

Figure 12.44 Typical galvanized tower nuts.

2000), EUROCODE 3, EN 1993-1-1 (EN 1993) and EN 10025 and EN 10113 (EN 50341–1) (CENELEC – EN 50341–1 2012).

Locking devices are used aiming to prevent nuts from loosing tightening due to dynamic or thermal effects and, in extreme circumstances, tampering by vandals. Locking methods can be done by means of adequating tightening of the nuts (controlled assembly torques), deformation of the threads, application of thread locking material, spring washers, “palnuts” installation, tamper proof nuts, swaged nuts, welding procedure, etc.

12.6.1.4 Minimum Bolt Distances

As just said before, bolted connections in OHL latticed supports currently need to be designed and detailed considering the use of reduced spaces due to the small leg dimensions of the angle profiles. The minimum bolt distances are, therefore, important premises to be taken into account in the preparation of the detailing drawings. The minimum bolt to bolt and bolt to member edge distances may have impact on the connection capacity and on the assembly easiness. In fact, distances vary according to the allowable shear and bearing stresses adopted in the calculations and can be reduced when those stresses are reduced.

Document Cigré TB 384 (Cigré 2009) shows how national and international standards as well as industry practices treat the subject.

Distances between Holes

As per ASCE 10–97 standard (ASCE 10–97 2000) (Figure 12.45):

$$s \geq \left(1.2 \ P / f_u \ t\right) + 0.6 \ d$$

s - distance between holes
P - force transmitted by the bolt
f_u - ultimate tensile strength of plate or bolt
t - plate thickness
d - nominal diameter of the bolt
s ≥ nut diameter + 3/8” (recommendation for assembly)

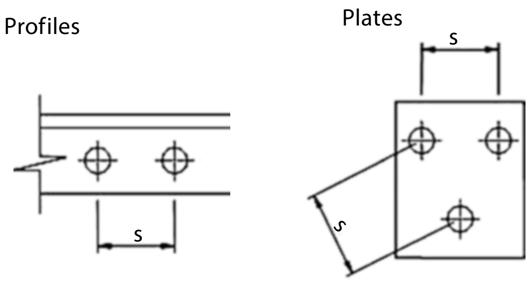


Figure 12.45 Distances between holes.

Table 12.3 Maximum nut diameter

ANSI B18.2.2/81	ANSI B18.2.4.1 M/79
1/2″ - 22.0	M12 - 20.8
5/8″ - 27.5	M14 - 24.3
3/4″ - 33.0	M16 - 27.7
7/8″ - 38.5	M20 - 34.6
1″ - 44.0	M24 - 41.6

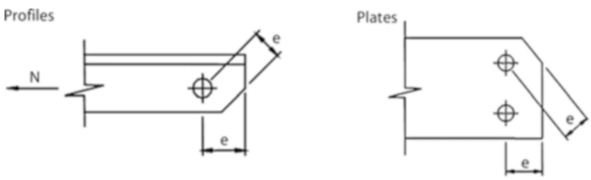


Figure 12.46 Hole distances to cut edge.

Maximum nut diameter (mm) in accordance to Table 12.3:

According to EN 50341–1:2001 – European CENELEC Standard (CENELEC – EN 50341–1 2012):

$$s = \left[\left(P \ \gamma_{M2} / 0.96 \ f_u \ \ d \ \ t \right) + 0.5 \right] \ d_0$$

s - distance between holes
P - force transmitted by the bolt
f_u - ultimate tensile strength of plate or bolts
t - plate thickness
d_0 - hole diameter
γ_{M2} - partial factor for resistance of net cross section at bolt holes
d - nominal diameter of the bolt

$$\gamma_{M2} = 1.25 \ \left(\text{Claues} \ \ 7.3.5.1.1 \ \ \text{of} \ \ \text{EN} \ \ 50341 \ \ 1 \right)$$

γ_{M2} may be amended in the National Normative Aspects or the Project Specification.

Distance between Hole and the Bar End
As specified by ASCE 10–97 Standard (2000) (Figure 12.46),

$$e \geq 1.2 \ \ P / f_u \cdot t$$

$$e \geq 1.3 \ \ d$$

$$e \geq t + d / 2 \quad \left(\text{for punched holes} \right)$$

e - distance of the hole to the end or the cut edge of the profile
f_u - ultimate tensile strength of the connected part
t - thickness of the most slender plate
d - nominal diameter of the bolt
P - force transmitted by the bolt

Redundant members:

$$E \geq 1.2\ d$$
$$e \geq t + d/2 \quad (\text{for punched holes})$$

Note: Maximum bearing stress f_p to implicitly check out minimum distances:

$$P_{max} = f_p\ d\ t$$
$$e \geq (1.2\ P_{max})/(f_u\ t) = (1.2\ f_p d\ t)/$$
$$(f_u\ t) = (1.2\ f_p / f_u) d$$

and because $e \geq 1.3d$

$$1.2\ f_p / f_u < 1.3 \text{ or}$$
$$f_p \leq 1.3/1.2\ f_u = 1.0833\ f_u$$

As per EN 50341–1:2001 - European CENELEC Standard (J.11.2) (CENELEC – EN 50341–1 2012),

The biggest of:

$$e \geq (P\ \gamma_{M2} d_0)/(1.2\ f_u d\ t)$$
$$e \geq \left[(P\ \gamma_{m2})/(1.85\ f_u d\ t) + 0.5\right]\ d_0$$

e - distance of the hole to the end of the profile
f_u - ultimate tensile strength of plate or bolt
t - plate thickness
d_0 - hole diameter
γ_{M2} - partial factor for resistance of net cross section at bolt holes
d - nominal diameter of the bolt
P - force transmitted by the bolt.

Distance between Hole and Rolled Edge

As quoted by ASCE 10–97 Standard (2000) (Figures 12.47 and 12.48),

$$f > 0.85\ e$$

with:

e - distance between the hole and the end
f - distance between the hole and the edge

Figure 12.47 Distance between hole and edge.

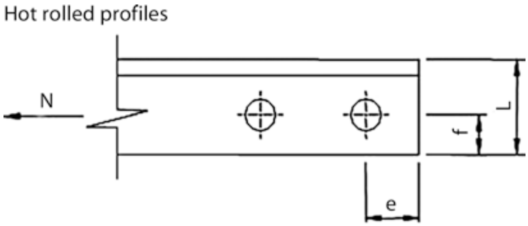
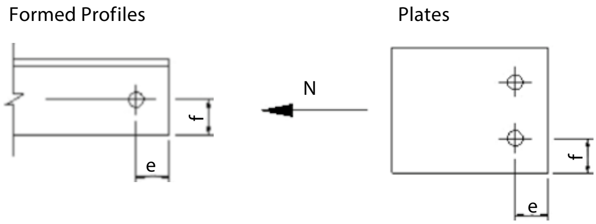


Figure 12.48 Hole distance to clipped edge.



According to EN 50341–1:2001 - European CENELEC Standard (J.11.2) (CENELEC – EN 50341–1 2012),

$$f = \{[(P\ \gamma_{M2})/(2.3\ f_u d\ t)] + 0.5\}\ d_0$$

f - distance between hole and edge
f_u - ultimate tensile strength of plate or bolt
t - plate thickness
d_0 - hole diameter
γ_{M2} - partial factor for resistance of net cross section at bolt holes (see Item 8.1.2)
d - nominal diameter of the bolt
P- force transmitted by the bolt.

12.6.1.5 Clearances in Holes

Usually the hole diameters are larger than the bolt shank to allow easy assembly. The increase in the hole size must allow some tolerance on fabrication and free zinc remaining in the hole after galvanizing process. Document Cigré TB 384 (Cigré 2009) indicates such clearances as per standards and practices around the world: 1/16" (1.6 mm or 1.5 mm) for bolts M12, M16, M20 and M24 or 2.0 m for bolts M27 and M30.

12.6.1.6 Other Detailing Assumptions

Cigré TB 384 (Cigré 2009), contains many other detailing decisions and/or assumptions that need to be taken into account in the preparation of shop drawings of lattice steel supports. As examples, it deserves to be mentioned, the “maximum permitted length” and the “minimum thickness limit for members”.

Maximum Permitted Length for Members
The maximum physical length of an individual member is generally controlled by restrictions of manufacture, transport and erection. Particular practical limitations are:

- The length of raw material;
- The ability to handle and maintain straightness;
- The size of the hot dip galvanizing bath;
- Transportation limits;
- In rare situations the maximum weight and handling.

As these are non-technical limitations and often based on economics, these limitations are indicated by the Industry or Guidelines, but not in the normative Standards. Industry practices around the world (Cigré TB 384 2009), suggest 9 m as the most accepted value.

Minimum Thickness Limit of Members
The minimum thickness limit of a member affects:

- The life of the member as it affects the thickness of applied zinc;
- The local buckling of sections;
- The vulnerability to damage from manufacture, transport and maintenance;
- The minimum bearing and pullout capacity in a connection.

According to Cigré TB 384 (2009) the more used values as minimum thickness limit of members are 3 or 4 mm.

12.6.2 Metallic Poles

Currently, the steel poles are made from carbon steel, mainly from the high strength low alloy quality. They are normally shaped in modulus from 9 up to 12 m length, with continuous variable polygon cross sections. Depending on the dimensions involved (height and pole base width), the cross section used can be from the square or rectangular (seldom used), to the dodecagonal or circular types (Figure 12.49). The most common joints used are from the “overlapping splices” type, more suitable for suspension or light angle poles. The flanged joints are currently used for the heavy angle or dead-end poles (Figure 12.49).

The finishing types are specified basically to meet two needs: the corrosion protection and the aesthetic. For this purpose, the poles can be only externally painted with

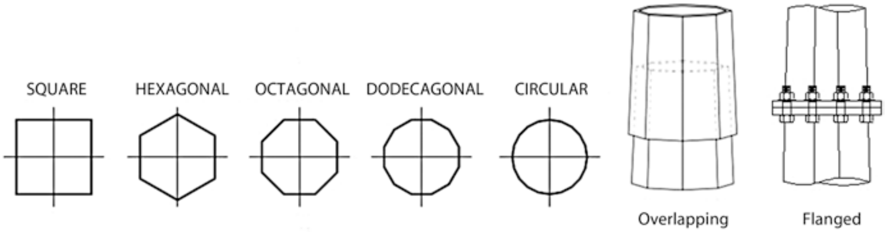


Figure 12.49 Typical Pole Cross-Sections & Joints.

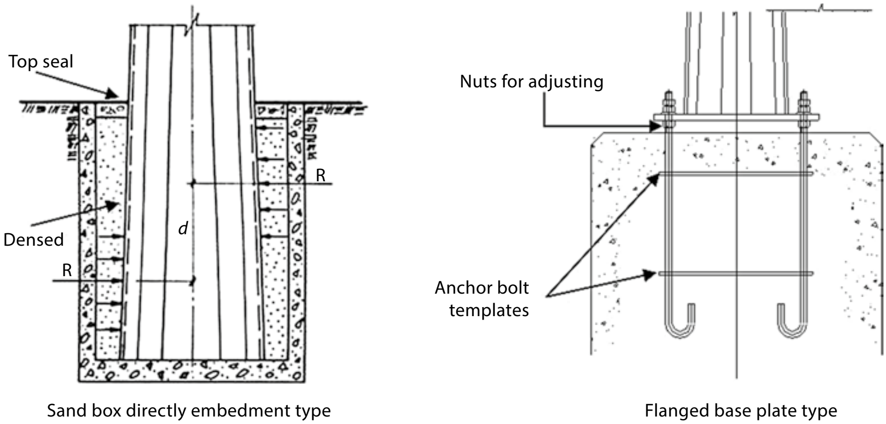


Figure 12.50 Typical PoleFoundation Details.

complete sealed joints, or hot-dip galvanized. The first solution provides an excellent aesthetic finishing, while the second one excellent protection. Therefore, some clients use to specify both finishing procedures, hot-dip galvanizing plus painting to obtain both advantages. For this, it is mandatory to use an appropriate "shop primer" over the galvanized coating in order to create a sufficient/necessary anchorage surface for painting.

As far as the pole foundations are concerned, they have been constructed using two different approaches: the "direct embedment" or the "flanged base plate with anchor bolts". The directly embedment on densed sand box, or concrete, is a very economic solution mainly when designed for light suspension poles. The flanged base plate proposal is specially recommended for angle/dead-end poles, since the "two nuts adjustable system" helps to adjust the pole top deflection (Figure 12.50).

12.6.3 Concrete Poles

Due to its quantity in the grid, the concrete poles are standardized by length and working load. This load is specified to a conventional distance "d" from the top of the pole, generally equal to 0.25 m.

Figure 12.51 CuNap-treated poles at PWP's yard in Sheridan.

The value of load is such that, its effect in terms of moment at the base of pole, is equivalent to the effect of the design live loads. The sections from top to the base increase with a certain ratio to obtain finally an economic structure with quite the same safety along the pole height. The concrete poles are manufactured in special forms, suitable to be centrifuged of vibrated.

The higher structures may be manufactured in modules, attached by bolts or telescoped.

12.6.4 Wooden Poles

The wooden poles are mainly of southern pine, Douglas-fir and Western red cedar. To increase their life, the wooden poles are treated with preservative such as pentachlorophenol (penta), CCA, creosote, copper naphthenate and ammoniacal copper arsenate or ammoniacal copper zinc arsenate.

All wood preservatives typically used by the Utilities in the poles are robust, with many decades of data supporting effectiveness. The Utilities usually need big quantities of wooden poles, both for new overhead lines, or to replace poles from existing ones which can reach the range of hundreds millions. To fulfill these requirements the wooden pole factories are located on large yards (Figure 12.51) and special protection environment measures are needed (Figure 12.52).

12.6.5 Fabrication Process

Due to the large number of pieces to be produced, usually millions, besides the repeatability and the required high speed in the operations of cutting and drilling, the towers must be produced in specialized factories.

Currently, the cutting, drilling and marking operations on angles and plates are made by automatic numeric controlled machines (CNC), which boost the production (Figure 12.53).

Figure 12.52 160′-long treating cylinders.

Figure 12.53 Transmission Line Supports Factory.

Hot dip galvanizing lines give the pieces the required finishing against corrosion, normally enough to withstand for typically longer than 40 years rural atmosphere, practically without any maintenance working.

One relevant aspect to be observed in the manufacture of TL structures is the accuracy to be assured by the machines during the cutting and drilling operations. As per standards and guidelines for design/detailing of towers, the gaps in holes are about 0.8 mm in relation to the bolt diameters. According to Cigré TB 384 (2009), the fabrication tolerances result in a total hole clearance of 1.6 mm (1/16”) over the bolt diameter as a consequence of the “punching procedures”. Anyway, to ensure good structural performance, and perfect mountability, these design and fabrication tolerances must be compatible with the construction and erection ones and be followed during all the process (Cigré TB 2009).

In accordance with Cigré TB (2010), positions of holes are punched or drilled within 1 mm of tolerance over the nominal value. During the fabrication process, the oversized holes result in a tolerance of ±1 mm on the member lengths. Still in accordance with Cigré TB (2010), for bracing members, length tolerances are about 0.15 % of the member length. Dimensions of the tower width are defined by erection and construction tolerances of about 0.1 % of the horizontal dimension of the tower base (Cigré TB 2009).

The erection of the supports can be done manually, piece by piece using auxiliary masts, or in a more automatic way through horizontal pre-assembly and lifting by cranes (see Chapter 15).

In any case, it must always be taken into account the large number of structures to be assembled (with millions of bars and bolts) and the difficulty of logistics that can be found in the field. Towers can be erected in locations with absolute lack of infrastructure, such as roads, any kind of access, electricity, water, concrete for foundations, etc.

12.7 Prototype Tests

It has been a current practice, that new OHL support designs are validated by prototype full scale tests. Clients, designers and tower manufacturers meet in a test facility area (test station) for simulation of all the extreme operational conditions to be supported by the structure during its expected lifetime (Figure 12.54).

In order to make the different interests of all participants compatible and to give a guide for such tests, the Standard IEC 60652 (IEC 60652 2002) was published in 1979 and reviewed in 2002. This document normally is the base to perform all the full scale prototype tests around the world.

12.7.1 Objectives

Full scale tests are normally carried out on prototype supports to verify the design method (and inherent assumptions), the detailing process, the quality of the materials and fabrication procedures. This way, full scale tests are currently performed on the following circumstances:

- to verify compliance of the support design with the specifications (known as "type tests").
- to validate fabrication processes.
- as part of a research or development of an innovative support.

As general test criteria, the material and the manufacturing processes used in the fabrication of the prototype support shall be from the same specifications to be used during the fabrication of the supports. These specifications shall include the

Figure 12.54 Full scale test facility.

member sectional properties, connection details, bolt sizes, material grades and fabrication processes. In other words, the materials used for the fabrication of a prototype support shall be representative of the materials used in the production of the structures. Aiming this objective, prior to or during the series fabrication, sample tests are required to check the quality of the materials being used. The prototype support to be tested shall be fabricated using material taken at random from the manufacturer stock.

Unless otherwise specified, prototypes shall be galvanized prior to the test procedures, since there is no "black support" in the line (unless they were designed to be installed without galvanization).

12.7.2 Normal Tests

The tests to be performed can be from the "normal" or "destructive" types. They are considered "normal tests" when they are carried only to the specified design loadings (100 %). As a general rule, all loading cases that are critical for any support member should be simulated during the normal tests. As test procedure, according to IEC 60652(IEC 60652 2002), loads shall be applied in increments to 50 %, 75 %, 90 %, 95 % and 100 % of the specified loads (Figure 12.55).

Figure 12.55 Normal test - 500 kV Guyed Tower.

Even if only the 100 % step the only one important for the tower acceptance, intermediate steps are perceived to be useful for the following reasons:

- For balancing the loads prior to the 100 % step.
- For comparing measured displacements and stresses to theoretical values, and possibly, for rapidly identifying any abnormal structural behavior.
- They can be essential to ensure proper rigging settings (load orientation and rigging interference).
- To prevent a premature collapse of the whole tower.

Once the final 100 % load level is reached, the loads shall be maintained for a period of 5 minutes (minimum 1 minute as per IEC 60652). As an acceptance criteria, during this holding period, no failure of any component can occur, mainly near below 100 % step. As in the majority of the cased, the loading hypotheses are "ultimate loads", it is common that during "normal tests" some failure occurs. In these cases, designs are checked, sometimes members are reinforced and the tests continue until reach the 100 % level (Figure 12.56).

Figure 12.56 Failure at 100 % loading step.

12.7.3 Destructive Tests

If required by the client, and upon agreement with the designer and/or the fabricator, "destructive test" can be performed. If a destructive test has to be carried out, it is a common practice to do it using one of "exceptional loading cases" (e.g., extreme transverse wind), by increasing both transverse and the vertical loads (or even longitudinal in case of "anti-cascade" hypothesis or dead-end tower), in steps of 5 % until the support failure. This procedure permits to gain information on actual versus predicted behavior or, in the case of suspension towers, the failure load can be related to an increase in span utilization. In cases where there is no ice involved, it is a current practice to increase only the transverse (or longitudinal) loads (Figures 12.57 and 12.58).

12.7.4 Acceptance Criteria

As full scale prototype test acceptance criteria, IEC 60652 (IEC 2002) quotes that "the performance of the support shall be considered acceptable if it resists the specified design loads (at 100 % of each load case) for minimum 1 minute without

Figure 12.57 Destructive test – 230 kV Double Circuit tower.

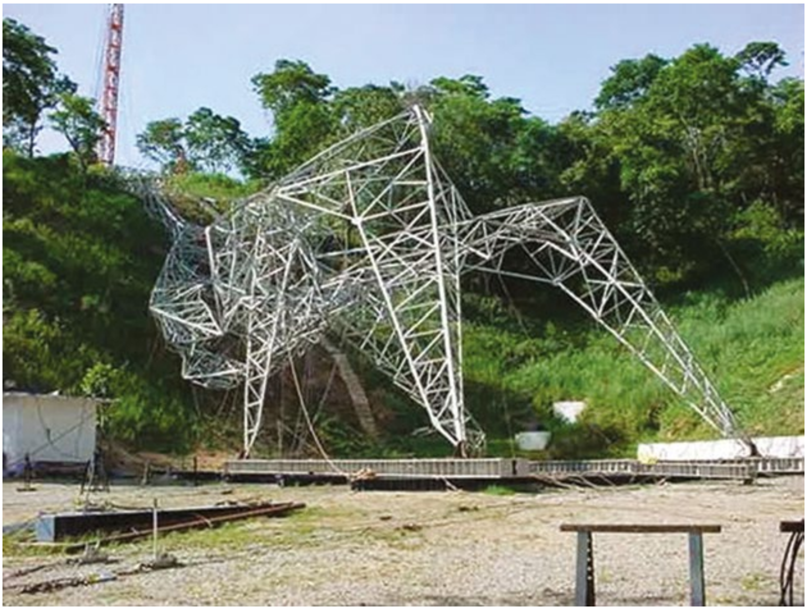


Figure 12.58 Destructive test – 500 kV TL Tower.

failure of any components or assemblies even though a longer holding period may have been specified (normally 5 minutes)". This is a "deterministic approach" and, even being practical, it is not perfectly coherent with the probabilistic based design method. As per IEC 60826 Standard (Design Criteria of Overhead Transmission Lines), concepts such as statistical distribution of support strengths, strength factors ($Ø_R$), exclusion limits etc, need to be taken into account due to their importance for the support designs and consequently, for the prototype test result interpretations.

As per Cigré TB 399 (Improvement on the tower testing methodology 2009), applying IEC 60826 (Design Criteria of Overhead Transmission Lines) as basic philosophy for the design of overhead lines, means in terms of structures, to adopt the following general equations:

$$\gamma_u Q_T \leq R_{10\%}$$

Where:

Q_T = Design loading referred to a returned period T (or/with specific load factors);
$R_{10\%}$ = Design strength with a 10 % exclusion limit
γ_u = Use factor coefficient.

On the other side, the 10 % exclusion limit strength can be obtained by:

$$R_{10\%} = \phi_R R_C$$

Where:

R_C = Characteristic strength assessed by calculations and calibrated by loading tests (or professional experience);
ϕ_R = Strength factor to be used in the design, and evaluated as function of the statistical distribution of towers strengths.

Therefore, as far as the OHL support designs are concerned, to use IEC 60826, enables the designer to estimate the characteristic strengths of the towers applying realistic known "Strength factors". Both, the characteristic strength and the strength factor, are concepts, parts of the same issue involving design and loading tests.

As mentioned in Section 3, the statistical distribution of tower strength has been firstly studied by, Paschen et al. (1988), and afterwards by Riera et al. (1990). Both studies have similar conclusions indicating log-normal distribution as the best fitted curve to represent the population of support strengths, with mean values "little above" 100 % and coefficient of variations below 10 %.

Taking the Riera et al. (1990) study as example, the design curve showed on Figure 12.59 can be established:

Where Cv = Coefficient of Variation, Rm = Mean Strength, Rc = Design or characteristic Strength, R_{10} = 10 % Exclusion Limit Strength;

From that study, and making the calculations accordingly, the 10 % Exclusion limit Strength and the "Strength Factor" "ϕ_R = 0.93" can be obtained.

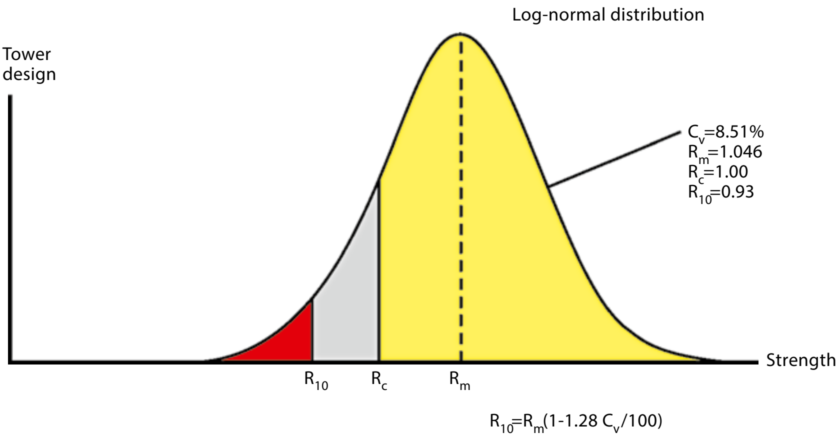


Figure 12.59 Support design strength statistical distribution.

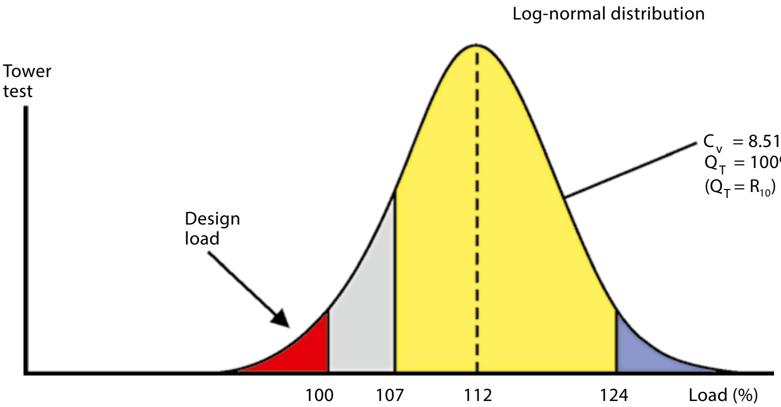


Figure 12.60 Tower test strength statistical distribution.

A corresponding loading test on a probabilistic based approach should also have as targets, to reach statistical distribution curves such as, for example, the herebelow shown on Figure 12.60, where Q_T = Design Load.

So, the results of tower loading tests on a probabilistic based philosophy, should have the objective to confirm and/or calibrate both curves in terms of "Loading and Strength".

As conclusion, the current practice adopted by the industry on testing OHL supports is correct and valid, but it seems that the test objectives should be improved aims should be to check the loading supportability and the design adequacy.

As well as desigh premises specially for long new lines, at least the light suspension(s) tower(s) should be tested, preferably up to the destruction. It is always important to remark that, according to IEC 60826 (IEC 60826 Standard Design Criteria of Overhead Transmission Lines), those towers should be designed as the "weakest link" of the transmission line system, being, therefore, its risky element.

When, for any reason, it is not possible to test at least the most numerous suspension tower, the desirable reliability level should be evaluated and adequate "Strength factors $Ø_R$" should be adopted aiming to reach that proposed target.

Finally, if the "Probabilistic Based Approach" is used as the main design philosophy, it is recommended to perform loading tower tests coherent with that philosophy. Using this concept, those tests should be carried out aiming to get from the supports the following responses:

- To support expected "loading cases" as minimum;
- To behave as estimated by the structural calculations, having a "failure strength" compatible with the strength factor ($Ø_R$) adopted.

Therefore, as better explained previously, the interpretation and approval of the test results should be based in two premises: the "loading support capability" and the "expected strength/behavior".

12.8 Special Structures

12.8.1 Guyed Supports

As mentioned in Section 2, guyed supports are those that combine rigid elements (mainly lattice beams, masts, frames or even poles) with prestressed guy wires resulting in stable economic and structural systems (Figure 12.61).

They are very much used in high voltage overhead transmission systems, especially for long lines where the servitude in not a so critical issue. Currently, guyed structures are used, or in distribution lines (voltage level below 50 kV), or extra high voltage lines (above 300 kV). For intermediate voltage levels, due to the heights and loadings involved, the guyed supports, in the majority of the cases, use to be not economical.

Normally, guyed structures are used as suspension supports, while self-supported towers are applied to the other support functions in the line. Therefore, according to IEC 60826 (IEC 60826 Standard Design Criteria of Overhead Transmission Lines), the suspension guyed structures are designed to be the weakest links in the transmission line systems.

12.8.2 Guyed Structure Types

Depending on the arrangements proposed among the rigid elements and the wires, the guyed supports can be of the following types:

12.8.2.1 V-Guyed Type

The V-guyed type support is very successful as suspension tower, and the most used type of guyed structure for high voltage overhead lines around the world so far (Figure 12.62).

Their main advantages are:

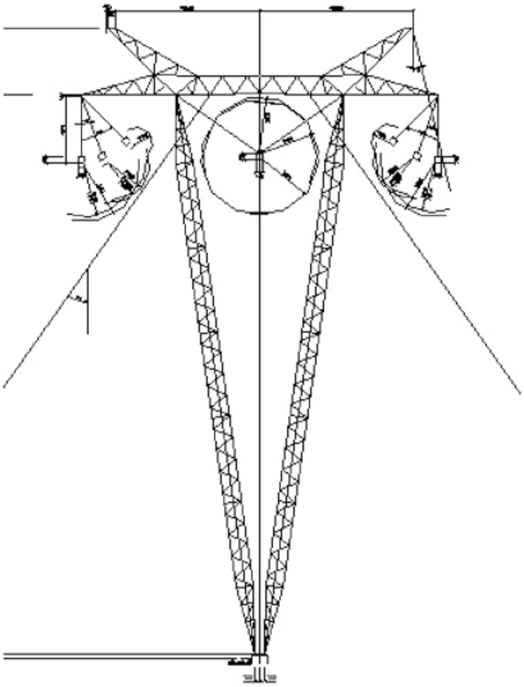


Figure 12.61 Guyed OHL support.

Figure 12.62 V-Guyed Support.

Figure 12.63 Portal Guyed Support.

- Narrow corridors required as compared with other guyed types (≤60 meters for 500 kV).
- Lower weights in comparison with equivalent self-supported towers (about 40% less).
- Only 5 small foundations (4 of them having only uplift loads)
- very easy erection and adjustments.
- Only a single point in the terrain required for installation.

12.8.2.2 Portal Guyed Type

Portal guyed type (or H-type) is also a well known and very used type of OHL suspension support in the world grid (Figure 12.63).

Their main characteristics and advantages are:

- Possible reduced servitude as compared with the V-type.
- Only 4 foundations required (2 only in uplift).
- Normally a little heavier than the V-guyed.
- Two location points in the terrain for settlement
- Easy to assemble and erect.

12.8.2.3 Cross-Rope Suspension (CRS) Type

The Cross-rope suspension towers are an evolution of former “chainette” concept and started to be installed during the 90’s. The evolution done on the chainette type, was basically a simplification on the suspension arrangements of the conductors, using, in this case, a single rope crossing through the top of the masts. This single modifications enables to reduce the number of joints (compression terminals or pre-formed strips) and simplifies the installation (Figure 12.64).

Thousands of kilometers of extra high voltage overhead transmission lines have been successfully installed around the world using cross-rope suspension supports. When applicable, excellent results have been reported with the use of this type of support.

Figure 12.64 Cross Rope Suspension Support.

The main characteristics and/or advantages of the CRS supports are:

- Larger “right of way” required (normally above 75 m for 500 kV).
- Very cost effective.
- 6 small foundations necessary (4 only in uplift loading).
- Due to the open space on the tower top geometry, it is the best structural solution for the use of “phase compaction” or “expanded bundle”(HSIL) techniques.
- More feasible and specially recommended for very long lines crossing inhabited areas, or on other cases where the servitude width is not a so critical issue.

12.8.2.4 Lattice Guyed Monomast

The “lattice guyed monomast” support is not a new solution on the transmission line grid, but its use has been recently increased quite a lot, due to the great number of long EHV line projects under construction in the world (Figure 12.65).

The main characteristic of these structures is that they have only one mast. Their advantages normally are:

- Very cost effective, similar to CRS type.
- Reduced servitude when compared to all the other guyed support types (50 m can be adequated for 500 kV OHL’s).
- 5 foundations, similar to V-guyed type.

Figure 12.65 500kV Lattice Guyed Monomast Support.

12.8.2.5 Structure Characteristics

All the types of guyed supports are a combination of masts beams or frames, basically latticed elements, with guy wires. The joints between those elements are from the pin-joint type with bolts, while the mast base support is from the "universal" hinge type. This way, it is possible to design masts and beams as modules, calculating them according to their critical loading cases (beams very sensitive to insulator string "swing angles" and vertical loads while masts to their heights and wind loads) and combine them accordingly forming interesting and economic modular supports.

Aiming to reduce the support elastic deformation, the guy wires to be specified must be of the "pre-stressed" type. Their initial installation stresses are, currently, of about 10 % of the "ultimate tensile stress"(UTS), while the maximum calculated guy wire loads shall not exceed 75 % of their UTS.

12.8.2.6 Structural Analysis

As quoted by ASCE 10-97 (2000), *guyed structures normally require a second-order analysis. Guyed structures and latticed H-frames may include masts built-up with angles at the corners and lacing in the faces. The overall cross-section of the mast is either square, rectangular, or triangular. Latticed masts typically include a very large number of members and are relatively slender, that is, may be susceptible to second-order stresses. One alternative to modeling a mast as a three-dimensional truss system is to represent it by a model made up of one or several equivalent beams. The properties of equivalent beam that deflects under shear and moment can be worked out from structure analysis principles. The beams are connected to form a three-dimensional model of the mast or entire structure. That model may be analyzed with any three-dimensional finite element computer program. If large deflections are expected, a second order (geometrically nonlinear) analysis should be used. Once the axial loads, shears, and moments are determined in each equivalent beam, they can be converted into axial loads in the members that make up the masts.*

The guyed supports are, in general, very flexible and elastically deformable structures when compared to the self-supported ones. They adapt much better to the flexibility and elasticity of the cables, making the transmission line itself to behave more similar to a homogenous system. This way, in many circumstances they may act as a kind of "transverse or longitudinal virtual line dampers" dissipating energy through their deformations and helping the system to absorb for example, breakage of conductors, impacts, cascade effects, etc. This can be seen when segments when a segment of line containing some spans and structures are entirely modeled like a system.

12.8.3 Supports for Direct Current Lines

The DC transmission systems have has had a great demand by the electricity market lately. This recent tendency is basically due to:

- New technology development for the DC equipments (valves, converter stations, etc) allowing considerable cost reduction.
- Conversion of AC to DC lines, aiming to optimize power transfer capability in existing corridors.
- Very big blocks of electrical energy to be transported (up to 6000 MW per bipole) in some regions.
- Very long transmission lines (above 1500 kms) being installed.
- Reduction in the line losses especially on those "supergrids".

As a consequence, more and more DC line supports have been installed recently.

12.8.3.1 Main Characteristics

From the supports point of view, DC lines are very similar to the AC ones. When applicable, suspension towers are normally from the monomast guyed type, while self-supported structures are used for the other support functions in the line.

Their format is always from the "pyramidal" type, having only two cross arms (one for each pole) and two ground wires peaks (Figure 12.66 and 12.67).

12.8.3.2 Structural Analysis

In the majority of the cases, the structural element used is the so called three dimensional truss, formed by lattice planes of "tension-compression" systems as described in Section 4.

As far as the structural analysis is concerned, the DC supports are generally modeled as 3-D truss linear analysis. For the guyed-monomasts, however, "nonlinear analysis" is always required.

12.8.4 Supports for Large Crossings

Finding new routes for high voltage overhead lines may require designs that address obstacles such as valleys, wide rivers and arms of seas. Large overhead line crossings are currently designs at the limit of the "state-of-the-art", as they can demand

Figure 12.66 DC Guyed Monomast Support.

very long spans and/or extra high supports. Standards generally do not cover all the necessary load assumptions and design approaches for such projects. This way, information about crossing projects already constructed can be essential to assist designers around the world to make decisions in the absence of relevant standards. Aiming to contribute to this demand, Cigré has published TB entitled (Large Overhead Line Crossings 2009). An interesting data bank was created containing valuable information, such as used conductor types used, tension applied and vibration control devices, employed phase spacings, spans, sags, insulator strings, tower heights, tower weights, etc.

For the purpose of the Cigré study, a large crossing was defined as a project having a wind span of 1000 meters or above, and/or a tower with height of 100 meter or more (Figures 12.68, 12.69, and 12.70).

12.8.4.1 Main Characteristics

Currently, supports for big crossings are uncommon and unique projects, usually having very high structures and supporting big loads as result of large spans.

They may demand the fabrication of "out of standard and special profiles", having double or quadruple sections, or even latticed elements as diagonals or main members. Many welded joints are normally used to make parts or structural components.

Figure 12.67 DC Self-Supported Structure.

Figure 12.68 132 kV Ameralik Fjord Crossing, Greenland (5.37 km crossing span).

Figure 12.69 4 × 380 kV - Elbe River Crossing, Germany.

Figure 12.70 500kV Jiangyin Yangtze River Crossing, China (Suspension tower with 346.5 m height).

Due to the support heights and the inherent elastic deformations, non linear analysis models are always required. In the majority of the cases, a structural modeling covering the entire crossing is recommended to take into account dynamic effects.

Supports fabrication demands special machines and devices, as well as strict quality control system for the welding procedures. In many cases thermal treatments are required on welded components for stress relieving purposes.

Pre-assembling of parts at the factory yard is well recommended and erection at site location currently demands special equipments and methods.

12.9 Environmental Concerns & Aesthetic Supports

12.9.1 Environmental Issues

Years ago, aesthetics was not a value taken into account in the design of supports for new transmission lines. Towers were not judged as "pretty" or "ugly"; they were just considered essential elements for transmission of electricity. Many thousands of kilometers of transmission lines were, thus, built in all continents justified by the benefit of the electricity, considered a privilege of modern societies.

This reality started to change mainly after the 60's, when the environmental aspects of the lines and the aesthetics of the supports, began to be more and more questioned in the implementation of new projects. These changes can be understood as a result of many factors, such as:

- The existence of thousands of kilometers of lines already built in some countries and/or some regions.
- The evolution of the benefit of electricity, from "a privilege of few societies" to an "acquired right" of the citizens of the twentieth century. Electricity subtly became a "social right", and an obligation of the governments to provide it.
- The increasing presence of transmission lines in inhabited areas, in such a way, that the towers became familiar elements in the cities.
- The difficulty of obtaining new urban corridors for bringing more power to central regions of cities especially those with high vertical growth.
- A greater environmental conscience motivated by the various aggressions to the environment in different regions of the world.

All this together made that the environmental aspects had become one of the most important premises in the studies for the implementation of new transmission lines. Nowadays, transmission line projects have to start with an environmental impact assessment, where environmental auditors identify and analyze the impacts on the nature and human environment. New line routes have to find a balance between the need of electricity transmission and the environmental perspectives. As part of these studies, the visual appearance and the aesthetic of the towers began to play an important role in the analysis, once they are the most visible elements on the landscape.

12.9.2 Innovative Solutions

12.9.2.1 First OHL Tower Aesthetic Studies

The subject of the aesthetic of transmission line towers is not a new issue. During the 60's, designers and power lines engineers had already started to study improvements on their aesthetics.

One of the first remarkable initiatives was the studies reported by H. Dreyfuss & Associates, through a publication of Edson Electric Institute in 1968 (Electric transmission structures – a design research program 1968). The document contains 47 innovative proposals for Overhead Line Supports with different conductor configurations, on single or double circuits, and using different materials such as steel, concrete or wood. Outstanding aesthetic solutions were suggested, perhaps a little advanced for their time, but with a clear vision of future (Figure 12.71 and 12.72).

The Dreyfuss' studies were carried out in times when more and more power lines began to cohabitate with citizens and cars on the cities, disputing their urban space. Transmission lines had to bring more power to the downtown of big cities growing vertically, and/or cities expanding horizontally reaching existing servitudes of lines already constructed. For these reasons, in different parts of the world, utilities have seriously started to think more and more seriously on the aesthetic of the overhead line supports.

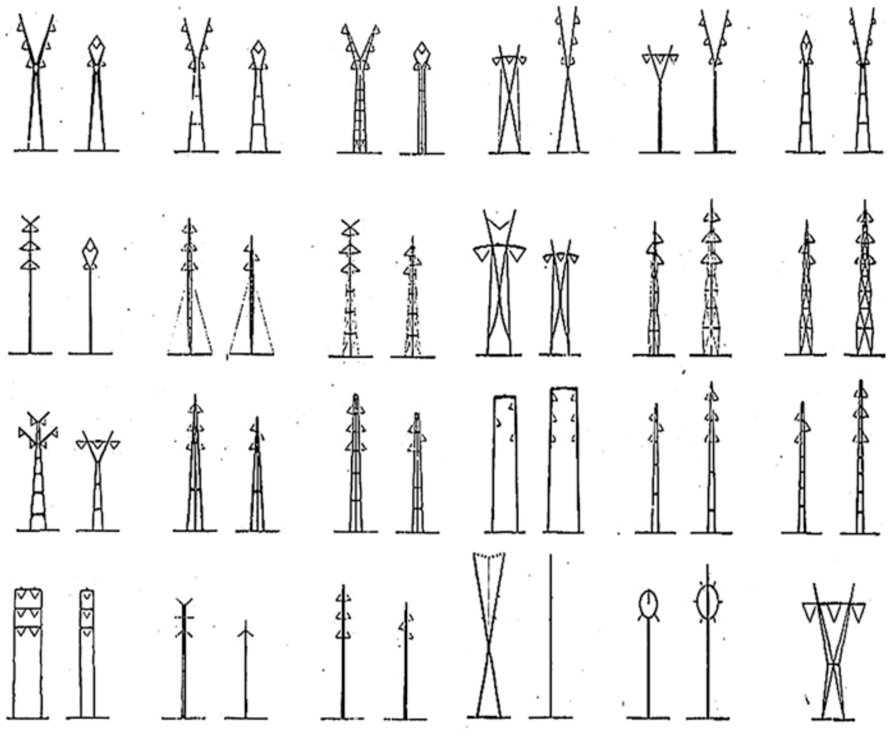


Figure 12.71 H. Dreyfuss Pictorial Index.

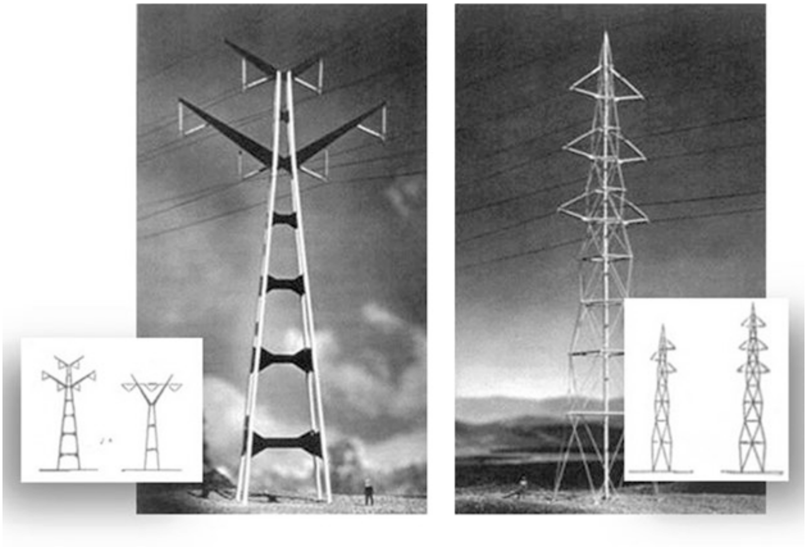


Figure 12.72 H. Dreyfuss Proposal's.

12.9.2.2 First Initiatives

The first practical initiatives in terms of "aesthetic towers" were not so ambitious and, basically, oriented by the following principles:

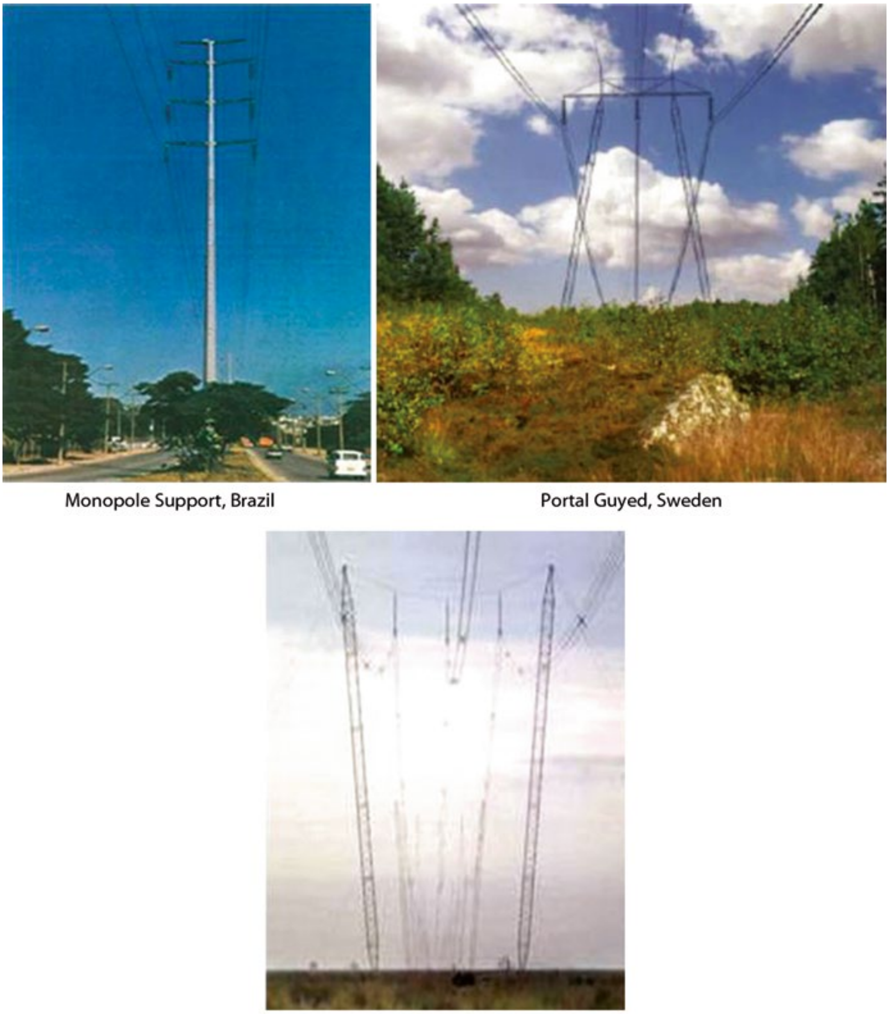
- To compact the lines and the supports as much as possible;
- To reduce the number of structural elements on the towers;
- To try to put them invisible or camouflaged at the landscape.

The compact solutions like the monopoles, the portal and V guyed, the chainette and the "cross-rope suspension - CRS", were solutions that have fulfilled those objectives (Figure 12.73).

Thousands of kilometers of lines were constructed around the world using these solutions, which aesthetic principles were based on simplicity, slenderness, symmetry, invisibility, reduced number of structural elements, transparence.

12.9.3 Landscape Towers

During the 90's, the aesthetic of the OHL towers became a real issue in some regions, and the first "landscape towers" were installed. New approaches and techniques were applied envisaging a better public acceptance. Aiming to collect all those new ideas, Cigré carried out a survey publishing a document entitled (Innovative Solutions for Overhead Line Supports 2010).



Monopole Support, Brazil

Portal Guyed, Sweden

Invisible Cross rope, Argentina

Figure 12.73 First Aesthetic Solutions.

An interesting databank was created showing the great variety of aesthetic solutions adopted in different parts of the world.

Analyzing the solutions reported, it could be identified that the so called "aesthetic proposals" already adopted by the Utilities, follow three basic principles: to design aesthetic solutions for unique places, for a single line, or to develop standard aesthetic solutions. Examples of these trends can be found, for example, in Finland, in Denmark and in France, as described in the following items.

12.9.3.1 Solutions for Unique Places: The Finnish Experience

In Finland, there are good examples of unique tower solutions for specific places. The first landscape towers were constructed in the early 90's by Fingrid Plc, the

Figure 12.74 The "Yellow beak" - Turku, A. Nurmesniemi.

national grid operator in Finland. The company wanted to get better public acceptance for its lines and, in some cases, to use them as landmarks in public places.

First landscape towers were installed in 1994, in the Southwest of Finland coast in the city of Turku. It was a series of six towers, the design of which was matched with the gabled one-family houses of the residential area nearby. Colour schemes were inspired by the surroundings (Figure 12.74).

Few years later, a multi-level junction in Espoo was provided with an unique landmark and piece of environmental art: a series of three 400 kilovolt towers, referred to as "Espoon sinikurjet" (Blue cranes of Espoo) on account of their blue colour, (Figure 12.75).

After this, towers adapted to the surroundings were erected at the cities of Virkkala (Figure 12.76), Tuusula (Figure 12.77), Jyvaskylan (Figure 12.78), Hameenlinna (Figure 12.79), Porvoo (Figure 12.80), Vantaa (Figure 12.81) and Oulu (Figure 12.82) (Pettersson et al. 2008; Exhibition "Suuret Linja" 2003).

12.9.3.2 Solutions for Specific Lines

The most common approach for reaching environmental friendly power lines, is to propose an aesthetic solution for a specific line (or just a line segment in some cases), which crosses a sensitive region.

A good example of that, is the 400 kV connection line between the cities of Aarhus and Aalborg in Denmark (Öbro et al. 2004). Another remarkable case is the transmission line Salmisaari-Meilahti in Helsinki, Finland, shown in Figures 12.83 and 12.84.

Figure 12.75 “Blue Cranes”, Espoo, Studio Nurmesniemi.

Figure 12.76 Petäjävesi, Virkkala, B. Selenius.

Figure 12.77 Tuusula, IVO Power Engineering.

Figure 12.78 Jyvaskylan, J. Valkama.

Figure 12.79 "Antinportti", Hämeenlinna, Studio Nurmesniemi.

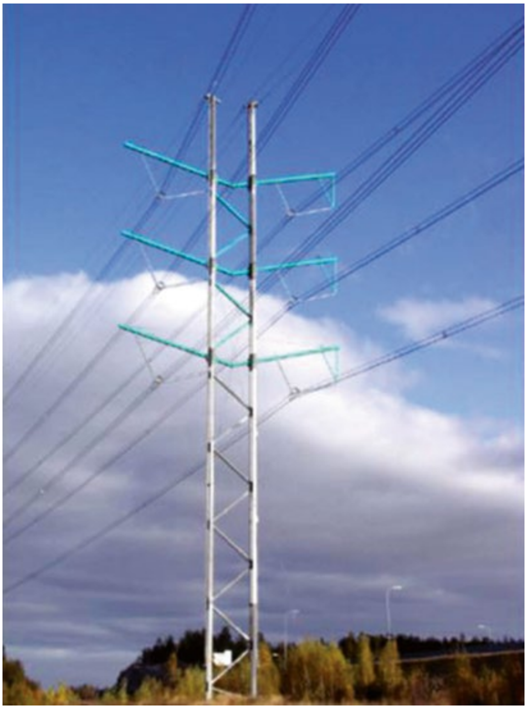


Figure 12.80 Ilola, Porvoo, Studio Nurmesniemi.

Figure 12.81 Rekola, Vantaa, J. Valkama.

Figure 12.82 2003: Oulu, Kuivasjarvi.

Figure 12.83 400kV TL Aarhus/Aalborg - Denmark.

Figure 12.84 TL Salmisaari/Meilahti - Finland.

12.9.3.3 Standard Aesthetic Solutions

To develop "standard aesthetic tower solutions" is one of the approaches used by RTE, the French Transmission Grid Operator, for the integration of Overhead Lines

Figure 12.85 The "ROSEAU" and The "FOUGERE" Towers.

into the environment. Aiming to reach this objective, RTE has promoted two experiences for development of innovative supports: the architects and the tower manufacturers design competitions.

The first architects design competition was carried out in 1994 and had, as main target, to develop standard aesthetic solutions for 400 kV Overhead Line Towers, to be used when and where it would be necessary. As per (EDF Brochure 1995), the competition process lead to the definition of two standard aesthetic tower families: the "Roseau (reed)" and the "Fougère (fern)".

The "Roseau" is a slender structure, exploring the verticality of the support element. An original technology was used based on open-work modules of casting material for the lower part of the tower (Figure 12.85).

The "Fougère" type support consists of a tubular tower whose originality lies on the distribution of conductors in a horizontal position spread over two independent structures in the shape of an "f". In these solutions the architects were looking very pure forms (Figure 12.85).

The second experience was performed along 2004/2005 and proposed only among support manufacturers. Differently from the previous architects' competition, when as much freedom as possible was given to the proponents, the advantages of this new procedure were basically the use of tested/existing solutions, with little industrialization difficulties, reduced development times and at reasonable costs. The main disadvantage was that the creativity was reduced resulting on more traditional shapes and formats. With this procedure, a new wood support was developed for using in the 225 kV OHL's, named as "The Arverne". (Figure 12.86).

Figure 12.86 The "ARVERNE" Tower - Transel, Linuhonnun.

12.9.4 Overhead Line Supports into Artworks

The various experiences carried out in the world with aesthetic towers were, generally, very successful in terms of public acceptance. Those initiatives motivated the Utilities that had lines in sensitive areas, to expand the concepts and the use of "landscape towers": Since the 90's, slowly, the towers were evolving from OHL Supports to "Urban Electrical Sculptures".

In Finland, after the well succeeded first experiences, landscape towers have continued to be designed and constructed. As examples, Figures 12.87 and 12.88, show new solutions in the cities of Lempäälä and Vihti (Pettersson et al. 2008), that are really sophisticated sculptures used as towers to support conductors.

In France a new technique was utilized for improving the aesthetic of OHL transmission Lines: The artistic treatments of lattice towers designed by Elena Paroucheva (2007).

Her works aim at emphasizing the above ground networks such as, energy transmission and distribution supports. Instead of trying to hide them in the landscape, they are transformed into "artworks" (Paroucheva 2007). Generally, two kinds of techniques are applied: "Art Installations" and "Sculptures". The "Art Installations" solutions treat the transformation of existing infrastructures elements in the

Figure 12.87 Lempäälä, Konehuone/J. Valkama.

Figure 12.88 Nummela, Vihti, Konehuone/J. Valkama.

environment. They are investigated according to their installation areas and allow the modification of their visual aspect into artistic works (Figures 12.89 and 12.90).

The "Sculptures" explore new forms of towers to be implanted in the landscape, in both urban and rural areas (Figure 12.91).

Figure 12.89 Art Installations on Overhead Line Supports.

12.9.5 Experiences around the World: Conclusions

Analyzing the aesthetic solutions collected, and the arguments justifying them, interesting aspects can be reported. Firstly, it can be observed an increasing

Figure 12.90 Paroucheva's art installation works at Amnéville-les-thermes.

environmental concern resulting in a great discussion for approval of almost all new OHL projects around the world. This is valid for short or long lines, and for both, urban and rural landscapes. There are, however, different policies regarding the OHL Lines and the environment.

In the case of very long lines, normally crossing rural areas, cost is an absolute relevant issue which targets of economy cannot normally be reached with aesthetic towers. In these cases, premises adopted for environmental friendly supports are still the same as already mentioned before: invisibility, transparence, slenderness, compaction, camouflage, all together driven by cost (Figure 12.92).

Figure 12.91 Paroucheva's Studies: Tower Sculptures.

In urban areas (or even rural sometimes), aesthetic solutions have been more and more used in different parts of the world, aiming to reach public acceptance. As seen previously, to achieve this, different policies have been implemented such as to design "unique landscape towers" for specific places, "for a specific line", and even to design "standard aesthetic solutions" (Figures 12.93, 12.94, and 12.95).

Figure 12.92 Tower solutions for long OHL's around the world.

Figure 12.93 1992 Seville Expo Tower - Spain.

Figure 12.94 Vaasa, Palosaari, Konehuone/J. Valkama.

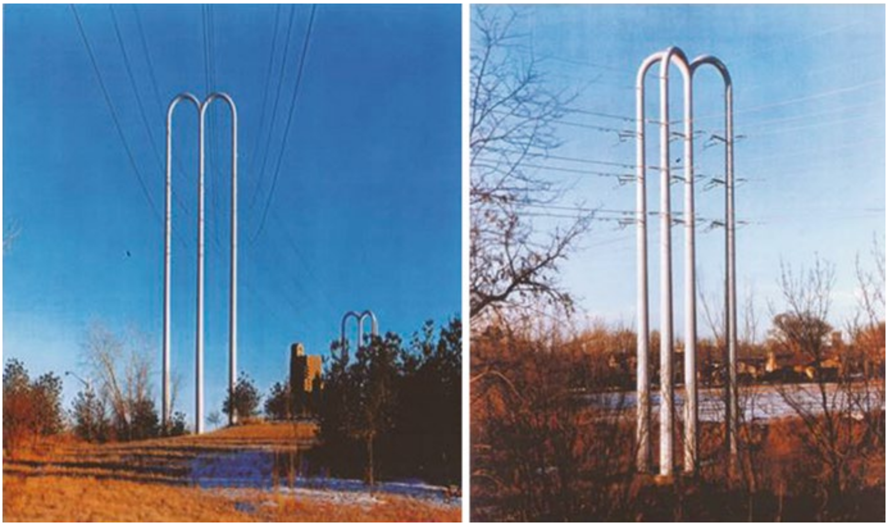


Figure 12.95 Double circuit and triple arches - USA.

12.10 Existing Lines & Tower Aging

12.10.1 Asset Management/Grid service

Asset management models, currently assign distinct roles to the asset owners, asset managers and service providers. Under this approach the asset owner prepares the strategy for the high-voltage grid, inclusive accompanying frameworks and targets. Within these prescribed risk confines, the asset manager formulates proposals for construction and maintenance of the grid. The asset manager subsequently instructs one of the service providers to carry out the work, manage services and perform maintenance.

The employees of the Grid Service performance unit take care of the infrastructure (stations, lines and cables) used by the market parties to transmit electricity. This performance unit manages and maintains the grid, takes care of grid planning and provides advice on possible new installations to be constructed. Transmission Operations also continually monitors whether the grid needs to be altered.

This chapter shall focus on asset management of supports. More details can be found in Chapter 17, which treats the subject in a broader approach. Furthermore, it shall be pointed out the activities of Cigré Study Committee C1, which deals with general asset management strategies and practices, risk and reliability assessment, new approaches and system planning criteria.

12.10.2 Assessment of Existing Supports

Aiming to assess information about the aging process of the existing OHL supports, Cigré carried out an international practices survey regarding assessment of existing supports and the consequences for maintenance, refurbishment and upgrading (TB: Assessment of existing overhead line supports 2003). The following keywords describe the subject:

- Inspection tools and methods
- Inspection reports
- Assessment of inspection data
- Type and cause of defects
- Inspection philosophies
- Criteria for management decisions
- Experiences and solutions.

The questionnaire was replied by 61 company representatives from 29 countries. The majority of answers came from Europe, only a few replies came from America, Asia and Africa. As the questionnaire was split between overhead transmission and distribution lines, 104 filled in forms were received. The percentages in Figures 12.96, 12.97, 12.98, 12.99, 12.100, 12.101, 12.102, and 12.103 refer to these responses and reflect the “yes”-answers only.

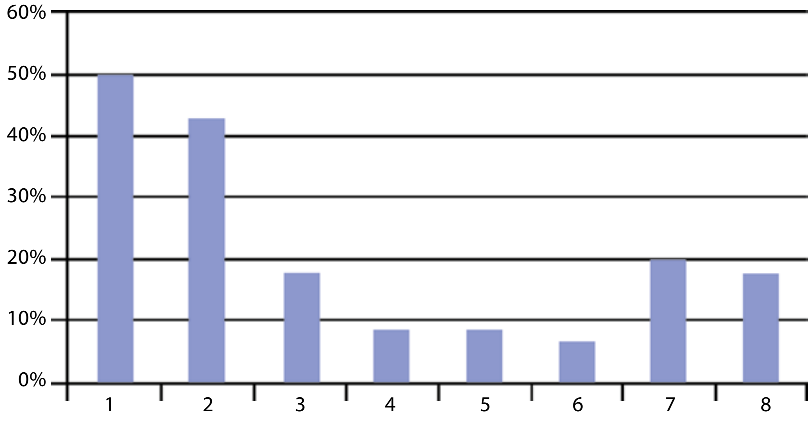


Figure 12.96 Used inspection tools.

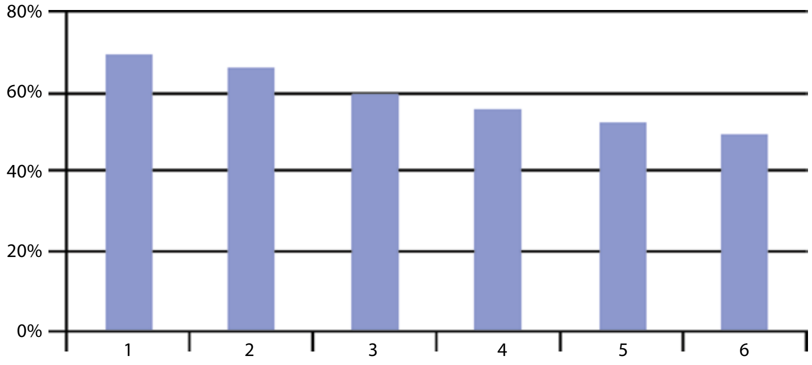


Figure 12.97 Importance of information regarding support member deformation/damage.

The chapter shall support companies when establishing or benchmarking a support management system.

For a better understanding, important terms are defined below:

- Maintenance - routine conservation and small/local repair
- Refurbishment - extensive renovation or repair to restore their intended design strength
- Upgrading - increasing the existing strength which may resist increasing loads.

12.10.2.1 Inspection Methods and Tools

The questionnaire asked for the methods of support inspections and the tools used. It was differed between steel, concrete and wooden supports. There were also questions regarding laboratory examination on materials.

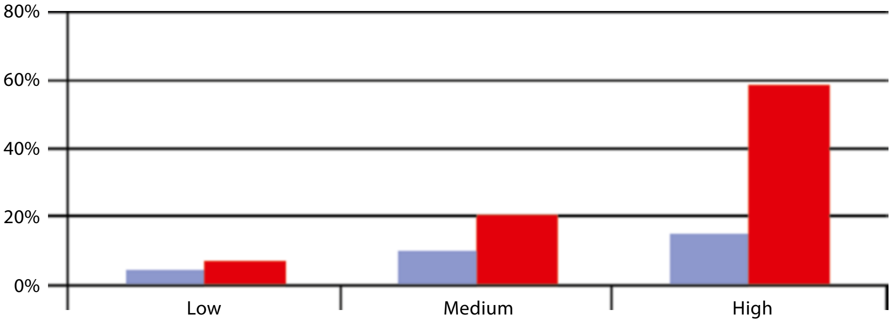


Figure 12.98 Different classification of corrosion extend (percentage of surface attacked).

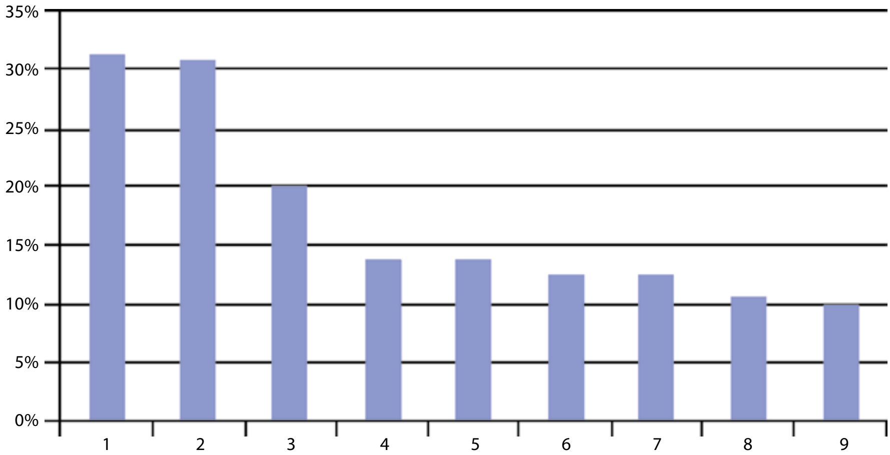


Figure 12.99 Typical identified faults.

Generally, it can be said that inspection is mostly limited to visual inspections but the majority of the companies use also special tools. Destructive tests are seldom applied on existing supports.

Nearly 50 % of the companies stated to perform laboratory tests on support material (metallurgical, chemical and/or mechanical analysis). This special laboratory examination is not done systematically but rather rarely, mostly after failure. Many companies mentioned that laboratory tests are useful only before manufacturing or erection, so it is not clear whether the 50 % refers to existing structures or both new and existing ones. On the other hand, recent findings of possibly steel aging (hydrogen brittlement) have released a systematically laboratory analysis of transmission line tower steel produced in the sixties in Germany.

It shall be pointed out to a German pre-standard VDE V 0109–2 (DIN V VDE V 0109 2 Maintenance of buildings and plants in electrical networks Part 2 Diagnosis

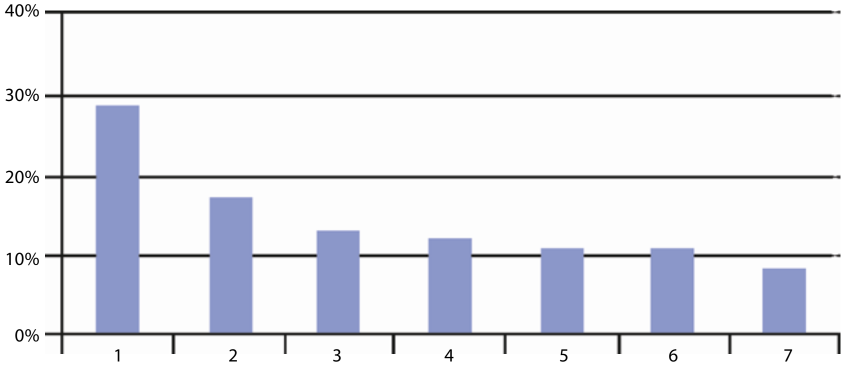


Figure 12.100 Reasons of support failures.

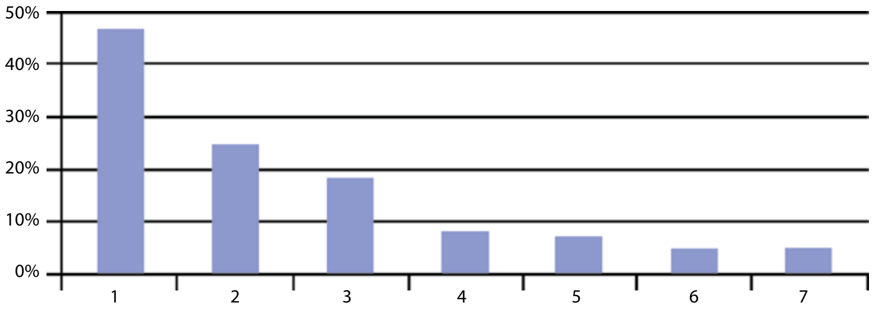


Figure 12.101 Reasons of corrosion.

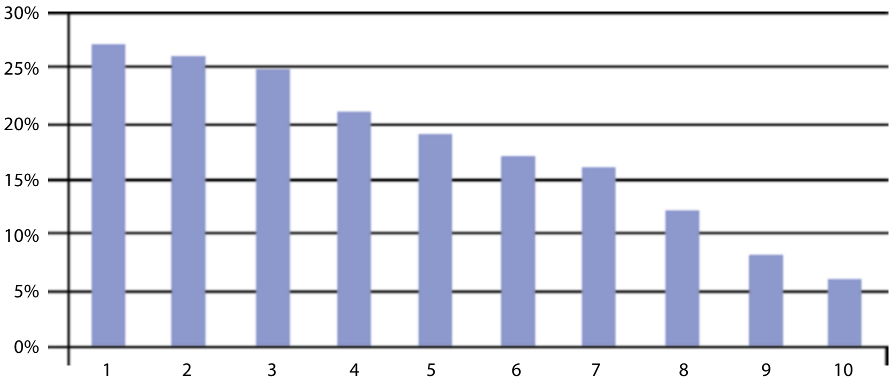


Figure 12.102 Reasons of corrosion.

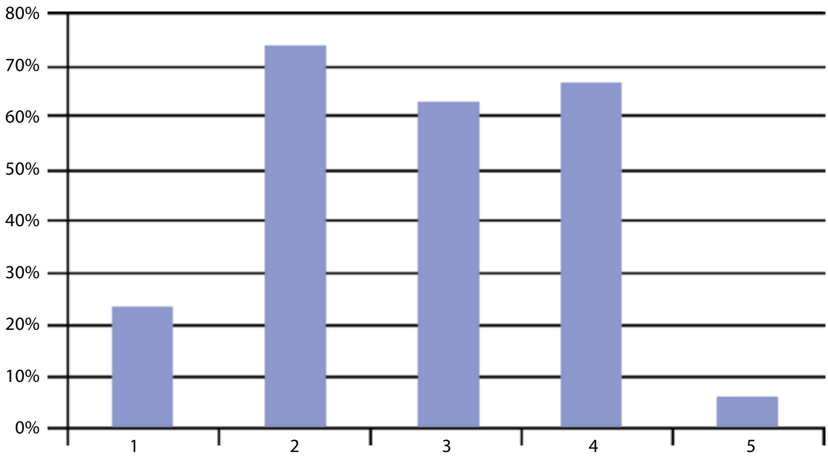


Figure 12.103 Kind of support inspections.

of conditions of buildings and plants) which deals with the diagnosis of conditions of electrical buildings and plants, in order to guarantee security of human, operation, environment and function. Inspection items for supports (steel tower, concrete and wood poles, bolts, anchors) and methods are defined (mostly visually but with measurements of mechanical strength in case of visible defects).

The mostly used tools are measuring equipments for galvanization and painting thicknesses of steel supports. The application of other tools was also questioned and responded as following (Figure 12.96):

- Galvanization thickness meter (electromagnetic gauge) for steel supports
- Paint thickness meter (electromagnetic gauge) for steel supports
- Deflection of supports (e.g., with theodolite)
- Steel corrosion metrology
- Surface carbonation (chemical) for concrete poles
- Concrete impact drive (Schmidt hammer)
- Drilled core for wood poles
- Hammer test for wood poles.

12.10.2.2 Inspection Reports

The questionnaire also aimed to document the inspection results, asking for the practices regarding checklists and records, which shall be taken during support inspections, e.g., regarding displacements, deformations and corrosion attacks.

74 % of the companies use formatted checklists for support inspections. Some companies record the inspection data in a special data base for statistical evaluation. The following gives a ranking of the importance of the information (Figures 12.97 and 12.98):

- Location of deformed/damaged members
- Number of deformed/damaged members
- Kind of deformation - local
- Kind of deformation - bending
- Kind of deformation - cracking
- Kind of deformation - buckling.

Other kinds of records were noted like presence of danger of number plates, anti-climbing devices and deformations at base level due to animals and tractors.

Many companies (75 %) differentiate the corrosion attack according to the surface extent, location and depth. The extent of corroded surfaces is assessed in a wide range. While some companies classify a corrosion attack as medium when 3-10 % of the surface is corroded, others allow up to 20 %.

As a result of the inspections, many companies (70 %) categorize the urgency of repairs, mostly in two or three categories in their reports (Figure 12.98):

- Good - no repair required
- Not good - actions required but not with urgency
- Critical - repair with urgency.

12.10.2.3 Assessment of Inspection Data

The assessment of the inspection data is a comparison of the inspection findings with the transmission line documentation. The documentation of line and support data is essential therefore. 88 % of the questioned companies have complete documentations regarding:

- Support lists
- Site maps/longitudinal profiles
- Workshop drawings of supports
- Input data for structural analysis (support geometry, load trees)
- Results of structural analysis (steel quality, profile and bolt data)
- Computerized data basis with reference to geographical information systems.

The findings during inspections are mostly reductions of support strength (locally or generally) due to damages, corrosion, deflection or theft of components. The comparison with the support documentation enables the line operator:

- To replace damaged members by using workshop drawings for re-manufacturing
- To re-calculate the support considering actual conditions (support deflections, reduced member sizes due to corrosion, altered material properties).

Good and complete support documentations also allow statements about refurbishment or upgrading. Support re-calculations can be performed easily taking into account new load trees or updated design standards. Only 37 % of the companies verify load carrying capacity of existing supports by tests.

The evaluation of inspection results and the comparison with the line and support documentation is done by experienced technical personnel in 97 % of the questioned companies. The following comments were received in addition:

- Damage or corrosion of members is usually obvious and replacement or refurbishment goes without saying
- Training to assess degree of corrosion is required
- Evaluation of the personnel's experience is done
- Assessment of inspection results is based on technical audits.

Furthermore, 55 % of the companies have defined parameters to support management decisions about repair, refurbishment or upgrading. These parameters are:

- Importance of the line
- Public and worker safety
- Weather conditions
- Existing damage classification
- Comparison with actual standards in use.

The following methods can be used if no documentation is available but assessment of inspection findings is necessary:

- Field measurements of sizes and model support for re-calculation
- Mechanical tests of support components in order to ascertain material properties.

12.10.2.4 Type and Causes of Defects

In order to focus the support inspection program on the essential items, the questionaire asked then for typical identified faults, the main cause of collapse of supports, the type and reason of corrosion as well as the most affected components, and the type of crossarm deformations or failures.

The most typical defects in supports are related to corrosion and painting problems.

Loose or missing bolts as well as deformation of support elements are other typical types of defects. For many companies, the corrosion problems occur at or below ground level, where steel is in contact with soil. Wood and concrete deterioration are very important defects for distribution lines. Reduced tensions in stay wires or deformed stays are major defects for guyed supports. The Figure 12.99 gives a ranking of typical identified faults.

- Fault of structural steel corrosion
- Fault of protection painting
- Loose or missing bolts, nuts, washers
- Foundation connection
- Concrete deterioration
- Deformation of support members

- Missing or deformed stays
- Deformation of crossarms
- Reduced tension in stay wires.

The main causes of support collapse are wind loading. It is followed by combined wind and ice loading and ice loading only. Vandalism and material defects are also reasons for support collapse. The Figure 12.100 gives a ranking of main reasons for support failures.

- Wind loading
- Wind and ice loading
- Vandalism
- Ice loading
- Cascade
- Material defect
- Erection/construction faults.

Many other reasons of support collapse are mentioned in the response to the questionnaire but with less general importance: motor vehicle collision, landslide, avalanches, tornados, foundation failures.

As corrosion is the most frequent support fault, more details were queried in this regard. The Figure 12.101 shows the main reasons of corrosion.

- Normal weathering
- Industrial pollution
- Salt (maritime) corrosion
- Gap corrosion
- Heavy vegetation growth in temperate zones
- High humidity in temperate zones
- Inter-crystalline corrosion of material.

Other typical causes of corrosion are steel in contact with soil, grillage footing below ground level and temporary accumulation of rain water. The reasons for corrosion problems are various, but the following are typical:

- No galvanization
- No painting or re-painting
- Delayed maintenance
- Weathering steel (Corten)
- Inadequate detailing.

Referring to corrosion, another question should clarify which support components are mostly affected by corrosion problems. The responses revealed that bolts, washers and nuts are often corroded. For the rest of the supports, secondary members are affected followed by main members and their connections (Figure 12.102).

- No galvanization
- Nuts of bolts
- Secondary members of lattice steel towers
- Complete supports
- Main members of lattice steel supports
- Shafts and washers of bolts
- Connections between members
- Gusset plates
- Stays
- Welding seams.

The last item of the questionnaire concerning type and causes of defects deals with crossarm deformations and failures. Deformation of crossarms is considered as a minor problem.

Rotation or torsion of crossarms around its longitudinal axis is more problematic than deformation of insulator string attachment points or local deformation or bending.

Thirteen companies (12 %) mentioned problems with crossarm hangers resulting fatigue failures due to aeolian vibration of conductors. To avoid resonance between conductor and member frequency, it is suggested to reduce the slenderness ratio of less than 300 for such members. Steel ductility problems are not reported but local vibration cracks of bolt holes due to stress concentration are established.

12.10.3 Inspection Philosophies

Inspection philosophies differ on the period of time between inspections, the qualification of inspectors, the available budget and the organization of inspection, maintenance or refurbishment.

Each of the companies responded to the questionnaire they perform regular inspections on supports. Inspections by helicopter are becoming the most common method while inspection from car or on foot is becoming less popular. Mostly there are visual inspections (Figure 12.103).

Nearly 40 % of the respondents confirmed to inspect in more detailed way by diagnostics.

However, it seems that those diagnostics are not related to supports only but to conductors, insulators and foundations too.

It shall be referred to a German VDE - Application Rule VDE-AR-N 4210–4 (VDE AR N 4210 4 Requirements for the reliability of existing supports of overhead lines) which guides a network operator in providing evidence that the technical security of his transmission lines is guaranteed. Supports are analyzed regarding their endangering of third parties, categorized in five reliability classes and the consequences of support collapses are assessed.

- Car
- Ground

- Climbing
- Helicopter
- Other.

The mean period of time between two successive inspections is nearly 1.5 years from helicopter, 1.4 years from ground and 4.2 years by climbing.

Besides the regular inspections, some companies stated to perform extra inspections, e.g., after damage event, after special meteorological circumstances.

Line inspectors have line experience in the field in 84 % of the questioned companies. The inspectors completed periodic practical or specialized trainings. Many of them have experience in tower erections and are former linesmen. Special training programs are foreseen in 47 % of the companies. There are special safety procedures, tests, and new skills developed on the job.

Half of the companies have a maintenance and refurbishment budget of more than 15 % of the overall budget expended on supports. The mean budget amounts to 28 % as per the results of the questionnaire.

12.10.4 Types and Causes of Defects/Industry Repair Practices

The most typical defects in supports are related to corrosion and painting problems (Figure 12.104).

Corrosion caused by normal weathering is more frequent than by industrial pollution. Salt corrosion and heavy vegetation growth are circumstances favouring the corrosion process. The reasons for corrosion problems are various and none of them is preponderant except no galvanizing and no-repainting. Low or delayed maintenance are also recorded as possible causes.

Here, typical refurbishment measures are applied: Removing pollution, rust and old paint by hand cleaning or sand blasting, repainting, replacement of single support members and bolt connections.

Wind loading remains, by far, the most important causes of collapse of supports. It is followed by combined wind and ice loading and ice loading only. Such higher

Figure 12.104 Corroded members.

Figure 12.105 Replacement of main members.

loads (e.g., due to climate changes) require an upgrading of the supports. The need of upgrading can also be caused by increasing of conductor sizes for reaching higher transmission capacities.

Upgrading studies and corresponding works, may require replacements on the main members (Figure 12.105), or just reinforcement by adding an additional angle profile (Figure 12.106).

12.11 Highlights

This chapter has reported different aspects regarding OHL Supports, from the conceptual design drawings to the complete design, calculations, testing and fabrication process.

Emphasis was given to the great variety of solutions, available for the transmission line designers, to face the increasing challenges for the installation of new projects. It was shown that towers, even looking similar, are not all equal and, certainly, there is one single solution that fits better for each new specific line design.

The new design philosophy based on probabilistic assumptions was emphasized as the best proposal for reaching both required targets for new projects, reliability and economy. New advanced softwares and techniques for structural analysis were described, which enables tower designers to improve their accuracy and predictability of results.

Figure 12.106 Main member reinforcement by bolting additional angle profile.

The aging process of the existing supports was also addressed showing its critical mechanisms (e.g., corrosion) and utilities' great concern. In this context, the inspection tools and methods, the diagnostic and assessment procedures, and experiences and solutions adopted for repairs in the industry were shown.

12.12 Future of Overhead Line Supports

The future indicates that the consumption of electricity in the world will keep on growing, giving the market the need for even more transmission line projects, but also indicates great challenges regarding to increasingly demanding societies in terms of environmental friendly solutions.

The first solution for that challenge can be expected as ultra high voltage "super transmition grids", in both AC and DC technologies, can be already foreseen. Those super long lines will carry much higher quantities of energy, making the servitude strip more efficient, but also requiring great quantities of supports which designs will face new levels of challenges in terms of reliability and cost, as well as environmental requirements and public acceptance.

Regarding to downtown areas of big cities, it is expected to keep on growing vertically, needing more and more power to keep it running. In this important areas, underground cables and landscape towers overhead lines may grow in application, competing each other in terms of cost benefit ratio and public acceptance.

The last predictable overhead line project trend has to do with new materials being developed (such as carbon fiber, polymers, super conductors, composite materials etc). Soon, new material technologies will be available at the market influencing the design of conductors and supports, enabling reduction in tower heights and weights and facilitating the fabrication, erection and maintenance procedures.

Finally, thinking about the operation and maintenance point of view, it is expected the population of existing supports spread around the world to increase dramatically: the aging process of these structures will be a matter of great concern by the utility companies. As a result, more efficient diagnostics, inspection tools and methods will be a great demand on a near future.

Those utility companies will, thus, face the challenge of conserving their older and older tower population in a market of great cost concerns.

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João BGF da Silva obtained his degree in Civil Engineering from the Federal University of Minas Gerais, Brazil, where he was Professor of Steel Structures from 1975 to 2012. At the industry, he has been working in many companies been responsible for OHL projects particularly in Brazil and other American countries. Currently, he is the Technical Director of Furnas Trans-Cos being also member of the Consulting Council of the Brazilian Electric Power Research Center – CEPEL, since 2006. On Cigré, he has been member of the Study Committee B2 – Overhead Lines since 1985. He was Convener of the former WGB2.08 – Transmission Line Structures being nowadays the OHL Components Technical Advisory Group Chairman. He has published more than a hundred articles and brochures devoted to design, construction and performance of high voltage overhead lines. He is an honorary member of Cigré, having also got the "Cigré Medal" in 2008.

Andreas Fuchs has Diploma (MSc) in Civil Engineering and is presently employed in Fichtner GmbH & Co. KG, a German consulting company. He holds the position of a senior project manager with focusing in transmission line engineering and has been worked as a professional on power transmission field for more than 30 years. He has worked actively in the Cigré Study Committee SC B2 (overhead lines) since 2002 and was involved in the preparation of technical brochures on aspects of support design and testing, assessment of existing supports and large overhead line crossings. He is the German representative in IEC TC11 (overhead lines) and Secretary of CENELEC TC7X (conductors).

Georgel Gheorgiţă obtained his degree in Electrical Engineering in 1971 and in 1991 his PhD from the University "Politehnica" Bucharest, Romania. He is employed in Fichtner Engineering, the Romanian Consulting Company when he is involved in HVAC, HVDC and Special Projects such as Large Crossings. In Study Committee B2 (Overhead Lines) he represented Romania between 1996 and 2004 and since 1996 he was involved in B2-WG 08 Structures. He has published more than fifty articles, brochures and books. He is a distinguished member of Cigré.

Ruy Carlos Ramos de Menezes obtained the degree of Civil Engineer in 1981 and the degree of Electrical Engineer in 1984 at the Federal University of Rio Grande do Sul (UFRGS), Porto Alegre, Brazil. He received M.Sc. degree in Civil Engineering in 1988 from UFRGS and the Dr. techn. degree in 1992 at the University of Innsbruck, Austria, Since 1994, he is Professor at the School of Engineering of the UFRGS and member of the Postgraduate Program in Engineering. His main area of interest is Reliability Based Design of Transmission Lines. Dr. Ramos de Menezes is the chairman of the Brazilian Study Committee on Transmission Lines of Cigré-Brasil and fellow of the Brazilian National Research Council (CNPq).

Jan Pieter van Tilburg obtained his degree in Electrical Engineering with focus on power systems in Fluminense Federal University, Brazil. He is employed in Paranaiba Transmission Company, being the manager of technical department in the implementation of an innovative project of one thousand kilometers, six-conductor expanded-bundle, 500 kV transmission line and its substations with reactors and series capacitors.

Foundations 13

Neil R. Cuer

Contents

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N.R. Cuer (✉)
Dyke, Bourne, UK
e-mail: neil.r.cuer@btinternet.com

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Executive Summary

The aim of this chapter on Support Foundations is to provide a résumé of the previous Cigré publications, prepared by SCB2 WG07 and WG23, on their design, installation and testing; where appropriate these have been revised to include current design and installation practice. An underlying theme of these publications is that the support foundations, unlike the other Overhead Line (OHL) components, e.g., conductors, insulators and support, are constructed partly or wholly in-situ, in a medium (the ground), which does not have constant properties and is unique at each support site. The installation of a typical OHL support foundation is shown in Figure 13.1.

Within this overall context of the variability of the ground, i.e., soil, rock and ground water, the concept of an "Integrated approach" has been developed such that there are no artificial boundaries between the design and installation process, i.e., the design, including the geotechnical studies, and the installation activities should be seamless; with a continuous exchange of information between all parties, e.g., the

Figure 13.1 Installation of a 330 kV reinforced concrete raft foundation.

client, the foundation designer(s), the ground investigation contractor and the installation contractor(s), from the initial feasibility stage through to the foundation installation. An integral part of this approach is the ongoing need for hazard identification and corresponding risk assessments to be undertaken; thereby ensuring that health and safety, environmental, project and financial management issues are adequately considered and resolved throughout the project. Correspondingly, the application of this approach has been maintained throughout this chapter.

Section 13.1 provides an introduction to the concept of an "Integrated Approach", together with an example of the serous consequences of not adopting this proposed approach; which was effectively the result of a failure in communications between the foundation designer and the installation contractor. Continuing on the theme of an "Integrated Approach", Section 13.2 considers the requirements in respect of Health and Safety, the application of Risk Assessment, Environmental Impacts and potential mitigation measures in respect of foundation installation including access development, together with an overview in respect of the Quality Assurance measures required during the different phases of the works.

The design of the support foundations has been divided between Sections 13.3, 13.4 and 13.5 and is based on Cigré Electra 131, 149 and 219, and Cigré TB 206, 281, 308, 363 and 516. Section 13.3 considers the design basis, the interdependency between foundation and ground both in terms of the interaction between the foundation loading and the ground, and the affects on the ground during the foundation installation. Also considered in this section are the affects of applied static and dynamic loadings on the foundation, and an overview of the different foundation types. Section 13.4 considers the Site Investigation requirements, especially the need for ongoing geotechnical assessment during the foundation installation. The geotechnical and structural design of the three typical foundation types: Spread footings, Drilled shafts and Ground anchors/micropiles is considered in Section 13.5, including the interaction with the installation process. Also considered in this section is the calibration of the theoretical foundation model against full-scale foundation test results, together with a précis of new developments in the analysis of spread footings under applied uplift loadings.

Section 13.6 considers foundation testing both full-scale and model testing including the use of centrifuge modelling techniques. Although, this section is generally based on Cigré Special Report 81 and the subsequent IEC standard 61773, concerns are raised regarding the suitability of the maintained load test, if the behaviour of the foundation under gust wind loading or other dynamic loadings is to be investigated.

The installation of the foundations is considered in Section 13.7 and provides a summary of the main installation activities, previously considered in Cigré TB 308, e.g., temporary works, foundation excavation, concreting, backfilling, etc. The refurbishment and upgrading of existing foundations is considered Section 13.8 and is based on Cigré TB 141. Topics reviewed in this section include foundation deterioration, foundation assessment, refurbishment and upgrading.

The outlook for the future in respect of the need for further research into the complete support-foundation system, the permissible displacements of foundation-support system, the design of foundations in respect of application of dynamic loadings is considered Section 13.9. While, Section 13.10 provides a brief summary of this chapter.

A bibliography of the main documents quoted in this chapter is also provided.

Glossary

To assist the reader of this chapter on support foundations, a glossary of terms which have not been explained in the relevant text is given below:

- *Alluvium*: Unconsolidated, fine-grained loose material (silt or silty-clay) brought down by a river and deposited in its bed, floodplain, delta, estuary or in a lake.
- *Brownfield site*: A site or part of a site that has been subject to industrial development, storage of chemicals or deposition of waste, and which may contain aggressive chemicals in residual surface materials or ground penetrated by leachates.
- *Cone Penetration Test [CPT]*: Comprises pushing a standard cone into the ground at a constant rate and electrically recording the resistance of the cone point and the side friction on the cone shaft perimeter.
- *Expansive soil*: A soil which is subject to shrink-swell phenomena.
- *Foundation assessment*: The process of interpreting information collected during the foundation inspection, geotechnical investigation, full-scale foundation testing, in service data/experience, etc., to estimate the current strength/condition of

the foundation and/or predict the useful service life under the original/increased design loads.

- *Foundation refurbishment*: All methods used to extensively renovate or repair the foundations, thereby restoring their original design strength and condition.
- *Foundation upgrading*: All methods used to increase the strength of the foundations to resist the increased applied loads, arising from upgrading and/or uprating the OHL.
- *Fluvial deposits*: Produced by or due to the action of water derived from melting glaciers or ice sheets.
- *Geotechnical hazard*: An unforeseen geotechnical condition, inappropriate design or construction method arising from a poor understanding of the known ground conditions,
- *Hold Point*: A stage in the material procurement or workmanship process beyond which work shall not proceed without the documented approval of designated individuals or organisations.
- *LIDAR*: Light Detection and Ranging, a technique using light sensors to measure the distance between the sensor and the target object. The equipment can be both airborne or ground based.
- *Muff concrete*: Muff or reveal concrete is used to form a watershed to the top of a concrete foundation, particularly the chimney. This secondary concreting is frequently undertaken after the main concrete has already cured and hardened.
- *Notification Point*: A stage in the material procurement or workmanship process for which advance notice of the activity is required to permit the witnessing of the activity.
- *Organic soil*: A soil consisting of organic material, derived from plants, e.g., peat.
- *Quality Assurance*: Part of the quality management, focussed on providing confidence that quality requirements are fulfilled. Quality Assurance has both internal and external aspects, which in many instances may be shared between the contractor (1st party), the customer (2nd party) and any regulatory body (3rd party) that may be involved.
- *Quality Control*: The operational techniques and activities that are used to fulfil requirements for quality. Quality control is considered to be the contractor's responsibility.
- *Standard Penetration Test [SPT]*: Is a dynamic penetration test undertaken using a standard test procedure and comprises driving a thick wall sample tube into the ground at the bottom of the borehole by blows from a standard weight falling through a standard distance. The resistance to penetration, expressed by "N" (blow count) is measured by the number of blows required to give the penetration through 300 mm and thereby gives indication of the density of the ground.
- *Working Load*: An un-factored load derived from a climatic event with an undefined return period.

General note

Where reference is made to a Cigré TB, or other publications, etc., the full corresponding cross-reference, e.g., Cigré TB 141 (Cigré 1999), is only stated initially; subsequently only an abridged reference, e.g., Cigré TB 141 has been used.

In Section 13.5.3 “Foundation Design – Geotechnical and Structural” cross-reference has been made to publication by many different authors by name and date; however, no space is available in the References to list all the details and correspondingly where the date reference is shown, thus (1943*), the reader should refer to the Bibliography in Cigré TB 206.

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- Downer Australia: Figures 13.1, 13.48 (bottom), 13.49, 13.50 (bottom), 13.53, 13.55 (top), 13.58 and 13.59a.
- NIKES, JSC SevZap NTC Saint-Petersburg: Figures 13.20 to 13.24 and 13.66.
- sae-pl: Figures 13.14a and 13.17b.
- SSE plc: Figures 13.8, 13.46, 13.56, 13.57, 13.62, 13.63, 13.64, and 13.65.

13.1 Introduction

OHL support foundations are the interlinking component between the support and the in-situ soil and/or rock, i.e., the ground. However, since the ground does not have constant properties and is unique at each support location, there is no other element of the OHL about which less is known. To ensure that the OHL achieves its required level of reliability, it is preferable that the support foundations, the ground and the ground water, either free flowing or as pore pressure, should be viewed as an interdependent system, with the properties and behaviour of the constituent parts of the system adequately identified. Furthermore, the ground’s behaviour depends, to a degree, on the foundation installation techniques and although many sites are relatively insensitive to construction activities, skill and knowledge are required to evaluate if this is the case, for the site in question.

Consequentially, based on the premise outlined above, the following factors should be considered in the design, installation, refurbishment and upgrading of the support foundations:

- Support type, support base size or diameter and applied loadings;
- Foundation type, e.g., drilled shaft, pad and chimney, steel grillages, piles, etc.;
- Geotechnical conditions, e.g., soil or rock type and condition, ground water level, and whether “geotechnical hazards”, e.g., landslides, rock falls, ground subsidence, aggressive ground conditions, etc. are present;
- Permanent or temporary installation;
- Primary installation, refurbishment or upgrading of existing foundations;
- Environmental, e.g., topography, climate, contamination, etc.;

- Resources, e.g., foundation materials, labour, construction plant, foundation installation temporary works requirements, programme and financial constraints;
- Constraints, e.g., environmental impact, client requirements, third parties with respect to access, use of the surrounding land, etc.;
- Health, safety and quality management requirements.

To ensure that all of the factors, listed above, are adequately considered, there should be no artificial boundaries between the initial feasibility, planning, design and installation process, i.e., the design, including the geotechnical studies, and the installation activities should be seamless; with a continuous exchange of information between all parties, e.g., the client, the foundation designer(s), the ground investigation contractor and the installation contractor(s). In addition, to the obvious interaction between the design and installation process, the interaction with respect to: environmental constraints, site access, health and safety, quality and resource management, should all be taken into account and continuously evaluated throughout the design and installation activities, i.e., from the initial OHL routing or the initial reassessment of an existing OHL, through to the final site reinstatement. The interaction process is shown diagrammatically in Figure 13.2, while a detailed diagrammatic representation of the foundation design and installation process is shown in Figure 13.3.

As stated above, good communications between the respective parties, i.e., the client, the client's representatives, the foundation designer(s), the installation contractor(s) and any external bodies, form an essential part of the overall design and installation process and will have a direct influence on the successful outcome of the project, in respect of quality, safety and the environmental impact.

The client and/or his representatives should ensure that their technical requirements are clearly stated in the appropriate technical specification and that for any work on existing support foundations the "as-built" foundation drawings, calculations and associated health, safety and environmental information are made available, at the earliest opportunity, to both the foundation designer(s) and the installation contractor(s).

The foundation designer should ensure that all the information used in the design and especially any assumptions made in respect of the ground conditions and the installation contractor's method of working are made available to all appropriate parties. The information should, as a minimum include the foundation installation drawings, the geotechnical report and the initial design hazard review and risk

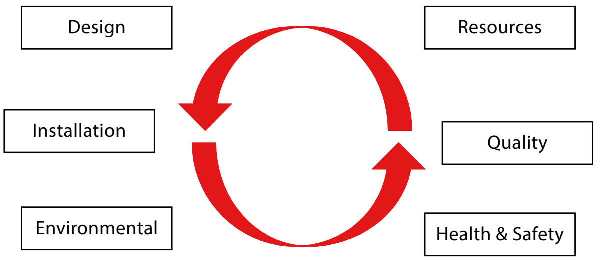


Figure 13.2 Interaction process.

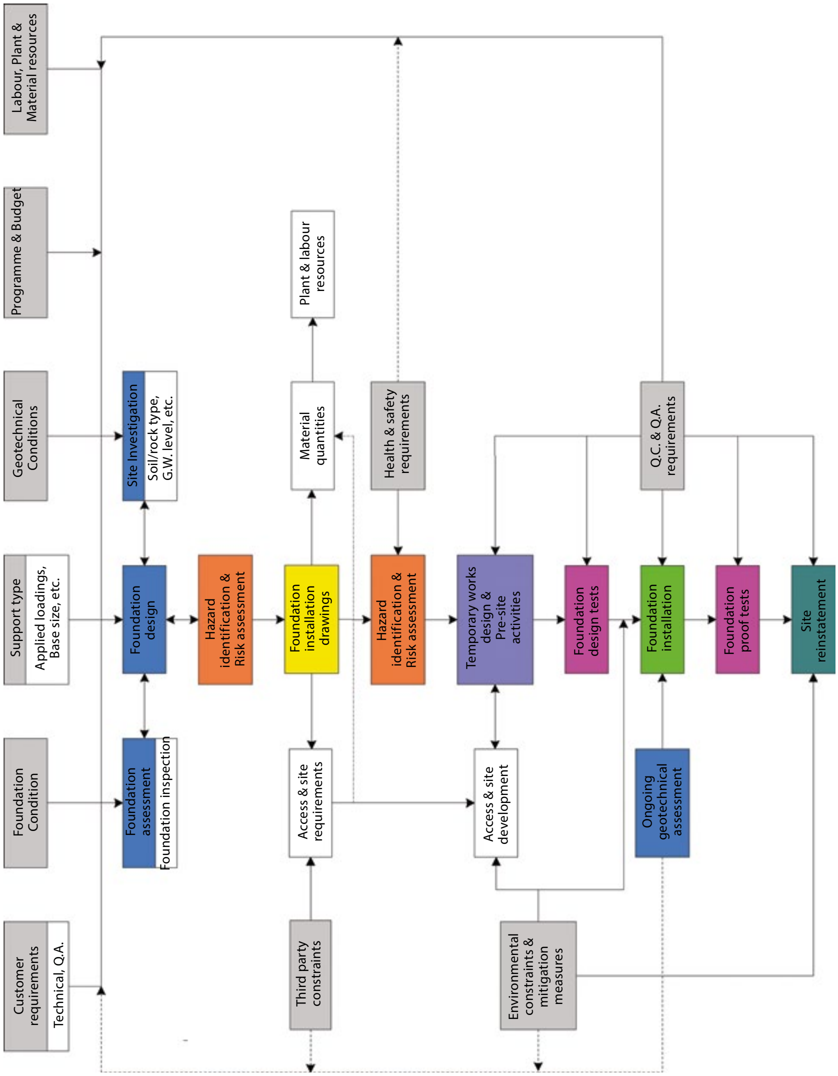


Figure 13.3 Diagrammatic representation of foundation design & installation process.

assessment. Furthermore, the necessity to undertake ongoing geotechnical assessment during the foundation installation should be clearly stated.

The foundation installation contractor should ensure that all the appropriate information is considered in the preparation of the: installation procedures, temporary works design, construction health and safety plan, site risk assessment, and associated installation method statements. Critically, the foundation installation contractor's site staff and operatives should ensure that if there are any changes in the ground conditions from those assumed in the foundation design, e.g., variations in ground water level or soil properties, the foundation designer is immediately informed and, if necessary, work on-site suspended until a reassessment of the design has been made and, if appropriate, a revision to the method statement undertaken. Correspondingly, the foundation designer and/or foundation installation contractor should ensure that the services of a geotechnical engineer are readily available on site.

13.1.1 Reasons for the Failure

The serious consequences of failing to verify the assumed geotechnical design parameters during foundation installation are shown in Figure 13.4 and emphasise the need for effective communications between the foundation designer and the installation contractor.

Failure due to a combination of circumstances, but basically due to a lack of communications:

- Tower failure precipitated by high Santa Ana wind prior to commissioning of the line;
- Based on the geology of OHL route the foundation designer assumed cohesive soil and decided to use a drilled shaft foundation with an under-ream (bell) at the base;
- No on-going geotechnical assessment undertaken during construction and no one noticed that the soil was granular;
- During concreting the side walls of the shaft collapsed, especially at the bottom;
- Installation contractor did not measure quantity of concrete poured, therefore no check against theoretical volume of concrete and hence whether the foundation was installed correctly.

13.2 Health, Safety, Environmental Impacts and Quality Assurance

13.2.1 Introduction

One of the primary requirements of the "Integrated Approach" is the necessity to continuously evaluate the potential Health, Safety, Environmental and Quality issues throughout the foundation design and installation activities, i.e., from the initial OHL routing or the initial re-assessment of an existing OHL, through to the final site reinstatement. To ensure that this evaluation is undertaken in a systematic manner and can be effectively communicated to all parties, the use of on-going hazard identifications and risk assessments should be considered.

Figure 13.4 Failure of a 500 kV suspension tower drilled shaft foundation.

13.2.2 Health and Safety: General

Health and Safety (H&S) requirements in respect of foundation installation have been extensively covered in Section 5 of Cigré TB 308 (Cigré 2006) and although there have been changes in the appropriate statutory legislation since the publication of the Cigré TB, e.g., the UK's "Construction (Design and Management) Regulation was revised in 2007, the fundamental principles remain unchanged, i.e.:

- There is a "Duty of Care", so far as reasonable practical on employers in respect of their employees, persons not in their employ or third parties (e.g., general public), who may be affected by their work. This applies equally to clients and contractors;
- Similar principles also apply in respect of consultants and the self-employed;
- The "Duty of Care" relates to the health and safety of their employees, provision of a safe working environment, safe systems in respect of plant, materials, transport, provision of adequate training, etc.;
- Employees shall take reasonable care of their own safety and that of others.

Similar principles also apply in respect of any geotechnical investigations undertaken during all stages of the project, from the initial OHL routing to the on-going geotechnical assessments during the foundation installation.

Consequentially, there is a need to identify and where possible eliminate the hazards, but where this is not possible, to reduce the residual risks to an acceptable level. This hierarchy of hazard elimination and risk reduction can be summarised as:

- *Eliminate*: By removing the hazard, e.g., rerouting the affected section of the OHL;
- *Reduce*: Use of alternative installation techniques e.g., changing from bored to driven piling on sites affected by contamination, where it is not possible to relocate the support;
- *Inform*: Provision of information on the residual risks, such that the foundation installation contractor can develop the appropriate Method Statement;
- *Control*: Provision of appropriate barriers, warning notices, personal protective equipment/clothing, training, etc.

Correspondingly, to apply this hierarchy of hazard elimination a formal risk assessment should be undertaken.

13.2.3 Risk Assessment

A risk assessment is a systematic identification of what the hazards are, the probability of "harm" occurring and the possible consequence of the harm and its severity, i.e., the "risk". In this context "harm" can be considered as injury or death (health and safety), spread of pollutants into an aquifer (environmental) or cost overruns (project considerations).

Although a risk assessment is normally considered in respect of H&S during the installation activities, in reality it should be extended to include all aspects of the design, construction, the subsequent operation, maintenance, refurbishment/upgrading, to the final dismantling and include not only the H&S issues, but also the environmental impacts and project considerations.

The risk assessment can be either qualitative or quantitative. In the former engineering judgement is used in respect of severity and frequency rating; whereas, in the latter numerical values are assigned to both. A precise estimate of the risk is not required under most conditions and therefore a qualitative approach could be selected, provided its limitations are recognized. For examples three categories of severity could be assumed, e.g., High (fatality), Medium (injury causing short term disability) and Low (minor injury) and similar categories could be assumed in respect of the likelihood of the "harm" actually occurring.

When the risk is considered to be unacceptable, the adoption of the appropriate mitigation (control) measures would be required; these could range from changes in the proposed OHL route, the adoption of different foundation types, different installation techniques or delaying the work such that it is, for example outside the bird breeding season.

Extracts from a quantified foundation design hazard identification and risk assessment is shown in Figure 13.5 while a qualitative geotechnical desk study hazard identification and associated risk assessment is shown in Figure 13.6.

Foundation Design Risk Register

The risk assessment used classifies the likelihood of a risk into several categories according to the probability of occurrence , before classifying the risk into one of several 'consequence' categories, according to the severity of the consequences if the risk event occurs. Each category has a score and the score for the likelihood is multiplied by the score for the consequence to determine the score for the risk event. The risk events with the highest combined score are then selected for priority analysis.

Risk Assessment Table A - Likelihood

Description	Scenario	Probability	Scale Value
Highly Likely	Very frequent occurrence	>85%	16
Likely	More than even chance	50-85%	12
Fairly Likely	Quite often occurs	21-49%	8
Unlikely	Small likelihood but could well occur	1-20%	4
Very unlikely	Not expected to happen	<1%	2
Extremely unlikely	Just possible but very surprising	<0.01%	1

Risk Assessment Table B - Impact

Description	Scenario	Scale Value
Disastrous	Death	1000
Severe	Serous threat to life	100
Substantial	Impacts to health	20
Marginal	Small effect to health	3
Negligible	Trivial effect on health	1

Risk Assessment Table C - Risk Rating

Qualitative Assessment Matrix used for assessing risk

Likelihood		Impact: Negligible	Marginal	Substantial	Severe	Disastrous
	High Likely	16	48	320	1600	16000
	Very High	12	36	240	1200	12000
	High	8	24	160	800	8000
	Medium	4	12	80	400	4000
	Low	2	6	40	200	2000
	Very Low	1	3	20	100	1000

Risk Assessment Table D - Risk Acceptance

Points	Category	Action Required
Over 1000	Intolerable	Hazard must be eliminated and risk reduced
101-1000	Undesirable	Attempt to reduce risk
21-100	Acceptance	Manage risk
Up to 20	Negligible	Risk not significant but must be managed

Ref No.	Aspect of Design / Construction	Hazards Identified	Mitigation Status	Likelihood	Impact	Risk	Risk too…	Risk control Measure [RCM]	Residual Risk
1	Rock strength weaker than anticipated	Reduced pile capacity and potential failure	Prior to RCM	4	20	80	Contractor / Designer	Shaft friction in rock limited to 600 kPa. Where necessary rock socket depths increased based on review of core logs.	
			After RCM	1	20	20			
2	Thickness of overburden varies from anticipated	Reduced pile capacity and potential failure	Prior to RCM	4	20	80	Contractor / Designer	Analysis undertaken based on a range of overburden thickness. Note included on drawing indication overburden limits to which the design is applicable.	Design Engineer to be notified if overburden thickness exceeds indicated limits.
			After RCM	2	20	40			
3	Pile Installation	General risks associated with pile construction	Prior to RCM	4	100	400	Contractor	Work to be carried out in accordance with Contractor's MS and agreed SoW.	Review SoW and update during course of works as necessary.
			After RCM	2	100	200			
4	Piling Platform	Unsuitable piling platform resulting in rig toppling and potential injury/death	Prior to RCM	8	100	800	Contractor / Client	Note added to design report.	Piling platform to be designed by others. Piling contractor to assess design in advance of mobilizing onto site.
			After RCM	8	100	800			

Figure 13.5 Quantified foundation design hazard identification and risk assessment.

Ref.	Considerations / Activity	Hazard (or Opportunity)	Severity Rating			Frequency Rating			Risk	Control Measures	Residual Risk
			L	M	H	L	M	H			
1	Assessment of ground conditions at tower site	Ground conditions worse than predicted from desk study / walkover		M			M		M	Review of all available geotechnical Information - additional investigation required at other tower sites on similar geology	L
2	Assessment of ground conditions at tower site	Ground conditions better than predicted from desk study/ walkover		M			M		M	Review of all available geotechnical Information - reduced investigation possible at other tower sites on similar geology	L
3	Tower stability affected by unidentified solution features	Failure of foundation			H		M		H	Review of all available geological information - specific consideration of any towers located on geologies prone to solution features	M
4	Tower stability affected by unidentified landslide	Failure of foundation			H		M		H	Review of all available geological information - identify towers which lie in zones of potential landslide activity	M

Figure 13.6 Qualitative geotechnical hazard identification and risk assessment.

Table 13.1 Foundation installation typical risk assessment

Hazard	Method of controlling risk
Complete collapse of excavated hole with persons working in excavation.	All excavations to be sheeted and framed, unless alternative methods used, e.g., battering back the side of the excavation.
Persons falling into excavation when working adjacent to open excavation.	All excavations are fenced or side sheeting extended above ground level.
Spoil stacked by excavation falls onto persons working below.	Material to be stacked a minimum of 1.5 m from edge of excavation.
Mechanical excavator too close to excavation edge causing partial collapse and or excavator falling into excavation.	Stop boards positioned 1 m from edge of excavation.
Instability of excavation arising from high ground water table and or accumulation of water in excavation.	Use of pumps or de-watering plant installed.
Objects falling on persons working in excavation.	Safety helmets to be worn at all times.
Persons falling during access/egress to excavation.	Ladders to be used for access and to be adequately secured.
Risk of falling when working on chimney section of formwork or stub setting template.	Provision of ladders, working platforms or scaffolding and use of safety harness.
Risk of personnel being impaled by projecting reinforcement.	Use of temporary caps on the ends of reinforcing bars.

Although, the two previous examples are related to the design activities, similar principles should be adopted for the actual foundation installation activities. An extract from a typical risk assessment for foundation installation for a concrete pyramid/pad and chimney foundation is shown in Table 13.1. For convenience, it has been assumed that risk assessments for material delivery to site, storage of material on site, safe use of lifting gear, the effect of substances hazardous to health e.g., cement, etc., have already been undertaken.

For further details regarding risk assessment reference should be made to Section 3.12 of Cigré TB 516 (Cigré 2012) and Section 5.4 of Cigré TB 308.

13.2.4 Environmental Impact

Both the local environment and the communities adjacent to the route of the OHL are affected by the construction activities, with access construction and foundation installation having a major impact. Consequentially, the adoption of the appropriate mitigation measures can significantly reduce the environmental impact of an OHL during the construction phase.

Potential environmental impacts, which may occur, during access construction and foundation installation activities include:

- Increase in traffic on local roads, especially as regards the delivery of plant, equipment and materials, e.g., excavation or piling equipment, supply of ready-mix concrete;
- Impact of access tracks on the environment;
- Disturbance to the land and vegetation and removal of trees;
- Noise, dust and vibrational pollution;
- Soil erosion and pollution of water courses;
- Disturbance to birds and other fauna;
- Foundation installation, including the dispersion of contaminated soil or ground water.

Other impacts that may occur are:

- Disturbance to farming, agriculture and other business or leisure activities;
- The client's relationships with landowners, grantors, local authorities and other statutory or public agencies;
- Disturbance of archaeological remains.

While it is not possible to completely remove all of the potential impacts, described above, it is possible reduce their impact and therefore to a degree, the public's and/or landowners/grantors perception of the affect of OHL construction on the environment.

As an integral part of the planning and consent process, normally new OHLs are subject to an environmental assessment. This also usually applies to the constructional activities associated with the refurbishment and/or upgrading of existing OHLs. Both an initial desk study and site assessments would be undertaken to establish which of the support sites are likely to be affected by environmental and/or archaeological constraints. The area to be considered would possibly extend to include a buffer zone 500 m wide either side of the route centre line and including the access roads/tracks.

Where OHL support sites are located in designated areas of importance under international conventions or by national regulations, specific studies will require to be undertaken in consultation with the appropriate statutory bodies. In conjunction with the environmental studies, a separate study is usually undertaken in respect of determining whether any support site, or the area adjacent to any site, may have an archaeological interest.

Once the studies outlined above have been completed and depending on their outcome in terms of the environmental and archaeological impacts, it may be necessary to prepare a site environmental plan, detailing the mitigation measures required.

With regards to the actual design of the foundation, consideration should be given to the use of alternative foundation types, which may lessen the overall environmental impact, e.g., the use of micropiles, driven steel tube piles, helical screw anchors, etc., as an alternative to conventional reinforced concrete spread foundations. However, this may need to be counterbalanced against the possible temporary increase in environmental impact during the installation phase from the use of larger plant and equipment.

Other environmental mitigation measures, which could be considered at the design stage (in the widest environmental context), are the use of alternative cementious materials to Portland cement, e.g., use of pulverised fly ash (pfa) or ground granulated blast furnace slag (ggbs), which in themselves are waste by-products from other industrial processes or the use of reclaimed aggregates, including those derived from waste ready-mixed concrete. The latter overcomes the environmental hazard related to the disposal on-site of the cement slurry arising from the washing out of ready mix concrete mixer trucks.

The successful planning and construction of site access roads or tracks, modifications to field fences and/or hedges, gateways, etc. (accommodation works), will obviously make a significant contribution to the overall impact of the project, both in terms of the environmental impact and the relationship with landowners, grantors and the general public, and where appropriate the environmental protection agencies. Consideration will also be required in respect of the use of public roads by site traffic, e.g., road width, weight limits on bridges, clearance to structures or OHLs, location of schools or other areas where there is a concentration of children, etc. Any traffic management scheme will need to be agreed with the responsible authorities. Figure 13.8a shows the use of a height barrier to identify restricted height clearance from an overrunning OHL.

Wherever possible, use should be made of existing tracks as access roads/tracks; although, they may need to be upgraded, depending on the existing wearing surface, drainage conditions, general ground conditions and the anticipated volume and size/weight of site traffic using the proposed access. Consideration may also need to be made in the respect of provision of temporary bridging of water courses or drainage systems, see Figure 13.8b. The removal of hedges, fences, widening of gateways and possible insertion of new entrances from the public highway, will all need control and agreement with the appropriate parties. In addition, the landowner/grantor should not be put to any inconvenience in gaining access to his land/property by the installation contractor's use of the access route.

Where new access tracks are required, these should wherever possible, follow the natural contours of the terrain to minimise cut and fill quantities. Care should also be taken to minimise the effect of erosion caused by water runoff and siltation of water courses. Consideration should also be given to the use of special temporary access systems, e.g., wood or aluminium track way panels or temporary stone roads (i.e., crushed imported stone laid on a geotechnical membrane), see Figure 13.8a, b. As an alternative to the use of special temporary access systems, consideration should be given to the use of low ground pressure vehicles, thereby preventing excessive soil compaction or damage; Figure 13.8c shows the use of an excavator fitted with wide tracks for use in moorland terrain with peat present.

As an alternative to the use of vehicular transport, it may be necessary to consider the transportation of materials, equipment and site operatives by helicopter. One of the key features of the use of helicopters is the need for careful planning prior to commencing the work, taking into consideration payload limitations, duration and altitude limit of the helicopter, downtime for helicopter maintenance, weather conditions, possible need to "breakdown" installation equipment into manageable units, the establishment of strategically placed depots for the transfer of materials, equipment and personnel from road to air and possibly changes in the concrete mix design to allow for longer periods of workability. The use of a helicopter to transport concrete for foundation construction is shown in Figure 13.56.

Potential mitigation measures that the foundation installation contractor could undertake are:

- Removal of the topsoil and vegetation for subsequent reinstatement;
- Where it is necessary to bench the site, because of excessively steep hillsides or cross-falls, ensuring that this does not become a cause of future soil erosion or slope instability;
- Keeping the top soil separate from the subsoil during on-site storage prior to backfilling;
- Fencing off the site working area to prevent injury to farm livestock or wild animals;
- Preventing the contamination and/or siltation of water courses arising from removal of water from the excavation or surrounding area, e.g., well point dewatering;
- Ensuring that the removal of any ground water, does not affect adjacent land or properties;
- Controlled disposal of contaminated soil or materials used in the installation process;
- Prevention of fuel, oil, concrete or grout spillages;
- Use of synthetic (biodegradable) oil for hydraulic lubrication as opposed to mineral oil;
- Ensuring all material wrappings, general site litter, etc., are removed off-site on a daily basis;

- Possible restriction in the hours of working and control of noise, dust and vibration pollution;
- Use of wheel washing facilities or regular sweeping of public roads;
- Ensuring that site is secured against vandalism, all plant and equipment are immobilised when not in use and that all chemicals are correctly stored, etc.;
- Having a contingency/emergency plan ready, in the case of an environmental accident on-site.

Site reinstatement should include, as appropriate, the following actions: reinstatement of site drainage and/or provision of new site drainage, reinstatement of hedges, etc.; replanting of removed flora and removal of access roads/tracks. The sequence of the reinstatement will obviously depend on the construction activities and to a degree will not be completed until all site work has been finished.

All mitigation measures required should be considered as part of the "Integrated Approach" and therefore considered as part of the foundation design, installation, quality management and health and safety requirements for the scheme.

For further information on environmental impacts and associated mitigation measures, reference should be made to Cigré TB 308.

13.2.5 Quality Assurance

13.2.5.1 General

OHL construction is effectively undertaken on a long linear site with isolated areas of activity. Since OHL support foundations are installed in a variable naturally occurring medium, quality assurance and quality control should form an integral part of the construction activities. Consequentially, the majority of OHL technical specifications or design standards require that all activities are undertaken in accordance with the relevant requirements of ISO 9001 (BSI 2000), i.e., that the designer and/or installation contractor will prepare project quality plans for all aspects of the work undertaken to ensure compliance with the project requirements.

This section provides an overview of the various aspects of the quality assurance (QA) and quality control (QC) activities undertaken during the foundation design and installation.

For simplicity, this overview of the QA requirements has been divided between the pre-project and the actual project foundation installation activities.

13.2.5.2 Quality Control

While this sub-section mainly concentrates on the QA activities, it is an inherent responsibility of both the foundation designer and the installation contractor to instigate his own internal quality control procedures and verification methods. Without these procedures and activities including the appropriate level of internal auditing in-place, the overall QA requirements of the project will be difficult to achieve.

Identified below are examples of QC activities that may be applicable during the foundation installation:

- Verification of all foundation design and installation drawings, technical specifications for sub-contracted goods and services, e.g., concrete, foundation test programmes, installation method statements, concrete mix design, etc.;
- Auditing of proposed material supplier(s) and/or sub-contractor(s);
- Verification of the concrete trial mix results;
- Verification of the foundation type test results;
- Verification of the support and foundation setting out;
- Verification of the foundation geotechnical design parameters during the foundation installation process, if this is not undertaken as part of the project quality assurance activities;
- Verification of concrete identity test results and concrete returns;
- Verification of the backfill density;
- Verification of the foundation setting dimensions;
- Verification of the proof and integrity test results;
- Verification of the "as constructed" foundation drawings and associated records.

13.2.5.3 Pre-project Foundation Installation

The pre-project foundation installation activities basically encompass all aspects of the design process and associated site preparatory work, including the foundation design tests, prior to the installation of the project foundations. A diagrammatic representation of the key activities involved, together with an indication of the documentation required and the associated Hold and Notification points is shown in Figure 13.7a. For additional information regarding the QA/QC requirements for this stage of the installation process, reference should also be made to Sections 13.5.6 (foundation selection) and 13.7.3 (foundation installation method statement), and Section 4.3 of Cigré TB 308.

Note: With respect to Figure 13.7b the actual sequence of installation activities will depend on the foundation type and whether it is a one stage or two-stage process. The installation of a concrete pad and chimney foundation is normally a one stage process; while pile or anchor foundations are normally a two-stage process, with the piles or anchors installed first and the cap constructed subsequently.

13.2.5.4 Project Foundation Installation

The key areas which require QA during the foundation installation are:

- Setting out, in respect of both the support location and the support foundation;
- On-going geotechnical assessment;
- Verification of foundation installation requirements based on foundation type test requirements, e.g., anchor depth,
- Inspection prior to concreting or grouting;
- Concrete or grout identity tests;
- Backfilling;
- Foundation setting dimensions, after installation;
- Proof and integrity test results;
- Final records.

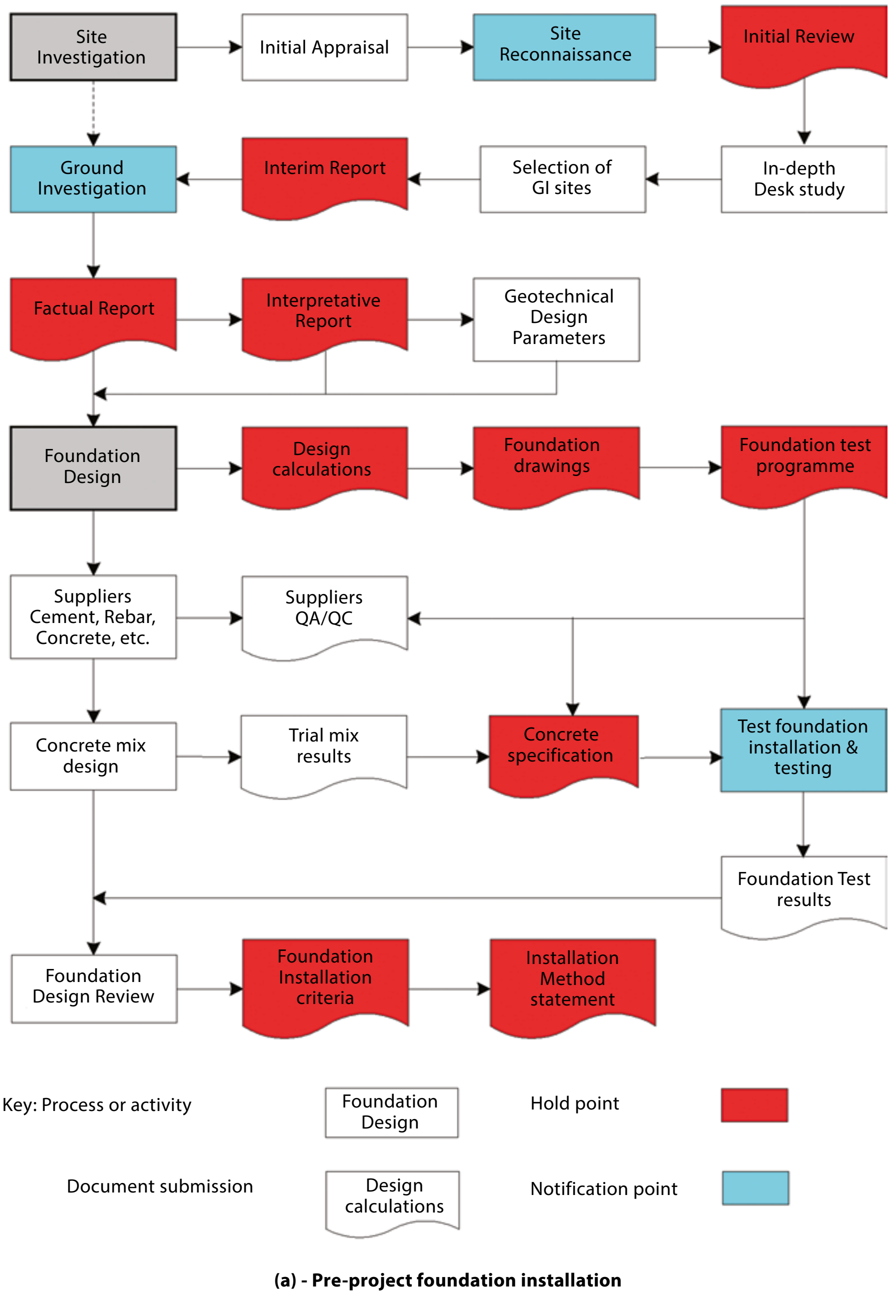
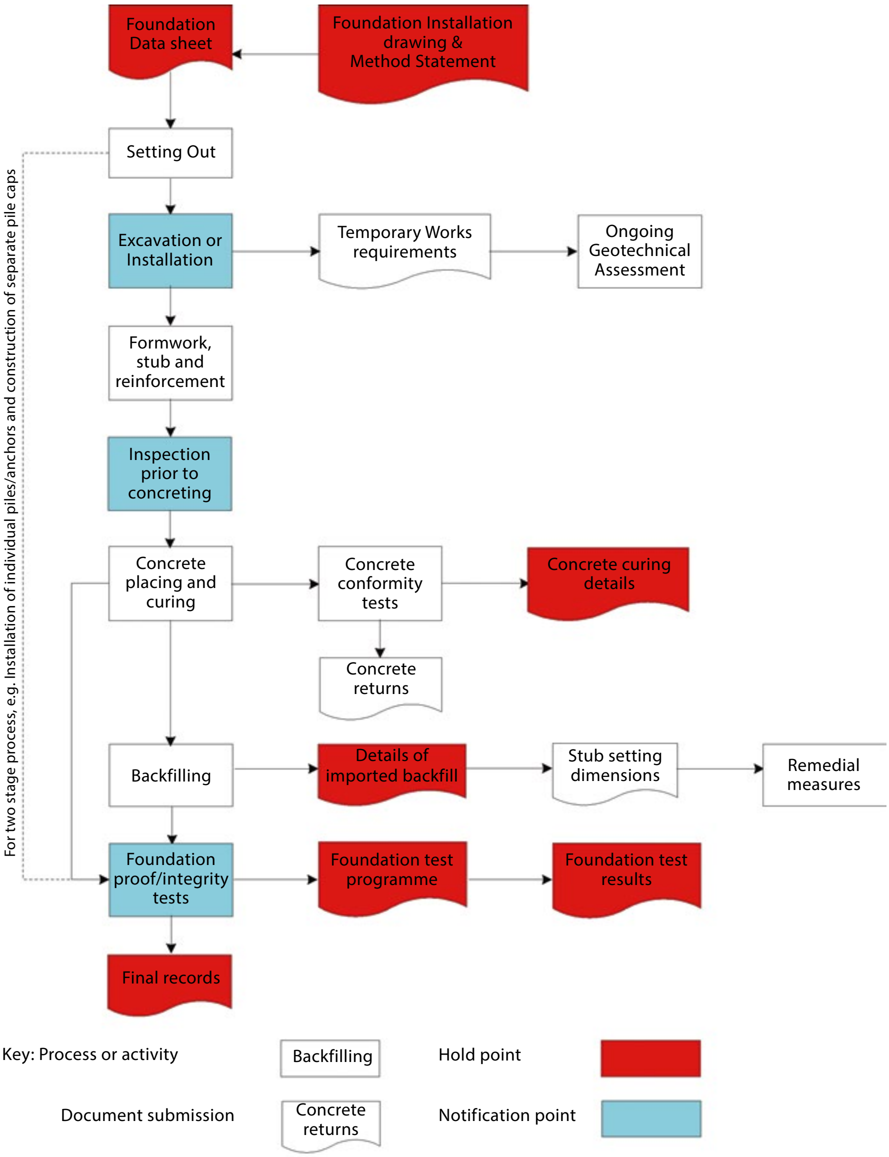


Figure 13.7 Diagrammatic representation of foundation installation QA requirements.



(b) - Project foundation installation

Figure 13.7 (continued)

The relationship between the various foundation installation activities and the associated QA requirements are represent diagrammatically in Figure 13.7b.

For further information in respect of project foundation installation QA requirements, reference should be made to Section 4.4 of Cigré TB 308.

Figure 13.8 Reduction in environmental impact.


a) Temporary stone access road. Note use of height restriction 'goal post'

b) Temporary access track using aluminium track way panels and temporary bridging over a stream

c) Use of low ground pressure excavator to reduce impact on peat soils

13.2.6 Integration

The integration of the project H&S, environmental and quality assurance requirements into all aspects of the foundation design and installation process should ensure that that these important considerations are not overlooked and that serious H&S or environmental incidents, together with costly repairs or the replacement of work previous undertaken are avoided.

13.3 Foundation Design (Part 1): Design Concepts and Applied Loadings

13.3.1 Introduction

For convenience the design of the support foundations has been divided into three parts, Part 1 (this section) considers: the overall design basis, i.e., deterministic or probabilistic, the interdependency between the foundation and the ground, the applied support foundation loadings and an overview of the different foundation types; Part 2 (Section 13.4) provides a resume of the overall site investigation requirements and the determination of the foundation's geotechnical design parameters; whereas Part 3 (Section 13.5) provides an overview of: system design considerations, the geotechnical and structural design of the foundations, the interaction between the foundation design and the installation, the calibration of the theoretical foundation design model and the foundation selection.

13.3.2 Basis of design

Historically, the determination of the applied support loadings (normal and abnormal – broken wire) and hence the applied foundation loads, has been based on deterministic principles; however, with the adoption of reliability based (probabilistic or semi-probabilistic limit state) design (RBD) concepts, the climatic loadings are usually derived using this approach. However for the RBD approach both the security and maintenance loads will remain deterministic in concept.

In the deterministic approach a "working" or everyday loading event is multiplied by an overload factor and must be resisted by the ultimate (nominal) strength of the support foundation divided by a safety factor or alternatively multiplied by a strength reduction factor. Alternatively, the "working" load is multiplied by an "overall global factor" of safety which must be resisted by the ultimate (nominal) strength of the support foundation. In this instance the overall global factor of safety is a combination of the overload factor and the strength reduction factor. The two principal loading events usually considered under this approach are "normal" everyday climatic events and abnormal or exceptional events, e.g., "broken wire". Different overload or global safety factors are applied to the loading event and different strength reduction factors are used, depending on the degree of security required, which may in turn vary between different design methods and foundation types.

For the RBD approach, a "Limit state" is defined as having occurred if the OHL or any part of it fails to satisfy any of the performance criteria specified. The principal limit state condition is the climatic loading, whereby the defined climatic loading, corresponding to a specific return period, multiplied by a (partial) load factor must be resisted by the nominal (characteristic) strength of the component, e.g., support foundation multiplied by a (partial) strength reduction factor.

Usually the RBD approach considers the application of system design concepts and recognises that an OHL is composed of a series of interrelated components, e.g., conductors, insulators, supports, foundations etc., where the failure of any major component usually leads to the loss of electrical power. The advantage of this concept is the ability to design for a defined uniform level of reliability or, alternatively, to design for a preferred sequence of failure by differentiating between the strength of the various OHL components, e.g., the supports and their foundations.

For further details regarding the different design approaches, reference should be made to EN 503411 (BSI 2001a and 2012), IEC 60826 (IEC 2003), ASCE Manual No.74 (ASCE 2005) and the appropriate national standards.

Irrespective of the design approach adopted, i.e., deterministic or RBD, due cognisance should be taken of the following points:

- That the foundation designers must have a clear understanding of whether the foundation applied loads are the maximum loads a support can resist, the maximum loads from a range of similarly loaded supports or unique site specific loads for an individual support. They must also know which factors, e.g., global safety, partial load or partial strength factors are included or excluded in the foundation applied load schedule. In addition, they must consider whether there are different partial load factors in respect of the climatic loading, dead weight, security loading, etc., and whether the partial strength factor includes factors related to the strength co-ordination between the support and foundation, the number of components, e.g., foundations or footings subject to the design load, etc. This is particularly important when an RBD approach is adopted, since at present the majority of empirical geotechnical correlations for the design of piles and ground anchor have been derived using deterministic concepts.
- That foundation nominal (characteristic) ultimate strength is derived from an uncalibrated theoretical design model, i.e., obtained when the geometric and geotechnical parameters are input into the theoretical design equation. This is usually taken to be R_n or R_c (IEC 60826). The relationship between the nominal (characteristic) ultimate strength and eth percent exclusion limit strength of the foundation R_e is given by the following equation:

$$R_e = \varphi_F \; R_n$$

Where φ_F is defined as the “Probabilistic Strength Reduction Factor”, which adjusts the predicted nominal ultimate strength R_n to the eth percent exclusion limit strength R_e. However, this factor does not taken into consideration any desired strength co-ordination between the support and its foundation or the number of foundations (components) subject to the maximum load.

For further details regarding the determination of the probabilistic strength reduction factor, reference should be made to Section 13.5.5.

13.3.3 Interdependency

The ground is itself a vital element of all OHL supports and since the ground does not have constant properties and is unique at each support location, there is no other element of the OHL about which less is known. To ensure that the OHL achieves its required level of reliability, it is preferable that the support foundations, the ground and the ground water, either free flowing or as pore pressure, should be viewed as an interdependent system, with the properties and behaviour of the constituent parts of the system adequately identified.

Furthermore, the ground's behaviour depends, to a degree, on the foundation installation techniques and although many sites are relatively insensitive to construction activities, skill and knowledge are required to evaluate if this is the case, for the site in question.

A diagrammatic representation of this interdependency, in terms of the interaction between the foundation loading and the ground, and the affects of the foundation installation on the ground are shown in Figures 13.9a and 13.9b.

- Foundation interaction with the surrounding ground (Figure 13.9a):
  - Support uplift and compression loading transferred to the ground via the foundation;
  - Weak soil/rock within the zone of influence of the foundations may be affected by additional loading, thereby leading to foundation failure or settlement;
  - Existing ground conditions, e.g., slope stability, cavities, mine workings, etc., may be affected by additional loading on the ground;
  - Loading from the soil (vertical and horizontal) will increase the loading on the foundation;
  - Changes in ground water level, will affect soil properties and the foundation's resistance to the applied loading;
  - Affects of aggressive ground or ground water on the foundations.
- Foundation installation interaction with existing features (Figure 13.9b):
  - Stability short and long term, past history of site and/or area;
  - Installation methods;

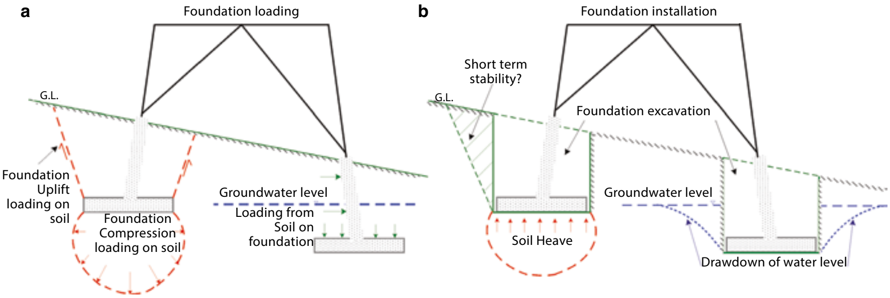


Figure 13.9 Diagrammatic representation of foundation interaction with the ground.

– Groundwater control during foundation installation;
– Long term effects of groundwater;
– Heave at base of excavation;
– Weathering of the ground at the base of excavation prior to foundation installation.

13.3.4 Static Loading

OHL support foundations differ from those for buildings, bridges and other similar foundation types from two points of view: the modes of loading they are subjected to and the performance criteria they must satisfy.

Generally, foundations for buildings, etc. are subjected to large dead loads (mass) which result mainly in vertical compressive loads. The allowable movements of the foundations which support these types of structures are limited by the flexibility of the supported structures. Conversely, the forces acting on OHL foundations are typically an overturning moment. These foundation loads arise primarily from dead load and a combination of wind and/or ice action on both the conductors and the support. Correspondingly, these loads have variable and probabilistic characteristics. The allowable displacements of the foundations must be compatible with the support types (lattice tower, monopole and H-frame supports) and with the overhead line function (electrical clearances). For poles located in populated areas, the foundation displacement must ensure that the corresponding pole displacement is compatible with a visual impression of safety.

Irrespective of the design approach adopted, traditionally the applied foundation loading has been treated as a “static” or “quasi-static” loading; although, in reality the applied foundation loading arising from wind gusts, security broken-wire events, ice drop, seismic events, etc., are in reality dynamic loadings.

Although, the determination of the actual support loading and the hence the foundation loading is outside the terms of reference for this chapter, a summary of the primary applied (static) foundation loading for the main support types is described below and the corresponding support type – foundation load free body diagram is shown in Figure 13.10.

13.3.4.1 Single Poles and Narrow Base Lattice Towers

The foundation loads for single poles and narrow base lattice towers with compact foundations primarily consists of overturning moments in association with relatively small horizontal, vertical and torsional forces.

13.3.4.2 H - Framed Supports

H - Framed supports are basically structurally indeterminate. The foundation loads can be determined either by making assumptions that result in a structurally determinate structure or by using computerised stiffness matrix methods. The foundation loads for H-frame supports principally consist of overturning moments in association with relatively small horizontal, vertical and torsional forces. If the connection

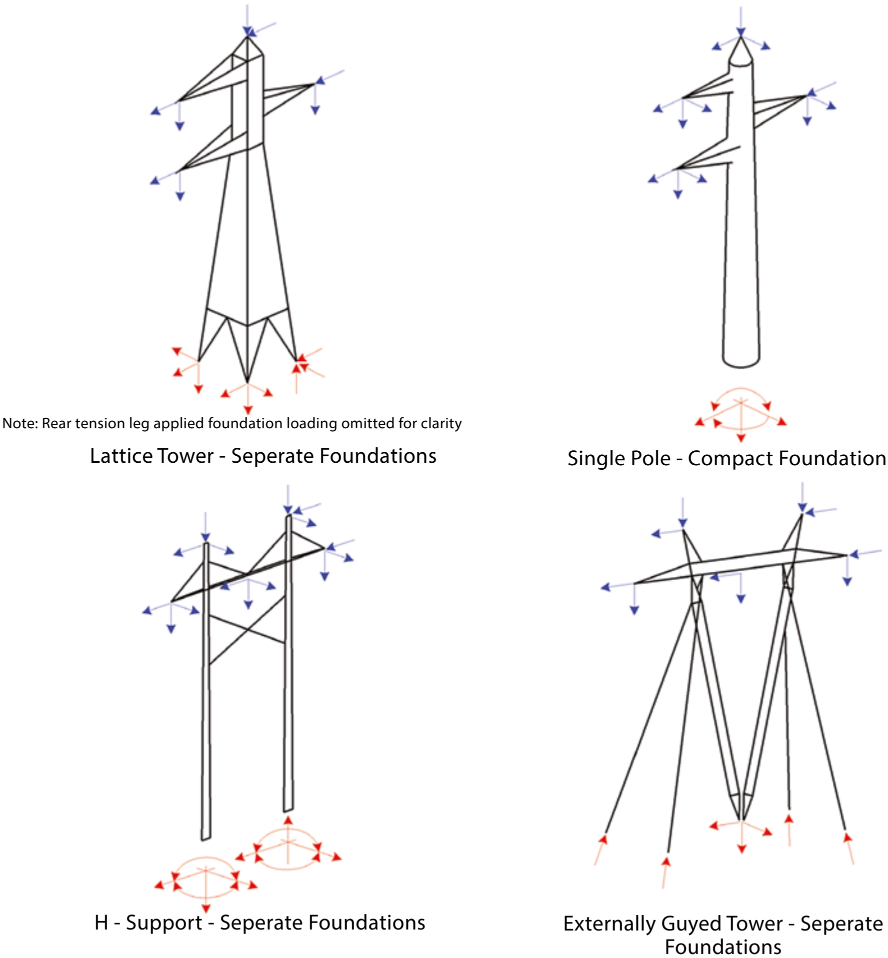


Figure 13.10 Free body diagram support type – applied foundation loading.

between the supports and foundations are designed as pins or universal joints, theoretically the moments acting upon the foundations will be zero.

13.3.4.3 Broad Base Lattice Towers

Lattice tower foundation loads consist principally of vertical uplift (tension) or compression forces and associated horizontal shears. For intermediate and angle towers, with small angles of deviation, the vertical loads may either be in tension or compression. For angle towers with large angles of deviation and terminal towers normally two legs will be in uplift and the other two in compression. Under all loading combinations the distribution of horizontal forces between the individual footings will vary depending on the bracing arrangement of the tower.

13.3.4.4 Externally Guyed Supports

For all types of externally guyed supports, the guy anchors will be in uplift, while the mast foundations will be in compression with relatively small horizontal forces.

13.3.5 Dynamic Loading

In the previous section reference has been made to the application of static loadings on the support-foundations arising from the mass (dead weight) of the conductor system and the support, that due to everyday conductor tensions or the mean wind speed loadings (quasi static). However, the support-foundation system can be subjected to forces that are time dependent and can act quickly in time or can quickly change in magnitude and direction, e.g., wind gusts and earthquakes.

A special case of dynamic loading is that arising from an impact load, where the load is applied for a very short time interval and rapidly decays to a steady state condition, e.g., broken wire or ice drop events. Figure 13.11 illustrates the various types of dynamic loading on a lattice tower with separate foundations and the resulting loading on the foundations.

Depending on the duration of the load, the soil condition can vary from undrained to a drained state. In the undrained state the soil particles are surrounded by incompressible water and changes in the pore pressure and soil stress will occur; however, in the drained state water can escape and therefore the pore pressure remains constant and the soil is free to dilate or contract under load.

During earthquakes the shaking of the ground may cause a reduction of soil strength and stiffness degradation, such that the support may lose its integrity because of large foundation movement or complete collapse. This phenomenon known as "soil liquefaction" is frequently observed in cohesionless soils depending on the density of the soil, but can also occur in other soil types.

To assess the performance of the support foundation under dynamic loading, the following factors should be considered:

- The soil response to short term transient loads;
- The foundation's response including changes in capacity and load displacement behaviour;
- The effects of foundation type, shallow or deep;
- Loading characteristics including amplitude, loading cycles and loading type, one or two-way;
- Soil state drained or undrained.

For further information of the effect of dynamic loading on the support foundations, reference should be made to the forthcoming Cigré TB "Dynamic Loading on Foundations".

13.3.6 Foundation Types

For simplicity, three basic categories of foundation are considered in this chapter, i.e., spread, anchor and compact foundations. The use of any particular category of

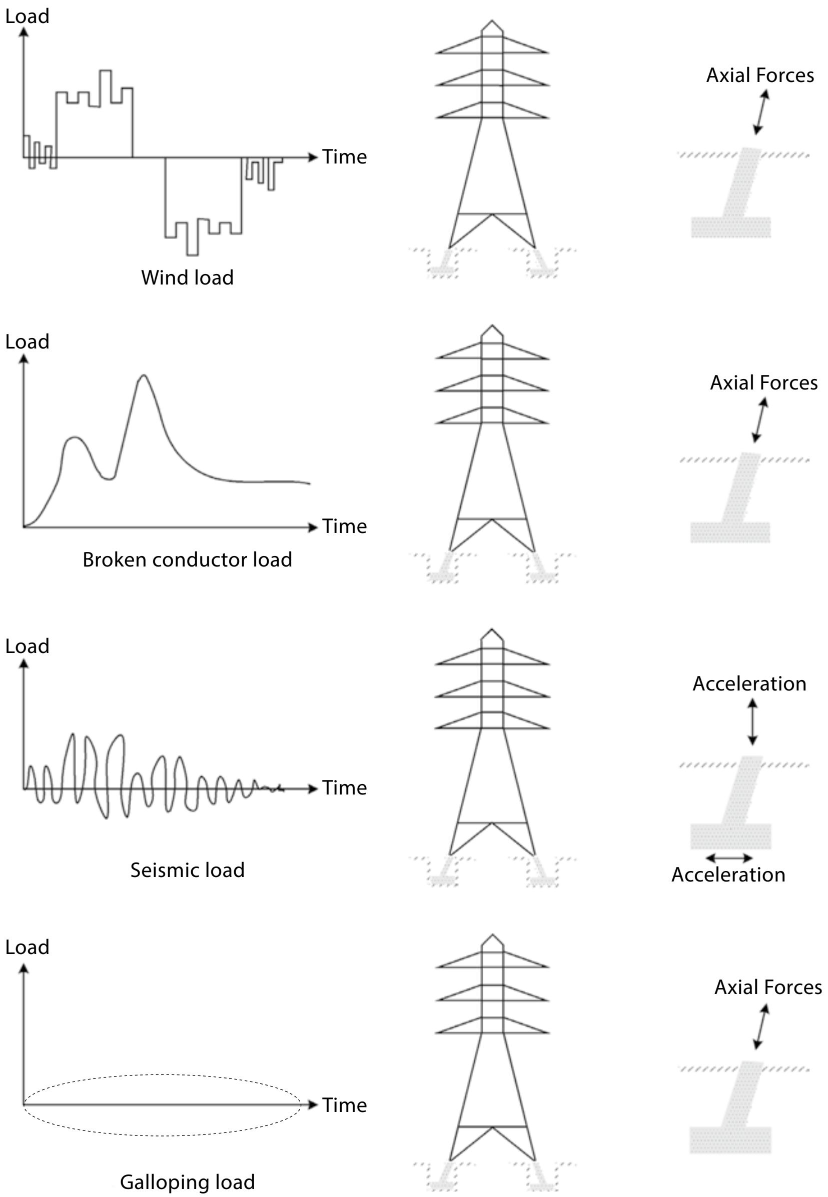


Figure 13.11 Diagrammatic representation of dynamic loading on support foundations.

foundation, and specifically an individual foundation type, will to a degree depend on both the support type and the geotechnical conditions present. The geotechnical conditions will influence both the foundation design and the foundation installation. A diagrammatic representation depicting the relationships between the support

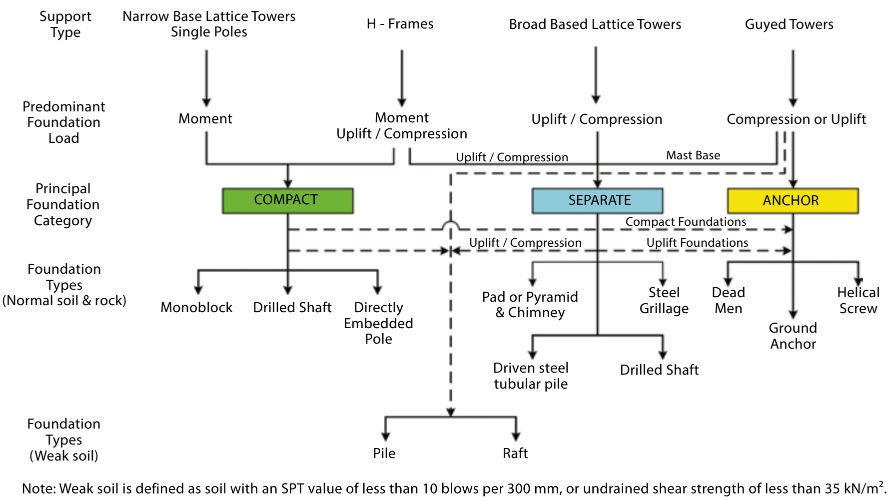


Figure 13.12 Diagrammatic representation of interrelationship between support types and principal foundation categories.

type, the basic foundation category, the foundation type and the geotechnical conditions, is shown in Figure 13.12.

13.3.6.1 Separate Foundations

Separate foundations are predominately loaded by vertical uplift and compression forces, and generally they are used for lattice towers or H-frame structures when the face width exceeds 3 m, provided that the geotechnical conditions are suitable. The connection between the leg of the support and the foundation is normally provided by stubs encased in the foundations or by the use of anchor bolts.

Under the classification "separate", the following types of foundations have been considered: spread footings; drilled shafts and piles.

Spread Footings

Spread footings include: concrete pad and chimney foundations including stepped block foundations, concrete pyramid and chimney including non-reinforced concrete pyramids and pyramids with extended pads, shallow reinforced pyramids and steel grillage foundations. A diagrammatic representation of the various types of spread footings is shown in Figure 13.13. A typical shallow pad and chimney foundation, and a grillage foundation are shown in Figure 13.14a, b respectively; while, Figure 13.20 shows the use of a stepped block foundation for a 220 kV river crossing tower.

Drilled Shaft Foundations

A drilled shaft or augered foundation is essentially a cylindrical excavation formed by a power auger and subsequently filled with reinforced concrete. The shaft may be straight or the base may be enlarged by under-reaming or belling; thereby increasing, in non-caving soils, both the bearing and uplift capacities of the drilled shaft.

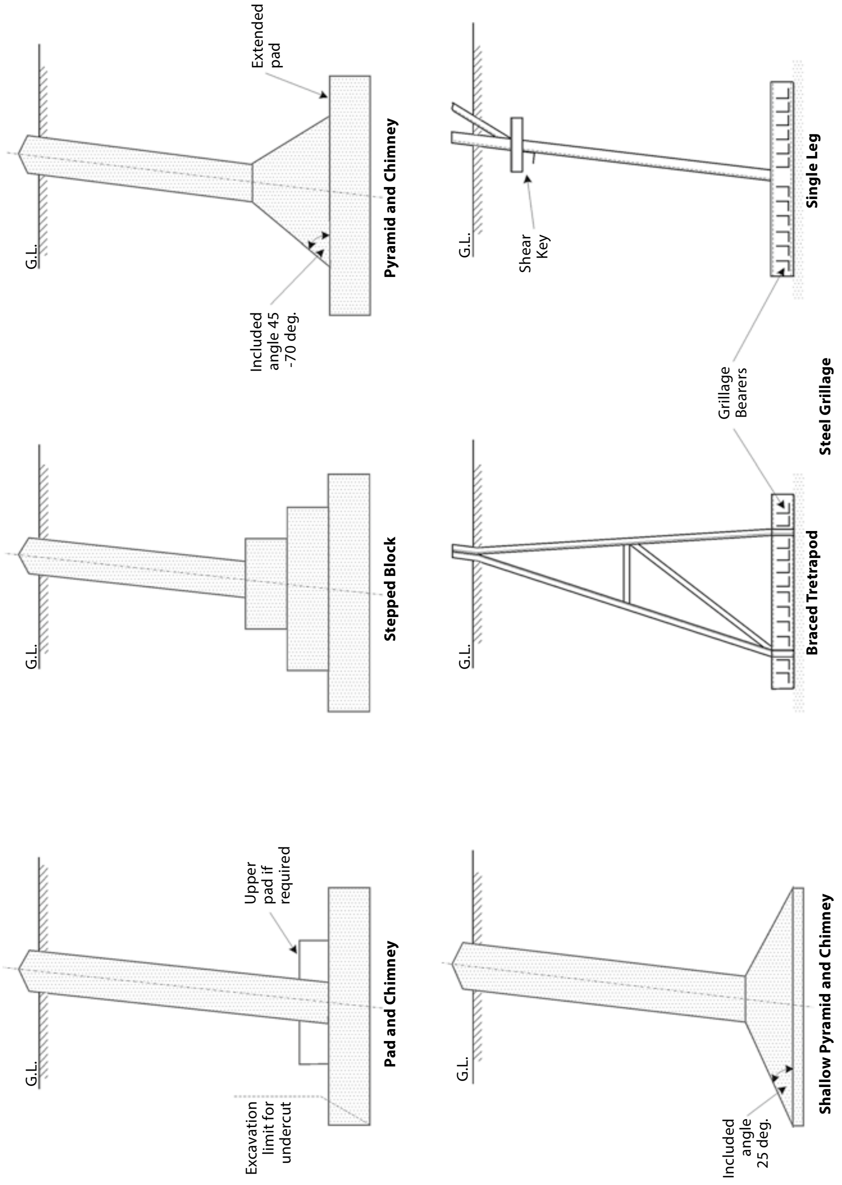


Figure 13.13 Spread footings.

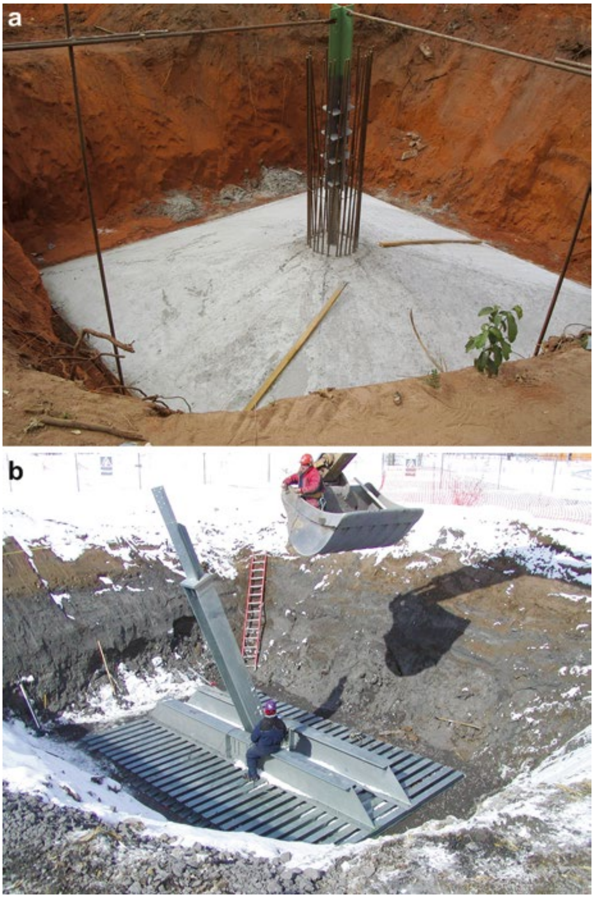


Figure 13.14 Typical shallow pyramid and chimney (**a**), and grillage (**b**) foundations.

Although this type of foundation is effectively a bored pile, the American Concrete Institute defines them as drilled shafts (piers) when their diameter is greater than 760 mm.

For broad base lattice towers drilled shafts may be installed vertically or inclined along the hip slope of the leg as shown in Figure 13.15. The shaft shear load is greatly reduced for drilled shafts inclined along the tower leg hip slope. For H-frame supports the shaft would be installed vertically.

Piled Foundations

Pile foundations can comprise either a single pile or a group of piles connected at or just below ground level by a reinforced concrete cap or a steel grillage, i.e., a piled foundation.

Piles may be classified as "driven" (displacement) where the soil is moved radially as the pile enters the ground, or "bored" (non-displacement) when little disturbance is caused to the soil as the pile is installed. Driven displacement piles may comprise a totally preformed section from steel, pre-cast concrete or timber. Alternatively, where hollow steel or pre-cast concrete sections are used these are normally subsequently filled with concrete, or for steel H-sections post grouted.

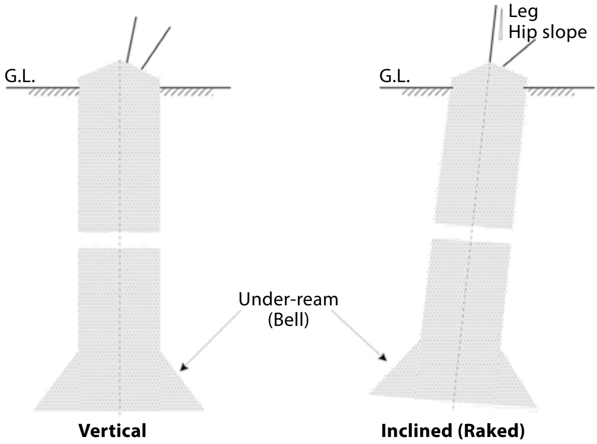


Figure 13.15 Drilled shaft foundations.

Non-displacement piles are cast-in-situ using either concrete or grout, with the pile section formed by boring or drilling.

The application of tubular steel piles (either driven or screwed), to form the individual foundation of a lattice steel tower or a portal guyed tower mast base, is shown in Figures 13.21 and 13.22 respectively. The application of pre-cast concrete piles to form a portal guyed tower mast base and as a guy anchor is shown in Figures 13.23 and 13.24.

Although, piles are normally used in poor ground conditions, driven tubular steel piles are frequently used in good ground conditions, if there are economic, environmental or H&S benefits. In these instances only the upper section of the pile will be filled with concrete at the pile – pile cap or pile – tower interface with remaining pile section filled with granular material above the soil plug.

Micropiles are normally defined as piles with a diameter of 300 mm or less and for the purpose of this report they have been included within the section related to anchors and anchor foundations.

Anchor Foundations

Anchors may be used to provide tension resistance for guys of any type of guyed support and to provide both primary and additional uplift and/or compression resistance to spread foundations, in which case various types of anchors can be used.

Ground Anchors

Ground anchors and micropiles consist of a steel tendon (either reinforcing steel, or high grade steel thread bar) placed into a hole, drilled into rock or soil, which is subsequently filled with a cement, or cementious grout usually under pressure (Figure 13.16a). Ground anchors can also be grouped together in an array and connected by a concrete cap or steel grillage at or below ground level to form a spread footing anchor foundation (Figure 13.16b). Figure 13.17a shows the cap and

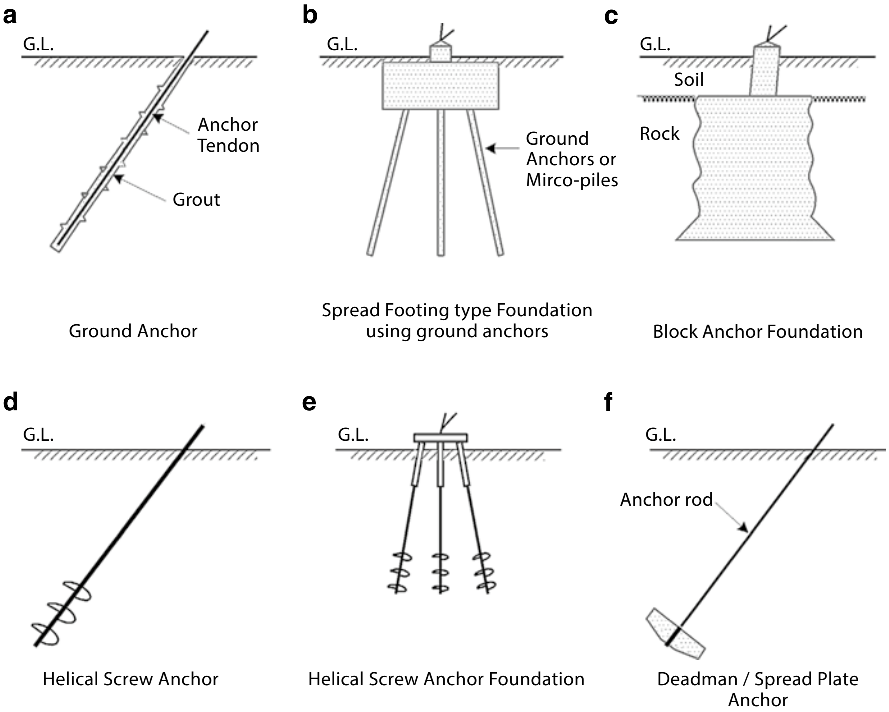


Figure 13.16 Anchor foundations.

chimney of a spread footing anchor foundation. The application of piles as ground anchors is considered in the previous sub-section.

Block Anchors

Block anchors comprise a pad and chimney spread type footing whereby the concrete is cast directly against the face of the excavation preferably with an undercut at the base (Figure 13.16c).

Helical Screw Anchors

A helical screw anchor comprises a steel shaft with individual steel helices attached to the shaft, which is screwed into the ground (Figure 13.16d). Helical screw anchors can also be connected together at or above ground level by a steel grillage or concrete cap to form a helical screw anchor foundation (Figure 13.16e).

Deadman/Spread Anchors

Typically these anchors consist of a timber baulk, a pre-cast concrete block/pad or deformed steel plate installed in the ground by excavating a trench or augering a hole, placing the anchor against undisturbed soil and backfilling the excavation (Figure 13.16f). The anchor rod may be installed by cutting a narrow trench or drilling a small diameter hole. Figure 13.17b shows a pre-cast concrete guy anchor “deadman” foundation.

Figure 13.17 Typical spread anchor (**a**) and pre-cast concrete guy 'deadman' (**b**) foundations.

Compact Foundations

Compact foundations are defined as those specifically designed to resist the applied overturning moment from the support. Generally this type of foundation is used for single poles, for lattice towers with narrow base widths (less than 3 m) and for H-frame supports with a predominant moment loading. In addition, they may be used to replace separate footings for wide base lattice towers when there is a specific geotechnical requirement, e.g., low allowable ground bearing pressure, i.e., raft foundations. The connection between the support and the foundation is normally provided by anchor bolts, by a section of the pole directly encased in the foundation, or by stubs encased in the foundation.

Monoblocks

Concrete monoblock foundations in their simplest form, comprises a cast-in-situ reinforced concrete block. A typical one for a single pole or a narrow base lattice tower is shown in Figure 13.18a; alternatively they can be cast in-situ using prefabricated formwork or be pre-cast, Figure 13.18b.

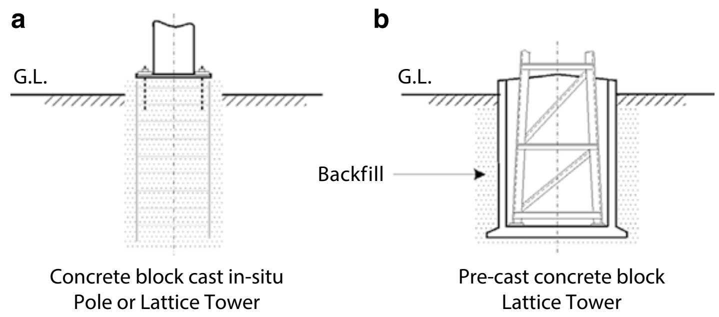


Figure 13.18 Monoblock foundations.

Figure 13.19 Reinforced concrete raft (slab) foundation for a 110 kV lattice steel tower.

Direct Embedment

Originally used for the direct embedment of relatively lightly loaded wood poles, this type of foundation is now also used for steel and concrete poles subjected to high overturning moments. However, for steel and concrete poles the size of the excavation, the type of backfill material, e.g., imported granular or concrete and the compaction of the backfill material will require careful control.

Raft Foundations

Under the general classification of raft foundations, the following types of foundations have been considered: concrete raft foundations and steel grillage raft foundations.

Concrete raft foundations in their simplest form comprise a cast-in-situ reinforced concrete pad at or below ground level as shown in Figure 13.19.

Steel grillage raft foundations, similarly to those shown in Figure 13.14b, are normally only used for narrow base lattice steel towers, and basically consist of steel angle section grillage members which are connected to two steel angle or channel section bearers orientated at 90 degrees to the grillage members. Depending on the fabrication process used, the grillage members are either bolted to, or slotted

Figure 13.20 Typical stepped block spread foundation – 220 kV Kama River Crossing.

Figure 13.21 Driven steel tube piles with steel grillage – lattice steel tower leg connection.

in the bearers. In the latter case it is common practice to "spot" weld the grillage members to the bearers prior to installation. The connection of the grillage to the support is by means of an extension of the tower body.

For further details regarding the different types of foundations outlined above, reference should be made to Sections 3 and 4 of Cigré TB 206 (Cigré 2002).

13.3.7 Ground Conditions

The relationship between the support type – the applied foundation loadings – foundation type and the ground conditions have been outlined in this section. One of the

Figure 13.22 Steel screw piles with steel grillage – 500 kV portal guyed tower mast base.

Figure 13.23 Pre-cast concrete pile – Portal guyed tower mast base.

key features of this relationship is the ground conditions and the determination of the ground conditions and the associated geotechnical hazards is considered in the next section of this chapter.

13.4 Foundation Design (Part 2): Site Investigation

13.4.1 General

The site investigation encompasses all aspects of the geotechnical appraisal of the OHL route and/or the individual support sites from the initial OHL routing phase or during the initial phase of an existing OHL upgrading study, through to the on-going geotechnical assessment during the foundation installation or upgrading activities.

Figure 13.24 Pre-cast concrete pile – Portal guyed tower guy anchor.

The aim of the assessment is to identify the properties and behaviour of the ground and the ground water, the geotechnical hazards and associated risks that these pose to the OHL supports/foundations, and how the support foundations could adversely affect the ground and surrounding area. To achieve this aim, a site investigation should be undertaken in a systematic manner and should be uniquely planned and designed for the specific OHL project under consideration.

In the context of this section, unless otherwise stated, the terms "OHL route" and "support sites" encompasses both the proposed and existing OHL route and the supports sites.

The overall site investigation can normally be divided into the six distinct phases which are outlined below and shown diagrammatically in Figure 13.25.

- Initial Appraisal ~ desk study and site reconnaissance (walk over survey);
- In-depth desk study, including geotechnical hazard identification, risk assessment and recommendations regarding the type and extent of the ground investigation and/or enhanced geotechnical desk studies to be undertaken;
- The actual ground investigation (GI) and/or enhanced geotechnical desk studies;
- Review of the factual information and preparation of the factual report;

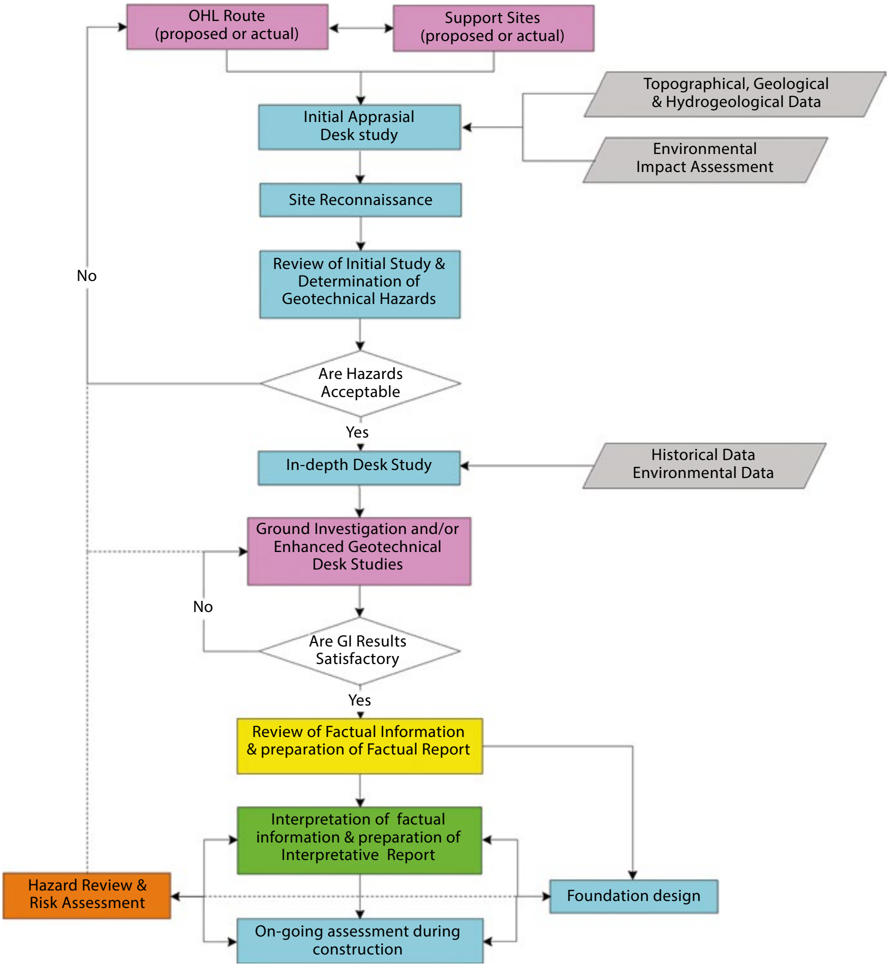


Figure 13.25 Diagrammatic representation of the site investigation process.

- Interpretation of the results of the desk study and the ground investigation, preparation of the geotechnical ground model, determination of the geotechnical foundation design parameters and the preparation of the interpretive report including geotechnical hazard identification and risk assessment;
- Ongoing assessment during the actual construction phase, including associated geotechnical hazard reviews.

13.4.2 Initial Appraisal

The initial geotechnical appraisal comprises two interrelated actions, the initial desk study and the site reconnaissance. The aim of the initial desk study, to be confirmed by the subsequent site reconnaissance, is to establish from published information, e.g., topographical, geological and hydrogeological maps, what is already known about the ground conditions on the OHL route and associated support sites and, as such, will enable a preliminary understanding of the ground and its behaviour to be ascertained and will provide an initial basis:

- For assessing the geotechnical hazards present and the associated scheme risks;
- For assessing the type and extent of the subsequent GI and laboratory testing required;
- For determining the need for any additional or enhanced geotechnical studies.

The information collected during this initial phase of the evaluation process, will also form the basis of the geotechnical model for the OHL route, against which every piece of acquired data can be checked. As the evaluation process continues, so the geotechnical model will either be confirmed or amended.

If the Environmental Impact Assessment report is not available at this stage in the design process, it would be pertinent to check if there are any environmentally sensitive areas on or adjacent to the OHL route (or route corridor) or support sites.

Prior to undertaking the actual desk study and the site reconnaissance, consideration should be given to the method of recording the acquired data and ensuring that potential geotechnical hazards are easily identifiable and thereby providing the basis for the subsequent risk analysis. One method of achieving this aim is the preparation of a geotechnical summary table (see Figure 13.26), for each of the support sites.

The aim of the site reconnaissance (walk-over survey) should be to identify potential site conditions at the support sites and the verification of the information gathered during the initial desk study. The main features which should be identified and/or verified during the site reconnaissance are:

- Features indicating the geology at or near the support sites;
- The presence of any hydrologeological features at or near the support sites;
- The geomorphology of the support site and the surrounding land use;
- The presence or evidence suggesting the presence of geotechnical hazards;
- The presence of any environmental features;
- Any other information that may be relevant to the study.

In temperate regions where there is a marked variation in the seasonal rainfall, or in semi-arid areas where extreme rainfall only occurs infrequently, care needs to be taken in assessing the potential changes in soil properties arsing from changes in moisture content. Similar comments apply in respect of changes in the extent or depth of surface water features, drainage patterns, flash floods and wadi flows.

The combined information would then permit the identification of potential geotechnical hazards and potential scheme risks. If possible, the site data should be extended to include potential access requirements.

Geotechnical Data Summary

Client:	
OHL Route & Circuits:	
Date:	
Compiled by:	
Checked by:	

1	**Support description**	1,1	**Support no.**	PKF18	RMC21
		1,2	**Support, type & extn.**	PL16 D60° E20 (1)	STL1 K1124 D2°E5 (7)
		1,3	**Foundation type, depth of comp. & uplift footing.**	C ~ Conc. Pyramid (2) U ~ Conc Pyramid & Chimney	4U/C Pyramid & Chimney (8)
		1,4	**Obvious signs of support distress**	None observed, tower bracings recently replaced	None observed
		1,5	**GL. Condition of foundation concrete**	Good. However, the original concrete exposed on leg A is in poor condition at joint between old & new concrete.	Minor cracks present in leg A muff
		1,6	**Evidence of possible settlement**	None observed	Depression around leg D suggests possible settlement
2	**Geology**	2,1	**Solid geology**	Folkestone Beds (3)	Branksome Formation (9)
		2,2	**Drift geology**	Head & Alluvium (3)	Alluvium over River Terrace deposits(9)
		2,3	**Faults**	None indicated (3)	None indicated (9)
		2,4	**Fill/made ground**	None observed	None observed
3	**Hydrology and hydrogeology**	3,1	**Watercourse/surface water, e.g. Pond, stream, lake, river, ditch, estuary, type of river, rate of flow, colour of water**	A river is indicated ~ 10 m SSE of tower (4). Water present and ponding within the tower base, stream 10 m South of tower.	None observed or indicated within 50 m of tower (10)
		3,2	**Groundwater level**	None observed	None observed
		3,3	**Flood risk**	Tower located within a designated flood zone (5). None observed	Tower not within designated flood zone (5)
		3,4	**Springs**	None observed or indicated (4)	None observed or indicated (10)
4	**Geomorphology**	4,1	**Landform, e.g. hill, valley, coast, marsh, tidal, river flood pain, moorland**	Hillside / forest (4)	Flood plain (10)
		4,2	**Topography & Slope gradient, e.g. flat, slope, concave, convex, rocky**	At tower location gently sloping to the North but essentially flat	Flat
		4,3	**Ground level (m AOD)**	70 - 75 m (4)	5 - 10 m (10)
		4,4	**Surface depressions**	None observed	None observed
5	**Geohazards**	5,1	**Evidence of slope instability, e.g. leaning trees/posts, tension cracks, toe buldge, soil creep**	Leaning trees 20 m Northeast and Northwest of tower, landslip section with marshy ground at back of failed section	None observed
		5,2	**Valley cambering**	None observed	None observed
		5,3	**Soft ground e.g. peat, alluvium**	Alluvium indicated (3) Soft ground at base of tower	Alluvium is indicated to be present (9)
		5,4	**Erosion, scour**	None observed	Unlikely to affect tower, no flow river within vicinty of tower (10)
		5,5	**Mining, quarrying, earthworks, etc.**	None indicated (3) and none observed	None observed or indicated (10)
		5,6	**Caves, subsidence & soluble rocks (limestone, gypsum, halite or chalk)**	None observed	Unlikely to occur due to absence of soluble lithologies (9)
6	**Environmental factors**	6,1	**Vegetation, e.g. marsh, woodland, forest, field, Japanese Knotweed, etc.**	Marsh vegetation at base of tower, dense nettles to the South, silver birch trees to East & West	A hedge consisting of deciduous shrubs (2 m) is present beneath tower with grass beyond
		6,2	**Other site features, e.g. burrows**	None observed	None observed
		6,3	**Other environmental features, e.g. SSSI, National Park, nature reserve, etc.**	Tower located within SSSI and SAC (6)	None indicated (6)
7	**Land use**	7,1	**Other third party activates, e.g. Pipelines, other power lines, etc.**	Scrap yard - 50 m East of tower	None indicated or observed within 50 m of tower
		7,2	**Land-use around support**	Forest	Livestock grazing
		7,3	**Construction around support**	None observed	None observed or indicated
		7,4	**Evidence of past human activity**	None observed	None observed
8	**Evidence of possible land contamination**		**Presence of surface staining, litter, burning of material, fly tipped materials, stored chemicals, present/historic land use**	None observed	None observed
9	**Access to support for GI, etc.**		**If a GI investigation is likely, describe any access problems, i.e. services, height restrictions, trafficked areas or presence of landfill that are likely to affect the SI scope and techniques**	Access is via sandy track & then across a bog which is very wet. A tracked rig will be required with access track cleared/created to permit access to tower location and working space	Access to tower is via Erlin Farm for 4WD vehicle and tracked rig

References:

1 PKF Line schedule drw….
2 Foundation drw ….
3 1:10,000 series geological map SU73NE BGS 1998
4 1:25,000 OS map No 133
5 Environmental Agency data base 2009
6 Multi-agency database 2009
7 RMC Line schedule drw….
8 Foundation drw….
9 1:10,000 series geological map SZ19NW
10 1:25,000 OS Map OL22

Figure 13.26 Geotechnical Data Summary (existing OHL).

Where the proposed OHL is located in remote areas with little or no infrastructure or where there is a lack of appropriate topographical and/or geological mapping, it will be necessary to adopt a different approach based on the use of aerial photograph interpretation in conjunction with the use of LIDAR to assist in identifying geological or geomorphologic features, e.g., slope instability or natural cavities. In addition to the use of LIDAR, aerial electromagnetic surveys can also be used to identify geological features.

Once the initial desk study and site reconnaissance has been completed, it is recommended that an initial geotechnical hazard review is undertaken, with the aim of identifying potential significant risks to the OHL route, sections of the proposed route, or a significant number of support sites. This would also apply for the reassessment of an existing OHL, since the presence of significant scheme risks could have an impact on the viability of the proposed upgrading.

Potential major geotechnical hazards and consequential scheme risks would be:

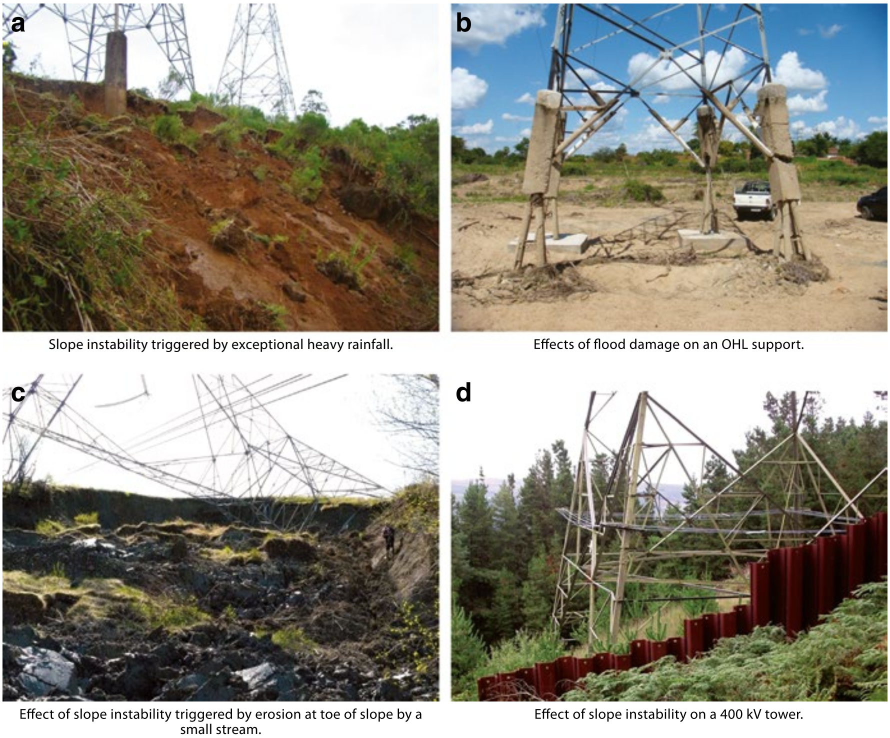
- The presence of a significant area(s) of poor ground, e.g., organic soils, alluvium or fluvial deposits, expansive clays, made ground, etc.;
- The presence of significant area(s) of permafrost;
- The high probability of flooding and/or river or coastal erosion;
- The presence of caves, subsidence and soluble rocks;
- The presence of high water surface levels or ground water tables;
- The presence of significant landslides or peat slides, etc.;
- The presence of significant areas of unstable rock cliffs or loose boulders;
- The presence of significant areas effected by soil erosion;
- Marked seasonal variations in the soil properties, ground water level, or drainage patterns;
- Areas of high seismic activities, e.g., faults;
- The presence of surface or underground mine workings;
- The presence of spoil heaps or waste dumps.

Figure 13.27a–d illustrate typical geotechnical hazards arising from slope instability and flooding.

However, it should be borne in mind that there are a significant number of geotechnical hazards that cannot be identified at this stage of the evaluation process, but which could have a major influence in respect of the proposed OHL route, support sites or the viability of the proposed upgrading, e.g., presence of expansive clays, the industrial legacy of brownfield locations, ground instability arising from steep slopes, etc.

Where significant risks have been identified, if possible, consideration should be given to re-routing the proposed OHL route in part or completely, or revising the proposed support sites. Although it is accepted that it may not be possible to undertake the desired changes, the hazard review should still be undertaken such that all the stakeholders are aware of the potential implications. This again would also apply in respect of the reassessment of an existing OHL where normally the existing support locations cannot be changed.

On completion of the initial hazard review and risk assessment, consideration should then be given to the in-depth desk study. The objective of the in-depth desk study is to combine the data obtained from the first stage of the process with the results obtained during the in-depth desk study, such that an overall geotechnical hazard review and risk assessment can be undertaken with the aim of prioritizing the ground investigations; especially if it is not proposed to undertake all the site works at this stage in the OHL routing process.



a Slope instability triggered by exceptional heavy rainfall.

b Effects of flood damage on an OHL support.

c Effect of slope instability triggered by erosion at toe of slope by a small stream.

d Effect of slope instability on a 400 kV tower.

Figure 13.27 Geotechnical Hazards.

For further information regarding hazard reviews and associated risk assessments, reference should be made Section 13.2.3 and Section 3.12 of Cigré TB 516.

13.4.3 In-depth Desk Study

The aim of the in-depth desk study phase of the process is to combine the information obtained from the initial desk study, the site reconnaissance and the detailed geotechnical studies undertaken during this phase, such that:

- A geotechnical hazard identification and risk assessment can be undertaken;
- Recommendations can be made in respect of the type and extent of the ground investigation;
- Recommendations can be made for enhanced specialist desk studies.

In-depth desk studies may include:

- An initial historical review of the previous use of the support sites, e.g., underground or opencast mining for coal or other minerals;

- The potential effects of mining or open cast quarrying, e.g., mining subsidence, void migration, abandoned mine shafts, etc;
- Initial slope stability assessments, e.g., arising from slopes in excess of 10 degrees, peat and rock slides;
- A review of potential aggressive ground conditions arising from chemical agents that may be destructive to concrete and steel embedded in the ground. These may be naturally occurring or arising from the previous use of the site;
- The effects of natural cavities, seismic activity, expansive clays, collapsing soils, permafrost, river, coastal and soil erosion; etc.

Throughout the in-depth desk study, the geotechnical summary sheet, hazard identification and corresponding risk assessment should be updated as further information is obtained. An example of an overall geotechnical hazard review and risk assessment, for an existing OHL prior to undertaking the GI, has been shown previously in Figure 13.6.

Although, it would be preferable to undertake a GI at each support site, this may not be possible for a variety of reasons, e.g., access, environmental or financial constraints or actual ground conditions; consequentially, a risk based process should be adopted to identify the potential support sites with the highest geotechnical risk. In addition to the sites selected from the risk assessment, consideration should also be given to inclusion of control sites. The control sites should be located at support locations where there is no perceived geotechnical hazard and these would then be used to confirm any initial presumed geotechnical foundation design parameters and as a cross-check on the data obtained to date.

The objectives of the GI are to verify and expand the information previously obtained, to identify any unforeseen geotechnical hazards and to provide sufficient geotechnical design information to permit an economic and reliable support foundation design to be undertaken.

To ensure that there is the greatest flexibility in the selection of the appropriate type of support foundation or foundation upgrade, it is suggested that in the majority of cases the following geotechnical information/design parameters should be available after the GI has been completed:

- Ground profile, depths and thickness of each stratum encountered;
- In-situ soil type and density; if appropriate for existing foundations this should also apply to backfill material type and density;
- Groundwater table depth, potential variations in depth and the mobility of the groundwater;
- In-situ shear strength parameters, i.e., the drained cohesion (c') and the angle of internal friction (Ø') and the undrained shear strength; if appropriate this should also be extended to include the details for the backfill material;
- Compressibility indexes for the in-situ soil (to estimate the amount and the rate of consolidation settlement);
- Unconfined compressive strength or point load test on rock, the Rock Quality Designation (RQD) and Rock Mass Rating (RMR) (normally only required for foundations socketed or anchored into rock);

- To assist in the design of the earthing system, the soil electrical resistivity value should also be measured.

Where applicable, seasonal variations in the soil moisture content should also be considered. In addition, the following data should also be obtained from the GI with respect to the overall durability of the foundation and/or its constituent materials:

- Sulfate, sulfide, magnesium and chloride concentration in both the ground and ground-water;
- Potential Hydrogen (pH) value in both the ground and the groundwater;
- Organic matter;
- Soil corrosivity in respect of steel piles and anchors.

For further information regarding the geotechnical design parameters, reference should be made to Section 4.2 of Cigré TB 516.

13.4.4 Ground Investigation Methods

Ground investigation methods can vary between simple trial pits with visual-tactile examination of the soil to rotary drilled boreholes in rock with a combination of in-situ tests and the recovery of soil and rock samples for subsequent laboratory testing. A comparison of the advantages and disadvantages of different investigation methods commonly used is given in Table 13.2.

A combined SI rig capable of providing both a percussive action and rotary boring facilities is shown in Figures 13.28a and 13.28b.

In ground investigation use is commonly made of either the standpipe or else the standpipe piezometer which can be installed in the actual investigation borehole, thereby facilitating the monitoring of groundwater levels and retrieval of water samples over a period of time following the site work.

The in-situ tests undertaken during the GI are dependant upon both the ground category and the geotechnical data required. A summary of potential in-situ tests with respect to the different ground categories are given in Table 13.3.

An assessment of the various in-situ tests, together with an indication of geotechnical information that may be derived from in-situ test results is given in Table 13.4. Reference should be made to the appropriate international/national GI standard, reports or geotechnical journals for details of the appropriate empirical correlations.

Where it is not possible to directly or indirectly determine the required geotechnical design parameters from in-situ tests, laboratory tests should be used to complement the field observations. Laboratory tests will always be required to establish the durability of the foundation and/or its constituent materials. All laboratory tests should be undertaken in accordance with the requirements of the appropriate standard. Details of the laboratory tests which could be used to assist in determining specific geotechnical design parameters are given in Table 13.5.

Table 13.2 Comparison of ground investigation methods

GI Method	Advantages	Disadvantages
Trial pit	Allows detailed examination of ground conditions. Easy to obtain discrete and bulk samples. Rapid and relatively inexpensive.	Limited by the size of machine. Not suitable for sampling below water or excavation in rock. Greater potential for disruption/damage to site than boreholes or probe holes. Depth restricted to 4.5 m below GL. Width and height restrictions of equipment.
Cable percussion	Allows greater sampling depth than with trial pits, window sampler or probing. Can penetrate most soils. Allows collection of undisturbed samples. Enables installation of permanent sampling/monitoring wells.	Not suitable for investigation in rock. Smaller sample volumes than for trial pits. More costly and time-consuming than trial pits. Width and height restrictions of equipment.
Rotary boring	Allows greater sampling depth than with trial pits, window sampler or probing. Can penetrate all soils and rocks. Allows collection of undisturbed samples. Enables installation of permanent sampling/monitoring wells.	Smaller sample volumes than for trial pits. More costly and time-consuming than trial pits. Width and height restrictions of equipment.
Window sampler	Allows greater sampling depth than with trial pits. Undisturbed samples of the complete soil profile can be recovered. A variety of measuring devices can be installed once hole is formed. Substantially faster than cable percussion. Portable, so can be used in poor and limited access areas.	Not suitable for investigation in rock and cannot penetrate obstructions. Depth restricted to 8 m under favourable circumstances. Smaller sample volumes than for trial pits. Poor sample recovery in non-cohesive granular soils. Width and height restrictions of equipment.
CPT	Allows greater sampling depth than with trial pits. Substantially faster than cable percussion.	Not suitable for investigation in rock and cannot penetrate obstructions. No sample recovery. Ground water level not recorded. Width and height restrictions of equipment.
Dynamic probing	Essentially profiling tool. Portable, so can be used in poor and limited access areas. Very quick and inexpensive.	Not suitable for investigation in rock and cannot penetrate obstructions. No sample recovery. Ground water level not recorded.

Figure 13.28 Combined cable percussion and rotary boring rig (a. existing tower, b. new tower site).

Table 13.3 In-situ test methods

Ground category	In-situ tests
Non-cohesive (granular)	Standard Penetration Tests (SPTs), Cone Penetration Tests (CPTs) or Pressuremeter (PM)
Cohesive and organic	As non-cohesive soil. Vane Shear tests (VSTs) may be used in fairly uniform, fully saturated soils.
Rock	Weak rock SPTs or Pressuremeter, medium to hard rock Point load tests or Pressuremeter.

Normally, the chemical tests outlined below should be undertaken on the soil and groundwater samples, in accordance with the appropriate standard.

- pH in a 2.5:1 soil/water extract and in the groundwater;
- Soluble sulfate in a 2:1 soil/water extract and in the groundwater;
- Acid soluble sulfate in soil;
- Total sulfur in soil;
- Magnesium in 2:1 soil/water extract and soluble magnesium in the groundwater;
- Ammonium ion in soil and in the groundwater;
- Nitrate in a 2:1 soil/water extract and nitrate ion in the groundwater;
- Chloride in a 2:1 soil water extract and chloride ion in the groundwater;
- Aggressive carbon dioxide in the groundwater.

Prior to the final selection of the proposed ground investigation methods, e.g., trial pits, cable percussion or rotary boring, or a combination of these methods, a review of the following factors should be undertaken:

- The geotechnical information required in respect of the design of the proposed support foundation(s) or for any proposed upgrading of existing foundation(s) and hence the sampling, in-situ and laboratory testing requirements;

Table 13.4 Assessment of in-situ tests

In-situ test	Geotechnical data	Basis for interpretation	Advantages	Disadvantages
SPT	Relative density and effective angle of friction for non-cohesive soils Bearing capacity of shallow and deep foundations Undrained shear strength of clays	Empirical	Simple, rugged equipment suitable for most ground categories Disturbed soil samples possible from split-spoon sampler	Point profile only Test results affected by boring disturbance
CPT	Soil classification Relative density and angle of friction of sand Undrained shear strength of cohesive soils Pile bearing capacities Bearing capacity of shallow foundations	Empirical & Theoretical	Very fast and relatively inexpensive Continuous soil profile	Cannot penetrate dense or coarse granular soils, hard layers or rock Does not provide soil samples
VST	Undrained shear strength	Theoretical	Allows in-situ strength determination Simple, rugged	Useful only in soft clays Point profile only
PM	Deformation modulus, shear strength and horizontal stress conditions	Empirical & Theoretical	Can be used in soil and rock In-situ measurement of volumetric deformation	Test holes must be carefully prepared, frequent membrane failures which require repeat tests and requires installation and interpretation of results by specialist contractor

- Whether the GI is going to be undertaken at all support sites or only at selected support sites and whether different levels of GI will be undertaken, depending on either the number of support sites to be considered or on the perceived geotechnical risk;
- The potential combination of drift and solid geology, e.g., depth to bedrock or competent strata and the potential type of drift and rock to be investigated;
- The presence of fill or made ground or other "aggressive ground conditions" and the necessity to avoid contamination of the natural groundwater and underlying strata from material, leachates or aggressive groundwater present in the overlying strata;
- The presence of any known contaminated ground and the need to undertake a specialist contamination investigation;
- Whether monitoring equipment is to be installed in the borehole on completion of the drilling, e.g., piezometers or inclinometers;

Table 13.5 Laboratory tests – geotechnical design parameters (Reference modified from Table 10 of BS 5930 (1999))

Category of Test	Name of test or parameter measured	Remarks
Classification	Moisture content	Used in conjunction with liquid and plastic limits, it gives an indication of undrained strength
	Liquid and plastic limits (Atterberg limits)	To classify fine grained soil and fine fraction of mixed soil
	Particle size distribution	Identification of soil type
	Mass density	
Soil strength	Triaxial compression	Both undrained and drained tests or undrained tests with measurement of pore pressure are required
	Unconfined compression	Alternative to undrained Triaxial test for saturated non-fissured fine grained soil
	Laboratory vane shear	Alternative to undrained Triaxial test or unconfined compression test for soft clays
	Direct shear box	Alternative to the Triaxial test for coarse grained soils
Soil deformation	One-dimensional compression and consolidation tests	Compressibility indices for the in-situ soil
Rock strength	Uniaxial compression and point load test	
Chemical	Mass loss on ignition	Measures the organic content in soils, particularly peat

- Access constraints, e.g., size and mass of proposed ground investigation equipment, access requirements, e.g., will it be necessary to upgrade the proposed site access;
- Headroom constraints, e.g., will the equipment be operating under or adjacent to a "live" OHL and the associated safety clearance requirements;
- Ground conditions at the site, e.g., soft or firm and any potential seasonal variations arising from changes in ground water level or moisture content of the ground, ground temperature variations, etc.;
- Environmental constraints.

For further information regarding GI including laboratory testing and enhanced desk studies reference should be made to Section 4 of Cigré TB 516.

13.4.5 Factual Report

The factual report of the GI should contain and describe accurately and concisely and the following information:

- Details of the site, e.g., a map of the overall OHL route considered and separate plans for each of the support sites investigated showing the location of the trial pit, borehole, etc., relative to the actual support location;
- A summary of the actual GI undertaken including a description of the equipment and methods used;
- Copies of Trial Pit or Borehole records, etc.;
- The results obtained from in-situ and laboratory testing;
- Photographs of rock core samples recovered.

Once the factual report has been completed, the geotechnical hazard review should be updated to ascertain whether the perceived geotechnical risks require to be revised and the consequential scheme risks modified.

After the completion of geotechnical risk assessment, consideration should then be given to preparing the interpretive report, determining the foundation geotechnical design parameters and the requirements for the on-going geotechnical assessment regime to be used during the actual foundation installation phase of the project.

The interpretative report is the documentary record of the final part of the geotechnical design phase, prior to the actual foundation design and subsequent installation of the support foundations. The actual timing of the interpretive report will depend on the sequencing of the GI, i.e., whether this is undertaken completely during the OHL routing process or partly during the routing and completed during the actual design phase of the project.

13.4.6 Interpretive Report

The interpretive report should contain, as appropriate, the following information:

- A review of the geotechnical and associated information obtained on the site, i.e., the OHL route and the individual support locations, thereby confirming or modifying the preliminary understanding of the ground conditions;
- A description of the ground in relation to the project;
- Recommendations in respect of possible foundation design solutions, especially as regards any non–standard foundations, e.g., piles, anchors, etc., together with guidance on what might be preferable in terms of cost, timing, ease of construction, hazard reduction, environmental impact, etc;
- Recommendations in respect of the foundation geotechnical design parameters;
- Recommendations in respect of the protection of buried concrete or steelwork against aggressive ground conditions (soil and groundwater);
- Recommendations in respect of the alleviation of potential environmental impacts from the excavation of aggressive soils, e.g., acid sulfate soils;
- A summary of the geotechnical hazards identified during the course of the overall investigations and their potential affect on the project;
- Recommendations in respect of any further geotechnical investigations required;

- If contaminated soils have been encountered, recommendations in respect of Health and Safety requirements during the construction of the OHL and especially, during foundation installation;
- Recommendations in respect of any slope stability issues, both temporary during construction and permanent, including where necessary, drainage measures;
- Recommendations in respect of any flood protection measures required;
- Recommendations in respect of mining subsidence: description of workings voids and stability, possible recommendations for method of filling known cavities near the surface, etc.;
- Recommendations in respect of potential foundation installation issues, e.g., excavation stability, drainage, groundwater lowering and construction equipment, etc;
- Recommendations in respect of potential sources of constructional materials e.g., fill for access and accommodation works and/or aggregate for foundation construction where there are no commercial sources available;
- Recommendations in respect of on-going geotechnical assessment during the foundation installation.

The integration of the information obtained during the different phases of the evaluation process, i.e., the initial appraisal, the in-depth desk study and the GI, is essential if an accurate understanding of the ground conditions along the OHL route is to be achieved. To achieve this objective, it is recommended that a "geotechnical model" of the OHL route is prepared.

If appropriate, the ground should be divided into a series of soil and rock types for which the engineering properties are reasonably constant; with the division usually related to the geological succession. For each of ground types a description should be given, together with an indication as to whether any anomalies have been observed.

Details of the sequence of the ground types along the OHL route should be given. Wherever possible the stratigraphy of the OHL route should be related to the topographical, geological and geomorphological features; any anomalies which could have a significant effect on the proposed constructional activities should be highlighted.

Since the GI will only show the ground conditions at the investigations sites (support locations), the degree to which they can be used to represent conditions between such sites, is however a matter for geological interpretation, rather than factual reporting and the associated uncertainties must be recognised. To assist in the understanding the ground profile, i.e., the stratigraphy, it is recommended that a series of cross-sections indicating the ground profile and groundwater level are included in the report.

A summary of the potential geotechnical design parameters is given in Section 13.4.3; however, there is no universally accepted method of deriving/selecting these parameters, but the following approach may assist:

- Comparison of both in-situ and laboratory test results with bore-hole logs, ground descriptions, etc;

- If possible, cross-check in-situ and laboratory test results in similar ground;
- Collate individual acceptable results for each soil/rock and decide on representative values appropriate to the number of results;
- Where possible, compare the representative values with experience and published data for similar geological formations, soil or rock types;
- Consider and explain apparent anomalous or extreme results.

A similar approach to that outlined above, should also be used where a presumed set of initial geotechnical design parameters has been considered, as part of the foundation design process.

Since the groundwater has a large influence on the design of the foundation and also the proposed installation techniques, details of the regional groundwater condition, presence or otherwise of perched, artesian or downward drainage conditions should be included in the report. In addition, observations should be made in respect of possible seasonal, tidal or other long term variations.

The identification of any geotechnical installation issues in respect of the foundation installation or upgrade of an existing foundation, during the interpretive stage, will obviously benefit all parties and should assist in the reduction of the H&S risks.

The principal foundation issues that should be considered are:

- Excavations: methods and sequence of excavations; temporary works and plant requirements; how to avoid soil liquefaction and heave of the excavation base;
- Groundwater: potential flow, head and quantity and proposals in respect of sump drainage or well-point dewatering;
- Piles or anchors: method of installation suited to the ground profile, environment and adjacent structures or buildings;
- Contamination: known or suspected contaminants and gases in soil, groundwater and any cavities;
- Environmental impact in respect of foundation type, e.g., type and quantity of material to be excavated, quantity of material to be disposed off of-site, plant and equipment required, access and accommodation works required, etc.

13.4.7 Ongoing Geotechnical Assessment

There is an inherent difficulty in predicting the actual ground conditions from the ground investigations undertaken prior to construction commencing, since irrespective of the extent of the ground investigation only a small proportion of the ground is examined. Consequentially, there is an inherent risk in the foundation selection process, i.e., determining the type of foundation to be installed, both in terms of the overall reliability of the OHL and the H&S of the site operatives prior to work commencing on site. To try and minimise these risks, there is always a need for an ongoing geotechnical assessment to be undertaken during the foundation installation.

The primary purpose of this ongoing assessment is to determine to what extent the conclusions drawn from the ground investigation are valid or whether there is a need for them to be revised, i.e., is there a need to change or modify the type of foundation to be installed or the method of installation. Typical potential variations could be in respect of:

- Changes in the assumed ground profile, e.g., rock head being lower than expected;
- Changes in the assumed soil and/or rock properties, e.g., presence of soft strata at the proposed foundation setting depth, weaker rock at the foundation installation level than anticipated;
- Changes in the groundwater level, e.g., groundwater level higher than anticipated.

All of which will have an implication in respect of type of foundation to be installed and/or in the method of installation, and the H&S risk. Consequentially, there is a need for an effective interaction process between the foundation designers and those installing the foundation.

A further geotechnical hazard review should form an integral part of the preparation of the interpretative report. If it has not been possible to eliminate the major geotechnical hazards by rerouting the proposed OHL route, resiting of the affected supports, undertaking further detailed studies or by the proposed associated works, e.g., hillside slope stabilization, at the sites where major geotechnical hazards are still present it will be necessary to consider how the associated risk can be reduced or eliminated during the foundation design or foundation installation.

For further details in respect of both the interpretative report and the ongoing geotechnical assessment, reference should be made to Section 5 of Cigré TB 516.

13.4.8 Geotechnical Design

There are hazards associated with the ground and unless these hazards are adequately understood they may jeopardise the project, its environment and the H&S of the site operatives and the general public. This section has highlighted the requirements for a thorough site investigation, since unless is adequately undertaken, there will be expensive delays to the project.

Once the site investigation has been completed the geotechnical design of the support foundations can be undertaken; although it may be possible to commence the foundation geotechnical design using presumed geotechnical parameters, which will subsequently be confirmed by the GI.

13.5 Foundation Design (Part 3): Geotechnical and Structural

13.5.1 General

As previously stated, this third section on the design of the support foundations provides an overview of: system design considerations, the geotechnical – structural design of the foundations, the interaction between the foundation design and the installation method, the calibration of the theoretical foundation design model and the selection of the support site foundations.

To avoid any mistakes the foundation designer must have a clear understanding of which factors have been included or excluded in any foundation applied loading schedule. This also applies in the use of any probabilistic based geotechnical design code, since the partial factors on actions or the effects of actions are normally related to requirements for buildings or bridges and not to OHL supports and their foundations. This cautionary note also applies the use of geotechnical design or analysis computer software. The foundation designer must have a clear understanding of the theoretical basis of the software, including the boundary conditions and any assumptions/simplifications made, especially as regards the input data required; together with the validation process.

13.5.2 System Design Considerations

The support foundations for an OHL normally comprise a combination of "standard" designs usable at the majority of support sites and site specific designs; thereby minimizing the overall cost of the foundations. "Standard" designs would be developed for specific support types – range of support extensions and generic ground conditions; while, site specific designs would be for specific support sites, where the ground conditions are outside the "standard" design boundary conditions.

"Standard" designs are usually prepared against presumed (generic) geotechnical design parameters; which have been shown to be satisfactory, based on the service life history of existing OHLs and/or full-scale foundation tests. "Custom" designed foundations however, will require geotechnical parameters specific to the site in question.

The number and types of different "standard" foundation designs developed for a specific OHL will depend on the support type, the variability of the ground conditions present, the length of OHL, whether "standard" foundations designs have already been developed for specific range of supports, etc. For a typical OHL comprising self-supporting lattice steel towers the range of "standard" designs could comprise: concrete pad/pyramid chimney foundations for a specific range of soil conditions together with rock anchors, while the site specific designs could comprise both pile and micro-pile foundations. However, even for the pile foundations normally practice is to develop a standardised design for the pile caps.

13.5.3 Foundation Design – Geotechnical and Structural

13.5.3.1 General

This section provides a basic overview of the geotechnical and structural design of three common types of support foundations, i.e., spread footings (separate), drilled shafts (separate footings and compact) and ground anchors including micropiles.

For further details on the geotechnical design, including the full cross-reference to the quoted sources of these and other types of separate, compact and anchor foundations, reference should be made to Cigré TB 206.

All of the design methods outlined in this section, unless stated to the contrary, relate to the application of static or quasi-static applied foundation loadings.

Irrespective of whether a "standard" or site specific foundation design is undertaken, the basic approach would be:

- Undertake a initial assessment of potential foundation types based on the support type, applied foundation loadings, ground conditions and geotechnical design parameters, the installation requirements including the temporary work's design, economic, programme, H&S and environmental impacts, etc., to determine the preferred foundation type;
- Undertake the initial foundation geotechnical design and hence determine the physical size of the foundation;
- Undertake the structural design of the foundation and hence determine the material and installation quantities for the foundation, e.g., concrete, excavation, etc.;
- Undertake a review of the installation requirements, economic, programme, H&S, environmental implications, etc., and confirm the foundation type;
- Finalise the foundation design and installation requirements;
- If appropriate, undertake full-scale foundation type tests or tests on individual components, e.g., individual test piles to calibrate the theoretical foundation design model or to confirm the assumed geotechnical design parameters and review/revise the design accordingly;
- Undertake the installation of the project foundations including the ongoing geotechnical assessment during the installation.

13.5.3.2 Spread Footings

Compression Resistance

The applied compression load is resisted by the in-situ ground in bearing and a typical free body diagram is shown in the Figure 13.29a.

Depending on the geotechnical design model used the horizontal shear force (H) will be resisted wholly or partly by the lateral resistance of the soil L_P and by the friction/adhesion at the base of the foundation F. However, the resultant shear moment arising from the applied load (H) will also give rise to minor eccentricities in the bearing pressure.

For steel grillages the net area of the base, i.e., the area of bearers in contact with the soil, is normally used for the calculation of the bearing pressure; however, this will depend on the spacing between the individual grillage members.

The ultimate bearing pressure (shear failure) can be calculated using the classical bearing-capacity equations developed by Terzaghi (1943*), Meyerhof (1951*, 1963*), Hansen (1970*) or Vesić (1973*). Alternatively, they can be calculated directly from in-situ test results, Bowes (1996*) gives procedures for the Standard Penetration Test based on the work of Terzaghi and Peck, and Meyerhof, and for the Cone Penetration Test based on the work of Schmertmann.

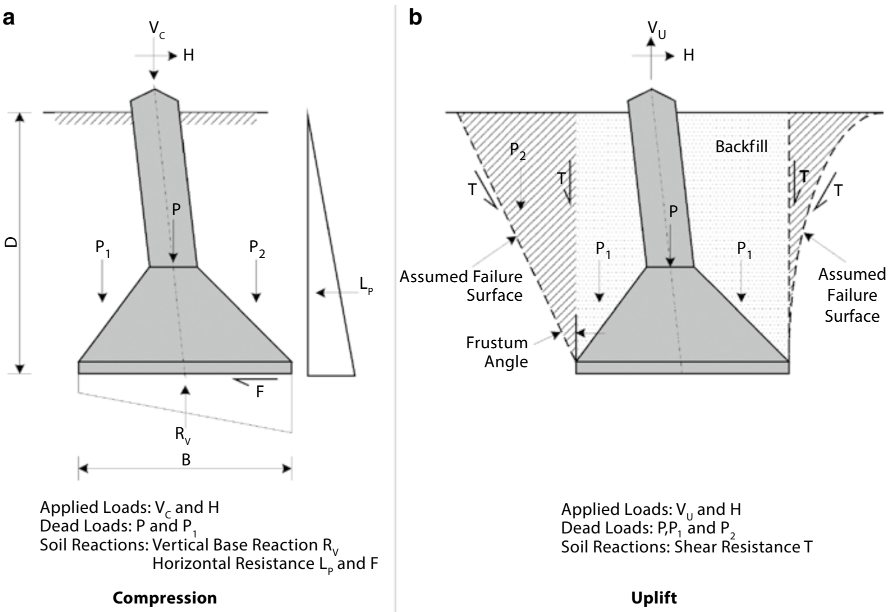


Figure 13.29 Free body diagram – spread foundations (compression and uplift).

The weight of the soil above the foundation (force P_1 in Figure 13.29a) should only be included in the calculations for the applied loading, if gross bearing pressures and not net bearing pressures are calculated.

Presumptive allowable bearing pressures are contained in the majority of international and national design standards; however, due caution should be exercised when using these values, since generally the assumed safety factor or partial strength (resistance) factor is not stated and thus the values quoted maybe conservative.

The settlement of spread foundations can be divided between immediate, consolidation and secondary conditions. Immediate settlements are those that occur as soon as the load is applied in the soil mass and may exhibit significant values for non-saturated clays, silts, etc. Consolidation settlement is related only to the sustained load component in cohesive soils and may normally be ignored if everyday "working" loads or loads arising from mean wind speeds are considered. Secondary settlement occurs after consolidation settlement is complete and may contribute significantly to the total settlement in highly organic soils due to soil creep. For further details reference should be made to the appropriate foundation design text book or design guide.

Uplift Resistance

Various design methods for determining the uplift resistance of spread foundations have been developed using a variety of techniques combined with load tests on reduced or full scale models. The parameters considered are the weight of the foundation, the weight of the soil contained within the assumed failure surface extending from the base of the foundation or the shear strength mobilized along the failure or slip surface. The failure surface has been assumed to vary from vertical planes to frusta and to various curved surfaces. A typical free-body diagram for a spread foundation in uplift, applicable to concrete pad, pyramid, block or steel grillage foundations is shown in Figure 13.29b.

A review of various methods of determining the uplift resistance is given in Table 13.6 together with the resisting forces and failure surface considered. Provided that the true leg slope is less than 1*H*: 5 *V* it is normally satisfactory only to consider the vertical component of the leg load in uplift. For further details on the effect of inclined loads on the uplift resistance, reference should be made to Cigré Electra No 219 (Cigré 2005a).

The effect of the horizontal shear component of the applied loading (*H*) is usually ignored in the calculation of the uplift resistance and none of the methods listed in Table 13.6 take account of the horizontal shear component.

For further details regarding the various methods summarised in Table 13.6, reference should be made to Section 3 of Cigré TB 206. However, due caution should be excised in applying any of these methods, since the majority have only been checked against a relative small number of full-scale foundation tests, often all of a similar

Table 13.6 Methods of Determining Uplift Resistance for Spread Footings

Author or Method	Resisting forces			Assumed failure surface	Ultimate or working resistance	Comments
	P	P_1 & P_2	T			
Biarez & Barraud [1968†]	Y	Y	Y	Along inclined plane from base of foundation	Ultimate	Dependant upon soil type and depth of foundation
Cauzillo [1973†]	Y	Y	Y	Logarithmic spiral	Ultimate	Dependant upon soil type and shape of foundation base
Flucker & Teng [1965†]	Y	Y	N/A	Along edge of frustum	Ultimate	Frustum angle dependant upon soil properties
Killer [1953†]	Y	Y	Y	Along vertical plane from base of foundation to G.L.	Ultimate	Shear resistance dependant upon soil type
Meyerhorf & Adams [1968†]	Y	Y	Y	Along vertical plane from base of foundation	Ultimate	Dependent upon soil type and depth of foundation
Mors [1964†]	Y	Y	Y	A simplified logarithmic spiral	Ultimate	Frustum based method
Vanner [1967†]	Y	Y	Y	Complex frustum	Ultimate	Resistance dependent upon Base to Depth ratio
VDE 0210 [1985†]	Y	Y	N/A	Not quoted	Working	Frustum based method

size. As previously, stated the only reasonably reliable method is to undertake the calibration of the theoretical geotechnical design model against full-scale test data for the appropriate ground conditions and relative size of the proposed foundations, noting that both scale effects and backfill density will have a significant affect.

The density of the backfill has a major influence on the performance of foundations constructed using formwork. The interaction between the in-situ soil density, backfill density and the foundation depth to width ratio (*D*/*B*) and their effect on the uplift resistance was reviewed by Kulhawy et al. [1985]. Based on a series of laboratory model tests which attempted to reproduce the effects of the foundation installation method, Kulhawy proposed the following qualitative trends in uplift capacity:

- Increase in Backfill density ~ increase in uplift resistance (dense in-situ soil and $D/B = 3$);
- Increase in in-situ soil density ~ moderate increase (dense backfill and ($D/B = 3$);
- Increase in D/B ~ substantial increase (dense in-situ soil and backfill).

Seasonal variations in the water level and the affect on the geotechnical parameters should be taken into consideration when calculating the uplift resistance, especially if the site investigation is undertaken at the end of the “dry” season.

13.5.3.3 Drilled Shaft Foundations

General

This sub-section considers the determination of the compression, uplift and lateral resistance of drilled shaft separate foundations, together with the moment resistance of drilled shaft compact foundations.

For drilled shaft separate foundations the geotechnical design has been divided into three principal load components: compression, uplift and horizontal shear, although obviously the shear loads acts concurrently with the other two design loads, The method of load super-position where each load design loads are considered separately was justified by Downs and Chieurrzi (1966*) for a ratio of lateral to uplift load of 1:10, based on an extensive series of full-scale foundation load tests. The ACI “Report on drilled Piers” (1993*) also permits this approach.

Compression Resistance

The ultimate resistance of a drilled shaft is composed of two components: base resistance (end bearing) and the skin resistance (skin friction) developed by the shaft. A typical free body diagram for a drilled shaft under compression loading is shown in Figure 13.30a.

Since the two resisting components are not fully mobilized at the same time, which is particularly true for cohesive soils, the skin friction reaching its ultimate value prior to the base resistance, it is necessary to consider:

- The ultimate skin friction in conjunction with end bearing at the transition point from ultimate to limit skin friction, or
- Residual skin friction and the ultimate end bearing.

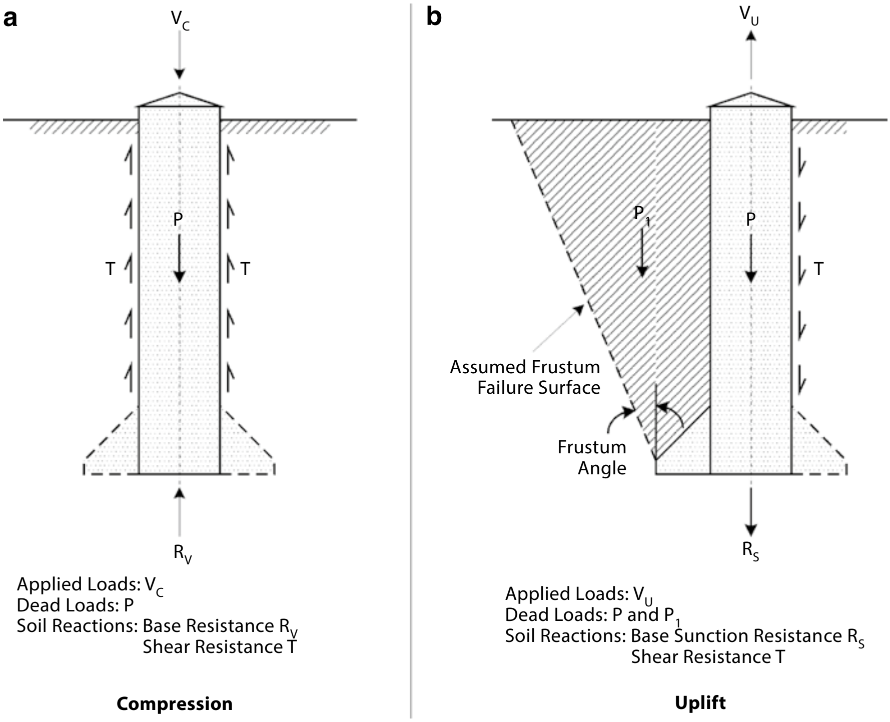


Figure 13.30 Free body diagram – Drilled shaft foundation (Separate).

For further details regarding the load distribution under compressive loadings, reference should be made to Section 3 of Cigré TB 206.

The end bearing resistance can be determined using any of the classical bearing-capacity equations developed by Terzaghi (1943*), Meyerhof (1951*, 1963*) and Hansen (1970*).

The shaft resistance can be determined using the "Alpha" method (Tomlinson 1971*), or the "Beta" method (Burland 1973*). In the "Alpha" method for cohesive soils the ultimate skin friction is related by an empirical correlation to the undrained shear strength of the soil; whereas, for non cohesive soils it is a function of both the effective vertical stress and the angle of friction between the shaft and the soil. The "Beta" method does not differentiate between soil types and the ultimate skin friction is a function of both the effective overburden pressure and the angle of friction between the shaft and the soil.

Where drilled shaft foundations are installed in rock, reference should be made to Horvath (1978*) and Benmokrane (1994*). For further details regarding the effective length of the shaft, reference should again be made to Section 3 of Cigré TB 206.

Uplift Resistance

There are no generally agreed methods for determining the ultimate uplift resistance of drilled shaft foundations, due to the difficulty of predicting the geometry of the failure surface. This point is further complicated depending on whether the shaft is straight or under-reamed. A typical free body diagram for a drilled shaft foundation is shown in Figure 13.30b.

A review of the various methods used for determining the uplift resistance of drilled shaft foundations is given in Table 13.7.

A summary of the key aspects of the different design methods outlined in Table 13.7 is given below and for further details reference should be made to Section 3 of Cigré TB 206.

- Adams and Radhakrishna, model is based on laboratory and full-scale uplift load tests. For straight shafts in uplift (non cohesive soil) an expression based on the horizontal earth pressure was developed, with the uplift coefficient K_u related to D/B (depth/diameter) ratio. However, for deep belled shafts an alternative solution based on a method previously developed for spread footings was considered. A cylindrical shear "Alpha" model was developed for straight shafts (cohesive soils); whereas, for belled shafts a bearing capacity theory was developed.
- CUFAD considers the uplift resistance to include the weight of the foundation, tip suction and the side shear resistance. For deep drilled shafts (D/B > 6), the side resistance is based on the cylindrical shear model; whereas, for shallow shafts the potential for a cone breakout is also considered in addition to the cylindrical shear.
- Downs and Chieurrzi proposed two different uplift models based on an extensive series of full-scale uplift load tests. For straight shafts, in any type of soil, a cylindrical shear model was proposed. While for belled shafts in non-cohesive soil a model based on the weight of the soil contained in a frustum radiating from the base of the bell was proposed; with the frustum angle equal to the internal angle of friction of the soil.

Table 13.7 Methods for determining the uplift resistance of drilled shaft foundations

Author or Method	Shaft type	Soil type	Resisting forces			Assumed Failure Surface
			P	P_1	T	
Adams & Radhakrishna [1975†]	Straight	Non Cohesive	Y	N/A	Y	Cylindrical
	Belled		Y	Y	Y	Frustum
	Straight	Cohesive	Y	N/A	Y	Cylindrical
	Belled		Y	N/A	Y	Cylindrical
CUFAD [1989†]	Straight	Any	Y	N/A	Y	Cylindrical
	Belled		Y	N/A	Y	Cylindrical
Downs & Chieurrzi [1966†]	Straight	Any	Y	N/A	Y	Cylindrical
	Belled	Non cohesive	Y	Y	N/A	Frustum
Williams [1994†]	Straight	Cohesive	Y	N/A	Y	Cylindrical
VDE 0210 [1985†]	Belled	Any	Y	Y	N/A	Frustum

- The investigations undertaken by Williams et al. into the uplift capacity of straight shafts was a direct consequence of the failure of five 275 kV towers/foundations under high wind loadings. Both analytical and studies using cylindrical shear models (Alpha and Beta) and full-scale foundation load tests were undertaken to estimate the load transfer along the shaft under uplift loading. The results of the study indicated that the Beta method gave the best correlation with the test results.
- The method given in VDE 0210 for belled shafts is based on the frustum method and different values are ascribed to the frustum angle dependent upon the soil type, and D/B ratio.

Lateral Resistance

For details regarding the lateral resistance of drilled shafts, reference should be made to the Section 3.5 of Cigré TB 206.

Moment Resistance

Drilled shafts used as compact foundations are similar to those described for separate foundations, except that they are always installed vertically and are predominately loaded by high overturning moments.

The applied moment loading is resisted primarily by the lateral resistance of the soil, in conjunction with the vertical side shear resistance, a base axial and shear resistance, and a typical free body diagram is shown in Figure 13.31.

The geotechnical design of the foundation should take account of the orientation of the applied loading and should be designed to prevent excessive deflection and rotation, and shear failure of the soil.

Initially, the determination of the geotechnical capacity of the drilled shaft under high moment loading was based on the work undertaken by Broms (1964*), Hansen (1961*) and Reese (1956*) for long flexible piles with high lateral shears but small overturning moments. For both piles and drilled shafts the principal resistance to the applied load is provided by the lateral resistance of the soil. However, for drilled shafts additional resistance is also provided by the vertical side shear, base shear and base axial resistance.

A comparison between the various methods of determining the ultimate geotechnical capacity of drilled shaft foundations subject to high overturning moments was present in Electra 149 (Cigré 1993). The three basis models considered were:

- MFAD (Moment Foundation Analysis and Design) a four-spring nonlinear subgrade modulus model, developed in the USA for EPRI by GAI Consultants Inc;
- EdF's model which is similar in concept to MFAD, except that it incorporates the results from pressure meter tests for the determination of both the ultimate capacity and displacements;
- Dembicki and Odrobinski's (D&O) model which is based on a limit equilibrium solution.

In addition, to these design models, a comparison with three general purpose pile design models previously referred to, i.e., Broms, Hansen and Reese was also made.

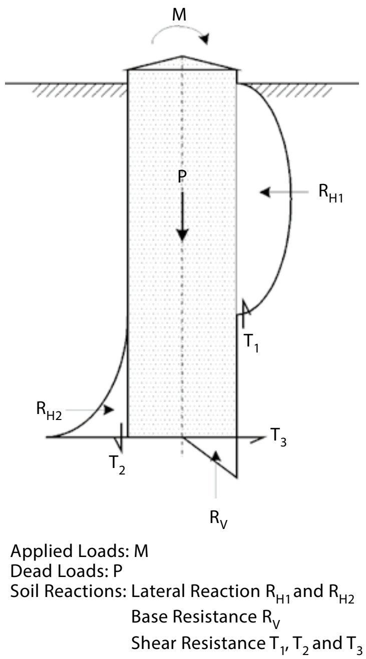


Figure 13.31 Free body diagram – Drilled shaft foundation (Compact).

Both MFAD and the EdF design models take into consideration all the resisting forces shown in the free body diagram; whereas, D&O, Broms, Hansen and Reese's models ignore the effects of the base shear (T_3) and the base axial resistance (R_V).

All of the design models were compared against the results of 14 well documented full-scale drilled shaft load tests. The results indicated that all of the general purpose models under predicted the ultimate moment capacity when compared to the 2 degree rotation measured moment capacity. MFAD slightly over predicted the capacity, whereas both the EdF and D&O model both under predicted the capacity.

For further details regarding the application of MFAD for the design of drilled shafts socketed into rock, reference should be made to Section 4 of Cigré TB 206.

13.5.3.4 Ground Anchors and Micropiles

Ground Anchors

Ground anchor foundations can either comprise an individual anchor for guy (stay) foundations or a group of anchors connected at or just below ground level by a reinforced cap, i.e., an anchor foundation. Ground anchors are normally designed to resist only axial tensile forces; whereby the ground anchor transfers the applied loading via the tendon into the surrounding rock or soil by interfacial friction. The interfacial friction in soil may be considerable and can be increased by high pressure grouting.

The steel tendon can be high tensile grade steel ribbed reinforcement or thread bar. Corrosion resistance can be either a single protection system relying on the grout thickness, possibly in conjunction with a stainless steel tendon or using a

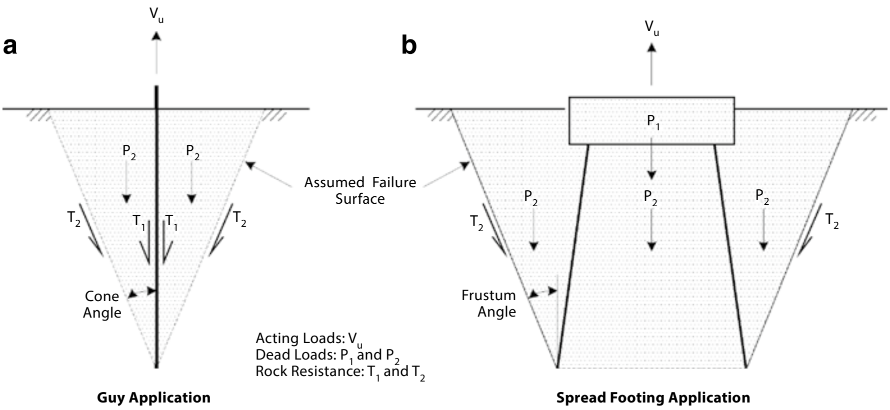


Figure 13.32 Free body diagram – Ground anchor (uplift).

double protection system; where the manufacturer pre-grouts the tendon within a ribbed plastic sheath prior to installation. Although ground anchors may be active where the tendon is prestressed prior to the application of the load, normal OHL practice is to use passive anchors where no prestressing is applied.

A free body diagram for an individual ground anchor used as a guy foundation is shown in Figure 13.32a, while Figure 13.32b shows a group of ground anchors utilized in a spread footing application.

For ground anchors in the rock, the ultimate uplift resistance is determined by the lesser of the strength of the following materials and critical interfaces:

- Rock mass;
- Grout – rock bond;
- Grout – tendon bond;
- Tensile strength of the tendon or connection;
- Free and fixed tendon length.

With respect to the strength of the rock mass, the resistance is assumed to be provided by the dead weight of a cone of rock, delineated by a failure surface inclined at the “frustum” angle from a defined point on the fixed length of the tendon. The defined point may vary from the midpoint of the fixed tendon length to the bottom of the tendon, depending on the tendon end condition, e.g., fitted with a plate at the bottom of the tendon. Additional resistance can be provided by the shear resistance within the rock acting on the perimeter of the assumed failure surface. Rock masses are rarely monolithic but are discontinuous due to the presence of bedding joints, faults and other structural features which give the rock mass a blocky structure. Consequentially, the engineering properties of the rock mass are function of the intact rock material and the geometry, nature and condition of the discontinuities in the rock. This block structure will have a marked influence on both the frustum angle and shear resistance developed by the rock. Correspondingly, a “rock mass quality” classification system is used to describe the rock mass and hence determine its engineering properties. For further information on the rock mass quality, reference should be made to Hoek (1983), Bieniawski (1989), Wylie (1999), and ISO 14689 (BSI 2003).

Similar materials and critical interface strengths apply to ground anchors in soil except that the soil mass is usually not a critical parameter. The intensity of the grout pressure and hence the depth of penetration into the soil will have a marked influence on the effective anchor diameter for the determination of the uplift capacity.

Horizontal shears can be resisted by inclining (raking) the ground anchors such that the lateral forces are resisted by the horizontal component of the axial capacity, by dowel action in the rock (vertical anchors) or by the lateral resistance provided by the cap.

Ismael et al. (1979*) based on the full-scale load tests on passive ground anchors in rock, considered the failure mechanism for both individual anchors and group anchors in relation to the ultimate resistance. For single anchors the uplift resistance was based on the weight of the rock cone radiating from the bottom of the anchor plus the shear resistance on the conical surface, while for group anchors a frustum was considered projecting from the perimeter bars. The frustum angle and minimum embedment being dependent upon the rock type and/or quality. Further research correlated the ultimate rock – grout bond to the unconfined compressive strength of the rock or grout, while the tendon – grout bond was related to a function of the square root of the unconfined compressive strength of the grout.

A similar mechanism was assumed by Vanner et al. (1986*) for passive anchors installed in hard soil. The results of full-scale load tests indicated that there was no deterioration in the anchor resistance when subjected to 100 cycles at a level equal to 50 % of the ultimate resistance. Further tests confirmed this result when the anchor was subjected to 300 cycles equivalent to 78 % of the yield stress of the tendon.

Littlejohn and Bruce (1977*) published an extensive state of the art review of the design, construction, stressing and testing of both active and passive ground anchors in both rock and soil. Subsequently, this formed the basis of BS 8081 (1989*) which contains extensive details of all aspects of ground anchor design, installation, testing and corrosion protection.

Micropiles

Micropiles are normally only used in a group, similar to that described for anchor foundations. Micropiles transfer the applied load from the steel reinforcement to the surrounding rock/soil by interfacial friction with minimal end bearing and are capable of resiting both axial loading (tension and compression) plus lateral loads. For the latter this may be achieved by raking the micropile, by lateral resistance of the surrounding soil and rock for vertical micropiles or by the resistance developed by the cap. Grouting of the micropiles may vary from a single stage operation under gravity to multiple stage post-grouting under pressure. The intensity of the grouting pressure will have a marked influence on the effective diameter of the micropile and hence its load carrying capacity.

The steel reinforcement normal comprises a central tendon plus a reinforcement cage for bending resistance or alternatively the cage may be replaced by a circular hollow steel section.

Although normally micropiles are constructed using a drilled or bored cast in-situ system, micropiles can also be constructed using driven precast reinforced concrete sections using a mechanical jointing system or bottom driven small diameter circular steel sections which are subsequently filled with reinforced concrete or grout. Where micropiles are designed to be socketed in the rock a permanent sacrificial casing system is frequently used if the micropile passes through weak overburden material.

The uplift resistance of micropiles including the global resistance of the group may be determined using similar procedure as those described for ground anchors., while for compressive resistance the “Alpha” method (reference Section 13.5.3.3) can be used. The lateral resistance for vertical anchors in soil can be determined using similar procedures described for piles in Section 3.5 of Cigré TB 206. For further information on the design principles, geotechnical site characterisation, determination of the design capacity and installation requirements, reference should be made to Cigré TB 281 (Cigré 2005b).

13.5.3.5 Foundation Structural Design

The structural design e.g., reinforced concrete, etc., of the foundation is not covered in this overview and reference should be made to the appropriate national standard or code of practice; noting that due care needs to be taken as to whether the standard or code of practice is in ultimate limit state or allowable (working) load format.

The design of the interconnection between the support and the foundations will depend on the proposed method of connection, i.e., stubs and cleats/shear connectors, anchor (holding down) bolts or direct embedment of the lower section of the support. A review of International practice with regards to the design of stubs and cleats for lattice towers with separate foundations is contained in Cigré Electra paper No 131 (Cigré 1990), together with recommendations of “Good Practice” especially regarding the distribution of the load between stub and cleats. Recommendations and/or requirements regarding the design of anchor bolts, stub/cleats, etc. are usually given in the majority of national standards or codes of practice.

13.5.4 Interaction with Installation Process

This sub-section considers how the foundation installation activities can have an adverse effect on the foundation design, taking into consideration not only changes in the actual geotechnical conditions, but also errors or mistakes during the actual foundation installation.

For the various types of foundations considered, the site activities that normally affect the foundations are:

- Failure to recognise changes in the geotechnical conditions;
- Inappropriate installation techniques;
- Variations in foundation dimensions;
- Inappropriate concreting or grouting methods;
- Inappropriate backfilling techniques.

Since the effect will vary depending on the foundation type, three typical foundation types have been considered, i.e., separate (concrete pad/pyramid and chimney), separate/compact (drilled shafts) and anchor (micropiles and ground anchors). For further information regarding the effects on the different foundation types included in Section 13.3, reference should be made to Sections 3 and 4 of Cigré TB 206, and Section 2 of Cigré TB 308.

13.5.4.1 Concrete Pad/Pyramid and Chimney

To illustrate how the foundation installation activities interact with the foundation design process a composite concrete pad/pyramid and chimney foundation is shown in Figure 13.33, while Figure 13.34 illustrates a typical adverse effect.

Detailed in Table 13.8 are the relevant construction activities and the affect they have on the overall foundation design:

Figure 13.34 Separate foundations incorrect concrete mix design and curing (Key 8).

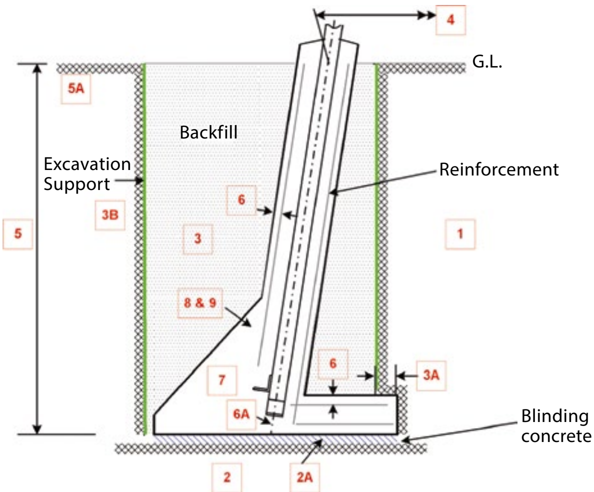


Figure 13.33 Spread foundations – interaction diagram (Numbers in red refer to Table 13.8).

Table 13.8 Interaction installation activities and foundation design – Spread footings

Key	Parameter	Possible changes during installation activities	Adverse effect on foundation design
1	Soil/rock properties and/or ground water level	Actual soil/rock properties or ground water level encountered during foundation excavation differs from design assumptions.	Changes in foundation geotechnical design may affect foundation design strength and/or long term durability.
2	Soil/rock beneath base of foundation	Failure to remove 'soft spots' below setting level of foundation or premature removal of bottom layer of cohesive soil prior to placing blinding concrete.	Possible reduction in foundation design bearing pressure and/or the cause of differential settlement of adjacent footings.
2A	Blinding concrete	Failure to place blinding concrete.	In cohesive soils possible reduction in bearing capacity due to softening of the soil. In soils with high concentration of sulfates or chlorides, reduction in the long term durability.
3	Backfill	Backfill bulk density lower than assumed in design calculations.	Reduction in foundation design uplift strength. Reduction in foundation design lateral resistance to shear loads.
3A	Undercut	No undercut or reduced undercut.	Reduction in foundation design uplift strength.
3B	Excavation support	Failure to remove excavation support.	Change in design basis for foundation uplift resistance.
4	Stub setting	Incorrect stub setting dimensions or stub alignment.	Increase in foundation loading.
5	Foundation dimensions	Foundation dimensions smaller than design values.	Reduction in foundation design strength.
5A	Ground profile	Changes in ground profile adjacent to foundation	Reduction in foundation design uplift and shear strength.
6	Reinforcement cover	Reinforcement cover less than specified.	Reduction in foundation design strength and/or long term durability.
6A	Stub cover	Stub cover less than specified.	
7	Construction joint	Inadequate construction joint.	
8	Concrete strength, workability & compaction	Reduced concrete strength and/or poor workability – insufficient compaction.	
9	Concrete curing	Inappropriate concrete curing.	

Note: Foundation design strength reference in Tables 13.8, 13.9 and 13.10, refers to both the geotechnical and/or the structural capacity of the foundation.

For further details reference should be made to Section 2.2.1 of Cigré TB 308.

13.5.4.2 Drilled Shaft Foundations

To illustrate how the foundation installation activities interact with the foundation design process a composite drilled shaft (with and without an under-ream) is shown in Figure 13.35, while Figure 13.36 illustrates a typical adverse effect.

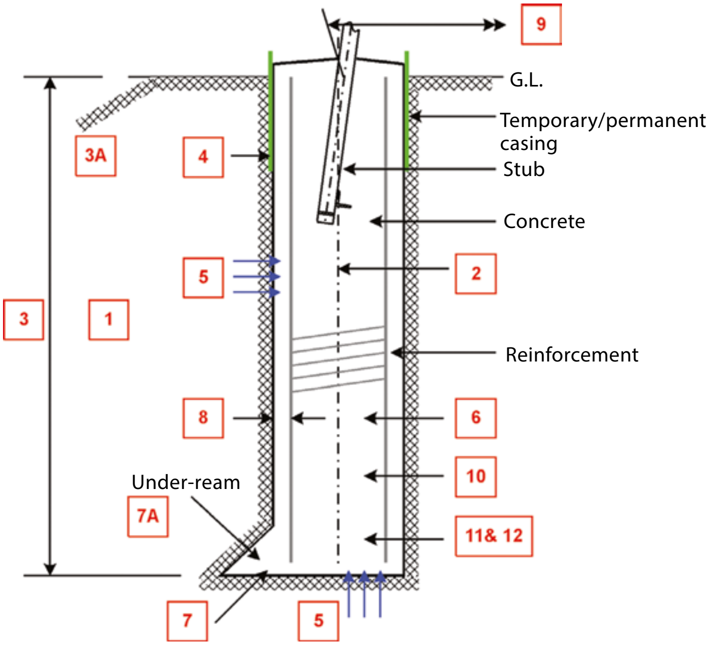


Figure 13.35 Drilled shaft foundation – interaction diagram (Numbers in red refer to Table 13.9).

Figure 13.36 Drilled shaft foundations failure to adequately remove all of excavation material during concrete placing (Key 7 & 10).

Detailed in Table 13.9 are the relevant construction activities and the affect they have on the overall foundation design:

13.5.4.3 Micropiles and Ground Anchors

Since there are a variety of different types of micropiles and ground anchors and corresponding installation techniques, the parameters identified in Figure 13.37 and described in Table 13.10, have been generalised and may not be applicable to a specific type and/or method of installation.

Table 13.9 Interaction installation activities and foundation design – drilled shafts

Key	Parameter	Possible changes during installation activities	Adverse effect on foundation design
1	Soil/rock properties and/or ground water level	Actual soil/rock properties or ground water level encountered during foundation excavation differs from design assumptions.	Change in foundation geotechnical design may affect foundation design strength and/or long term durability.
2	Alignment of shaft	Misalignment of shaft.	Possibly increase in foundation loading and/or reduction in strength.
3	Foundation dimensions	Incorrect depth and/or diameter, under-ream and/or insufficient penetration into bearing stratum.	Reduction in foundation design strength.
3A	Ground profile	Changes in ground profile adjacent to foundation	Reduction in foundation design strength.
4	Temporary/permanent casings	Incorrect installation techniques with respect to temporary and/or permanent casing. Incorrect length of permanent casing.	Reduction in foundation design strength and/or long term durability.
5	Ground water penetration	Incorrect installation techniques with respect to the control of ground water penetration causing shaft instability, reduction in c.s.a. or contaminated concrete.	Reduction in foundation design strength or long term durability.
6	Stabilizing fluids or drilling muds	Incorrect installation techniques with respect to the use of stabilizing fluids or drilling muds, causing shaft instability, reduction in c.s.a. or contaminated concrete.	Reduction in foundation design strength and/or long term durability.
7	Base cleaning or forming	Failure to remove loose or disturbed soil from shaft base causing inadequate bearing material or contaminated concrete.	Reduction in foundation design strength or long term durability.
7A	Under-ream	Incorrect dimensions and/or partial collapse of under-ream.	Reduction in foundation design strength or long term durability.
8	Reinforcement alignment and/or cover	Misalignment of reinforcement and/or reinforcement cover less than specified.	Reduction in foundation design strength or long term durability.

(continued)

Table 13.9 (continued)

Key	Parameter	Possible changes during installation activities	Adverse effect on foundation design
9	Stub setting	Incorrect stub setting or alignment.	Increase in foundation loading.
10	Concrete placing	Inappropriate concreting techniques causing concrete to segregate, concrete contamination, voids, etc. Delays in placing concrete after completion of excavation, failure to check actual against theoretical concrete volumes.	Reduction in foundation design strength and/or long term durability.
11	Concrete strength and/or workability	Reduced concrete strength and/or poor workability.	
12	Concrete curing	Inappropriate concrete curing techniques.	Reduction in long term durability.

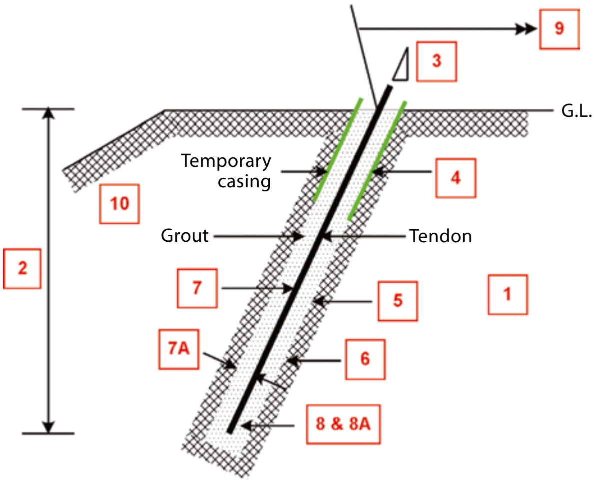


Figure 13.37 Micropiles and ground anchors – interaction diagram (Numbers in red refer to Table 13.10).

13.5.5 Calibration of Theoretical Foundation Design Model

As previously mentioned, the only reasonably reliable method of deriving the ultimate uplift resistance, of the majority foundation types, is to undertake the calibration of the theoretical design model against full-scale test data for the appropriate ground conditions and physical size of the proposed foundation. Correspondingly, this subsection provides a brief overview of the theoretical basis for determining the probabilistic foundation strength reduction factor (ϕ_F), which adjusts the predicted foundation nominal (characteristic) strength (R_n) to the eth percent exclusion limit strength (R_e).

The relationship between the eth percent exclusion limit strength and the mean strength (R) is given by the relationship:

Table 13.10 Interaction installation activities and foundation design – micropile & ground anchors

Key	Parameter	Possible changes during installation activities	Adverse effect on foundation design
1	Soil/rock properties and/or ground water level	Actual soil/rock properties or ground water level encountered during foundation excavation differs from design assumptions.	Change in foundation geotechnical design may affect foundation design strength and/or long term durability.
2	Micropile/ground anchor dimensions	Incorrect depth and/or diameter and/or insufficient penetration into bearing stratum.	Reduction in micropile/ ground anchor design strength.
3	Alignment	Misalignment of micropile/ground anchor.	Possibly increase in foundation design loading and/or reduction in foundation design strength.
4	Temporary/permanent casings	Incorrect installation techniques with respect to temporary and/or permanent casing. Incorrect length of permanent casing.	Reduction in micropile/ ground anchor design strength and/or long term durability.
5	Drilling and hole stabilisation	Inappropriate drilling techniques, hole collapse.	Reduction in micropile/ ground anchor design strength and/or long term durability.
6	Hole flushing	Inappropriate hole flushing techniques, failure to remove all soil/ rock particles.	
7	Tendon placement (homing)	Inappropriate tendon handling technique, causing damage to tendon.	
7A	Tendon alignment and/or cover	Misalignment of tendon and/or cover less than specified.	
8	Grout strength and/or workability	Reduced grout strength and/or poor workability.	
8A	Grouting	Delay between hole drilling and/or incorrect grouting techniques.	
9	Foundation setting	Incorrect micropile/ ground anchor setting.	Increased foundation loading.
10	Ground profile	Changes in ground profile adjacent to foundation.	Reduction in foundation design strength.

$$R_e = R(1\text{-}k.V_r) \tag{13.1}$$

where k is a factor depending on the exclusion limit strength adopted and the type of probability density function (i.e., normal or log-normal) and V_r is the coefficient of variation of strength for the foundation design model used. The exclusion limit strength, R_e, corresponds to a defined exclusion limit (5% or 10%), depending on the design code requirements.

Figure 13.38 presents a schematic representation of a probability density function fitted to the strength data derived from full-scale uplift tests on a specific type of foundation. The terms R_{Test} and R_n are the test measured capacity of the foundation and the nominal strength of the foundation predicted by the selected design model, respectively. The predicted nominal ultimate strength (R_n) is based on the selected design model, the subsurface geotechnical parameters and the foundation parameters at each test site.

If the average value of the ratio of R_{Test}/R_n is denoted by m, then the expected (mean value) of R of the nominal ultimate foundation strength can be estimated as:

$$R = R_n\, m \tag{13.2}$$

Substituting Equation 13.2 into Equation 13.1 gives:

$$R_e = R_n\, m\, (1\text{-}k\ V_r) \tag{13.3}$$

In addition, assuming that V_m (the coefficient of variation of m) is a good measure of V_r, then Equation 13.3 becomes:

$$R_e = R_n\, m\, (1\text{-}k\ V_m) \tag{13.4}$$

For ease of use, Equation 13.4 can be simplified as follows:

$$R_e = R_n\, m\, (1\text{-}k\ V_m) = \varphi_F\ R_n \tag{13.5}$$

$$\text{where } \varphi_F = m(1\text{-}k\ V_m) \tag{13.6}$$

The factor φ_F has been previously defined in this chapter as the probabilistic foundation strength reduction factor which adjusts the predicted nominal (characteristic) strength (R_n) to the e[th] percent exclusion limit strength (R_e).

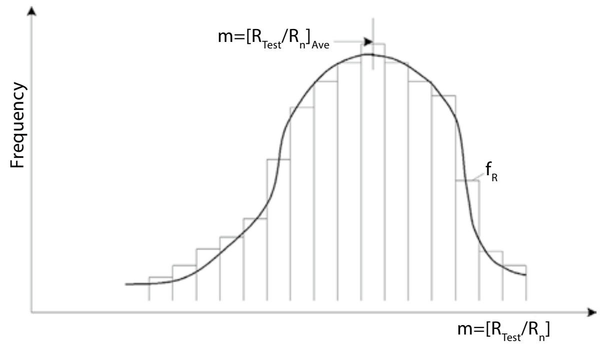


Figure 13.38 Probability density function for foundation strength test data.

For further details on the determination of the eth percent exclusion limit strength and the calibration of the foundation design model reference should be made Section 5 of Cigré TB 206 and Cigré TB 363 (Cigré 2008).

13.5.6 Foundation Selection

If a "standard" plus site specific foundation design approach has been adopted, as outlined in Section 13.5.1, it will be necessary to decide at which support sites the "standard" foundation can be used and those sites which require a site specific design; noting that it may be possible to reuse an existing "standard" foundation design for site specific conditions.

In the selection process, the following factors should be taken into consideration:

- Support type, partial applied load factor and partial foundation strength factors or equivalent deterministic factors;
- Results of the site investigation, e.g., soil/rock type and thickness, ground water level, aggressiveness of the ground and ground water, etc;
- Whether there are long-term or short term (during the foundation installation) ground instability issues at the support site, e.g., slope, peat slides, etc;
- The range of "standard" foundation types available;
- The temporary works requirements in respect of foundation installation;
- The H&S, environmental, resource and project constraints.

To assist in the foundation selection, it is recommended that a foundation selection summary schedule is prepared. Typically the foundation selection summary schedule would contain the following information:

- Support number, support type together with details of any extension (body and leg);
- Partial applied load factor and partial foundation strength factors or equivalent deterministic factors;
- Brief soil description, in-situ test results and depth to ground water level, together with details of the aggressiveness of the soil and ground water;
- Concrete mix type or designation;
- Proposed foundation type and associated cross-references to the foundation design booklet, GA drawing, bar bending schedule, stub drawing, foundation setting level diagram and foundation data sheet;
- Details of any potential geotechnical hazards at or adjacent to the support foundation, e.g., flood and slope stability risks;
- Any comments regarding the foundation selection, together with details of the client's acceptance, if appropriate.

In addition to the foundation selection summary schedule, a foundation data sheet (see Figure 13.39) should also be prepared for each support site.

However, it should be noted the foundation selection should not be regarded as final, since it may be necessary to change the foundation design as a consequence of the on-going geotechnical evaluation during the foundation

Tower No	AB109	Tower type	D E9	Deviation	0° 00' 0"

Setting Details		
Tower Offset	Zero m	
Tower Setting Level	429.51 m A.O.D.	
Ground Level at Tower Centre Peg	428.74 m A.O.D.	
Tower Leg/Stub Hip Slope	13.0 / 100	7.41 Degrees

Leg	A	B	C	D
Foundation and Leg Details				
Foundation Type	P&C Class 1 Uplift/Comp	P&C Class 1 Uplift/Comp	P&C Class 1 Uplift/Comp	P&C Class 1 Uplift/Comp
Tower Leg Extension	0 m	2 m	1 m	-1 m
Concrete column extension	0,00	0,40	0,70	0,50
Foundation GA Drawing Number	A1/xx/8000	A1/xx/8000	A1/xx/8000	A1/xx/8000
Bar Bending Schedule	A4/xx/8001	A4/xx/8001	A4/xx/8001	A4/xx/8001
Concrete Mix	FND 3	FND 3	FND 3	FND 3
Minimum Backfill Density (kg/m^3)	2000	2000	2000	2000
Excavation Details				
Ctr Peg to Excavation Ctr (horz)	7500	7830	7730	7430
Foundation Base Size	6400	6400	6400	6400
Nominal Depth	4800	4800	4800	4800
Btm Exc below Centre Peg	4030	6430	5730	3530
Stub & Cleat Details				
Stub Mark No.	WX4000	WX4000	WX4000	WX4000
Requirement to Cut Stub (Y/N)	N	N	N	N
Stub True Length to be Installed	3200	3200	3200	3200
Cleat Mark No.	WX4002	WX4002	WX4002	WX4002
Number of Cleats	6	6	6	6
Single or Paired (S/P)	S	S	S	S
Stub Setting Details				
ToS above Tower Setting Level (m)	1,142	-0,858	0,142	2,142
ToS above GL at Tower Centre Peg (m)	1,912	-0,088	0,912	2,912
Centre Peg to ToS (Horiz)	6753	7031	6892	6614

Face	AB	BC	CD	DA	AC	BD
Back to Back Dimensions at ToS (Horiz)	9746	9844	9550	9542	13645	13645

General Notes:
All Dimesnions in Millimetres unless otherwise noted
Estimated Rock head Level 5 m (Leg B)
Expected Water Strike at 3 m

Figure 13.39 Foundation data sheet.

installation or as a result of changes in the resources or programme requirements, etc.

13.5.7 New Developments

The majority of the methods for determining the uplift resistance of spread footings shown in Table 13.6, were developed in the 1960s and later research in the USA was then concentrated on the behaviour of drilled shaft foundations under axial or moment loadings (Table 13.7). However, with the ongoing need to upgrade existing OHLs and hence the need to ascertain the actual geotechnical resistance of existing foundations there has been a renewed interest in this design aspect, especially by the UK's National Grid (NG).

In addition to the need to uprate the transmission system, NG was faced with the contradictory evidence of a satisfactory service life history of the installed towers/ foundations and the poor performance of the existing conventional concrete spread pyramid/pad and chimney foundations (cast in formwork within supported excavations) when subjected to maintained static load tests (IEC 61773) compared to their theoretical design resistance. In addition, there has also been a change in the design basis from a statutory deterministic basis to an RBD based approach.

As a consequence of this conflicting evidence NG has commissioned the following research, with the aim of developing an improved method of the determining the uplift resistance of conventional spread foundations:

13.5.7.1 Wind Loading

The initial research undertaken was to investigate the transfer of the wind loading on the conductors, through the tower to the foundations. The monitoring programme was undertaken on a fully instrumented 400 kV lattice steel suspension tower between 1995 and 1999. The results of the investigation indicated that there was a marked difference between the measured leg strains in the main tower leg (immediately above the foundation), when the wind gust was predominately on the conductors, and the theoretical wind loading, calculated using the EN50341-3-9 (BSI 2001b). The difference ranging from 12 percent to 49 percent reduction (measured to theoretical) with an average variation of 42 percent, depending on the wind incidence angle.

13.5.7.2 Broken Wire Tests

A series of broken wire tests were undertaken on a redundant section of a 400 kV twin phase conductor OHL to assess the rate and the pattern of load transfer to the foundations during the broken wire events. All of the towers concerned, both suspension and tension, were instrumented with strain gauges attached to the tower main legs and K-bracing members immediately above the concrete muffs. For further information on the tests undertaken, reference should be made to Clark et al. (2006).

13.5.7.3 Centrifuge Model Testing

As part of the overall foundation evaluation, a series of reduced scale model tests on shallow foundations subject to fast uplift rates were undertaken between 2001 and 2008. The tests were undertaken using both beam and drum geotechnical centrifuge modelling techniques (see Section 13.6.3 for further information on centrifuge modelling tests).

The model foundation bases were fabricated from Dural aluminium, with Kaolin and fine sand used to represent cohesive (clay) and non-cohesive (granular) soils respectively. Later tests were undertaken using models of typical UK separate pyramid and chimney foundations. All of the pull-out tests were performed at a centrifuge acceleration of 50 g and the foundations were loaded to failure at a constant displacement rate (V_f), which varied from 0.03 mm/s to 100 mm/s. Although, the majority of models were tested with vertical uplift loads, some of the models were tested with inclination values of 5°, 10° and 15° to the vertical, thereby representing typical transmission tower foundations.

The conclusions from the tests on individual footings were:

- The magnitude of the suction force generated across the foundation base can be considered to generally be proportional to the uplift rate (V_f);
- The increase in uplift capacity attributed to the suction force across the base of the foundations is greater for those bearing on clay;
- At uplift rates greater than 1 mm/s partial undrained behaviour of the soil leads to an increase in uplift resistance;
- At faster uplift rates (V_f greater than 3 mm/s), the peak uplift forces increases linearly with the proportion of the foundation base in contact with clay;
- That for load inclinations of up to 15° there is no significant reduction in the vertical uplift capacity; thereby confirming the results in Electra 219.

In addition to the individual foundation tests, tests were also undertaken on representative models of complete tower and foundations (individual spread footings) under simulated wind gust or broken wire events.

The conclusions of the tests on the complete tower-foundation models were:

- That the resistance to horizontal applied loading on the tower-foundation system is rate dependent, due to the potential for tensile resistance and reverse bearing capacity to be mobilised beneath the individual footings;
- The resistance to horizontal forces in fast tests exceeds the resistance in slow tests, due to the development of suction across the base of the footings subject to uplift;
- Individual footing performance can provide a useful basis for estimating the overall capacity of the tower-foundation system when the tower is subjected to horizontal loading.

For further details on both test series reference should be made to Rattley et al. (2008) and Richards et al. (2010).

13.5.7.4 Full-Scale Uplift Tests

During 2012 a series of full-scale foundation uplift tests were undertaken in clay to confirm the results of model testing. The results of the tests indicated that enhanced uplift resistance was achieved at increased uplift rates and that these were generally in excess of the nominal theoretical ultimate design capacity; thereby, confirming that base suction provides a significant additional contribution to the foundation's uplift capacity compared to that under static maintained loading.

For further details of the full-scale foundation load tests reference should be made to the forthcoming Cigré TB on "Dynamic Loading on Foundations".

13.5.8 Conclusions

This section has considered the design of the support foundations including system design considerations, the interaction with the foundation installation activities, the calibration of the theoretical foundation design model and the selection of the appropriate foundation type for the individual support sites, together with an outline of new developments in the determination of the uplift resistance of spread footings.

Two of the important issues identified are the full-scale testing of the foundations and the foundation installation, which are considered in the next two sections respectively.

13.6 Foundation Testing

13.6.1 General

The load testing of full-scale and model support foundations can be undertaken for a variety of reasons, i.e.:

(a) To verify design parameters and/or methodologies;
(b) To verify construction procedures;
(c) To determine geotechnical design parameters/methodologies for a specific application;
(d) To verify the compliance of a foundation design with contract specifications;
(e) To determine average failure load and coefficient of variation for the foundation, i.e., the probabilistic calibration of the foundation design for a specific soil/rock type;
(f) To verify that the installed foundation has been correctly installed and/or that there is no major variation in the assumed geotechnical design parameters.

Foundation tests undertaken in accordance with c) and d) are also known as type tests; while, those to f) are also known as proof or integrity tests.

Although testing of OHL support foundations have been undertaken since at least the early 1950s, there was no formalisation of the testing procedure until the preparation of the Special Report 81 (Cigré 1994), which was subsequently codified as IEC 61773 (IEC 1996). Similarly, the testing of individual piles, for non OHL foundations in the UK, has progressed from CP No 4 (ICE 1954), to the current "Specification for piling and embedded retaining walls" (SPERW) (ICE 2007). The latter document is also frequently used by UK piling contractors for the testing of individual piles and/or anchors for OHL foundations in preference to the IEC 61773, for both design and proof tests; especially the latter, since the IEC does not cover the integrity testing of piles.

In addition, it should also be noted that the current version of IEC 61773, does not cover the dynamic load testing of foundations, model testing or the rapid loading of the foundation to simulate short term events, e.g., wind gust loadings.

13.6.2 Full-Scale Testing

13.6.2.1 Design Tests

Design tests can be undertaken on: specially installed “test” foundations, which may be the complete foundation, e.g., concrete pad and chimney, on constitute parts, e.g., individual piles or ground anchors, or on existing foundations. If it is proposed to undertake any statistical evaluation of the test results and especially the probabilistic calibration of the foundation design, a minimum of two foundations, in similar ground conditions, must be tested.

Preferably, the design tests should be undertaken as part of the initial design activities, prior to installation of the project foundation; although, if there are unexpected major changes in the ground conditions, changes in the design basis and/or installation process, it may be necessary to undertake further design tests as the project progresses. The test sites selected should be representative of the lower boundary limits of the geotechnical design parameters; however, this may need to be balanced against site access and environmental constraints.

Details of the test arrangement, test foundation installation, test equipment, test procedure, test acceptance criteria, health and safety requirements, are given in SR81 and IEC 61773. As previously noted these documents are only applicable to the conventional static load testing and do not include dynamic testing or the simulation of short term rapid loading of foundations. Further information on the evaluation of the test results and the determination of the characteristic strength of the foundation, is given in SR81 and IEC 61773; while details of the calibration of the theoretical design model are given in Section 13.5.5.

The test arrangement for a full-scale design uplift test (categories d and e) on a 400 kV reinforced concrete pad and chimney foundation is shown in Figure 13.40, while Figure 13.41 shows the corresponding time-load-displacement plot for the same test foundation. Table 13.11 summarises the evaluation of the test results for three similar foundations tested at the same location. As part of the same series of project verification tests, full-scale load tests were also undertaken on complete rock anchor foundations; although, for this type of foundation, both axial leg loads and horizontal shear loads were applied, thereby ensuring the correct load distribution within the foundation. The corresponding test arrangement is shown in Figure 13.42.

Design tests can also be undertaken on existing foundations (test categories e and f), either with the support removed or with the support in-situ; the latter arrangement is used when it is necessary to keep the OHL fully operational during the testing. When the test is undertaken with the support in-situ and it is proposed to re-use the foundation after the test, it may be necessary to restrict the magnitude of the applied test loading, such that the foundation displacement is within specified limits; thereby, ensuring that the foundation – support can be re-connected at the end of the test. Figure 13.43 shows the full-scale uplift test on an existing foundation, with the support in-situ, such that the OHL could remain fully operational.

For further information regarding the testing of existing foundations, reference should be made to Cigré TB141.

Figure 13.40 Full-scale uplift test arrangement for P&C concrete foundation.

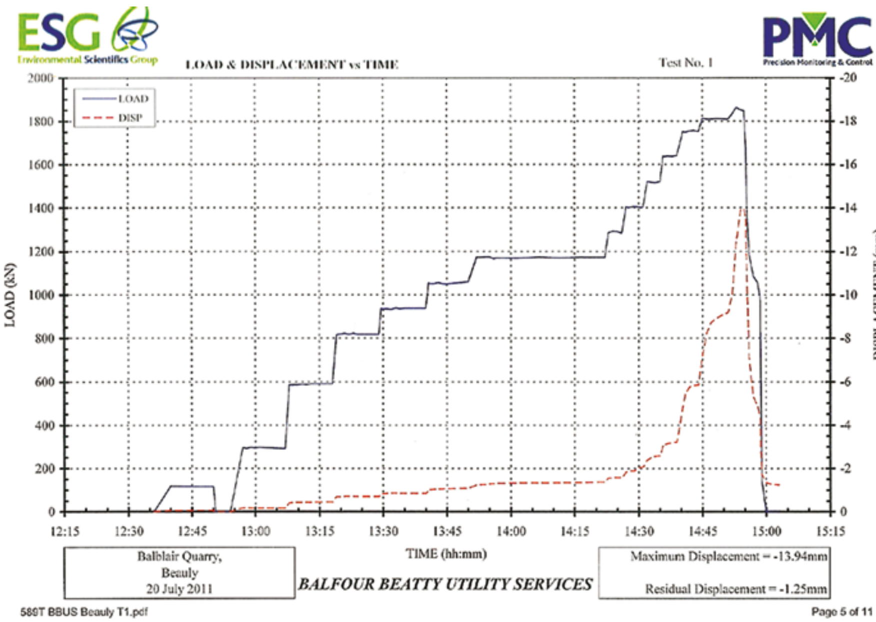


Figure 13.41 Time – Load – Displacement plot for a full-scale uplift test.

Table 13.11 Evaluation of design full-scale uplift test results

Test Foundation		T1	T3	T4
Ultimate design load (inclusive of PSF)	kN	1575	1575	1575
Theoretical design capacity	kN	1636	1636	1636
Maximum applied test load	kN	1847	1700	1755
Actual test capacity (slope tangent intersection)	kN	1810	1660	1690
Calculated design capacity (based on measured soil properties)	kN	2239	2189	2159
Characteristic strength (5% exclusion limit)	kN	1563	1563	1563

Note: PSF ~ Partial Safety Factor (strength/material factor)

Figure 13.42 Full-scale test arrangement for Rock Anchor foundation.

Due consideration should be taken in the application of the test criteria specified in IEC 61773, which are not applicable if full-scale dynamic load tests are undertaken. For tests under dynamic loading either a constant rate of foundation displacement is required, rather than loading being increased by specific increments or a rapid load application is required without consideration of the rate of foundation movement.

Figure 13.43 Full-scale testing of an existing foundation – support in-situ. (Note: Bottom tower leg disconnected and removed during the test)

13.6.2.2 Proof and Integrity Tests

Proof tests are either undertaken on the complete project foundation or the major geotechnical elements of the foundation, i.e., individual piles or anchors, where there are concerns regarding the assumed geotechnical design parameters (marked variations in the ground conditions), or to verify the installation workmanship and/or materials (integrity tests).

Proof tests can be undertaken using similar test procedures and test arrangements to those outlined for design tests; although, it will be necessary to limit the applied test loading and hence the displacement of the foundation/geotechnical element, such that the foundation can be satisfactorily used on the project. Figure 13.44 shows the test arrangement for proof testing of individual rock anchors.

Typical proof load test loading and acceptance criteria are given below:

- The 100% proof load test should be taken as 50% of the applied foundation loading, inclusive of both partial load and strength factors for supports designed using a probabilistic approach or equivalent to the working load, for supports designed using deterministic approach;
- The permanent displacement of the test foundation (after 100% proof test load has been maintained for 10 minutes), should be less than 5 mm for separate foundation including drilled shafts or 10 mm for individual piles or rock anchors.

For further details regarding proof tests, reference should again be made to SR81 and IEC 61773.

Integrity tests are undertaken to identify anomalies in piles and/or anchors that could have a structural significance with regards to their performance and durability; however, they do not give any direct information regarding their performance under load.

Figure 13.44 Proof testing of individual rock anchors.

The test methods used are:

- Impulse response: The impulse response is a stress wave reflection method, which relies on the measurement of both stress wave reflections and low-strain impact force induced by an impact device (hand-held hammer) applied axially to the pile head.
- Sonic echo, frequency response or transient dynamic steady-state vibration method: The test method measures and analyses the stress wave velocity response and acoustic properties of the pile induced by an impact device (hand-held hammer) applied axially to the pile head.

There is normally a limit to the length/diameter ratio of a pile which can be successfully tested. Since the test methods measure the acoustic properties of concrete and from these infer the condition of the pile, the wave patterns produced are complex and requires a high degree of judgement and subjective interpretation.

For further details regarding the integrity testing of piles including the use of Cross-hole sonic logging, reference should be made to SPERW and Cigré TB 308.

13.6.2.3 Dynamic Design Tests

Dynamic load (DL) and rapid load (RL) testing of piles are much quicker to complete than the normal static load testing, since they do not require any pre-installed reaction system. However, the piles can only be tested under compressive loading and not under the normal critical uplift loading for OHL supports.

DL tests involve striking a pile with a hammer (for driven piles it is usually the same one used to install the pile) and measuring the resulting forces and displacements recorded by gauges fixed near the pile head. The DL tests should be undertaken in accordance with ASTM 4945 (2012).

RL tests are undertaken by applying a dynamic load at the pile head through a fast burning material in a confined cylinder and piston arrangement, and a reaction weight. The weight is accelerated at around 20 g and the resultant force is applied to the pile. Pile head load is measured using a load cell and the pile head displacement using a laser or deduced from accelerometers fixed to the pile. The load and deflection measured during the test are plotted to give pile head load against deflection. However, there are no national/international standards at present for RL testing.

The interpretation of the test results should be undertaken by specialists carrying out the tests using procedures developed by the manufacturer of the test equipment. Although, both tests apply compressive loading on the piles, it is possible to ascertain both the base resistance and the shaft resistance of the pile and with the latter confirm the uplift resistance of the pile. For further details reference should be made to SPERW.

13.6.3 Model Testing

The load testing of model (reduced scale) foundations is normally undertaken as part of a research programme to:

- Calibrate and validate analytical or numerical modelling studies of a specific foundation design aspect, e.g., the uplift resistance of separate spread footings under short term dynamic loadings arising from wind gusts or broken wire events, the resistance of directly embedded steel pole foundations, the resistance of complete tower-foundation models to overturning moments;
- To predict the performance of a foundation design under specific loading or geotechnical conditions prior to undertaking full-scale testing;
- To develop qualitative trends in the uplift resistance of separate spread footings relative to changes in the foundation design parameters, e.g., backfill density, depth to width ratios, angle of inclination of the applied loading, etc.

For details of the model tests undertaken to determine the effects of inclined loads on separate spread footings, reference should be made to Cigré Electra No 219.

The advantages of model testing is that it is relative inexpensive compared to full-scale testing, it can be undertaken under controlled environmental conditions, e.g., native soil and backfill densities, etc., can be easily repeated to ensure that there are no anomalies in the test results and changes in the scale model, applied loading, etc., can be easily accommodated.

The disadvantages of small scale testing under the earth's gravitational acceleration (1 g models) is that it is not possible to effectively scale down the non-linear behaviour of the soil, since the ratio of the soil stresses due to self-weight (gravity) to strength is different for the model and the full-scale foundation. In addition, it is not always possible to use an analogue material to overcome this problem, since all of the properties such as strength and stiffness do not usually scale concurrently. To overcome these deficiencies centrifuge modelling techniques can be used to complement the analytical/numerical studies, small scale (1 g) and full-scale models.

The centrifuge modelling technique replicates gravitational effects by the centrifugal acceleration experienced by an object in circular flight. If a full-scale support foundation is represented by a model to a scale of n (every linear dimension in the real foundation being n times greater than the model), then the vertical stress levels in the soil due to self-weight will be n times greater at any position in the real foundation than the corresponding point in the model. Consequentially, the behaviour of the model will not replicate the real foundation because of the different stress levels. However, if the model weight is increased to n times greater than the earth's gravitational acceleration (g), the stress distribution between the real and model foundation will be similar.

The n-fold increase in the model weight can be achieved by placing the model under a centrifugal acceleration equivalent to n times g. If the same soil is used in the model as the real foundation, the stress-strain relationship in the soil should be similar. Similarly, any external applied loading must also be scaled so that the corresponding stress-strain relationship is maintained. If these conditions are met the reaction of the model to the external applied loading should be similar to the full-scale behaviour.

With regards to use of centrifuge model testing of support foundations, unless there are specific reasons to the contrary, due care should be taken in respect of the boundary conditions, e.g., the method of model foundation installation and backfilling (if appropriate) should replicate those used for the contract foundations, i.e., use of enclosed supported excavations. Similarly the model soil should be representative of the actual soil found on site. Where complete support-foundation systems model tests are undertaken, the support model should reflect the stiffness/flexibility of the full-scale support.

For further general information regarding centrifuge modelling techniques, reference should be made to Schofield (1980) and Corté (1989); while for the application to specific OHL support foundations, reference should be made to Richards et al. (2010).

13.6.4 Testing Benefits

Although full-scale and model testing are both relatively expensive, they do provide sufficient benefits to outweigh the costs, i.e.:

- For design tests undertaken on full-scale foundations, that the foundation design fulfils the contract requirements and hence achieves the required level of reliability.
- For proof tests undertaken on complete working foundations or individual foundation components, e.g., piles or anchors, that the installed foundation/components are fit-for-purpose.
- For full-scale tests undertaken as part of a foundation design research programme, that the results/conclusions drawn from numerical analysis and/or model testing are valid.
- For model tests undertaken as part of foundation design research programme, that the results of the numerical analysis are valid, prior to undertaking full-scale testing.

13.7 Foundation Installation

13.7.1 General

Foundation installation can be considered as a series of discrete interrelated activities commencing with the initial foundation design and associated drawings, site access preparation, setting out, excavation, etc., through to the site reinstatement. A diagrammatic flow chart of the foundation installation activities is shown in Figure 13.45.

A summary overview of the key foundation installation requirements in respect of pre-site activities, temporary works, foundation excavation, stub-setting, concrete and reinforcement, and backfilling are considered in this section. For further details in respect of the foundation installation requirements, reference should be made to Cigré TB 308.

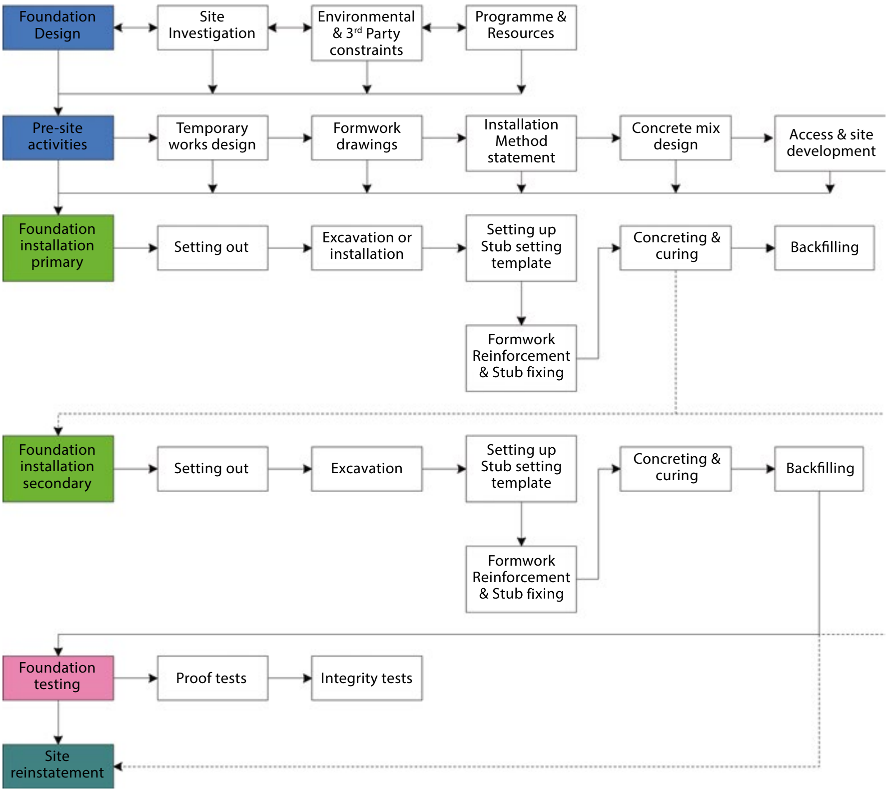


Figure 13.45 Diagrammatic representation of foundation installation activities. (Note: Primary activities refer to the main foundation installation, i.e., for piled foundations the installation of the individual piles, while the secondary activity refers to the construction of the pile cap.

13.7.2 Pre-site Activities

The pre-site activities will encompass the transition from the design phase to the installation phase of the project, especially as regards the hand-over from the foundation designers to the foundation installation contractor; although this transfer of information may be on-going throughout the project depending on the timing of the SI and associated foundation design. In particular, due consideration should be given to the transfer of H&S and environmental data.

Pre-site activities may include some or all of the following:

- Site establishment;
- Identifying proposed borrow pits or other sources of construction materials, e.g., for access track construction or concrete aggregates;
- Finalisation of the temporary works requirements;
- Undertake site access development, taking into consideration any client, environmental and/or third party constraints, the size and weight of the installation equipment, the transportation of site personnel and materials. If the use of helicopters is required for the transportation of equipment/materials/site personnel, all the appropriate planning and off-site activities should be undertaken;
- Finalisation of the concrete mix design(s);
- Finalisation of supplier(s) and sub-contractor(s) requirements;
- Finalisation of H&S, environmental and QA/QC requirements;
- Preparation of the foundation installation drawings, if not previously undertaken;
- Manufacture of the foundation formwork (shuttering) and the stub or anchor bolt setting templates. If the lower portion of a lattice tower is used to set the stubs, then the associated erection and rigging drawings should also be available;
- Preparation of the foundation installation method statement and associated hazard identification/risk assessment.

For further information regarding foundation installation drawings and the design of foundation formwork and setting templates, reference should be made to Section 3.2.2 of Cigré TB 308.

13.7.3 Foundation Installation Method Statement

Foundation installation method statements should contain the following information:

- Scope of the proposed work, together with details of the supporting documentation, e.g., foundation installation drawings, bar bending schedules, Work Instructions in respect of the activities to be undertaken;
- Details of the mobilization, traffic management, access, utility services, environmental, welfare and training requirements;
- Details of the Temporary works, plant/equipment, materials, etc;

- Method of working, e.g., site preparation, excavation, concreting, curing, stripping and backfilling, etc;
- Permits required, e.g., temporary works inspection record;
- Proformas for recording inspections undertaken, concrete returns, as built details, etc;
- Personal protective equipment and training requirements;
- QA Hold and Notification points;
- Emergency arrangements in case of accidents or environmental incidences.

13.7.4 Temporary Works

Temporary works, i.e., those activities not forming part of the permanent installation, would normally comprise the following activities:

- Design and installation of the access track or road and associated drainage; noting that this could be a permanent installation for future maintenance of the OHL;
- Site preparation including, as appropriate, site levelling or benching, the installation of temporary drainage, etc. Depending on the installation method adopted for rock anchors (temporarily cased or uncased), it may be necessary to remove any overburden present to expose the rock head, thereby permitting further geotechnical evaluation of the complete support site;
- Preparation of the working platform, which may require the appropriate geotechnical design, depending on the geotechnical conditions present and the imposed loading from the proposed foundation installation equipment, e.g., piling rigs or use of large mobile cranes for subsequent support erection;
- Design of the temporary excavation support system, taking into consideration the foundation type and size, geotechnical conditions, etc.

The use of a temporary working platform for both the foundation installation and subsequent tower erection is shown in Figure 13.46. As part of the final reinstatement the temporary foundation working platform will be removed and the ground re-contoured back to the original slope.

13.7.5 Foundation Excavation

Foundation excavations should be adequately supported or formed to ensure stability of the sides, to prevent any damage to the surrounding ground or adjacent structures and to ensure the safety of all personnel and should be in accordance with the appropriate code of practice.

The risk of the collapse of the excavation is influenced by the following factors:

Figure 13.46 Temporary working platform, including the use of gabion baskets for slope stability.

- Loose uncompacted soils, especially fill materials or made-up ground;
- Excavations through different strata;
- Presence of groundwater or surface water running into the excavation;
- Proximity of earlier excavations;
- Loose blocks of fractured rock;
- Weathering, rain and freeze/thaw effects;
- Vibration from plant and equipment;
- Surcharging by spoil;
- Proximity of loaded foundations.

Although, the factors listed above are applicable for installation of all types of foundation, the following details are specifically related to the installation of spread foundations, including pile and anchor caps.

Unless the excavation is battered or stepped, excavations in non-cohesive loose sand and gravel, soft clays and silts will require the use of steel trench sheeting, timber boards or propriety excavation support system installed as the excavation progresses. A typical excavation with side support is shown in Figure 13.54.

Excavations in cohesive soil and weak rock may stand unsupported; however, there is always a risk that excavations in these ground conditions will collapse without warning. Cohesive stiff or very stiff clays may be adequately supported by open trench sheeting where alternate sheets/boards are omitted; however this will depend on local H&S requirements. Care is necessary when excavating rock which may fracture, to ensure that loose blocks do not fall from the excavation face.

Other key points which should be taken into consideration during the foundation excavation are:

- For excavation in cohesive soil, the final 150 mm above the formation level should only be removed immediately prior to placing the blinding concrete, thereby preventing softening of the exposed formation layer.
- Use of a concrete blinding layer 75 mm thick, although in chemically aggressive soils it may also be necessary to use an impermeable membrane between the blinding concrete and the soil.
- Similar requirements may also be required for certain weak rocks that deteriorate due to the presence of moisture, e.g., uncemented mudstones.
- No water should be permitted to accumulate in the excavation; any water arising from the excavation or draining into it, should be drained to an approved location, clear of the excavation area and in a manner that does not cause erosion, silting or contamination of existing drains and watercourses.
- Adequate steps should be taken to prevent the adjacent ground being adversely affected by the loss of fines in any groundwater control process.
- The water removal system may include conventional pumping from a sump in the corner of the excavation or alternatively in soils with a high permeability using well pointing dewatering techniques.
- The design of the groundwater control system should ensure that any upward flow of water is not sufficient to cause "piping" at the base of the excavation, whereby the soil cannot support any vertical load.

Figure 13.47 shows the installation of temporary sheet steel piles to support the subsequent foundation excavation and a fully supported excavation is shown in Figure 13.54. Unsupported excavations in rock and dense non cohesive material are shown in Figure 13.48.

13.7.6 Drilled Shaft, Pile and Ground Anchor Installation

To avoid the problems and their effect on the foundation design outlined in Section 13.5.4, all drilled shaft foundations, piles and anchors should be installed in accordance with the appropriate standards or recognized codes of practice.

For further details in respect of installation techniques including methods of excavating or forming the drilled shaft, pile or ground anchor, methods of dealing with unstable ground conditions or ground water infiltration, use of temporary and/or permanent casings or other means of excavation support, e.g., use of stabilizing fluids, concrete and grout mix design, placing of the reinforcement, concrete or grout, installation tolerances, inspection requirements and associated

Figure 13.47 Foundation excavation installation of temporary support system (sheet steel piles).

Figure 13.48 Foundation excavation in soil (left) and rock (right).

records, and testing requirements, reference should be made to Section 3.6 and 3.7 of Cigré TB 308 respectively.

Figures 13.49 and 13.50 shows the installation of bored and driven piles, while Figure 13.51 illustrates the drilling of vertical rock anchors for a rock anchor spread foundation.

Figure 13.49 Installation of Bored piles.

Figure 13.50 Installation of Driven piles ‘H’ section (left) and tubular steel (right).

Figure 13.51 Rock anchor installation.

13.7.7 Formwork

The following parameters should be considered in the design of formwork:

- The formwork should be sufficiently rigid and tight to prevent the loss of grout or mortar from the fresh concrete;
- The formwork and its supports should maintain their correct position and ensure the correct shape and profile of the concrete;
- The design of the formwork should take into account any safety considerations applicable, including manual handling;
- The formwork should be capable of being dismantled and removed from the cast concrete without shock, disturbance or damage.

Formwork may comprise standardised reusable steel "shutters" for the construction of concrete pyramid foundations or for the construction of foundation chimneys, proprietary steel formwork used for construction of pile/anchor caps, timber, or for specific applications disposable card or steel wire mesh with a heat shrink layer of polyethylene applied to both faces of the mesh.

Figure 13.51 shows the use of reusable steel shutters, while Figure 13.52 shows the use of disposal steel mesh/polyethylene formwork.

Figure 13.52 Steel formwork.

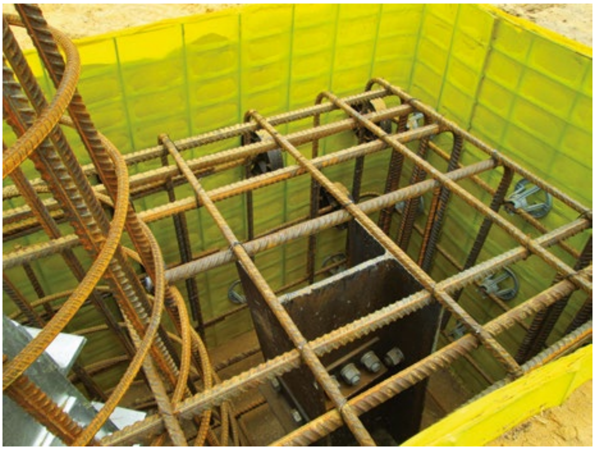


Figure 13.53 Disposal formwork.

13.7.8 Stub and Bolt Setting Assemblies

The key points for consideration in respect of use of stub setting or holding down bolt assemblies are:

- Stubs/holding down bolt assemblies should be held firmly in position by a setting template (see Figure 13.55) or other devices including the bottom panel of a tower, while the concrete is placed and during the initial curing period.
- The support should be maintained until backfilling of the foundation is complete, or for drilled shaft, anchor and pile caps, compact and raft foundations until a minimum period of 48 hours has elapsed after concreting.
- Where individual templates are used (i.e., per footing), as opposed to an overall frame template, additional care should be taken to ensure the setting dimensions

Figure 13.54 Intermediate stage concrete pad cast prior to placing stub and chimney formwork.

Figure 13.55 Stub setting.

and the level, rake and orientation of the stubs/holding down bolt assemblies are correct and within any specified setting tolerance.

- Where the lower section of the support is used, as an alternative to a setting template, adequate measures should be taken to ensure the stability of the support.

13.7.9 Concrete

For the majority of support foundations, the effectiveness of the concrete is crucial in achieving the desired level of reliability over the foundation's intended service life. This section provides an overview of the key factors to be considered in trying to achieve this aim.

13.7.9.1 Concrete Mix Design

The primary objective of the concrete mix design is to ensure that the fresh concrete has the required workability to enable a dense, void-free concrete to be placed, such that the hardened concrete has the required strength and durability for the foundation's intended service life. For the majority of overhead line support foundations, the durability of the concrete and not the strength is the key requirement.

To achieve these aims, the concrete mix design should take into account the following factors:

- The design strength in terms of the 28-day characteristic strength, strength grade or compressive strength grade;
- The durability required, taking into consideration the intended service life of the foundation, the chemical aggressiveness of the surrounding soil or ground water (static or mobile), whether the site is a greenfield or a brownfield location and whether the concrete is prone to freeze-thaw attack;
- The workability required, taking into consideration the delivery time to site from the batching plant, the proposed method of transporting and placing the concrete, the method of compaction, environmental conditions, e.g., cold or hot weather, etc.;
- The type of cement and combinations available, e.g., Portland cement combined with pfa or ggbs;
- The type and size of the coarse aggregate, taking into account the proposed method of placing, e.g., rounded aggregates are preferred for concrete placed by tremie or pumping, the clear spacing between reinforcement and the diameter of the concrete vibrator;
- The permitted use of admixtures;
- Whether a design mix or a standardised mix in accordance with a national standard is required;
- The relevant requirements of the client's technical specification and/or national/international standards;
- Whether the concrete is going to be supplied from an external ready mix supplier or batched on-site;
- Whether the external supplier is accredited to an approved quality assurance scheme;
- For site batched concrete, the source and types of aggregates and the quality of water.

Similar details to those listed above will also need to be considered in respect of the design of cementious grouts for micropiles and anchors.

With regards to durability, the concrete and especially the cover to the reinforcement undertakes a series of functions, i.e.:

- Provides a high alkaline environment which passivates the reinforcement, thereby inhibiting corrosion;
- Provides a low permeability physical barrier (of sufficient depth) to the chemical agents that would otherwise promote corrosion in embedded steel items, e.g., chloride attack on concrete reinforcement;
- Forms an outer shell to protect the foundation from physical attack, e.g., freeze-thaw damage.

To achieve the desired level of durability requires: the correct cover to the reinforcement, the appropriate concrete mix, good compaction (i.e., reduction of voids and hence permeability), correct curing, and possibly the use of admixtures.

The effect of modifying (increasing) the proportions and/or properties of the concrete mix constituents, i.e., cement, aggregates and water, on the workability, cohesiveness and stiffening time of the mix, are:

- Water ~ increase in workability;
- Portland cement ~ increase in cohesiveness and decrease in stiffening time;
- Pfa and ggbs ~ Increase in workability, cohesiveness and stiffening time;
- Max. aggregate size ~ increase in workability, decrease in cohesiveness;
- Fine aggregate content ~ decrease in workability and increase in cohesiveness.

For further details reference should be made to CIRIA report R165 (1977).

Concrete in the ground is prone to attack by a variety of different chemicals in the soil and/or the ground water, with a corresponding reduction in both its long term strength and durability. The chemical constituents of aggressive ground and groundwater are: sulfates and sulfides, acids, magnesium ions, ammonium ions, aggressive carbon dioxide, chloride ions and phenols. Concrete can also suffer from internal degradation from alkali-aggregate reaction, normally in the form of alkali-silica reaction.

Admixtures are a useful way of modifying or improving the concrete mix in respect of the workability or durability. All admixtures should be used in accordance with the manufacturers' instructions, especially where multiple admixtures are used in combination for their compatibility and in accordance with the relevant standard. The range of admixtures available includes:

- *Accelerators*: reduce the stiffening/setting time; thereby offsetting the effects of cold ambient temperatures, and increases the rate of strength gain;
- *Retarders*: increase the stiffening time while retaining the workability; thereby; offsetting the effects of high ambient temperatures, and hence prevention of cold joints between pours;
- *Air-entraining agents*: increase the durability of concrete to resist freeze-thaw attack, also increases both the workability and the cohesiveness of the mix; however, the use of this admixture can cause a reduction in the concrete strength and may require a change in the mix design;

- *Water reducers and plasticisers*: increases both the workability and cohesiveness for a given water content hence denser concrete, higher strength for a reduced water content at a maintained workability therefore stronger concrete, same strength at a reduced cement content whilst maintaining the same w/c ratio hence lower permeability;
- *Superplasticisers*: increases both the workability and cohesiveness, hence very high workability at given water content thereby assisting placing in difficult situations, time and energy saving since no compaction is necessary or for use in non-shrink/non-bleed grouts;
- *Pumping aids*: increases both the workability and cohesiveness of the mix.

13.7.9.2 Concrete Placing

Normally, concrete should be placed within two hours after the initial loading in a truck mixer or agitators, or within one hour if non-agitating equipment is used. These periods may be extended or shortened, depending on climatic conditions and whether ggbs, pfa, accelerating or retarding admixtures have been used.

Before the concrete is placed, all rubbish should be removed from the formwork and the faces of the forms in contact with the concrete should be cleaned and treated with a suitable release agent without contaminating the reinforcement.

Unless a self-compacting concrete mix is used, all concrete should be thoroughly compacted by vibration, or other means, and worked around the reinforcement, embedded items, e.g., stubs and into corners of the formwork to form a solid void-free mass. When vibrators are used, vibration should be applied until the expulsion of air has practically ceased and in a manner that does not promote segregation. Over-vibration should be avoided to minimize the risk of forming a weak surface layer or excessive bleeding.

Figure 13.56 shows the transportation of concrete by a helicopter, while the use of a concrete pump is shown in Figure 13.57 and the placing of concrete using a chute and by a skip is shown in Figures 13.58a and 13.58b.

13.7.9.3 Concrete Curing

The setting and hardening of cement depends on the presence of water; drying out, if allowed to take place too soon, results in low strength and porous concrete. At the time of concrete placing, there is normally an adequate quantity of water present for full hydration; however, it is necessary to ensure that this water is retained so that the chemical reaction continues until the concrete has thoroughly hardened. Correspondingly, curing and protection should start immediately after compaction of the concrete and should ensure adequate protection from:

- Premature drying out, particularly by solar radiation and wind;
- Leaching out by rain and flowing water;
- Rapid cooling during the first few days after placing
- Low temperatures or frost until the concrete has reached an adequate maturity;
- High internal thermal gradients;
- Vibration and impact which may disrupt the concrete and interfere with its bond to the reinforcement or other embedded items.

Figure 13.56 Transportation of concrete – helicopter.

Figure 13.57 Placing of concrete using a concrete pump.

Figure 13.58 Placing of concrete using chute (left) and skip (right).

For further information on this and related subjects references should be made to:

- Concrete mix design: Section 3.2.3 of Cigré TB 308;
- Reinforcement: Section 3.5 of Cigré TB 308;
- Concrete production, delivery, placing, construction joints and curing: Section 3.9 of Cigré TB 308;
- Working in cold and hot weather: Sections 3.9.8 and 3.9.9 of Cigré TB 308.

13.7.10 Backfilling

For spread foundations, the failure to adequately compact the backfill is one of the prime reasons for a foundation's actual uplift strength being less than its theoretical design strength. Correspondingly, the following recommendations should be taken into consideration:

- Backfilling should be compacted in 300 mm layers to achieve a bulk density equivalent to that assumed in the geotechnical design model;
- Backfilling should be undertaken progressively over the whole foundation plan area, with particular emphasis on the area adjacent to the inner face of the chimney;
- During backfilling, the side support sheeting to the excavation should, wherever possible, be progressively withdrawn such that the toe of the sheeting is never more than 600 mm below the surface of the compacted material;
- Extreme care should be taken during compaction to ensure that the foundation is not damaged nor displaced out of position;
- The compaction plant should be selected to achieve the required bulk density. The actual method of compaction selected will depend on the type of material to be compacted, the difficulty in accessing areas within the excavation and the safety of the site operatives;

- For spread footing foundations in soils subjected to permafrost and frost forces, consideration should be given to backfilling with non frost susceptible materials, e.g., granular fill with less than 8% silt content and passing through a 200 sieve. For further recommendations regarding the use of insulating materials and the application of a lubricant to steel foundation members, reference should be made to Cigré TB 141 and Cigré TB 206;
- Where it is proposed to use a proprietary cement based additive to improve the backfill density, due consideration should be given to both the potential environmental effect and whether there will be a change in the assumed geotechnical uplift failure surface and the results of any previous full-scale foundation uplift tests;
- The use of coarse granular backfill material in cohesive (clay) soils, thereby permitting the weakening (softening) of the clay at the backfill-soil interface in the continued presence of water.

Figure 13.59a shows the backfill compaction in an open excavation, while Figure 13.59b shows the same process in a supported excavation.

13.7.11 Conclusions

The importance of ensuring that the support foundations are correctly installed has been emphasised throughout this chapter. Without the adoption of the correct installation practices being adopted, there will be potential short term issues in respect of H&S and the environment and long term issues in respect of the reliability and durability of the foundations, the integrity of the support and hence the OHL itself.

When it does become a necessity to refurbish or upgrade the support foundations, the key requirements are considered in the next section of this chapter.

Figure 13.59 Backfill compaction (open excavation) (left). Backfill compaction (temporary support system in place)(right).

13.8 Foundation Refurbishment and Upgrading

13.8.1 Introduction

Although there is an ever increasing need for electrical power, electrical utilities are now under intense pressure from such diverse interest groups as customers, shareholders, regulatory authorities, environmentalists, landowners, etc., to minimise the extent and impact of further OHL construction. Correspondingly, there is a need to maintain, if not improve, the reliability of an ageing OHL network, especially if there is a need to increase the electrical capacity of the OHL by upgrading.

As previously mentioned, the support foundations are unique in that unlike the other OHL components they cannot be seen and are constructed partially or wholly in-situ in a natural medium whose characteristic properties may vary between support sites and possibly between adjacent footings of a common support. In addition, the original "as-built" construction records for the OHL may not be available or provide adequate reliable information in respect of: the foundation type, the design basis, basic dimensions and the geotechnical conditions present. Consequentially, there is a need to undertake a structured investigation (foundation assessment) to determine: the physical characteristics of the installed foundations including the extent of any foundation deterioration, the actual ground conditions, the applied foundation loadings and, if applicable, the actual foundation geotechnical strength (capacity), such that a decision can be made as to whether to refurbish, upgrade or accept the current condition and geotechnical strength of the installed foundation.

This approach was identified in Cigré TB 141 and can be summarised as:

- Initial review and investigation
  - Initial feasibility and economic appraisal, which would normally form part of the overall feasibility study for the complete OHL refurbishment or upgrade;
  - Document survey to determine, if possible, the support and foundation types, applied loadings, geotechnical design parameters, existing foundation condition, etc.;
  - Initial geotechnical desk study and visual inspection of the above-ground condition of the foundations and the support interface;
  - Review of the applied loading criteria and determination of the revised foundation loading arising from the proposed upgrading scheme, and/or change in design basis from deterministic to a RBD design approach;
  - Initial foundation assessment–hazard review–risk assessment to decide whether it is safe, practical, economic, etc., to proceed with further investigations or whether an alternative strategy, e.g., replacing all the existing foundations, should be adopted.
- Detailed investigation and assessment
  - Determine the extent of further foundation inspections required, both structural and geotechnical;
  - Undertake foundation inspection and ground investigation and if required full-scale foundation load tests on the existing foundations;

  - Determine the geotechnical capacity of the foundations, based on the inspection, ground investigation full-scale test results and loading studies, etc., and the extent of any foundation deterioration;
  - In-depth foundation assessment–hazard review–risk assessment to determine whether it is safe, practical, economic, etc., to use the existing foundations or whether an alternative strategy should be adopted;
  - Decide whether to accept the existing foundation's geotechnical strength/condition, refurbish, upgrade or adopt an alternative strategy.
- Foundation upgrading or refurbishment
  - Undertake the foundation refurbishment or upgrading as appropriate and if required full-scale load tests on the upgraded foundations.

A diagrammatic representation of assessment process is shown in Figure 13.60.

13.8.2 Foundation Deterioration

The deterioration of the installed foundations or their constituent materials can arise from a variety of different causes, e.g., concrete cracking, chemical attack, design/construction errors, etc., which are summarised in Table 13.12.

Figure 13.61a illustrates the effect of AAR on a substation structure foundation, while Figure 13.61b illustrates the effect of severe embedded steelwork corrosion, arising from chloride attack on the foundation concrete.

For further details regarding the deterioration of foundations, reference should be made to Section 3 of Cigré TB 141 and Section 3 of Cigré TB 516.

13.8.3 Foundation Assessment

The overall assessment of the existing foundations and hence the decision as to whether to accept the current condition of the foundation (physical and geotechnical), refurbish, upgrade or replace is outlined in Section 13.8.1 and requires a multiphase approach comprising: an initial desk study – site reconnaissance, detailed investigation and a final evaluation. Although, the different phases of the assessment are extensively covered in Sections 4, 5 and 6 of Cigré TB 141, due cognizance should be taken of the following points, in respect of: H&S, Environmental and QA, Geotechnical investigation and Foundation inspection techniques.

13.8.3.1 H&S, Environmental and Quality Assurance

Since the publication of Cigré TB 141 in 1999, greater emphasis has been placed on the need to ensure that all work is undertaken safely, that there are no detrimental effects on the health of site operatives, that the effect on the environment is minimised and the quality of the work is improved. This has been reflected in changes in statutory regulations, technical standards and specifications and the attitude of the general public. Consequentially, the "Integrated Approach" advocated in Section 13.3 and the salient points contained in Section 13.4 should be adopted, especially as regards the application of on-going hazard identification and risk assessment.

The extensive coverage given in Cigré TB 308 to the QA requirements for foundation installation is equally applicable to the refurbishment and upgrading of

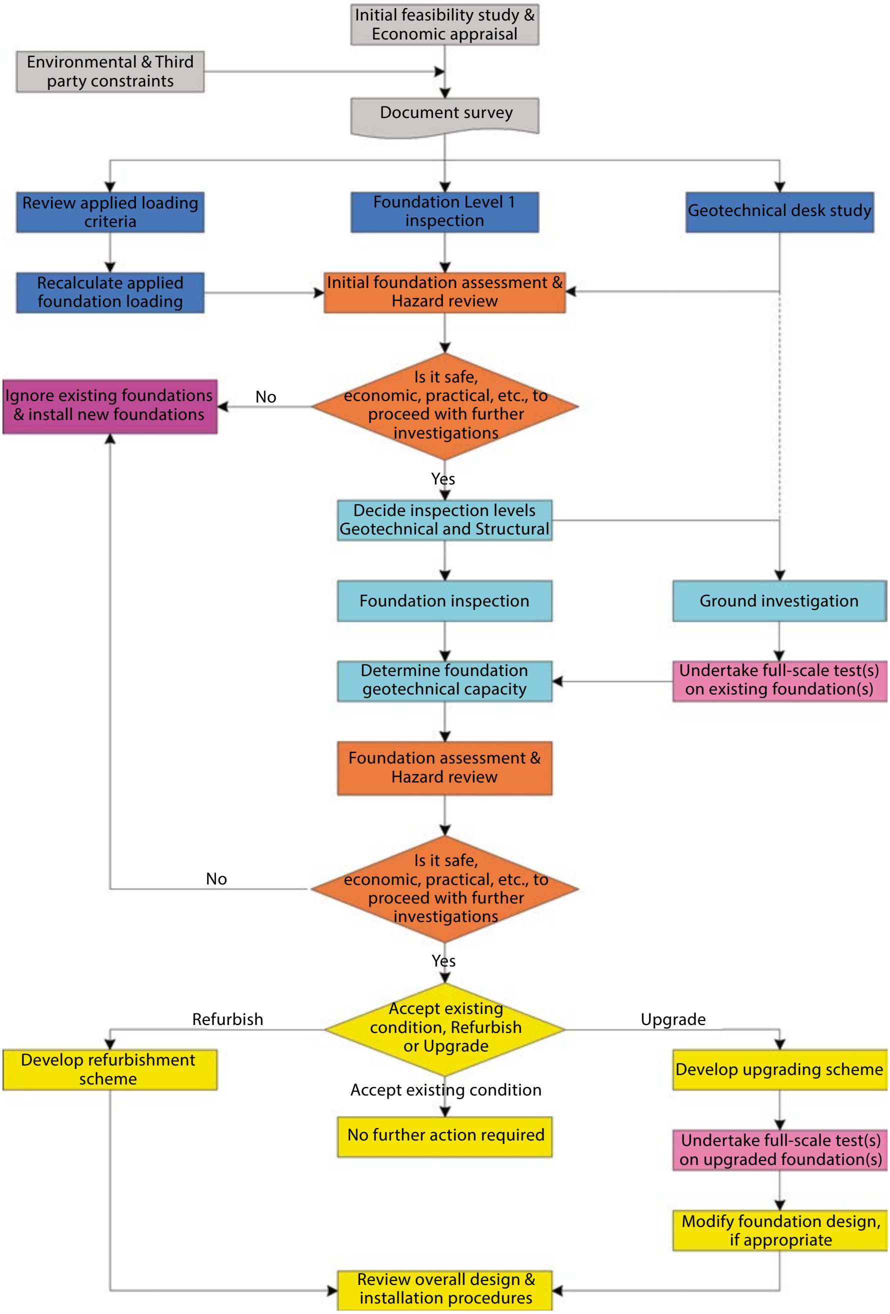


Figure 13.60 Diagrammatic representation of foundation assessment process.

Table 13.12 Causes of foundation deterioration

Generic group	Primary cause	Principal effect
Cracking	Early-age cracking	Path for ingress of aggressive agents to attack concrete, reinforcement or embedded steelwork.
Chemical	Acid attack	Dissolution of the cement paste matrix and increasing porosity of the concrete.
	Alkali aggregate reaction (AAR)	Can cause extensive cracking of the concrete and under certain conditions cause the cement paste matrix to become a mushy incohesive mass.
	Carbonation	Loss of alkalinity in the cement paste and hence increase the probability of deterioration of embedded reinforcement/steelwork.
	Chloride	Corrosion of embedded steelwork.
	Corrosion	Loss of section size and hence loss of strength of embedded reinforcement/ steelwork or steelwork embedded in the ground. In addition, cracking/spalling of the concrete from reinforcement corrosion.
	Salt crystallisation	Cracking or delaminations of the concrete
	Sulfate/sulfides attack	Cracking of the concrete.
Physical	Aggregate unsoundness	Surface cracking or disintegration of concrete arising from aggregates unable to withstand large volume changes arising from freezing – thawing, changes in moisture content, etc.
	Freeze-thaw	Disintegration of concrete surface arising from freezing of water in the concrete pores.
AdFreeze	Permafrost	Excessive differential settlement of the support.
	Frost forces	Increase in loading on the foundations, especially individual members of grillage foundations.
Design/Installation errors	Reference should be made to section 13.5.4 of this chapter.	

existing foundations. For all investigations undertaken, there is also a need to ensure that all the data collected is electronically recorded, is traceable and where applicable is included in the final records for the project.

13.8.3.2 Geotechnical Investigation

Although, a total of three potential levels of geotechnical investigations were envisaged in Section 4 of Cigré TB 141, in practice normally only inspection levels 1 and 2 are undertaken. An initial desk study – visual site reconnaissance (Level 1) followed by a detailed ground investigation (GI) at selected support sites (Level 2). The site selection is usually derived from quantified risk assessment undertaken as part of the initial foundation assessment and would comprise a mixture of sites where there is a potential geotechnical misalignment or foundation overloading plus control sites. For further details regarding the site selection reference should be made to Section 13.4.

Figure 13.61 (**a**) Effect of AAR on concrete. (**b**) Steelwork corrosion.

In practice, the number of support sites selected for a GI should not be less than 20% of the total number of supports on the OHL under consideration, with a further 10% of the support sites selected for a full-depth intrusive foundation inspection (IFI). Although, this quantity may increase, it should not be decreased, unless the inherent risks are minimised. In addition, all of the support sites may be subject to a restricted intrusive foundation inspection, i.e., removal of the muff concrete, thereby permitting a check on the condition of the interface steelwork between the supports and the foundations. This would only be undertaken if there was prior knowledge of inherent installation defects, or sufficient evidence from previous inspections of similar OHLs, e.g., same construction, contractor, ground conditions, etc.

For support sites, where no ground investigation or IFI has been undertaken, the confirmation of the initial geotechnical model should be based on a review of the nearby GI borehole logs and data from IFI, noting the inherent risks involved.

13.8.3.3 Foundation Inspection Techniques

In Section 5.2 of Cigré TB 141 reference was made to the possible use of both surface penetrating radar and acoustic pulse echo, as indirect methods of ascertaining or confirming the installed foundation dimensions. However, in practice neither of these methods has produced satisfactory results and their use has effectively been discontinued. Where confirmation of the actual foundation dimensions is required for normal spread footings, recourse is usually made to the use of IFIs at selected sites. This involves the exposure of at least one face of the foundation for: measurement, condition assessment, the recovery of concrete core samples and a visual examination of the in-situ ground conditions and backfill material. If required bulk samples of the in-situ soil and backfill material may also be taken for subsequent laboratory testing.

Figure 13.62 Intrusive foundation inspection.

Figure 13.62 shows existing support foundations exposed during IFIs.

13.8.4 Foundation Refurbishment

If the conclusion from the foundation assessment is to refurbish the existing foundation, then due consideration should be given to the proposed repair system, i.e., the method of preparation, repair materials, the method of application, the appropriate quality assurance requirements including any initial trials, the health and safety, and environmental impacts, etc.

Irrespective of the type of repair required, due consideration should be given to the following points in the selection of the appropriate repair system:

- From the foundation assessment, identify the cause and extent of the deterioration;
- If possible remedy the underlying cause of the deterioration, e.g., freeze-thaw effects;
- Decide whether the deterioration is structurally significant;
- Select the appropriate repair system, considering the method of preparation, application, durability and whether the repair system has to be used under specific climatic conditions, e.g., above a specified temperature, etc;
- Prepare the technical specification for the work, if necessary in conjunction with specialist suppliers, manufactures or trade associations;
- Where appropriate, reference should be made to the relevant international or national standards for the work, e.g., EN 1504 (BSI 2006);
- Monitor performance and establish site feedback procedures.

Detailed recommendations in respect of the repair of: embedded foundation steelwork, e.g., lattice tower stubs, foundation grillage steelwork, structural concrete including reinforcement, foundations affected by AdFreeze forces, etc., are contained in Section 8 of Cigré TB 141.

13.8.5 Foundation Upgrading

Upgrading of the foundations will be necessary if the conclusion of the foundation assessment is that existing foundation strength is less than imposed loading. The extent of the upgrading will depend on the following factors:

- The degree of increase in foundation strength (resistance) required;
- Support type;
- Foundation type and size;
- Geotechnical conditions present, e.g., soil/rock type, ground water levels, etc;
- The extent of any foundation deterioration present;
- Whether the upgrading is restricted to isolated foundations or is required for a series of foundations;
- The temporary works requirements, e.g., whether the support will require any external support or restraint during the foundation upgrading activities;
- Access restrictions;
- Financial and time constraints;
- H&S and Environmental impacts.

One of the uncertainties in the design of the foundation upgrade is to determine the relative resistances provided by the existing foundation and the upgrade. A conservative approach, frequently adopted, is to ignore the resistance of the existing foundation and assume that all the resistance is provided by the foundation upgrade.

Detailed recommendations in respect of structural improvements to the foundation load carrying members or components, geotechnical improvements to the surrounding ground including the existing backfill material and methods of upgrading different types of foundations are contained in Section 9 of Cigré TB 141.

For conventional spread type foundations e.g., concrete pyramid and chimney, typical approaches adopted in the UK to increase the uplift or compression resistance of the existing foundation are to:

- Recompact or replace the existing the backfill material to achieve a higher in-situ density;
- To install a reinforced concrete pad at the required depth, normally at the intersection of the existing pyramid and chimney, or;
- To install micro-piles or ground anchors connected to the existing foundation using reinforced concrete beams or slabs. Usually the micropiles or ground anchors are installed outside of the perimeter of the existing foundation. Depending on the ground conditions, the rig height and whether the OHL remains

operational during the installation, the micropiles could be drilled cast in-situ, driven steel tubes or pre-cast concrete piles.

- In areas of high environmental sensitivity the use of precast concrete blocks placed on the surface of the ground to increase the uplift resistance of a spread foundation.

The actual type of upgrade solution selected will depend on the extent of the deficit in the foundation resistance, the type of ground and ground water level, whether there are any potential geotechnical hazards, the desired level of integrity required on the support and OHL during the upgrading, whether the work will be undertaken with OHL live, the consequential H&S and environmental risks, etc.

Figure 13.63 shows the use of precast concrete blocks, while Figure 13.64 shows the installation of micropiles and Figure 13.65 shows the construction of the pile

Figure 13.63 Foundation upgrade – Use of precast concrete blocks.

Figure 13.64 Foundation upgrading – Installation of micropiles.

Figure 13.65 Foundation upgrading – Installation of micropile reinforced concrete cap.

Figure 13.66 Foundation upgrading using steel screw piles and steel beam.

cap. Figure 13.66 shows the upgrading of a single pile foundation for a monopole guyed support, using steel screw piles with an interconnecting steel beam.

13.9 Outlook for the Future

The fundamental requirements for the support foundation to provide the interlinking component between the OHL support and the in-situ ground will not change in the future, even though there may be changes in the support type. Similarly, since the ground does not have uniform characteristics, there will always be a degree of uncertainty in respect of geotechnical assumptions made and the corresponding risks to the project. Consequentially, there will still be a need for an "integrated approach", outlined in this chapter, to be applied and sound engineering judgements to be made.

With regards to future developments, the aim should be to reducing the assumptions made and hence the inherent risks by improving the knowledge in respect of:

- The load transfer mechanism from the OHL to the support foundations;
- The resistance of the foundations and the behaviour of the ground to the applied loading;
- Alternative installation techniques or materials to reduce the H&S and environmental risks.

Based on the premise outlined above, the following developments should be considered:

- Further research into the complete support-foundation system to determine the actual loadings on the foundations and the rate at which load is transferred. To determine whether the rate is soil/rock type dependant and the effect of cyclic loading on the ground.
- Research into the permissible temporary/permanent displacement of the foundation – support system and hence the determination of the actual design resistance (capacity) of the foundations.
- Changes to the procedures for full-scale foundation uplift load tests to reflect the actual load transfer rate between support and the foundations.
- Development of foundation design guides/procedures in respect of the application of dynamic loads to the supports.
- For both new build and the upgrading of existing foundations an increased use of different types of piling to lessen environmental or H&S risk. Examples could be auger displacement piling in which no spoil is produced, the use of large diameter screw piles which can be installed in cohesive soils with an SPT blow count of up to 70, with reductions in installation time and quantity of concrete required.
- Increased use of recycled aggregates in the production of concrete and hence reduction in the environmental impact.

Unlike the other major OHL components, e.g., conductors, insulators and supports, where it is possible to introduce new materials, the support foundations are installed in a natural medium which does not have constant properties and taking into consideration that an OHL is effectively a long linear site with isolated areas of activity is not envisaged that there will be marked use of ground improvement techniques in the future.

13.10 Summary

"Quality is never an accident, it is always the result of intelligent effort" (*John Ruskin 1819 – 1900*). This quotation is particularly relevant to the design and installation of OHL Support Foundations; whereby, the major component of the foundations (the ground) is a natural product, which does not have constant properties and is unique at each support location.

To ensure that the desired level of reliability of the foundation is achieved, i.e., the quality, the "intelligent effort" the adoption of the concept of an "Integrated Approach", outlined in this chapter, is recommended. Whereby, there are no artificial boundaries between the design and installation process, i.e., the design, including the geotechnical studies, and the installation activities should be seamless; with a continuous exchange of information between all parties, e.g., the client, the foundation designer(s), the ground investigation contractor and the installation contractor(s). An integral part of this approach is the ongoing need for hazard identification and corresponding risk assessments to be undertaken; thereby ensuring that health and safety, environmental, project and financial management issues and adequately considered and resolved throughout the project.

Section 13.1 provides an introduction to the concept of an "Integrated Approach, together with an example of the serious consequences of not adopting this proposed approach. Continuing on the theme of an "Integrated Approach" Section 13.2 considers the requirements in respect of Health and Safety" the application of Risk Assessment, Environmental Impacts and potential mitigation measures in respect of foundation installation including access development, together with an overview in respect of the Quality Assurance measures required during this phase of the works.

The design of the support foundations has been divided between Sections 13.3, 13.4 and 13.5 and is based on Cigré Electra 131, 149 and 219, and Cigré TB 206, 281, 308, 363 and 516. Section 13.3 covers the design basis, the interdependency between foundation and ground both in terms of the interaction between the foundation loading and the ground, and the affects on the ground during the foundation installation. Also considered in this section are the affects of applied static and dynamic loadings on the foundation, and an overview of the different foundation types. Section 13.4 considers the Site Investigation requirements, especially the need for ongoing geotechnical assessment during the foundation installation. The geotechnical and structural design of the three typical foundation types: Spread footings, Drilled shafts and Ground anchors/micropiles are considered in Section 13.5, including the interaction with the installation process. Also considered in this section is the calibration of the theoretical foundation model against full-scale foundation test results, together with a précis of new developments in the analysis of spread footings under applied uplift loadings.

Section 13.6 considers foundation testing both full-scale and model testing including the use of centrifuge modelling techniques. Although, this section is generally based on Cigré Special Report 81 and the subsequent IEC standard 61773, concerns are raised regarding the suitability of the maintained load test, if the behaviour of the foundation under gust wind loading or other dynamic loadings is to be investigated.

The installation of the foundations is considered in Section 13.7 and provides a summary of the main installation activities, previously considered in Cigré TB 308, e.g., temporary works, foundation excavation, concreting, backfilling, etc. The refurbishment and upgrading of existing foundations is considered Section 13.8 and is based on Cigré TB 141. Topics reviewed in this section include foundation deterioration, foundation assessment, refurbishment and upgrading.

The outlook for the future in respect of the need for further research into the complete support-foundation system, the permissible displacements of a foundation-support system, the design of foundations in respect of application of dynamic loadings is considered Section 13.9.

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Neil Cuer has over 50 years experience in the design and construction of overhead transmission lines, especially the design, installation and full-scale testing of lattice steel towers and their foundations. For the last 20 years he has been providing consultancy services to electrical utilities, contractors and other consultancy firms for OHL projects throughout the world. In Study Committee B2 (overhead lines) he has been both a member and convenor of the WG on support foundations for the last 26 years and has been instrumental in the preparation of Cigré Technical Brochures 141, 206, 308 and 516. He is a Chartered Civil Engineer, member of the UK Institution of Civil Engineers, the American Society of Civil Engineers and a fellow of the UK Institution of Engineering and Technology.

Overall Design

14

Rob Stephen

Contents

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R. Stephen (✉)
Durban, South Africa
e-mail: stepherg@eskom.co.za

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14.1 Introduction

The power line is a device that transmits power over long distances; in this respect it is different in nature to other devices such as transformers in that the design of the line is dependent on terrain and ambient conditions to a far greater extent.

The benefit of this for the utility is that the line can be specifically designed for the position in the grid to a far greater extent than other devices.

The concept of overall line design or line design optimisation is often misunderstood by line designers. The concept of line optimisation applies to many as only to the location of the towers in a line so that the use of the towers is optimised and the overall cost of the line is reduced. This interpretation misses the opportunity to design the line to suit the network requirements as defined by the system planner. A far larger opportunity exists in selecting the optimum conductor, tower and foundation combination to meet a certain load transfer and impedance requirement for the network. The tower spotting optimisation is a subset of the overall line design process.

This chapter describes the parameters that affect the electrical aspects of the line as well as the conductor (Cigré 2015), tower configurations which will assist in this being realised. As this results in a large amount of different conductor, tower and foundation combinations, it is necessary to use an objective indicator as a guide to the best options to pursue, this is covered in the document.

The chapter will cover the AC line design as well as the DC line overall design.

14.2 AC Parameters

In understanding the function of a line it is necessary to understand the parameters that will control the electrical function of the line. This is covered in the following section.

14.2.1 Line Impedance

The electrical model of an overhead power line can be depicted as shown below (Figure 14.1).

In order to maximise the power flow down the line it is necessary to minimise the series components (resistance and inductance) and maximise the shunt components (capacitance). Optimal load flow down the line is a measure of the surge impedance loading.

The surge impedance of the transmission line is defined as the (Muftic 2005) square root of the ratio of the line inductance to the line capacitance.

$$Z_S = \sqrt{\frac{L}{C}} \tag{14.1}$$

Thus

Where Z_s is the surge impedance
L is the series inductance and
C is the shunt capacitance.

The Surge impedance loading (SIL) is the load at which the inductance and capacitance will negate each other and represents an indication of the capability of the power line to transfer load and will affect the stability of the overall network in the stability limited system.

$$SIL = \frac{(V_{LL})^2}{Z_S} \tag{14.2}$$

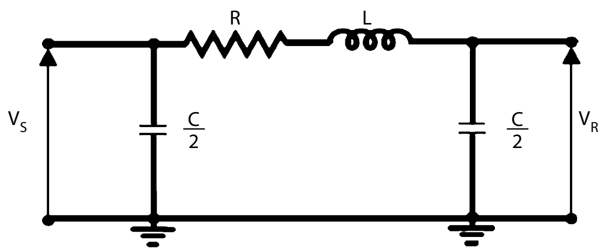


Figure 14.1 Simplified electrical diagram of a power line.

where V_{LL} is the line voltage.

It is desirable in most cases to increase the capability of the line to transfer load thus to increase C and reduce L to maximise this parameter.

It is important to understand the parameters that make up the Resistance (*R*), Inductance *L* and the Capacitance *C* of a transmission line.

14.2.2 AC Resistance

The calculation of AC resistance is covered in Chapter 2 item 1.3 and in Douglass (2008). It depends on the construction of the conductor as well as the temperature of the conductor (Stephen 1992). The construction of the conductor will give rise to magnetic, transformer and skin effects. The first two parameters are only prevalent in steel cored conductors.

For reduction in AC resistance as a function of current, the ACSR conductors could be replaced with AAAC (aluminium alloy) conductors which will not display an increase in resistance as a function of current. However, the cost or availability may not suit the use of AAAC. In these cases if single layer is the optimum size to use the effect of AC resistance on current needs to be taken into account with load flows and conductor temperature calculations.

14.2.3 AC Inductance

The inductance is a function of the Geometric mean radius (GMR) and the Geometric mean distance (GMD) of bundle and phase geometry (Refer Chapter 4 Section 4.1.3).

$$GMR = \sqrt[n]{n\ k\ r\ R^{n-1}} \tag{14.3}$$

Where

$k = 0.7788$
$r =$ radius of the conductor in m
$R =$ Radius of the conductor bundle
$n =$ number of subconductors
$GMR =$ Geometric mean Radius in meters (m)

$$GMD = \sqrt[3]{\left(d_{12}\ d_{13}\ d_{23}\right)} \tag{14.4}$$

Where

d_{12} d_{13} and d_{23} are the distances between the phases and GMD is the geometric mean distance in meters (m)

$$L = 2\times10^{-7}\ l\ln\left(\frac{GMD}{GMR}\right) \tag{14.5}$$

L = inductance of the line in Henry's (H) per length l in meters.

Thus to decrease the inductance which will reduce losses and enable higher power transfer, the GMR should be large and the GMD should be small. Thus the bundle size (diameter) should be large with a high number of subconductors and the phase spacing should be small.

14.2.4 Determination Of C

The shunt capacitance of a power line (refer Chapter 4 Section 4.1.3) is affected by the earth plane which affects the field of the charged conductors.

$$C = \frac{0.05556}{\ln\left(k_1\frac{GMD}{GMR_c}\right)}\ \mu\text{F / km} \tag{14.6}$$

$$GMR_c = \sqrt[n]{n\ r\ R^{n-1}} \tag{14.7}$$

k_1 depends on distances between conductors and conductors and images in the soil (equal to 0.95-1.0 for 138 kV and 0.85-0.9 for 400 kV and higher voltages).

Thus for C to be high, which is the intent if the aim is to increase the line SIL then the phases need to be closer together to increase the C value. Similarly the conductors need to be close to the ground to increase the C value.

14.2.5 Summary

In summary, the SIL of a line can be altered by varying the bundle size and the phase spacing as well as the number of subconductors in a bundle. The resistance of the line can be altered by the type of the conductor chosen as far as lay ratio and composition of the conductor is concerned. Homogenous conductors, or non steel cored conductors will not exhibit a variation of resistance as a function of current as will steel cored conductors.

14.2.6 Corona Limitations

The following factors affect the Corona effect on a conductor surface (see Chapter 4 Section 4.12).

- System voltage
- Conductor diameter

- Clearances between conductor and adjacent phase conductors
- Clearance between conductor and earth
- Number of conductors per phase
- Bundle geometry (diameter of bundle position of subconductors)
- Conductor surface condition
- Atmospheric and weather conditions.

As the conductor diameter increases the surface field gradient decreases, however, when the conductor surface field gradient exceeds the inception voltage the radio interference and audible noise levels will be higher than that of a smaller conductor diameter with the same surface field gradient. According to Muftic (2005), this phenomenon is caused by the fact that the rate of reduction of electric field with lateral movement away from the conductor decreases as the conductor diameter increases.

As phase to ground and phase to phase clearances increase the surface field gradient decreases in a complex way.

There are two relationships that need to be understood with regard to Corona, the first is the Corona inception voltage and the second is the surface field gradient present on the conductor (refer Chapter 4 Section 4.12).

The Corona inception voltage E_C is that voltage above which the conductor will become visible. It is defined by Peek's law and is directly proportional to the surface roughness factor, the air density and is inversely proportional to the diameter of the conductor

The higher the value of E_C the less chance of the conductor going into Corona. The smaller the conductor diameter the higher the E_C. Thus the higher the gradient needs to be on the conductor before it will go into Corona.

Decreased air pressure also decreases the inception voltage gradient. Thus design of lines at high altitude (above 1000 m) needs to be more cognisant of Corona.

The effect of the air pressure is quite marked as shown in refer Section 4.12.1.1.

The Corona inception voltage is not dependent on the number of conductors in the bundle and is calculated as if it is a single conductor irrespective of the bundle configuration (Muftic 2005).

The second aspect that needs to be taken into account is the calculation of surface field gradients. The design of the line needs to ensure that the ratio of the surface field gradient to the Corona inception voltage is <0.95 (Muftic 2005).

In order to calculate the surface field gradients on multiphase bundle conductors the equations shown in refer Chapter 4 Section 12.2 are used.

$$[V]=[P][Q] \tag{14.8}$$

where [V] and [P] are column vectors of the voltage and phase conductor bundle charges.

Thus

$$[Q]=[P]^{1}[V] \tag{14.9}$$

The average conductor surface field gradient is described as follows:

$$E_{ave} = \frac{Q}{2\pi\ \varepsilon_0 n\ r} \tag{14.10}$$

where Q is the total charge on the bundle, n is the number of subconductors in a bundle, and r is the radius of the conductor in cm.

The maximum conductor surface field gradient Emax is given by

$$E_{\max} = E_{ave}\left[1 + \frac{(n-1)r}{R}\right] \tag{14.11}$$

where R is the bundle radius in cm.

The compliance to radio interference and audible noise limits may be difficult to achieve if the line's loading requirements are low relative to the system voltage as the aluminium area required is far smaller than the minimum area required taking into account Corona design parameters. This normally leads to different alternatives being considered such as smaller conductors but more sub-conductors in a bundle. Practical considerations need to be taken into account such as stringing of large bundles of small diameter conductors is problematic. Small conductors also tend to move more erratically in the wind which could cause problems.

14.2.6.1 Rectification of Corona Problems

Corona mitigation after the line is built is one of the most difficult aspects to rectify. This is because it requires either a reduction in system voltage (thereby reducing the surface field gradient) or the use of an additional sub-conductor which may not be possible without strengthening of the towers. Thus it is critical to ensure that the bundle design caters for all weather and construction possibilities to ensure that the audible noise limits are not exceeded.

14.2.6.2 Summary

The surface field gradient, in general, increases with smaller phase spacing and larger (but fewer) conductors in the bundle. It reduces with wider phase spacing and increase in the number of sub-conductors.

14.2.7 Lightning Performances

For single circuit lines, Lightning Performances are defined as lightning-caused outages to be less that σ_s per 100 circuit-km per year

For double circuit lines, Lightning Performances are defined as-lightning-caused outages to be less that σ_s per 100 circuit-km per year for each line circuit;

The Lightning performances is studied in two parts:

- Lightning climatology and
- Lightning outages and performances.

The lightning climatology is a function of the thunderstorm days and lightning flash density which can be used to predict the performance of the line (refer Chapter 4 Section 11).

14.2.7.1 Lightning Outage and Performances Study

The estimate of lightning-outage rates shall be calculated by computer programs conforming to IEEE (1997) and Cigré (1991): (refer Chapter 4 Section 11).

It is understandable that absolute precision and accuracy are not possible in calculating power system lightning performance. Lightning ground flash densities, and resulting flashovers, are statistical in nature and can vary significantly from year to year.

The overall lightning flashover rate (lightning performance of the line) is the sum of:

- direct strikes in the line (in the conductor and in the tower/shield wires) flashover rate;
- nearby strikes flashover rate.

During the design stage of the project, only the flashover rate of the overhead power line caused by direct strike in the line will be evaluated, in order to check if the selected insulation level will meet the reliability criteria set for the system.

There are several ways to mitigate the line performance to lightning:

- Improvement of footing resistances on towers.
- Increasing the Critical Flash Over (CFO) voltage of the insulator strings, increasing their length. Doing this results in unusually long insulator strings and consequently in very high towers
- Installation of line surge arresters.
- Finally, the lightning outage and performance study permits the selection of the gap clearances.

The switching overvoltages is normally coordinated with the utility.

14.2.7.2 Power Frequency Performances

The requirements for power frequency live working is normally agreed to with the utility.

Normally, the HVAC Lines tower top clearances and all insulator sets shall be designed to facilitate maintenance under live line conditions.

Expected line Availability

In networks with overhead lines, the auto-reclose relay interrupts 1 of 3 phases of the power feed to the faults detected by the time-overcurrent relay or distance relay and then reconnects it after an adjustable interval of about 300 ms. The arc across the fault is able to de-ionize during this time, and operation can resume without interruption. If the autoreclosure is not successful, the result will be a 3-phase definite trip.

From a total 100 % line outages, only about 50 % are related to transients (lightning outages, switching outages or power frequency outages), please see an example in Figure 14.2, related to the records on a period of 12 years in Sarawak.

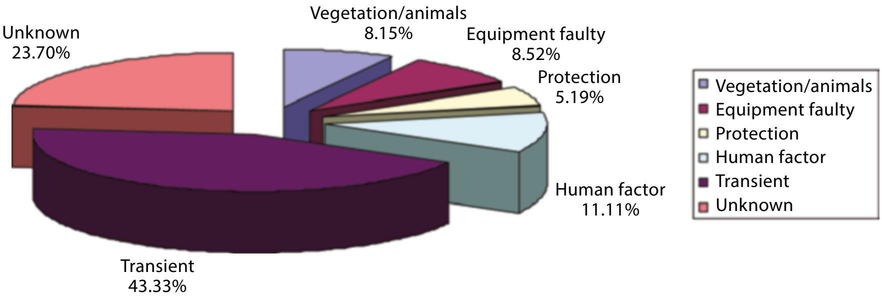


Figure 14.2 SESCo 275 kV transmission line outages distribution (12 years records).

14.2.8 Thermal Rating

The amount of current that can be transferred down an overhead line depends on the stability of the network as well as the temperature the conductor reaches. The limit is mainly to minimise the risk of safety to the public (as the conductor sags when heated) or to prevent strength loss in the conductor. According to Stephen (1992), the thermal rating of a line is termed "ampacity" and is defined as, "The ampacity of a conductor is that current which will meet the design, security and safety criteria of a particular line on which the conductor is used."

The temperature or thermal component is encompassed in the term "design" in the above definition as the design of a line involves determining the templating or design temperature of the line which is the temperature at which the conductor is at the minimum height allowed in terms of law (Stephen 1992).

The rating on the conductor is determined in the steady state (no energy stored in the conductor) equation and the dynamic equation (conductor is heating up or cooling down). The steady state of the conductor is determined by using the heat balance equation.

$$\begin{gathered}\text{HEAT GAIN} = \text{HEAT LOSS} \\ P_{\mathrm{j}} + P_{\mathrm{M}} + P_{\mathrm{S}} + P_{\mathrm{i}} = P_{\mathrm{c}} + P_{\mathrm{r}} + P_{\mathrm{w}}\end{gathered} \tag{14.12}$$

where

P_{j} = joule heating
P_{M} = magnetic heating
P_{S} = solar heating
P_{i} = Corona heating
P_{c} = convective cooling
P_{r} = radiative cooling
P_{w} = evaporative cooling.

According to Stephen (1992), the Corona heating is prevalent at times of high humidity and high wind speeds. It is thus normally irrelevant in the determination of the conductor temperature as the cooling effect due to the wind is far more dominant and error in wind speed is greater than the effect of heating of Corona.

Evaporative cooling, on the other hand is extremely effective and can have a major effect on the temperature of a conductor. However, as the equation is often used to determine the rating of lines for use in planning and operations, this cooling is ignored as it is rare that the entire line will be wet. To take it into account will result in ratings that are higher than could safely be used.

The P_j and P_M are incorporated in the AC resistance calculations which are covered in detail by Douglass (2008), and by Stephen (1992) a simplified formula was used to determine the magnetic heating component. The transformer effect, covered by Douglass (2008) was not incorporated by Stephen (1992).

In short, the steady state equation is used for development of rating of conductors (normally deterministic). This rating is used by planning and operations staff to determine when network strengthening is required. Operations staff use these ratings to determine when to load shed or transfer load. In the case of operations, these may be short term or long term ratings (Stephen 1992). It is possible to increase the load in the short term (30 minutes) above the steady state rating thus avoiding the shedding of load (real time monitoring systems are required for this analysis).

The ratings can be either deterministic or probabilistic (Stephen 1992, 1996). Deterministic "determines" the weather parameters up front and uses equation (14.12) to determine the current for a given conductor temperature. Probabilistic ratings (Stephen 1996) take into account the risk to equipment and public for different current levels in different climatic areas. This can either be a relative risk ("exceedence level") or absolute risk. The latter can be used to compare the risk of an unsafe condition occurring to the risk of failure of other facilities such as failure in a nuclear station or earthquake etc.

The parameters that affect the thermal rating of transmission lines are the height of the conductor above the ground. The height affects the temperature at which the conductor can operate prior to an unsafe condition arising. Another parameter is the ability of the conductor to withstand the temperature at which the rating is determined. The increase in the current rating from 50 °C to 80 °C is shown in the table below (Table 14.1) (Eskom 2000).

The ability of the conductor to withstand the required design or templating temperature depends on the structure of the conductor as well as the material from which the conductor is made. It is possible to use high temperature alloy conductors

Table 14.1 Conductor Rating as a Function of Templating Temperature for 158-A1/S1A 30/7"wolf" conductor (Eskom 2000)

Conductor type	Templating temperature (°C)	Rating (A)
Wolf	50	354
Wolf	60	435
Wolf	70	492
Wolf	80	540

which can withstand temperatures up to 210 °C. In this case the templating temperature can be increased to that level with the corresponding current rating. Normally, due to joule heating losses, high temperature conductors are employed where the thermal rating of the line is critical for short periods of time. They are generally more expensive than the conventional ACSR conductors and require a specialised application to warrant the additional expense.

14.2.8.1 Rating of Bundles

The rating of a bundle is determined from the addition of the rating of the subconductors.

The important fact to note is that for the same aluminium area, it is possible to have one conductor with a large diameter or many smaller conductors with smaller diameters. Although the cooling for the larger conductor is greater due to the higher Reynolds number, the rating for a bundle of smaller conductors can be higher than the single conductor as shown in the following table (Table 14.2):

As can be seen from Table 14.2, it is possible to increase the thermal rating with lower aluminium area and cost by a factor of greater than 3 by using smaller conductors in the bundle.

14.2.9 Environmental Constraints

The factors which affect the Transmission Lines should be selected and analyzed by the designer. The main factors are wind, ice, air pressure, temperature, solar radiation, lightning incidence, pollution, seismic disturbances, switching over voltages, power voltages and live line working.

The possible influences on the environment caused by High Power Electricity Transmission Systems should be individually analyzed vs. conditions from international standards. i.e.:

- Wind velocity;
- Air pressure;
- Temperatures (ambient i.e. minimum & maxim and average);
- Solar radiation;
- Lightning incidence.

Table 14.2 Increase in thermal rating using smaller conductors with more sub-conductors in a bundle

Conductor	Number in bundle	Diameter of conductor (mm)	Al Area of bundle (mm2)	Total rating (A) (50oC)	Cost/m of bundle USD	Amps/USD invested
Zebra	1	28.62	428.88	642	3.806	168.6
Wolf	2	18.13	316.12	756	3.584	210.9
Hare	3	14.16	314.94	876	1.518	577.0

- Pollution;
- Seismic disturbances;
- Switching overvoltages;
- Power voltages;
- Live line working.

The wind velocity and wind pressure should be given, or can be calculated in accordance to IEC 60826 Standard, based on data from Airports and Meteorological Stations.

The ice, wind velocity with ice and wind pressure with ice should be given, or may be calculated in accordance to IEC 60826 Standard, based on data from Airports and Meteorological Stations (IEC 60826).

Relating the air pressure the design value may be used for insulation design. The value should be in accordance to IEC Standard 60721-2-3 "Classification of environmental conditions, Part 2: Environmental conditions appearing in nature. Air pressure", in dependence on altitudes (IEC 60826).

The temperatures to be proposed for the design, i.e. minimum ambient, maximum ambient, average and together to the maximum wind pressure should be in accordance to recording data and previous design.

The solar radiation should be in accordance to IEC Standard 60721-2-4 "Classification of environmental conditions, Part 2: Environmental conditions appearing in nature. Solar radiation and temperature" for the defined line areas (IEC 60721-2-4).

Lightning Incidence should be evaluated using multiannual average values for the number of thunderstorm days per year (keraunic level) and, if available, multiannual average values of the lightning flash density (GFD-Ground Flash Density). The lightning performance of each line expressed as the annual number of lightning flashovers per 100 km of line and per year should be assessed using utility data, the IEEE FLASH program and others computer programs. In the mean time, line morphologies, data from diagrams of altitudes vs. line length, should be used.

The pollution data should be based on previous data from existing lines and accommodates with industry opportunities.

In project area, the seismic disturbances should be evaluated in accordance to IEC Standard 60721-2-6 "Classification of environmental conditions, Part 2: Environmental conditions appearing in nature. Earthquake vibration and shock" (IEC 60721-2-6).

The switching over voltages, power voltages and live line working requirements should be coordinates with the Utility.

14.2.9.1 Environmental Impact of HVAC Lines

The Electro Magnetic Field (EMF) may have implications in the design of the Space to be occupied by the HVAC line. The construction and operation of the High Power Electricity Transmission Systems and equipment can affect the electromagnetic conditions in their vicinity, the people, the land on the line route and the landscape.

Electric power transmission may have perturbing effects on other nearby industrial installations, such as pipelines, telecommunication circuits, computers and other electronic systems. Most of the annoying effects reported relate to the induction of voltages on metallic structures or objects which are not well connected electrically to the ground.

Much attention has been paid to the various form of interference, which may extend up to radio frequencies, and to finding ways of eliminating the effects or reducing them to acceptable levels.

The possible influences on the environment caused by High Power Electricity Transmission Systems, shall be individually analyzed vs. conditions from international standards. i.e.:

- The effects of electric fields;
- The effects of magnetic fields;
- Radio interference;
- Audible noise;
- Ground currents and corrosion effects;
- The use of land for transmission line;
- Visual impact.

The scope of calculations of electric fields is to select the ground clearances for electric fields: (refer to Chapter 4 Section 12 and Section 20).

Magnetic field under HVAC transmission lines is comparable with the earth magnetic fields consequently the magnetic field is not a condition in HVAC line design.

Radio interference and audible noise shall be calculated at the Edge of the Right-of-way to be compared to the limit values. For insulator strings the RI shall be proved by type tests.

Space occupied by the transmission line has a varying effect depending upon the way leave customs of the country concerned; for example whether the "restricted" area is only the area occupied by the towers themselves, or whether the entire strip of land occupied by the plan view of the transmission line is regarded as a restricted area. To define the space occupied by the OHL following line corridors shall be analyzed:

- land usage corridor which to permit the line to pass through route;
- HVAC environmental corridor, Right of Way (ROW);
- Special corridors:
  - related to radio antennas;
  - related to GSM and microwave antennas;
  - related to the parallelism with other HVAC/DC lines;
  - related to special areas, i.e. military areas, special forests, city areas which are locally defined/identified;
  - related to airports;
  - related to the visual impact (to camouflage the line).

The outline geometries for HVAC lines shall be analyzed based on the following tower configurations both from technical, economical and aesthetical point of views:

- Self support lattice structure
- Guyed lattice structure (including cross rope suspension)
- Tubular structure.

14.2.10 Mechanical Design Configurations

The main purpose of the mechanical system is to support the current carrying component. It is also important to consider all mechanical aspects of the line including the steel support in the conductors. Therefore if the mechanical aspect of the conductors can perform the dual purpose of carrying current and supporting load the more efficient the conductor.

The line is exposed to ambient conditions such as wind and ice loading which implies that the conductor system needs to be designed so as to minimise the effect of the wind and ice on the system. This is generally achieved by using fewer conductors in the bundle so as to minimise the wind load on the conductors. In addition, the lower the steel content the lower the ultimate tensile strength (UTS) of the conductors and hence lower loads result in the strain towers allowing for lighter tower designs.

The same applies to ice loading with fewer conductors in the phase bundle the lower the overall ice load.

In certain circumstances with guyed and cross rope suspension towers, the wider the tower the lower the loads in the masts and the guys. Wider servitudes are therefore generally preferred if guyed structures are to be used. Guyed structures are generally lighter and hence less expensive than self supporting structures.

Figure 14.3 and Figure 14.4 show the cross rope and guyed V tower designs. These tower types use guyed wires as supports as opposed to self-supporting towers which use lattice leg supports and no guy wires.

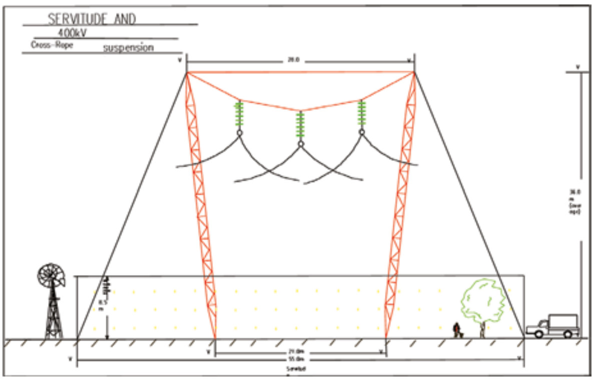


Figure 14.3 Cross Rope Suspension Tower (Variable Phase Spacing).

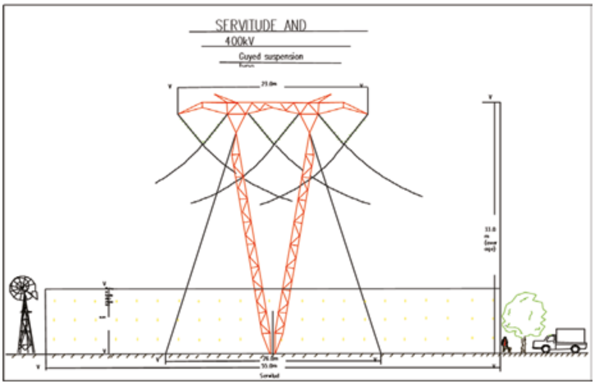


Figure 14.4 Guyed Vee Tower (Type 518).

The HVAC overhead lines mechanical performance refers to the following design and operation aspects:

- safety level of line components to actual loads (deterministic safety);
- probabilistic safety of towers by maximum wind load (probabilistic safety);
- endurance of conductors at wind induced vibrations (endurance to vibration);
- long life to first maintenance of tower galvanizing (galvanizing performance);
- long life to foundation failure (stability performance);
- long life of OPGW optical continuity (endurance to lightning strokes).

Since all these aspects are strongly influencing the line cost and line operation reliability, an optimum shall be achieved taking into account the importance of the lines within the Power Transmission system as a whole and the local service conditions.

Following is described the Probabilistic safety design philosophy. The overload factor related to actual loads resulted by Probabilistic safety approach can be compared with safety factors in case of Deterministic safety.

14.2.10.1 Reliability Requirements; Reliability Levels (Weather Related Loads)

Reliability requirements aim to ensure that lines can withstand the defined climatic limit loads (wind with a return period Tyears) and the loads derived from these events during the projected life cycle of the system and can provide service continuity under these conditions.

In accordance to EN 50341-1 (or IEC 60826 Standard), (IEC 60826) the reference reliability level is defined as the reliability of a line designed for a T year return period climatic event associated with a e % exclusion limit of strength (applies to the components selected as the least reliable).

14.2.10.2 Summary

The fewer subconductors per phase, the lower the UTS and the wider the tower the more cost effective the line design from a mechanical viewpoint. This is especially true for guyed vee and cross rope suspension towers.

14.2.11 Conclusion

The AC parameters that affect the ability of the line to transmit power over long distances are primarily the R, X (inductance) and B (capacitance) values. The thermal rating can be affected by the height above ground as well as the conductor choice which affects the sag/temperature relationship of the conductor where the sag is the distance from an imaginary line linking the attachment points of the conductor to the lowest point on the conductor catenary. The optimal line requires a low X, high B and low R. In order to achieve this, it is important to realise the constraints as far as Corona and mechanical loading are concerned. The table below indicates the relationship between SIL, Corona, mechanical loading and thermal rating, where:

"Bad" implies that the option chosen will require that parameter to be studied in depth and mitigation action taken.

"Good" means that the parameter will be favourably influenced by action (e.g. the SIL will be higher with a decrease in phase spacing).

"Neutral" means that the parameter chosen will not be affected by the choice of action.

14.3 Optimisation of AC Lines

A line is a device that transmits power over long distances ("long" in this instance in comparison to a busbar which transmits power over extremely short distances). It is a system of towers, foundations, hardware, insulators and conductors. Each of the components that make up the line affects each other and cannot be optimised on its own. Thus, for example, conductor optimisation cannot be performed in isolation. Optimisation is therefore an iterative process to ensure the overall design is an optimal one.

The optimisation process would be initiated with the purpose of the line that is being designed.

The purpose of the transmission line is to transfer a certain power over long distances. The information required in order to design the line is the power that needs to be transferred but not only the average power but the normal and emergency power transfer requirements of the line. The load profile expected on a daily weekly and annual basis is also required (Table 14.3).

- The average power is required to determine the aluminium area or best conductor selection based on the initial cost and cost of losses.
- The normal (network without any faults or outages) power requirements are used to determine the average power over the life of the line.

Table 14.3 Relationship between actions taken in line design and effect on SIL, Corona, Mechanical loading and thermal rating.

	SIL	Corona	Mechanical loading	Thermal rating
Phase spacing decrease	Good	Bad	Good	Neutral
Large Al area/per conductor (less conductors)	Bad	Bad	Good	Bad
Diameter bundle increase	Good	Bad	Bad	Neutral
High steel content	Neutral	Neutral	Bad	Good

- The emergency power transfer is the power the line is required to transmit under contingency conditions (n-1 criterion) when an element of the network is out of service.
- The load profile on a daily basis allows the conductor temperature to be determined taking into account the wind, solar and ambient temperature at that time.
- The shape of the profile will determine the cost of losses as well as the risk of exceeding the conductor design or templating temperature. A peaky profile allows for smaller conductor cross sectional areas as the cost of losses are lower (function of the area under the curve) (Stephen 1992).
- The annual load profile will indicate whether the prevailing conditions will be line loading peaks in winter or summer where the ambient temperatures will be cooler thus allowing a lower templating temperature to be determined.

The parameters such as load forecast are dependent on a number of external factors such as the economy, thus the certainty of the figures may be unknown. The designs therefore need to be robust enough to cater for the variances in the load from a growth and load profile perspective.

The planners use the model of the line described earlier to determine, via load flow analysis, the required network solution. The model used in the analysis will assume certain R, X and B values.

The planners thus need to define for the designers, the R, X and B ranges that can be accommodated as well as load profile (daily, weekly, annually) expected over the life of the line.

In order to draw the graph of the cost of construction and cost of losses need to be determined. In order for the cost of construction to be established it is necessary to decide on a range of possible line designs and their cost. This is derived from previous line designs as well as using tables for the conductor rating which is available in the conductor manufacturer's catalogues (normally deterministic rating (Stephen 1992)).

Utilities normally have a range of tower families that can be used to support the conductor types selected. The tower families will provide for phase spacings from which the R, X and B parameters can be determined using the theory explained in Chapter 4. These tower and conductor types can then be used to determine the line costs. These will be approximate costs as the soil conditions and line length will not be accurately known. It will provide an idea of the conductor ranges that could be used for the proposed line.

Once a group of options relating to conductor type, phase spacing, tower and foundation types are assumed and costs can be depicted as a function of the mean expected power transfer as shown in the graph below (with permission from Eskom) (Figure 14.5).

The graph indicated the range of power transfer for which conductor combination may prove the lowest *Life Cycle Cost (LCC)* In the range of mean power transfer in this case, from 780 MVA to 884 MVA, triple "Bersfort" (A1/S1A 48/7 687 mm^2) conductor combination appears to be the lowest *LCC*.

14.3.1 Factors Relating to Conductor Choice

The conductor consists of a current carrying portion and a mechanical load bearing portion. There is often a combination of electrical and mechanical load bearing where the conductor is made up of a mechanically strong conductive alloy. These alloys normally exchange conductivity for strength with the higher the conductivity the lower the strength. National Grid changed the conductor type on its Zebra lines (Tunstall 2000) with aluminium alloy Rubus 500 mm^2 (nominal equivalent aluminium area). This enabled an increase in the rating of the conductors and prevented new lines having to be built. In another example (Tunstall 2000) the UK faced a situation where twin Zebra conductor lines were placed in series with quad Zebra conductors. They thus had to choose a conductor which could be placed on the existing towers and carry as much current as the quad conductor lines. A gapped conductor (GZTACSR) was chosen, which has a very small variation of sag to temperature within the same cross sectional area of previous conductors (Zebra).

The load on the tower, due to wind, is depends on the conductor and in particular on the conductor diameter. If the cross sectional area is increased (thus

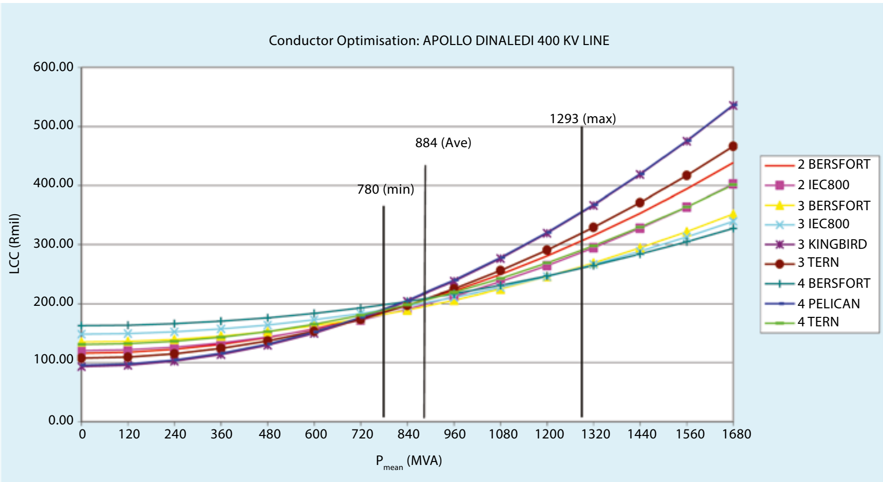


Figure 14.5 Mean Power as a function of Life Cycle Cost (LCC) (Vajeth 2004)

increasing the diameter) in comparison to the previous conductors, there could be a need to strengthen the towers. This is often not possible due to environmental constraints or could be prohibitively expensive.

According to IEC (IEC 60826) the load on the conductor is given as:

$$A_c = q_0 C_{xc} G_c G_L d \ L \sin^2 \Omega \tag{14.13}$$

Where:

A_c is the load in newtons N due to the effect of the wind pressure upon a wind span L, applied at the support and blowing at an angle Ω with the conductors.
q_0 is the dynamic reference wind pressure in P_a which is dependent on the reference wind speed and the roughness factor corresponding to the terrain.
C_{xc} is the drag coefficient of the conductor taken equal to 1.00 for the generally considered stranded conductors and wind velocities.
G_c is the combined wind factor for the conductors which depends on conductor height and terrain categories.
d is the diameter of the conductor (in m)
L is the wind span of the support, equal to half the sum of the length of adjacent spans of the support.
Ω is the angle between the wind direction and the conductor.

The force is that which is imparted on the attachment point due to the wind on the conductor. As can be seen from the equation, it is directly proportional to the diameter d.

In bundle conductors, the total effect (according to IEC (IEC 60826) shall be taken as equal to the sum of the actions on the subconductors, without accounting for possible masking effect of one of the sub-conductors on another.

This means that two conductors of diameter 18 mm with a combined aluminium area of 300 mm^2 will impart the same load as a single 36 mm conductor with an aluminium area of 600 mm^2. Thus, from a mechanical loading point of view, the less number of conductors in the bundle the better.

The conductor choice has to impact on the tower design (which is a function of the load the tower must take) which in turn has an effect on the foundation design (which is a function of the load the foundation must bear). As a rule, the fewer number of conductors in a bundle and the lower the tensile strength of the conductor, the lower the tower strength required. Corona limitations will dictate the minimum number of conductors in a bundle and the diameter of the conductor.

The life cycle cost (*LCC*) is a function of the aluminium area of the conductor which is determined from the average power required to be transmitted down the line. The aluminium area then has an input into the number of conductors in the bundle which is a function of the Corona inception voltage, which in turn is a function of the bundle configuration, phase spacing and altitude at which the line operates.

The larger the phase spacing the lower the Corona inception voltage. The higher the number of conductors in the bundle, the lower the Corona inception voltage. Unfortunately the larger the phase spacing, the higher the line impedance and losses. The higher the number of subconductors in the bundle, the higher the wind loading on the tower. Thus, the conductor structure needs to ensure maximum aluminium area for the minimum cross sectional area, low mechanical load on towers and ability to carry the normal and emergency current in the specific geographic area. In order for this to be achieved the conductor designs vary. In order to minimise the cross sectional area, conductor stranding can be trapezoidal or "Z" strand which removes any air gaps in the conductor that are present with round wire stranded conductors.

In addition, the current carrying area in the structure is increased by reducing or removing the non carrying strength component. This can be achieved by changing the material to a mechanically strong alloy which is current carrying or by reducing the steel component in the conductor. It is known that only 8 % of current flows down the steel core (Morgan 1982). Thus if this can be reduced without adversely affecting the mechanical performance it will have the effect of lower cost and lower tensile strength, which will allow for lighter tower designs especially strain towers. The reduction in steel core can be achieved by varying the diameter of the aluminium strands and the steel strands. Thus the stranding is depicted as 45/7 or 42/7 as compared to 54/7 which is the same strand diameter throughout. The 45/7 and 42/7 strandings have lower % component of steel.

In addition to the mechanical and electrical characteristics of the conductor, it is important to determine the relationship between the conductor components that carry the mechanical load as a function of temperature. As the temperature increases the load bearing in the conductor changes from the aluminium to the steel. The point at which the load is transferred from the combined aluminium and steel to steel only is the knee point as shown in the Figure 14.16.

The lower the temperature at which the knee point occurs, the higher the temperature can rise before the maximum sag is reached. Thus, depending on the required sag, the sag temperature relationship of the conductor can be specifically designed. Conductors with low knee points are either annealed aluminium conductors or gapped conductors. The conductors are more expensive than the standard ACSR conductors but allow for increased thermal rating. In addition the construction challenges in stringing a special conductor, such as gapped conductor are difficult to overcome (Tunstall 2000).

In Figure 14.6, the knee point is the point at which the slope of the sag-temperature curve changes. The lower this occurs the more the conductor temperature sag relationship will follow the steel core. This will result in a higher temperature and lower sag condition. The gapped conductor (GZTACSR) has no knee point and the sag is therefore far lower than other conductors for a wider range of temperatures. It was this characteristic that allowed the National Grid to obtain the same rating as quad rating with a twin conductor bundle (Tunstall 2000).

In conclusion, the conductor designs at present allow for tailor making the conductor parameters to the line design.

The conductor optimisation process is interactive and specialised conductor application would be undertaken after estimates made using standard conductors.

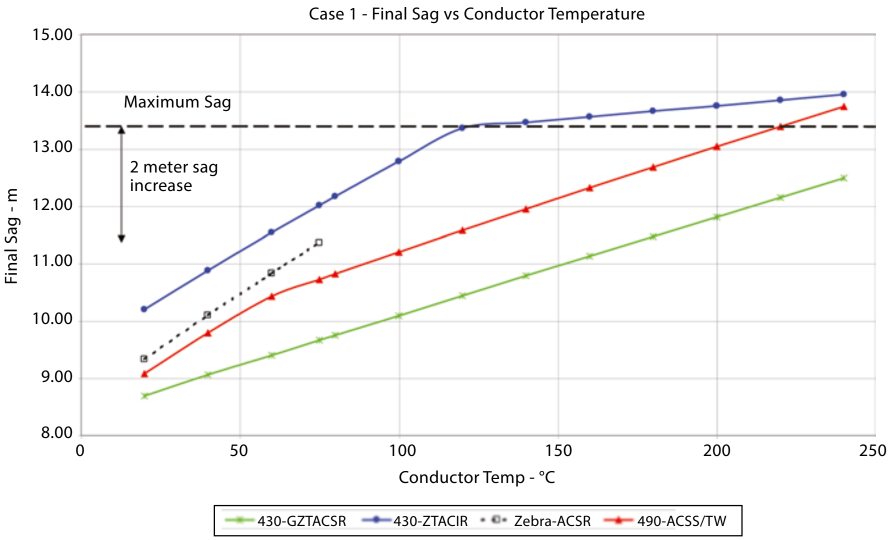


Figure 14.6 Sag vs conductor temperature (Douglass 2004)

14.3.2 Steps Required in Optimisation

The steps that are required in optimising lines, which includes the iteration with planners, are thus as follows:

- Obtain requirements from planners. This includes the following:
  - Start and end points for the line
  - Intended line voltage
  - Load peak under normal conditions
  - Load peak under emergency conditions
  - Load profile over the life of the line in terms of daily, weekly and annual load variation
  - Load factor and/or loss factor
  - Range of *R*, *X* & *B* that can be applied to the line (planners may prefer to state the standard conductor options that were considered
  - Environmental constraints
  - Cash limitations
  - Reliability requirements.
- Determine a first pass in relation to the aluminium area by assuming initial cost and calculated cost of losses.
- Determine, knowing the altitude and the voltage, the possible conductor, bundle and phase spacing options by calculating the Corona inception voltage and the voltage gradient and expressing these two figures as a ratio.
- Develop at least 10 conductor, tower and foundation combinations that will meet the planner's requirements.

- Take options back to planners to check if all options do in effect meet the planner's needs. Remove options which are a technical non optimum solution. This is because the designers can develop a number of options based on the assumptions of the planners. The planners are operating in a less certain environment and hence the designers will have a number of possible solutions for them. It is necessary to check with the planners which options will best meet their needs.
- The remaining design options now need a further analysis and a more detailed design analysis performed.

Templating, or design temperature optimisation needs to be undertaken. The emergency rating is normally taken as the parameter to meet with templating temperature increase. Thus small aluminium area conductors with more subconductors in the bundle (perhaps with a smaller overall aluminium area) with a higher templating temperature. The larger the overall aluminium area the higher the likelihood of being able to reach the emergency rating with a lower templating temperature. It may be necessary at this point to identify possibilities for special high temperature low sag conductors. The cost of the line increases with templating temperature for the same conductor bundle. However, it is possible to meet the thermal rating requirements of the line with different conductor and templating temperature configurations.

Obtain, via digital terrain modelling, a likely geographical profile for the line. This can be obtained by laser survey techniques taken over possible routes or by using the profile of a line in the area.

With the line profile, determine the optimum tower family combination for the selected conductor bundle and templating temperature options.

Further refine the tower selection with likely environmental constraints which may affect the tower selection. For example land owners in a certain area may insist on self supporting rather than guyed structures.

Re-check options using the more accurate R, X & B values from the tower families selected with planners. The load flow studies need to be performed for each year, or every five years if load and network configurations do not vary too much. The total network losses need to be determined to extract the exact effect the line has on the network (not only the loss on the line) and this information used to determine the function of P_{mean} vs. *LCC*.

The group of designs that meet the *LCC* as well as meets planner's requirements needs to be objectively rated to determine the final 2–3 designs that can be used for more detailed design process.

The detailed designs on the actual line route and geographical profile need to be done.

Other options which are hard to quantify, such as maintenance preferences, stock levels and range of materials are then taken into account from which a single tower, conductor and foundation combination is chosen to be taken to the detailed design stage.

The detailed design phase may include design and testing of a new tower design as well as specialised research for example, in joining and stringing of specialised conductors as described in (Tunstall 2000). In certain cases it may be beneficial to design a conductor specifically for the project.

The step where the possible designs are objectively rated is critical. Without an objective rating per design it is not possible to rationally decide on the best group of options. It is likely that there will be a large amount of discussion with no decision, or a sub optimal decision being taken. The nature of the line design team is that it is a multi-disciplinary team consisting of civil, geotechnical, electrical and mechanical engineers. They may tend to prefer the solution best suited to their discipline. The electrical engineers tend to prefer a large number of sub-conductors in the bundle with small phase spacing. Mechanical engineers prefer the lowest possible sub-conductors in the bundle with a wider phase spacing allowing for lower guyed loads and tower member loads.

14.4 Need for an Objective Measure

The planners' requirements of a line can be met in numerous ways to different extents. For a particular power transfer, there are many different tower, conductor configurations and templating or design temperatures that can meet the power transfer and voltage criteria required by a planner.

For example a particular required line impedance can be realized in many different ways: by changing the number of conductors/bundle, phase spacing and phase configuration.

It is thus useful to attempt to devise an objective method whereby a best group of line designs can be determined. From the best group a final decision can be reached looking at present standards, maintenance practices and the availability (or cost) of capital.

It is necessary to narrow the options by objective analysis to identify the likely best combinations without detailed analysis of every option. Thereafter, the desired solution is determined by the detailed analysis of only a few alternatives.

14.4.1 Combining Line Parameters

The optimal line design for a particular application must meet the planners' criteria for load transfer, voltage, impedance, time and cost.

The lowest cost may not result in the lowest life cycle cost, reliability criteria and other important requirements being met. Alternatively, if only life cycle cost is considered the thermal rating may not be given adequate consideration. It is not possible to determine the optimum line design without some form of combination of parameters.

The SIL is a parameter derived from the geometric configuration of the line. Thus the towers, bundles, and the bundle orientation in space are encompassed by the SIL parameter. The life cycle cost is a function of the SIL or line impedance, and in addition takes into account the initial cost, cost of losses and the maintenance cost of the line configuration.

The above parameters do not take into account the thermal rating of the line. Lines with similar SIL and *LCC* values may have different templating temperatures which will result in different thermal ratings.

Determining what constitutes a good line design is made complicated not only by the inter-related parameters, but also the variety of objectives used to determine the appropriateness of alternatives. Therefore, the purpose of an indicator must be determined up front. For example, the indicator could be as simple as the initial cost only where a temporary solution is needed in conditions of scarce capital. In different conditions, other indicators could include the life cycle cost, or a combination of cost and physical parameters.

In combining the parameters there is a risk that some value may be lost.

The number of variables and parameters used to determine an optimal line design is such the indicator should identify the four or five best line design options from which the final option can be decided by the designers taking into account all aspects such as equipment and spares holding, terrain, and current cash situation. For the indicator to select a unique best option would require many constraints and limitations to be entered into the algorithm for determination. This is not always practical and the decision might not be accepted by all stakeholders in any event.

Therefore, an indicator to determine the optimal line design must be simple in nature, take as many parameters into account as possible, and clearly indicate which design options are to be taken further for analysis.

14.4.2 Different Indicators

14.4.2.1 Life Cycle Cost

The life cycle cost includes the initial cost and the costs of maintenance and losses. Vajeth (2004) uses the life cycle cost as the main indicator, but adjusts it with the cost of additional compensation to normalize the alternatives in respect of the power transfer of the line in the actual network.

14.4.2.2 Composite Indicator

The objective measure should be a simple score or value that can be understood by designers and shared with non technical managers. Thus it can be expressed as a cost or a dimensionless score.

Stephen (2004) proposed a combination of the cost and two physical line parameters representing the purpose of the line as defined by the planners, in particular the load transfer stability and thermal limits.

The thermal rating or limit can be expressed in terms of the MVA line rating under normal, contingency and emergency conditions. It depends on the templating temperature that determines the height of the conductor above the ground.

The stability limit is a function of the line impedance which can be expressed as the SIL in units of MVA.

The initial cost (investment) is strongly influenced by the physical parameters and the life cycle cost includes the system losses. The losses can be reflected either as an MVA figure, like the ratings, or as a financial cost determined from the energy losses and the marginal costs of generation.

The challenge is to combine the parameters into a single useful index to determine the best group of designs. This is achieved by identifying three factors and translating the value of each into a score out of 10 with the present practice or normal standard being given a score of 3/10.

Factor 1 (k1) = Life cycle cost in present day currency value (*LCC*).

This is one of the main aspects of line design and covers the determination of the optimum aluminium area required (the higher the aluminium area the lower the losses but the higher the capital cost), the maintenance costs, the operating costs and project costs. Depending on the cost of capital and the cost of losses the solution may differ. For example with a high cost of capital and low cost of losses the option with the smaller conductor area will likely to be the best. Although it is difficult to determine the *LCC* as it depends on many assumptions and cost of capital, it is still possible to use the indicator if the assumptions are the same for all options being investigated.

The cost of losses must be determined using the integrated network losses and not the losses relating only to the line itself. This is because it may be found that to include a line of low impedance in the integrated network may cause a power flow that increases the overall system losses.

The lower the number the better the score.

Factor 2 (k2) = Capital investment in present day currency *CI*/MVA thermal (normal).

The second factor is a combination of the capital investment as well as the thermal rating of the line. The higher the templating temperature the higher the thermal transfer capacity of the line and higher the capital cost. In reviewing the nature of the factor or parameter the optimum design is one that will have the highest thermal rating for the lowest cost. Thus in using a ratio the lower the figure the higher the score. The absolute value of the ratio or the score is not important as the indicator is used for comparison of different designs.

The lower the value the better the score.

Factor 3 (k3) = Capital investment present day currency *CI*/MVA surge impedance loading (SIL).

The MVA (surge impedance loading) is a function of the impedance of the line. Lower impedance may result in higher capital costs but not necessarily so. Certain compact or large bundle configuration lines providing lower impedance may prove a lower cost than the higher impedance lines. Once again a ratio was found to be the best manner in which to express the two parameters. The lower the value the higher the score. The optimum line being the one with the lowest investment for the highest surge impedance loading.

The lower the value the better the score.

Stephen, (2004) uses the line characteristics and costs to form ratios.

The equation according to Stephen (2004) is as follows:

$$ATI_{AC} = w_1 LCC + w_2 \frac{IC}{MVA_{sil}} + w_3 \frac{IC}{MVA_{th}} \tag{14.14}$$

Where *ATI* is the appropriate Technology Index.

LCC is life cycle cost using system losses, maintenance and initial cost
IC is the initial cost of the line
MVA_{sil} is the surge impedance loading
MVA_{th} is the thermal limit under contingency conditions
w is the weighting of each term

As the units of each term in the equation is different, the model proposes that the "objective matrix" method is used whereby the present line design standard is given a score of 3/10. The score of 0/10 or 10/10 is arbitrary determined based on best estimate as to the best possible performance. The terms are then converted to scores out of 10 by using linear interpolation. The ATI then results in a score out of 10 for a particular line design. The weighting of each term is determined by the network planners which will then determine the importance of each component in relation to the need of the line in the network. The *LCC* would be given a high rating if the cost of Capital relatively low and the marginal cost of generation is high. If the cost of Capital (COC) is high the initial cost is often more important in relation to deciding whether the line is to be a "go" project or not. The lower the *LCC* is more effective the line design.

The $\mathrm{MVA_{sil}}$ is an important factor for long lines (above 50 kms) where the line will not be thermally limited but more limited due to system stability. The higher the $\mathrm{MVA_{sil}}$ the higher the initial cost thus as a ratio the higher the ratio the more effective the line design.

The $\mathrm{MVA_{th}}$ is an important factor on shorter lines that need to transfer large amounts of power under contingency conditions to ensure a reliable network.

The drawback of this model is that the score derived is relative and not absolute. It is thus difficult to explain to decision makers that the line design is optimum because it has a score of 5/10 or 8/10 whereas management would be more concerned with the cost of the project and tend to go for the lowest initial cost which would result in the quickest payback period.

Another drawback is that when designing lower voltage lines on which the power transfer is limited by voltage drop, the $\mathrm{MVA_{sil}}$ and $\mathrm{MVA_{th}}$ parameters does not adequately describe the purpose of the line in the network.

The implementation of the weighting factors are problematic in the future loading of the line is very difficult to determine. One use of the weighting was that, by using a range of weightings, the most robust line design option can be determined.

14.4.3 Application of the Indicator

For a particular line requirement, the following conductor combinations will meet the impedance parameters of the planner (Table 14.4).

In the use of the *LCC* method, the Table 14.5 indicates the ranking of the options in line with this method.

Table 14.4 Conductor combinations that will meet planners requirements

Case	Conductor Bundle	Conductor IEC Code	Conducting Area per Bundle (mm^2)
1	3xTern	403.77-A1/S1A-45/3.38 + 7/2.25	1211
2	4xKingbird	323.01-A1/S1A-18/1/4.78	1292
3	2xBersfort	687.36-A1/S1A-48/4.27 + 7/3.32	1375
4	3xGreely	469.6-A2-37/4.06	1409
5	6xPelican	242.31-A1/S1A-18/1/4.14	1454
6	2xIEC800	800.00-A1/S1A-84/7/3.48	1600
7	4xTern	403.77-A1/S1A-45/3.38 + 7/2.25	1615
8	3xBluejay	565.49-A1/S1A-45/4.00 + 7/2.66	1696
9	4xGreely	469.6-A2-37/4.06	1878
10	6xKingbird	323.01-A1/S1A-18/1/4.78	1938
11	3xBersfort	687.36-A1/S1A-48/4.27 + 7/3.32	2062
12	4xBluejay	565.49-A1/S1A-45/4.00 + 7/2.66	2262
13	3xIEC800	800.00-A1/S1A-84/7/3.48	2400

Table 14.5 Use of LCC method for ranking

Case	Conductor Bundle	Capital Investment Cost (Rm)	Total Line Losses Cost (Rm)	Line Life Cycle Cost (Rm)	LLCC Ranking	Deviation from Best Option (%)
1	3xTern	270	126	396	4	3.2
2	4xKingbird	273	117	390	3	1.7
3	2xBersfort	271	113	384	2	0.1
4	3xGreely	303	105	409	6	6.5
5	6xPelican	352	104	455	9	18.7
6	2xIEC800	285	98	384	1	0.0
7	4xTern	337	94	432	7	12.5
8	3xBluejay	311	91	402	5	4.8
9	4xGreely	414	79	493	10	28.6
10	6xKingbird	426	78	504	12	31.5
11	3xBersfort	377	75	452	8	17.9
12	4xBluejay	437	68	506	13	31.8
13	3xIEC800	436	66	502	11	30.8

From the initial cost analysis certain options were excluded from further analysis. These were then analysed using the composite indicators.

The composite indicator results are indicated below (Table 14.6).

The *LCC* method only looks at the first column in the Table 14.6. The rankings indicate that the other factors will bring in different options, in fact a number of options that are dropped in the *LCC* analysis will come to the fore when the SIL and MVA thermal is taken into account.

Table 14.6 Composite indicator rankings (Stephen 2004)

ATI CASE	W_1, W_2, W_3: 0.8,0.1,0.1	RANK	W_1, W_2, W_3: 0.6,0.2,0.2	RANK	W_1, W_2, W_3: 0.4,0.3,0.3	RANK	W_1, W_2, W_3: 0.2,0.4,0.4	RANK	AVE RANK
1	3.84	4	3.82	2	3.80	2	3.78	2	2.50
2	4.10	1	4.24	1	4.37	1	4.51	1	1.00
3	3.88	2	3.71	3	3.53	5	3.36	6	4.00
4	3.64	6	3.62	6	3.60	4	3.58	4	5.00
6	3.86	3	3.66	5	3.46	7	3.26	7	5.50
7	3.37	7	3.44	7	3.50	6	3.57	5	6.25
8	3.73	5	3.69	4	3.65	3	3.61	3	3.75
11	3.00	8	3.00	8	3.00	8	3.00	8	8.00

14.4.4 Analysis of Designs

The *LCC* (Vajeth 2004) method uses compensation to indicate the variation in the SIL of the design options. This is shown in the capacitance to be used to ensure the power transfer capability is comparable across all options. However, it could be argued that it is not realistic to add costs to the *LCC* which may not be required or ever installed. Thus the composite indicator, in using the actual SIL of the lines seem to indicate a more equitable method of comparing designs.

The analysis of the designs in this case are as follows.

Both indicators show the quad Kingbird as the best option, however, the option 2 is shown as the triple Bluejay conductors in triple (Vajeth 2004) method and triple Tern in the composite indicator method. This is because the triple Tern option displays excellent properties in relation to higher weighting in SIL and thermal rating. The life cycle cost is slightly higher than the other options hence its lower rating in the *LCC* method. By including other parameters such as SIL and Thermal rating the triple Tern option may be preferred over the *LCC* value only.

The composite indicator method leads to the most robust design based on the "bang for the buck" principal as it uses the ratio of initial cost to the MVA rating in terms of thermal rating and surge impedance loading. The robustness of the design can be determined from the ranking of the design in using various weightings. Thus if the design is high in ranking for a variety of weightings, it indicates that the "bang for the buck" components as well as the *LCC* is favourable for this design options. In this case the quad kingbird conductor is the favoured option.

14.4.5 Inclusion of the Constructibilty and Reliability Factors in the Indicator

It is feasible to include the reliability and constructability factors in the composite indicator. As the indicator described by (Vajeth 2004) uses the *LCC* cost, it is likely that this indicator can include only the increase in the mitigation costs in the initial cost of the line. This is minimal in the case of the cost/km of a EHV line and is not likely to affect the outcome in terms of the *LCC* cost of the line as described by (Vajeth 2004).

14.4.5.1 Constructability

The design options in this case use standard conductors at present in use in the utility. The tower types have also been used on a number of projects in the past. The one issue that needs to be taken into account is stringing of fairly light conductor such as kingbird which is an 18/1/4.78 construction meaning it is 18 strands of aluminium and 1 strand of steel all 4.78 mm in diameter. The diameter to weight ratio is an indicator of the ease of these conductor in relation to stringing. The lower this ratio the easier the stringing of conductor is as the higher the ratio the more the conductor is prone to movement in the wind. As mentioned previously the higher the diameter the more the wind load on the conductor hence the more the conductor will move when exposed to a certain wind pressure.

The Table 14.7 below uses the three conductors that includes the top three in accordance with the composite indicator. The additional conductor "zebra" is 428 A1/S1A 54/7/3.18 has been used extensively up to 6 bundle (765 kV) in Eskom and is known as a conductor that is relatively easy to string even in bundles with higher numbers of sub conductors.

The above Table 14.7 indicates that the kingbird conductor is more than 10 % higher than the other options when it comes to the diameter to weight ratio. It is also noteworthy that the Zebra conductor, which is proven to be easier to construct is again over 10 % better than the Tern or Bluebird options with the Tern option being slightly better than the Bluejay option.

The higher the number of subconductors in a bundle also affects the constructability of the line. In this case the requirement due to power transfer loading is quad kingbird compared to triple Tern and Bluejay. Thus the increase in subconductors as well as the higher diameter/weight ratio make kingbird a conductor bundle choice that is harder to construct than other options.

The type of tower as well as equipment used is also a factor in construction. This will vary from line to line and depend on the terrain, soil conditions, weather conditions and environmental constraints. The environmental constraints also refer to the right of way or servitude width, if the width is fairly narrow it will not be possible to use the tower families mentioned in the example given above and a pole or similar narrow servitude design may have to be considered.

In these cases the constraints should be determined up front and the tower family and conductor types determined for analysis after this is specified.

14.4.5.2 Reliability

The different design options are all designed with the same expected reliability. The tower window or clearances in the case of no tower window are determined using similar overvoltages in all cases as well as the same wind loading criteria as per IEC 60826 (IEC 60826). Thus the reliability levels as calculated with standards such as IEC (IEC 60826) are incorporated in all design options. However, where these tend to break down has been experienced in certain 400 kV lines on the Eskom network.

Table 14.7 Diameter to weight ratio of selected conductors

Conductor	Weight kg/mm	Diameter mm	Dia/Weight mm^2/kg
KINGBIRD	$1.030*10^{-3}$	23.9	23204
TERN	$1.336*10^{-3}$	27.03	20217
BLUEJAY	$1.870*10^{-3}$	38.9	20802
ZEBRA	$1.621*10^{-3}$	28.6	17643

Thus the use of bundles of conductors (two sub conductors and above) with high diameter to weight ratios are likely to be less reliable than bundles with diameter to weight ratios of lower than 2300 mm^2/kg.

The reliability requirements for the line need to be specified up front as well as the terrain and environmental constraints that need to be met so that the designers can design the tower family and conductor options that need to be considered for further optimization.

As mentioned above, not all constructability and reliability functions can or should be included in the indicator

The ratio can either be included in the indicator or be used as a "gate keeper". This implies that if the design is outside the ratio specified the design is not considered and therefore does not obtain a score in the indicator for further consideration.

14.4.5.3 Inclusion of Constructability

The constructability was not included in any of the indicators discussed; however, it is possible to include this aspect as a function of tower type or terrain route. Again this is likely to be subjective and vary from contractor to contractor.

In the changing of the towers from self supporting to guyed V to cross rope suspension, the contractors that were experienced in cross rope design stated in discussion that these were the easiest to erect whereas those that were more experienced in self supporting stated that this design was easier to construct.

Thus it depends on the line, terrain, contractor and equipment available at the time in determining the constructability of the line. With this complexity it is considered preferable to discuss this aspect with the stakeholders for the four designs identified by the indicator.

Based on the above analysis it is possible to determine a representative indicator for AC lines.

The indicator proposed by (Vajeth 2004) proposes that load flow studies are used to determine the *LCC* portion of the indicator as is the case with Stephen (2004), however, the MVA (thermal) and MVA (SIL) values are calculated values and are not the values that can be transferred down the line which is determined by network configuration which determines limits of transfer due to voltage or stability constraints.

The voltage drop criteria is not specifically included in any of the indicators studies but is implicitly included in the fact that there are load flow studies undertaken for both of the indicators. Thus it could be argued that if load flow studies are undertaken the voltage and stability limits are taken into account in that if the line design option is not suitable as a result of these constraints it will not be considered for further analysis.

14.4.5.4 Conclusion

The following conclusion can be reached.

The indicators parameters must be determined by actual load flow studies as well as calculated *R*, *X* and *B* values. The load flow analysis needs to take into account the various contingencies from a network and generation viewpoint.

The voltage drop, stability limitations as well as the reliability criteria in terms of the weight to diameter ratios need to be used as a "gate keeper" for the line design options that are to be further analyzed.

The ratios proposed by Stephen (2004) which indicate the amount of power transfer from a thermal and SIL viewpoint (based on calculation not load flows) per unit of currency invested gives an idea of the benefit of the design option. Thus with the load flow analysis and the calculated values the (Stephen 2004) indicator can indicate the most efficient investment in terms of initial capital invested.

14.4.5.5 Recommended Indicator for AC Lines

The recommended indicator for AC lines is therefore that proposed by (Stephen 2004), however with the following additions:-

- That the load flow analysis be undertaken to determine losses as well as those design options that will not be voltage or stability limited. Load flow runs are not always viable for years far into the future. In this case concentrate on the first 5 years due to their bigger influence at the present values of investment plus cost of losses. For the remaining years use the best possible and reasonable estimates.
- The reliability criteria for weight to diameter ratio be included as a "gate keeper"
- The ratios be used as indicated by (Stephen 2004)
- The current option be given a score of 3 and the linear function be determined per case rather than the generic limits as shown in the case study described in (Stephen 2004).

14.5 HVDC Parameters

14.5.1 Introduction

As with AC lines, the DC line is a device that transmits power over long distances (Stephen 2004). It is different in nature to other devices, such as transformers in that the design of the line is dependent on terrain and ambient conditions to a far greater extent, but is similar in some respects to AC lines.

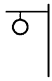
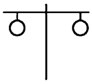
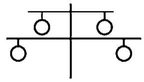
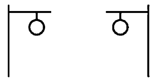
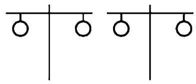
The benefit of this for the utility is that the line can be "tailor made" for the position in the grid to a far greater extent than devices other than lines.

With HVDC lines the line is often a point to point supply over long distances. In this case the terminal equipment and line design can be tailor made to the load transfer capability required.

Whilst the mechanical aspects of both AC and DC lines are similar, the DC line can have 1 or 2 poles per structure. The electrical parameters are very different. The various types of DC configuration are shown below (Nolasco 2009).

The HVDC options are shown in Figure 14.7 and indicate a wide variety of conductor locations on tower types. In addition each tower can be guyed or self supporting adding more variation.

Figure 14.7 Different DC configurations (note that the single homopolar line is practically not used) (EPRI 1993)

Variant	Tower Configuration
Single monopolar line	
single bipolar line	
double bipolar line	
two monopolar lines	
two lines (bipolar or homopolar)	

14.5.2 Load Flow Characteristics

The load flow on DC lines is determined merely based on the V = IR ohms law.

$$P_{\max} = \frac{V^2 vd\%}{100 R_x L} \quad \text{MW / Pole} \tag{14.15}$$

where vd% is the voltage drop expressed as a % of V,

V = Sending end voltage, pole to ground in kV
R_x = Dc Resistance of the conductor in ohm/km
L = Line length in kilometres.

Thus, with a higher sending end voltage, lower resistance and shorter distance the power flow can be increased. As there is limited means to adjust the distance the designer has the option of sending end voltage, voltage drop that is allowable, and resistance.

14.5.3 Calculation of DC Resistance

DC resistance is a function of the stranding and the resistance of the components of the conductor (steel, aluminium or alloy).

Note that in most cases the parameters are determined at 20 °C and then the entire R_{dc} term is modified in terms of temperature in the steady state equation for determination of conductor temperature as found in (Stephen 1992).

14.5.4 Construction of the Conductor

The conductors used on HVDC lines need not be any different from the conductors used for AC lines. The benefit of not having the transformer or skin effect does not penalise the steel core options and effect of lay ratios are more related to the dc resistance of the conductor and the resistance is therefore not a function of the current.

14.5.5 Corona Inception Gradient

As with AC parameters, the gradient is dependent on the size of the bundle and the pole spacing as well as height above the ground (Chapter 4 Section 12.1). The higher the conductor diameter and the more subconductors in the bundle the more resistant the bundle, in general, is to Corona and therefore the designer is more able to raise the voltage to ground and hence increase the power capability of the line.

According to the equations presented in Chapter 4 equation 4.152 - the higher the number of subconductors in the bundle and the higher the subconductor diameter the lower the maximum conductor surface gradient E_{max} for a constant voltage to ground.

14.5.6 Corona Power Loss

In HVDC lines the loss of power due to Corona on long lines is important. The equations for fair and foul weather are shown in refer Chapter 4 Section 19.

It is apparent (from Chapter 4) that the Corona parameters are similar to those of AC as mentioned below:

- System voltage
- Conductor diameter
- Clearances between conductor and adjacent conductors
- Clearance between conductor and earth
- Number of conductors per pole
- Bundle geometry (diameter of bundle position of subconductors)
- Conductor surface condition
- Atmospheric and weather conditions
- Earthwire design and location.

The DC Corona is also a function of the ground wire (if grounded) size and height above ground (which is also the case for AC Corona).

For reduced Corona loss a lower E_{max} is required for a given voltage thus higher bundle diameters and more subconductors will be preferable.

14.5.6.1 Radio and Audible Noise

The calculation procedure is shown in refer Chapter 4.12.1.3 and Chapter 4.12.1.5.

The conductor surface gradient has a major impact in the values and the line design shall generally adopt a lower value.

Electric field is also influenced by the conductor surface gradient that should be lower.

14.5.7 Summary

The Corona losses as well as the electric field AN and RI increase with E_{max}. E_{max} is a function of the pole spacing, the higher the subconductors in the bundle the lower is the E_{max} for a given voltage. E_{max} is the maximum voltage gradient on the conductor.

14.5.8 Mechanical Considerations

The same relationships for AC apply to DC with regard to mechanical considerations. The fewer subconductors in the phase the lower the wind forces on the tower. The lower the UTS the lower the horizontal forces applied to the towers for a standard percentage every day tension and the wider the tower the lower the forces on the guy wires for guyed vee and cross rope suspension towers.

14.5.9 Thermal Rating

The thermal rating calculation for DC rating is similar to AC with the exclusion of the magnetic heating.

The steady state equation stated in the AC section is thus still valid.

$$\begin{gathered} \text{HEAT GAIN} = \text{HEAT LOSS} \\ P_j + P_M + P_S + P_i = P_c + P_r + P_w \end{gathered} \tag{14.16}$$

where

P_j = joule heating
P_M = magnetic heating
P_S = solar heating
P_i = Corona heating
P_c = convective cooling
P_r = radiative cooling
P_w = evaporative cooling

As mentioned previously, the P_M component will not exist in the case of DC.

In the case of DC lines, the load factors are closer to unity than on AC lines as the power flow can be controlled. Thus it may be preferable to allow for higher templating temperatures to increase the power flow capability of the line which is, in this case, only voltage and temperature limited.

14.5.10 Other Factors

Other factors such as overvoltages, lightning performance, right of way (ROW) or servitude options will need to be taken into account for each line design to determine the ROW requirements depending on the tower types chosen. Guyed and cross rope towers will have a larger tower footing area than self supporting but may have lower phase spacing thus reducing ROW requirements as far as conductor blow out is concerned. These are covered in detail in Nolasco (2009) with a guideline being given for clearances.

The clearances and other factors are largely independent of the conductor/bundle (assuming the options are reliable and do not have the diameter/weight ratio as mentioned previously) and more linked to the voltage level. Thus, in the optimisation of the line using a specific voltage level, these factors are common to all options.

14.5.11 Conclusion

The Corona limitations in relation to loss, E_c and E_{max} are the important parameters with regard to DC transmission lines. Thus the bundle design and the positive and negative pole separation as well as the voltage chosen for the optimal power flow is critical in the optimisation of the HVDC lines.

The table below (Table 14.8) summarises the options relating to conductor and bundle selection for HVDC lines. Note that the SIL mentioned in the AC section is not valid for HVDC. Hence, this column is replaced with voltage drop. Where

Table 14.8 Summary of options relating to conductor and bundle selection

Action Parameter	Voltage drop	Corona	Mechanical loading	Thermal rating
+ and – pole spacing decrease	Neutral	Bad	Good (b)	Neutral
Large Al area/per conductor (less conductors)	Good	Neutral (a)	Good	Bad
Diameter bundle increase	Neutral	Bad	Bad	Neutral
High steel content	Neutral	Neutral	Bad	Good

(a) It may be good due to diameter increase and decrease of E_{max}

(b) Note that in this case the decrease in pole spacing refers to a bipolar line which is good from a mechanical viewpoint. This is because of the forces imposed on the tower due to a broken conductor condition are less if the moment on the tower is less. The spacing between two separate monopolar lines will have no effect on the mechanical characteristics.

"Bad" implies that the option chosen will require that parameter to be studied in depth and mitigation action taken.

"Good" means that the parameter will be favourably influenced by action (e.g. the voltage drop will be lower with large Al area conductors).

"Neutral" means that the parameter chosen will not be affected by the choice of action.

14.6 Optimising HVDC Line Design

14.6.1 Introduction

The HVDC line design exhibits more system parameters than the AC line. In the case with AC, the voltage is generally fixed as are the start and end points of the line. In the case of HVDC the voltage is a function of the optimisation process and is normally a function of the acceptable voltage drop, power transfer requirements, and length of line.

14.6.2 Suggested Process

14.6.2.1 Voltage Selection and Conductor Bundle Selection

A comprehensive analysis of costs is to be found in Nolasco (2009) where a detailed analysis of a range of line configurations, voltages, and terminal station options are taken into account. The following results are obtained from this document which will allow for a designer to rapidly determine the voltage level for a particular load and line length. From this graph it is possible to determine the optimum voltage for a particular load and distance as a function of annual cost per year. The cost is a function of the losses as well as the payment of the initial capital invested.

The approach used by Nolasco (2009) should be used initially by the utility to determine the ideal voltage range for a particular project. After that is determined, the optimum conductor/bundle as well as tower and foundation combination is chosen.

It is preferable to limit the number of parameters in line design and therefore it is suggested to determine the voltage prior to the line being optimised. The indicator proposed does not take into account voltage variation in AC or DC. This is because there will be too many variables to objectively determine the best option. The voltage needs to be determined prior to the line designs being determined.

14.6.2.2 Calculation of Corona

The next step is to determine the E_c and E_{max} values to determine, for the given voltage, the conductor/bundle configurations that are valid.

Following this certain conductor bundle combinations may be disqualified due to the E_{max} exceeding the E_c values.

The Corona power loss is then calculated per valid conductor/bundle options.

14.6.2.3 Calculation of Life Cycle Costs for Voltage Level Determination

In Figure 14.8, three set of line length are indicated namely 750 km, 1500 km and 3000 km for each length a set of curves of the costs for the voltages alternatives are indicated. From these the boundaries of changing optimal voltage is identified. For example, for 1500 km with power transfer below 3500 MW the voltage ±600 kV is the most economic whereas above this level ±800 kV is preferred (Nolasco 2009).

Thus, using the work of Nolasco (2009) it is possible to obtain a fair idea of the ideal voltage for the length and power required. This analysis is based on present converter station costs although it is interesting to note that the voltage for the Cahora Bassa line in South Africa (built in 1975), is appropriate according to work done by (Nolasco 2009).

14.6.3 Proposed Optimisation of HVDC Lines – Voltage Assumed

Based on the work by Nolasco (2009), the following optimisation process can be considered for a given power transfer and line length requirement.

14.6.3.1 Decide on Optimal Voltage

From the curves of Nolasco (2009) the voltage level can be decided. There should therefore be no need to design lines for different voltage levels relating to the specific project.

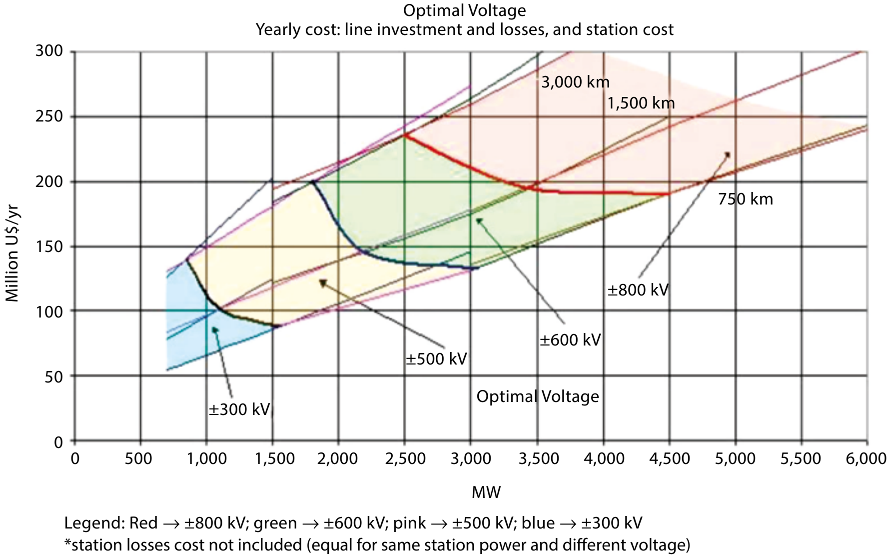


Figure 14.8 Optimal Voltage As A Function Of Converter Station Power And Line Length (Nolasco 2009)

14.6.3.2 Decide on the Conductor/Bundle Configurations

The power loss is the major factor in the running of the line and based on the initial cost, the total cost of the line, including losses, can be determined for a number of conductor/bundle configurations that will meet the Corona requirements of the voltage chosen.

14.6.3.3 Optimise the Line Design

With the voltage known and the number of conductor bundle options determined, it is possible to determine the tower, foundation and conductor combination that is optimal for the power transfer and line length considered.

The tower configurations are more varied in the case of HVDC than in HVAC. The poles of an HVDC line do not have to be on the same tower and the poles can be on different towers in different servitudes. Thus monopole, bipole, are possible.

In addition to these options there are also the options of guyed vs self supporting, cross rope, mono pole or H pole etc. The foundation and total line cost will depend on these options chosen.

From this design process, it is suggested to use an indicator as derived for the AC case to objectively determine the best group of line design options.

Note that the voltage drop considerations will be automatically taken into account in the line losses cost over the life of the line.

14.6.3.4 Re-Check the Voltage- Line Design- Converter Combination

From the initial determination of the voltage and the converter design relating to the voltage choice, it is necessary to recheck the final design to determine whether the original assumptions are valid or not. If valid, the line design can be finalised based on detailed analysis of the final group, as indicated by the objective determination process.

14.6.4 Optimisation Process Voltage Variable

It is possible to assume that the voltage is not fixed and optimise the system. If this procedure is followed, the cost of the converter stations need to be taken into account with the line design options. This will apply to the life cycle cost and the initial cost calculations.

14.6.5 Summary of Optimisation Process

14.6.5.1 Optimisation Assuming Voltage Pre-Determined

The optimisation process for a line design given a power transfer and line length requirement is proposed as follows:

- Determine the voltage level from the method proposed by Nolasco (2009).
- Determine the conductor/bundle configurations that will meet the Corona level limits for the selected voltage level

- Determine the range of tower, conductor and foundation combinations using an objective indicator
- Once the final group of line design options have been finalised, revisit the voltage, converter, line design options to check if the options chosen are indeed valid. If not the process needs to be restarted.
- Finalise the system design.

14.6.5.2 Optimisation with Varying Voltage

If the voltage is considered to be a variable, the cost of the converter station is to be taken into account in determining the life cycle cost and the intial cost. The line design options will then need to be optimised per voltage level and the overall combination determined.

14.6.6 Conclusion

The HVDC system design process is very similar to the AC design process even though there is an opportunity to vary the voltage level which is often not the case in AC systems. In HVDC the positive and negative poles need not be on the same tower, whereas in AC the phases need to be in close proximity. With these variables, it has been found that the voltage selection can be narrowed down and selected quite readily from work published by Nolasco (2009)

The line design options can be more varied than in the AC case which strengthens the case for an objective indicator to determine the best line design solutions.

14.7 HVDC Indicator for Objective Determination of Line Design

In determining the HVDC indicator the AC indicator can be used as a basis. The terms for Life Cycle Cost (*LCC*) and the thermal rating component are common to both HVDC and HV AC. The HVDC *LCC* term will use the cost of I^2R losses as well as the Corona losses which are smaller than the resistive losses. Instead of the SIL parameter used in the case of HVAC, the Corona loss parameter (or the surface gradient *SG*) can be used for HVDC.

Based on the above, the following can be used as an Appropriate Technology Indicator for HVDC.

$$ATI_{DC} = w_1 LCC + w_2 P_{losscorona} + w_3 \frac{IC}{MVA_{th}} \tag{14.17}$$

where

ATI_{DC} Appropriate Technology Index for DC lines
LCC is the life cycle cost expressed in terms of a score from 1 to 10 and IC is the initial cost.

$P_{\text{lossCorona}}$ is the power loss due to Corona.
IC is the initial cost (Investment).
MVA_{thermal} is the thermal rating of the line and depends, as in the AC case, to the templating temperature of the line.

The terms in the ATI_{DC} equation are similarly normalised into a score out of 10 to ensure these terms can be added.

The weightings are determined by system operators, but as is the case in AC instance the analysis should vary the weightings and take the option with the highest ranking across all variations of weightings representing the most robust design.

14.8 Application of Indicators

14.8.1 Application of Indicators for AC Lines

14.8.1.1 400 kV Line in South Africa

The line was to be built from Everest to Merapi substations and built to 400 kV specifications but initially energised at 275 kV.

Information pertaining to the line is as follows (rate A is the normal rating, rate B is the contingency (n-1) rating (no time limit). The MVA calculated at 400 kV (Table 14.9).

The loading on the line over the life of the line is as follows:

The initial tower and conductor selection is as follows:

The options in Table 14.10 indicate the different conductors to be used with the Cross rope suspension towers (529 series) and self supporting towers (517 series). As can be seen there are 10 conductor configurations that can meet the required load.

The following step is to determine the Corona performance of the conductor options. This takes into account the bundle configuration and line altitude. The results are shown in Table 14.11.

From Table 14.11 the items in red indicate those options whereby the surface gradient option is below standard of 5 %.

Using the conductor configurations that comply to the Corona levels, the following impedance and surge impedance loadings are calculated (Table 14.12).

The thermal limits, based on probabilistic determination of the thermal ratings of conductors, using actual weather conditions prevailing in South Africa are then

Table 14.9 Information pertaining to the line

Line Length (km)	130 km
System voltage (kV)	400 (initially operated at 275 kV)
Rating A (Normal) (MVA)	873 MVA
Rating B (Contingency) (MVA)	1163MVA
Maximum altitude (m)	1500 m
Load Factor	0.56

Table 14.10 Design options that can meet the requirements

Case	Cond. Bundle	Conducting Area per Bundle (mm^2)	Current Density per Bundle (A/mm^2)	Overall Cond. Diameter	Sub-Cond. Spacing (mm^2)	Tower Types
1	2xIEC 315	630	0.35	23.9	380	529 and 517 series
2	2x Tern	807.54	0.27	27	450	529 and 517 series
3	2x IEC450	900	0.25	28.5	450	529 and 517 series
4	3x IEC315	945	0.24	23.9	380	529 and 517 series
5	2x IEC500	1000	0.22	31.1	570	529 and 517 series
6	2x IEC560	1120	0.20	31.8	570	529 and 517 series
7	3x Tern	1211.31	0.18	27	450	529 and 517 series
8	2x IEC630	1260	0.18	333.8	570	529 and 517 series
9	4x IEC315	1260	0.18	23.9	380	529 and 517 series
10	2x Bersfort	1373	0.16	35.6	570	529 and 517 series

Table 14.11 Corona performance of conductor options

Case	Cond. Bundle	Sub-Cond. Spacing (mm)	Susp Tower Type	L_{50} Wet Audible Noise at Right of Way Boundary ≤53.1dBA	L_{50} Wet Radio Noise at Right of Way Boundary ≤72dBA	Surface Gradient Margin ≥5 %	REQ Rough Factor
1	2x IEC315	380	529C	57.8	76.4	−18.74	0.95
2	2xTERN	450	529C	55.8	73.5	−11.93	0.88
3	2x IEC450	450	529C	54.7	72.0	−8.42	0.85
4A	3x IEC315	380	529C	45.2	63.5	2.95	0.75
4B	3x IEC315	380	529A	50	65.4	−5.76	0.82
6	2x IEC500	450	529C	53.6	70.6	−4.71	0.81
7	2x IEC560	450	529C	52.5	69.2	−0,85	0.79
8	3x TERN	450	529A	48.3	62.8	1.31	0.77
9	2x IEC630	450	529C	52.4	67.6	3.58	0.75
10	4x IEC315	380	529A	44.1	56.5	11.06	0.7
11A	2x BERSFORT	450	529A	54.8	67.8	−1.02	0.78
11B	2x BERSFORT	450	529C	50.4	66.3	7.47	0.72

determined and checked against the required maximum loading of 873 MVA and 1163 MVA. The thermal limits are as follows (Table 14.13).

The life cycle costing is then determined in South African Rand (millions) (1USD = R10.00). This is shown in Table 14.14.

The Life Cycle Cost (LCC) in this case is determined from the system losses and not the losses pertaining to the line only. It takes into account the effect of the line in the network.

From Table 14.14, it is apparent that the best life cycle cost option is the option 1. Using the proposed indicator the ranking of the options are shown in Table 14.15.

Table 14.12 Impedance and surge impedance loadings of the conductor options

Case	Cond. Bundle	Tower Types	Per Unut Positive Sequence Impedances			Surge Impedance Loading SIL (MW)
			R	X	B	
1	3x IEC315	529C	0.002558	0.024232	0.788299	570
2	3x TERN	529A	0.001984	0.021371	0.895975	648
3	2x IEC630	529C	0.001975	0.026046	0.737160	532
4	4x IEC315	529A	0.001892	0.020143	0.948366	686
5	2x BERSFORT	529C	0.001819	0.025903	0.740990	534

Table 14.13 Thermal rating of the conductor options. Rate A is normal Rate B emergency (n-1)

Case	Conductor	Templating Temperature (°C)	Thermal Rate A (MVA)	Thermal Rate B (MVA)
1	3x IEC315	50	1195	1724
2	3x TERN	50	1382	2001
3	2x IEC630	50	1229	1754
4	4x IEC315	50	1594	2298
5	2x BERSFORT	50	1337	1967

Table 14.14 Life cycle cost

Case	Cond. Bundle	Capital Investment Cost (Rm)	Life Cycle Benefit from Reduced System Losses (Rm)	System Life Cycle Cost (Rm)	LCC Ranking	% Deviation from Best LCC
1	3x IEC315	176	46	129	1	0
2	3x TERN	186	48	138	2	−6.8
3	2x IEC630	186	47	138	3	−7.0
4	4x IEC315	205	49	156	5	−20.5
5	2x BERSFORT	191	48	143	4	−10.9

In the Table 14.15 k1 = Life cycle cost, k2 = initial cost/thermal rating A, k3 = initial cost/surge impedance loading.

In this case the twinBersfort conductor was taken as the basis and allocated a score of 3/10. The 10/10 scores were randomly chosen and used for all options. The score out of 10 is then determined via linear interpolation. Based on this exercise the case 1 and case 2 appear to be the best options to be taken further in the design stage. The final decision will be taken based on available capital, conductor standards used, availability of spares etc.

Table 14.15 Indicator showing score out of 10 for various weightings

Case	Cond Bundle	K1	K2	K3	$W_1;W_2;W_3$ 0.8;0.1;0.1	Rank	$W_1;W_2;W_3$ 0.8;0.1;0.1	Rank	$W_1;W_2;W_3$ 0.8;0.1;0.1	Rank	$W_1;W_2;W_3$ 0.8;0.1;0.1	Rank
1	3x IEC315	3.7	3.4	2.8	3.6	1	3.5	1	3.3	2	3.2	3
2	3x TERN	3.3	3.8	3.4	3.3	2	3.4	2	3.5	1	3.6	1
3	2x IEC630	3.2	2.9	2.6	3.1	3	2.9	4	2.8	5	2.7	5
4	4x IEC315	2.4	3.6	3.6	2.8	5	2.9	5	3.1	3	3.4	2
5	2x BERSFORT	3.0	3.0	3.0	3.0	4	3.0	3	3	4	3.0	4

14.8.2 Application of Indicator on HVDC Lines

14.8.2.1 HVDC Line Brazil

The example is a line from Brazil in which the voltage is considered variable.

The optimization methodology was applied to a HVDC transmission system with the following data (obtained from Dr. Jardini, Brazil):

- DC voltage (V) 600;700;800 kV
- number of subconductors per pole (N) 4; 5; 6
- conductor type ACSR
- Line length 1750 km
- transmitted Power 3000 MW (bipolar)
- cost of the losses 60 U$/MWh; loss factor = 0,5
- life = 30 years; yearly interest rate = 10 %
- interest during construction 10 %; maintenance 2 % per year
- cost of the line (Cl), in U$/km, according to (Nolasco 2009) and adjusted to Brazilian conditions - taxes

$$Cl = A + B\ V + N\ Si\ \left(C\ \ N + D\right) \tag{14.18}$$

$A = 86360$ $B = 130.28$ $C = 1.5863$

$D = 25.92$

Si = Aluminum cross section of one subconductor (MCM)

(Note: 2 MCM ≅ 1 mm^2)

◆ station cost (Cst), in Million U$ according (Nolasco 2009)

$Cst = 1.047$ V = 0.317 P = 0.557

P = Converter Station rated power MW

The Life Cycle cost (*LCC*), in Million U$ per year, include Line and Converter Capital Investment (*CIC*) and the line Joule and Corona losses cost.

Initially the economic aluminum cross section is determined considering the line cost and joule loses cost. This value should be used in the next calculations, however if the conductor size is above 2515 MCM (1274 mm^2) this latter value is so considered.

Then the conductor surface gradient (*SG*) is calculated and kept if the value is below the assumed limit of 26 kV/cm; it not, the conductor size is increased up to *SG* obtained is in the limit.

Next, the Thermal Rating (MVA_{th}), in MVA, is then calculated according (Nolasco 2009) considering the maximun temperature of 90 °C (40 °C for ambient temperature and 50 °C of temperature rise). Note that this example used the reference (Nolasco 2009) to determine the thermal rating. This will depend on the method used and varies from utility to utilty. The MVA_{th}, in this case depends on the voltage chosen.

Apart from *LCC* other two indexes are considered in the decision process: (CIC/MVA_{th}) to consider the impact in future expansion of the transmission; and ($CIC \times SG$) to consider the environmental impact of the line (Corona, noise, right-of-way requirements). As mentioned previously, the obtaining of the correct level of *SG* involves the bundle diameter, number of subconductors, pole spacing and height above ground (similar to MVA_{SIL} for AC).

In Table 14.16 there are 6 alternates' studies with 3 different voltages. Due to Corona limitations the minimum subconductors for 800 kV is 5 in this case.

In Table 14.17 the alternative 1 was randomly chosen to have a score of 3. The score of 10 was then also chosen for each variable. It is not critical as to what the value is that corresponds to a score of 10 as it is used to compare options and not calculate an absolute score.

Table 14.18 calculates the score by weighting the three variables viz *LCC*, IC/MVA_{th} and *SG**IC. For each weighting a ranking is determined and this is averaged in the last column. The option 6 appears to the be the best option for a higher weighting on life cycle cost and thermal rating but is not good on the *SG* rating. This is

Table 14.16 Options considered for optimization

Case	kV	N	mm^2	LCC Life Cycle Cost (MU$/yr)	CIC Capital Investment Cost (MU$/yr)	TR Thermal Rating (kA)	MVA Thermal	SG Surface Gradient (kV/cm)
1	600	4	805.7	236.3	189.3	1.49	7152	22.7
2	600	5	544.5	237.9	192.1	1.25	7500	21.6
3	700	4	765.4	231.8	194.4	1.4	7840	26.2
4	700	5	564	232.9	192.6	1.15	8050	25.7
5	800	5	684.8	234.3	211.3	1.33	10640	26.2
6	800	6	523.7	233	208.8	1.1	10560	25.9

Table 14.17 Options with scores for each option

Case.	LCC	Score	CIC/MVA Thermal	Score	SG*CIC	Score
1	236.30	3.00	0.0265	3.00	4297.11	3.00
2	237.90	2.69	0.0256	3.39	4149.36	3.31
3	231.80	3.87	0.0248	3.76	5093.28	1.31
4	232.90	3.66	0.0239	4.15	4949.82	1.61
5	234.30	3.39	0.0199	5.99	5536.06	0.37
6	233.00	3.64	0.0198	6.03	5407.92	0.64

Table 14.18 Scores for various values of the weighting factors

Case	0.8;0.1;0.1	Rank	0.4;0.4;0.2	Rank	0.2;0.4;0.4	Rank	0.1;0.3;0.6	Rank	Average
1	3.00	5	3.00	6	3.00	5	3.00	2	4.50
2	2.82	6	3.09	5	3.22	3	3.27	1	3.75
3	3.60	1	3.31	4	2.80	6	2.30	6	4.25
4	3.50	3	3.45	3	3.04	4	2.58	3	3.25
5	3.34	4	3.82	2	3.22	2	2.36	5	3.25
6	3.58	2	3.99	1	3.40	1	2.56	4	2.00

because of the high initial cost and the relatively high surface gradient given it a rank of 4/6. Looking at the options, the options 4,5 and 6 should perhaps be looked at further. As option 4 is for 700 kV and the other 2 options for 800 kV it may be preferable to assume a voltage of 800 kV and expand the number of conductor and tower options.

14.9 Component Cost of Lines

14.9.1 Method Applied to General Costing of Lines

The transmission line unit investment cost is calculated depending on tower/pole standard spans or economic span (for which the investment cost is lower). The following are a rule of thumb method to roughly determine the cost per km of line.

Standard span is selected between four or five selected spans (such as 300 m, 350 m, 400 m, 450 m and 500 m in case of high voltage lines), it is presumed that the economic span will be between them.

The cost may include or exclude VAT and ancillary expenses, such as shipping insurance, custom duties, surcharges or land acquisition.

The proposed method is to calculate and add the costs of main elements which compose the line, i.e.:

- Conductors, including Joints and Spacers,
- OPGW and EW, including accessories and Joint Boxes,
- Towers/Poles, including tests and Earthing Systems,
- Insulator Strings and
- Foundations of the line.

The cost of transport + insurance + erection is considered as coefficients applied to each line element cost. For conductors and towers/poles, the formulas are:

$$\begin{aligned}\text{Conductor cost} = {} & 1.03 * \text{mass/km} * \text{N phases} \\ & * \text{N circuits} * \text{N cond/phase} * \text{Cost/ton} \\ & * \text{Erection factor}\end{aligned} \tag{14.19}$$

$$\begin{aligned}&\text{Towers/Poles cost} = \text{Mass of suspension tower} \\ &\text{/ pole} * \text{Heavy \& Angle tower/poles factor} \\ &* \text{Cost/ton} * \text{Erection factor} * 1000/\left(0.95 \times \text{selected span}\right)\end{aligned} \tag{9.1-2}$$

Heavy & Angle tower/pole factor includes and the influence of the percentage of Angle towers/poles in line.

Mass of suspension towers may be calculated, or estimated with Cigré (Cluts 1991b) formula:

$$\text{Mass} = \text{Constant} \times \text{Height} \times \left(\text{Maximum Moment}\right) 0.5 \quad (9.1\text{-}3)$$

OPGW cost is calculated with a similar formula like Conductor cost adding the costs of accessories and Joint Boxes.

Insulator String cost is calculated depending to the percentage of Angle towers/poles in line.

Foundation cost is calculated with a similar formula like Tower/Pole cost, using the volume of suspension structure and the cost for volume (cubic meter).

If data is available, the costs shall be calculated based on Manufacturers' prices (Figures 14.10 and 14.11).

Below are represented the results of cost calculations in case of a HVDC bipolar line, Figure 14.9 and a HVAC double circuit line Figure 14.12.

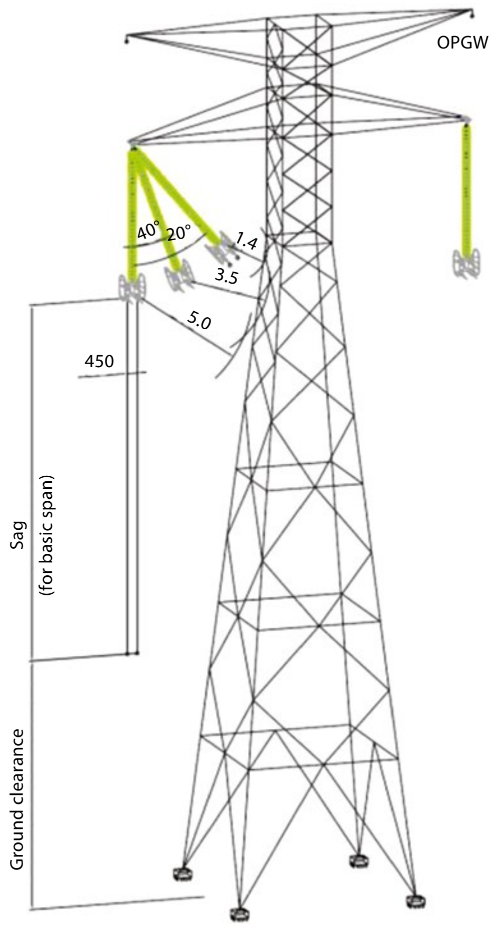


Figure 14.9 Tower for bipolar line, medium pollution. (Fichtner Engineering +/− 500 kV HVDC Projects)

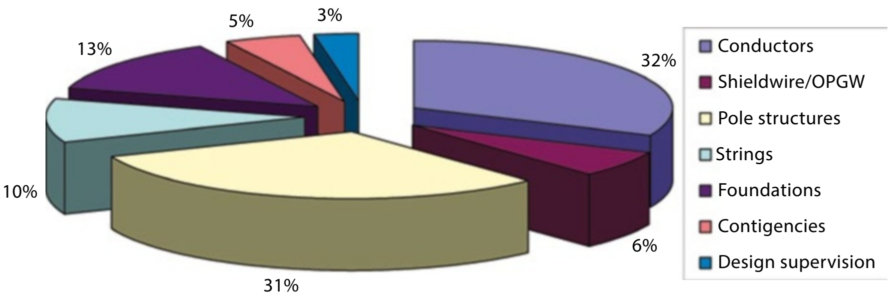
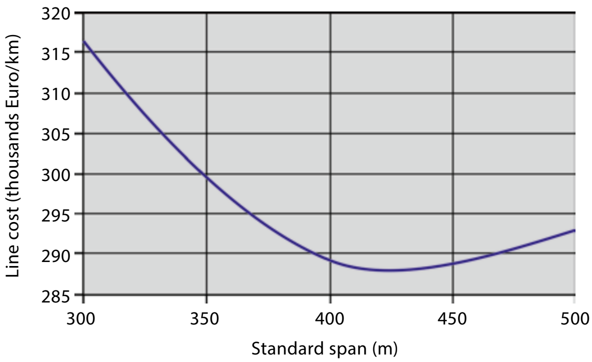


Figure 14.10 Cost repartition for HVDC bipolar line, medium pollution (+/– 500 kV Projects).

Figure 14.11 Dependence of Line cost with standard span for bipolar line, medium pollution (excluding VAT and ancillary expenses) (+/– 500 kV HVDC Projects).



14.9.2 Questionnaire

In order to update the cost components of lines, it was decided, in 2013, to undertake a survey on line costs. The result was a very small sample of lines submitted but the results can indicate certain trends when compared to the 1991 survey (Figures 14.13 and 14.14).

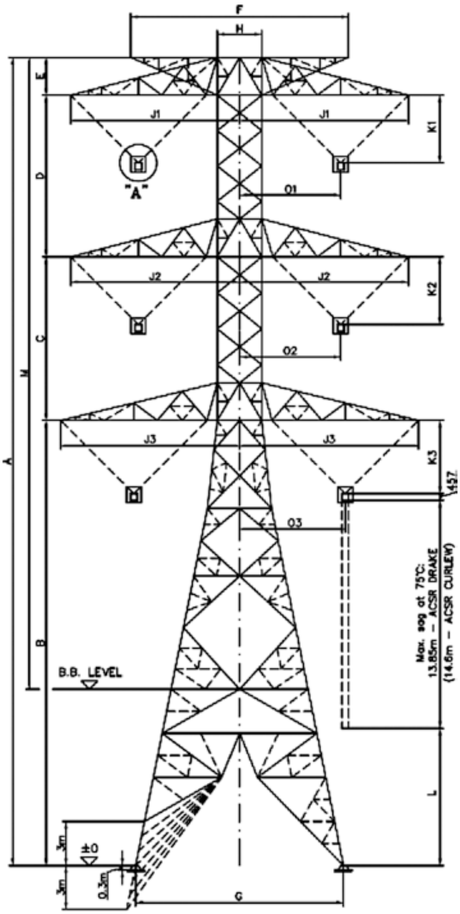
The analysis of the results indicates the following

Figure 14.15 indicates a wide variation between the different submissions with most countries indicating construction costs exceed the material costs. The main exception is South Africa which may have imported materials with lower labour costs. Design costs average around 20 % of the line cost which includes the landowner and environmental considerations. Of interest was the Iceland consider these examples to have very high material costs, percentage wise this does not seem to be the case compared to other submissions.

A further investigation into line costs revealed the following:

Figure 14.16 indicates fairly widely varying cost per km figures where the voltage does not seem to be a deciding factor relating to cost per km.

Figure 14.12 Tower for HVAC line.(Fichtner Engineering 500 kV double circuit line in tropical area)



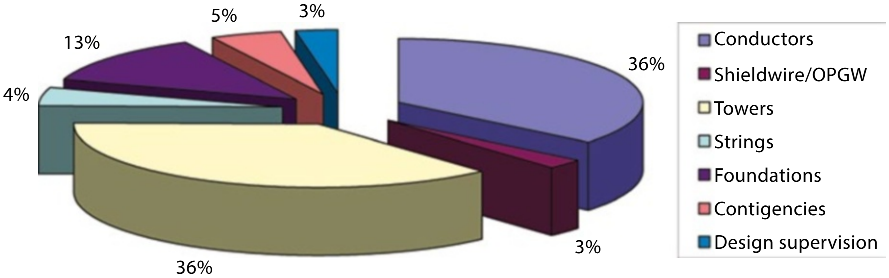


Figure 14.13 Cost component for HVAC line (500 kV double circuit line in tropical area).

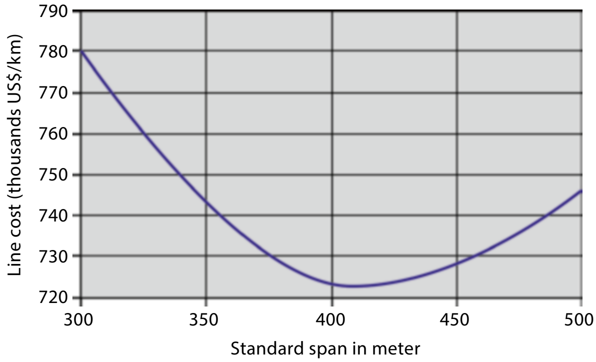


Figure 14.14 Dependence of line costs with standard span for HVAC line (excluding VAT and ancillary expenses) (500 kV double circuit line in tropical area).

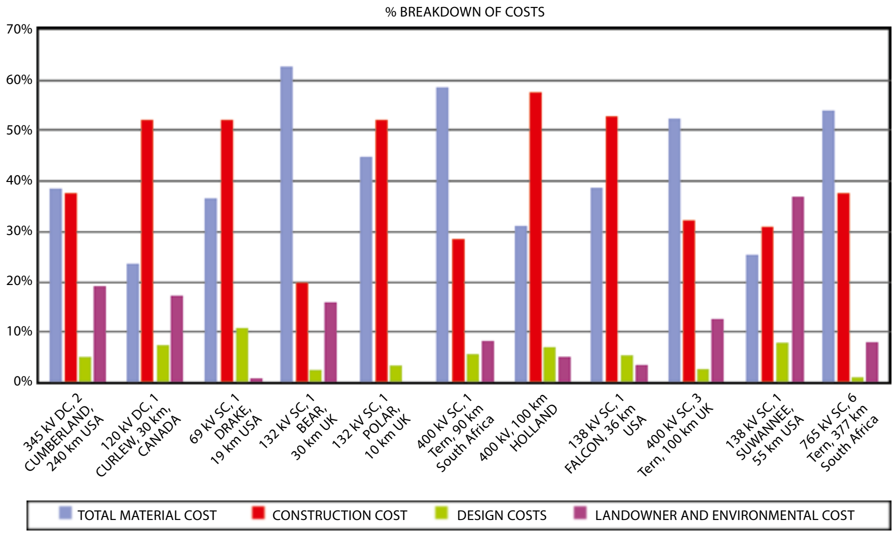


Figure 14.15 Indication of component percentages.

14.9.3 Comparison with Previous Work

Table 14.19 is taken from the work performed by WG 22–09 (Cluts 1991a).

Table 14.20 refers to the percentage costs for the different components between 1991 and 2013. The figures for 2013 may not be accurate due to the small sample of lines received in the questionnaire feedback.

Material and construction costs: the trend appears to be that the material cost has reduced as a function of total cost with the construction cost being the more prevalent cost. This appears to be the case over the entire range of lines investigated.

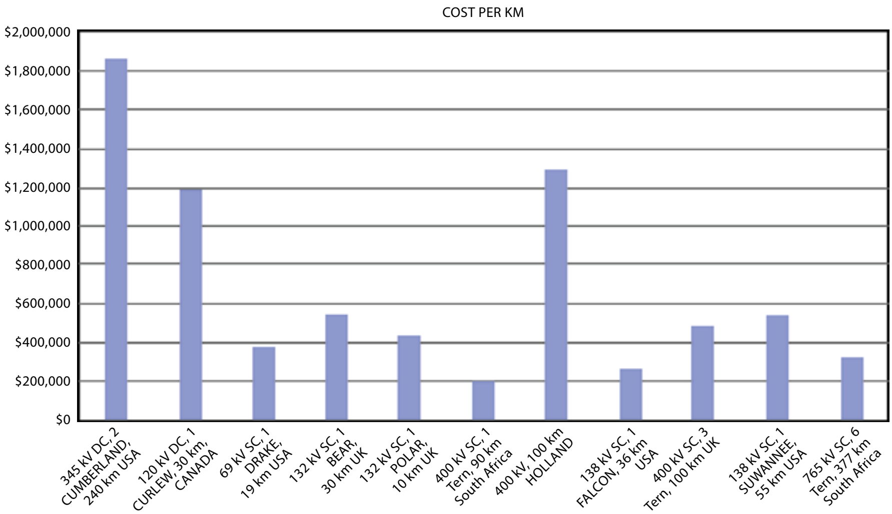


Figure 14.16 Cost per km for each case (prices in USD).

Table 14.19 Line components from 1991 (Cluts 1991a) report

Category		Total Cost Percentages		Component Cost Percentages				
		Material Costs	Constr Costs	Cond	Shield Wire	Insula-tors	Towers	Found
1	For all lines and votlages	63.7	36.3	32.7	3.8	8.1	3.2	19.2
2	For all lines up to 150 kV	64.3	35.7	31.6	4.1	8.8	36.0	19.5
3	For all lines between 150 kV and 300 kV	65.0	35.0	31.5	3.5	9.3	36.0	19.7
4	For all lines over 300 kV	62.6	37.4	34.1	3.9	6.9	36.4	18.7
5	All single circuit lines	63.6	36.4	33.1	4.2	8.2	35.6	18.8
6	All Double Circuit lines	63.8	36.2	32.0	3.3	7.9	37.1	19.7
7	Self-supporting steel tower lines	64.1	35.9	31.9	3.9	8.1	36.6	19.6
8	Guyed structure lines	59.6	40.4	32.8	3.2	8.3	36.0	19.8
9	Other types of structure lines	66.2	33.8	41.5	4.4	8.3	32.0	13.7
10	Lines with 1 conductor/phase	64.4	35.6	32.2	4.2	8.5	36.3	18.8
11	Lines with 2 conductors/phase	64.6	35.4	32.3	4.0	8.1	36.2	19.4

(continued)

Table 14.19 (continued)

Category		Total Cost Percentages		Component Cost Percentages				
		Material Costs	Constr Costs	Cond	Shield Wire	Insula-tors	Towers	Found
12	Lines with 3 conductors/phase	60.8	39.2	35.1	3.7	7.0	40.3	13.8
13	Lines with 4 conductors/phase	61.4	38.6	33.4	2.7	7.6	33.4	22.9
14	Lines with ice loading	63.9	36.1	31.2	3.7	8.5	35.4	21.2
15	Lines without ice loading	63.9	36.1	31.2	3.7	8.5	35.4	21.2
16	Lines with ACSR conductor	64.4	35.6	32.4	4.0	8.3	35.7	19.7
17	Lines with AAAC conductor	59.6	40.4	34.3	3.1	7.1	38.9	16.6
18	ACSR conductored lines up to 150 kV	64.0	36.0	31.0	4.1	8.7	36.2	19.9
19	AAAC conductored lines up to 150 kV	6.2	33.8	36.3	3.8	9.4	34.5	16.1
20	ACSR conductored lines 150 kV to 300 kV	65.1	34.9	31.5	3.7	9.3	35.7	19.8
21	AAAC conductored lines 150 kV to 300 kV	62.7	37.3	30.9	0.5	10.1	41.3	17.2
22	ACSR conductored lines over 300 kV	64.3	35.7	34.1	4.0	7.2	35.3	19.3
23	AAAC conductored lines over 300 kV	57.0	43.0	34.0	3.2	6.0	40.0	16.7
24	Short lines – less than 30 km	66.3	33.7	31.6	3.5	8.4	36.8	19.7
25	Medium length lines 30-100 km	65.0	35.0	33.3	3.8	8.4	36.6	17.8
26	Long length lines over 100 km	62.0	38.0	32.8	4.0	7.8	35.7	19.6
27	Contractor built lines	64.3	35.7	32.3	3.8	8.3	34.3	21.3
28	Utility built lines	62.7	37.3	33.3	3.9	7.8	39.2	15.7

Conductors: in the 2013 cases the steel shield wire is included in the conductor cost. Even with this inclusion, it appears the conductor cost is generally the same or lower percentage of the total cost as compared to 1991.

Shield wire: this cost is related to the OPGW cost for 2013 and the steel wire cost for 1991. The sample for double circuit and single circuit lines for 2013 is very small and therefore cannot be considered to be representative. However it indicates a similar percentage to the 1991 costs even though the shield wire is more complicated and expensive in real terms in 2013.

Table 14.20 Comparison of line component costs between 1991 and 2013

	Year	Material Costs	Construction Costs	Conductors	Shield Wire	Insulators	Towers	Foundations
For all lines and voltages	1991	63.7	36.3	32.7	3.8	8.1	36.2	19.2
	2013	42.4	57.6	31.8	2.7	7.6	46.3	11.6
For all lines up to 150 kV	1991	64.3	35.7	31.6	4.1	8.8	36.0	19.5
	2013	46.4	53.6	28.6	2.0	7.9	49.6	11.9
For all lines over 300 kV	1991	62.6	37.4	34.1	3.9	6.9	36.4	18.7
	2013	46.8	53.2	35.7	3.0	7.2	42.7	11.4
All single circuit lines	1991	63.6	36.4	33.1	4.2	8.2	35.6	18.8
	2013	42.8	57.2	33.4	2.8	6.9	43.7	13.3
All double circuit lines	1991	63.8	36.2	32.0	3.3	7.9	37.1	19.7
	2013	31.0	69.0	24.7	2.3	10.6	58.1	4.3
Guyed structure lines	1991	59.6	40.4	32.8	3.2	8.3	36.0	19.8
	2013	55.0	45.0	36.5	3.2	6.3	41.3	12.7
Lines with 1 conductor/phase	1991	64.4	35.6	32.2	4.2	8.5	36.3	18.8
	2013	38.7	61.3	28.3	2.0	7.8	45.1	16.9
Lines with 2 conductors/phase	1991	64.6	35.4	32.3	4.0	8.1	36.2	19.4
	2013	38.0	62.0	32.3	2.3	10.6	48.4	6.3
Lines with 3 conductors/phase	1991	60.8	39.2	35.1	3.7	7.0	40.3	13.8
	2013	41.5	58.5	36.6	4.6	6.6	42.6	9.6
Lines with 4 conductors/phase	1991	61.4	38.6	33.4	2.7	7.6	33.4	22.9
	2013	56.5	43.5	34.2	3.4	7.9	37.9	16.7

Insulators: the percentage of total cost spent on insulators seem to be slightly lower than in 1991. This could be due to the advent of composite insulators which have dropped in price considerably over the years as well as glass being more competitive with merger of manufacturers.

Towers: The percentage of the total cost spent on towers seem to be higher than in 1991. This cost includes the erection cost which could indicate the higher cost of labour which is reflected in the construction cost compared to material cost.

Foundations: The percentage of the total cost spent on foundations seems to be lower than is 1991. This may be due to the higher level of mechanisation and perhaps use of more pile foundations but this is not confirmed.

14.10 Conclusion

In conclusion it is possible to tailor design a HVAC and HVDC line to suit the actual requirements of the network. The same techniques can be used in uprating or refurbishment of lines where conductors and tower may need to be replaced. The techniques offered propose a "return on investment" approach whereby the good designs are considered lines which will provide a low Life Cycle cost, high thermal rating for low initial cost and high surge impedance loading (or low Corona loss) for low initial cost. The designer has a method whereby it is possible to objectively determine the set of line designs to pursue further. This assists in optimising the line function for the requirements of the grid whilst being able to indicate the benefit to the utility.

Experience with the use of the indicators has resulted in Civil, Mechanical, Geotechnical, electrical and material engineers coming together to design a line as a whole rather than designing a line in different, separate components.

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Robert Stephen has MSc, MBA degrees and recently received his PhD degree in line optimisation from the University of Cape Town South Africa. He is employed in Eskom, the South African utility where he holds the position of Master Specialist. He has been involved in all aspects of line design as well as network planning, electrification and project management. In study committee B2 (overhead lines) he has held position of working group convener, special reporter, advisory group convener and was chairman of SC B2 from 2000–2004. He has published over 100 papers and been involved in technical brochures on aspects of thermal rating, real time monitoring and overall line design since 1988. He is an horonary member of Cigré and a fellow of the South African Institute of Electrical engineers.

Construction

15

Zibby Kieloch, João B.G.F. Silva, Mauro Gomes Baleeiro, Mark Lancaster, Marcin Tuzim, and Piotr Wojciechowski

Contents

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Z. Kieloch (✉)
Winnipeg, Canada
e-mail: zkieloch@hydro.mb.ca

J.B.G.F. Silva • M.G. Baleeiro • M. Lancaster • M. Tuzim • P. Wojciechowski

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15.1 Introduction

This chapter will address practical aspects of constructing overhead transmission lines. Various aspects of material procurement, inventory control, construction supervision and engineering support during construction are addressed in Chapter 3 "Planning and Management Concepts" of the Green Book and are not addressed here.

Material contained in this Chapter is intended to provide a concise picture of the most common construction activities and installation techniques used in installation of an overhead transmission line. Special attention is being paid to construction activities requiring either high degree of accuracy or those posing high safety risks to construction crews. This Chapter does not address custom type design applications requiring very specialized and rarely used techniques or equipment, as these issues are being addressed by other chapters dealing with either design approaches or material requirements.

15.2 Construction Surveys

Placement of transmission line structures in specific locations as determined during the tower spotting process is critical from legal, environmental and technical perspectives. Field surveys are needed to:

- Establish the limits of the transmission line right-of-way,
- Establish transmission line centre line,
- Identify structure locations including individual legs, anchors, foundations,
- Mark locations/zones where special construction techniques are required (i.e. use of mats to protect the soil or areas requiring hand clearing),
- Identify danger tress for removal.

Accurate locations of structures and their components in the field are important to allow for ease of installation and to provide safe operational performance as intended.

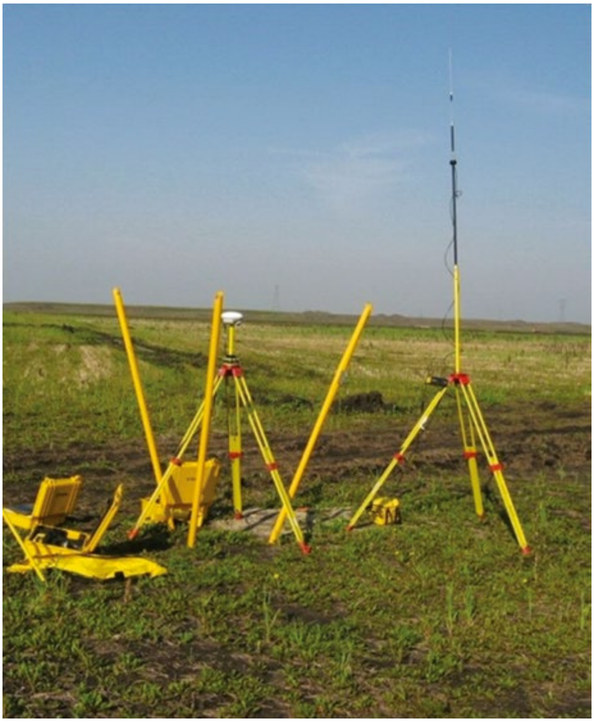

Figure 15.1 Modern electronic equipment used in transmission line surveys.

In the past, field surveys required mostly optical instruments, various manual calculations and intensive labour resources. Presently, some of these tasks are simplified thanks to the use of computerized tools and instruments such as total station equipment or real time kinematics GPS systems based on satellite signals (Figure 15.1). Subsequently, the speed of surveying and the accuracy of work have both improved significantly.

15.3 Right-Of-Way Clearing and Site Access

Transmission line right-of-way may require removal of trees and shrubs to allow for construction activities. In many cases, vegetation is allowed within a transmission line right-of-way providing it is controlled and does not lead to operational problems (i.e. tree contacts with an energized conductor leading to line outages).

Various techniques are used in the right-of-way clearing depending on site specific requirements and license conditions. They range from the use of shear blades to remove most of the vegetation to the use of chain saws to remove individual trees. In some cases, vegetation clearing is done at the structure locations only. In other cases, no vegetation clearing is allowed at all and so called "tree canopy" towers are used with the conductor hanging above the tree tops.

In some cases, selective clearing is used to minimize negative effects on the environment. This may be required at the stream, lake or river crossing or at any environmentally sensitive locations. Selective clearing may be done by hand clearing using chain saws or by use of specialized equipment such as feller-bunchers (Figure 15.2).

Removal of the cut trees/vegetation will depend on the conditions of the project licence. In some cases, trees are cut and sold as merchantable timber. In other cases, trees and shrubs are chipped/mulched down and disposed at the job site or within the right-of-way.

Access to a new transmission line right-of-way needs to be provided for the construction activities. In many cases, temporary access roads are developed to bring in required materials and construction equipment. In some cases, these temporary access roads are within a right-of-way and they continue to be used later by asset owners for maintenance purposes.

Site access may be limited to specific periods of time due to either environmental constrains or terrain conditions. In some areas with poor terrain such as swamps or permafrost, access may be restricted to winter months only with frozen conditions allowing the use of heavy equipment. An example of such conditions is shown in the photograph below (Figure 15.3).

Other measures to help gain access to the transmission line construction site include the use of soil mats to minimize damage to the soil or the use of helicopters. In very remote areas, difficult terrain conditions or areas with severe restrictions to vehicular traffic, helicopters may be the only option. In order to use helicopters for transportation, special provisions need to be made at the design stage. Often, additional lifting brackets may be required in the tower design (Figure 15.4).

Figure 15.2 Feller buncher used to remove danger trees at the edge of right-of-way.

Figure 15.3 Transportation of heavy construction equipment over a frozen lake.

Figure 15.4 Steel tower lifted by a helicopter and transported to the installation site.

15.4 Foundations

15.4.1 Introduction

This chapter will highlight the main challenges encountered during installation of transmission structure foundations.

Foundations are the most critical components of an overhead transmission line system. They are responsible for transfer of the line loads from the structure onto the soil. They also provide stability of the supporting structure and protection from extensive deformations. Failure of foundations can have catastrophic consequences to the overall transmission line system - often causing prolonged line outages and requirements for extensive rebuilds. In comparison, failures of other components, such as hardware or structural members, can be localized and may not result in line outages at all.

Selection of foundation and anchor options for a given project is done at the design stage. Various foundation design options include:

- Spread footings (concrete, steel or lumber),
- Drilled concrete with reinforcing steel,
- Piles (driven type, screw type, concrete, micropiles, single or group arrangements),
- Direct imbedded foundations,
- Anchors (helical screw, grouted, plate, single or in a group).

In many cases, especially when a transmission line traverses large and diverse environment, foundation designers develop multiple foundation design options allowing the installer to choose the most suitable option as determined at the specific site.

Cigré TB 308 provides a comprehensive overview of various foundation options. TB 308 also contains a foundations installation guide, a review of health and safety concerns as well as an assessment of the environmental impacts and various mitigation measures.

Cigré TB 281 deals with the installation of micropiles and ground anchors which might be good foundation choices in terrain with poor soil conditions or difficult access.

An additional source of good information on foundation installation is the IEEE 977 Standard.

15.4.2 Excavation

The foundation installation process starts with excavation. Usually, a trial pit is excavated at a structure site to identify the soil conditions. In case of guyed towers, multiple pits may be required. Selection of the foundation type is the responsibility of the contractor. However, the final decision generally resides with the site engineer/supervisor who has the right to override the contractor's selection (in cooperation with the foundation designer).

Once the foundation option has been selected, the full excavation process (if applicable) can begin. The work must be performed in a manner ensuring due stability of the foundation holes, surroundings (trees, roads, buildings, etc.) and safety of people.

Hydraulic excavators, such as the one shown in Figure 15.5 are often used for the excavation in normal soils such as clay. Excavations with unshielded walls may only be performed in un-saturated soils and while maintaining safe wall inclination.

In more loose soils, internal sheeting, as shown in Figure 15.6, can be used to keep open access to the excavation hole. The main load-bearing elements of the structure are steel or wooden puncheons, while the elements protecting the soil from falling are made of boards or steel sheets.

The excavated material is removed and stock-piled. It can be later used as a fill but not as compacting material.

If in the course of the foundation works the excavation is made too deep, it should not be filled with the excavation material, but a concrete or condensed gravel substructure up to the foundation depth needs to be installed. During installation, water should be prevented from entering the foundation excavation. When required, an appropriate drainage system is used to lower the ground water level without causing decrease in the load-bearing parameters of the surrounding soils or negative impact on the environment or surrounding infrastructure.

Figure 15.5 Hydraulic excavator during the work of strengthening the foundation of 110 kV OHL.

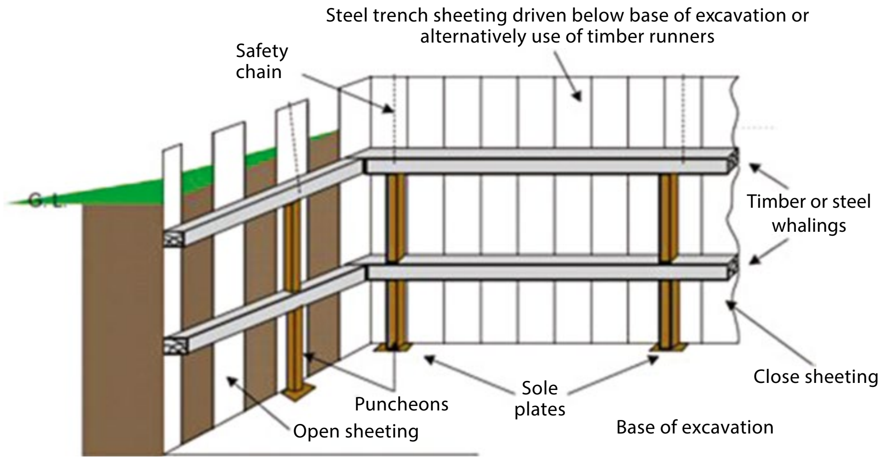

Figure 15.6 A view of an properly made excavation sheeting.

In very dense soils, heavy duty excavators are used. In rock, hydraulic hammers or explosives may be required.

Other construction equipment used in excavations include: trucks, energy generators, vibration plates, jumping jacks, vibration hammers, levelers, etc.

15.4.3 Concrete and Reinforcement Works

Concrete foundations are used on overhead transmission lines worldwide. Their popularity is due to ease of design, ease of obtaining base materials (cement, sand, water) and low installation costs.

15.4.3.1 Reinforcement

Foundation stub angles get positioned in the excavation prior to insertion of steel reinforcement. Proper alignment of the steel stub angles is critical in successful tower installation and can be achieved by the use of rigid steel leg templates reproducing the position of all four tower legs in relation to each other or by the use of independent concrete slabs to which individual stub angle is attached.

The reinforcement bars/rods should be free from visible defects and damage, clear from excessive amounts of rust, mud and other dirt. The bars should be joined by means of tie wire or welding. To ensure proper setbacks, plastic distance holders providing minimum distance between the reinforcement and the formwork are used. An additional procedure increasing the firmness of ready-made reinforcement cages and protecting it from canting during installation or concrete works, is to use additional inclined bars along and across the mounted reinforcement cases.

15.4.3.2 Concrete Mixing and Placement

The concrete used in foundation works may be mixed directly on site or brought in or from the concrete mixing plant. If mixed at the job site, the following measures must be taken:

- Proper storage for cement, sand, stone, aggregate, and water is required,
- Silos used for bulk storage of cement should be weatherproof and protected from dust pollution,
- Bagged cement should be stored to prevent it becoming damp and used in the same order as delivered,
- Cement that is adversely affected by damp should not be used,
- Aggregate storage areas should have adequate drainage,
- Water should be protected against contamination.

If produced at the concrete mixing plant, mixing of the concrete should be done with the use of machines preventing its fractions from separating and its consistency from changing. For longdistance transport of concrete mixes, truck concrete mixers with low rotation speed should be used to prevent segregation of the materials. For short-distance transport on site, conveyor pumps are often used.

Normally, concrete should be placed within two hours after the initial loading in a truck mixer or agitators, or within one hour if non-agitating equipment is used. These periods may be extended or shortened, depending on climatic conditions and whether accelerating admixtures or retarding admixtures have been used. Before the concrete is placed, all rubbish should be removed from the formwork and the faces of the form in contact with the concrete should be cleaned and treated with a suitable release agent.

The quality of the concrete mix can be checked at the job site using a slump test which involves filling a steel cone with concrete mix, removing the cone and then measuring the concrete shape slump. Additional tests include preparation of concrete cubes for strength testing at the lab after 7 and 28 days to verify adequate strength.

The free drop height of the concrete mix should be made as small as possible. It should not exceed 100 cm. The thinner the mix, the smaller should be the height of its drop. With liquid mixes, the height should not exceed 50 cm. In higher trenches, concrete should be placed with the use of tubes, sleeves or chutes. Whatever the method used, the last stretch to be filled with concrete (50 cm) must be vertical and not sloping as this prevents separation of the mix.

15.4.3.3 Concrete Consolidation

Consolidation of the concrete mix is the last procedure but one (before curing) that determines the quality of both the concrete itself and the structure made of that concrete. For this reason:

- the mix must be consolidated until it is compact and homogenous,
- the excavation must be tightly filled, and the reinforcement – precisely coated,
- the surface of the structure should be as smooth and pore-free as possible.

The most widespread method of concrete consolidation is vibration. In practice, internal or external vibrators are used. Vibration lasts for 10–30 seconds, which depends on the consistency and composition of the concrete mix as well as the type and parameters of the vibrator. Vibration should be discontinued as soon as the cement wash appears on the concrete surface.

15.4.3.4 Concrete Curing

Proper concrete curing in essential in achieving desired mechanical parameters. The concrete, particularly in the summer time, requires proper humidity to be maintained. Unrestricted water evaporation can lead to undesired concrete shrinking. Therefore concrete must be protected from water loss due to extensive wind and temperature, using a special curing compound, covering with foil or pouring with water. During rain fresh concrete shall be protected from direct effects of rainwater. During winter the proper maturing conditions for concrete shall be ensured by:

- external warming of the foundation by means of e.g. straw batts, styrofoam,
- using chemical concrete additives shortening the concrete bonding time or increasing its temperature,
- heating the water or the aggregates,
- use of heating rods inside and outside the foundation,
- increasing the cement content, that increases the hydratation temperature.

Concrete works in temperatures below −10 °C is not recommended.

15.4.4 Drilling and Blasting

In some soil conditions, foundation excavation is done by the means of drilling and blasting methods. In stable materials drilling should be to the full depth of the excavation. According to IEEE 977, inspection of the drilling and blasting activity should include monitoring to ensure that survey controls such as tower center monuments, survey hubs, reference points and benchmarks are not distorted or lost.

During such drilling and blasting, work safety procedures must be followed. When blasting are done near existing infrastructures (ie. OHL) or inhabitants, a "heave mat" should be placed over the blast area. This mat prevents or minimizes the danger of rocks impacting existing infrastructures.

15.4.5 Assembly and Setting of Foundations

Accurate placement of foundations and anchors is extremely important to achieve proper installation of the structures while maintaining legal commitments to the affected land owner. Additionally, incorrect installations may lead to undesired visual effects. It is always recommended to use proper surveying techniques.

In order to ensure proper steel tower stub anchor installations in the concrete foundations, steel templates are used. They are usually made of steel angles that are welded to the reinforcement or steel trench sheeting of the foundation. There are ready made holes in templates in order to provide temporary connection with the anchor of the tower. Sometimes, when the foundations are very big, steel truss constructions are used as templates. It is recommended to place and measure all foundations anchors of the tower at one time.

Each country has its own installation tolerances based on their own experiences and local regulations. Some of the tolerances are presented in Cigré TB 308 (Figure 15.7).

15.4.6 Backfilling

Proper compaction of the backfilling is crucial for achieving desired uplift resistance. Most failures of foundations take place due to the tower leg being pulled out and not pressed down (see Figure 15.8). The main principle of using proper backfill is to achieve soil characteristics close to those of natural soil.

The following methods are used to obtain the appropriate condition of the backfill:

- Backfilling should be done by placing backfill in layers,
- Use of proper backfill material which is easy to compact,
- Modification of the structure of the backfill by application of an additive for draining of the moisture (e.g. lime),
- "Fixing" the particulates of cohesionless soil (reducing its deformability) by chemical stabilization, joining with additives, e.g. cement,
- Separating the soil and broken stone levels or reinforcing them by means of reinforcement (e.g. geosynthetics).

The most popular method used in the construction of the overhead power lines is compacting of the backfill. Cohesionless backfill should be placed in layers, approximately 25–35 cm thick, each compacted by vibration plates, jumping jacks or vibration hammers. A commonly used practice enhancing condensation is to damp the filling soil by pouring it with water and its simultaneous compaction. Another method of increasing the load-bearing capacity is the stabilization with cement.

Cohesive soils shall be condensed in layers every 20–25 cm, using non-hammering methods, e.g. tamping rollers after fragmentation of the agglomerated soil or vibration plates instead of hammer-type methods. Damping the filling soil with water is a gross mistake.

The compaction index, typically in the range of 0.96-0.98, is often specified by the foundation designers to be achieved during installation.

15.4.7 Foundation Installation Challenges

Installation of transmission structure foundations presents various challenges and problems. Some of them are:

Country	Face Dimensions	Diagonal Dimensions	Rake of Stub	Stub Levels	Twist of Stub in plan
Belgium (Elia)	Linearly from ± 0 to 10 mm for 0 to 5 m face or diagonal dimensions, then ± 10 to 15 mm for 5 to 15 m face or diagonal dimension.		≤ 5 mm / m	Max. difference between highest and lowest stub ≤ 2 to 5 mm varying linearly between 0 and 12 m face dimensions.	≤ 5 mm / m
France (EDF)	± 10 mm	± 15 mm	Angles ≤ 100 mm 10 mm / m Angles > 100 mm 5 mm / m	Max. difference between each pair of stubs 10 mm.	-0.01< tgα < + 0.02 + towards centre of tower.
Ireland (ESB)	± 5 mm	± 10 mm	Nil – Bottom panel of tower used as stub setting template.	Max. difference in level between all 4 stubs 3 mm; Max. difference between mean level of pairs of diagonally opposite stubs 3 mm.	Nil – Bottom panel of tower used as stub setting template.
Italy (ABB)	± 12 mm or ± 0.2% of face or diagonal dimension.		0.3°	Difference in levels between one stub and a plane passing through other 3 stubs ± 3 mm or 0.1%.	0.5°
Norway (Stanett)	Use of Holding Down Bolts with holes 8 to 10 mm larger than bolt diameter, horizontal tolerance ± 4 / 5mm, vertical maximum difference 3 mm.				
Spain (Red Electrica) (Iberdrola)	± 0.1% of face dimension	± 0.15% of diagonal dimension	± 5 mm /m	Max. difference in level between all 4 stubs ± 0.01% of diagonal; Max. difference between mean level of pairs of diagonally opposite stubs ±.0.15%.	Not defined
	± 6 mm or ± 0.1% of face dimension	± 6 mm or ± 0.1% of diagonal dimension	± 5 mm /m	Max. difference in level between all 4 stubs 3 mm or ± 0.01% of diagonal; Max. difference between mean level of pairs of diagonally opposite stubs 3 mm or ±.0.1%.	1% of width of steel frame
UK (NGT)	± 10 mm or ± 0.1% of face dimension	± 15 mm or ± 0.1% of diagonal dimension	1:100 from hip slope	Max. difference in level between all 4 stubs 10 mm or ± 0.05% of diagonal; Max. difference between mean level of pairs of diagonally opposite stubs 6 mm.	1° about longitudinal axis
USA (GAI)	± 0.1% of face dimension	± 0.1% of diagonal dimension	± 1.6 mm / 300 mm	Max. tolerance from the top of each stub 0.1% of face or diagonal dimension; Max. difference between mean levels of diagonally opposite stubs 0.1% of diagonal dimension.	Not defined

Figure 15.7 Foundation setting tolerances.

Figure 15.8 Foundation uplift. The right hand foundation is intact.

15.4.7.1 Safety

During all installation foundation stages (excavation, reinforcing, concreting, back-filling) good safety procedures must be followed in order to avoid human injuries and equipment damage.

15.4.7.2 Environmental Requirements

Special measures are required to minimize negative impact on environment and surroundings.

15.4.7.3 Logistical Problems

- Delays in delivery of the concrete,
- Improper backfill material,
- Malfunctioning of the equipment,
- Encounter of unexpected conditions: underground infrastructure, war explosives, big rocks, unstable soil, high ground water levels, etc.,
- Inexperienced construction personnel causing installation errors.

15.4.7.4 Extreme Weather Conditions

- Heavy snow or rain,
- Flooding,
- extreme cold or heat.

15.4.8 Foundation Failures

Transmission structure foundation failures may occur as a result of either poor design or incorrect installation. Typical causes of such failures include:

- Mistakes in design calculations,
- Improperly collected or assumed soil strength parameters,

- Faulty materials used,
- Improper backfilling,
- Insufficient reinforcement or piles.

Additionally, transmission foundation failures can occur due to the failure of other line components such as an insulator or a hardware string.

The catastrophic failure of a single foundation can lead to cascading failures of several structures, especially if a transmission line has no provisions for anti-cascading or "stop" type structures.

The following are two examples of foundation failures.

15.4.8.1 Failure of a 220 kV OHL

The failure started at a tension tower. Over 7 km of OHL was destroyed (Figures 15.9 and 15.10).

Figure 15.9 Destroyed tension tower of a 220 kV OHL.

Figure 15.10 A view of the destroyed suspension towers of a 220 kV OHL.

Figure 15.11 Tension tower destroyed and moved down about 14 m on a 110 kV OHL.

Figure 15.12 Landslide causing destruction of a road, a house and a tower on a 110 kV OHL.

15.4.8.2 Failure of a 110 kV OHL

Failure caused by a landslide (bad geotechnical design). 1.3 km of OHL was destroyed (Figures 15.11 and 15.12).

15.5 Structure Assembly and Erection

15.5.1 Introduction

This Section provides an overview of all the activities involved in the erection of HV Transmission Line structures, addressing the typical installation techniques, equipment and safety requirements, as well as general advice regarding the best and most common industry practices used to achieve safe and cost effective installation.

15.5.1.1 Structure Types

The installation techniques may vary according to the structure types and may be better suited or be more effective in regard to cost and time, for one type or another. This Section focuses on the installation of guyed and self-supporting steel lattice tower types, designed and manufactured using steel angles and plates, with bolted joints, corresponding to the vast majority of the high and extra-high voltage transmission lines built up around the world. This construction type is the most common in all parts of the world.

Cigré TB 416 provides examples of various alternate and innovative structure designs used worldwide.

15.5.1.2 Preparation Work

Prior to commencement of tower installation, the following preparation work must be done:

- All structural design drawings including structure layout, erection, and bill of materials must be available,
- Plan and profile drawings identifying structure types and their locations must be available,
- Structure and anchor foundations must be in place, with their cast in metallic inserts clean and ready for erection start up, observing the minimum time lapse for concrete curing, as applicable,
- All the steel must be made available.

15.5.1.3 Logistics, Site Facilities and Mobilization

A good logistical planning and execution at site is essential for the success of the tower installation activities, as multiple resources are applied simultaneously at multiple spots, organized in a logical sequence. Large quantities of steel angles of different sizes are usually delivered by "the like pieces" to a marshaling yard (usually called "cemetery"). They need to be re-bundled by "component" prior to the transportation to their erection sites.

15.5.1.4 Equipment and Tools

The typical equipment and tools used for HV transmission structures assembly and erection can be grouped into 4 basic categories:

- Small Individual and portable tools, suitable for the manual tower erection activities. The ordinary individual or portable tools for work at height consist of the fork wrenches and torque wrenches used by the linemen. A handheld electric-rechargeable battery screw driver is also used for the tower preassembling on the ground.
- Medium-light equipment and tools, for the partly mechanized tower erection activities. The medium-light category comprises small equipment and heavier tools mainly used for pulling ropes and lifting the tower pieces and sections, or tensioning the guy wires, such as hoists, handheld devices such as the come-alongs, small stand-alone motorized winches, together with sets of fiber or nylon ropes, sets of anchors, pulleys and hooks or equivalent, or hydraulic light

truck-mounted types; also steel or aluminum truss-type beams to be attached to the tower legs or masts and work as gin poles; ladders.
- Heavy equipment, for the extensively mechanized tower erection activities. In general, the heavy equipment determines the installation method, and vice-versa; it can be one or multiple gin poles, mobile-cranes, preferably the "all terrain" types on wheels, or giant helicopters, known as "sky-cranes".
- Auxiliary stuff. A radio communication system is extensively used; grounding devices are mandatory to be in place, prior to commencement of any tower erection work; theodolites are used to control leveling, alignment and plumbing.

15.5.1.5 Safety Requirements

Tower erection is amongst the activities posing the highest safety risks to the construction crews and therefore it requires special individual and collective protection and strict compliance to the safety rules. As a general safety rule, every piece of equipment, tools, ropes, pulleys, hooks, safety clamps, etc, need to be inspected, calibrated and have their nominal capacity tested and certified, prior to be released to the sites and/or put into service.

Laws and Regulations

Special provisions concerning the management of risks and safe work procedures at height apply to the tower erection activities, according to the local laws and regulations for each country.

Labor Qualification

The assembly and erection of any tower requires team work, where each member of the team performs a specific task that has to be perfectly orchestrated with the others. Only professionals who are well trained and certified to work at height shall be hired to perform such a job.

Individual and Collective Protection

It is mandatory that the employer provides and ensures that all his/her employees properly uses and continuously keep their individual and collective protection devices, know and abide to the local legislation, guidance and codes of practices, whenever working at the tower sites, as applicable.

Weather Condition Restrictions

As another safety rule, the tower erection activities shall not be performed or has to be discontinued whenever subject to the risk of lightning or under rainfall, snowfall, fog or haze.

15.5.2 Installation Techniques

Provided that the preparation work has been properly done as above, and the towers have been sorted out to their spots in a sequence, complete with their legs, extensions, bodies and accessories, according to the construction lists, then the installation work shall commence. Special attention has to be paid to prevent damage to the steel and to the galvanizing coat, by splitting the tower members, and/or preassembled sections, preferably over a timber bed and providing them with proper rigging with fiber or nylon ropes during the lifting and temporary guy wiring processes. No tower element shall be bent or eventually subjected to undue straining during erection. As a generally accepted practice, the tower joints shall not have their bolts tightened to the prescribed torque at first, so that a minimal degree of freedom is allowed in order to accommodate the necessary corrections in the level, verticality and/or alignment of each tower section. A surveyor with the theodolite has to be positioned along the tower axis line to control and command these corrections during the entire tower erection process.

There are four main methods of erection of steel lattice transmission towers which are described below:

15.5.2.1 Manual Erection Piece by Piece: the Build-up or Piecemeal Method

This method consists of building up the tower, member by member, from bottom upwards. The tower members are laid down serially on the ground according to the sequence and closest possible to their erection positions, to avoid time loss.

For self-supporting towers, the erection procedure starts with the preparation and positioning of the first four leg segments together with their relative step bolts, joint plates and splices; then lifted and tilted to the right angle, bolted to the foundation stubs and hold their upper end firmly in their positions, by a temporary guy wire anchoring system. Linemen climb up the leg segments and stay positioned to proceed forward with the tower erection. Subsequently, bracings and diagonals are rigged, lifted and rendered to the linemen to be located at their respective joint plates, then inserting as many bolts, washers and nuts that corresponds to the assembly drawings and to the joint holes, and tightened, in order to complete the first section, i.e., the base frame of the tower. The same procedure is repeated for the following sections until the tower is completely erected.

For guyed towers, the procedures are similar and need to be adapted to the vertical erection of the tower mast components, anchored all the way up by temporary guy wires, until it reaches the final and definitive guy wire anchoring positions and then the tower head is completed.

Generally, hoisting of members is carried out manually and/or by an auxiliary beam, having ropes and pulleys attached to the tower legs, to work as a gin pole, or even assisted by small standalone winches.

While it is still extensively used in many parts of the world, this is a labor intensive and less productive method in comparison to the others and can only be suitable and advantageous if:

- The use of a heavy equipment, such as a crane or a helicopter, is not available, or is not feasible for technical or economic reasons,
- There is qualified and cheap labor available, in abundance,

- There is not enough flat land near to the tower spot available and cleared for tower and/or tower sections preassembling,
- It is used as a complementary activity in special circumstances and in combination with other methods, such as
  - to erect the upper part of a tower, if its height and weight exceeds the capacity range of a crane,
  - to erect a heavy tower base, especially in case of unequal legs, in preparation for a faster helicopter erection of the remainder parts, particularly in rough terrain with difficult access, or inside to a rainforest with a narrow ROW clearance; for smaller jobs, especially out of sequence,
  - illustration of the Build-up Method as complementary to the Section Method is provided in Figures 15.13, 15.14 and 15.15.

Figure 15.13 Build-up Method - Manual erection of a self-supporting tower aided by gin poles, in a swampy area; no access for cranes; no place for preassembling.

Figure 15.14 Build-up Method - Manual erection of a self-supporting tower aided by gin poles, in a mountainous area; no access for cranes; no place for preassembling.

Figure 15.15 Build-up Method/Complementary -Manual erection of the upper part of a self-supporting tower aided by gin poles; tower height exceeded crane capacity range.

15.5.2.2 Section Pre-assembling on the Ground and Equipment-aided Erection: the Section Method

This method consists of the preassembling of the major sections of the tower on the ground and then to rig and lift them as units, using a gin pole, a mobile crane or a helicopter, up to their final elevation, section by section, until the erection of the entire tower is complete. Hence, it speeds up the erection process and reduces the risk exposure to the construction crews. Prior to commencing, an analysis of the dimensions and weight of the tower components, as well as for the entire tower height, per each type and quantities, needs to be conducted so that the right erection strategy is formulated and the most suitable lifting equipment can be selected.

Using a Gin Pole

The gin pole used consists of a steel or aluminum truss-type beam, approximately 10 m long, and is held in place by means of guys on the side of the tower to be erected. The erection procedures inherent to the Section Method are mostly the same, whether using a gin pole or a mobile-crane. However, the gin pole-aided erection has some limitations and depending upon the size and weight of the tower sections and members, they may have to be split. For instance, a common practice is to divide it in two pairs of legs forming two panels preassembled on the ground that correspond to the opposite faces of the tower section, then lifted, tilted, spliced to the immediately subjacent stubs or leg segments and anchored with temporary guy ropes. In case only one gin pole is being used, to raise the second face of this section, it is necessary to shift the foot of the gin pole on the strut of the opposite side of the tower.

After the two opposite faces are raised, the bracings on the other two sides are fitted and bolted up by the linemen to complete the tower section. The tower sections are lined up and made square to the line, as the erection develops. After completing a tower section, the gin pole needs to slide up to be able to pull up another section. The gin pole is then made to rest on the top strut of the tower section's leg, immediately below the leg splice and properly guyed into position. The last lift raises the top of the towers.

After the tower top is placed and all side bracings have been bolted up, all the guy are removed, except the one which is to be used to lower the gin pole. An illustration of the gin pole-aided erection of guyed and self-supporting towers is provided in Figures 15.16, 15.17, 15.18, and 15.19.

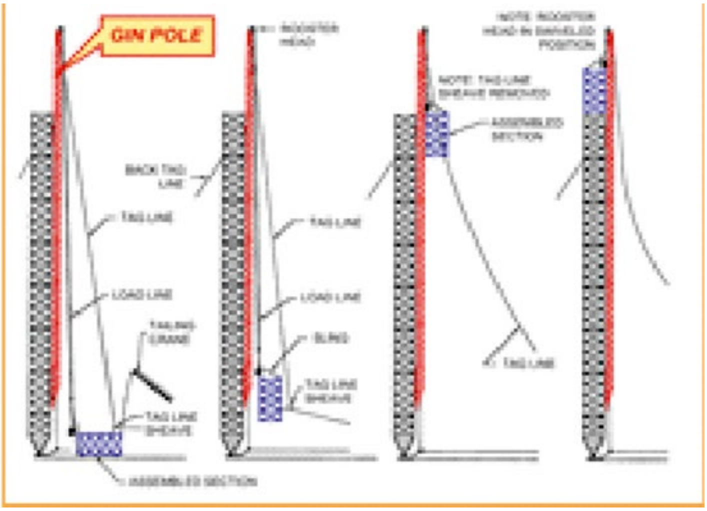

Figure 15.16 Section Method – Illustration of the erection of the central mast of a guyed tower using a gin pole; mast sections were preassembled on the ground.

Figure 15.17 Section Method – a cross arm section of a self-supporting suspension tower is erected using a gin pole.

Figure 15.18 Section Method – a cross arm section of an angle tower is erected using a gin pole.

Figure 15.19 Section Method – a cross arm section of a tower is preassembled on the ground; this method speeds up the erection process.

Using a Mobile-Crane

The Section Method using a Mobile-Crane, preferably an “all-terrain-on-wheels” type, is the most productive for the erection of self-supporting towers, particularly in flat terrain with good access conditions. An illustration of this Method is shown in Figures 15.20, 15.21, and 15.22.

Figure 15.20 Section Method – tower sections preassembling takes place at the tower spot in preparation for erection using a mobile crane.

Figure 15.21 Section Method using a Mobile Crane – a lateral section of a tower is preassembled on the ground and then lifted and mounted on its final position by the crane.

Figure 15.22 Section Method using a Mobile Crane – a cross arm section of an angle tower is preassembled on the ground and then lifted and mounted on its final position by the crane.

Using a Helicopter

The Section Method using a helicopter, as an air-crane, is also very productive for the erection of self-supporting towers, particularly in bad terrain with limited access conditions. Special accessories combining a coupling and guiding system and consisting of angle guides and steel frame corner brackets, need to be installed on both ends of the four corners of the tower sections to be coupled. This coupling system is designed to ease and speed erection, to quickly release the helicopter and to be stand alone, i.e., with no linemen attendance. Linemen will then climb up the tower to bolt up the remaining joints and leg splices, to finalize erection and remove the coupling and guiding accessories. This method is illustrated in Figures 15.23, 15.24, and 15.25.

15.5.2.3 Tower Assembly on the Spot and Mobile-crane Erection: the Tilting and Stand Up Method

This method consists of assembling the whole tower on the ground just aside and/or closest possible to the tower footings, and then tilt and stand it up, as a complete unit, using a mobile-crane, that holds the tower while the linemen crew connects and strings the guy wires to their anchoring positions. This is the most usual and most productive method for the erection of guyed towers, particularly in flat terrain with good access conditions (Figures 15.26, 15.27, 15.28, and 15.29).

In some cases, it may be disadvantageous because it requires plenty of land cleared at the tower spot to allow for the entire tower preassembling. Therefore, it may be subject to restrictions by the land owners in case a large damage to their plantations or tillable areas could occur. Limitations may also apply in case of hilly terrain where the assembly of complete tower on slopping ground may not be possible or, either if it may be difficult to get the crane into position to raise the complete tower. This method may also not be useful if the towers are too large and heavy.

Figure 15.23 Section Method using an Air-Crane – mid sections of a tower are preassembled on the ground and then lifted, flied off and mounted by the S-64 Erickson air-crane; linemen not necessarily required to assist up to this point.

Figure 15.24 Section Method using an Air-Crane – the top beam of the head of a "delta" tower is mounted. No linemen on the tower.

15.5.2.4 Tower Assembly in a Yard, Stand up and Air Transport to the Spot: the Helicopter Method

This method consists of the setup of a batch production line for the entire preassembling of a group of towers, corresponding to the tower row in a line segment as per the construction sequence, altogether in a marshaling yard and prior to erection. Then plan for the helicopter pick up and erection campaign, to properly rig, tilt and lift, tower by tower, as complete units, and fly over the line by the shortest distance up to each tower spot, respectively, where they are placed and left in their final erection positions. For self-supporting towers, there are special coupling and guiding accessory systems, located at the tower stubs, capable of managing the entire tower, in order to allow for a faster release of the helicopter back to another trip, while the linemen finally bolt up the tower leg splices and remove the coupling accessories. For guyed towers, a line crew needs to be on the ground when the helicopter arrives and hovers on the tower spot, to assist with the tower placement on the central pin,

Figure 15.25 Section Method - the head of a "racket" tower is mounted.

Figure 15.26 Tilt and Stand up Method – The entire tower is preassembled on the ground (step 1).

Figure 15.27 Tilt and Stand up Method – The entire tower is tilted, keeping its foot on the ground (step 2).

Figure 15.28 Tilt and Stand up Method – The tilting and lifting of the entire tower continues (step 3).

Figure 15.29 Tilt and Stand up Method – The tower is lifted and mounted in the central pin, the guy wires are anchored. (step 4).

as well as, to provisionally connect and string the four guy wires to their anchoring position, for a quicker release of the helicopter. This is the most productive method for the erection of either guyed or self-supporting towers, particularly in bad terrain with difficult access conditions. The use of helicopters, however, is expensive, weather-dependent and requires especial arrangements for the fuel supply. Also, more strict and stringent safety and labor regulations governing the aviation industry applies. This method may not be useful if the towers are too large and heavy (Figures 15.30, 15.31, and 15.32).

15.5.3 Bolt Tightening and Finishing

It is a usual industry practice that during the course of erection the bolts and nuts at the tower joints receive a provisional torque, just enough to keep all the members together securely and allow the whole assembly to stand upright. The same procedure is applied to the guy wires. This is a strategy to speed up erection and make efficient use of the bulk erection crew and expensive equipment.

Figure 15.30 Helicopter Method – an entire guyed tower is preassembled on the ground and then lifted and air transported to its erection spot by the helicopter.

Figure 15.31 Helicopter Method – an entire guyed tower is rigged, tilted and then lifted and air transported.

Figure 15.32 Helicopter Method – an entire guyed tower is air transported by the helicopter to its erection spot.

15.5.3.1 Tower Assembly Revision Checking and Tightening of Bolts at the Required Torque

However, as the joints might remain slightly loose, prior to commence the cable stringing, it is mandatory that a second and smaller crew come just behind to perform a check of the tower assemblies. Linemen have to check all the joints, in regard to missing pieces and improper joint assembly and then firmly tighten together the members, plates, fillers, bolts, nuts and washers at the final torque specified in the assembly drawings, using pre-calibrated torque wrenches. The same procedure applies to the guy wires, that are finally adjusted to the proper tension and this is the right time to check the leveling and alignment of the cross arms and verticality of the towers, and provide for necessary corrections, prior to the final tightening of the joints. The tightening shall be carried on progressively from the top downwards, care being taken that all bolts at every level are tightened simultaneously. It is advisable to employ four persons, each covering one leg and the face to his/her right. Tolerance limit for tower verticality shall be a displacement of one in 360 of the tower height.

15.5.3.2 Finishing and Installation of Signaling and Special Devices

If during the tower assembly check it is found any part of the tower members and plates have any damage to their zinc protective coating, then the affected areas must be cleaned and recoated with a rich zinc paint. Signaling and special devices, such as numbering, phase, circuit and danger plates, anti-climbing devices and bird perching guards shall be installed, as applicable, according to the assembly drawings.

15.5.4 Erection Method Selection Criteria

Achieving an optimal selection of the structure assembly and erection method involves a complex decision matrix, as multiple variables exist and affect each other and need to be balanced altogether, at the same time. Overhead transmission line structures vary significantly according to functional and situational factors, and are designed to enable a large spectrum of combination possibilities, in response to these variations. Similarly, their assembly and erection activities are often subject to logistical, local markets supply, land availability, access, safety, legal permits and environmental constraints, so that, there is no universal rule or single solution that would apply to encompass all these variations and constraints, in a cost-effective and timely manner. Therefore, it needs to be customized for each single transmission line project.

However, it's been proven by the practice that, whichever assembly and erection method has been chosen, the smoother is the work, the better, meaning good planning in advance, continuous in sequence, keeping on schedule and having an early warning and problem resolution system in place to prevent slippage. It is of utmost relevance to avoid working out of sequence, moving back and forth with the assembly and erection crews, as experience shows it is one of the major sources of cost overruns and project delays. In particular because the cable stringing activities cannot commence until a reasonably long stretch of the line has all the structures completely erected and revised.

15.5.4.1 Combining Methods

Due to the high cost of mobilization and hourly rates of the heavy equipment, like mobile-cranes and air-cranes, it requires a minimum volume of work to be viable, so that, in the normal course, a decision has to be taken upfront on which method and equipment is best suited to the circumstances, bearing in mind that a later shift from one method to another will be more expensive. Also, it is a good practice to advance the structure preassembling on the ground, before one or another type of equipment comes in. Nevertheless, a combination of different structure assembly and erection methods may lead to an optimal erection plan for longer lines, provided that there are opportunities to improve cost and time, by capturing the advantages of different erection methods in response to different work environments.

15.6 Conductor Stringing

Installation of a bare overhead conductor can present complex problems. Careful planning and a thorough understanding of pull requirements and stringing procedures are needed to prevent damage to the conductor during stringing operations. The selection of stringing sheaves, tensioning methods and measurement techniques are critical factors in obtaining the desired sagging results. Conductor stringing, sagging equipment and techniques are discussed in detail in the IEEE Standard 524. Some basic factors concerning installation are covered in this section.

15.6.1 Preparation

Before conductor stringing can commence, structures must be equipped with required insulator strings and hardware. In the case of suspension structures, complete insulator strings are attached to the structure. Instead of conductor clamps, running blocks with stringing sheaves (pulleys) with large diameter are attached to the bottom of the insulator string to allow for the movement of the conductor through the structure. On dead-end structures, running blocks are attached directly to the take-off (landing) plates on the structure and the dead-end hardware assemblies are installed after the conductor is cut to its required length.

15.6.2 Stringing Methods

There are two basic methods of stringing conductors, categorized as either tension or slack stringing. There are many variations of these methods and the selected method depends primarily on the terrain and the sensitivity to conductor surface damage.

15.6.2.1 Tension Stringing Method

A tension stringing method is the preferred method for installing transmission conductor. Using this method, the conductor reel is mounted on a payoff that is capable

Figure 15.33 Trailer mounted payoffs and a truck mounted bullwheel for tension stringing (Courtesy of Southwire Co.)

of applying braking force to the reel to maintain tension on the conductor. The conductor is then strung (or "reeved") through a multi-groove bullwheel tensioner so that the conductor is under tension during pulling and is not allowed to contact the ground (Figure 15.33). It is important to coordinate the bullwheel speed with the puller speed to prevent excessive sagging or dynamic loading (jerking) of the conductor during the pull.

In a typical tension stringing operation, blocks (also known as "travelers" or "sheaves") are attached to each structure or the end of an insulator string. For re-conductoring applications, the existing conductor can be transferred to the blocks at each tower, then connected to the new conductor and used to pull in the new conductor as it is removed. For new construction, a pilot line is pulled through the blocks and used to pull in a heavier pulling line, which is then used to pull the conductor through the blocks. The tension in the conductor is controlled by coordinating the tension puller at the pulling end and the bullwheel tensioner at the conductor payout end of the installation. This installation method keeps the conductor off the ground, minimizing the possibility of surface damage and limiting problems at roadway crossings.

It should be noted that the reels the conductor is shipped on are designed only for transportation and should not be used as a tensioning device. Minimum breaking tension should be applied to the reel on the payoff, just enough to prevent "over-spin" when the pull is interrupted or stopped. A common problem in the field is to over tension the conductor due to excessive braking of the payoff reel, thus causing conductor "pull-down" (Figure 15.34). Pull-down can occur in layers under the outer layer, thus making it appear the conductor was not properly wound by the manufacture. For this reason payoff tension should be carefully monitored during pulling.

Figure 15.34 Conductor Pull-Down due to excessive braking force on the payoff (Courtesy of Southwire Co.)

15.6.2.2 Slack or Layout Stringing Method

Slack stringing of a conductor should be limited to lower voltage distribution lines and smaller conductors where some surface damage is tolerable. The conductor reel(s) are placed on reel stands or "jack stands" at the beginning of the stringing location. The conductor is unreeled from the shipping reel and dragged along the ground by means of a vehicle or pulling device. When the conductor is dragged past a supporting structure, pulling is stopped and the conductor is placed in stringing blocks attached to the structure. The conductor is then reattached to the pulling equipment and the pull is continued to the next structure. This method requires heavy traffic in the right-of-way and is not recommended for transmission applications.

15.6.2.3 Helicopter Stringing Method

Conductor stringing using helicopters is rarely used due to high cost. This is usually done in terrain with very difficult relief and access or in locations where environmental constrains prohibit traditional access to a right-of-way.

15.6.3 Tension Stringing Equipment and Setup

Stringing equipment and requirements can vary based on the type of conductor being installed. The customer should always contact the conductor manufacturer for recommended guidelines when installing a conductor for the first time. Stringing equipment typically includes payoffs to support the reel and back-tension the conductor going into the bullwheel, a bullwheel for back-tensioning the conductor during stringing and sagging; blocks (travelers or sheaves) at the structure attachment points to support the conductor; a puller for pulling the conductor through blocks; a means of gripping the conductor; and various other special items of equipment.

During the stringing, it is necessary to use the proper tool to grip the strands of the conductor evenly to avoid damaging the outer layer of wires. The preferred type of grip is often referred to as a basket or Kellems® grip. It is often used because its flexibility and small size make it easily pulled through blocks during the stringing operation. A swivel should be installed between the pulling grip and pulling line, or between grips when double-socked, to allow free rotation of both the conductor and the pulling line (Figure 15.35).

A stringing block consists of one or more sheaves or pulley wheels enclosed in a frame to allow it to be suspended from structures or insulator strings (Figure 15.36). The frame must have some type of latching mechanism to allow insertion and removal of the conductor during the stringing operation. Blocks are designed for a maximum safe working load which must not be exceeded during pulling or sagging. Sheaves are often lined with neoprene or urethane to prevent scratching of conductor in high voltage applications; however, unlined sheaves are also available for special applications. Block diameters and groove design must be properly sized for the conductor being used per the conductor manufacturer's recommendation.

Blocks used in tension stringing must be free-rolling and capable of withstanding high running or static loads without damage. Proper maintenance is essential. Very high longitudinal tension loads can develop on transmission structures if a block should "freeze" during tension stringing, possibly causing conductor and/or

Figure 15.35 Basket grip and swivel.

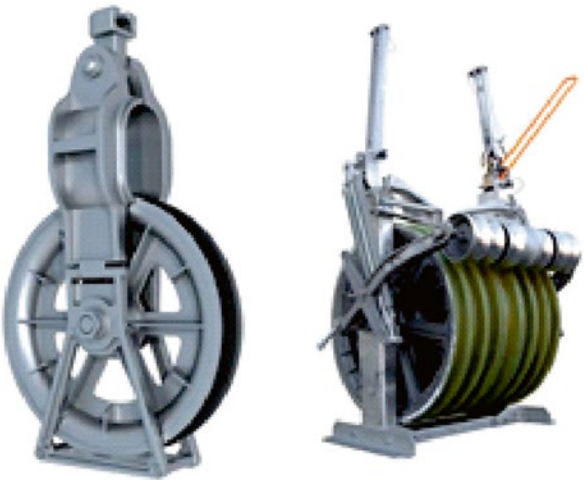

Figure 15.36 Single and multi-grooved, lined blocks (Courtesy of Sherman & Reilly).

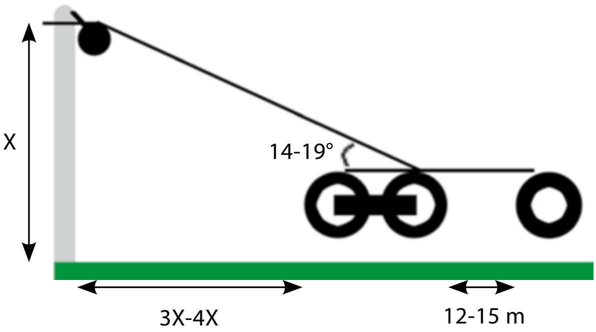

Figure 15.37 Recommended minimum bullwheel and payoff setback.

structure damage and posing safety risk to the construction crews. Significant levels of rotation resistance will also yield tension differences between spans, resulting in incorrect sag.

Equipment setup is generally limited by the terrain available for the payoff and pulling sites. The recommended bullwheel and payoff setup and their minimum setback distances are shown in Figure 15.37. It is important that the angle the conductor passes over on the first "entry" block be large enough to prevent conductor "birdcaging". If the recommended setback cannot be achieved, other methods of maintaining this angle should be used, such as, increasing the diameter of the entry block or lowering the entry block on the structure.

Generally, splices cannot be pulled through blocks. However, some manufacturers have developed splices that can be used for long pulls through blocks. Unless approved for pulling, provision for conductor splicing must be made at the tension site or mid-span sites to avoid pulling splices through the blocks. Failure to follow manufacturer's recommendations for stringing equipment can result in unsafe conditions, equipment damage, or conductor damage. Conductor damage can include scuffing (Corona issues), damage to the outer strands, and damage to the core strands (especially critical for composite core designs).

15.6.4 Conductor Sagging

It is important that the conductors be properly sagged, at the correct stringing tension and reference temperature per the design. A series of several spans, called a line section, is usually sagged in one operation. To obtain the correct sags, and ensure the suspension insulators hang vertically, the horizontal tension in all spans must be equal. Most sagging information is given relative to the conductor temperature. A sagging thermometer should be used to accurately determine the temperature of the conductor (Figure 15.38).

15.6.4.1 Sagging Grips

Once the conductor is pulled in and lying in the blocks, the conductor can be pulled up to design (or "sagging") tension. Generally the conductor is dead-ended to a structure at one end and the slack pulled out of the spans. Next a grip is applied to

Figure 15.38 Sagging Thermometer (Courtesy of Tallman Equipment).

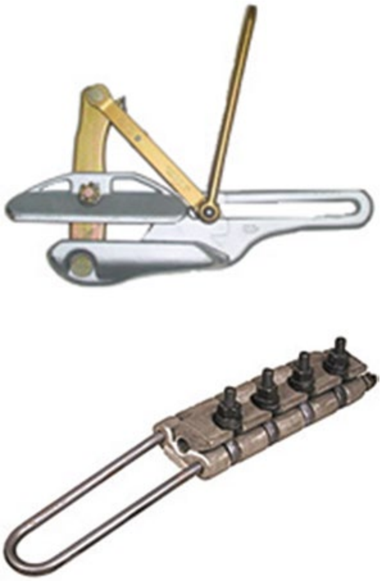

Figure 15.39 Chicago-style and pocketbook grips.

the conductor free end and the grip is attached to a ratcheting tensioning device, like a come-along to pull the conductor up to sag. There are several types of grips available so verify the conductor manufacturer's recommendation. Common grip types include scissor type (Klein "Chicago-style") and pocketbook (Figure 15.39).

Each grip should be sized for the specific conductor it is used with and each grip has a tension rating that should not be exceeded. Grips have specific installation methods which must be followed to ensure proper gripping. When the needed tension cannot be obtained using a single grip, grips can be connected in tandem to achieve a higher rating. However, the grip manufacturer should be consulted as to the proper connection method and the resulting rating. In many instances the rating of tandem grips is less than twice the rating of a single grip.

15.6.4.2 Sagging Methods

There are many different methods available for sagging lines. Two of the most common are the stopwatch method and the transit method. A third method, using a dynamometer, is sometimes used for small conductors over one or two spans but is not recommended for transmission applications as its accuracy diminishes with each span.

The stopwatch method is based on the principle that a mechanical pulse imparted to a tensioned conductor moves at a speed proportional to the square root of tension divided by weight per unit length. Three or five return waves usually provide an accurate measurement of sag. The equation for the stopwatch method can be seen below.

$$D = 0.3067\left(\frac{t}{n}\right)^2 \tag{15.1}$$

D = conductor sag, m.
t = time, sec.
n = number of return waves

By initiating a pulse on a tensioned conductor and measuring the time required for the pulse to move to the nearest termination and back, the tension and sag of the conductor can be determined. This stopwatch method has come into wide use even for long spans and large conductors.

IEEE Standard 524 lists three methods of sagging conductor with a transit: “Calculated Angle of Sight”, “Calculated Target Method” and “Horizontal Line of Sight”. The method best suited to a particular line sagging situation may vary with terrain and line design. While the transit method is considered more accurate, the stopwatch method is favored due to is relative ease and quickness.

15.6.4.3 Sagging Accuracy

Sagging accuracy depends on many factors and it is usually prescribed in construction specification document used in tendering. IEEE Standard 524 suggests that all sags be within the lesser of 13 mm (0.5 in) of the design value for every 30 m (98 ft.) of span length or 152 mm (6 in.) of the design value for any span. Additionally, possible errors in terrain measurement, variations in conductor properties, loading conditions and hardware installation have led some utilities to include up to 1 m (3 ft.) of additional clearance in addition to the required minimum ground clearance.

The type and condition of the structures can also affect sagging accuracy. Certain structure types (such as flexible tubular poles, tall wood poles, etc.) can deflect under sagging tensions. Older structures may have reduced ability to sustain sagging tensions due to damage, corrosion or other environmental effects. In these cases it may be necessary to reinforce structures and crossarms, or temporarily add reinforcement through guying.

Sag adjustment devices such as turnbuckles or sag adjustment plates are often used in the deadend hardware strings to allow for adjusting conductor sags and make necessary sag corrections (Figure 15.40).

15.6.5 Offset Clipping

If conductor is to be sagged in a series of suspension spans where span lengths vary widely or, more commonly, where the terrain is steep, then clipping offset calculations may need to be employed in order to yield vertical suspension strings after

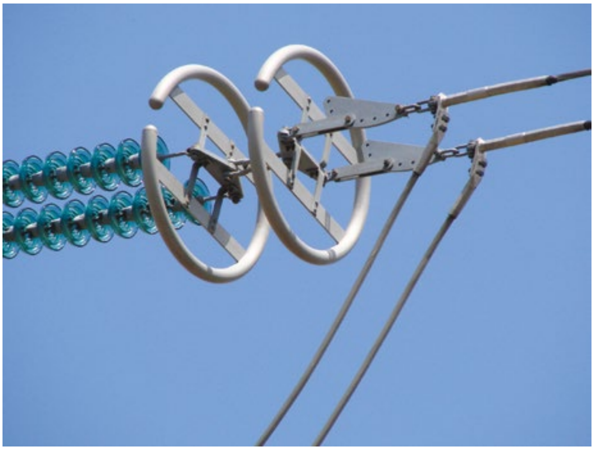

Figure 15.40 Example of a sag adjustment plate used with a dead-end insulator string.

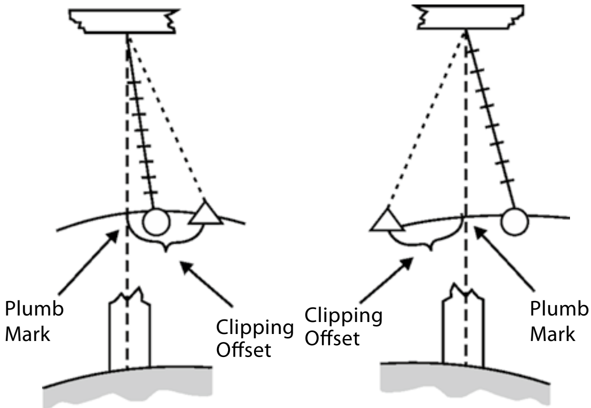

Figure 15.41 Offset clipping example.

installation. More information can be found in the Southwire Overhead Conductor Manual (Figure 15.41).

15.6.6 Conductor Creep and Pre-stressing

Upon completion of conductor stringing, a time of up to several days may elapse before the conductor is tensioned to design sag. Since the conductor tension during the stringing process is normally well below the initial sagging tension, and because the conductor remains in the stringing sheaves for only a few days or less, any elongation due to creep is normally neglected. The conductor should be sagged to the initial stringing sags listed in the stringing tables. However, if the conductor tension is excessively high during stringing, or the conductor is allowed to remain in the blocks for an extended period of time, an abnormal amount of creep will occur. If this occurs, the stringing tables should be corrected to compensate for the additional creep elongation.

When installing a new conductor that will be spliced into an aged, existing conductor it is sometimes beneficial to pre-stress the new conductor to match the aged creep of the existing conductor. The pre-stressing tension is normally much higher than the unloaded design tension for a conductor. The degree of stabilization is dependent upon the time maintained at the pre-stressing tension. After pre-stressing, the tension on the conductor is reduced to stringing or design tension limits. At this reduced tension, the creep or plastic elongation of the conductor has been temporarily halted, reducing the permanent elongation due to strain and creep for a defined period of time. By tensioning an ACSR (Aluminum Conductor Steel Reinforced) conductor to levels approaching 50 % of its rated breaking strength for 1–2 hours, creep elongation will be temporarily halted. For an ACSS (Aluminum Conductor Steel Supported) conductor, the hold time is substantially less and greatly improves the conductors self-damping capability.

15.6.7 Crossings

When a conductor installation is required to cross a highway, river, rail or other sensitive area advanced planning is required. Permits should be sought from the AHJ (Authority Having Jurisdiction) over the crossing. Coordination with local authorities, rail, shipping and other entities must be made, especially where the installation requires disruption of commercial or public transportation.

Crossings often involve installation of temporary intermediate structures, long pulls and high tensions. Custom, high strength conductors and composite core conductors are often used. In many cases conductor and connector selection can mitigate tension and long pull concerns.

When stringing is done over the existing power lines, these lines should be de-energized for safety reasons. When this is not possible, additional safety measures are needed which may include the use of insulating blankets and presence of “safety watch” on the job site.

15.6.8 Grounding

Care should be taken to ensure that the conductor is isolated from all electrical influences during the installation procedure. This includes incidental contact with nearby energized sources, static voltage buildup during pulling and induced voltage from nearby energized lines. All equipment should be properly grounded. The conductor should be grounded, usually with a running ground, and all blocks should be grounded at structures.

15.7 Insulators, Hardware and Fittings

15.7.1 Insulators

Insulators are the most important element of the strings connecting the electrical parts (conductors) with grounded structures. They are made of dielectric materials and have dual purpose by providing an adequate level of electrical insulation for the given voltage and sufficient mechanical strength to support mechanical loads.

Insulators come in different types as shown in Figure 15.42.

Construction techniques will vary depending on the insulator type used.

15.7.1.1 Handling

Cigré TB 184 provides a full overview of composite insulator handling techniques. However, most of the rules from the brochure also apply to other types of insulators (especially long-rod types).

Insulators should be delivered to the construction site in wooden crates protecting them from damage during transportation and handling. At delivery, the crates must be thoroughly checked for any damage. If cracks, dents or other damage to the crate are found, each insulator should be examined for damage. Any unit with exposed core or damaged sealing of the triple point should be immediately rejected and replaced. Crates containing insulators should be stored above the ground in a dry and covered area. Lids should remain closed to prevent entrance of rodents and to protect insulators against weather elements.

Insulators should be delivered to a job site in their original packaging. Direct contact with the ground must be avoided to ensure that clean units without any mechanical damage are installed on the transmission line. A good solution to protect insulators after removing them from crates is application of a wrap-on shield. The use of a wrap-on shield helps to prevent the insulator from damage during installation or tower painting. The wrap-on must be set up to allow the air flow, so that it keeps the insulator from getting mouldy.

15.7.1.2 Assembling Strings

Before installation, each insulator must be re-checked for damage. If any cuts, exposure of the core, torn cover, puncture or split is detected, that insulator must be rejected and removed from the construction site to ensure it is not accidentally used.

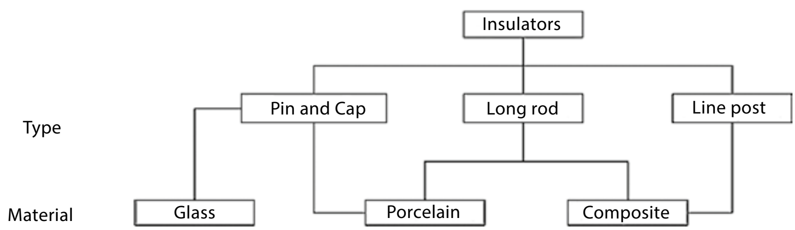

Figure 15.42 Main types of insulators.

Moving insulators should be performed manually. Extra care should be taken when lifting and moving long insulators so that no additional bending or twisting to the unit is introduced. Under no circumstances can the insulators be pulled on the ground or carried by a rope tied under the shed.

Assembly of insulator strings should be done as closely to the tower as possible. A plastic foil or canvas should be spread out so that the assembly is not carried directly on the ground. Any stones and other hard objects that may cause damage to the housing of the insulator must be removed.

All the components should be assembled without the use of excessive force. After assembling the string, one should check if the pins and the nut are set up correctly. Nuts and bolts should be checked for proper tightness. Any dirt or contamination should be removed with soft cloth.

It is important to install Corona (grading) rings in the proper position to achieve the desired protection. Installation procedures should be followed to avoid installing the Corona rings upside-down.

15.7.1.3 Installation

Lifting ropes should be attached to the earth-end insulator metal fitting only. Ropes should not have contact with the silicon housing of composite insulators. To tighten the screws, use the manufacturer's recommended torque. When installing, insulators must not be subjected to bending or torsional loads. It is forbidden to walk, sit or climb on the insulators and their Corona rings. During installation special ladders or temporary bridges must be used.

Ladders, tools, blocks and other equipment, should be kept away from the housing of an insulator string to avoid mechanical damage.

Insulators damaged during hardware assembly should always be replaced and removed from the site.

15.7.2 Conductor Hardware

15.7.2.1 Suspension Strings

Suspension strings can be installed from a bucket truck or by using mounting ladders suspended from the crossarm. The length of the ladder should be properly matched to the length of the suspension string to allow the installer to work in a standing position. Strings should be pulled using lifts securely attached to a crossarm and providing a uniform load transfer to both vertical walls of the crossarm. The place of attachment of a conductor in the suspension clamp must be clearly marked and cleared. Care shall be taken to transfer the conductor from the stringing travellers to the suspension clamp accurately to ensure that the suspension clamp is centered on the conductor contact point mark.

15.7.2.2 Dead-End Strings

The dead-end strings should be assembled near the tower using necessary protection methods to prevent direct contact with the ground to avoid contamination or damage. When fitting the string particular attention should be paid to:

- Proper alignment of arcing devices and protective rings,

- Turning screws to the ground,
- Correct assembling of locking pins.

Once assembled, the deadend string must be connected to the insulator string on one side, and on the other to the hook rope of the tensioning system. Next, the dead-end string must be tied to the crossarm of the tension tower. For safety reasons, the installer must be standing on the shaft of the tower and not on the crossarm.

15.7.3 Vibration Control Devices

Vibration dampers, spacers and spacer dampers are mounted on the conductor using either bolted clamps or preformed rods, depending on design. Vibration dampers must be installed at the specified distance from each suspension clamp, in accordance with manufacturer's installation instructions to provide optimum damping performance. They must also be installed in the vertical position, directly below the conductor. Spacers and spacer-dampers must be installed along the conductor in specific locations, in accordance with the installation spacing charts, to provide optimum damping performance.

Installation of vibration control devices should be carried out on aerial work platforms or from cable trolley carts. During installation, special attention should be paid in order not to distort the conductor bundle. The manufacturer's recommended tightening torques should be used when tightening the bolts to avoid conductor damages. Bolt heads should point downwards so that it is easy to validate the installation from the ground.

15.7.4 Warning Devices

Warning devices on high voltage lines are required in the zones where there is air traffic. They come as coloured balls or cones usually mounted on ground wires and glowing elements mounted on phase conductors. These devices must be placed in specific location along the wire/conductor to satisfy local regulations.

To protect birds against collisions with overhead wires, various warning devices, often called bird diverters, are being used. Common designs are flapping discs or spiral rods attached and distributed along to the overhead wire. Similarly to vibration control devices, bird diverters can be installed using lifts/cranes or cable trolley carts.

15.7.5 Conductor Fittings

Conductor fittings used with transmission line overhead conductors include full tension deadends, full tension joints, jumper terminals, and repair sleeves. These fittings are needed to provide for continuity of the conductor.

The most common conductor fittings are of a compression type involving one or more sleeves. The sleeves are pressed onto the conductor by means of applying

Figure 15.43 Simultaneous installation of multiple implosive type sleeves.

mechanical pressure using hydraulic dies. They require filler compound to be inserted into the sleeve prior to compressing to provide corrosion protection.

Other types of compression sleeves use the energy of a small implosive charge to press the sleeve onto the conductor. These sleeves do not use filler compound and they can be installed simultaneously (Figure 15.43).

In all cases, proper installation procedures must be followed to provide full strength of the fitting and trouble free performance.

15.8 As-Built Inspection

15.8.1 Needs

Commissioning of an overhead transmission line involves an as-built inspection which is needed to confirm full conformance of the installed line components with design drawings and specifications as provided by the line owner. As-built inspections are performed with due diligence, typically by design engineers and before the transmission line is energized, for safety reasons. Typically, they involve design engineers responsible for different line components (electrical, mechanical, civil), contractor's project engineers and asset owners who will be responsible for maintaining the new overhead line. As-built inspections are carried out in two phases: acceptance of the "as-built" documentation and acceptance of the line components (towers, foundations, conductors…).

15.8.2 Documentation Review

Prior to carrying out the as-built inspection in the field, the contractor provides the owner with documentation which may include the following documents:

- Work completion certificates confirming installation meeting all the technical requirements,
- Foundation records: type of foundation installed, size and depth, soil logs (if requested by the owner), foundations test protocols,
- Structure records (i.e. structural deflections, insulator string deflections, guy wire tensions, deviations from the original structure location or orientation),
- Conductor stringing records (temperature, tension, sag checks made),
- Reports of any field measurements performed (i.e. anchor pull-out, foundation deflection, etc.),
- Reports of any material testing done (i.e. inspection of welds),
- As- built documentation,
- Attestations of the materials used,
- Warranty cards of materials and equipment used,
- Instruction for operation of the line.

These documents are to be reviewed and accepted by the Project Engineer and later transferred to the asset owners for maintenance purposes.

15.8.3 Field Inspection

Following review of the above documents, field inspection is performed to assess technical condition of all the line components. The diagnostic procedures constitute the basic source of information concerning the current condition of the line as built.

They include visual inspection, measurements and tests of:

- Foundations: size and placement, condition of the concrete, alignment, type and condition of backfill,
- Support structures: condition of all structural, completeness and tightness of all connections, proper orientation of the circuits/phases, phase and aviation plates, locations of bird nests and foreign elements on the towers, condition of the warning lights, corrosion of any elements,
- Insulation of the line: condition and completeness of the insulation equipment, insulator string deflections,
- Phase conductors and equipment: bird-caging and cracks of phase conductors and jumpers, condition of clamps and joints, location of foreign objects on conductors),
- Vibration control devices: condition, completeness and proper spacing
- OPGW: earthing jumpers, OPGW downleads to connection boxes,

- Grounding system: condition, completeness, connections,
- Crossings: adequacy of conductor clearances, proper offsets, markings of the line crossing with roads and waterways,
- Site conditions: tree clearing, terrain grading, restoration of the existing fences, disposal of materials.

Upon completion of the field inspection, a detailed report is issued capturing all the observations. All deviations and non-conformances are identified and presented to the contractor for corrections. Once all the line components are accepted by the Project Engineer, work completion certificates are issued to the contractor confirming full compliance with all the technical requirements.

15.9 Conclusions

This Chapter has addressed many challenges and risks encounter during installation of an overhead transmission line. It has also presented common construction practices found around the world. Other special construction techniques can be found in the reference documents.

Transmission line construction practices may vary depending on multiple factors, such as design details, availability of manpower resources and construction equipment, geographical location, weather conditions, or past experiences. However, best construction practices have many common elements, including proper logistical planning, safe work procedures, good workmanship, and cost effective solutions.

Success of an overhead line placed in service can be measured based on trouble-free operation of the line and all of its components. This greatly depends on the design effectiveness, proper selection of the components and finally on the best construction techniques and methods used.

15.10 Outlook

The ever changing regulations of how new overhead transmission lines are developed and constructed puts a lot of pressure and high demands on construction companies and their operations. Legal regulations and various conditions prescribed by the transmission line project licence identify numerous restrictions on how and when construction activities can be carried out. In addition, high expectations of the general public and environmentalists force construction companies to adjust their practices in order to minimize the effects on the humans and environment.

These increasing restrictions will be forcing construction companies to change their existing work practices. Improvements to job planning, optimization of the use of available resources, materials management and application of electronic tools will be necessary to stay competitive. Recent advances in Geographic Information Systems (GIS) based technologies offer new tools which can lead to improved productivity and cost efficiencies. Bar coding offers efficiencies in material control.

GPS units can be used for work progress tracking and real-time reporting. New software products offer advanced scheduling and work simulation options to maximize available resources.

New construction equipment will become readily available to help meet the needs of the industry. Helicopters will be utilized more frequently in the areas where access is difficult or restricted. Robotic devices will aid in installations requiring live-line techniques. Various remote sensing and condition assessment techniques will be used frequently to help with upgrading projects.

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Zibby Kieloch has MSc in Civil Engineering from Warsaw University of Technology. He has been designing overhead transmission lines at voltages up to 500 kV at Manitoba Hydro, Canada for over 25 years. Most recently, he is responsible for one of the largest HVdc projects in North America – Bipole III Transmission Line Project. He has been a CIGRE member and the Canadian Representative on the Study Committee B2 since 2005, making contributions to a number of Working Groups. Since 2012, he has been the Convenor of the SC B2 Customer Advisory Group. He is also an active member of the Canadian Standards Association technical committees responsible for overhead line design and conductor design standards.

João BGF da Silva obtained his degree in Civil Engineering from the Federal University of Minas Gerais, Brazil, where he was Professor of Steel Structures from 1975 to 2012. At the industry, he has been working in many companies and has been responsible for OHL projects particularly in Brazil and other American countries. Currently, he is the Technical Director of Furnas Trans-Cos being also a member of the Consulting Council of the Brazilian Electric Power Research Center – CEPEL, since 2006. On Cigré, he has been member of the Study Committee B2 – Overhead Lines since 1985. He was Convener of the former WGB2.08 – Transmission Line Structures being nowadays the OHL Components Technical Advisory Group Chairman. He has published more than a hundred articles and brochures devoted to design, construction and performance of high voltage overhead lines. He is an honorary member of Cigré and a holder of the “Cigré Medal” awarded in 2008.

Mauro Gomes Baleeiro Engineer, MBA, Entrepreneur. Executive Education in USA, Switzerland, Japan and South Africa. Head of Sales and Business Development at ABB SBE Power Lines-Brazil (1978–1991) responsible for design, testing and supply of lattice towers to large power transmission projects in Latin America, USA and Middle East. Director of ABB Power Systems-Brazil (1992–2001) & team leader for the 2000 MW Power Interconnection Project between Brazil and Argentina. Co-founder, owner and 1st CEO of DAMP ELECTRIC-Brazil (2004–2009). President & CEO of ALTA ENERGIA S.A. (2010–2013), responsible for the design & construction of 1500 km of the 600 kV Power Line Porto Velho - Araraquara associated to the 6400 MW Madeira River Power Project in Brazil. Co-founder, owner and 1st CEO of ALTIVA HELIMONT (2014), a startup co. dedicated to the intensive use of helicopters for power line towers erection in Brazil.

Mark Lancaster has BSc, BSEE and MBA degrees including the Georgia Institute of Technology, and is a registered Professional Engineer. He is employed at Southwire Company, Carrollton, Georgia, USA where he is Director of Overhead Transmission Engineering. He has been in wire and cable manufacturing, R&D and applications since 1987 and has been active in the development of new HTLS conductors, line monitoring and dynamic line rating, holding 4 US patents in these areas. He is active in industry groups including IEEE Overhead Lines, ASTM International and Cigré and has held several leadership positions in these organizations including Chairman of ASTM B01 Conductors Committee from 2009–2014. He is a co-author of the Southwire Overhead Conductor Manual and contributor to the Cigré Overhead Green Book.

Marcin Tuzim is an engineer who graduated from Warsaw University of Technology. He is employed in ELBUD-PROJEKT Warszawa Ltd. as an assistant designer of high voltage overhead lines. He participated in the design of significant energy investments in Poland (eg. cable and OH high voltage lines and substations).

Piotr Wojciechowski has MSc Eng. degree received from Warsaw University of Technology. He has achieved Certified Project Management Associate level D of IPMA Association. He is employed in Elbud-Projekt Warszawa Ltd. as a Chief Constructor. He has designed several hundred km of Overhead lines: 110, 220, 400 kV and several substations 110/15 kV. He is responsible for designing foundations and construction of towers. He has published over a dozen papers for presentation at various scientific conferences and for technical magazines. He is Poland's Representative on CIGRE Study Committee B2. He is also member of Polish Normalization Committee (group KT-80) and Poland's Representative on CENELEC TC-11 and a member of TC-11 WG 09.

Maintenance

16

André Leblond and Keith E. Lindsey

Contents

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A. Leblond (✉)
Varennes, Canada
e-mail: Leblond.Andre.2@hydro.qc.ca

K.E. Lindsey

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16.1 Introduction

This Chapter covers the description of maintenance of Overhead Transmission Lines (OHTL). Due to difficulties encountered by most Line Owners in building new OHTL and even with upgrading existing lines, the present Chapter is to understand issues and technologies related to the safe maintenance and operation of existing transmission lines. Since most of the world's power utilities' OHTL are approaching their design life or beyond, a good maintenance strategy is important to ensure their integrity.

The environment in which utilities operate has changed drastically in recent years. In the past, investment and maintenance decisions were often determined more by avoiding technical risks than by budget restrictions. The introduction of regulators and other new business drivers has changed this situation. Investment and maintenance cost must be well founded more and more and utilities have to apply modern asset management methods.

Traditionally, maintenance decisions on overhead lines have mainly been based on visual inspections. The results of visual inspections are normally entered into a maintenance management system. This way a valuable database is created. However, the basis of these maintenance methods is mainly qualitative and leaves room for inaccuracies. More importantly, it is hard to substantiate decisions regarding maintenance or replacement of components on the basis of a qualitative system. This Chapter describes how, with a combination of inspections, testing of samples and analysis, quantitative insight into the condition of components is obtained. The quantitative nature of the assessment results enables the asset manager to take intelligent and well-founded decisions regarding maintenance, refurbishment, upgrading, replacement, etc. of overhead lines.

Defects and failures occur in practice due to:

- Unforeseen external causes such as faults in an adjoining grid, extreme weather conditions, sabotage;
- Internal causes like wear, aging, deformation, poor construction or material;
- Operational aspects such as electrical overload, switching faults, improper functioning of protection and control.

Defects can lead to failures causing unforeseen unavailability of the line. Proper analysis of defects and failures can give a contribution to the development of strategies to maintain a sound condition of the overhead line.

16.2 Maintenance Strategy

16.2.1 Introduction

Formulating a transmission line maintenance strategy is dependent on the transmission line asset owners' drivers and constraints. Drivers could be a requirement to improve reliability and availability of the system, i.e., to meet System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). Drivers could also be a requirement to satisfy new regulatory requirements, customer or user requirements (e.g., a new aluminum smelter customer or a wind farm generator). Constraints are typically budgetary or schedule constraints.

The maintenance strategy will be dependent on the asset owners' particular environment (i.e., coastal, desert, forest, etc.), existing condition of the assets and, perhaps most important, criticality of the existing transmission lines (e.g., lines from a nuclear power or must run plant).

Maintenance activities can be divided into three basic categories:

- Periodic normal maintenance,
- Preventative maintenance or component repair, and
- Emergency restoration or repair.

Each of these three areas can have its own maintenance strategy based upon the asset owner's drivers and constraints.

Periodic normal maintenance consists of activities such as:

- Vegetation management,
- Tower painting,
- Insulator washing.

These activities lend themselves to an economic risk analysis as outlined it Cigré TB 353 and used for the uprating and upgrading of transmission lines (see Chapter 18 – Uprating & Upgrading). The optimum time intervals between these activities can be determined based on risk assessment and cost evaluation (see Cigré TB 175 and 353).

Preventative maintenance or Component repair consists of activities such as:

- Damaged insulator replacement,
- Conductor repair,
- Hot splice replacement,
- Spacer and spacer-damper replacement,
- Repair of structural tower members or foundation repair,
- Correcting electrical clearance problems, etc.

These activities do not lend themselves to an economic "optimum time to do the work" analysis, but they can be prioritized and usually are dealt with in the near term. The driver for these items is the need to maintain system reliability, availability and capacity (i.e., hot conductor splices may reduce the maximum capacity of the line). If left unnoticed and unattended to, these items will eventually result in line failures with resulting economic consequences (Cigré TB 175).

Emergency restoration is usually a result of component failure and therefore line failure or the result of major storm damage, sabotage or delayed maintenance. The economic consequences of such a line failure are discussed in Cigré TB 175. Strategies to prepare for emergency restoration have been discussed in Cigré ELT-222-4. The purpose of the Cigré ELT-222-4 article is to help asset owners develop their own emergency response plan or strategy for their overhead transmission lines. The implementation of the plan should result in adequate material, manpower and equipment resources to address identified emergency situations. The key to the development of an adequate emergency response plan is for the asset owner and senior management to commit to a proactive long term plan for responding to anticipated emergency situations, and the formulation of a corporate policy on how the utility will respond to emergencies.

16.2.2 Steps in Developing a Maintenance Strategy

No matter what the maintenance activities are, they all share similar requirements that must be considered when developing a maintenance strategy.

16.2.2.1 Prioritizing the Transmission Lines

Some transmission lines are more important than others. Some lines can not be taken out of service without large financial and political penalties for the asset owner. These lines need to be identified and ranked in importance (i.e., risk and consequence).

16.2.2.2 Periodic Inspection of the Lines

All the lines need to be inspected. The time interval between inspections may be based on their priority ranking above. Inspections can be as simple as walking the right-of-way, climbing the structures and visually inspecting the components. Recently more sophisticated methods are available such as flying the lines with helicopters using high definition video cameras, LiDAR cameras and infrared cameras looking for such items as hot joints and splices or spacer-damper failures before significant conductor damage occurs. All transmission line components can be inspected in this way as well as the vegetation along the right-of-way and access roads. In recent years, real time transmission line monitoring equipment have been developed that measure critical maintenance parameters (e.g., conductor sag, vibrations, insulator contamination, etc.). This new equipment will need to be considered in an overall maintenance strategy, if not today then in the near future.

16.2.2.3 Data Base Management

Proper data base storage and retrieval systems are necessary, otherwise the results of the periodic inspections would be lost. The importance of having good and accurate data in the data base is discussed in Cigré TB 175. With this data deterioration trends can be used to catch problem areas early and avoid line failures. When line failures do occur, this data should also be gathered and maintained for proper asset management.

16.2.2.4 In-House or Outsourcing of Maintenance Work

A decision needs to be made as to which activities will be performed in-house and which activities will be outsourced. Few asset owners perform all of their maintenance activities (e.g., vegetation management along the right-of-way is typically outsourced). The risks and rewards associated with outsourcing of maintenance activities and the development of key performance indicators for evaluating outsourcing contractors are discussed in Cigré TB 201 and in Cigré TB 561.

16.2.2.5 Performing Live Work or De-Energized Work

Depending on the criticality or priority of a line, it may not be able to be taken out of service for extended periods of time to perform required maintenance. In this case, live working techniques may need to be implemented by the asset owner. Again, these may be performed in-house or outsourced, but in either case extensive planning is required as part of an overall maintenance strategy. If work can be done de-energized, planning and coordination with other organizations is required for a successful implementation of a safe maintenance program (see Cigré TB 561).

16.2.2.6 People, Equipment and Training

Depending on the maintenance activities that are planned to be performed by in-house personnel, consideration must be given to the technical skill levels and the numbers of maintenance personnel required. Training facilities and periodic retraining drills are an essential part of any successful maintenance program. The capital investment in specialized equipment, maintenance of the equipment and replacement of this equipment should also be part of the overall maintenance strategy. This equipment may include helicopters, robots or transmission line monitoring equipment which has not normally, in the past been associated with transmission line maintenance.

16.2.2.7 Outside Resources

Few asset owners have all the personnel and equipment to handle all of their maintenance activities, especially emergency restoration after large storms. Because of this, a successful maintenance strategy should also include a plan for sourcing additional outside personnel, equipment and line materials as required (see Cigré ELT-222-4). Mutual assistance between asset owners has been used successfully for this purpose; however, initial planning between different asset owners is required for successful implementation of the option.

16.2.2.8 Benchmarking and Continual Improvement

To implement a successful maintenance program the asset owner should compare his performance with other comparable asset owners. A plan for doing this should be considered as part of the overall strategy. After any major event (e.g., storm restoration) or periodically after normal maintenance activities, the asset owner should do a “lessons learned” with maintenance and engineering personnel involved in order to continuously improve the maintenance activities.

16.2.3 Conclusion

Formulating a successful transmission line maintenance strategy is dependent on the transmission line asset owners’ drivers and constraints. The maintenance strategy will be dependent on the asset owners’ particular environment, existing condition of the assets and, perhaps most important, criticality of the existing transmission lines.

No matter what the maintenance activities are, they all share similar requirements that must be considered when developing a successful maintenance strategy. They include:

- Prioritizing the transmission lines,
- Periodic inspection of the lines,
- Data base management,
- Considerations for in-house or outsourcing of maintenance work,
- Performing live work or de-energized work,
- Planning for people, equipment and training,
- Developing outside resources,
- Benchmarking and continual improvement.

The remaining sections in this Chapter will discuss some of these aspects in greater detail.

16.3 Condition Assessment of OHTL

A transmission line is regularly inspected in order to achieve updated information about the condition of the line as well as the immediate surroundings. Various inspection techniques have been developed to enable the condition of the OHTL to be assessed (Cigré TB 175). Inspections may be performed from a plane, a helicopter, a car, by foot patrols or by climbing the towers.

Condition assessment will enable transmission line asset owners to achieve greater efficiency when planning OHTL refurbishment’s or more effectively to direct their maintenance activities, at a time when systems are ageing and consents for new lines are becoming increasingly difficult to obtain. The inspection should be performed so that the transmission line owner is provided with sufficient information to plan the maintenance of the OHTL.

The purpose of this section is to list common defects found in OHTLs and to list generic techniques that are currently available and can be used to find these defects in-situ.

This section is limited to the common defects which are found on conductors (phase and earth-wire) and fittings, insulators, supports and foundations on high voltage OHTLs.

This section does not deal with laboratory tests or problems that might occur in the right of way. It highlights those defects and inspection techniques, which an asset manager can use to establish or improve a basic inspection programme.

16.3.1 Conductor System Including Joints and Fittings

Conductor deterioration follows different patterns in different geographic areas. Deterioration such as conductor corrosion (internal and external), conductor broken strands, defective or loosened spacers, missing or drooping vibration dampers, lightning strikes, etc. (Cigré TB 175) may happen.

For the last decade numerous failures of conductor joints have been reported, the reasons for which have included asymmetrical installation of the aluminum sleeve as well as accelerated ageing and deterioration of the contact surface in the joint due to an increased electrical load (Cigré TB 216).

As the transmission grids around the world age, there is increased need for a consistent method and guide of evaluating "aged" fittings for inspection and testing, and for their replacement (Cigré TB 477).

16.3.1.1 Conductor Corrosion

Conductor deterioration follows different patterns in different geographic areas. Some factors should be kept in mind when considering the effects of location of internal and external corrosion.

For example, prevailing weather pattern in the area of interest. Airborne industrial pollution can be carried several kilometers or more downwind from its source. In this situation, all conductors in the effluent plume are likely to be affected. If the primary source of pollution is an industrial complex with a very tall smokestack the corrosive effluent will be carried farther than if the smokestack is short.

Also, corrosion at joints and clamps is generally not representative of the overall condition of the conductor because corrosive effluent will tend to concentrate in these places.

Technical Background – Internal Corrosion

Internal corrosion is caused principally by industrial and salt pollution environment in the presence of moisture. Original conductor grease levels, together with condition and thickness of the galvanizing coating of the steel, will determine rate of corrosion.

Zinc Corrosion

Salt and industrial pollution will act as an electrolyte when combined with prolonged wetting of the conductor. This will form corrosion cells once the zinc layer has been breached.

In the first instance, the zinc will protect the aluminum from corrosion by sacrificial galvanic action. However, after the steel is exposed the galvanic cell forms between steel and aluminum.

Corrosion of the zinc coating is temperature dependent and is a maximum between 60-70 °C. Above this temperature, the rate of corrosion decreases.

Aluminum Corrosion

When aluminum and unprotected steel (either by design or after the loss of protection such as grease or zinc or aluminum cladding) are in a conductor the aluminum is sacrificial. The rate of corrosion is high when there are marine and industrial pollutants present. The aluminum and its corrosion products eventually cause the conductor to "bulge". Reduction in the aluminum section leads to a loss of mechanical strength and electrical conductivity. In severe cases, this causes a transfer of current to the steel and subsequent failure due to overheating. It is possible that all the outside strands of the conductor appear intact whilst the inner aluminum wires have severed completely.

When internal conductor corrosion has started, it continues at a uniform rate until the surface area of steel becomes greater than that of aluminum. At this point, the corrosion rate increases exponentially.

Steel Corrosion

It is possible in non-polluted areas, for the unprotected steel to act as the anode, resulting in loss of section of the steel without loss of aluminum section. No external indication of this process of deterioration will be visible until the conductor fails in tension.

Inspection Techniques – Generic Description

Visual Inspection (Ground or Helicopter)

Unlike the OHL Corrosion detectors, visual inspection will not detect the problem at an early stage. As corrosion becomes more advanced, an experienced line inspector will detect the conductor bulging due to the corrosion products being several times the volume of the aluminum and possible discoloration of several strands. Where there is only a single layer of aluminum stranding over the steel core, the bulging is not so evident but in these cases, the corrosion products are visible between the strands.

OHL Corrosion Detector (OHLCD) - Eddy Current

This OHLCD is only suitable for detecting corrosion in ACSR and AACSR conductors. It works in an indirect manner by detecting the loss of galvanizing from the steel strands of the conductor. Loss of galvanizing can be detected by inducing eddy currents into the conductor from a coil that clips around the conductor. The resultant magnetic field is measured with a second coil that is sufficiently sensitive to detect the disturbed field in regions where the galvanizing has been attacked.

The detector will detect corrosion, even where it occurs over a length of a few centimeters. It cannot make a quantitative judgment on the actual loss of aluminum section. It is advisable to take conductor samples at locations indicated by the non-destructive test to determine the extent of corrosion and to test the residual strength of the conductor. These additional tests performed on conductor samples may improve the knowledge of residual life expectancy (e.g., bending and torsion tests on wires).

When conductors are to be tested, the instrument is carried up the tower, the vibration dampers and where applicable, spacers are removed and the two trolleys attached to the conductor. The equipment is then remotely guided along to the next tower and back. Readings are transmitted to a ground station where they can be analyzed with a computer and the results displayed in a form of a corrosion chart. Survey rates of between 6 and 10 spans a day is achievable depending on access. This OHLCD cannot be used where an optical cable has been wrapped on the ground wire.

When planning the deployment of this equipment, the choice of spans to determine the most severe corrosion can be made on evidence for sources of pollution. This is possible, provided an effluent stream map is available showing prevailing wind flows and industrial areas. Alternatively, a survey that is evenly distributed and comprises at least 10 % of the route may indicate the average condition.

OHLCD can also be used on ground wire made of galvanized steel by adding to the sensing head a plastic shell with adequate number of aluminum wires fitted in it.

OHL Corrosion Detector - Steel Core

This OHLCD detects a loss in steel cross sectional area. This area is measured by generating and receiving 2,000 pulses per second: the highest amplitude of every 20 pulses received is recorded on the in built computer, which compiles the data at 100 points per second. This information can be printed later by the computers graphing program. Survey rates of between 6 and 10 spans a day is achievable depending on access and time of year.

This equipment is sufficiently sensitive to indicate loss of steel to levels, which are much less than any likely critical amount.

It is advisable to take conductor samples at locations indicated by the non-destructive test to determine the extent of corrosion and to test the residual strength of the conductor. These additional tests performed on conductor samples may improve the knowledge of residual life expectancy (e.g., bending and torsion tests on wires).

The detector can be applied to the conductor either by hand from a trolley, or a helicopter. It runs across the conductor span by a number of means, i.e., motorized tug, helicopter or gravity.

When planning the deployment of this equipment, the choice of spans to determine the most severe corrosion, can be made on evidence for sources of pollution. This is possible, provided an effluent stream map is available, showing prevailing wind flows and industrial areas. Alternatively, a survey that is evenly distributed and comprises at least 10 % of the route may indicate the average condition.

The OHLCD is only suitable for detecting corrosion in ACSR and AACSR conductors. It cannot be used where an optical cable has been wrapped on the ground wire.

Technical Background – External Corrosion

Aluminum Corrosion

Sulphurous pollutants cause pitting of the surface where solid impurities are deposited on the outer surface of the conductor. Small corrosion cells are then set up when moisture is present. Normally this type of corrosion is evenly spread on the outside of the conductor and does not reduce strength to the same extent as internal corrosion.

Where a helix coil has been applied over the aluminum strands and under a suspension clamp or spacer, serious corrosion of the helical bars could occur in addition to corrosion of the conductor strands. This has been found to occur on routes close to the coast. The only method available in this situation is to dismantle the clamp or spacer and visually examine the condition of the conductor underneath.

Research has shown that the most serious attack occurs in the narrow crevices. Narrow crevices are formed between rubber and helix coils due to the deep impressions made by the helix coils in the rubber. Rubber contributes to the attack of the aluminum helix coils as well as the aluminum conductors. This is because seawater acids and other particles adhere to the aged rubber surface and because the rubber retains moisture.

Copper Corrosion

This form of corrosion is due to the combination of H_2S gas in the atmosphere and moisture.

The concentration of H_2S in the atmosphere in order to produce this corrosion can be very low, making it very difficult to detect and to eliminate. The most frequent sources are marshy or swampy areas, sewers and certain industrial processes.

The corrosion is usually even across the conductor, with a very thick film of dark grey/black copper oxide as shown in Figure 16.1.

16.3.1.2 Wind Induced Damage

Technical Background

Overhead lines are affected by wind induced oscillation in three ways (Aeolian vibration, Sub conductor oscillation, and Galloping).

In general, the forms of damage can be seen as:

- Drooping/missing/slipped vibration dampers,
- Missing nuts from suspension clamps or hardware,
- Split pins missing or displaced from their normal positions in cotter (clevis) pins, etc.,
- Corona rings or insulator strings displaced from their proper positions,
- Broken outer conductor strands, usually emanating from the ends of the suspension clamps,
- Broken inner conductor strands (Figure 16.2),
- Aircraft warning markers moved or missing from conductors or support wires,
- Loose or broken tower members,
- Severe wear of suspension hardware.

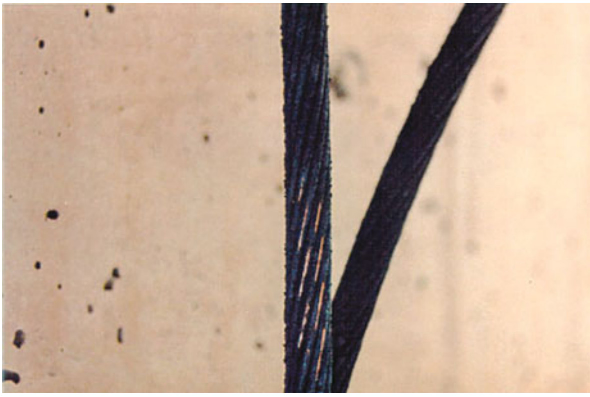


Figure 16.1 Corrosion of Copper Conductor.

Figure 16.2 Broken Inner Conductors Strands.

Aeolian Vibration

Aeolian vibration arises when the wind blows over individual conductors and induces high frequency vibration by the creation of vortices downstream of the conductor. This can create vibration amplitudes of the order of one conductor diameter with frequencies in the range of 5-150 Hz. It occurs predominantly when the wind is perpendicular to the line and in open flat terrain. Often the noise is first indication that there is Aeolian vibration.

Aeolian vibration may cause fatigue of the conductor strands after millions of vibrations. The risk of damage occurring is dependent upon the local wind climate as well as the conductor composition (capability of self-damping of the conductor, resistance to fatigue of the wires).

The point, at which damage occurs on conductors suffering from this wind-induced motion, is usually where the conductor is secured in a fitting, most often a clamp.

Sub Conductor Oscillation

Sub conductor oscillation (SCO) is also caused by wind-induced instabilities due to change in wind load on the leeward sub conductor. In this case the problem occurs on conductors with spacers and is worst with quad bundles, although it may also occur to a lesser extent on twin bundles. This form of vibration occurs at frequencies of about 1 Hz, but with amplitudes equal to the sub-conductor spacing and has resulted in "clashing" in some locations. The modes of oscillation are complex and numerous for quad bundles with horizontal, vertical and rotational forms. SCO is strongly reduced by providing a sufficient number of spacers with corresponding wind characteristics and unequal subspans between spacers.

Damage resulting from this wind-induced motion usually occurs where conductors are secured in a fitting, most often a spacer. The oscillations cause bending of the aluminum strands of the conductor and after tens of millions of cycles, fatigue failure of the outer and inner aluminum strands can occur.

Dynamic bending caused by sub conductor oscillation or Aeolian vibration is at a maximum in the external strands but the maximum damage occurs between the second and outer layers. This wear results in the formation of lens shaped markings on the second layer and undersides of the outer layer strands. Wear will be visible throughout the length of the conductor, with more wear being exhibited adjacent to the fitting. This ultimately results in cracks caused by fretting fatigue.

In the worst cases, observed on ACSR, all the aluminum strands in the conductor can fail and the consequent flow of current in the steel core causes melting and conductor failure.

Galloping

Galloping of overhead line conductors is a large amplitude (1 m to 10 m) predominantly vertical, low frequency (0.1 Hz to 1Hz) wind induced oscillation. Galloping usually depends upon the simultaneous existence of specific meteorological conditions in the presence of wind that may lead to the formation of an ice profile, displaying peculiar aerodynamic characteristics required for galloping (There are known cases where galloping has occurred without the presence of ice).

Galloping can cause damage to conductors in mid span where flashover between phases has melted the outer aluminum layer. The conductor damage is indicated by burn marks, which are dark regions around the flashover locations and globules of melted metal on the outer surfaces. Sometimes this may be accompanied by an increase in audible and Corona noise at the line section.

Galloping will also cause excessive wear to fittings, loosened spacers, and damage to tower members and insulators.

The main problem, as with conductor corrosion, is the identification of vulnerable sections of line to inspect for incipient damage in time to effect repairs. The first breaks in conductors occur under clamps and spacers and are not detectable by any practical techniques tried to date. However, in good conditions it may be possible to detect broken conductor strands protruding from the clamp by use of visual techniques.

Damage to suspension clamps and associated fittings can occur in areas subjected to wind induced motion. The worn surfaces are usually very difficult to see from the ground and may even be missed in a climbing or helicopter inspection. In time this wear can be sufficient to reduce the remaining strength of the supporting hardware to dangerous levels (see Figure 16.3) and to allow the conductor to drop.

Figure 16.3 Worn conductor hardware.

Inspection Techniques – Generic Description

VISUAL INSPECTION (GROUND OR HELICOPTER)

Stabilized Video Camera (Helicopter Use)

The camera is a suitable method to survey a line from a helicopter and examine all fittings in a relatively short period.

Provides pictures at a long distance allowing the majority of OHTL components to be examined. The images are recorded and can be analyzed later. Broken strands wear on fittings, defective or loosened spacers and missing or drooping dampers can be detected by this method.

RADIO FREQUENCY/MICROWAVE EMISSION DETECTOR

Overhead lines in good condition emit a predictable electric field, which in turn produces a continuous predictable Corona pattern. Distortions in the standard pattern indicate the presence of abnormalities. When defective, different line elements will create unique (distorted) Corona patterns. By recording and analyzing these Corona patterns, defective elements can be identified and their condition determined.

The sharp ends of broken strands of conductor generate Corona emission that can be detected with a helicopter-mounted detector. However, broken strands that do not protrude cannot be detected by this method. In one particular case, there were up to 20 broken strands, which were only identifiable, when the clamp was opened.

In some instances, Corona is generated from sources, which are not critical e.g., flashover damage on arcing horns. Previous experience and follow up examination of the suspect spans with high quality binoculars or a tripod- mounted telescope, is required to identify conductor damage at an early stage. The most practical method of identifying "fatigue related" damage at spacer positions is to target sections of line which are most at risk to sub conductor oscillation and then survey these sections (or all the line) with the detector. The line must be energized during this survey.

Where Corona is observed in a particular section, the line should be subsequently flown with a stabilized video camera, visually examining each spacer position.

Irregular Corona can also be detected and located with the use of a "Night Vision Binocular".

Gauges

Gauging can be used to measure wear providing the components are uniform in their dimensions.

Radioactive Isotopes

Radioactive isotopes can be used to expose sensitive film to detect broken strands. It is mainly used dead line but can be carried out live line. Experience has shown this method to be unreliable and should be used with caution.

16.3.1.3 Lightning Strike Conductor Damage

Ground wires are installed at the top of high voltage lines to protect the conductors from lightning strikes. However, although they are designed to have a good level of resistance to lightning impact, phase conductors may suffer damage during particularly severe strikes.

The damage varies from pitting of the outer surface, to melting and breakage of outer strands with consequent reduction of the mechanical strength of the conductor.

16.3.1.4 Conductor Joint Defects

Technical Background

Incorrectly Constructed Joints

Most joints used on ACSR have been of the compression type although bolted joints are used in jumpers. Overheating of these joints arises from inadequate compression along the length of the joint, mainly due to either poor design or installation problems. This will allow moisture penetration and result in oxidation of the internal aluminum surfaces between the joint and conductor. The resistive aluminum oxide reduces the paths for current flow and may cause micro arcing within the joint. Moreover, the resistance of the joint can increase due to the reduction of the contact pressure as a consequence of ice formation inside the joint, thermo-mechanical stresses, conductor vibrations, etc.

The consequence of this deterioration is that the joint becomes warm which further increases the rate of oxidation. Over a period of time, the joint resistance will increase resulting in excess current flowing in the steel core of the conductor. This can then overheat and rupture.

Instances have been reported where the non-oxide grease has been omitted, the wrong dies have been used for compressing the joints and the conductors have been only partially inserted into the joints.

Mid span joints are typically bolted parallel groove type, compression type and wedge type clamps. Overheating of these joints occurs primarily due to improper preparation and installation of the joint. Bolted parallel groove and compression type clamps seem to be most susceptible to overheating caused by high resistance due to corrosion, while wedge type clamps appear to be less so.

Corrosion has been discovered in mid-span joints after initial tests indicated excessive resistance. The corrosion is concentrated in the area where the steel core enters the steel joint sleeve. In addition mechanical failure of joints can occur where the joint has not been centralized correctly over the conductor. As discussed in Cigré TB 216, the failure of a joint is usually a result of an increased resistance due to corrosion, leading to an unacceptable increase in temperature and unstable mechanical conditions. Very few joints have been reported to display failure resulting purely from mechanical loads.

The reported events involving basically mechanical failures have occurred on joints that have been asymmetrically installed, where the ingress of the aluminum layers of an ACSR at one end of the joint has been less than 2,5 times the conductor diameter.

Detection of asymmetrically installed aluminum sleeves on ACSR conductors can be performed by a reluctance test. Detection of asymmetrically installed aluminum and steel sleeves on ACSR can be performed by a radiographic test.

Mechanical failures of ACSR joints caused by corrosion of the steel core on ACSR conductors, causing mechanical failure of joints, have not been reported so far. However, intense corrosion of the steel core has been detected in the vicinity of the steel sleeve. Detection of this corrosion can be performed with a boroscope test.

A.C. Corrosion

Resistance measurement and experience, has shown that potential differences which exist between the strands of overhead line conductors can cause premature failure of the conductor by interstrand arcing or a.c. corrosion of the aluminum and steel strands. The risk of failure may be increased where the potential differences between the strands are present at an early stage after installation.

A likely cause of potential difference between strands is faulty termination in which one or more strands may make poor contact at the terminations. It may also be due to one or more broken conductor strands.

At conductor positions adjacent to unstable terminations that are of very high resistance and probably dissipating sufficient power to be detectable by thermovision surveys, a.c. corrosion may have been initiated. This is likely to be accompanied by a mechanical and electrical failure of the joint itself.

The voltage differences due to broken strands are large enough to promote a.c. corrosion. Current transfer to other strands will also occur in the region of reduced strand cross section where this has occurred due to wear, fretting or corrosion.

Main Reasons for the Failure of Joints

The main reasons for the failure of joints have been identified as follows: corrosion of the aluminum contact surfaces, improperly cleaned conductors, and asymmetric installation of the aluminum sleeve and steel sleeve (on ACSR). All these reasons for failures can be attributed to an increased resistance across the joint. The total resistance across the joint consists of the conductor resistance, the sleeve resistance and the contact resistance. Only the latter will change with time in service.

Since the stranding creates a non-homogenous conductor and the compression of the joint does not completely eliminate the voids between strands, water, sometimes contaminated, will penetrate the joint. The water will then remain in the cavities until it evaporates through the air gaps inside the conductor. This will take time, depending on the temperature in the joint and the humidity in the surrounding atmosphere.

The water will, during the time inside the joint, change the oxygen content along the route, creating differences in potential. The difference in potential will create crevice corrosion in the aluminum, inside the joint. The time it takes for the water to dry influences the severity of the crevice corrosion.

Corrosion of the steel core is generally a result of galvanic corrosion. It has been observed that when the temperature of the galvanized steel core rises above 60 °C, the protective role of the galvanizing with respect to the steel can be reversed. The steel then "protects" the galvanizing.

Inspection Techniques

The electrical resistance of a joint is the main factor for assessing its condition. It can be determined using temperature measurement methods, resistance measurement methods or both.

It is not possible to detect the asymmetrical installation of joint sleeves using a temperature measurement method since the temperature distribution in the aluminum will be too uniform.

When using a resistance measurement, an asymmetrical installation of the aluminum sleeve results in too small a difference in the obtained resistance value to be detectable. Calculations of the change in resistance over a joint indicate that an asymmetry of 20 mm will give the same increase in the resistance as a temperature increase of 1 °C and a doubling of the contact resistance gives an increase of 10 °C at maximum conductor design temperature.

Detection of asymmetrical installation of the aluminum sleeve on ACSR conductors can be performed by a reluctance test.

Detection of asymmetrical installation of the aluminum sleeve on AAC, AAAC and of the steel sleeve of ACSR conductors can be performed by a radiographic test.

Detection of steel core corrosion in the vicinity of a steel sleeve can be performed by visual inspection with a boroscope.

These different test methods are described in detail in the following sections. Some of them are performed live line, such as temperature measurement tests, and others with the circuit dead, such as the radiographic (X-ray) tests.

Temperature Measurement Tests

The reliable measurement of joint temperature is highly dependent on the current flowing through the joint. Since the thermal conductivity of aluminum is very high, the temperature will be equalized along the joint. It would therefore be difficult to detect joints that have an unacceptable contact resistance at one end, but a lower resistance at the other end. Also, the higher resistance at one end will not be detected if the resistance is measured across the entire joint. To increase the chance of detecting defective joints, the current flow in the overhead line should be increased as much as possible. The temperature detection along the joint gets more difficult under some ambient conditions when the heat generated in the joint is transferred to the surroundings e.g., rain, snow or high wind velocities.

Infrared photography detects heat radiated in the infrared spectrum. Detected temperatures at the joint are compared with detected temperatures at the conductor. The resolution is normally 1 °C. Infrared photography can be performed from the ground (see Figure 16.4) or from a helicopter (see Figure 16.5). In the following sub-sections both methods are described.

Measurement of temperature by infrared photography can be a time-saving method enabling a utility to get a good indication of the condition of the joints along a line.

Figure 16.4 Thermographic inspection performed from the ground.

Figure 16.5 Thermographic inspection performed from a helicopter.

The infrared energy measured by the instrument pointed at the object of interest is the sum of the energy emitted, in a specific wavelength window, by the object itself and of the ambient energy radiated by the surroundings and reflected by the object towards the instrument. The latter, in the case of very reflecting objects (with low emissivity coefficient), can be a considerable proportion of the total measured energy and it is essential to accurately determine its value in order to determine the actual amount of energy emitted by the object. The surface structure will also influence the radiated energy.

A joint over-temperature is usually detected by comparing the brightness of the joint, with the unaided eye, on the screen with a suitable reference. This reference is usually the ground, the other half of the joint or the conductor when airborne surveying is used. In order to detect the over-temperature, the joint must appear brighter than the reference on the screen. Due to the lower emissivity of the joint compared with the ground, a fault-free joint appears darker than the ground, because the radiation from the cold sky is partly reflected from its surface. The colder the appearance of the sky and the lower the emissivity of the joint, the darker the joint appears on the screen. Therefore the less overcast the sky, or the higher the cloud ceiling, the higher the over-temperature needed for the joint to appear bright. Consequently a defective joint becomes more difficult to detect without making point measurements. In order to generalize the diagram the radiation temperature of the sky is plotted on the horizontal axis as an under-temperature when compared with ambient or the ground. The plotted curves show the critical joint over-temperature above ambient that is needed for the joint to appear brighter than the ground, on the screen, for different emissivities.

When a thermographic inspection is performed from the ground, the situation is different. The joint is always shown on the image as brighter than the sky in the background. Therefore it is not possible to visually detect joints with an over-temperature. Instead, the temperature of every joint must be measured with a camera having a sufficiently high resolution and compared with other joints.

Resistance Measurement Method

Various devices are available which can be used live line or with the circuit dead.

Measurement made by this method is more direct than infrared thermography and is not subject to emissivity, weather, current loading and background conditions. Although it is a time consuming activity, it can be useful to confirm the initial IR survey.

The lightweight live line devices are designed to attach directly to the high voltage line by the use of an insulated stick and read the resistance of any joint directly in micro ohms. They can also be designed to simply indicate "good" or "bad" for a given joint.

By pressing the two electrodes against the joint so that the connection under test is between the two, a resistance measurement can be obtained from the display panel in a matter of seconds. It calculates resistance by measuring AC current in the line and the voltage drop due to the resistance of the section under test.

The resistance should be measured from the conductor, in the vicinity of the joint, to the centre of the joint. The resistance measurement should be taken for each half of the joint since the degradation along the joint could be different. It has been observed that out of all joints with an increased resistance, around 10 % have unacceptable degradation over just one half of the joint.

The ratio of joint- to conductor resistance is widely spread over the range of conductors used, even for the same design of joint, e.g., 10 to 45 % for one type of joint. These circumstances indicate that it is not practical to use the ratio of joint- to conductor resistance as a criterion for the interpretation of results.

It is recommended that the joint resistance R_{joint}, is classified according to three reliability levels for each combination of conductor and joint using the same parameters as in the current carrying capacity calculation for conductors. For the interpretation of results, all resistance values should be translated to the same temperature, for example 20 °C. Out of the calculated resistance values for the joint, the maximum value should be used for comparison with the appropriate acceptance criterion.

Reluctance Tests

The aim of the reluctance test is to detect the asymmetrical installation of the aluminum sleeve on ACSR conductors by measuring the magnetic resistance (reluctance) of the joint. The asymmetry of the aluminum sleeve versus the steel sleeve should be detected by the use of a magnetic detector. The detector should be thoroughly calibrated for the actual type and size of joints with the aim of giving a proper detection of each end of the steel joint. It should be taken into consideration that the compression joint might be bent so that the steel core is not concentric inside the aluminum sleeve. Furthermore, the increased distance from the outer surface to the steel sleeve should be taken into account when the aluminum sleeve has an uncompressed section in the middle.

The transducer should slowly be carried along the joint axis and when the ends of the steel joint are detected, those points should be marked.

Radiographic (X-ray) Tests

The aim of the radiographic test is to detect asymmetrical installation of the aluminum sleeve on AAC, AAAC, ACAR, and ACSR conductors as well as the asymmetrical installation of the steel sleeve on ACSR conductor cores.

The X-ray film should be placed on the top of the joint. The exposure should be selected in such a way so as to allow the detection of the end of the steel core within the steel sleeve. Because it may be difficult to detect the ends of the aluminum sleeve, the ends of the aluminum sleeve should be marked with straps of lead.

The X-ray tube should be hung beneath the conductor at a distance such that a suitable exposure time and beam angle will be maintained.

Boroscope Test

The aim of the boroscope test is to detect corrosion of the steel core in ACSR conductors, in the vicinity of the steel sleeve.

If the joint has been filled with grease during installation, the boroscope test is not useful. Before detection, a hole, with an appropriate dimension for the lens, should be drilled through the aluminum sleeve in the immediate vicinity of each end of the steel joint. It should be noted that the wire strands of the steel core must not be damaged by this procedure.

The detector should be equipped with an internal light for illumination of the zone to be inspected. After the inspection has been performed, the drilled holes should be sealed with aluminum plugs.

The interpreter should be aware that the image of the surface of the steel core will depend on the type of corrosion protection applied to the steel sleeve, i.e., red lead paint, zinc-rich paint, hot dip galvanising, oil rich paste, or other treatments.

Acceptance Criteria

To reach a higher degree of confidence in the joints on an old transmission line, a set of acceptance criteria should be determined, as shown in Cigré TB 216. The criteria could be given for three levels of reliability, reflecting the importance of the line in terms of its sensitivity to outages, the occurrence of line crossing points and the risk to people beneath the line. The transmission line owner should state the requirements for the reliability of the particular section of the line where the joints are installed.

Since there is the ability to run standard conductor types (ACSR, AAC, AAAC and ACAR conductors) at temperatures up to 100 °C and many countries assume a maximum normal design temperature of less than 75 °C the resistance of the joint will be the triggering value for immediate replacement. In that case the expectation of future increases in current loading should be taken into account.

As shown in Cigré TB 216, when the replacement of a joint must be performed, repair joints and extended joints could be used. The preparation of the old as well as the new conductor should include mechanical cleaning of the contact surfaces intended to be inserted in the aluminum sleeve in order to obtain a low contact resistance. It is also recommended that protective grease be applied. This should be brushed on with a steel brush at these surfaces before compression.

Also the contact surfaces of the aluminum sleeve should be prepared in the same manner. After installation of the joints a resistance measurement should be performed.

To eliminate poor workmanship and associated warranty claims, particular attention should be made to meticulous preparation as well as ensuring that all compression equipment is set to provide a consistent product replicating what was prepared during type registration.

16.3.1.5 Evaluation of Aged Fittings

Evaluation and testing techniques for a variety of fittings are discussed in detail in Cigré TB 477. The evaluation is divided into two parts:

- Evaluation of Aged String Hardware,
- Evaluation of Aged Conductor Fittings.

String fittings are defined as fittings that attach conductor fittings to the towers. Conductor fittings are components that are in direct contact with the conductor, and they are generally used to tension, support or join conductors. Aged fittings are defined as fittings installed for over 30 years (see Chapter 9 and Cigré TB 477).

The assessment of the state of overhead lines should therefore include the evaluation of whether conductor fittings and conductor at the point of application still comply with design characteristics and present requirements, respectively. Original specification and design criteria at the time of the line erection may differ from today's requirements, and should be noted. In some cases, relevant information will simply not be available.

Initial field inspection can be done with thermal cameras for joints and dead-ends to determine potential fittings that should be evaluated. For the purpose of conductor fittings evaluation, it is recommended to cut out a representative number of fittings samples with a sufficient length of conductor without opening the fittings (see Chapter 9 and Cigré TB 477).

16.3.2 Insulators

16.3.2.1 Technical Background – Porcelain and Glass Insulators

General

There have been occurrences where loss of the split pin and washer from the dowel pin at the earth end of suspension insulators has resulted in failure of insulator strings. This has been more evident on towers with smaller vertical loads. Broken insulator sheds can result from vandalism and defects induced during the manufacturing process.

Porcelain

The main cause of failure to suspension and tension porcelain insulators is corrosion of the steel pin in the cap and the pin assembly. Surface leakage currents are concentrated at the pin, causing a higher current density in this area and consequent dry band formation around the pin base. Partial discharges bridge these dry bands resulting in severe spark erosion and after rapid removal of the galvanizing, natural corrosion of the pin occurs until the remaining cross sectional area can no longer support the load. Additionally the expansive corrosion products create a tensile, hoop stress, which leads to radial cracks in the porcelain.

Defective insulators will be more susceptible to failure during a pollution or lightning flashover as the arc passes through the cap of the punctured unit causing it to split open and precipitate a line drop. Most failures of this type have occurred at the line end of suspension strings where the voltage across the sheds is highest.

Glass

With glass insulators, the discharges erode the glass and pin and after fairly minor surface damage, the imbalance in the internal mechanical stresses in the toughened glass causes the shed to shatter completely. Cigré TB 306 provides guidance to utilities and engineers who are in charge of the maintenance of transmission lines on how to check the state of insulators and how to decide on the safe time for replacement.

16.3.2.2 Inspection Techniques

The inspection techniques listed below can be used for porcelain and glass insulators:

- Visual Inspection,
- Insulator Voltage Drop Measurer,
- Electric Field,
- Infrared Thermography,
- Radio Frequency/Microwave Emission Detector.

Generic Description – Insulator Voltage Drop Measurer

Incipient radial cracks that occur in porcelain insulator sheds and which can initiate tensile fracture, can be detected by application of a 30 or 50 kV test voltage at ground level. As this requires extensive outage duration, 1 kV to 10 kV meters have been developed for testing in-situ, dead line or live line. This method is time consuming and the reliability of the results is dependent upon the weather, pollution and humidity levels.

Generic Description – Electric Field

There is a measurable electrical field existing between the energized and grounded end of an insulator string. When one or more of the insulator sheds is defective or leaking current, the electric field will be reduced. The measuring equipment is applied over the insulator string and the electric field over each shed is measured. There is no electrical contact between the device and insulator. The measurements are then downloaded to a computer, which analyses the results to identify the location of defective insulator sheds.

Generic Description – Infrared Thermography

The infrared camera, operated from a helicopter or from the ground, can be used to identify defective insulators. The technique can identify defects under favorable conditions where head cracks (incipient defects produced within the porcelain during manufacture, or as result of damage during transport) result in warmer insulator caps.

However, the differentiation between warm insulators and cracked insulators is not always great enough for it to be completely reliable and therefore this method should be used in conjunction with the electric field or voltage drop measurer.

16.3.2.3 Technical Background – Composite Insulators

Composite insulators have become a highly developed alternative to conventional insulators in all transmission level voltage classes for AC and DC applications around the world. The assessment of line components, which includes insulators, insulator sets, conductors, dampers as well as towers, foundations, etc., is a well established philosophy in terms of line maintenance.

An essential issue that limits an even wider application of composite insulators in some countries is the concern about the assessment of their conditions in service and especially before the application of live line working (LLW) techniques. The diagnostics is easier for LLW, since its aim is to identify only large conductive or semi-conductive defects which may be critical during the specific linemen activity. A well chosen combination of available diagnostic methods make it possible to identify the absence of critical defects of composite insulators and to carry out LLW safely on overhead lines equipped with composite insulators, in a similar way as it is for ceramic and glass insulators.

For composite insulators, degradation can occur through premature ageing or internal manufacturing defects and it is not possible, using current technology, to choose a single technique that will detect all types of defective insulators with a satisfactory degree of confidence. A combination of two or more techniques has in practice, been proven to be the most effective means of identifying defective composite insulators in service. The inspection techniques listed below can be used by utilities on live lines on composite insulators:

- Visual inspection,
- Night vision equipment,
- Electric Field Measurements,
- Directional wireless acoustic emission,
- Infrared (IR) thermography,
- Ultra-violet (UV) detection,
- Combined IR- and UV-measurements (Multicam),
- High frequency high voltage measurement tool.

The high frequency high voltage tool is applied using a hotstick and has two spring-loaded electrodes separated by approximately six inches (152 mm – adjustable depending on the insulator design) as shown in Figure 16.6.

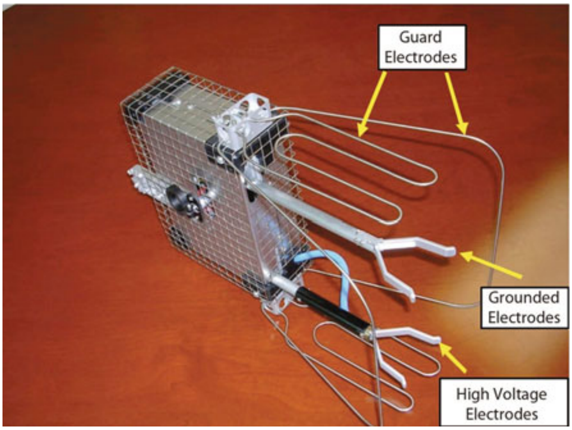


Figure 16.6 Recently introduced high frequency/ high voltage tool showing high voltage electrode, grounded electrode and guard electrodes.

Ten prototypes of the tools are being tested in 2014 by utilities in the United States, Canada and Australia. After these field trials, the tool is expected to be available commercially. Considerable effort has been made to make the tool light and field-rugged and successful testing up to 345 kV has been completed. At 500 kV, the length of the hotstick results in high mechanical cantilever loads for the operator and a crawling robot which can take the tool as a payload is being developed by EPRI as described in Section 16.6.2.4.

16.3.3 Supports

16.3.3.1 Steel Structures Condition

Technical Background

The main factors, which affect the rate and onset of steel structure corrosion, can be categorised into two groups: environment factors and protection factors.

Environment Factors

The following factors affect the rate and onset of steel structure corrosion:

- Prevailing Weather Conditions,
- Tower Altitude,
  - Affecting pollution flux & time of wetness
- Fertilisers,
- Brushwood,
- Pollution Levels,
  - Industrial
  - Coastal.

Protection Factors

The following factors affect the rate and onset of steel structure corrosion:

- Surface Protection Quality,
  - Preparation and weather conditions
- Painting Policy,
  - Frequency and time of first paint
- Tower Access,
- System Access.

All of the above factors contribute to the time before onset of corrosion and to the rate at which it progresses. In most circumstances, it will be a combination of two or more factors. Any combination of the above factors will lead to a variety of support steel conditions (see Figure 16.7).

If the first painting is delayed until significant loss of galvanising has occurred and the steelwork has become corroded, extensive preparation may be required before painting. This work may involve grit blasting or replacement of certain tower members. Inevitably, this will reduce the overall life of supports.

Figure 16.7 Corrosion at tower joints.

Most supports are constructed using galvanised steel members, which may be pre painted prior to erection or painted some time after erection. A few supports are manufactured from "Corten steel", which is a steel alloy with a special low rate of surface corrosion. However, Corten appears to be more susceptible to high rates of corrosion at joints, in areas close to the coast and in areas subjected to high levels of humidity.

In addition to corrosion of the steel, the support members can be subjected to buckling due to soil movement, loose bolts or broken members. Excessive wind movements are the normal cause of loose bolts and steel breakage. These can be detected by visual examination or "rapping" the support with a hammer to detect loose components.

Inspection Techniques

The inspection techniques listed below may be used to assess the steel structure condition:

- Visual Climbing Inspection,
- Binoculars,
- Telescope,
- Camera,
- Electronic Paint & Galvanising Thickness Measurement,
- Cross Hatch Cut Test.

Generic Description – Visual Climbing Inspection

For the purposes of the inspection, each support is subdivided into zones according to the height and design of the support. Steelwork condition is assessed against standard photographs showing steelwork at various stages of deterioration. Each zone is then given a score accordingly.

Generic Description – Electronic Paint & Galvanizing Thickness Measurement

Measurement of non-ferrous metal paints (e.g., chromium, copper, zinc, etc.) or plastic coatings on steel, can be carried out by means of instruments using magnetic induction. With paint or plastic coating, or on non-ferrous structures, measurements are possible using instruments, which employ eddy currents (this technique can also be used for the measurement of ferrous and non-ferrous metal coating on steel.

Generic Description – Cross Hatch Cut Test

This is the method by which the adhesion values for the paint on the support members as specified in standards EN-ISO 2409 or ASTM-D-3359, can be ascertained.

16.3.3.2 Reduction in Stay Wire Tension and Stay Wire Corrosion

Technical Background

Stay wires are subjected to elongation due to the numerous oscillations whilst under tension. These oscillations result in mechanical fatigue of the cable wires, causing minor separation of the strands and thus, a relaxation and/or lengthening of the cable, which can result in mechanical damage to the support. It is therefore necessary to verify the tension of the stays on a regular basis and in some cases, to carry out re-tensioning.

Under certain conditions, i.e., the presence of moisture and oxygen, these stay wires will corrode.

Inspection Techniques

The inspection techniques listed below may be used to assess the stay wire condition:

- Hydraulic Method,
- Vibration Method,
- Deflection Method,
- Corrosion Detector.

Generic Description – Hydraulic Method

Measurement of the tension related to the pressure measured on jacks fixed to the stays anchorage devices. Allows simultaneous re-tensioning if required.

Generic Description – Vibration Method

The tension is determined by timing the reflected travelling pulses on the cable. The generation of the initial pulse and timing is computer controlled. The device is calibrated by comparing the timing and tension with cables of known tension. The equipment is light and easy to operate.

Generic Description – Deflection Method

Measurement of the perpendicular effort required to initiate a calibrated deflection between two points and calculation of the corresponding tension in the stay. The equipment is light and easy to operate.

Generic Description – Corrosion Detector

This device is based on magnetic induction process, which measures the variation of the magnetic flux at the defect location. These variations are identified on the signal records and then compared to signals related to typical defects of various magnitudes (corrosion, broken strands).

16.3.3.3 Corrosion of Anchor Rods

Technical Background

Overhead transmission lines supported by stay wires are sometimes anchored to the earth with rods. Under certain conditions, i.e., the presence of moisture and oxygen, these rods will corrode along their length.

Inspection Techniques

The inspection techniques listed below may be used to assess the corrosion of anchor rods:

- Ultrasonic Pulser and Receiver,
- Potential Measuring.

Generic Description – Ultrasonic Pulser and Receiver

This non-invasive technique eliminates the need to excavate, which is the only other alternative to fully assess their condition. The extent of corrosion can be categorized into three groups:

- No Corrosion (Good),
- Moderate Corrosion (Moderate),
- Excessive Corrosion (Excessive).

The system is compact and lightweight, consisting of an Ultrasonic Pulser and receiver together with a PC-based data collection and processing system.

Successful application requires a smooth, flat surface for coupling the probe to the anchor rod. This may require the grinding of a flat surface in the eyelet of the rod at right angles to the longitudinal axis in order to properly direct the ultrasonic wave.

Generic Description – Potential Measuring

The potential of a metallic surface is measured in relation to a reference electrode (i.e., $Cu/CuSO_4$). Potential measuring will indicate if the zinc coating is still able to protect possible exposed steel areas.

Measurements that gives the depth dependent potential distribution, may indicate if anchor rods are exposed to local corrosion attacks. By following the potential growth trend, the lifetime of the construction may be estimated.

16.3.3.4 Wood Poles Condition

Technical Background

The main damage, to which wood poles are subjected, is the degradation of mechanical strength due to wear and decaying of the wood and to the action of insects and woodpeckers.

Decaying takes place mainly in the ground line zone where humidity, fungi, bacteria and pollutants may penetrate inside the pole through the natural cracks in the wood or through the passages created by insects.

The ground line zone extends from about 45 cm below ground line to about 15 cm above. This is due to the typical limit of oxygen below ground and to the reduction of moisture at heights above ground (water and oxygen are necessary elements for the decaying of wood).

In order to protect the pole from the above agents, the wood is treated prior to installation. Supplemental "in situ" treatments may be applied during the lifetime of the pole in order to prolong the life (Figure 16.8).

Figure 16.8 Typical Wood Pole Structure.

Inspection Techniques

The inspection techniques listed below may be used to assess the wood poles condition:

- Visual Inspection,
- Climbing Inspection,
- Excavation,
- Sound and Bore,
- Electrical Resistance Measuring Device,
- Wood Pole Strength Measuring Device,
- Penetration Measuring Device,
- Trained Dogs,
- Portable Ultrasonic Detector.

Generic Description – Sound and Bore

This method involves first repeatedly hitting the pole surface with a hammer from ground line to 15-20 cm above. The main purpose of this is to locate internal decay pockets by listening to the sounds and noting the feel of the hammer. Borings should be made in the sections where decay is suspected. For poles that sound completely solid, at least one boring should be made at a 45° angle near ground line. An experienced inspector will notice a change in resistance against the drill when it contacts decayed wood.

Generic Description – Electrical Resistance Measuring Device

The decay process, even in early stages, will develop negative ions that lower the electrical resistance of the wood tissue. By measuring the electrical resistance of the wood by this instrument it is possible to detect incipient decay. The measurement is carried out by slowly inserting a probe (which consists of a twisted pair of insulated wires with bare tips) into a bore in the pole. When a sudden drop (75 %) in the resistance reading occurs, incipient decay is located.

Generic Description – Wood Pole Strength Measuring Device

This instrument utilizes the correlation that exists between the bending strength of the pole and spectral analysis of sound waves travelling through cross sections at various locations along the pole. The relationships between these factors are held in a computer and are used for comparison to determine the strength of wood poles to be assessed.

This instrument is not a substitute for traditional inspection. It does not detect decay and the results obtained should be coupled with a physical evaluation of the pole (e.g., by sound and bore).

Generic Description – Penetration Measuring Device

Measuring the number of rotations of a probe needed to penetrate a given distance indicates the condition of a given wood type (more rotations are needed to penetrate a given distance in harder wood than in softer wood). This is achieved by rapidly rotating a probe into the wood and measuring the rate of progress.

Any type of wood can be tested whether it is hard, soft, wet or dry.

The results are stored on a computer for easy data collection and analysis. The data collected can be used to calculate the wood density.

Generic Description – Trained Dogs

Dogs can be trained to smell certain types of wood rot.

Generic Description – Portable Ultrasonic Rot Locator

A transmitter is screwed into the pole and emits an ultrasonic pulse three times a second. The probe of a hand held receiver is placed firmly against the wood to detect the ultrasonic pulse. If the wood is in good condition, a strong signal will be received. A weak signal indicates decay. Where decay is detected, the results can then be feed into a program, which will calculate the strength and determine the rot position.

16.3.4 Foundations

16.3.4.1 Technical Background

For the majority of foundations, constructed using the appropriate materials, there are no significant modes of degradation. Poor workmanship and design deficiencies do however, give rise to potentially serious problems. Uplift failures, where the pyramid block remains in the ground, can occur if the stub is insufficiently encased in the block or the cleating is inadequate. Corrosion of the tower steel stub can occur when moisture and oxygen are present. The corrosion is usually only found at the chimney/muff interface where poor construction has left the joint open and bare steel is exposed. Problems with ground conditions such as mining subsidence can also occur.

The main factors, which affect the rate at which the tower stub can corrode, are:

- Foundation Construction Quality,
  - Continuity of concrete, interface quality, concrete thickness
- Soil Types,
  - Clay, alluvial soils are worst due to water retention
- Ground Water Levels and frequency of change in level.

For more detailed explanation of foundation deterioration mechanisms refer to Section 3 of the Cigré SC22 WG07 Report on “Refurbishment and Upgrading of Foundations” reference CE/SC 22 GT/WG 07, 1999, 160 pages Ref. No.141.

16.3.4.2 Inspection Techniques

The inspection techniques listed below may be used to meet the following foundation criteria:

- Foundation Type and Dimensions
  - Visual
    - Above ground
    - Below ground

- Surface Penetrating Radar
- Acoustic Pulse Echo
- Probing
- Foundation Condition
  - Visual
    - Above ground
    - Below ground (Figure 16.9)
- In-situ Concrete Strength Tests
  - Core Samples
  - Penetration Resistance Tests (Windsor probe)
    - Comparative Quality and Localised Integrity
      - Surface Hardness Measurement (Schmidt hammer)
      - Surface Penetrating Radar
      - Acoustic Pulse Echo
      - Hammer Test
    - Durability
      - Carbonation Tests
      - Corrosion Rate Measurement
      - Half-cell Potential
      - Resistivity Tests
      - Concrete Dust Samples
      - Sulphate and Acid Concentration in soil or ground water
      - Concrete Core Samples
      - Steelwork Measurement
      - Timber Strength
      - Ultrasound
- Ground Resistivity
  - Soil Resistivity Meter.

For further details, see Chapter 13 – Foundations.

Figure 16.9 Foundation condition below ground.

16.4 Use of Carts for In-Span Maintenance Work

16.4.1 Introduction

One maintenance method commonly employed by many line owners and operators is working in-span on the conductors, shield wires and even the OPGW of a transmission line, especially when the accessibility with alternative methods such as the use of bucket trucks, cranes or helicopters is difficult, problematic or restricted. Sometimes, the work makes use of carts or man-baskets (see Figure 16.10) and sometimes the work is done without any apparatus at all to support and transport the person(s) on the wires.

As line components age, concerns arise for the safety of in-span work insofar as it increases the mechanical tension in the conductor on which it rides and that may be weakened with age or by the damaging actions of attachments on the conductor. Carts are used for in-span work such as the repair or replacement of spacers, dampers, aircraft warning markers, etc.

Cigré TB 471 identifies the factors that affect the structural integrity of the aged conductor systems and therefore, the risks associated with the use of carts on aged conductors. Guidelines are given for developing criteria or rules for use of carts, for inspection and assessment of safe conditions as well as alternative methods for dealing with presumed or known unsafe conditions.

16.4.2 Technical Considerations

Before working in-span on a wire, it was felt essential to know or to measure the present condition level of the wire, of its joints (compression or otherwise) and the insulators and fittings. The condition is generally unseen or difficult to quantify as damage is typically due to lightning, arcing, galloping, fatigue, corrosion, ageing and vandalism (bullets). The condition of the conductor at invisible places, such as under existing aircraft warning markers, and inside connectors is a major concern.

Figure 16.10 Cart used on a horizontal twin bundle.

Prior to carting, a specific engineering analysis can be carried out to establish its effect on line tension, and also check for adequate clearances. If necessary, the wires in question would be closely inspected by helicopter. An inspection may also involve the removal of a sample section of conductor for laboratory (external) analysis.

It is important to understand that the point load of persons on a span of wire generate a tension increase in the wire that can be 300 % to 500 % of the point load weight depending on the length of the span, the location in the span of the load and so on.

Minimum safety factors for using carts are considered useful to allow the possibility of sending a second (emergency) cart to help an imperilled one. Alternative emergency solutions are sometimes planned (especially when the accessibility from ground is difficult or impossible). Safety can be increased by using safety ropes to secure the insulators and hardware on both sides of the span to be traversed. A safety rope can also be tied to other phases. The clearance to the nearest live phase is calculated in advance.

Once the wire is aged, the work is to inspect and repair the conductor and the hardware and connections attached to it. Carts can carry one or more persons. These carts are supplied by manufacturers or are custom built by the user. They come in many sizes and weights. As described in Cigré TB 471, cart design, fabrication and usage are without many national or international standards, except standard BS EN 50374 applicable to all European manufacturers.

16.4.3 Sources of Tensile Strength Loss with Time

The tensile strength loss in the conductor, OHGW or OPGW, and in its tension-carrying connectors (end fittings, strain insulator assemblies and splices) is of interest in this Section.

Consider the suspension assemblies at structures. Compared to the issue of wire tension increase and integrity, this is an easy subject to understand and manage. As noted the tension increase is limited to the actual, gross weight of the cart and/or people placed on the wire.

This assembly is made up of the structures attachment plate, the hole(s) in it that support the assembly and all parts of the assembly. Rolled steel parts of this assembly tend to weaken only by loss of material through wear or corrosion. Either action is discoverable by visual inspection. Forged or cast metal parts and ceramic insulator parts are capable of weakening with time by micro-cracking—that is to say, invisible actions.

It is advantageous that most transmission lines and systems have a great number of these assemblies and load-carrying problems with them, i.e., failure of any of their parts, have a reasonable chance of showing up statistically before cart usage on them is considered.

Barring the development and collecting of statistical performance data, the risk associated with a failure of such an assembly caused by the use of a cart is only a matter of chance. Cart users must decide whether to operate under the conditions of "chance" or to do the data-gathering work beforehand to form a basis for risk assessment. The action that can be taken to mitigate the risk—known or unknown—is to tie the conductor off to the structure support above and by-pass the assembly that is not trusted.

Consider the conductors, including the tension-carrying connections such as end fittings, strain assemblies and in-span splices. Work by others and common knowledge within the industry allow the listing of sources of tensile strength loss in conductors and their tension carrying connectors. These are:

- *Core corrosion*: Steel, the most common core material does oxidize with time in selected environments. It is accelerated by industrial or sea coast environments. It has also shown to be a problem in self-damping conductors where the intentional gap (airspace) between the core and aluminum can fill with water at mid-spans causing loss of material in that location sufficient for breakages to be recorded at some utilities. Excepting these conditions, steel cores tend to retain strength for respectable periods of time.
- *Partial core breakages*: The strands of conductor cores can be broken over time from Aeolian vibrations. This will occur at structure support hardware or at point masses in–span such as marker balls. Generally, core strand fatigue failures are rarer than breakages in the aluminum strands caused by the same action. The brittle cores on the new high temperature conductors can be fractured during installation if the installation procedures are poorly executed. If not realized at the time, this can set up a future event when the conductor is tensioned to a higher value. This type of event has no recorded data to allow measurement of frequency of occurrence and is to be considered as very rare and eventually revealed by the natural tension fluctuations in the wire.
- *Aluminum strand breakages*: Aluminum strands are easily fractured in partial numbers by Aeolian vibration if the wire is not properly equipped with vibration dampers. Each broken strand is a calculable percentage loss of strength. Generally, the most likely location for broken strands to exist is under hardware attached to the conductor or in the layers of strands beneath the outer layer. This makes finding these broken strands nearly impossible by simple visual inspections. Various techniques do exist to look into these hidden places and these techniques are worth employing from time to time to track any progressions of strength loss caused by vibration.
- *Lightning damage*: Lightning strikes can burn aluminum strands. The result tends to be a large area that is clearly heat damaged. Lightning strikes damage steel strands of ground wires with much less visible evidence and much greater strength loss. The visible damage to steel strands can be as small as 1-2 mm but the instant, extreme heating changes the metal to Martensite—a brittle material. It is common to see several of the typical seven strands completely severed in brittle fracture at more than one location in most spans on a line. All tensile load in the wire is carried in the remaining, intact strands and failure will occur when the tensile strength of those remaining strands is exceeded. If two strands are fractured by a previous lightning strike, then the strength of the OHGW, while appearing to be intact and or full tensile capability, is actually reduced to 5/7th of its original strength. This is not an uncommon condition for steel OHGWs.

- *Bolted fittings*: Bolted deadends are reasonably common. They are generally made of cast steel or aluminum and use U-bolts to hold the wire in a saddle shape of the casting. They are often of reasonably complex shape, including a "wave seat" to hold the wire in a bent position to assist with the grip. There have been cases where these types of fittings—those of a particular shape and application—have broken while in use at tensions well below the published rated strength. The point to understand is that great care and study should be made of these cast hardware components before relying on the manufacturer's claims. They can be complex entities with poorly defined or understood limits of use.
- *Compression fittings*: Compression splices and deadends are designed to transfer the full tension in a wire from the wire to something else. The industry is beginning to understand that the high temperatures that are being applied and the long years of service of these connectors are both leading to higher tensile failure rates with compression fittings than previously understood.
- *Flashover, galloping and vandalism* may happen.

16.4.4 Alternate Methods and Criteria for Cart Use

If there are any doubts about the condition of the components, work is done by an alternate method to in-span work such as:

- Lowering the damaged conductor to the ground,
- Lowering the damaged conductor to the level of another undamaged conductor,
- Using a bucket truck or a crane (depending on the conductor height),
- Using a helicopter (with or without live line working),
- Using robotics (see Section 16.6).

The natural environmental changes in temperature and the occurrences of wind and ice events can possibly generate tensions in the spans and weights on the support points comparable to those to be generated by in-span work. Thus, these natural events can be looked to as evidence that the spans have recently supported at least these loads. Finding evidence or proof of greater capability is much more difficult and generally not sought. Thus, the decision to work in-span will typically be made with only partial supporting data. The risk to be taken is a function of the organizations' willingness to take such risks.

16.5 Live Work Maintenance

Live work (work on energized circuits) has been carried out in different parts of the world for many decades. Live work is the preferred method of maintenance where system integrity, system reliability, and operating revenues are at a premium and removal of the circuit from service is not acceptable. Live work may also be beneficial in construction, upgrading and uprating.

Live work has been found to be a safe means of performing maintenance operations due to the additional planning and crew training required for live work. Most maintenance operations that are performed de-energized can also be performed using live work techniques.

This section describes the costs and benefits of live work versus de-energized methods. Examples of typical live work operations are given that are applicable to many asset owners. There is also a brief description of some of the technical requirements for implementing live work programs. For a more detailed discussion of the costs of developing an in-house live work programs and the outsourcing of live work, refer to Cigré TB 561.

16.5.1 Why Consider

16.5.1.1 Trends

Grids are getting older and need more maintenance. It will be more difficult to get the authorization to build new lines. There is consequently a need to increase capacity on existing facilities (e.g., replacing conductors). Increasing renewable generation (connection to the grid of wind farms, co-generation, solar farms, etc.) has impact on the availability of the network for scheduling maintenance.

16.5.1.2 Customers

There are difficulties and in some cases impossibilities to get outages of client feeders for de-energised work. Moreover, penalties may be claimed for undelivered energy (from power plant point of view).

16.5.1.3 Safety

With respect to the number and severity of accidents, live work has been found to be a safe way of performing maintenance operating. However it requires extensive training, qualification, and certification for each worker and supervisor.

16.5.1.4 Regulators

Regulators are requiring reliability and availability standards (i.e., respect of n-1 criteria, penalties for outages, etc.). Live work can help complying with these requirements.

16.5.1.5 Politics, Stakeholders

Performing live work on lines and substations to reduce customer outage time presents considerable advantages (public image, national consequences of outage, etc.).

16.5.2 What Can Be Done

Most maintenance operations that are performed de-energised can also be performed using live work techniques. To do so requires proper operating procedures that take into account the complexity of the task and technical standards referring to equipment, procedures, safety and quality assurance (see Cigré TB 561).

16.5.2.1 Complexity of Various Jobs

Live work has mainly been developed for overhead lines, fewer utilities are able to carry out live work in substations.

Table 16.1 gives a relative complexity rating of performing live working on overhead. The relative complexity is ranked as either low, medium or high (1, 2, 3), where:

- Low complexity work normally does not modify the electrical and mechanical characteristics of the structure and are often some distance away from the structures.
- Medium complexity work may modify the network configuration. These operations sometimes include connection/disconnection of electrical parts of the network.

Table 16.1 Live line work; Complexity of live work: Low, Medium, High (1, 2, 3)

		LINES	Complexity	Reference
Insulators	Change out	Suspension I-string	1	Figure 16.11
		Suspension V-string	2	Figure 16.12
		Dead Ends	2-3	Figure 16.13
	Testing		1	
	Cleaning and Washing		1	
	Splicing	Conductor	2	Figure 16.14
		Shield Wire	1	
Conductor & Shield Wire	Sampling & Testing		1-3	
	Repairing/Patch rod/ split sleeve		1	
	Replacing & Restringing		3	Case Study 16.1
	Relocating Phases		3	
	Installing OPGW		3	
Components	Communication device		2	
	Aerial Markers		1	
	Inter-Phase Spacers		2	
	Spacer-dampers		1-2	Case Study 16.2
	Corona rings		1	
	Suspension clamps		1	
	Jumpers		1	
Tower and Poles	Replacing tower		3	
	Replacing wood pole		2-3	
	Relocating		3	
	Refurbish, replacing steel members		2	
	Raising		2-3	
	Painting		1	

Figure 16.11 Changing 220 kV I-string insulator using bare hand techniques (Spain).

Figure 16.12 Changing a 500 kV V-String Insulator using Bare Hand Techniques (USA).

- High complexity work corresponds to the operations where the aim of the work will modify the network configuration. These operations include connection/disconnection of electrical parts of the network.

16.5.3 General Cost Comparisons

The feedback from utilities performing live work on overhead lines is that the cost is comparable to that in de-energised conditions. However, there will be a minimum additional cost of 1 or 2 more days for preparation of live work plans.

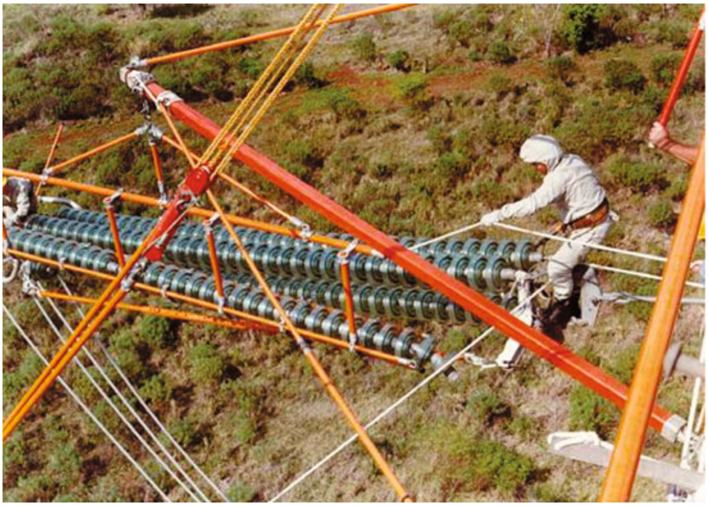


Figure 16.13 Changing 600 kV Insulator String using Bare Hand Method (Brazil).

Figure 16.14 Making a full Tension Conductor Splice (South Africa).

Table 16.2 gives a comparison of time required between live work and de-energised method and for different works.

Depending on whether live work program is carried out in house or outsourced, the Table 16.3 will give a general idea about the (in-house) costs for the utility of each stage in the live work program.

Referring to Table 16.3, the (in-house) costs for an in-house project will mainly depend on labour costs. In case of outsourcing the live work, total costs may be higher, because the fixed costs of the contractor will be calculated on the project. The level of these costs depends on the number of projects to be done, the situation in the market, short-time versus long-time contracts etc.

Table 16.2 Comparison of Time Required to Complete Live Line Work versus De-energised Work

	Bare hand method	
	225 kV	400 kV
Changing suspension insulators	From 5 to 15 % more	from 5 to 10 % more
Changing fitting and insulators	From 5 to 15 % more	From 5 to 10 % more
Changing wire components	30 % less	30 % less

Table 16.3 Comparison of Fixed Costs of In-house versus Outsourced Live Work

Item	In-house	Outsourced (In House Cost)
Preparing the conditions for a live work organisation	100 %	10 %
Feasibility study	At the beginning of the project	At each new situation.
Implementing a live work organisation	100 %	5 %
Validation of rules	100 % for initialising	100 % at each new situation
Training of teams	100 % for initialising	0 %
Training of system operating staff	100 % for initialising	100 % for surveying at each new procedure
Staff re-training	100 % (more or less due to the live work activity)	5 % for each new procedure
Purchasing tools	100 % for initialising	0 %
Regular testing	100 %	0 %
Tool repair	100 %	0 %

Case Study 16.1 (USA): Replacing & Restringing while Energised

The increase in capacity was accomplished by replacing the existing ACSR conductor with ACSS/TW (trapezoidal wire) and matching the design working tensions so that it would not be necessary to change out structures or anchors.

Due to system constraints the line could not be taken out of service for the extended period of time required for normal uprating. Therefore, the 52 km line, consisting of 234 H-Frame structures with the three phases in a horizontal configuration, was reconductored while energised. Work plans were developed to enable the sequential transfer of electric load between the three existing phases and a temporary transfer bus. Supplementary pole structures were constructed to support the energised temporary line. Rollers were installed on the de-energised existing phases to be reconductored. In this configuration, the induced voltages on the “de-energised” conductor ranged up to

30 kV, therefore, the equal potential stringing method was used to eliminate potential hazards to the line crews and public. Other procedures that were developed were:

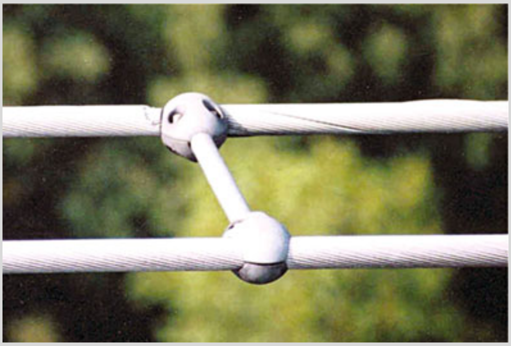
i. Tying off the existing and new conductor at night by insulating and isolating the conductor from the equipment.
ii. Transferring of large loads from existing conductor to the temporary line, and from the temporary line to the new conductor, using a mobile 345 kV breaker.

Installing rollers on the de-energised phase while the temporary line at the left is energised.

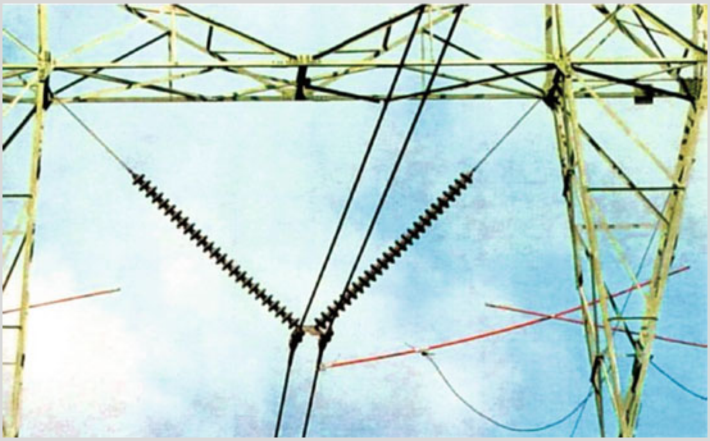
Mobile 345 kV Breaker.

Case Study 16.2 (USA): Spacer Replacement

This case study demonstrates how a spacer replacement programme could be completed live. The route is a 500 kV twin ACAR construction which has encountered spacer induced conductor damage.



Consideration was given to completing the work either de-energised or live. With circuit outage constraint charges at $75,000 per hour the decision was made to complete the work live with industry standard Portable Protective Air Gaps (PPAG) also fitted. The PPAG were installed on the towers at a distance of every 4 miles.



The work was completed over a 22 day period via a helicopter and this involved changing 6,208 spacers with a total cost of under $800,000 i.e., approximately 10 hours of outage cost.

16.6 The Use of Robotics and New Maintenance Techniques

16.6.1 Introduction

Strategic assets such as electricity transmission grids must be operated in a safe, predictable and reliable way. To do so, best practices in the operation and maintenance of transmission networks must evolve to respond to the changing context of pressured grid operators: operation and maintenance standards, laws and regulations, increasing loads, commercial exchanges, etc.

Nowadays, live-line work is a must for most maintenance operations, and the need to maintain system availability is a key factor in the introduction of robotics in this field. In order to maintain or increase the reliability of aging OHTL, new maintenance techniques are becoming available to assess and diagnose the condition of various OHTL components. Power line inspection and maintenance already benefit from developments in mobile robotics, which can reduce the potential risk to maintenance crews (e.g., live work), reach hardly accessible spans (e.g., river crossings), perform tedious labor faster, and decrease costs.

A comprehensive review of the state of the art in transmission line maintenance robot technologies have been presented by Toussaint et al. 2009 and in a Cigré TB entitled "The Use of Robotics in Assessment and Maintenance of OHL" to be published.

Most robotic technologies described here were published in CARPI 2010 and 2012 Conference Proceedings, where many papers were presented on power line robot design, simulations, subsystems and peripheral work (image processing, control and sensors).

16.6.2 Transmission Line Robotics

Robotic technologies have already proved to be a valuable means of inspecting certain systems, and robotic inspection is now considered to be a realistic approach for grid owners. A few major utilities have already introduced robotics into their maintenance practices, and several are funding projects to do so. Safety, efficiency, reliability and availability of equipment are the main factors driving this trend.

The expected increase in live-line work approaches has stimulated the development and use of robotic devices to minimize risk to field personnel safety and maintain power system reliability. This Section seeks to provide an overview and an assessment of the future possibilities for transmission line robotics. Four robot classifications are identified here:

- Ground-based robots,
- Line suspended robots,
- Aerial-based robots,
- Other types of robots (e.g., insulator robots).

16.6.2.1 Ground-Based Robots

The significant increase in live line work requirements within the OHLT industry has stimulated the development and use of robotic devices within the industry. The main benefits or aims of these devices are to increase safety to field personnel and minimize the risk to power system reliability when performing live line work. This section will look to review existing and developing robotic technology with respect to ground based robots.

In respect of ground robotics there is limited development in this area of robotics, with the main area for use focussing on the capture and control of energised conductors and carrying out tasks to provide safe working areas for linesman as well as keeping the lines energised during the projects. The development was driven to address specific live-line procedures, such as the replacement of rotten wood poles utilizing the existing hole (especially in rock) and reframing and re-insulating structures, which are typically difficult to execute with traditional live-line tools like hotsticks.

Much of the development has focussed around robotics arms for the manipulation and control of energised conductors. Examples of these being:

***LineMaster*™**

As shown in Figure 16.15, this is a robotic arm developed by Quanta Energized Services for remotely handling, moving and relocating energised conductors of varying voltages up to 500 kV.

Figure 16.15 Photo of the boom truck and LineMaster™ in action.

The robotic arm remotely captures and controls the energised transmission lines in a safe and efficient manner. The arm is controlled by a radio control device comprising of a portable transmitter and two receivers. The arm is powered via a hydraulic power source. There are two versions of the robotic arm which is generally mounted to a truck.

Main Features

- Operates by hydraulic actuator that attaches to conventional line trucks,
- Unit consists of adaptor, robotic arm and fibreglass segment,
- Robotic arm can extend up to +/−3 m (10 feet) and rotate 270 degrees,
- Primary unit models:
  - 227 and 454 kg (500 and 1000 lbs) lift
  - 2273 kg (5000 lbs), single-phase
  - 5455 kg (12000 lbs), three-phase
- Control is by ground-based safety spotter.

Benefits

- Enables upgrade relief to congested paths without adding to congestion by scheduling outages to perform work
  - Circuits most in need of relief are usually those difficult to schedule out of service
  - Reconductoring can increase thermal capacity
  - Structures beyond their expected service life can be repaired
- Enables reuse of existing rights of way
- Reduces matting and footprints in wetlands areas
- Reduces operational costs and delays of line switching and grounding
- Enables emergency repairs to generators (including nuclear plant substations) without plant outage
  - Avoid costs of shutdown, restart and replacement purchase power.

Three Phase Pick Robotic Arm

Developed for the capture and control of three conductors simultaneously, this technology is similar to that of the Quanta technology, however little technical specification available.

Single Pick Robotic Arm

Designed to handle higher conductor sizes and weights, which is used to remotely capture and control a single conductor at a time.

Significantly many of these technologies have been used extensively within the USA and South Africa.

Robotic Pole Manipulator

This is a design concept postulated in the academic paper compiled by Turner and Wilson 2010 titled System Development of a Robotic Pole Manipulator.

This concept was developed for wooden poles up to 16,8 m (55 ft) length. This is a truck mounted concept was identified and developed to eliminate injuries and near misses associated with the handling of power poles near overhead lines and in congested, urban environments.

In summary, the area of ground based robots is significantly restricted in terms of developmental paths. The main area focuses around ground manipulations of existing assets as well as the construction of new assets.

16.6.2.2 Line-Suspended Robots

The most used applications for robots suspended from the line are to perform visual inspection in transmission lines that cross difficult right of ways, such as large rivers or mountainous areas.

As described by Elizondo and Gentile 2010, line-suspended robot technology has been used since 2006 by Hydro-Québec IREQ (Canada) and since 2009 by Hibot (Japan). Development of this type of robot is active as more and more prototypes are being built and more players are expected to enter the market as service providers or technology users.

The robots or moving platforms are able to travel over the live or ground conductor of transmission lines within different conductor slopes (usually no more than 30-35 degrees) and many of them are able to pass through or cross over the following obstacles that are found attached to the conductors of transmission lines:

- Dampers for wind vibration (Stockbridge),
- Double suspension clamps with yoke plates and bundled conductor clamps,
- Single suspension clamp,
- Spacers for bundled conductor,
- Splices/sleeves,
- Warning spheres or aerial markers (sizes: 28, 56, 254 cm in diameter),
- Trunnion clamps.

Robots suspended from the line, can perform the following:

- Visual inspections by different types of cameras:
  - Live conductors and overhead ground wires and other transmission line components,
  - High risk vegetation encroachment in transmission line right of way by Light Detection and Ranging (LiDAR),
- Application of specialized sensors:
  - Measurements of electrical resistance in splices,
  - Recording of audible noise by a microphone,
- Temporary repairs/adjustments of transmission line components:
  - Mechanical clamp to repair broken conductor strands,
  - Motorized wrench for adjusting bolted assemblies,
  - Installation and removal of aircraft warning spheres or marker balls,

- Specialized applications:
  - De-icing,
  - Corrosion detection,
  - Electro-magnetic interference to identify arcing or nearby Corona,
  - Sensor reading systems to collect data from remotely installed devices strategically deployed,
  - Insulator cleaning.

Hydro-Québec IREQ has been developing different technologies to incorporate robots into transmission line maintenance practices. Their first technology, the LineROVer, was initially developed for de-icing, but also featured line inspection capabilities. A photo of the LineROVer is shown in Figure 16.16.

The LineScout was developed subsequently as shown in Figure 16.17. It has been designed to operate on two, four, or six conductor bundles and can cross

Figure 16.16 Photo of the LineROVer robot inspecting a transmission line.

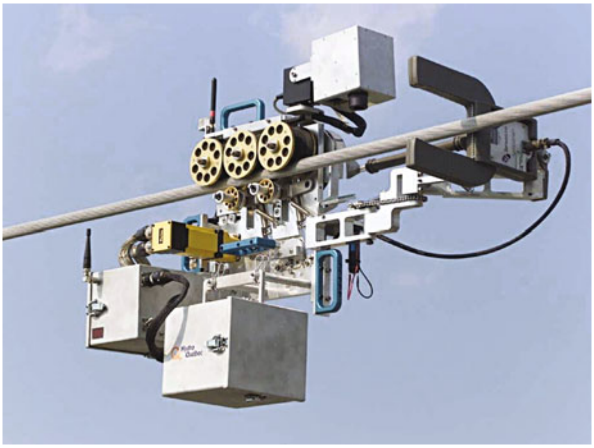


Figure 16.17 Photos of the LineScout robot.

obstacles up to 0,76 m (30 inches) diameter found on conductors including warning spheres, spacer-dampers and single- and double-suspension clamps. Crossing dead-end structures and jumper cables was not included in the design specifications.

The LineScout was developed with active involvement of the linemen and line maintenance technicians from Hydro-Québec TransÉnergie. The main applications and capabilities of the LineScout robot are listed below:

- Visual inspections by four operator cameras. Defective transmission line components can be identified either through classical cameras or infrared technology.
- Application of sensors such as for the measurement of a compression splice's electrical resistance.
- Temporary repair of components. Using a universal electric torque wrench, components could be re-adjusted. Also, broken conductor strands can be temporarily repaired by installing a clamp.

The Expliner robot has been designed for remote inspection of energized high voltage transmission lines, up to 500 kV. It has the capability to cross the typical obstacles found in a transmission line, such as cable spacers and suspension clamps. The robot can reach the transmission line from an access cable, as shown in Figure 16.18.

The main application of the Expliner robot is to perform visual inspections by cameras. Defective transmission line components can be identified. It has been tested in facilities that represent the field conditions and on energized transmission lines. Even though the robot is capable of crossing obstacles typically found in transmission lines, completely autonomous control for the unit has not yet been achieved due to the unstructured environment and the variety of spacers and obstacles that need to be crossed.

16.6.2.3 Aerial-Based Robots

Routine inspections and asset condition assessment in many cases are carried out using helicopters with trained personnel to capture information for an intended

Figure 16.18 Expliner climbing to a transmission line.

purpose. As another tool to help meet customer requirements for availability and reliability, the application of robots to automate the inspection of transmission line assets is of increasing interest to electric power utilities, as this work is performed while the transmission lines are energized. Currently, electric power utilities are interested in investigating the technology of aerial based robots or unmanned aerial vehicles (UAV's) as it provide a unique perspective as they fly close to the transmission line to inspect the asset (Elizondo and Gentile 2010).

The current state of the art for aerial-based robots can be described as an autonomously controlled flying device that operates close to the transmission line assets (Elizondo et al. 2012). Overall, the development of UAVs is in its infancy stage for transmission line asset management. Over forty nine UAV models were reviewed by Elizondo et al. 2013; twenty five models classified as commercial UAVs and twenty four classified as military UAVs. Of the forty nine, there are seven UAV models, which have performed transmission line inspections. The focus of the majority of UAVs today is toward military applications.

Robots of this type have achieved autonomous operation as they have been able to verify their own position as they fly and wirelessly transmit images taken to ground. The main applications include:

- Visual inspections by different types of cameras:
  - Live and ground conductors and other transmission line components,
- Power line corridor monitoring and high risk vegetation encroachment:
  - Algorithms developed for individual tree crown detection and delineation,
  - Evaluation of machine learning techniques for object-based tree species classification,
  - Algorithm developed for automatic power line detection from aerial imagery and LiDAR point clouds.

Development of this type of robot is very active as more and more prototypes are being built and more players are expected to enter the market as service providers of technology users.

For instance, the electric power industry in Japan have faced severe challenges related to the industry deregulation which has resulted in additional efforts for the operations efficiency and cost reduction. This, among other conditions, has driven the development of an unmanned helicopter for the inspection of power transmission lines. The development was carried out by Chugoku Electric Power Co. which operates in the southwest region of Japan and has more than 8000 km of transmission lines.

This UAV is equipped with a GPS, camera and image transmission equipment and is able to fly in predetermined routes along the power transmission line. The robot verifies its own position as it flies and wirelessly transmits images taken to ground. A photo of the device flying along a transmission line is shown in Figure 16.19. The costs of this unmanned helicopter are about half when compared with the costs of a conventional manned helicopter.

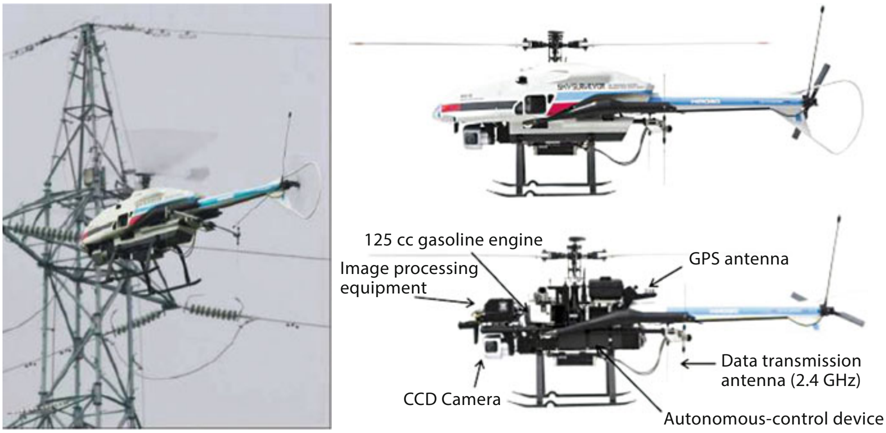


Figure 16.19 Unmanned aerial robot for transmission line inspections developed by Chugoku Electric Power Co. (Shimo 2006).

Figure 16.20 Live-line insulator cleaning robot developed by KEPCO 2006.

The limitations or barriers for aerial-based robots, which prevent them from wide deployment, are:

- Risk of sudden crash of the device,
- Unexpected environment changes like wind gusts,
- Invasion of privacy,
- Rules and regulations from aviation agencies,
  - In some countries, before using a UAV, a flight plan approval is required with associated time delay for approval process.

16.6.2.4 Other Types of Robots

Korea Electric Power Research Institute developed a robot for live line inspection of insulators (Cho et al. 2006) as shown in Figure 16.20. This robot was developed for 345 kV power transmission lines live-line insulator dry cleaning with brushes.

Korea Electric Power Corporation (KEPCO) developed a robot for live line inspection of suspension insulator strings as shown in Figure 16.21. The robot is measuring the insulation resistance and the voltage distribution along the insulator (Park et al. 2010).

As described in Section 16.3.2.3, the high frequency high voltage tool is usually applied for composite insulators using a hotstick. However, at 500 kV the length of the hotstick results in high mechanical cantilever loads for the operator and EPRI is developing a "walking beam" insulator crawling robot to operate under energized conditions, which can take the tool as a payload together with other inspection technologies. The objectives of the robot are to increase the repeatability of the measurement, reduce the mechanical stress on field personnel and increase safety. A version of this robot which is presently in testing is shown in Figure 16.22. For further information, refer to Cigré TB 545.

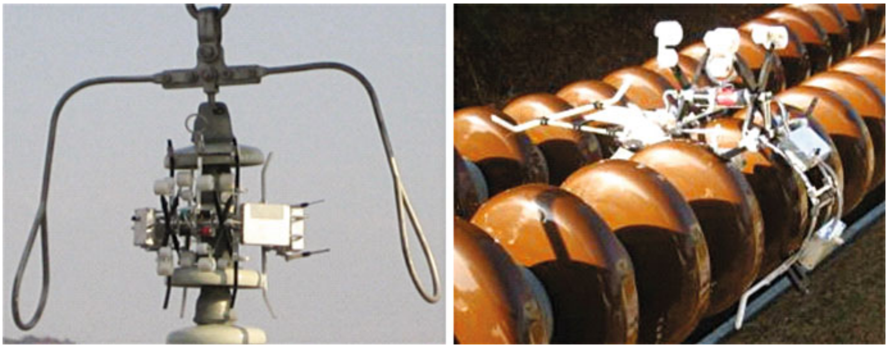


Figure 16.21 Live-line insulator inspection robot developed by KEPCO, 2010.

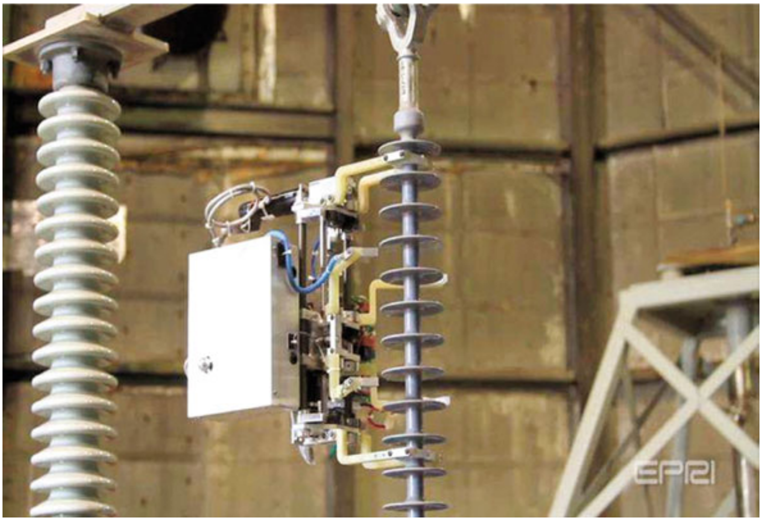


Figure 16.22 Technology demonstrator of the EPRI insulator crawling robot that is being investigated to replace the hand held operation.

16.7 Conclusion

Formulating a successful transmission line maintenance strategy is dependent on the transmission line asset owners' drivers and constraints. The maintenance strategy will be dependent on the asset owners' particular environment, existing condition of the assets and, perhaps most important, criticality of the existing transmission lines.

Inspection and maintenance activities are conducted to prevent degradation of an OHTL asset beyond a desired performance level. The time to perform these required maintenance activities in order to achieve a desired performance level of the OHTL is a critical question. Although failure of an OHTL is not desirable, total elimination of this risk may not be economically justifiable. A transmission line is regularly inspected in order to achieve updated information about the condition of the line as well as the immediate surroundings. Various inspection techniques have been developed to enable the condition of the OHTL to be assessed.

Condition assessment will enable transmission line asset owners to achieve greater efficiency when planning OHTL refurbishment's or more effectively to direct their maintenance activities, at a time when systems are ageing and consents for new lines are becoming increasingly difficult to obtain. The inspection should be performed so that the transmission line owner is provided with sufficient information to plan the maintenance of the OHTL.

One maintenance method makes use of carts for working in-span on the conductors and ground wires, especially when the accessibility with alternative methods such as the use of bucket trucks, cranes or helicopters is problematic or restricted. Carts are used for in-span work such as the repair or replacement of spacers, dampers, aircraft warning markers, etc. Guidelines are given for use of carts, for inspection and assessment of safe conditions as well as alternative methods for dealing with presumed or known unsafe conditions. Prior to carting, a specific engineering analysis can be carried out to establish its effect on line tension, and also check for adequate clearances.

Live work is the preferred method of maintenance where system integrity, system reliability, and operating revenues are at a premium and removal of the circuit from service is not acceptable. Live work has been found to be a safe means of performing maintenance operations due to the additional planning and crew training required for live work.

The expected increase in live-line work approaches has stimulated the development and use of robotic devices to minimize risk to field personnel safety and maintain power system reliability. There are three main classifications of robots: ground-based, those suspended from the line and aerial-based. Ground-based robots are designed to remotely capture and control energized conductors and execute tasks that are far beyond human capability from a mechanical and electrical stress perspective. Robots suspended from the line are designed to serve as the extended eyes and arms of the transmission lineman and their basic design function is to perform visual inspections. Development of aerial-based robots, which are designed to perform visual inspections, is very active as more and more prototypes are being built and more players are expected to enter the market as service providers of technology users.

16.8 Highlights

16.8.1 Maintenance Strategy

- Formulating a successful transmission line maintenance strategy is dependent on the transmission line asset owners' drivers and constraints. As described in Section 16.2, the maintenance strategy will be dependent on the asset owners' particular environment, existing condition of the assets and, perhaps most important, criticality of the existing transmission lines.
- No matter what the maintenance activities are, they all share similar requirements that must be considered when developing a successful maintenance strategy. They include:
  - Prioritizing the transmission lines
  - Periodic inspection of the lines
  - Data base management
  - Considerations for in-house or outsourcing of maintenance work
  - Performing live work or de-energized work
  - Planning for people, equipment and training
  - Developing outside resources
  - Benchmarking and continual improvement.

16.8.2 Condition Assessment of OHTL

- A transmission line is regularly inspected in order to achieve updated information about the condition of the line as well as the immediate surroundings. Various inspection techniques have been developed to enable the condition of the OHTL to be assessed. Inspections may be performed from a plane, a helicopter, a car, by foot patrols or by climbing the towers as described in Section 16.3.
- Condition assessment will enable transmission line asset owners to achieve greater efficiency when planning OHTL refurbishment's or more effectively to direct their maintenance activities, at a time when systems are ageing and consents for new lines are becoming increasingly difficult to obtain. The inspection should be performed so that the transmission line owner is provided with sufficient information to plan the maintenance of the OHTL.
- Conductor deterioration follows different patterns in different geographic areas. Deterioration such as conductor corrosion (internal and external), conductor broken strands, defective or loosened spacers, missing or drooping vibration dampers, lightning strikes, etc. For the last decade numerous failures of conductor joints have been reported, the reasons for which have included asymmetrical installation of the aluminum sleeve as well as accelerated ageing and deterioration of the contact surface in the joint due to an increased electrical load as described in Section 16.3.1.4.
- The main cause of failure to suspension and tension porcelain insulators is corrosion of the steel pin in the cap and the pin assembly. With glass insulators, the

discharges erode the glass and pin and after fairly minor surface damage, the imbalance in the internal mechanical stresses in the toughened glass causes the shed to shatter completely. Section 16.3.2 provides guidance to utilities and engineers who are in charge of the maintenance of transmission lines on how to check the state of insulators and how to decide on the safe time for replacement. For composite insulators, degradation can occur through premature ageing or internal manufacturing defects and it is not possible, using current technology, to choose a single technique that will detect all types of defective insulators with a satisfactory degree of confidence. A combination of two or more techniques has in practice, been proven to be the most effective means of identifying defective composite insulators in service.

- The main factors, which affect the rate and onset of steel structure corrosion, can be categorized into two groups: environment factors (prevailing weather conditions, pollution levels, etc.) and protection factors (surface protection quality, painting policy, etc.). Inspection techniques such as visual climbing inspection, electronic paint & galvanizing thickness measurement and cross hatch cut test are presented in Section 16.3.3.1.
- The main damage, to which wood poles are subjected, is the degradation of mechanical strength due to wear and decaying of the wood and to the action of insects and woodpeckers. Inspection techniques such as visual inspection, sound and bore, electrical resistance measuring device, penetration measuring device and trained dogs are presented in Section 16.3.3.4.

16.8.3 Use of Carts for In-Span Maintenance Work

- One maintenance method makes use of carts for working in-span on the conductors and ground wires, especially when the accessibility with alternative methods such as the use of bucket trucks, cranes or helicopters is problematic or restricted. Carts are used for in-span work such as the repair or replacement of spacers, dampers, aircraft warning markers, etc.
- Section 16.4 identifies the factors that affect the structural integrity of the aged conductor systems and therefore, the risks associated with the use of carts on aged conductors. Guidelines are given for developing criteria or rules for use of carts, for inspection and assessment of safe conditions as well as alternative methods for dealing with presumed or known unsafe conditions. Prior to carting, a specific engineering analysis can be carried out to establish its effect on line tension, and also check for adequate clearances.

16.8.4 Live Work Maintenance

- Section 16.5 deals with live work (work on energized circuits) that has been carried out in different parts of the world for many decades. Live work is the preferred method of maintenance where system integrity, system reliability, and operating revenues are at a premium and removal of the circuit from service is not acceptable. Live work may also be beneficial in construction, upgrading and uprating.

- Most maintenance operations that are performed de-energised can also be performed using live work techniques. To do so requires proper operating procedures that take into account the complexity of the task and technical standards referring to equipment, procedures, safety and quality assurance. Examples of typical live work operations are given in Section 16.5.2 that are applicable to many asset owners.
- The feedback from utilities performing live work on overhead lines is that the cost is comparable to that in de-energised conditions. Some comparisons of live work to de-energized work times and cost comparison of in-house verses outsourced live work are also provided in Section 16.5.3.

16.9 Outlook

- In order to maintain or increase the reliability of aging OHLs, new maintenance techniques are becoming available to assess and diagnose the condition of various OHL components.
- The expected increase in live-line work approaches has stimulated the development and use of robotic devices to minimize risk to field personnel safety and maintain power system reliability. Section 16.6 seeks to provide an overview and an assessment of the future possibilities for transmission line robotics. Four robot classifications are identified:
  - Ground-based robots (Section 16.6.2.1)
  - Line suspended robots (Section 16.6.2.2)
  - Aerial-based robots (Section 16.6.2.3)
  - Other types of robots (Section 16.6.2.4).

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Dr. André Leblond received his B.Sc.A., M.Sc. and Ph.D. degrees in mechanical engineering from Laval University (Québec) in 1990, 1992 and 1996 respectively. He joined IREQ in 1992 where he studied the modeling of wind-induced conductor vibrations such as Aeolian vibrations and galloping. Since the famous January 1998 ice storm, he has been involved in the development of new de-icing techniques and has been studying climatic loads on overhead lines. From 2001 to 2004, he worked as a Project Leader for the development of methods aiming at solving the ground wire problematic during icing conditions and coordinated the work of an important R&D team. Since the end of 2004, he has been working as a transmission-line engineer at Hydro-Québec TransÉnergie, where he has been continuously involved in studies and developments related to various mechanical aspects of transmission lines. He is an active member of several CIGRÉ Working Groups within Study Committee B2 and Convener of Working Group B2.52 "The Use of Robotics in Assessment and Maintenance of OHL". He is the author of several technical papers related to Aeolian vibrations of overhead lines and has participated to the preparation of two books.

Keith Lindsey has an MS and PhD degree in mechanical engineering from Stanford University. He is President of Lindsey Manufacturing Co. in Azusa, California, USA. He has been active in the design, manufacturing and installation of EHV hardware, transmission line emergency restoration systems and sensors for monitoring T&D lines for over 40 years. He has authored over 30 technical papers and holds sixteen design patents. In study committee B2 he has chaired working groups B2.13 that completed Cigré guidelines for "Overhead transmission line asset management", "Emergency resource planning for overhead transmission line asset owners" and "Guidelines for increased utilization of existing overhead transmission lines", and B2/B3.27 "Live work-a management perspective". He is a distinguished member of Cigré, a vice-president of the USNC to Cigré and a life fellow of the IEEE power and energy society.

Asset Management 17

Jarlath Doyle

Contents

17.1 Introduction

Asset management can be described as "co-ordinated activity of an organization to realise value from assets" (ISO 2014). Managers of overhead transmission line assets must increasingly anticipate more and varied threats as well as opportunities, which will have a negative or positive impact on these assets (Electra 205, WGB2.13 2002). Utilities responsible for managing overhead transmission line (OHTL) must

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J. Doyle (✉)
Dublin, Ireland
e-mail: jarlath.doyle@esbi.ie

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consider the myriad of threat which could have an impact on their assets. These threats can take on many forms such as the threat of changing generation patterns, lack of skilled manpower, weather related outages and failures, right-of-way joint use and availability of suppliers and materials, to name but a few. Utilities need to ask themselves have they considered how these threats may be turned into opportunities. In a fast changing environment it is vital to systems in place for constant monitoring and assessment of these threats and opportunities (Cigré TB 353).

17.2 Asset Management Processes

In the past decisions on the management of existing overhead transmission lines were frequently based on the qualitative judgment of experienced individuals. This chapter is an attempt to quantify this analysis using risk management techniques. This guide will present methodologies for estimating costs and risks associated with various actions required for proper management of an overhead transmission line asset. The conclusions to support these management actions will be based on adequate inspections, analysis of a database of the conditions of the transmission line components, cost factors, safety, regulatory and environmental considerations. Management actions to be considered include risk reduction, risk acceptance and risk increase (Cigré TB 175). In recent years many standards organisations have published specific guidance on the management of physical plant or assets. A good example which is widely used in electricity utilities is “PASS 55”. PAS 55 is the British Standards Institution’s publicly available specification is explicitly focussed on the optimal management of physical assets. In addition to this ISO 55000 is the international standard developed from PAS 55 and provisioned for release in February 2014. These asset management standards describe the requirements for reactive and proactive monitoring of an asset (Figure 17.1).

17.3 Guideline for Overhead Line Asset Management

Electric power is an essential lifeline in mature, as well as, emerging economies. Overhead transmission lines (OHTL) play a significant role in the operation of a reliable power delivery system. Because of their complexity, extent and bold exposure to the elements OHTLs are vulnerable to degradation and possible failure from a wide variety of initiating events. The electric utility industry is in a transient condition brought on by privatization, deregulation and competition. It is becoming increasingly difficult to obtain the required permitting and/or funding to acquire new right-of-way and build new lines, therefore, utilities are seeking ways to get the most from their existing OHTL assets. This explains the interest in increasing the availability of OHTLs. In order to increase the availability of an OHTL, there must be a clear understanding of the negative and positive risk resulting from management decisions involving an OHTL. In the past many decisions concerning the management of an OHTL were made using qualitative data. In the future these

Figure 17.1 Typical 220 kV double circuit lattice steel tower.

decisions will need to be made using quantitative data to support these decisions. Information and databases may be required that were not previously available to support these decisions. Using this data, risk management techniques can be used to support management decisions (Cigré TB 175) (Figure 17.2).

17.3.1 Net Present Value (NPV) of Annul Expenditure

It is assumed that the goal of any management decision is to minimize the net present value (NPV) of the annual expenditures over a predetermined investment period. In order to get comparable results, future costs must be discounted to the present (SC22.13 2000; C1.1 & 309 2006). In general terms:

$$NPV = \sum_{i=0}^{i=n} \frac{C_i}{\left(1+r\right)^1} \tag{17.1}$$

Where:

- NPV is the net present value of the annual expenditures
- n is the period taken into consideration
- r is the discount rate
- C_i is the annual expenditures in year i, and where:

$$C_i = E_i + R_i \tag{17.2}$$

Figure 17.2 220 kV single circuit lattice steel tower.

- E_i is the deterministic costs, or planned expenditures, in year i, and
- R_i is the probabilistic costs associated with risk of failure in year i.

Sometimes the investment period (n) to be considered is low, i.e. the power plant at the end of the transmission line will shut down in 5 years. Sometimes the investment period is much longer, i.e. the lifetime of the asset. For an OHTL asset all relevant cost factors (deterministic and probabilistic) have to be taken into consideration during the investment period. According to the discounting principle, costs in the far future are less important than costs in the early years. The deterministic cost factors are called “Planned Expenditures” E_i. They consist of normal operations and maintenance costs, planned outages and investment costs accounted for in the year or at the time they are incurred. These costs are discussed in section 4.1. The probabilistic cost factor is called “Risk of Failure” R_i. In general terms risk is defined as:

$$risk = [chance] \times [consequence] \tag{17.3}$$

Chance is usually expressed as a probability of an event. In common usage, the event is undesirable and the consequences are adverse; however, risk may include potential for gain as well as exposure to loss. When the event is an OHTL failure, the chance is the probability of occurrence of the event initiating failure, and the consequences are the totality of resulting consequences from the failure. This risk of failure (R) can be stated in its simplest form as:

$$R = [probability\, of\ failure] \times [consequence] \tag{17.4}$$

Risk of failure during a time interval may be de fined in economic terms, such as net present value (NPV), and is a function of time since both the probability of failure and the consequences will vary as a function of time. Risk may also be defined in non-economic terms if strategic, policy or political issues are involved. From the above equation, it is obvious that risk can be controlled by either:

- Controlling the likelihood of occurrence of the failure initiating event, or
- Controlling the magnitude of the resulting consequences.

17.3.2 Annual Expenditure

There are costs during normal operation and there are costs connected to the risk of failures. Costs during normal operations are deterministic costs. They are costs of a known magnitude incurred at a known time. On the other hand, the costs connected to the risk of failure are probabilistic costs. Their magnitude must be estimated in most cases, and when they will be incurred is not known with certainty (Cigré TB 175).

Planned expenditures include costs of normal operations and costs of investments. These costs can be connected to different levels within the company: the company, as a whole, the system operation division (electricity commerce), and the OHTL division.

- Company level:
  - Costs of investments are frequently connected to the company and not to a division.
- System operation level:
  - There are energy and capacity losses. Depending on the conductors and the load. These losses may be substantial if the line operates close to its thermal limit.
  - Costs of planned outages.
- OHTL operation level:
  - Operation and maintenance are obvious cost elements of the OHTL operation. Regular inspections and patrols are necessary and the conditions of the components and elements must be checked. Painting, tree trimming and smaller interventions are performed regularly.
  - Costs for collecting information and maintaining a database for proper management of the OHTL asset.

17.3.2.1 Risk of Failure

As mentioned in section above the risk of failure of an OHTL is defined as the probability of failure times the totality of resulting consequences. The event causing failure may be predictable or unpredictable, and the consequences of the failure may be expressed qualitatively or quantitatively. The consequences of a predictable event may be different from the consequences of an unpredictable event.

17.3.2.2 Failure due to Predictable Events

The mechanical system of an OHTL consists of arrays of foundation, structure, conductor and insulator components that provide safe support for the power carrying conductors along an ever changing right-of-way. To be able to predict the probability of failure of an OHTL, it is first necessary to understand the present capabilities of the specific line configuration. In order to do this; the as-built line and terrain details can be entered into a three-dimensional analysis design computer program to create a model of the line and corridor. The present capabilities including residual electrical and mechanical strength, of all existing OHTL components can be determined using appropriate inspection/assessment technology as those outlined later in this chapter. The present value of each component's capability would be substituted for its new value in the analysis program. After that, loading conditions, such as different magnitudes of wind velocity at different angular directions, accreted ice or wind and ice, are applied to the model in increasing increments until the first component is loaded up to its capacity. That is the critical loading condition for that component. The probability of occurrence of that loading condition is an indication of the reliability level of that component. This process is continued until all loading events of interest have been applied and the weakest link identified. Probability of failure due to predictable events is equated to the reliability of the weak link components that cause failure of the OHTL. This is somewhat of a "reverse engineering" approach to the probabilistic method of design described in IEC standard 60826 (IE60826 2003). Once the weak link has been determined, the probability of cascading or a progressive line failure can also be determined. Progressive line damage after the initial failure of a component is line specific and not the same for all components. For instance, if the probability of occurrence of mechanical separation of a porcelain insulator is determined for a particular OHTL, it makes a difference whether the insulator is in a suspension string or dead-end string. In a suspension string, the event could lead to a dropped phase, which may not result in progressive line damage. On the other hand, a failure in a dead-end string would also drop the phase, however it would also release full line tension, which could be sufficient to set a line cascade in motion. Analytical techniques are available for determining the extent of progressive mechanical damage to an OHTL after the initial failure of a component, and devices and techniques are available for containing such a failure. The components of a line are subjected to many types of deterioration, such as: wear, fatigue, corrosion, deformation and elongation. Since they are made from different materials with different properties in different environments, it is likely that some of these components will deteriorate faster than others. If a database of past component capabilities exist then the future capabilities including residual electrical and mechanical strength can be extrapolated new weak links determined and the probability of survival and thus the probability of failure over a period of n-years can be calculated. The failures due to predictable events may be managed by proactive measures due to the predictability of the event.

17.3.2.3 Failure due to Unpredictable Events

The term "unpredictable event" is used to represent events that are managed by reactive measures, since their probability of occurrence cannot be economically reduced with proactive measures. Past service experience may indicate that certain events such as natural disasters, sabotage or human error will occur; however, the nature of the event precludes taking proactive corrective action before the event thus reducing the probability of failure of the event. Natural disasters such as hurricanes, cyclones or typhoons, tornadoes, massive ice storms, floods, earthquakes and earth slides fortunately occur infrequently. When they do, these disasters can cause total destruction of the above ground elements of OHTLs as well as have a destructive impact on and make serious changes to the very topography along the right-of-way. This makes post event access difficult and complicates restoration processes. This combination can make the total outage time for the OHTL very long. As previously mentioned, management decisions will always have to be made under conditions of risk and uncertainty. Intuition, judgment, and experience and information available from the database must be used to assign the probability of failure due to unpredictable events. Thus the assignment of probabilities in situations of uncertainty proceeds on a subjective basis, rather than an objective basis (Figure 17.3).

17.3.2.4 Consequences of a Failure

OHTLs may provide different functions, for example the function of an OHTL may be to:

- Transmit power between A and B continuously
- Transmit power between A and B if another line fails
- Increase stability margin (no continuous transportation of power required), etc.

Different functions lead to different consequences should the OHTL fail. The function of a particular line can change during time, for instance higher capacity is necessary because the load increases. Consequences resulting from an extended outage of an OHTL are site and function specific and can be considerable. Depending upon the extent and resulting consequences of the OHTL failure, monetary losses can occur to the OHTL asset owner, their customers and local or national governments. The total losses may be more than just the direct losses of the asset owner, especially if the owner is answerable to customers and government entities.

	Failure due to	
	predictable events	*unpredictable events*
The probability of *failure* is	relatively high	relatively low
An economic way to avoid *failure*	does exist	does not exist
Proactive action	can be taken economically	can not be taken economically
In case of proper action the OHTL	will survive the *event*	will not survive the *event*
Reactive action are	possible depending on economic evaluation	the only opportunities to reduce the *risk* economically

Figure 17.3 Summary table of predictable/unpredictable events.

The consequences arise generally at different levels within the company. Each case is different, however, in most cases, these costs can be connected either to the company as a whole, or to the system operations division (i.e. electricity commerce division), or to the transmission line division (Figure 17.4).

17.3.3 OHTL Asset Management Process

In order to present management with appropriate options that minimize the net present value of annual expenditures over an investment period, an information system and process must be in place. Figure 17.5 is an idealized process or model of the activities leading to management decisions for an OHTL asset. This process represents the technical activities leading to various management options and their associated risk. Management then decides which risk option is appropriate.

There is no starting point in this process, however, begin by examining the process after an OHTL failure (A). The box titled "OHTL Failures" could also be named "Anticipated or Expected Rate of OHTL Failures". As mentioned in failures will occur, however, management has made decisions to achieve an acceptable rate of failures due to certain events and consistent with Management goals. It would be unreasonable for management to anticipate no failures under all conditions. However, it might be reasonable for management to expect no failures due to corrosion of a tower, if tower painting is performed at least on a scheduled basis. Likewise, it would be reasonable for management to anticipate an OHTL failure if a tornado were to cross the OHTLs path.

Failures are not only a function of management decisions (B) but also outside failure events (C). The lack of failures under certain conditions may also tell management that there is a potential for gain, or reduction of costs, by taking advantage of this excess capacity of the OHTL.

Expenditures are connected mainly to	Annual Expenditures	
	Planned Expenditures	*Risk of Failure*
Company level	• Investments	• injury, death • serious damage in the built environment • bad publicity, loss of customers, even more difficulties finding new ROW • cascade *failures* with electrical system breakdown
Systems operation level	• energy and *capacity* losses	• additional energy and *capacity* losses • more expensive power generation • loss of profit due to non delivered energy • penalties due to non delivered energy • penalties by the regulator
OHTL operation level	• Operation and *maintenance* (including land owner compensation for the damages in vegetation) • Overhead costs for information collection and *maintenance* of a data base	• repair (including land owner compensation for the damages in vegetation)

Figure 17.4 Consequences of a failure summary table.

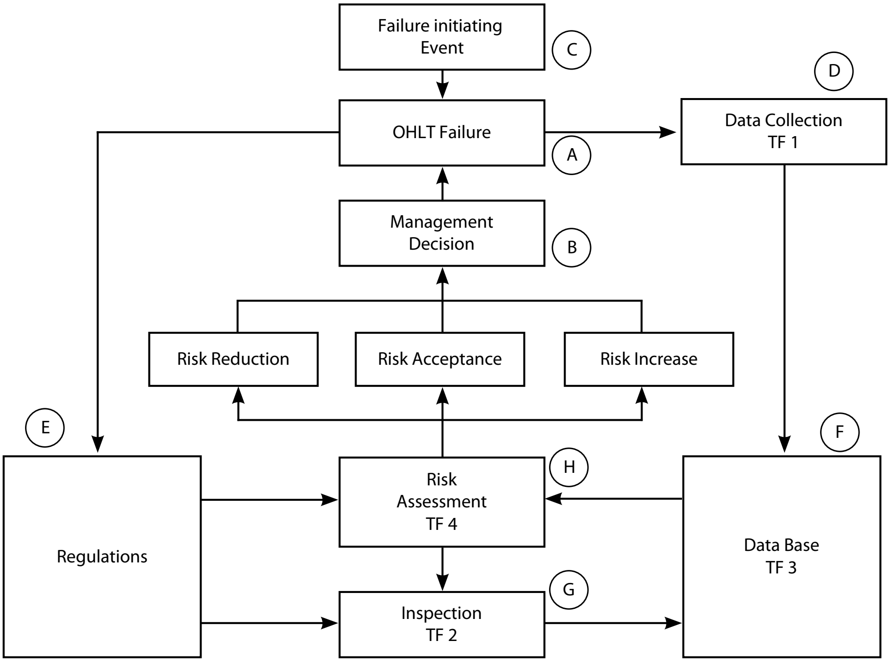

Figure 17.5 Model for OHTL Asset Management.

When an OHTL failure event occurs, data must be taken to determine the cause of the failure (D) as described in Cigré TB 175 Without this data collection, improvements to the management decision making process will be difficult if not impossible. Information on OHTL failures will also affect regulations, standards and company policy (E). Standards are written and regulations are normally formulated based on service experience and the anticipated failure rates of an OHTL by regulators and other governmental organizations as well as the public. If OHTL failures occur and adversely affect customers, regulations affecting the OHTL asset owner may follow (Cigré TB 175).

Ideally a useful database, as described in Cigré TB 175, will be established (F). This database will contain information on the OHTL, its components and its critical elements. Information for the database will be supplied by data collection after an OHTL failure (D) and from inspection of the OHTL right-of-way and its components and/or elements (G). Processing of the data in the database should reveal trends in the degradation of the OHTL components/elements in order to predict the remaining life of components/elements. Failure statistics due to predictable and unpredictable events must also be kept in the database in order to predict the probability of future events.

The OHTL must be patrolled and inspected (G) in order to update information on the degradation of the right-of-way and OHTL components/elements. This information is used to determine their present capabilities (H) including residual electrical or mechanical strength, and the remaining life of the component/element. This remaining residual strength must be compared to the historical data to determine if the strength is deteriorating, and to regulated requirements (E). The probability of failure must be estimated from historical data in the database (F). The consequence, or cost of the event, is calculated taking into account service experience (F) and environmental safety and availability requirements from regulators (E).

The risk must now be calculated for various management options. Risks may be expressed in net present value or in non-monetary terms. The cost and benefit of each management option is considered and accounted for in the net present value calculations. Various options and management initiatives are outlined in later in this chapter. These management options fall into three basic categories: risk reduction, risk acceptance and risk increase. Management must then select the best option consistent with company goals. Although the names might give the impression that one type of decision is better than the other, this is not true. All types are equally appropriate based on the risk assessment (H).

This process is continuous so that management decisions can be based on the latest risk assessment. It should be noted that the age of the assets should be considered along with the interval between risk assessments if the asset exhibits characteristics of accelerated reduction in capacity. The population and statistical distribution of the capacity also should be considered. However, it must realized that no matter what the management decision, failures will occur due to the nature of OHTLs and the environment they are subjected to. The discussion in this Section should not lead one into the “analyse-it-to-death syndrome”.

That syndrome leads to risk aversion by avoiding decision making and studying them forever looking for perfection. It should be noted that no decision is a management decision to accept the risk. While the analytical process seems formidable, there are many practical examples of how this process can lead to increasing the availability of OHTLs.

17.4 Data Collection for Overhead Line Asset Management

The purpose of this next section is to present guidelines on the data to be collected regarding defects and failures that effect the integrity of overhead transmission lines, in order to develop a strategy for the management of these assets (SC22.13 2000). This guidance is intended to assist transmission line asset owners (owners) and for the development of a uniform database leading to a maintenance management system conforming to good industry practice. Defects and failures occur in practice due to:

- Unforeseen external causes such as faults in an adjoining grid, extreme weather conditions, sabotage,
- Internal causes like wear, aging, deformation, poor construction or material,
- Operational aspects such as electrical overload, switching faults, improper functioning of protection and control.

Defects can lead to failures causing unforeseen unavailability of the line. Proper analysis of defects and failures can give a contribution to the development of strategies to maintain a sound condition of the overhead line. The availability, reliability and remaining life expectancy of overhead lines can then be improved with a known and controllable cost of ownership.

17.4.1 Consequences of Failures

Failures often involve the subsequent effects:

- Fluctuations in the voltage level leading to disturbances of operational processes of the customer;
- Reconfiguration of the system resulting in increased losses and/or higher generation costs;
- Disruption to planned maintenance programs;
- Restoration costs;
- Financial claims arising from unavailability of the transmission line.

17.4.2 Failure Analysis Data Collection

To be able to carry out a proper failure or defect analysis, there should be a database. This database should be unambiguous and contain, but not be limited to, pre-event, event, post-event and cost data. This can be expanded as follows:

17.4.2.1 Recording of Pre-Event Data

The following data is important for any transmission line database:

- Design criteria and applicable manufacturing and construction standards;
- As built/constructed data including all components, elements, their manufacturer, date of commissioning and location;
- All inspection and maintenance records including location, date, observation, deterioration, changes or modification to any component or element;
- Any refurbishment, uprating or upgrading;
- Climatic and pollution conditions along the line;
- Data from any previous event;
- Strategic emergency material and equipment inventory.

Data can be tagged with an accuracy level index. By doing this, generic data can be included which may not be precise for individual items but can be used for large scale assessment. It also allows data of different accuracy to still be included but used with care.

17.4.2.2 Recording of Event Data

Recording of data must be unambiguous (electrical/mechanical loading resulting in a defect or failure). For this purpose a failure recording form can be used. After each event this form should be filled in completely after which filing in a central database takes place. The form should contain a list of definitions, an explanation and the subsequent data, where applicable:

- Agency recording the event;
- Exact time of the beginning of the event;
- Distinction must be made between incidents involving manual tripping of the line, automatic tripping, automatic tripping with successful auto-reclose or automatic tripping with unsuccessful reclose (lockout);
- Climatic conditions such as wind, precipitation and ice accretion should be described as well as pollution influencing the line;
- Nominal voltage;
- Load current immediately prior to the event and an estimate of the fault current;
- Name and code of the circuit involved; arm, suspension, insulator, conductor, earth wire, damper, spacer etc.;
- Failure during operation, switching in, switching off or during works;
- Switching off by hand or by protection equipment;
- Switching off due to electrical phenomenon, secondary installation, inadequate functioning of protection, error in operating or switching, cause outside control area;
- Cause for electrical phenomenon or defect:
  - unforeseen external causes like fault in adjoining grid, fault at a user, extreme weather conditions, fire, sabotage, birds, crane, etc. (if weather related, estimate or measure values of wind and/or ice at the failure site and recorded values from nearby weather stations);
  - internal causes as wear, aging, deformation, poor construction, material, assembly, manufacturing and adjustment;
  - operational aspects such as overload, switching or testing errors, poor or insufficient maintenance and improper operation of protection and control;
  - works in or under the line by or on behalf of the owner;

- Any required continued investigation activities involving the failed component or element, or of additional like components or elements, measurements, outside expert opinions, accident reports, formulation of a repair or replacement plan and cost analysis;
- Exact time to start the repair work;
- Exact time to complete the repair work;
- Exact time of recommissioning the line.

17.4.2.3 Recording post-event data

As mentioned before every failure or defect causing switching off the line should be analysed. This analysis is meant to find the cause and detect possible deficiencies, wear, etc. of the type of component or element involved in order to take action at other points of installation. The results of an investigation and the measures taken should be recorded unambiguous in a database. At least the subsequent aspects should be mentioned:

- Agency reporting;
- Time of the failure;
- Name and code of the circuit involved;
- Failed component;
- Failed element;
- Manufacturer and type; number of years in operation;
- Voltage level;
- Comparison of the condition at the time of failure with the original design criteria (i.e. pollution, mechanical loading or electrical loading);
- Material;
- Description of the extent of the damage, including photographs;
- Description of the manifestation of the damage, including photographs;
- Identification of the cause of the damage;
- Measures to be taken and action plan.

17.4.2.4 Cost of Defects and Failures

The cost per event should at least comprise:

- Loss of income due to undelivered energy;
- Cost of increased network losses;
- Cost of switching operations;
- Customer claims or penalties;
- Cost of investigation;
- Cost of called in experts;
- Total cost of restoration including manpower, equipment, materials and outside contracts.

17.5 Database Management for Overhead Line Asset Management

The primary aim of a Database System for proper management of existing overhead transmission lines is to store and extract the data "as-built" of the line assets and their historical data. A very efficient tool to rank the various possible actions on existing and ageing overhead transmission lines and to select the most appropriate management action is a database on line assets. Experiences in the past, have learnt that poorly designed databases have failed. In this context, recommendations how to start a simple database and how to extend this database in different steps with increasing detailing may be useful. It is assumed that management decisions must be based on statistics processed from the collected quantitative basic data. This section is intended for the use of overhead transmission line asset owners in order to improve their database system, in such a way that it can provide statistics supporting management decision process on assets.

17.5.1 The Different Kinds of Data

As mentioned here above it is assumed that the Database System includes the data "as built" of the overhead transmission line assets as well as their historical data (SC22.13 2000).

17.5.1.1 Asset Data as Built

This Guide suggests to collect the asset data as built on three successive levels:

- lines and circuits;
- line components;
- elements of components;

The data stored on the three levels allow to analyze and compare successively:

- the performance of lines;
- the condition of components;
- the condition of elements.

17.5.1.2 Historical Data

Three different kinds of historical data on overhead transmission lines can be distinguished:

- The real historical actions such as:
  - Replacement or heightening of a support or a part of a line (for instance due to the construction of a railway), stringing of a second circuit, etc;
  - Maintenance or painting, life extension, refurbishment, uprating, upgrading, etc.
- Historical events such as failures, forced outages, etc;
- Historical observations and measurements on defects of assets registered in periodic inspection reports.

Finally a database can include costs and duration of actions, as well as costs of the replacement of line segments, components and elements.

17.5.2 Storing and Extracting Data

In the past information on overhead transmission lines was neither systematically kept nor even directly accessible. Nevertheless this information is required in an appropriate form or structure to support any management decision on overhead transmission lines. It is important to know where to find the information required. It has to be recorded on a consistent and comparable basis such as books in a bookcase or in a library in such a way that it can be found easily. Today, the use of a database system is the most convenient tool to store, to consult, to revise and to extract data.

This document gives guidelines as to which kind of data are at least required and how they can be stored efficiently. Generally, historical data are available in various reports and they must be extracted from the report. It is recommended to provide in the future special data collection checklists so that the inspection results can be stored in the database immediately after the inspection. The date (or the year) of each recorded data is important in view of management decisions.

The database represents the line as built in the present situation provided that the modifications and adjustments since the construction of the line have been introduced. Each historical data has to be linked with the appropriate asset in the network. So every action, every observation, every event can be located in the network. In this way, it becomes possible to follow the history of each asset in function of time and to estimate its degradation rate. Moreover the historical data of different assets can now be compared. This database allows to establish statistics on line performance, component and element condition. In the past, management decisions were frequently based on qualitative judgement of overhead line experts. Nowadays decisions can be supported by the quantitative data of statistics. Statistics can be processed from basic data only if the asset owner decided to list the present line assets on one side and the historical reports – at least for the last years – on the other side. In order to store and to retrieve both data, they must be related to one another in a simple framework.

17.5.3 Storing Reports

If an appropriate database system does not exist, a lot of historical and vital information may probably be lacking or has not been recorded at all. It could cost a considerable amount of money later to reacquire those data. Unfortunately, for various reasons, it would be impossible to include in the database all information available in the reports on historical actions, observations and events on line assets. So, this Guide recommends at least to refer in the database to the code number or the serial number of any historical report, so that the report remains traceable. In this way interesting data, for which any provision has been foreseen in the database, are not destroyed but can be indirectly consulted. Nevertheless, it would not be possible to use these data for the above mentioned statistics. The costs relating to the different historical actions, observations and events have also been recorded so that they can be extracted from the database when a new budget has to be established.

17.5.4 The Link with other Databases

If other databases containing information on overhead transmission line assets are available, they should be linked with this database. This can be achieved by using the same code or reference number for the same item. Databases with different specific purposes sometimes use common data with the same characteristics, so that integration of the data structure may be useful. In the future, databases with different purposes can be integrated in one unique and integrated system dealing also with finances, purchasing, storing, human resources, planning, etc.

17.5.5 The Quality of the Data

The quality of the data cannot be improved by recording in a database. Its quality depends mainly on the crew collecting inspection information and on the inspection technique. Both have to be recorded with the corresponding date to estimate its quality and reliability. Later on it might be found that one crew had a bias in one direction which caused a distortion in the input data. Without knowing which crew collected the data, it may be impossible to correct this misinformation. It is important to know who is responsible for inputting of the data. Who is in charge of updating? Can the stored data be guaranteed? Data must be validated and dated. A second factor determining the quality of a data is the inspection technique. The longer the distance is between the inspected item and the sensor, the less reliable the data may be.

17.5.6 Conditions for Success

In the past many databases on overhead transmission lines have failed. The reasons are known: a lack of reliable data for an extensive database; a lack of motivated manpower to collect, to store and to maintain the data; not so user-friendly input and output, and especially a lack of a clear accepted scope or a lack of integration with other databases. In general, it is relatively easy to store the data of a new line. Nevertheless, updating of a database is a challenge and can be a considerable cost. If it is updated, the database must be easy to use for the design of new lines just as for modifications of lines. A user-friendly access supposes a recording of data in the database in the same order as in the documentation. It is necessary to have a clear and concise method to store the relevant asset data relating to each other and to keep a history of the actions, observations and events of the overhead transmission line assets by filtering or selecting data and referring to historical reports.

17.6 Summary

Good asset management practice will ensure the utility or owner will follow a systematic process of maintaining, operating and refurbishing it overhead line assets. As outlined in this chapter it is vital that owners keep accurate and update database on the performance and failure that occur over time. On this basis it is possible to make comparisons and exchange information. This facilitates for instance to use the experience obtained from the investigation on events due to internal causes to prevent problems on the same type of component or element. Those owners that follow these guidelines will have a procedure in place to enable them to continually improve the quality of their maintenance management system. Furthermore, this will lead to an improvement of their transmission line availability and reliability, and give the owner a better insight as to the remaining life expectancy and future operating costs of their transmission assets. Further information on the methodologies and strategies in the asset management of overhead transmission lines can be garnered from the Cigré B2 committee and e-cigré website.

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Jarlath Doyle holds BE and MBA degrees and has worked in the area of transmission and distribution overhead lines since joining ESBI in 1999. He has gained many years' experience in the planning, design, construction and maintenance of transmission and distribution equipment and is currently working for ESB Network as a project director on major 400 kV projects. Mr Doyle is an active member of several Cigré Working Groups within Study Committee B2 and Convener of Technical Advisory Group B2.07 "Asset Management, Reliability & Availability.

Uprating and Upgrading

18

Gary Brennan, Zibby Kieloch, and Jan Lundquist

Contents

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This chapter is based on Cigré TB 353 (2008) *and the author and reviewers would like to acknowledge the original TB authors and contributors. In addition, TB 353 has 59 case studies and examples which are commended to the reader as an additional source of knowledge and understanding of uprating and upgrading overhead lines.*

G. Brennan (✉)
Huntingwood, Australia
e-mail: Gary.Brennan@endeavourenergy.com.au

Z. Kieloch • J. Lundquist

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18.1 Introduction and Definitions

Many countries with major electrical infrastructure are frequently confronted with four coinciding critical issues,

- much of this infrastructure was constructed in the fifties and the sixties, which result in the age of the assets being over 50 years;
- the design life of much of the infrastructure is in many cases about 50 years and has matured beyond the engineering serviceability and or economic life and requires some form of life extension;
- the need to increase capacity of the existing infrastructure places extraordinary demands on utilities to establish strategies to uprate the existing infrastructure; and
- approvals for the construction of new overhead lines are often difficult to obtain and in many cases result in critical delays to meet network capacity needs.

The following definitions will be used throughout the chapter.

increased utilization: increased utilization is one or any combination of uprating, upgrading, life extension and refurbishment of an overhead line

asset renewal: increasing the reliability and or availability of an overhead line by any combination of uprating, upgrading, life extension and refurbishment.

life extension: extensive renovation or repair of an item without restoring their original design working life Cigré TB 175 (Cigré TB 175 2000). Life extension results in a decrease of the probability of failure and no change to the consequence of failure.

refurbishment: extensive renovation or repair of an item to restore their intended design working life. Refurbishment results in a decrease of the probability of failure and no change to the consequence of failure.

upgrading: increasing the original structural strength of an item due to, for example, a requirement for higher meteorological actions or increasing the original electrical performance of an overhead line. Upgrading results in a decrease in the probability of failure and no change in the consequences of failure.

uprating: increasing the electrical characteristics of a line due to, for example, a requirement for higher electrical capacity, or larger electrical clearances. Uprating will increase the electrical capacity of the line and therefore potentially increasing the consequences of a failure.

18.2 Purpose

The purpose of this Chapter is to provide a general overview of the economic and technical considerations in order to facilitate considerations for up-rating and upgrading of overhead lines. The outline of the chapter is described in Figure 18.1.

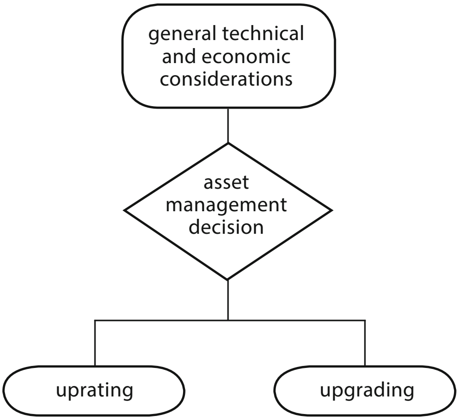


Figure 18.1 Outline of Uprating and Upgrading Overhead Lines.

18.3 General Economic and Technical Considerations

To increase the utilization of existing overhead lines, a number of economic and technical factors need to be considered. Some of these factors are influenced by the basic need to increase system capacity. The decision to increase the utilization of an existing overhead line will be influenced by the asset life, the load growth forecast, the planning horizon, the value of capital, a cost benefit analysis, economic optimization and consideration of other constraints. This Section will discuss each of these factors. Table 18.1 provides a summary of the various asset renewal options, risk management considerations, drivers, propositions and the effects on an overhead line.

18.3.1 Increasing System Capacity

The growth in demand for energy, the new developing energy markets and that electricity is fundamental to a modern society are all placing a greater demands on existing overhead lines. Growth in demand may be driven by normal demographic growth demands and or growth demands triggered by changes of technology and standards of living such as the affordability of domestic air conditioning. In more recent times, the growth of alternative and renewable energies is also placing new demands on the existing network of overhead lines.

The fundamental objective of an network asset owner is to continuously assess the capacity of the electrical network to determine the most economic and technical viable options to meet the increasing demands for electricity to ensure that the reliability of the electricity supply to customers is not compromised and the increasing demand for electricity associated with existing and future residential, commercial and industrial development is met.

Table 18.1 Overhead Line Increased Utilization Options

terminology	definition	failure			driver	action	proposition	effects on line													
								components or elements							electrical parameter						
		probability, P	consequence, C	risk, (R = PxC)				structure	foundations	conductors	insulators	fittings	earthing	earthwire	earth potential rise	lightning performance	induction	emf	radio interference	audio interference	pollution performance
uprating	increasing capacity	=	↑	↑	thermal rating by	installing	higher capacity conductors	o	o	x	o	o	-	-	-	-	o	o	o	o	-
							additional conductors	x	x	x	x	x	-	-	o	-	o	x	x	x	-
							active line rating systems	-	-	-	-	o	-	-	-	-	-	-	-	-	-
						increasing	conductor tension	x	x	x	x	x	-	-	-	-	-	-	-	-	-
							conductor attachment height	x	x	-	o	o	-	-	-	-	-	o	o	o	-
						adopting	probabilistic ratings	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						redesign	high surge impendance performance	o	o	o	o	x	-	-	-	-	-	x	x	x	-
					voltage rating by	increasing	insulation electrical strength	o	o	o	x	x	-	-	-	x	-	x	x	x	o
							conductor attachment height	x	x	o	o	o	-	-	-	o	-	x	x	x	o
upgrading	improving reliability	↓	=	↓	structural performance by	increasing	structure strength	x	o	-	-	-	-	-	-	-	-	-	-	-	-

terminology	definition	failure			driver	action	proposition	effects on line													
							foundation strength	-	x	-	-	-	-	-	-	-	-	-	-	-	-
		↓	=	↓	electrical performance by	improving	insulation pollution performance	-	-	-	x	-	-	-	-	o	-	-	-	-	x
							lightning performance by improving insulation	-	-	-	x	-	-	-	-	x	-	-	-	-	o
							lightning performance by improving earthing	-	-	-	-	-	x	-	x	x	-	-	-	-	-
							lightning performance by installing earthwires	o	o	-	-	-	-	x	x	x	x	-	-	-	-
						reducing	structure potential rise	-	-	-	-	-	o	o	x	o	o	-	-	-	-
							electrical induction	-	-	-	-	-	x	-	x	-	x	-	-	-	-
	working life						foundation strength	-	x	-	-	-	-	-	-	-	-	-	-	-	-
							conductor strength and capacity	-	-	x	-	-	-	-	-	-	-	-	-	-	-
							insulation pollution performance	-	-	-	x	-	-	-	-	-	-	-	x	x	x
							fitting strength	-	-	-	-	x	-	-	-	-	-	-	-	-	-

(continued)

Table 18.1 (continued)

terminology	definition	failure			driver	action	proposition	effects on line													
							lightning performance	-	-	-	o	-	o	o	o	x	-	-	-	-	-
life extension	repairing without	↓	=	↓	arrest degradation by	repairing	structures	x	-	-	-	-	-	-	-	-	-	-	-	-	-
	restoring to original						foundations	-	x	-	-	-	-	-	-	-	-	-	-	-	-
	design life						conductors	-	-	x	-	-	-	-	-	-	-	-	-	-	-
							insulators	-	-	-	x	-	-	-	-	-	-	-	-	-	-
							fittings	-	-	-	-	x	-	-	-	-	-	-	-	-	-
							earthing	-	-	-	-	-	x	-	-	-	-	-	-	-	-
							earthwires	-	-	-	-	-	-	x	-	-	-	-	-	-	-
increasing utilization		↓	=	↓	improve availability by	increasing	maintainability by adopting live line design	o	o	-	o	o	-	o	-	-	-	-	-	-	-
		=	↑	↑	provide third party access by	installing	telco equipment	x	x	-	-	-	o	-	-	-	-	o	-	-	-
							fibre optics (OPGW/ADSS)	o	o	-	-	-	-	o	o	o	o	-	-	-	-
x has an effect																					
o may have an effect																					
- has no effect																					

Decisions to increase the utilization of an overhead asset in a timely manner are influenced by technical and economic factors, including the age of the asset.

18.3.2 Optimum Time for Renewal (Cigré TB 294 2006; Cigré TB 353 2008)

The *economic end of life* of a long lived asset has been defined where the cumulative net present value (NPV) of cost of the asset including depreciation, maintenance, losses and risk costs per years of service is a minimum.

This can best be illustrated by the cumulative NPV costs shown in Figure 18.2, in which after the initial capital costs (o to a) and the annual maintenance and risk costs are a minimum for many years (a to b). During this period of time, the long-run average cost of the asset is decreasing. At some point in time, the maintenance costs and the risk cost of failure start to increase (b to c) until the long-run average cost per year of service starts to increase (beyond c). With some assets, at this point in time, when the long-run average cost is at a minimum value or the tangent of the angle δ is a minimum, the asset would be replaced with a new asset as shown in Figure 18.3. The new asset would have new long-run average costs which would be less than the previous long-run average annual costs.

An everyday example of this principal is the purchase of an automobile. After the initial purchase, very little maintenance is required. After ten or fifteen years, more maintenance is required and there is a risk that the automobile will not perform the designed function to transport the owner to his destination as scheduled. At this point in time, a new automobile would be purchased. Over the time span of purchasing several automobiles in this manner, the owner would receive the most benefit, that is travelled the longest distance for the least long run average cost per kilometre.

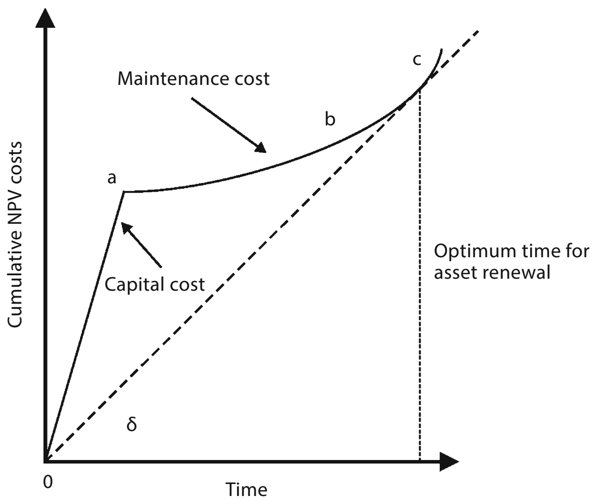


Figure 18.2 Example of Economic End of Life.

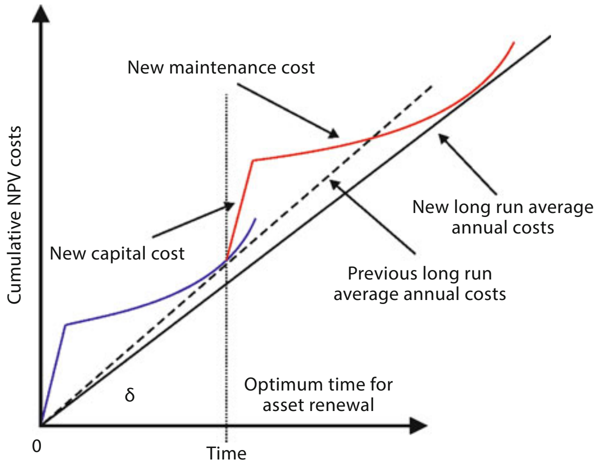


Figure 18.3 Example of Economic End of Life.

Unfortunately, an overhead line asset cannot be replaced as easily as an automobile and this simple economic model does not fully apply to the concerns of network asset owners. The most important exception to this model is that historical initial and maintenance costs are of little concern to the asset owner and a more important concern is the future maintenance and risk costs from the current point in time, which is from "now" as illustrated in Figure 18.4.

Thus the definition is modified to exclude historical costs as most of these costs are likely to be unknown and may not be relevant in considering future investment. Therefore for purposes other than normal accounting procedures, the technical end of life and the optimum time for renewal of an overhead asset will be defined as follows:

- *Technical end of life* is when the overhead line fails to perform within the normal operating requirements without abnormal maintenance or when the overhead line is no longer fit for the original purpose; or
- *Optimum time for renewal* is when the cumulative NPV of the future annual costs of the overhead line including maintenance, losses and risk costs per years of service as illustrated in Figure 18.4 when δ_1 is equal to the minimum long run average costs of an asset renewal project as illustrated in Figure 18.5 as δ_2.

The need of the network asset owner is to determine the optimum time of renewal to uprate, upgrade or refurbish an overhead line in order to produce the minimum long-run average cost for the overhead line within a specified planning horizon as illustrated in Figure 18.5 to produce the minimum tan δ_2.

The *optimum time for renewal* and the *technical end of life* are intrinsically linked as the optimum time for renewal is affected by a large number of technical factors, including

- original design of the asset;
- original construction materials and workmanship;

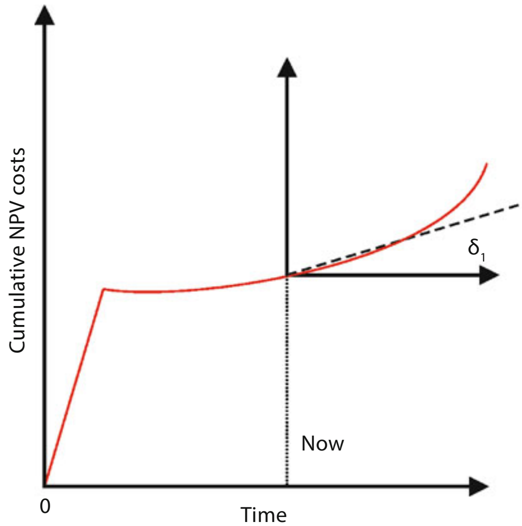


Figure 18.4 Example of Optimum Time for Renewal.

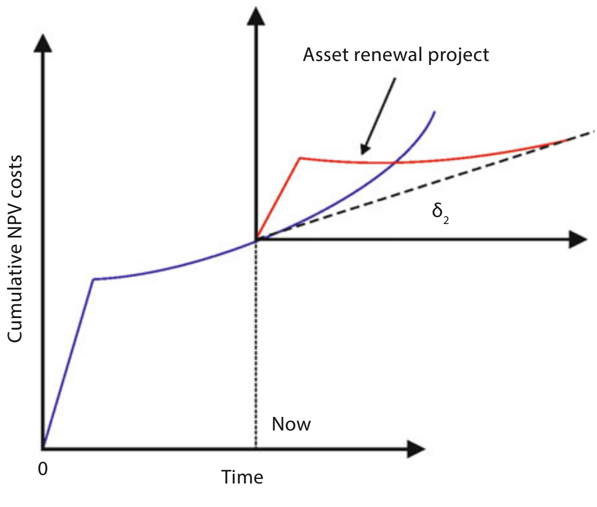


Figure 18.5 Example of Optimum Time for Renewal.

- operating environment that considers corrosion, ultra violet radiation, extreme ambient temperature, lightning, wind and ice exposure;
- level of accumulated damage through overloading and faults;
- maintenance standard and quality of material and workmanship;
- technological advances such as revised safety standards, design codes and legislation changes; and
- operational or environmental constraints on increased utilization for continued use.

The renewal option for an overhead line asset may include corrective, responsive and or preventive measures from any one or a combination of the following actions:

- repair at each failure;
- operate until first failure and then initiate responsive action;
- uprate to increase the electrical characteristics;
- upgrade to increase the mechanical strength;
- refurbish to extensively renovate or repair to restore the intended design working life;
- life extension to extensively renovate or repair without restoring the intended design life; or
- dismantle high risk obsolete assets with or without replacement.

All future management decisions should be based on a comparison of various options with the "do nothing" option. Therefore, assuming an example where the age of the asset in Figure 18.4 is forty years, so that "now" is year 40. Also assume a strategic view or the planning horizon is the next twenty years, reflecting future costs into today's values utilizing the NPV of future costs. An examination of the cumulative NPV of all the future costs associated with a renewal project as illustrated in Figure 18.5, it is clear that the minimum long-run average cost associated with this asset renewal project expressed in cumulative NPV cost per years of service is the slope of tan δ_2.

Cigré TB 353 (Cigré TB 294 2006) discusses several case studies and also explains in detail the concept of the optimum time for project renewal.

18.3.3 Planning Horizon and Net Present Value

The planning horizon selected for evaluation should cover all significant cost and benefit items throughout the life cycle for the overhead line for the renewal options considered. For overhead lines consisting of major components with differing life expectancies, the planning horizon should be chosen to synchronise replacement of different components to optimise the replacement costs. For example, insulators may have a life expectancy of 17 years and fittings may have a life expectancy of 32 years. For economic reasons, the common multiple periods for the insulators would be 15, 30, 45 and 60 years and for fittings 30 and 60 years.

Financial return for capital investments for a long planning horizon is achieved by recognising the time dependent value of capital, the entitlement to interest earnings and the NPV of capital. Consideration of the level of data accuracy, load seasonal demand variation, organisational budget control and long term budget variability suggests that annual aggregation of costs is a practical approximation. This approximation also applies when considering the effect of inflationary trends and NPV determination. A sensitivity analysis of the variation of the data assists in determining this approximation.

18.3.4 Cost-Benefit

Cost-benefit assessment based on NPV is widely accepted because influential factors will allow examination of a range of trade-off options. The future cost of construction such as a new overhead line, upgrading, component replacement, operation, energy losses, risk costs and the maintenance of the overhead line are estimated and calculated for each year within the planning horizon and converted to the NPV by applying a discount rate. The improvement of network availability should also be captured in the cost-benefit assessment by including an equivalent financial value to represent the community benefit.

The optimization focus is to minimise "costs minus benefits". A project option can deliver savings when the net present value of all cost-benefit summed over the assessment horizon is lower than that of the base case. The input data, intermediate processes and results of such assessment form an essential part of the analysis for justifying network renewal projects.

The economic and financial analysis of the renewal should take into account the following factors within the assessment horizon for the base case asset configuration and any renewal options under consideration;

- weighted average cost of capital;
- optimum time for renewal of an overhead asset;
- operating expenditure, including inspection and maintenance;
- statistical and probabilistic analysis of risk cost including failure rates and consequences that include supply interruption costs; and
- energy losses.

18.3.5 Optimization

The cost-benefit analysis for the project options should provide project economic viability and associated ranking. The net present cost of the do nothing option would provide the base case for comparison and any option with net present cost lower than the base case would be considered economical and viable.

Under most circumstances, renewal expenditure may be scheduled with considerable degree of flexibility and offer considerable opportunities for optimisation. In this regard, a proposed renewal option may be uneconomical in the current year if the capital expenditure cannot be adequately compensated for by the reduction of other costs. With the exception of capital expenditure component, all other cost items for a renewal option are likely to increase with the degree of "wear-out" accumulated on the existing overhead line targeted for renewal. Hence, an uneconomical option in the current year may become economical in subsequent years as all other costs gradually increase over time. However, the planning horizon should always take into account the time required for permitting, planning and executing any major renewal project.

The timing of a renewal project should be optimised by selecting the year of implementation to minimise the NPV of the cost-benefit. For a given project option there could be three types of possible results where the net present cost is

- minimal for renewal in the current year indicating that renewal is overdue;
- minimal for renewal at a future year within the planning horizon indicating the optimal time for renewal; or
- decreasing with delaying renewal throughout the planning horizon and indicating that renewal should be deferred beyond the planning horizon.

If there is more than one viable renewal option, the option with the lowest net present cost at its optimal time should be selected as the preferred option.

18.3.6 Constraints

Ideally the preferred option of all economically viable renewal projects should be implemented at the optimal time and thus the scheduled network asset renewal capital expenditure will deliver the most favourable cost benefit outcome to the asset owner. However, there are many practical constraints, which may prevent the timely execution of the optimum options. Typical constraints may be

- financial constraints due to limited expenditure budget or restrictions on raising revenue;
- labour resource constraints from either or both internal employees and external contractors;
- supply security constraints prohibiting coincidental outages of parts of the network;
- technical constraints due to testing and approving emerging technology;
- timing constraints due to obtaining approval from government authorities and or public consultation processes; and or
- sequential dependence among other network projects.

Some of the above resource constraints can be pooled. When a pooled resource becomes binding, the conflict has to be resolved by re-scheduling projects from the pool. Taking the original optimal timing as the ideal case, each rescheduling action whether to advance or defer can be assessed for its costs by calculating the corresponding increase in net present cost. Due to the difference in the sensitivity of net present cost to the timing for each project, the project with the smallest increase in costs should be selected for rescheduling.

In addition, there are a number of factors affecting the project renewal which should be considered when evaluating options and include.

18.3.6.1 Environmental Protection Measures and Permits

Any construction activities, including work on existing overhead lines, affect environment. Strict environmental regulations in many countries require that network asset operators must secure necessary work permits prior to carrying out field work, especially in environmentally sensitive areas. In some cases, the regulatory process might be quite lengthy and it may include review of an appropriate Environmental Protection Plan documents prepared by a power utility. Regulatory bodies may also impose very strict restrictions on types of construction activities and schedules. These may include: acceptable noise levels, use of specific materials and design configurations, protection of endangered wildlife and plant species, protection of religious/sacred sites and many others. This process can result in extensions to a project schedule.

18.3.6.2 Overhead Line Outage Availability

In current electricity markets, many utilities are operating their power lines close to their capacity. Under such conditions it is becoming increasingly difficult to remove overhead lines from service. Those utilities which use live-line work procedures may perform work on energized lines by deploying qualified personnel. Strict safety measures and proper work techniques must be used to complete live-line work. This often results in a lower productivity, higher number of staff involved and higher labour wages. However, these higher premiums are often offset by revenues realized from network charges.

As an alternative, a temporary line by-pass can be used to isolate an overhead line sections or an individual structure from the energized circuit. Such installation allows line crews to have access to the isolated and de-energized line section for a limited period of time. Since such installations are of temporary nature, lower safety factors are often used in design.

18.3.6.3 Working on Structures under Structural Loads

Safety of field staff is a primary concern while working on an overhead line under structural load. It is essential to carry out a comprehensive structural analysis of the overhead line system considered for upgrading prior to any field work. Existing conductor tensions, component dead weight and resulting loads transferred onto structural supports must be carefully examined and taken into account when developing work procedures and selecting required equipment.

18.3.6.4 Use of Heavy Equipment

Overhead line components are often under heavy loads and may require use of heavy construction equipment. Proper safety procedures must be adhered to and only qualified personnel must be allowed to work with heavy machinery.

18.3.7 Terminal Equipment Considerations

All overhead line source and end point connections involve terminal equipment. The primary terminal equipment generally consists of insulators, overhead connections to disconnectors, disconnectors, current and voltage transformers, circuit breakers and in some cases power line communication coupling equipment. Consideration for the uprating of an overhead lines must include a review of the rating of the terminal equipment to ensure compatibility with the line rating.

18.3.8 Electric and Magnetic Fields

The voltage of an overhead line produces an electric field and the current flowing in an overhead line produces a magnetic field. Considerations of uprating of an overhead line by increasing the thermal capacity or increasing the voltage rating or changing the geometry of the conductor configuration may result in changes to the electric and magnetic fields. The overhead line uprating design should consider the potential changes to the electric and magnetic fields limited by statutory and safety regulations.

18.4 Overhead Line Uprating

The definition of uprating is increasing the electrical characteristics of an overhead line due to a requirement for higher electrical capacity or larger electrical clearances. Uprating will increase the electrical capacity of the line therefore based on risk, potentially increasing the consequences of a failure.

Overhead lines are electrically modelled as either long or short. A long overhead line in general is a major interconnector between load centres or load centres and generation centres and voltage regulation is one of the principal operating criteria which results in determining the level of power transfer capacity. On the other hand a short overhead line in general is an interconnector around or within load centres and power transfer capacity is determined by thermal capacity and is the principal operating criteria.

The operation of long overhead lines is strongly influenced by the voltage regulation and the need to ensure that the receiving end voltage is within defined tolerances. The decision to uprate a long overhead line is therefore linked to improving the voltage regulation.

Short overhead lines are influenced by the thermal capacity of the conductors and the need to ensure that the electrical safety clearances are not breached. Therefore the decision to uprate a short overhead line is linked to improving the thermal capacity.

This Section is limited to discussions of increasing system needs to considerations of uprating either long or short overhead line elements and it is acknowledged that a number of other methods may be used to increase overhead system capacity such as Flexible AC Overhead Systems. Further, an emerging strategic network uprating option is the conversion of existing AC overhead lines to DC operation and this is discussed in Section 18.4.3.

The variety and number of methods and techniques adopted and implemented to uprate overhead lines is directly influenced by the considerable variation of overhead line designs and construction methods employed. Nevertheless, uprating of overhead lines generally fall into either increasing voltage capacity or increasing thermal capacity. In some circumstances, the opportunity is taken to simultaneously increase the voltage and the thermal capacity of an overhead line. Table 18.2 provides a list of the most common voltage and thermal capacity uprating mechanisms, the associated methods, techniques and solutions. In this Section will be discussed each of the methods as well as the conversion of AC lines to DC lines.

18.4.1 Increasing Thermal Rating (Cigré TB 353 2008)

The practicality of increasing the thermal rating of an overhead lines is a function of a number of variables;

Table 18.2 Overhead Line Uprating Mechanisms

Uprating mechanism	Method	Technique	Solution
increased thermal rating	increase conductor rating	conductor replacement	increased conductivity area high temperature conductors composite conductor systems
		modify rating criteria	meteorological study
	increase conductor temperature & maintain ground clearance	conductor tension	increase tension negative sag devices
		increased conductor attachment height	structure body extension
			insulator crossarms
			interspaced structures
	increased thermal rating by active line rating systems	line thermal, sag, tension and/or climatic conditions measurement	line sag or tension monitors
			conductor distributed temperature sensing
			weather stations
	probabilistic rating	actual load profile	temporary increase in rating
		modify rating criteria	probability based meteorological study
	high surge impedance	conductor bundling & geometry	physical reconfiguration
increased	increased electrical clearances	insulators	insulator crossarms
voltage rating		increased conductor attachment height	structure body extension
			insulator crossarms
			interspaced structures

- the terrain – overhead lines in hilly and mountainous terrain, where structure location is dictated by terrain rather than load, may have many structures that are not structurally loaded to design limits;
- the meteorological conditions and corridor characteristics;
- the condition of the conductor, insulation and structures;
- the cost of losses, which is a function of the planned length of time to operate at high electrical loads;
- the line to ground clearances regulations;
- the structure loadings regulations;
- the overhead line length; and
- the original structural design capacity of structures.

Increasing the thermal rating of overhead lines may be accomplished by one or a combination of the following:

- increasing the conductor area by either adding conductors to existing conductors or conductor bundles or replacing existing conductors with new conductors of different size or construction;
- increasing the conductor rating by changing the thermal rating criteria based on a statistically-based meteorological study and an evaluation of the characteristics of the line corridor;
- installation of special conductors intended for high temperature and or low sag operation;
- increasing the conductor operating temperature limit, which will require one or more of the following to maintain adequate ground clearance:
  - increasing conductor tension which may require associated structure reinforcement;
  - modifying structures and or insulation to increase ground clearance;
  - insertion of new structures in critical spans;
  - installing negative sag devices; and or
  - excavation at key locations to increase ground clearance;
- modifying the overhead line to achieve a higher surge impedance load;
- installation of active line rating systems (this may not be considered a method to increase line ratings as the method does not change the maximum capacity of the line but rather allows a better utilization of the existing capacity);
- increasing the rating at very nominal cost by a very precise survey of the conductor clearances against standards as the survey results may show that in hilly terrain there may be a very small number of structures to raise or ground profile to modify to achieve a significant increase in rating and or suspension insulator offsets may be used to remove sag from critical spans, although at the expense of a sag increase in adjacent spans.

These methods will be discussed in more detail in the following Sections.

18.4.1.1 *Increasing Conductor Rating Increasing Conductor Area* (Cigré TB 175 2000; Cigré TB 178 2001)

Increasing conductor cross sectional area (csa) will increase the thermal capacity of an overhead line. However, the following factors should be considered,

- in general, the higher the csa of the conductor, the higher the conductor weight. This may be mitigated to some degree by changing material or conductor type. Increased conductor weight will generally result in increased tensions, which will most likely require reinforcement of termination and angle structures. Higher csa may increase the ice and wind load on the conductor, increasing the vertical load on all structures. (Note: there are conductors with trapezoid wires where the csa of the conductor increases without an increase of the diameter and thus may increase the capacity of the line by about 10 %, with lower the impact on structural loading than an equivalent increase in csa using standard round stranding); and
- the larger the diameter of the conductor the larger the wind and ice loads which results in increases in the horizontal loads on the structures.

There are two basic solutions for increasing conductor area of an overhead line either with or without substantial reinforcement of the structures and foundations. Beyond the network requirements arising from expected electric loads in the future, there are structural factors to be considered before any decision about reinforcement. Some of these factors are

- it is important to make a distinction between the design status and the actual status of the structures. It is easy to evaluate the structural capacity of the structures in design status, however, the actual status of the structures need thorough investigation and evaluation;
- the structural capacity of the overhead line may be understated and additional loading may be applied without the need for substantial reinforcement to the structures;
- some structures may need only partial reinforcement on the body or the crossarms therefore may be strengthened relatively easily and economically;
- no additional load is advisable without substantial reinforcement on overhead lines where frequent mechanical failures have occurred in the past;
- overhead lines where structure location is governed by terrain rather than structure load limits, ie through very rough terrain, may have less than full utilization of structural design load capacity for a significant portion of structures and these structures may have increased loads with little or no reinforcement; and
- new conductors may operate on the same temperature or at higher temperatures than the old conductors therefore sagging and or conductor clearance is a key issue for consideration.

It is quite common to replace aluminium conductor steel reinforced (ACSR) with all aluminium alloy conductor (AAAC) with the same or slightly higher diameter as the ACSR. If the diameter of AAAC conductor is the same as the diameter of the ACSR then its weight is less, and the current carrying capacity of the line will increase up to 40 % (Cigré TB 141 1999) depending on the clearances and the conductor tension. Even higher capacities can be achieved if the diameter of the conductor is marginally higher. Changing ACSR to similar diameter AAAC does not need substantial reinforcements to the structures and foundations. Using AAAC with the same diameter as the ACSR but with trapezoidal sections will further increase the csa and the thermal capacity, with little or no structural loading impact. Also, replacement of standard ACSR with trapezoidal stranded ACSR with the same diameter will cause some increase in tensions and vertical load but should not change the wind and ice loading.

Conductors on overhead lines can be replaced with conductors of substantially larger diameter or conductors can be added to existing bundles or single conductors can be bundled. In addition to substantially increasing the thermal capacity, the addition of a bundled conductor configuration changes the surge impedance loading (SIL) of the overhead line, by reducing the reactance and the voltage drop by 10 % to about 15 %. The transfer capacity may be doubled if a new bundle is created in each phase doubling the number of the conductor. However, these methods generally require substantial reinforcement to the structures and foundations. Also line to structure clearances will require evaluation and perhaps some structure reconfiguration.

In order to minimize the effects of higher structural loads on the structures, special wires can be used. As mentioned previously, formed wires will have higher aluminium content in the same csa which results in less wind load and ice loads.

High Temperature Conductors **(Cigré TB 244 2004)**

Cigré TB 244 illustrates how an overhead line rating increases as a function of design temp for a same size conductor and there is a range of conductors that have been developed for higher than traditional temperature operation and some of these conductors are:

- aluminium-zirconium alloy conductors - TAL, ZTAL, XTAL;
- aluminium-zirconium alloy conductors steel reinforced - TACSR;
- aluminium-zirconium alloy conductors invar steel reinforced which are low thermal coefficient conductors - TACIR, ZTACIR, XTACIR;
- gap-type aluminium conductors steel reinforced - GTACSR, GZTACSR;
- aluminium conductor steel supported – ACSS; and
- aluminium conductor composite reinforced – ACCC.

The common features of these conductors are

- increase the design temperature of the line without any substantial increase of the conductor sags;
- the application of low thermal coefficient materials are used for the core material;

- depending on the conductor type, maximum operating temperature up to 230 °C;
- high losses during the peak hours and if the duration of the peak period is long then the costs of losses may be substantial;
- current carrying capacity of the overhead line may increase by up to 100 % without any substantial reinforcement to the suspension structures however for some conductor types the tensions are higher requiring reinforcement of terminal and angle structures.

Meteorological Studies

The traditional means for establishing thermal conductor ratings has been to perform the determination based a commonly used set of weather parameters deemed to be conservative for most situations. Cigré TB 299 (2006) suggests effective wind speed of 0.6 m.s^{-1}, 40 ° C ambient temperature and solar radiation of 1000 w.m^{-1}. Too often, less conservative criteria have later been selected based on quasi-scientific evidence as an easy way to increase these ratings. This is consider a significant risk and can lead to an unacceptable level of conductor clearance infringements. However, thorough scientific study of the meteorological variables can produce a less restrictive criteria that would still provide the level of risk management warranted. This approach is viable only if there is sufficient meteorological data to do so and a statistical study is conducted by competent professionals who consider the local effects of terrain.

18.4.1.2 Increasing Conductor Temperature & Maintaining Ground Clearance (Cigré TB 175 2000; Cigré TB 207 2002; Cigré TB 353 2008)

Knowledge of the material behaviour and limits of conductors when subjected to various heating conditions is essential when designing and operating overhead lines. Two areas are of particular importance to increasing the rating of an overhead line by increasing the operating temperatures of conductors is the loss of tensile strength by annealing and the longer term permanent conductor elongation through metallurgical creep. The additional effects of increasing conductor temperature on the galvanized steel core, current carrying connectors and joints (Cigré TB 216 2002), conductor hardware and the protective properties of grease are also key considerations and detailed in Cigré TB 353 (2008).

***Conductor Annealing* (Cigré TB 353 2008)**

The design maximum operating temperature of a conductor is partly a function of the acceptable level of permanent loss of tensile strength or annealing of the conductor. Annealing is caused by the heating of a material generally followed by a cooling period. During the annealing process, the material experiences a change in its microstructure and for metals, this not only results in a loss in tensile strength but also an increase in conductivity. In general, changes in conductivity will be insignificant compared with the changes of tensile strength.

Isothermal annealing curves illustrate the permanent loss of tensile strength when a conductor operates at elevated temperatures. It is appropriate to establish the maximum design temperature at which a conductor can operate while maintaining acceptable levels of degradation of tensile properties.

More recent research indicates that the annealing characteristics of a conductor depend not only on temperature and time of exposure but also on the diameter of the wires in the conductor. Smallest wire size suffering the greatest loss in strength and the largest size the least.

The temperature limit for normal operation of AAC, AAAC and ACSR of 100 °C results in an approximate loss of strength of 3 % of the original tensile strength after 1000 hours operation at this temperature.

For ratings for short time conditions (eg. when one circuit has to carry more than normal current for a short time), both the maximum temperature and the duration of the emergency load should be taken into account in determining the annealing of the aluminium wires. The annealing effect is cumulative. For example, if a conductor is heated to 150 °C under emergency conditions for 24 hours a year for 30 years it is much the same as heating the conductor continuously at that temperature for 720 hours. For this example the loss of ultimate strength in AAC would be approximately 15 %. For 30/7 ACSR the ultimate tensile strength would be reduced approximately 7 %. (The loss of strength with 30/7 ACSR may be less than 7 % since the increased max elongation of the partially annealed aluminium may be offset by the increased utilization of the steel core tensile strength beyond 1 % elongation) The effect is less significant for ACSR where an increase in temperature results in a load transfer from the aluminium to the steel wires. The steel provides a substantial component of the strength of the conductor and is essentially unaffected by the temperature up to 200 °C. Above this temperature for normal steel there is a gradual fall off in strength until at a temperature of 400 °C where the strength of the wire is only half of that of the room temperature strength.

If ratings for emergency conditions are to be applied then the combined effects of elevated temperature and increased tensile loading on the steel core due to compression loading in the aluminium wires on the sag of the line should be taken into account. Practically, the tension in a line reduces with increasing temperature so the effect is less severe (Cigré TB 244 2004).

***Conductor Permanent Elongation* (Cigré TB 353 2008)**

Conductor permanent elongation is non-recoverable for inelastic material deformation that is a logarithmic function of conductor stress, conductor temperature and exposure duration. Permanent elongation begins at the instant of applied axial tensile load and continues at a decreasing rate providing tension and temperature remain constant. Permanent elongation consists of, in the short term, primarily wire radial and tangential movement during the early loading period (settlement & short-time, high-tension creep elongation) and in the longer term, primary metallurgical logarithmic creep (long-time, moderate-tension creep elongation).

Conductors operating at elevated temperatures will experience elevated conductor creep. In changing from low temperature conductor creep to high temperature conductor creep, it is necessary to convert the equivalent low temperature elongation equivalent time to an equivalent high temperature elongation equivalent time and project the longer term reduction in conductor tension and increase in conductor sag. At higher than everyday temperatures, the tension in the aluminium strands reduces. This reduction tends to offset the increase in creep at higher temperatures. In particular, for ACSR this creep is not higher than at normal temperatures.

Increasing the conductor operating temperature of an overhead line within the previously mentioned material limits of the conductor and maintaining ground clearance will increase the thermal rating of the overhead line. A typical relationship of the thermal rating of non- homogenous and homogenous conductors is illustrated in Figure 18.6. This relationship is essentially based on the fact that increasing the current will increase the thermal elongation which results in a reduction of conductor tension and a corresponding increase in conductor sag.

For example, increasing the operating temperature from 85 °C to 100 °C of a 207 mm^2 ACSR non homogenous conductor results in an increase of the conductor thermal capacity from 565 A to 655 A or about 15 % which will result in a conductor sag increase of about 0.57 meters in 400 meter span or about 5 %. Similarly, for the same 400 meter span, for a 506 mm^2 ACSR homogenous conductor increasing the operating temperature from 85 °C to 100 °C results in an increase of the conductor thermal capacity from 880 A to 1030 A or about 17 % which will result in a conductor sag increase of about 0.62 meters or about 4 %.

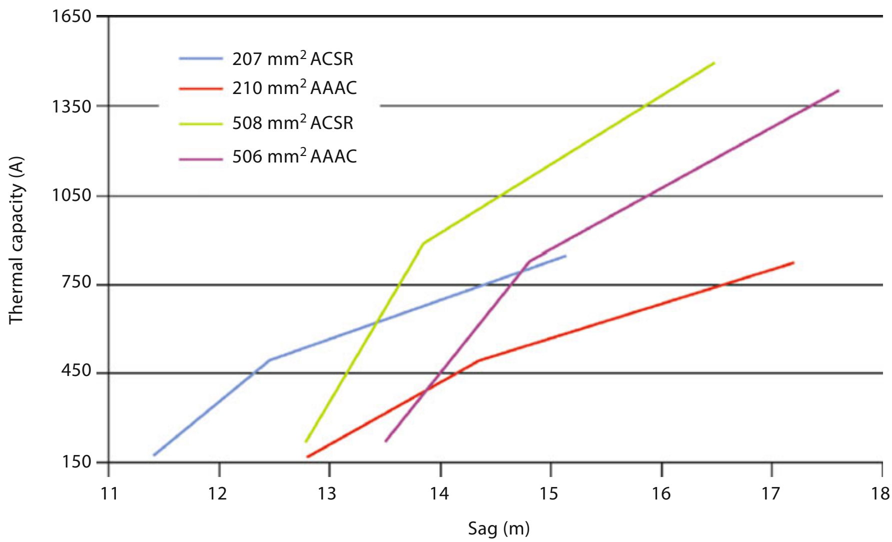


Figure 18.6 Typical conductor thermal capacity to conductor sag relationship for a given span.

To ensure ground clearance is maintained, mechanisms are required to compensate for this increased sag. Increasing the conductor operating temperature of an overhead line and maintaining ground clearance may be achieved by either increasing conductor tension, application of negative sag devices and or increasing the conductor attachment height. Increasing conductor attachment height is carried out by structure body extensions and or insulator crossarms and is discussed in Sections 18.4.2.

Increasing Conductor Tension **(Cigré TB 373 2005)**
Increasing conductor tension is one of the most common forms of increasing the rating of an overhead line. One of the most significant considerations in increasing conductor tension is the increased likelihood of aeolian vibration and associated increase in probability of longer term conductor permanent damage and even failure by metal fatigue. Notwithstanding this when consideration is given to increasing conductor tension it would be normal that the line would have been in service for a considerable period of time which would suggest that the aeolian vibration performance of the line is well known and the consequences of increasing conductor tension would be well understood.

Other design verification considerations would include

- increased conductor tension loads on angle and tension structures and even suspension structures under broken conductor loading conditions or other imbalanced longitudinal loading condition;
- increased foundation loads for angle and tension structures;
- increased conductor tension loads on tension insulators and associated fittings;
- for spans with differing conductor attachment relative levels, the changes in the weight span and resultant changes in suspension structure clearances for suspension insulators or changes in load factors for V string insulators
- increased conductor loads on all conductor joints under tension; and
- aluminium strands of the conductor will start creeping again if the tension is increased after more than 10 years.

The technical limits of increasing conductor tension is normally determined by

- the capacity of tension and termination structures and any associated cost benefit of increasing this capacity; and or
- aeolian vibration and or the fatigue limits of the conductors. The fatigue limits of conductors and the safe design tension has been the subject of widespread international research. An example of the publication of this research Cigré TB 373 (2005) and associated recommendation for conductor safe design tensions at average temperatures of the coldest month as a function of terrain category for homogeneous and non-homogeneous conductors and is given in Figure 18.7. Any proposed increase in conductor tension should be considered within the context of conductor safe design tension criteria.

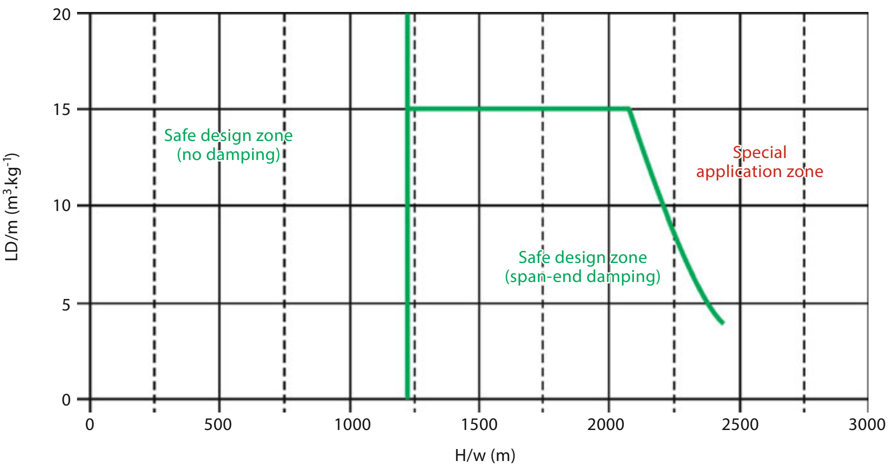


Figure 18.7 Cigré SCB2.11.04 Conductor Safe Design Tensions Recommendation (where: L = actual span length (m), D = conductor diameter (cm), m = mass of the conductor per unit kg/m, length H = horizontal tension in the conductor and w = weight of the conductor per unit length).

A typical relationship of conductor tension parameter (H/w) and conductor sag for non-homogenous and homogenous conductors is shown in Figure 18.8 and illustrates that decreasing the conductor sag will require a corresponding increase in the conductor tension.

18.4.1.3 Negative Sag Devices

Negative sag device remain relatively new overhead line hardware and are based on a reaction to increasing conductor temperature by decreasing the effective length of conductor in the span thus mitigating thermal expansion experienced by the conductor during high temperature operations.

The negative sag device is activated by the same temperature changes that cause the conductor to sag. As temperature rises, conductor lengthens and the conductor sag increases. Under same circumstances, the negative sag device changes the device's geometry to decrease span length. As the conductor temperature returns to normal and sag is no longer excessive then the negative sag device returns to the original shape.

18.4.1.4 Increasing Conductor Attachment Height

Increasing conductor attachment height to compensate for increased conductor thermal ratings is a natural consideration to compensate for increased conductor sag. Increasing conductor attachment height may be carried out by either the insertion of structure body extensions into existing structures and or application of insulator crossarms to existing steel crossarms.

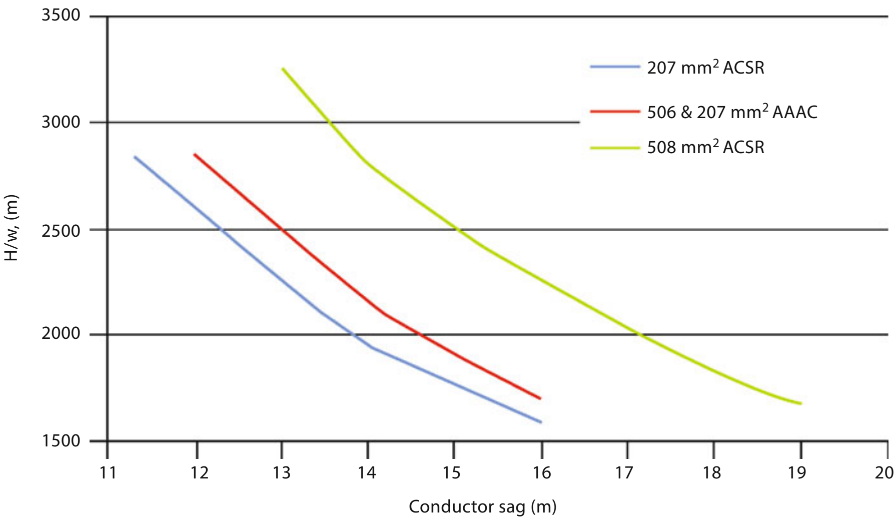


Figure 18.8 Typical Relationship of Conductor Tension Parameter (H/w) and Sag.

Structure Extensions **(Cigré TB 178 2001)**
General experience indicates that given the magnitude of the required structural works it is not economical to increase the heights of all structures in an overhead line. Nevertheless it has been found that in many cases an increase in maximum operating temperature may be achieved by selectively increasing the height of approximately 10 % of the structures. Selective inclusion of structure extensions is normally limited to the suspension structures given the inherent structural and practical difficulty of including a body extension into a tension or terminal structure.

Design verification of increasing conductor attachment heights by the inclusion of a body extension would include

- structural capacity of the existing structure to determine the availability of any marginal capacity;
- design of the structure extension which may in general be limited to the structure where the structure geometry would permit the inclusion of a structure extension; and
- an assessment of the foundation capacity and any increased overturning moments.

The technical limits (Cigré TB 308 2006) of the inclusion of a body extension would normally be determined by the structure and foundations ultimate load factor for the defined loading conditions.

Increasing Structure Height

Increments in the structure height have generally been achieved by inserting a new steel panel into the lower portion of the structure as illustrated in Figure 18.9. Usually a 2 to 3 metre new extension is enough to achieve the new desired clearance.

Figure 18.9 Increasing Structure Height.

The new panel is designed to provide compatible interface to the upper and lower parts of the structure. As the original base width of the structure is concurrently not changed this causes increases on the lower body stresses and this may require either a completely new reinforced lower part (this is not very common) or reinforcements on the existing lower body.

The reinforcements on the existing lower body will generally consist of duplication of the main members as illustrated in Figure 18.10 or complete substitution with members of larger cross sectional area. Replacement of cross bracing members may also be required.

Foundations (Cigré TB 141 1999)

In any uprating or upgrading consideration, current practice is not to change the structure base width with the aim to reuse the existing foundation. This causes increments on the foundation loading since they are now subjected to greater loads, due to higher conductor attachment points and the associated larger overturning moments. These moments will increase the structure uplift and compressive loads.

Increased uplift reactions can be counteracted by adding additional concrete within the soil frustum or in critical cases by the installation of injected micro-piles plus a new concrete block connected to the existing foundation. Compressive resistance is normally not a problem and if it is the proposed solution can be achieved with the same injected micro-piles technology.

Erection Techniques

The current erection technique consists of either using an external support structure or using an internal central mast. The later technique provides the advantages of standardization in the process, ease of transport, reduction in installation time and lower cost. Depending on the conditions, raising of the structure height is an erection process that can be done with the overhead lines in service without any

Figure 18.10 Duplication of Leg Members.

outage. This can be attained with sophisticated raising erection equipment and a team with extensive knowledge and experience.

Insulator Crossarms or Insulator Modifications **(Cigré TB 353 2008)**
Similar to increasing conductor tension, the replacement of existing insulators with some form of insulating crossarm or modifying the existing insulator arrangement are some of the most common and cost effective means of increasing the rating of an overhead line. The relative conductor attachment level is raised permitting the conductor sag to increase. Composite insulator provide a useful mechanism to design hybrid insulator sets to fulfil the geometrical, electrical and mechanical requirements of a new insulator system, with in most cases, enhanced performance.

One of the most important considerations in replacing existing crossarms or insulators is an understanding of the pollution levels and the performance of the existing insulation design of the overhead line. Notwithstanding this, when consideration is given to modifying the existing overhead line insulation it would be normal that the line would have been in service for a considerable period of time which would suggest that the insulation performance of the line is well known and the consequences of changing the insulation design would be well understood. Other design verification considerations would include changes in the,

- mechanical loads of the insulator arrangements;
- coupling point of the applied insulator loads on the structure;
- electrical clearance envelope caused by changes in the insulator swing;
- changes in the conductor attachment fittings and associated loads; and
- structure longitudinal load and restrained insulator movement.

The technical limits of insulator crossarms or insulator modifications are normally determined by required electrical clearance window, required coupling and creepage length of the insulators and flexibility of changing the insulator loading structure coupling points.

18.4.1.5 Use of Interspaced Structures

The use of interspaced structures is another way to increase conductor ground clearance. The selected spans and locations would normally be where the greatest amount of sag occurs or at the point on the ground profile where a clearance problem exists at an increased conductor operating temperature. It is desirable to install the structures at the mid-point of the span in order to minimize the amount of inline tension that would be affecting the structures tangential strength requirements. Essentially the structure should be capable of supporting the conductor weight and wind span and any ice loads.

Factors influencing the design and application of this solution may include items such as ownership of the right of way or easement restrictions as well as aesthetic considerations in built up areas.

18.4.1.6 Increasing Thermal Rating by Active Real Time Line Rating Systems (Cigré TB 299 2006; Cigré TB 353 2008)

Most utilities base the overhead line "book" ratings based on deterministic assumptions of a low wind speed and direction, high ambient temperature and full solar radiation. The most significant of these variables is the assumed effective wind speed. Cigré TB 299 suggests certain default weather conditions that are suitably conservative but suggests the possibility of performing field studies to determine regional specific weather assumptions or the use of real-time monitors to calculate dynamic line ratings. If properly selected, the weather assumptions used in line rating calculations result in a small risk of the conductor exceeding the design temperature when line current equals full rated load. This is illustrated in Figure 18.11.

The objective of using real time monitoring is to increase the line rating weather conditions as favourable compared to the assumptions used in static line ratings. This is illustrated in the green area in Figure 18.11 and simultaneously avoiding the rare conditions when the actual rating conditions are unfavourable as illustrated in the red area. During these periods, because the thermal state of the conductors changes rather slowly, with a time constant of about 10 to 20 minutes, the network operators may have sufficient time to reduce power flow and eliminate any clearance infringement risk.

The capacity increase and benefits of uprating achieved by real time monitoring depends on the static rating weather assumptions and the line design temperature.

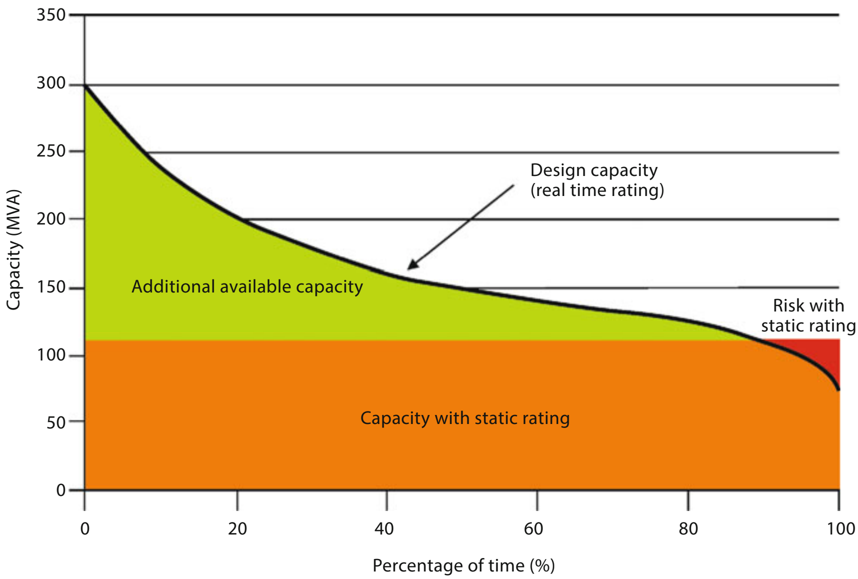


Figure 18.11 Relationship of Overhead Line Load Factor and Static & Real Time Ratings.

The benefits also depend on the economic and regulatory criteria used in each country.

Based on current experience, the rating gains vary between 5 to 15 % and higher gains may be achieved in special cases. For example, application at wind farms has shown realized gains of 30 to 50 %. The increase of line rating near wind farms is the result of prevailing winds. In addition real time monitoring can help to avoid uneconomic system dispatch when electricity costs are at peak.

Furthermore, a Cigré survey (Cigré TB 353 2008) indicated that under most circumstances overhead line thermal limits are caused by clearance limits and not material annealing limits. This has supported the consideration of adopting real time ratings of overhead lines to enable lines to operate closer to the clearance limits more often by utilizing the frequent occasions when the prevailing climatic conditions would permit higher ratings than those that would have been assumed by conservative deterministic static ratings. The difficulty in implementing dynamic line ratings concerns their lack of predictability. In most lines, it is not possible to predict line ratings beyond 1 to 4 hours and this prevents their use in determining transmission capacity for generation contracts which are usually determined a day ahead.

In summary, the objective of real time monitoring of an overhead line is based on

- the thermal rating of an overhead line is the maximum current that the circuit can carry without exceeding its temperature limit;
- the current required to enable the conductor to reach a given temperature can be far higher when the cooling is greatest than when the cooling is low which implies higher ratings at times of high wind speeds, low ambient temperatures or combinations of these parameters and vice versa; and hence

- real time monitoring is the monitoring of parameters such that the conductor position above the ground may be determined in real time at a current instant and the permissible thermal limits are then calculated to optimize the power flow of the overhead line.

Three common methods are employed to provide real time ratings and are the determination of,

- line clearances based on either real time conductor tension or sag measurements (direct method);
- conductor distributed temperature measurements using phase conductor embedded sensors (direct method) and direct measurement of conductor temperature; and
- prevailing climatic conditions by the installation of weather stations and the application of deterministic methods in rating (indirect method).

Two specific methods dominate the practical utility applications, tension and sag monitoring methods and weather methods used in different ways in several countries.

Line Tension and Sag Monitors
The tension or sag monitors are mounted on selected tension structures along the overhead line. At each location, the conductor's mechanical tension or sag is measured by a tension sensor or sag sensor.

When using a tension monitor, conductor tension is measured by an electronic load cell and communicated to the utilities' control room where an algorithm determines the real time conductor temperatures, real time line ratings and provides alarms of possible clearance violations. A sag monitor performs the same function by using a video sensor and target hung on the conductor to directly measure the actual sag and clearance in the monitored span.

In general, the monitored line tension or sag follows the average temperature of the line section between the adjacent tension structures and gives a representation of the rating conditions of a long section of the line. Typically, two monitoring locations, each monitoring two adjacent line sections, are required at line lengths of up to 25 to 35 km. The rating of the overhead line is then determined based on the lowest rating or highest temperature of the monitored sections. For longer lines, additional monitoring locations are required.

***Conductor Temperature Sensing* (Cigré TB 498 2012)**
Cigré TB 498 provides a complete guide to the application of direct real time monitoring systems applicable to overhead line which includes temperature sensing.

***Weather Stations and Application to Deterministic Rating Methods* (Cigré TB 299 2006)**
Weather monitors can be used to calculate conductor temperature and ratings using various methods such as the Cigré and IEEE methods. The Cigré and IEEE methods are applicable to all dynamic rating methods to calculate line ratings. The weather

stations typically monitor wind speed, ambient temperature and solar radiation. Although wind direction can also be monitored most rating calculations default to using a wind direction at a small angle to the conductor because of the high variability of wind direction.

Because wind conditions are highly dependent on the terrain and sheltering of the line, weather monitors must be mounted in the actual overhead corridor to be monitored. Use of weather data at airports or other remote locations away from the overhead line may have little or no correlation with the weather conditions at overhead line corridors.

Weather stations report data from a single point of the line and line ratings calculated from weather data will in general be influenced by the number of weather stations installed to monitor the overhead line. Weather based ratings can be least accurate when the wind speed is low which is the most critical rating condition.

The cost of weather monitoring stations are relatively low but the associated maintenance costs can be high.

18.4.1.7 Probabilistic Rating of Overhead Lines (Cigré TB 207 2002)

The ampacity of a conductor is defined as the "*current which will meet the design, security and safety criteria of a particular line on which the conductor is used*". Thus the thermal capacity of an overhead line is a function of the conductor integrity and the safety of the public. As such the thermal rating of an overhead line is depending on the following factors,

- ambient conditions;
- current;
- conductor type, rating and any bundle configuration;
- design temperature;
- exposure of the overhead line to the public;
- likelihood of above factors occurring simultaneously; and
- probability of flashover if the above conditions occurred simultaneously.

Probabilistic rating of overhead lines allows one to use the actual prevailing weather data to determine the risk associated with a particular current and design temperature. Caution is expressed when considering a change to probabilistic ratings. If probabilistic ratings are to be used, they should be based on a thorough scientific study of both the meteorological conditions of the area and the characteristics of the line corridors and it is important that the study be conducted by competent professional. Such a study will allow determination of the level of risk associated with a given deterministic rating method and provide guidance for establishing an appropriate risk level for future operations. The resulting probabilistic ratings are often less conservative than the deterministic method resulting in higher current ratings.

There are two major probabilistic methods of determining the thermal rating of conductors, the absolute method and the exceedence method.

The absolute method determines the current for a specific level of risk or probability of an unsafe condition arising. The primary benefit of using probabilistic rating is that it permits a utility to fully manage the risk inherent in overhead line operations. When desired, this method permits conductor ratings to be varied across geography, terrain, season and/or diurnal period while maintaining a constant level of operational risk. This risk can be expressed in terms of 1×10^{-6}, for example, allowing the comparison of overhead line safety to that of a nuclear power plant or other structures.

The exceedence method determines the amount of time the conductor will exceed the design temperature at full rated load. The method is normally used assuming a flat load profile that is assuming that the overhead line carries full load at all times.

For uprating of lines, it is possible to make use of these methods taking into account the local weather conditions as well as the actual load profile on the line to determine possible increases in the line rating. Caution must be exercised relating to possible low wind conditions on the line route as the location of the weather stations are not likely to be within the overhead line right of way.

The use of this method of rating should not be used to revise the "book" rating on a permanent basis. It is a method to use for a short term and may also be used to determine the effectiveness of real time monitoring systems.

The following Figure 18.12 shows the difference in rating between a flat load profile (blue line) and the load profile of the overhead line (red line). For example for a 10% exceedence for Hare conductor (105-Al/Si A-6/1) the rating can be increased from 290A to approximately 390A.

The method used in the rerating of lines is to determine the present exceedence limit used with the present "book" rating method or flat load profile. Then keeping this exceedence level constant, determine the new rating with the actual load profile. That is, if the Hare conductor "book" rating was 290A (blue line), the exceedence

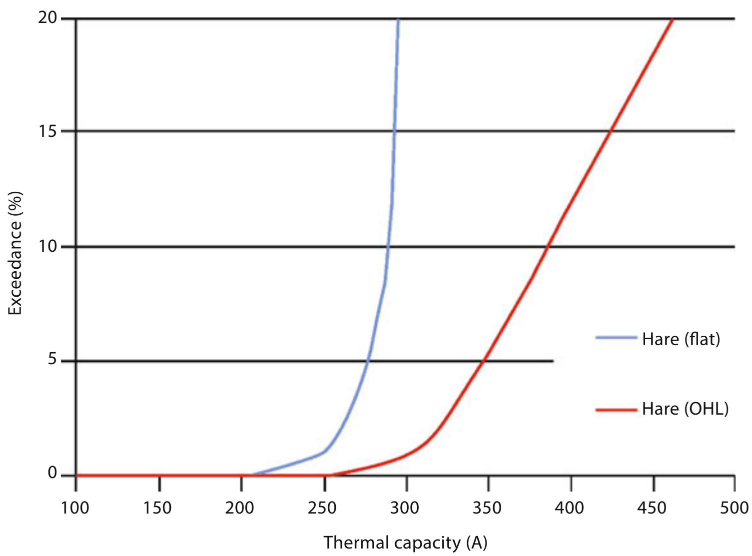


Figure 18.12 Variation of Conductor Thermal Capacity with Load Profile.

would be 10 %. With the actual load profile, and the local weather conditions, the rating could be increased to 390A (red line).

In addition, to this rating, care should be taken to inspect the line to ensure that the actual line design temperature complies with the original specifications. The line must be inspected for hot joints and broken conductor strands. With the new rating, an engineering assessment needs to be carried out to determine the possible maximum conductor temperature to ensure that there is no danger of annealing. (see Section 18.4.1.2)

18.4.1.8 High Surge Impedance Loading Lines (HSILL) (Cigré TB 353 2008)

HSILL is a technology that was initially developed in order to increase the capacity of overhead lines by maximising and equalising the electromagnetic field distribution on the conductors. The technique eventually evolved into an overhead line optimisation concept.

HSILL technology strives at a total optimisation of all significant electrical and geometrical parameters of an overhead line. In comparison, conventional overhead lines are designed on a step by step procedure, changing one parameter at a time and keeping some other parameters fixed such as the conductor cross section, number of sub-conductors per phase, phase conductors and bundle sub-conductors spacing and so on. Whereas the HSILL concept is a total optimisation process in order to reach more efficient and economical solutions.

HSILL concept represents a considerable change in the usual procedures such as the use of asymmetrical and or large conductor bundle configurations. The technology was initially developed for the overhead transmission of electrical energy from large generating units over long distances, to maximise overhead line capacity by operating the line at "the natural power" or the surge impedance loading (SIL). In recent times the technology has evolved to being an electrical design optimisation technique, known as expanded bundle technology (EXB), suitable for

- design of new overhead lines of high overhead capacity;
- uprating of existing overhead lines, to increase the overhead capacity; and
- modification of overhead lines electromagnetic parameters aiming to optimise the power flow distribution in overhead systems.

In the design of new overhead lines the optimisation of electromagnetic parameters leads to higher SIL and consequently a higher overhead capacity compared to conventional overhead lines. This is obtained by means of an optimised electromagnetic field distribution. Essentially increasing conductor bundle diameter results in increased shunt capacitance, reduced series inductance, reduced surge impedance to $Z_s = \sqrt{(L/C)}$, and increased surge impedance load resulting in increased power transfer.

In the uprating of existing lines, this technology explores different possibilities according to design characteristics of the original line. Either by the rearrangement of existing conductors or by addition of one or more conductors (not necessarily of the same type as the existing ones) the obtained result is an increased overhead capacity. Typical 230 kV in service overhead lines have increased the overhead line overhead capacity by 38 % in one case and 60 % in another case. In both cases the cost benefit ratio was 18 % and 25 % respectively compared to the total cost of a new overhead line. Typical HSILL overhead line capacity increases are illustrated in Table 18.3.

In the optimisation of overhead lines, a variation of the technique is used when desired values of overhead line electrical parameters (mainly the reactance) are selected instead of deigning for the maximum possible overhead capacity of a single line. Obtaining the desired parameters results in a better power flow distribution among the overhead lines in a given corridor or network. This possibility could be one of the most promising applications of the HSILL/EXB technology, since the ability to vary overhead line parameters may provide considerable gains with reduced investments.

HSILL and or EXB techniques are therefore well suited either to design new lines or to refurbish and or uprate existing overhead lines. In cases where overhead capacity limits are associated with voltage limits, SIL optimisation of line parameters may provide a solution by reducing series reactance and offering an economical and technical alternative to series compensation. In those cases where overhead capacity is limited by thermal ratings, the use of EXB techniques may allow for a better distribution of current flows on the overhead system, postponing or even eliminating the need for replacement conductors.

Another advantage of HSILL and or EXB technology is associated with systems having significant thermal generation, where sub-synchronous resonance may become a problem if the needed series compensation levels are high. Here again, the adequate choice of overhead line parameters may eliminate the problem.

Finally, it has become quite noticeable in the last decade that a technique allowing for greater overhead line capacity in the same right of way has an economic contribution which extends far beyond the simple overhead line construction costs, since the environmental issues are quite favourably met by HSILL and or EXB overhead lines as they provide means for higher power density flowing on a given corridor. Examples of HSILL and or EXB overhead lines are illustrated in Figures 18.13 and 18.14, respectively.

In summary, HSILL technology enables the design of overhead line configurations that optimises electric and magnetic field distributions and consequently the electrical parameters and the power overhead capacity of an overhead line, as well as the current sharing among different lines in the system.

Table 18.3 Typical HSILL Overhead Line Capacities

Voltage (kV)	SIL – Traditional (MW)	SIL – Expanded (MW)
69	9 – 12	10 – 40
138	40 – 50	50 – 120
230	120 – 130	130 – 440
500	900 – 1020	950 – 2000

Figure 18.13 230 kV Experimental HSILL Overhead Line.

Figure 18.14 500 kV EXB Overhead Line 744 km Long.

18.4.2 Increasing Voltage Rating (Cigré TB 353 2008)

Increasing the voltage of an overhead network is generally the most effective strategic way of providing a quantum step change in overhead capacity. In general for each nominal voltage level the natural capacity of the network is increased by about 4 to 5 times. An example which is not complicated by Corona, radio interference and audible noise considerations is the simple case of increasing the voltage of an existing 33 kV overhead line to 132 kV with the existing conductor configuration by which the capacity of an overhead line will quadruple with relatively small marginal cost of line reconfiguration works. Another relatively simple example of uprating a 110 kV line to 275 kV is shown in Figure 18.15.

This Section will discuss the basic electrical design requirements and strategies that may be implemented for existing overhead lines to increase the voltage rating. Given the enormous world wide variety of overhead line designs the discussion will be limited to the basic principles. An example of a typical overhead line voltage uprating study is shown in Table 18.4.

18.4.2.1 Requirements

The basic design considerations are

- clearances to ground, to support structures, to over crossings of other power lines, roads and railway lines and clearances to adjacent structures and vegetation;
- conductor motion and phase to phase electrical clearance between conductors;

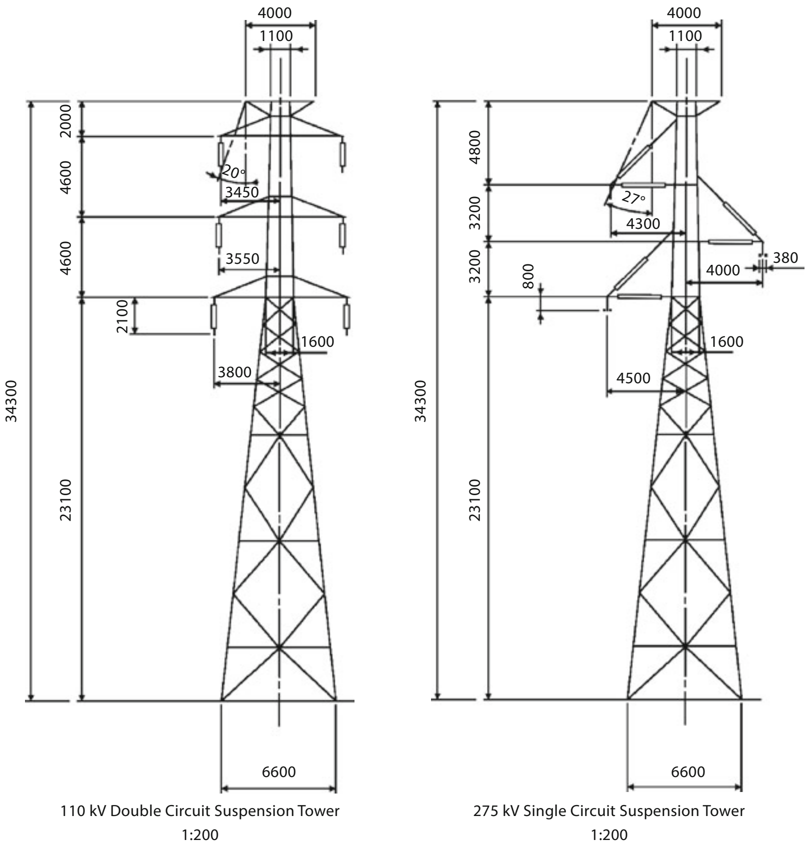


Figure 18.15 Overhead Line Structure Uprated from 110 kV to 275 kV.

Table 18.4 Typical Overhead Line Voltage Uprating Comparisons

Conductor	Circuits	Voltage (kV)	Power Transfer (MVA)	Cost ($/km)
1×18.1 mm	2	110 (AC)	160	No cost existing line
1×18.8 mm	2	110 (AC)	200	100
2×18.1 mm	1	220 (AC)	320	235
2×18.8 mm	1	220 (AC)	400	285
1×29.3 mm	2	+/− 250 (DC)	900	350

- clearance between earth wires and conductors;
- insulation requirements for power frequency, switching and lightning surges;
- clearance for live line maintenance;
- conductor surface voltage gradient, Corona onset voltage and radio interference voltages which are influenced by conductor diameter and conductor bundle diameter; and
- audible noise.

Clearances
One of the main criteria for an overhead line is to provide sufficient vertical clearance to the ground, over crossings, objects, supporting structures and vegetation; horizontal electrical clearance to adjacent structures, objects and vegetation; and clearances between phase conductors and earth wires and conductors. This criteria must comply with statutory regulations and or industry codes. Consideration of uprating an overhead line from the present voltage to a higher voltage will require the application of the higher voltage criteria to the uprated overhead line.

Internal clearance to supporting structures is a further primary insulation criteria consideration. Critical flashover values for air gaps are required to be assessed for power frequency voltage and switching & lightning overvoltages and applied to the insulator and conductor configuration for the uprated structure. Consideration of critical flashover voltages for insulator arrangements that are subject to horizontal swing movement are also required to be assessed to ensure satisfactory air clearance performance.

Earth wire to phase conductor clearance is a further important point to analyse if the line to be uprated was not originally provided with an earth wire. Structure extensions will probably be required to achieve adequate clearances and the body structure may need to be reinforced.

Phase to phase clearance and corresponding differential conductor motion is also a primary air clearance criterion for the uprated structure. Conductor motion may be induced by wind gusting, galloping, ice load shedding and fault currents.

In consideration of uprating an existing overhead line to a higher voltage rating, the design may result in the reduction of phase to phase clearances which will require special analysis of the phase to phase switching surge withstand. This analysis would include an examination of the maximum insulation stress and minimum insulation strength for higher voltage overhead line and also involve a probabilistic analysis of switching surge magnitudes and wave shapes with varying prevailing climatic variables such as air density, humidity, temperature and ice depositions.

In addition, internal clearance from conductor to structure is required to be provided for coinciding basic insulation level requirements and overhead line maintenance requirements.

Lack of adequate clearance could eliminate live-line maintenance operations or require more sophisticated and expensive maintenance procedures.

Insulation

For the insulation design of an uprated overhead line, an understanding of the critical flashover voltage transients and power frequency voltages and the corresponding insulation withstand is required.

Power frequency insulation design criteria is based either on the suggested geometric insulator creepage distance or the insulator deposited density of salt index for given pollution level. In consideration of uprating an existing overhead line the historical pollution performance of the line in general, would be well known and the opportunities to develop a design to meet the required new design voltage should be well understood. In addition, many insulator manufacturers are well placed to provide custom insulator designs to meet particular power frequency design criteria.

Transient voltages may be either lightning or switching surges. Switching surges determine the insulation design for higher voltage lines or lines that have low earth resistance or where lines operate in regions of low keraunic levels. Lightning determines the insulation design for lower voltage lines or lines that have high earth resistance or where lines operate in regions of high keraunic levels.

The insulation design will be determined from the primary variables of air clearances, the insulator geometry such as V-string, I-string, tension, post and or horizontal-V and the structure geometry. Secondary variables are size of conductor or possible bundle conductor configuration, phase to phase clearances, number of insulators and the application of Corona shields. Influencing climatic factors include air density, humidity, precipitation, temperature and pollution and ice depositions.

The outcome of the insulation design for an overhead line subject to voltage uprating is increased insulator surface creepage length and increased critical flashover transient voltage distances to meet the new voltage rating of the overhead line.

***Audible Noise, Interference Voltage and Corona* (Cigré TB 244 2004)**

Conductor surface voltage gradient is an important factor to be considered when uprating the overhead line voltage. For voltage gradients above a critical level the conductor will commence the Corona phenomenon resulting in the production of noise and power frequency energy loss. The effect of Corona is visible light, audio noise and radio & television frequency interference.

The magnitude of conductor surface voltage gradient is dependent on operating voltage, conductor diameter, phase conductor spacing and in the case of bundled conductors the bundle diameter, bundle configuration and the number of subconductors in the bundle. Changing the conductor geometry results in a number of

Table 18.5 Influence of Electrical Parameters with Changes of Conductor Geometry

Parameter		Electric Fields	Magnetic Fields	Radio Interference	Audible Noise
Phase to phase distance	↑	↑	↑	↘	↓
Conductor height above ground	↑	↓	↓	↘	↘
Number of sub-conductors (for a given total cross-section)	↑	↑	=	↓	↓
Sub-conductor spacing	↑	↗	=	↗	↗
Total conductor cross-section	↑	↗	=	↘	↘

↑ Strong increase ↓ Strong decrease = No significant effect

↗ Slight increase ↘ Slight decrease

changes to the electric and magnetic fields, the radio interference voltage and the audible noise and these the effect on the changes of conductor geometry is illustrated in Table 18.5. The fields, Corona and other phenomena, their impacts and mitigation are covered in the Chapter 6.4.

For voltage uprating projects involving significant changes in operating voltage, overhead lines with single conductor present significant difficulties to achieve satisfactory economical outcomes without the consideration of reconductoring with larger conductors and or the installation of bundled conductors. In these cases, the additional wind, weight and ice loads created by the new larger conductors and or conductor bundles may result in overloaded structures and or structure upgrading which is not economical. For example, a 132 kV overhead line with 3750 mm horizontal phase spacing with a conductor diameter of 25 mm would have a surface voltage gradient of about 12 kV.cm^{-1}. This line is under consideration for uprating to 220 kV. In this case the solution would require the installation of additional sub conductors to form a conductor bundle to meet a reasonable voltage gradient criteria and practical phase spacing. The installation of additional sub conductors may result in the structures being structurally overloaded making the uprating proposal unviable.

Notwithstanding this, there are many examples in the world where overhead line designs have been implemented in such a way that at some future point in time the line may be reconfigured to allow an increase in the voltage rating. An example of this is the operation of a double circuit 230 kV overhead line with suitable conductor diameter to meet the voltage gradient criteria with a horizontal conductor formation. At some time in the future, the line can be given over to a single circuit 500 kV quad bundle overhead line by aggregating the six twin bundle phase conductors into three phases with four conductors per phase bundles. The initial and final conductor separation is designed to meet both the single circuit 500 kV and the double circuit 230 kV configurations.

The concern of conductor surface voltage gradient is normally limited to overhead lines with small conductors, insufficient phase to phase distances and or operating voltage over 220 kV as the designed conductor spacing and conductor diameter for lower voltage overhead lines generally result in gradients that are below the criteria threshold. This is illustrated in Table 18.6 for two voltage gradient levels, 12 kV/cm and 18 kV/cm.

Table 18.6 Conductor Surface Voltage Gradient Versus Phase Spacing for a Single Conductor

Overhead Line Phase to Phase Separation (mm)

	Conductor Voltage Gradient = 12 kV/cm			**Conductor Voltage Gradient = 18 kV/cm**		
Conductor diameter (mm)	Nominal operating voltage (kV)			Nominal operating voltage (kV)		
	66	132	220	66	132	220
15	923	not practical	not practical	not practical	4210	not practical
20	not practical	13200	not practical	not practical	1220	not practical
25	not practical	3750	not practical	not practical	620	7650
30	not practical	1830	not practical	not practical	410	3220
35	not practical	1130	22400	not practical	315	1820
40	not practical	790	8300	not practical	265	1210

The table indicates that in the case of a voltage uprating of a 132 kV line with a 30 mm diameter conductor to a 220 kV line, would require a phase spacing of or 3220 mm with a conductor voltage gradient of 18 kV/cm. If a conductor voltage gradient of 12 kV/cm were required, then a practical phase spacing would require a conductor in excess of 40 mm. It should be noted that conductor motion criteria would dictate that the 132 kV phase spacing should more likely to be about 2100 mm. Therefore, voltage uprating for single conductor lines is very dependent on the maximum allowed conductor voltage gradient, conductor diameter and phase spacing. Practical application of voltage uprating may require a larger conductor or bundled conductors.

18.4.2.2 Increasing Clearances

The first and most elementary consideration for increasing the voltage of an overhead line is to ascertain the phase to earth clearance of the line at the proposed higher voltage of the uprated overhead line. This will determine whether opportunities exist to modify the existing overhead conductor attachment height to accommodate the new voltage rating within the context of a cost effective technical solution.

For example take a 132 kV overhead line with a design ground clearance of 7.5 m and a 1 900 mm long cap and pin insulator arrangement suspended from a crossarm with conductors in a flat formation and the crossarm supported by two poles. Considerations is being given to increasing the voltage rating of this line to 330 kV which requires 9.0 meters ground clearance with an insulator string length of 2900 mm. In this case, the conductor attachment height is required to increase 1500 mm to compensate for the required new ground clearance and an additional

1000 mm to compensate for the additional insulator string length. The aggregation of the increase in the conductor attachment height is 2500 mm and the existing structure and insulator arrangement will be required to be redimensioned to accommodate this design.

A design option would be to consider a combination of insulated crossarms and the insertion of pole extensions into the existing structures or simply the insertion of pole extensions into the structure to raise the conductor by the required 2 500 mm. If this was required for every structure on the overhead line then this may not be considered a suitable technical and economical solution for the particular overhead line.

Notwithstanding, there are a number of cases where utilities have successfully increased the voltage rating of existing overhead lines by examining in detail, the line sections and selectively applying uprating options to existing structures.

Hence, one of the most significant considerations in increasing voltage rating of an existing overhead line is the capacity of the existing line design and supporting structure design to accommodate the required increased ground clearance within the economic constraints of the existing structure geometry. Other coinciding design verification considerations have been mentioned in Section 18.4.2.1.

18.4.2.3 Insulating Crossarms

The replacement of existing insulators with some form of insulating crossarm or modifying the existing insulator arrangement is the most common form of increasing the voltage rating of an overhead line by increasing the relative conductor attachment level to provide greater ground clearance and at the same time increasing the insulator creepage distance and transient voltage flashover distances. Section 18.4.2.1 details insulator crossarm and associated insulator modifications. Design verification considerations are also mentioned in Section 18.4.1.4 and in addition increasing the conductor attachment height of the structure requires an assessment of the foundation capacity and any increased overturning moments of the structure.

18.4.2.4 Structure Extensions

General experience indicates that given the magnitude of the required structural works it is not economical to increase the heights of all structures in an overhead line for thermal capacity uprating projects (see Section 18.4.1.). In the case of voltage uprating projects which tend to be traditionally more strategic long term network development projects, it may be considered a viable option to invest in the uprating of the line structures by using structure extensions, which could be either or both body extension or leg extension. The inclusion of a structure extension is more common to suspension structures given the inherent structural and practical difficulty of including an extension into a tension or terminal structure.

Design verification of increasing conductor attachment heights by the inclusion of an extension are mentioned in Section 18.4.1.4.

The technical limits of the inclusion of an extension would normally be determined by the structure and foundations ultimate load factor for the defined loading conditions.

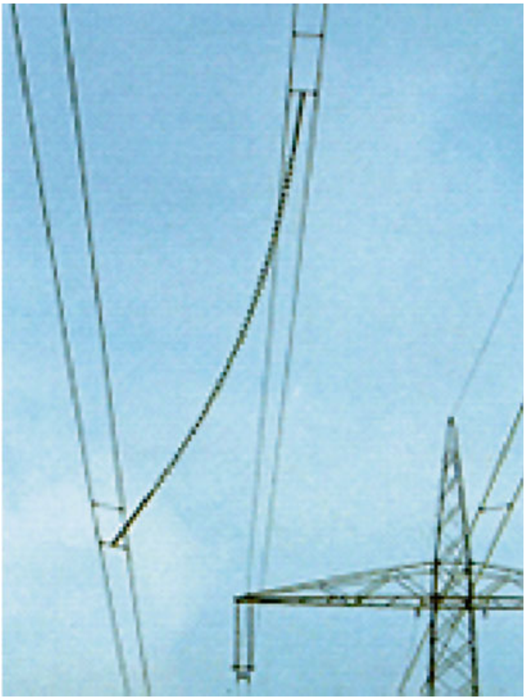
18.4.2.5 Mid Span Insulators

During the design considerations of mid span clearances and corresponding conductor motion, in some cases sufficient clearances cannot be maintained without limiting mid span conductor movement. A mid span insulator arrangement is illustrated in Figure 18.6. The availability of light weight composite insulators provides an excellent way to limit and control mid span conductor movement. In these cases, the application of phase to phase conductor spacers allows greater utilisation of existing conductor geometry at existing structures and permits voltage uprating that would otherwise have been excluded from economic and or technical consideration (Figure 18.16).

18.4.3 AC to DC Overhead Line Conversion (Cigré TB 583 2014)

An overall network strategic of increasing the capacity of existing AC major overhead lines is by the conversion to DC operation and especially applicable for stability limited AC lines. Conversion to DC provides additional system benefits such as improved control of power flow and enhanced stability & reliability of the surrounding AC system. The DC voltage can often be higher than the existing AC phase to ground voltage without major interventions to structures or conductors as the existing structure air clearances can be utilized more efficiently in the absence

Figure 18.16 Uprating from 245 kV to 420 kV by Changing Insulator Sets and Using In-span Insulator Sets.



of high switching overvoltages coupled with the Corona effects are less severe under DC operation. The major technical obstacle to conversion is the required insulator length in polluted conditions, while the major economic hurdle is the cost for the converter stations. This Section will discuss the possibilities and constraints associated with conversion of AC lines to DC and details a number of design considerations.

18.4.3.1 Requirements

The basic designs considerations are

- fundamental difference between AC and DC lines;
- DC line geometric configurations;
- Corona and field effects including audible noise;
- Insulation co-ordination; and
- economic including terminal stations.

18.4.3.2 Fundamental Differences between AC and DC Lines

Above about 245 kV, AC overhead lines are largely designed with respect to switching overvoltages and Corona effects, which are both related to the peak of the operating voltage, while the power capacity is determined by the rms voltage. DC lines, on the other hand, benefit from lower slow-front overvoltages and less severe Corona effects due to the influence of space charges, suggesting that some existing AC lines may be better utilized in terms of higher power transfer capability by application of a comparatively high DC voltage. However, insulator pollution is more crucial under DC and may be an important obstacle to conversion in polluted areas by limiting the attainable DC voltage level coupled with the existing insulators may not be suitable for DC operation due to corrosion effects. Both issues may generally be overcome by replacing the existing insulators with composite longrod insulators.

DC Line Geometric Configurations

Conversion of an AC line to DC can be done by various configurations, imposing different limitations related to the utilization of existing conductors as follows and illustrated in Figure 18.17:

- Monopole configurations utilize all three conductors for power transfer, but require current return through the earth which may not be allowed for several reasons;
- Bipole configurations utilize only two conductors for power transfer in normal operation, while the third conductor is used for metallic return under contingencies. Different conductor rearrangements may enhance the utilization of conductors in bipole configurations;
- Tripole configurations utilize all three conductors for power transfer to a certain extent by the use of an additional bi-directional converter; and
- Hybrid configurations comprise AC and DC circuits running in parallel and require special attention with regard to electrostatic and electromagnetic coupling between the circuits.

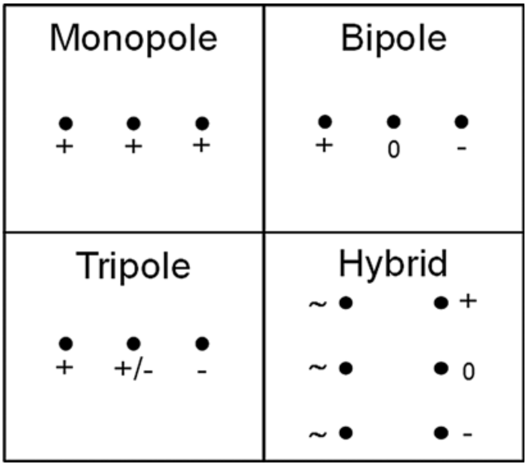


Figure 18.17 Possible configurations for AC lines converted to DC.

18.4.3.3 Corona and Field Effects

An important aspect of the Corona effects is that audible noise and radio interference from DC lines which decrease in wet conditions due to the influence of space charges. This is in contrast to AC lines where Corona effects in wet conditions is decisive for the design. As a consequence, the Corona effects in dry weather are among the parameters which determine the attainable DC voltage of a converted line. As an example, proposed limits for the audible noise level of DC lines are often about 10 dBA lower than for AC lines due to the longer duration of dry weather conditions. It should be noted that the highest audible noise level is produced by the positive DC conductor.

The mutual influences on the surface voltage gradient of the conductors when calculating the Corona effects of hybrid lines should be considered as a static charge will be induced on the AC conductors by the DC electric field, while time-varying charges will be induced on the DC conductors by the AC electric field. Hence, the voltage gradient on the surface of the AC conductors will include a DC component, while the gradient at the surface of the DC conductors will include an AC component. These electrostatic effects will influence the Corona activity on the AC as well as the DC conductors.

The field effects at ground level are also different for AC and DC lines. While AC electric fields are independent of Corona effects, the DC electric fields at ground are significantly influenced by Corona on the conductors and the corresponding generation of space charges. While the space charges limit the electric field at the surface of the conductors, the field strength is enhanced at the ground level. The resulting electric field in combination with the space charges may cause annoying perceptions for humans under the line, and is therefore another important parameter for determination of the attainable DC voltage level. Regarding possible health effects associated with the fields, the most important difference between AC and DC lines is that the electric and magnetic fields from DC lines are static, meaning that no induction effects are caused in the human body.

No internationally recommended limit has yet been proposed for static electric fields and Cigré TB 388 (2009) proposes 25 kV/m as limit in fair weather and 40 kV/m as 5 % exceedance level for inclement weather based on perception threshold. For hybrid configurations, the human sensitivity to the electric field is further enhanced due to the simultaneous presence of both AC and DC fields.

18.4.3.4 Insulation Coordination

When lightning strikes a DC line, the fast-front overvoltages appearing between the DC conductors and the tower depend on the magnitude and polarity of the lightning current as well as the polarity of the DC conductor. The DC voltage after conversion may be higher than the instantaneous voltage under AC, suggesting that the composite overvoltages occurring between conductor and tower on DC lines may be somewhat higher than on AC lines.

Slow-front overvoltage levels are rather low in DC systems, and the insulation design is often dominated by requirements on the pollution performance. Considering the space available on the towers, it is necessary to apply a detailed design approach for the DC insulators as described in Cigré TB 518 (2012). It is recommended to use the statistical approach to achieve an optimal dimensioning of the DC insulators for polluted conditions.

In many jurisdictions National regulations for the required safety clearance to ground are often expressed in terms of the AC system voltage and therefore not directly applicable to DC. However, if it is conservatively assumed that both fast-front and slow-front overvoltages are limited by flash-overs across the line insulators, the required safety clearances may be expressed in relation to the insulator striking distance by applying the appropriate gap factors for the respective air gaps and overvoltage types. Since slow-front overvoltage levels of DC lines are often low enough to prevent insulator flashovers, only fast-front overvoltages need to be considered for determination of the safety clearances.

18.4.3.5 Economic Considerations

The relation between capacity gain and costs for different uprating alternatives from AC to DC are discussed in general terms in Cigré TB 425 (2010). Regarding the specific costs for line uprating, many of the economic considerations are discussed in Section 18.3 also apply to the conversion of an overhead line from AC to DC with one important exception: the cost for terminal equipment will dominate in terms of the cost for the converter stations. In this respect, it is important to appreciate that the benefit of conversion is limited to *incremental* transmission capability while the cost for converter stations is governed by *total* capability. The effective cost multiplier as function of the capacity gain by conversion is illustrated in Figure 18.18. As an example, if the capability of a line increases from 1000 MW to 2000 MW by conversion to DC, the gain is 1000 MW while the converter stations must have a capability of 2000 MW.

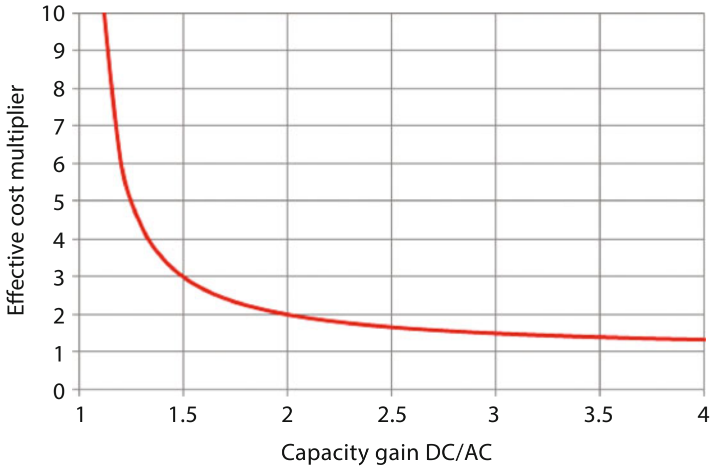


Figure 18.18 Effective cost multiplier as function of the capacity gain by AC to DC conversion.

18.4.3.6 Feasibility Study of Hybrid Lines

Paper B2-105 to Cigré Session 2014 (Sander et al. 2014) describes a pilot project of a hybrid line in Germany. The related feasibility study is focused on finding the most favorable DC polarity configuration when one circuit of 380 kV double-circuit lines (equipped with twin conductor bundles) is converted from AC to DC. Main tower dimensions are shown in Figure 18.19.

Composite insulators are proposed to replace the ceramic longrod insulators in order to utilize the available space in the most efficient way. The dimension of the composite insulators is determined by statistical calculation for varying pollution levels in terms of 2 % Equivalent Salt Deposit Density (ESDD) level. Using laboratory pollution test data in combination with an acceptable pollution flashover rate and an estimated frequency of pollution events, the required insulator length at ±400 kV DC varies from 3.4 m to 4.8 m for ESDD levels from 0.02 to 0.06 mg/cm^2. The length of the existing AC insulators is 3.8 m.

Using the required DC composite insulator lengths, the maximum allowable conductor sag is determined for the ruling span while respecting the minimum conductor clearance to ground as well as the maximum conductor temperature. Since the required DC insulator length exceeds the existing AC insulator length at higher pollution levels, the maximum conductor sag is limited either by the minimum conductor clearance to ground, or by the maximum conductor temperature. The maximum conductor temperatures are used to calculate the maximum current ratings at varying ambient temperature utilizing the Cigré basic rating method (Cigré TB 207 2002). The corresponding thermal power rating is calculated for 380 kV AC and ±400 kV DC as shown in Figure 18.20. Since the transmission capacity of an AC line is often limited by stability constraints, the surge impedance loading (SIL) is indicated as well.

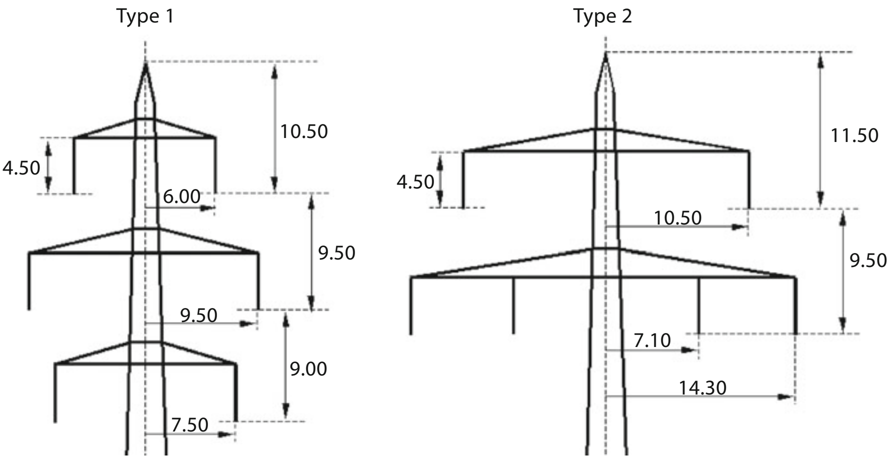


Figure 18.19 Main dimensions of the two 380 kV double-circuit tower types.

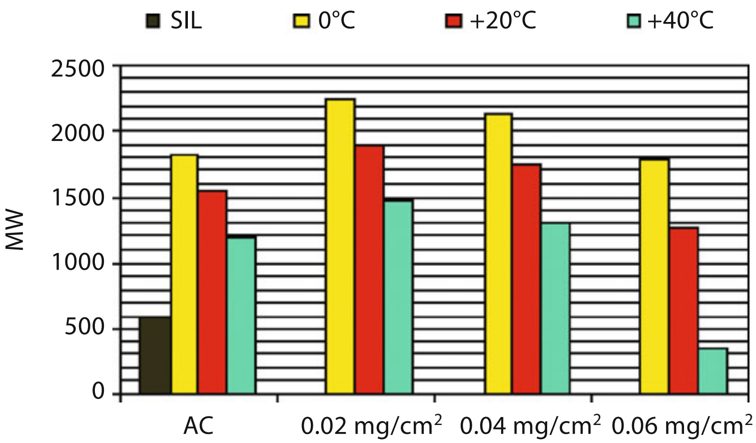


Figure 18.20 Power capacity of AC and DC circuits at varying ambient temperatures for different pollution levels and corresponding DC insulator lengths.

18.4.3.7 Experimental Studies of Hybrid Lines

Paper B2-105 (Sander et al. 2014) also presents results from comprehensive experimental studies of Corona and field effects as well as insulation coordination aspects of hybrid lines. The line configuration under study is shown in Figure 18.21. Since the bipolar DC circuit is positioned at the same side of the tower as one of the AC circuits, and since the line is equipped with quadruple conductor bundles, the Corona and field effects cannot be directly compared with the effects of the twin conductor bundle line used for the feasibility study.

The basic dielectric design is based on the insulation coordination procedure given in IEC 60071–2 (1996). For determination of the required air clearances to

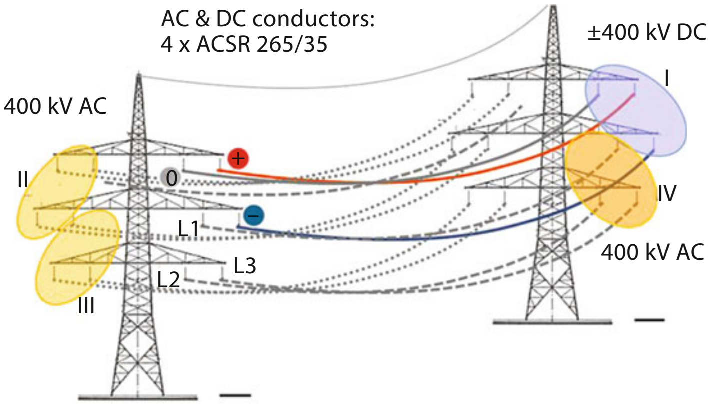


Figure 18.21 Hybrid line configuration under study.

ground, to the neutral conductor and between AC phase and DC pole conductors, laboratory tests on were carried out model arrangements as shown in Figure 18.22.

The slow front overvoltages occurring during earth fault are decisive for the air clearances on DC lines. Therefore, switching impulse tests were carried out to find the gap factor K of the configuration in question. Based on these results, the minimum air clearances to the crossarms as well as to the earthed return conductor were established for different DC voltages assuming an earth fault overvoltage level of 1.7 p.u.

For determination of air clearances between AC phase and DC pole conductors, a combined voltage stress has to be applied. Therefore the AC conductor was subjected to switching impulse voltage and the DC conductor to DC voltage, and vice versa. For combined voltage stress a gap factor K has to be taken into account which is not only depending on the arrangement but also on a factor α which describes the relation of the negative component to the total component (sum of negative and positive components). By means of these factors the required air clearance between phases can be obtained for different DC voltages assuming an earth fault overvoltage level of 1.7 p.u. for the DC conductor and a switching overvoltage level of 2.3 p.u. for the AC conductor.

External air clearances have to be considered with regard to safety, in particular lightning over-voltages; the overvoltage shall not cause a flashover between conductor and earthed objects, but shall lead to flashover across the insulator. As the DC insulators will be longer compared to the AC insulators, the flashover voltage will also be higher; thus the required external air clearance has to be adapted. Laboratory tests were carried out to find out the lightning withstand voltage of the DC insulators in order to determine the required air clearance between conductor and earthed objects for a gap factor of 1.3.

For investigation of the DC ground-level electric field and ion current density a similar model arrangement as for the dielectric studies was applied. The field strength was recorded by a field mill and the ion current by a plane electrode. The results are presented in Figure 18.23 for conductor heights of 10 and 15 m. It has to

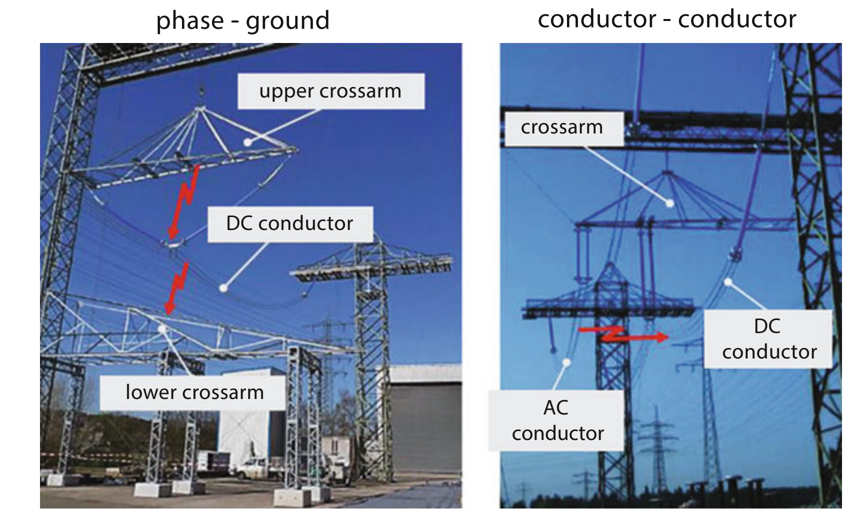
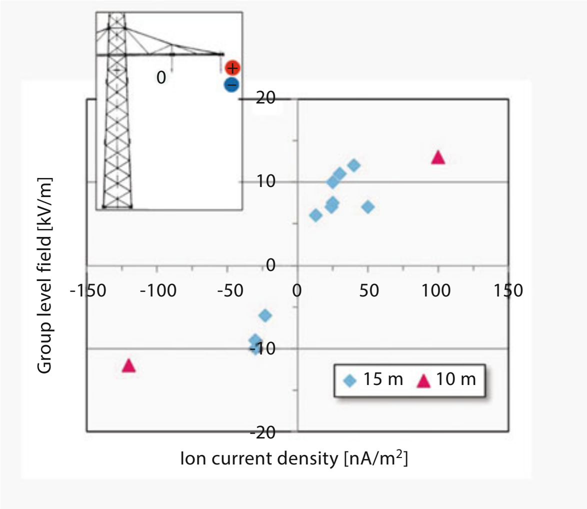


Figure 18.22 Model arrangements for dielectric tests on hybrid line.

Figure 18.23 Measured DC electric field and ion current density at ground level.



be noted that the ion current is strongly dependent on the ambient conditions, in particular the wind speed, consequently a noticeable scatter is observed.

Audible noise measurements were conducted in one span of a 2.5 km test line. The measuring arrangement is shown in Figure 18.24a. The line has a bipolar configuration similar to type 2 in Figure 18.19 with the positive DC conductor in the top position. The minimum conductor clearance to ground is 17 m. To simulate the capacitive coupling with the adjacent AC circuit, a DC voltage of 450 kV and 490 kV was applied. The results are presented in Figure 18.24b. The investigation

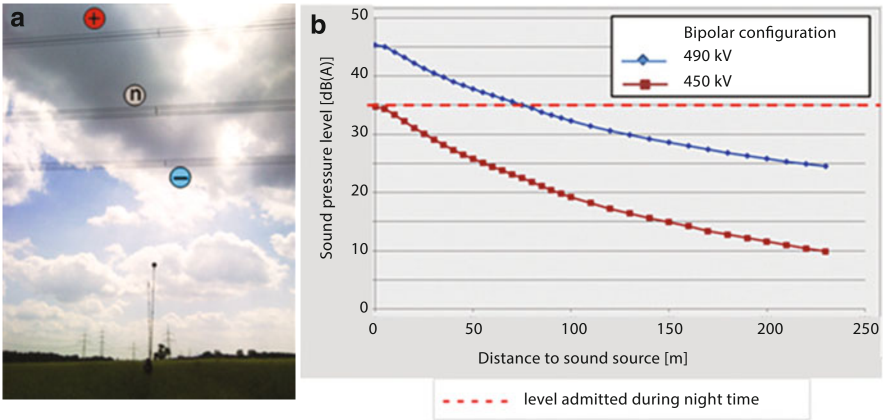


Figure 18.24 Arrangement and results of audible noise measurements.

demonstrates that at the edge of the ROW (Right of way), which is about 60…80 m, the AN is already decreased so far that the level admitted in Germany during night time is fulfilled, even if a DC voltage of 490 kV is assumed.

Due to Corona discharges on the DC conductors, a DC current is injected into the AC conductors on a hybrid line. The DC current may increase the magnetizing current of power transformers and inductive voltage transformers, possibly leading to saturation effects. Depending on line configuration and ambient conditions, the ion current may amount up to 15 mA/km. Consequently, remedial measures are of interest for long hybrid line, in particular for lengths of more than 100 km. To study the compensating effects of line transpositions, measurements of the ohmic coupling were carried out on the test line. The test configuration and the results are shown in Figure 18.25. The measurement results reveal that the ion currents injected into the adjacent AC conductors differ despite the symmetrical arrangement and nearly equal DC Corona currents; this can be explained by ion current drift in the wind direction. Thus, complete compensation cannot be expected in practice; however, the current in conductor 3, which is arranged in the middle between the negative and positive conductor demonstrates that a significant compensation effect can be achieved.

18.5 Overhead Line Upgrading

The definition of upgrading is increasing the original structural strength of an overhead line element and or component due to a requirement for higher meteorological actions and or electrical performance. Upgrading will decrease the probability of failure. Upgrading is often associated with uprating.

A prime example of upgrading is the meteorological data collected for many years may show that there could be higher ice and wind loads on overhead lines compared to the loads the lines were originally designed to withstand. Thus overhead lines may need to be upgraded to maintain reliability standards. In addition,

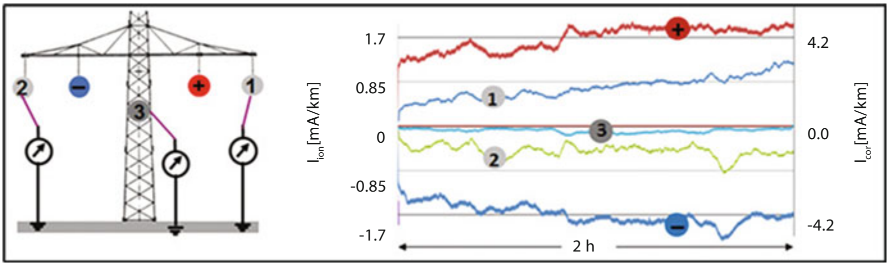


Figure 18.25 Test configuration and results of ohmic coupling measurements.

new overhead line modelling techniques and risk based probability design approach allow more detailed analyses to assess adequacy and risks associated with various overhead line components. Upgrading of an overhead lines depends on a number of factors and some of these factored are detailed in Table 18.7.

Generally the upgrading concerns the whole overhead line or some part of it, but there are some exceptional cases, such as the upgrading of only one structure due to installation of telecommunication equipment. Unanticipated rapid deterioration of an overhead line component may also require upgrading.

A comprehensive engineering study is required to consider all available upgrade options. Since overhead lines have many different design configurations and material choices, subsequently choices of upgrade solutions are often numerous. An engineering study should consider all choices available and assess their reliability levels, financial costs and practicability (availability of manpower, materials, outage requirements, etc.). When assessing financial cost of a given option, a life-cycle cost benefit analysis should be used to select the most cost effective solution and the associated project implementation timing. The engineering study should take into account further conditions of the maintenance of the line and whether live line maintenance is required. Such a decision could influence the design of some components such as structures, fittings and insulator strings.

18.5.1 Structures

18.5.1.1 Background

The overhead line structure is a key component and provides support to other components such as conductors and/or insulators. The structure has the most physical and aesthetic impact on the general public and private property. Overhead line structures are expected to perform satisfactorily for a very long time and often for 50 years or more.

During the course of an overhead line lifespan, the structure may be expected to carry additional functions or loads in excess of those specified in the original design. This is quite common as many utilities where network operators and system planners demand greater utilization from the existing overhead lines and thus strategically, resources are dedicated on planned overhead line structure upgrades.

Table 18.7 Factors Effecting Life and Performance of Overhead Line Elements

Environmental Factors	Operational Factors	Mechanical & Electrical Degradation
Climate	High temperature operation	Loosening or breakage of connections
Overloading due to ice and/ or wind	Increased continuous current	Fatigue of materials caused by vibration
Extreme temperatures	Increased fault current	Corrosion
Ultraviolet exposure	Lack of maintenance	Material wear
Fungi	No outage available for maintenance	Degradation of insulation
	Installation of telecommunication antennas on overhead structures	
Pollution		
Acid rain	Higher ground clearance	
Salt spay	Higher voltage level	
Fertilizer use		
Industrial gases	External Factors	
Lightning strikes	New obstacles in the vicinity of the line (ie roads, buildings)	
Fires		
Other External Factors		
Vandalism (gun shots, theft, abuse)		
Wildlife (i.e. woodpeckers, cockatoos, rodents, insects)		
Mechanical impacts (cars, farm equipment, planes)		

Upgrading an overhead line structure might also be as a result of in service failure due to unexpected weather events and or human made causes. In many cases, asset owners will only inventory higher strength suspension structures of a particular design class, for emergency spare structures. Typically, it is the lower strength suspension structures that fail and the structures will automatically be replaced with the higher strength equivalent structures, thus upgrading the line at the failed locations. If the failed overhead line is redundant or has low priority in the network, an upgrade option might be chosen instead of an emergency situation restoration. In this case the entire line, not just the failed portion, might be considered for upgrading.

18.5.1.2 Verification Considerations

Successful upgrading of overhead line structures depends on a number of factors.

Upgrade Studies

It is possible that the original structure capacity was not fully utilized during installation for various reasons such as unusual terrain conditions or perhaps site specific restrictions of availability of materials and therefore has reserve strength capacity. In such cases, structure upgrade can be achieved with minimum effort. In these cases it is critical that the original design assumptions be re-examined to confirm the basis of the design.

Availability of Original Design Information
It is essential to know the assumptions used in the design of the original structure such as strength and the parameters of the materials used and the design loads. This enables a designer to determine the existing structural capacity of the structure and to perform studies necessary to increase it.

Lattice overhead line structures are often of an old vintage. Some very old structure designs might have not been well documented. In some cases the properties of the steel material are unknown and member properties not documented making it very difficult for an engineer to model such designs. Material testing and careful engineering assessment may be required in these cases.

Assessment of Field Conditions
A field inspection is necessary to determine the condition of the existing structure which has been exposed to both the environmental elements and the overhead line loads. Chapter 6.3 lists the generic techniques that are currently available and can be used to find these defects in-situ. Such inspection might reveal reduction of capacity of individual structural members which might lead to a lower overall capacity of the structure. It may also trigger a need to replace these members in order to restore the original strength. Steel structures located in high industrial environment might be showing reduction in strength of the members due to corrosion of the steel.

Wood poles in particular should be treated with a detailed engineering assessment since they are products of nature and their physical properties are somewhat unpredictable. Furthermore, these properties change with time depending on environmental conditions. It is thus necessary to determine physical dimensions of the wood pole and condition of the wood to determine its strength. Wood pole deterioration may occur at higher rates in parts of the wood pole with drilled holes where there is potential for water and humidity to penetrate the wood.

Chapter 13.8 covered the detail review investigation of foundation assessment so that decisions can be made as to whoether to refurbish, upgrade or accept the current condition of installed foundations.

18.5.1.3 Technical or Practical Limitations

Overhead line structures offer designers multiple choices and large flexibility for performing upgrades. However structure upgrades have also technical and practical limitations, most of which were listed in Section 18.3.6. Additional limitations in upgrading structures include,

- *variability in wood pole sizes* - unlike other man-made materials, wood poles are natural product, come in variable sizes and their supply depends on harvesting patterns used by wood pole producers which may lead to difficulties matching required size and strength.

- *supply of wood poles* - availability of wood poles, especially in lengths exceeding 30 metres, may be limited.
- *availability of steel angles sizes* -in many cases, especially when original overhead line structures are of a very old, it might be difficult to find matching lattice steel members. Reasons for discontinuation of certain sizes may be new design codes, conversion of measure system (ie British to Metric) or different supply sources. This may lead to adjusting the detailing of joints to fit different size members.

Wood Pole Structures
Wood is a common material for building overhead line structures in many countries. Wood poles offer flexibility in designing custom structures whether it is required to match site specific conditions or to provide fast design to address emergency needs. Wood poles are easy to handle and assemble in the field. Upgrading wood structures may be involve,

- replacement of wood poles with higher timber class or of larger diameter;
- replacement of wood poles with poles of stronger species;
- replacement of wood poles with engineered laminated wood products;
- the addition and or replacement of braces;
- replacement of wood cross arms by steel arms or use of reinforcing metal channels to provide higher bending moment capacity or to increase structure height; and or
- use of stay (guy) wires to improve structural horizontal capacity.

Steel Lattice Structures
Steel lattice towers have been used successfully throughout the world as a design choice for overhead lines for almost a century now and are often considered as good candidates for upgrading considerations. A number of upgrade options exist for steel lattice towers and include,

- doubling or duplication of angle sections (often leg members);
- replacement of angle sections with larger section members;
- addition of redundant and or diagonal members;
- reconfiguration of low strength sections;
- addition of guy (stay) wires;
- upgrade of bolts to higher grade;
- use of tower extensions to raise conductor height; and
- use of longer length cross arms.

18.5.2 Foundations (Cigré TB 141 1999; Cigré TB 308 2006)

Foundations are located for the most part under ground level and the foundations are critical to the security and reliability of an overhead line. In general, a foundation failure will have significant consequences for the structure and may result in the failure of the structure of an overhead line. Failure of a foundation will result in long restoration times.

18.5.2.1 Background

Upgrading foundations generally arises from changing environment and load requirements from unexpected and extreme weather events that produce load excursion. Some of the load conditions that must be considered are wind loadings, snow and or ice loadings, landslides loads and or snow creep loads.

After a failure event, design loads are often recalculated. Generally this will lead to an upgrading of the structure design and often an upgrading of the foundations. Upgrading can be applied to the entire overhead line or for a limited number of structures and foundation in an existing overhead line.

New Standards and Legislation

In particular, catastrophic events can cause changes in Standards and or Legislation. In general, Standards will apply to new structures and foundations, however in some jurisdictions may also apply to existing overhead lines. New understanding of structure loadings can also lead to changes of existing Standards. In this case, for existing overhead lines, an assessment will be carried out where the changes in the Standard will be followed. Changes in Legislation for example in the case of electromagnetic fields (EMF), can lead to changes in overhead line conductors and thus changes in foundations. In some cases these changes can lead to adaptation of other structure configurations and this will have an influence on the foundations.

Changing the Function of a Structure

Changes of an existing overhead line by for example additional connections and or the conversion of structures to terminate cables can change the function of the structure such as suspension structure may be changed to an angle or a termination structure, and thus the new loads on a structure, may require the foundation to be upgraded.

Changes in Conditions Near Foundations

Frequently as a result of construction or mining in the vicinity of a structure, the soil characteristics around the foundation change and the design conditions are no longer valid. As a result these foundations may require to be upgraded of or reinforced.

Increasing Structure Height

There are a number of causes for which existing structures must be raised. Increase wind loads on the conductors of the overhead line will influence the foundations. Raising structures will lead to a redetermination of the structure foundation which may require the foundation to be upgraded. Causes for increasing structure height can be:

- larger sag of conductors as result of higher operation temperature mostly within the framework of uprating;
- new infrastructure under overhead lines such as roads, railways and other overhead lines; and or
- placing buildings or other infrastructures under overhead lines.

Uprating
Uprating options mentioned in Section 18.4 often require upgrading of the foundation.

18.5.2.2 Verification Considerations

Successful upgrading of overhead line foundations depends on a number of factors that must be considered.

Upgrade Studies
It is possible that the original foundation capacity was not utilized during installation for various reasons such as unusual terrain conditions, site specific restrictions of availability of materials and therefore has sufficient unused capacity. In such cases, foundation upgrade may be achieved with minimum effort. In these case it is critical that the original design assumptions be re-examined to confirm the basis of the design.

Availability of Original Design Information
It is essential to know the assumptions used in design of the original foundation such as strength and parameters of materials used and design loads. This enables a designer to determine the existing load capacity of the foundation and to perform studies necessary to increase it.

Foundation designs of some very old structure designs might have not been well documented. In some cases there may be deviation in the construction practice deviates from the design drawings. Material assessment and testing and careful engineering reviews may be required in these cases.

Assessment of Field Conditions
A field inspection is necessary to determine condition of the existing structure and foundation exposed to both the environmental elements and the overhead line loads. It may be necessary to excavate near the foundation to inspect the below ground condition of the foundation. Such inspection may reveal reduction of capacity of the foundation.

18.5.2.3 Technical or Practical Limitations

Beside the general constraints which are mentioned in Section 18.3.6 there will be for the upgrading of foundations several technical and practical limitations. These limitations may lead to restriction in the working methods, use of equipment, material and tools, and also in the design of upgrading of the foundation. It is possible that the technical and practical limitations make upgrading of the foundation impossible and an entirely new foundation must be chosen. Some examples of the limitations for foundation upgrading are:

Outage Availability
For upgrading foundations heavy equipment will normally be required. In general, the larger the upgrading of foundations, the heavier the equipment will be. Depending on the size of equipment used for upgrading it may be necessary to de-energize the overhead line. When it is not possible to de-energize the overhead line or the outage time is limited then this may require a redesign of the upgrading employing smaller equipment. Accordingly, the time necessary for upgrading a foundation and the associated outage availability is a key design and planning consideration.

Construction of Existing Foundation
There are several types of foundations for overhead lines. The use of any particular category of foundation will depend to a degree on both the support type and the geotechnical conditions present. Typical foundations are spread footing, shaft and anchor and are illustrated in Figures 18.26, 18.27 and 18.28 respectively.

Depending on the type of foundation used for the existing structure the solutions for upgrading may be limited. In some cases, it may be necessary to use different type of foundations to upgrade an existing foundation. For example, a ground anchor foundation illustrated in Figure 18.28 may be used in combination with an existing pad and chimney foundation illustrated in Figure 18.26 as an effective solution.

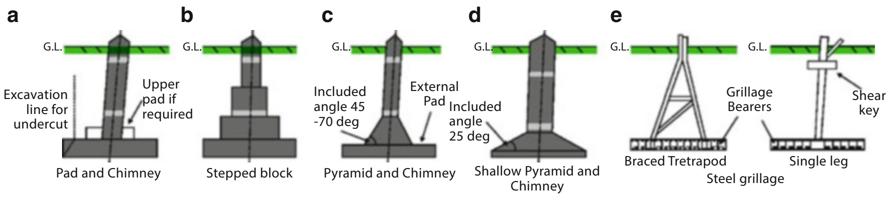
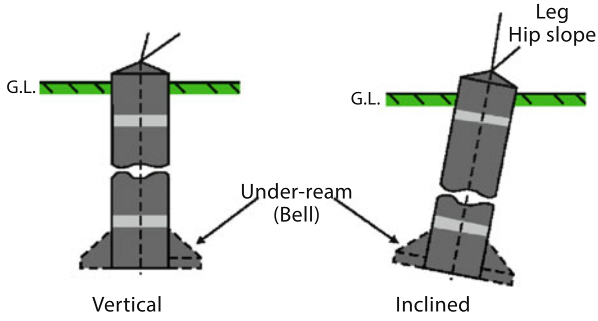


Figure 18.26 Spread Footings Foundations.

Figure 18.27 Shaft Foundations.



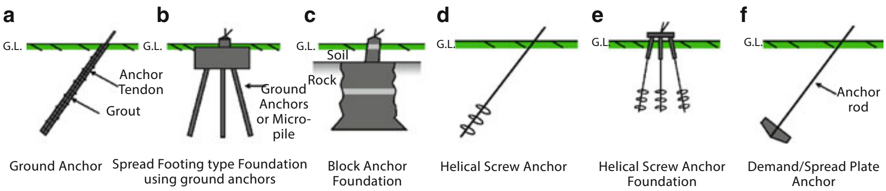


Figure 18.28 Anchor Foundations.

Permission from Land Owners
For privately owned land, upgrading an existing foundation may require the consent of the land owner. It may be a constraint when the upgrading of the foundation could limit the land owner for using the ground near to the structure.

Safety Issues
Working on existing foundations will have an effect on the stability of the structure. This is especially when the upgrading activities may be executed in windy areas or in windy periods and thus the use of temporary constructions may be required. The type of temporary construction may have effect on the outage time and also on the consent of the land owner. The use of temporary construction will have significant effect on the costs of upgrading the foundation.

18.5.3 Insulator Strings

Insulator strings are a key component of an overhead line providing the mechanical connection between conductors and support structures and at the same time electrical insulation between live line parts and earthed parts. They are covered extensively in Chapter 10 of this book. Depending on the environmental conditions, new insulator strings may be expected to be in service for over 40 years.

18.5.3.1 Background

Upgrading of an insulator string is achieved either by increasing the mechanical strength or by improving the electrical insulation performance. The methods of increasing the mechanical strength are limited such as strengthening of the weakest component in the string or multiple strings, the options to improve the electrical performance vary considerably and generally, the major objective is to improve the insulation pollution performance.

A pollution flashover of an overhead line is initiated by deposits of airborne contaminant particles on the line insulators surfaces. Under dry conditions, these deposits are harmless however, when they are wetted by light rain, fog or high humidity events, the salts in the contaminants dissolve, forming a conducting film on the surface of the insulators. This film reduces the leakage distance across the insulator surface and compromises the insulators withstand power frequency voltage capacity. If the withstand capability falls below the designed stress level, a pollution flashover will occur. The contaminant particles may be of natural origin or they may be generated as a result of industrial, agricultural, or construction activities. Overhead line flashovers occur due to a range of containments such as sea salts, road salts, cement dust, fly ash, potash, limestone and gypsum and may arise from a changing environment where the overhead line is located.

Depending on the frequency and the amount of rain, a varying amount of the contaminants could be collected on an insulator before they are cleaned by a natural rain washing event. During the period between the natural washings, if the insulator contamination level reaches the critical value, the moisture, the light rain or high humidity event could cause a flashover event.

A contaminated insulator flashover is more damaging to an overhead line reliability than a lightning or a switching flashover. Generally, an overhead line can be successfully reclosed after a lightning or a switching flashover, but a contaminated insulator flashover is frequently followed by additional flashovers if the atmospheric moisture producing condition persists and may not be able to be re-energized until the pollution is removed from the insulator.

The overhead line pollution performance is a function of the pollution level of the environment which may range from light to very heavy and determines the minimum nominal specific creepage distance for the insulator. The insulator pollution performance is therefore a function of the creepage distance and also the shape of the insulator.

Upgrading a overhead line pollution performance may consist of replacing the insulators with increased creepage distances and or introducing insulators with deep ribs such as a fog shape designs. In some arid countries an aerodynamic flat profile shape has been found to be satisfactory to minimize pollution flashover events. Upgrading of insulator strings is also required in cold climates where freezing rain could cause icicles and salt to form between various insulator units thus bridging the gap and reducing leakage distance.

Other mitigation techniques consist of the application of hyperphobic silicone greases, recurrent insulator washing, the use of semiconducting glazed insulators and or installation of polymeric or composite insulators. Other methods of insulation performance improvement are,

- increasing the arc distance by increasing the number of insulators or the length of insulator;
- increasing the leakage distance by increasing the number of insulators or providing a different shape of insulator; and or
- changing the pollution characteristics of the insulator using different shaped insulators for fog or desert environments or different insulation materials such as non-ceramic materials.

Choosing one or a combination of the mentioned methods depends on the overhead line geometry, progress in new material investigation, expenditures and the service experience of the utility.

18.5.3.2 Verification Consideration

Although new analysis methods and latest investigation applications assist designers to specify all possible loads and stresses on components, experience from in service operation remains one of basic sources of data when considering upgrading of some components. Designers should take into account,

- environmental conditions stated in the original design;
- parameters such as the mechanical and electrical strength of original components;
- operation experience and the records of failures and other events from extreme and or critical loading incidents;
- causes of any future deterioration such as vandalism, birds, industrial pollution, et al;
- availability of alternative designs and material technology from the market;
- traditional solutions for a particular place or country; and
- standard inventory considerations.

Upgrading of insulator strings affects other parts of an overhead line such as structures and conductors, consideration should also include the impact on all line components and the associated condition.

Verification of Parameters

Many utilities have established engineering standards which according to coordination of insulation levels specify parameters of the components of an insulator strings. Such standards assist designers to choose the proper components in accordance with the specified standards.

Mechanical Strength

When crossing any highway, railway or waterway, multiple suspension insulator strings or increased the strength class of the insulator is often used to reduce the probability of failure. In addition, deterioration of certain associated fittings should be considered as part of any upgrading option.

Pollution Performance

Improving the pollution performance of insulation is improving the ability of an insulator to resist contamination in ambient air. In some arid countries an aerodynamic flat profile shape has been found to be satisfactory to minimize pollution flashover events. The mitigation techniques may also consist of the application of hydrophobic silicone greases, recurrent insulator washing or the use of semi conducting glazed and polymeric or synthetic insulators with good hydrophobic properties.

Radio and TV Interference Resistance

Loose, poorly fitting and unearthed hardware can cause radio and TV interference. Minimising the number of connections or the application of hold down weights on lightly loaded insulator strings may decrease possible sources of radio and TV interference.

Verification of Used Insulation Material

Glass and ceramic insulators have a long history of satisfactory experience. The main advantage of glass insulators is that after glass failure the mechanical connection is maintained thus avoiding a dropped conductor. The ceramic insulators are produced from stable ceramic porcelain material and have excellent service performance over many decades. Both types of insulators are easy to add to or replace using live line techniques. Ceramic and glass insulators are both heavy and fragile. The composite insulators are a relatively newer type of insulator and an overhead line upgrading application is growing as the insulators,

- have a low weight strength ratio;
- are less sensitiveness to the mechanical impact;
- have high bending strength and have excellent application in rigid geometries; and
- have exceptional resistance to flashover in contaminated areas due to the hydrophobic characteristics of some composite materials.

18.5.3.3 Technical and Practical Limitations

New types of insulators allow a variety of modifications for upgrading and applications such as V and T strings and coupled with the variety of possible insulation materials such as glass, ceramic or composite allows flexibility to meet different requirements for shape and strength.

Continued development of new composite insulation materials has resulted in limited service experience which hinders an understanding of the materials longer term performance experience. Accelerated laboratory and field tests are necessary for performance and lifetime estimation of these types of insulators.

In addition, demands for minimizing of operation outages are practical limitations that effect planning of upgrading of an overhead line. Live line maintenance technique is one of the solutions for upgrading insulation without taking a line outage.

18.5.4 Upgrading or Improving Electrical Characteristics

The electrical parameters that provide opportunities to upgrade an overhead line are improvements in lightning performance or outage rate; improvements in insulator pollution performance; improvements in Corona, radio & television interference and audible noise; reductions in earth potential rise; reductions in electric and magnetic field (EMF) levels and reductions in induction in adjacent long parallel metallic infrastructure such as pipelines and or metallic telecommunications. These upgrading strategies are discussed in detail in the following Sections.

Reducing the levels of EMF of an overhead line may not be considered as upgrading the electrical characteristics of the line as the outcomes do not reduce the probability of failure. However these changes will reduce the environmental impact of an overhead line. Notwithstanding this, the opportunity will be taken to briefly discuss in the following Section strategies to reduce EMF.

18.5.4.1 Lightning Performance

The determination of the lightning performance of an overhead line requires a mathematical study based on probability involving nonlinear complex electromagnetic behaviour of the interactions of the lightning, conductors, insulators, the structure and the earthing. Minimizing the probability of outages due to lightning is a critical aspect of overhead line design and is normally undertaken at the conceptual stage so the structure configuration, insulation levels and earthing may be coordinated to achieve the desired level of lightning protection. The major factors that affect the lightning performance of an overhead line are,

- the keraunic level or ground flash density;
- the stroke current magnitude and wave shape;
- the structure height;
- the presence of an overhead earth or shielding wires and the associated geometry of the overhead earthwire relative to the phase conductors;
- the conductor phase to structure clearance;
- the midspan clearance between conductors and overhead earthwires;
- the insulator arcing distance;
- whether the structure is conductive or non-conductive and for nonconductive structures such as wood whether the fittings and crossarms are bonded and or earthed or unearthed; and
- for earthed structures the structure earth resistance.

With the exception of the intrinsic keraunic level, stroke current magnitude and wave shape, upgrading the lightning performance of an overhead line may be achieved by modifying one or a number of the mentioned factors. Opportunities to improve the lightning performance of overhead line will focus on the three principal lightning flashover mechanisms as follows:

- insulator and or structure flashover for overhead lines without overhead earthwires;
- shielding failures for overhead lines with overhead earthwires; and
- back flashovers.

Firstly, insulator and or conductor to structure flashover arises from either a direct lightning strike on the conductor and or for lines generally above 275 kV switching transient over voltage flashovers. In either case, the transient over voltage performance of an overhead line may be improved by installing insulators with longer insulator arcing distance and or increasing the conductor to structure clearance. In most cases, the original conceptual design of conductor, structure, insulator geometry has been optimized and any transient voltage upgrading opportunities for overhead lines without overhead earthwires will most likely require a complete reconfiguration of the insulator and crossarm arrangement as additional clearances are not likely to be practicable or possible. In some cases, it may be effective to add additional weight at the bottom of the insulator I strings to reduce insulator swing and increase conductor to structure clearances. For overhead lines without overhead earthwires, improvements in transient voltage performance for at least lightning strikes may be achieved by improving the shielding of the conductors by the installation of overhead earthwires or the installation of surge diverters. This will be discussed in detail later. In the meantime, a typical suspension insulator string illustrating, maintenance approach distance, lightning withstand clearance and power frequency clearance is shown in Figure 18.29.

Secondly, a common outage cause for overhead lines with overhead earthwires is a lightning shielding failure where the lightning strikes the conductor directly without being intercepted by the overhead earthwires. Typical shielding arrangements with single and double earthwires are illustrated in Figure 18.30. For overhead lines with existing overheads earthwires the lightning performance will be improved by reducing the shielding angle. This would normally be achieved by redesigning the overhead earthwire and conductor geometry and this may include changing the structural attachment point of the conductor or earthwire or changing the insulator design. Differing shielding angles by differing overhead earthwire attachments resulting in superior lightning performance are illustrated in Figure 18.31.

Similarly, installation of overhead earthwires for overhead lines without overhead earthwires, will result in a significantly improved lightning performance. The number of overhead earthwires is a function of the required outage performance and the available marginal structural capacity. Double circuit overhead lines and overhead lines with flat conductor configuration without overhead earthwires will

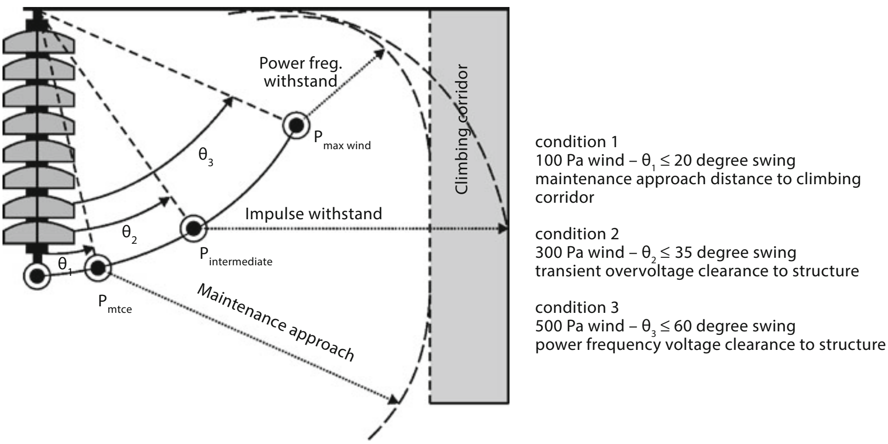


Figure 18.29 Examples of Swing Conditions for Clearance and Wind Criteria.

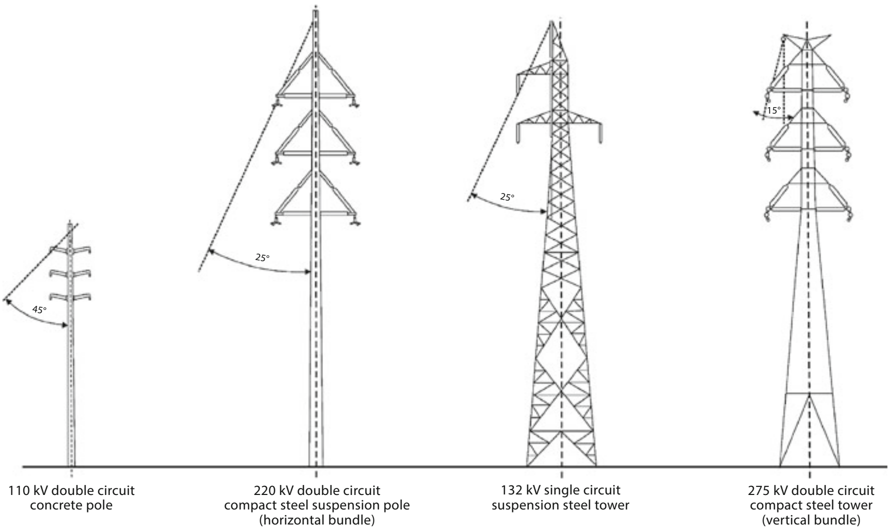
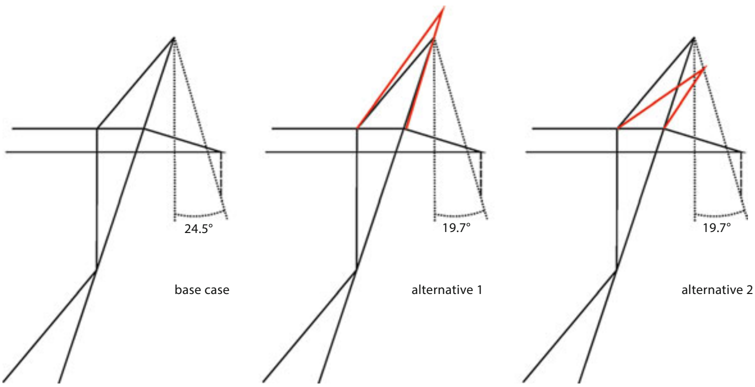


Figure 18.30 Typical Shielding Arrangements for Single and Double Earthwires.



alternative	shielding angle	outages/100 miles/year shielding failure	backflash	total
base case	24.3	0.03	0.54	0.57
1	19.7	0	0.58	0.58
2	19.7	0	0.53	0.53

Figure 18.31 Typical Shielding Failure Rates for Varying Shielding Angles (Cigré TB 353 2008).

in general require the installation of two earthwires to achieve a satisfactory outage performance. The installation of one or two overhead earthwires to reduce shielding failures will contribute additional wind structural loads to suspension, tension and termination structure and additional tension loads to tension and or termination structures. In this regard, structures may require substantial modification and structural capacity assessments to accommodate the additional overhead earthwires. Additional foundation loads is also a fundamental consideration.

It is also important to mention that any changes in clearances may eliminate opportunities to carry out live line maintenance.

The installation of surge diverters for overhead lines with or without overhead earthwires is also an effective technical mechanism to improve transient over voltage performance and is used widely in some countries. The installation of diverters for some overhead lines with optimized design may provide the only option to improve transient over voltage performance. This may also be the only viable solution for overhead lines with an unacceptable level of switching transient over voltage flashovers. The outage rate of the overhead line is a function of the number of diverters installed per kilometre and the earthing resistance of the diverter. For example a 66 kV overhead line without overhead earthwire, a structure earthing resistance of 5 ohms with an expected 35 strikes per 100 km.year^{-1} and diverter installed with a separation of 200 m would result in an outage rate of 0.15 per 100 km.year^{-1}. Increasing the diverter separation to 500 m would result in an outage rate of 4.9 per 100 km.year^{-1}. Clearly this example illustrates that diverters are novel technical solution to improve the over voltage performance of an overhead line, nevertheless the overall effectiveness of the solution would be the subject of a cost benefit analysis.

The final mechanism discussed is the back flashover and is the predominant cause of lightning induced flashovers on overhead lines. The sequence of a back flashover event leading to an insulation failure is,

- a lightning strikes an earthwire at or near a structure;
- current flows in the overhead earthwire(s) towards the structures either side of the lightning strike;
- the current flows down one or more structures;
- the current in the overhead earthwire induces voltages in the phase conductors;
- the current which flows down the structures is reflected at the earth;
- the reflected current establishes a voltage on the structure;
- the current which flows to the other structures via the earthwire is reflected at each structure and earth;
- when the voltage across any part of the overhead line insulation exceeds its electrical insulation strength, there will be a back flash-over from structure to the conductor; and
- often there will be a number of simultaneous back flashover failures.

Reduction of the incidence of back flashover is achieved by one or all of the following strategies,

- increasing the insulator arcing distance and or increasing the conductor to structure clearance thereby reducing the probability of back flashover;
- reducing the structure earth resistance as illustrated in Figure 18.32 thus reducing the structure voltage to earth and the voltage across the insulators and reducing the probability of back flashover; and

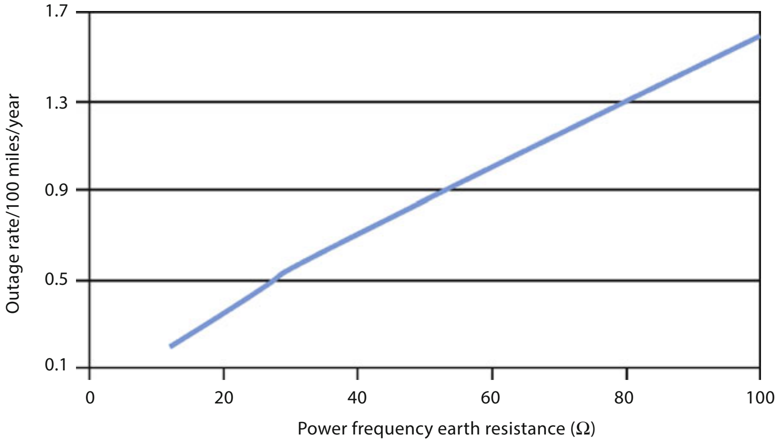


Figure 18.32 Typical Outage Rate as a Function of Structure Earth Resistance.

- reducing the conductor earthwire separation which improves the coupling and increases the conductor voltage relative to the earth thereby reducing the voltage across the insulators and the probability of back flashover.

The most common and generally the most cost effective strategy is reducing the structure earth resistance.

18.5.4.2 Corona, Radio & Television Interference and Audio Noise Mitigation

In general, for overhead lines above 200 kV, Corona discharges form at the surface of conductor and or hardware when the electric field intensity on the surface exceeds the breakdown strength of air and the air ionizes. Corona results in electrical losses which are proportional to the length of the overhead line. Several conditions control the breakdown strength, the air pressure, the electrode material, incident photo-ionizations and the type of voltage.

The presence of small protrusions such as water droplets, snowflakes, contamination or protrusions or sharp points on the insulator and or hardware surfaces may produce elevated electric fields and thus air ionization. The ionization of air generates light, audible noise, radio noise and in some extreme cases conductor vibration.

Minimizing the likelihood of Corona is a critical aspect of overhead line design and is normally undertaken at the conceptual stage in the selection of conductors, the bundled diameter and configuration for multi-phase conductors and the insulators fittings such as grading rings.

Corona activity may result in radio and television interference. The primary concern for interference is for amplitude modulated signals. Frequency modulated and television broadcasting signals are much less affected by Corona.

Audible noise arises from Corona discharges and consists of humming, crackling, frying or hissing characteristics. The intensity of the Corona noise is influenced by the weather conditions and the noise increases during periods of rain, snow and fog. The noise level is inversely proportional to the square of the separation distance and as one moves away from the overhead line then the level of noise reduces significantly.

Cigré TB 147 (1999) indicates that from surveys carried out that Corona noise is not a major problem for existing overhead lines. Nevertheless opportunities to upgrade the performance of the overhead line may arise as Corona may occur on contaminated insulators, or as a result of looseness or protrusions in hardware, or on imperfect or damaged conductor surfaces or from inappropriate insulator fitting designs and grading rings.

18.5.4.3 Reductions in Structure Earth Potential Rise

Most higher voltage overhead lines are normally earthed at every structure location to provide a local low impedance circuit to the body earth for transient earth fault currents. Low impedance earthing is necessary to minimize the possibility of elevated touch and step voltages in the vicinity of the structure in the event of an earth fault. High touch and step voltages may result in unsafe structure voltage and a risk of electric shock and the possibility of electrocution. The structure earth potential arises from a fault current flowing to earth via the structure and hence the magnitude of the potential rise is a function of the fault current and the structure earth resistance.

Low impedance earthing also minimizes the risk of structure voltage rises exceeding the flash-over voltage of an insulator string causing and indirect lightning strike outage or back flash over as mentioned in Section 18.5.4.1.

Allowable step touch potentials are generally defined in various jurisdictions through standards, regulation and or codes and one such example is IEC 60479. IEC 60479 defines the physiological effects of body current as a function of duration of current flow.

The design of the overhead line earthing system will depend on the structure earth resistance criteria and will vary with the soil resistivity along the route of the line. Two methods are commonly used to achieve an effective earthing system for an overhead line, the provision of a continuous earthwire and the placement of locally buried structure earth electrodes having a low earth resistance. The earthwire provides an alternative return current path to the source reducing the magnitude structure earth fault current and hence the structure earth potential rise. Typical earth fault structure current paths are illustrated in Figure 18.33.

Upgrading to reduce structure potential rise may consist of installing additional structure earthing, installing buried grading rings at step locations to reduce step touch potential, installing larger overhead earthwires to reduce the current flowing in the structure, the application of insulating paints and or epoxies to structure touch locations and or the installation of high speed protection schemes to reduce electric shock duration.

There are basically three types of methods to upgrade structure earthing and are counterpoise, metal cladding and deep drilling. All the methods use either a galvanized steel or copper rod that is placed in a hole at various depths in the ground and lengths from the structure leg and each method will be discussed in more detail.

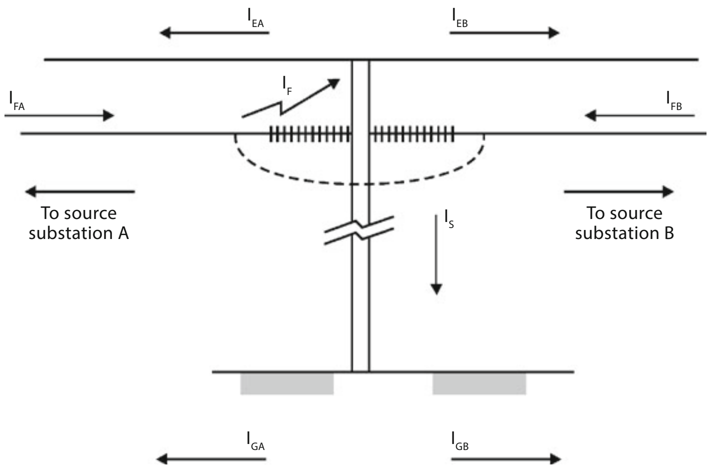


Figure 18.33 Typical Overhead Line Earth Fault Structure Current Paths (Cigré TB 353 2008).

The aim of implementing structure footing improvements is to achieve a low resistance connection between the structure and an earth. The soil type and resistivity are basic determining factors and influence which method of earthing is economical and technically feasible. Counterpoise and metal clad methods can only be applied in normal ground soil conditions and the deep drilling is normally applied in rocky terrain. In areas where there is basically only rock alternative methods like line surge diverters may be considered as the only feasible option to improve lightning performance of the line.

Counterpoise is the method that is mostly used for the earthing of structures. The method consists of a metal strap or copper rods that is connected to the structure leg at the bottom and is buried in the ground in a trench at an average depth of 0.5 m. It is buried normally at an angle of 45^0 and the distance is dependent on the soil resistivity and the required structure earthing.

Metal clad earthing consists of either copper rods or galvanized steel rods connected to the structure at the structure leg foundation interface. The rods are buried in a trench of about 0.5 metres and are then horizontally buried for about 7 meters long before it is buried in vertical holes.

In some circumstances soil resistivity is very high requiring special techniques such as deep drilling. Deep drilling method is the placing of copper or steel rods in a hole bored and varies in depth depending on the soil type and resistivity.

18.5.4.4 Reductions in Electric and Magnetic Field Levels

Electric and magnetic fields (EMF) from overhead lines and concerns over suggested health effects has emerged as a major public policy issue for utilities worldwide. Cigré has considered the subject and the associated debate and published in Cigré TB 147 (1999).

The strength of the EMF depends on both line voltage, line current and on the conductor geometrical parameters. The electric field decreases rapidly with lateral distance from the line and is further reduced by grounded objects like trees, lamp posts, buildings and other structures. The magnetic field also decreases rapidly with lateral distance from the line. Minimizing the EMF is a critical aspect of overhead line design and is normally undertaken at the conceptual stage in the selection of overhead line phase conductor geometry. For existing overhead lines existing conductor and structure geometry presents major technical constraints to retrospectively modifying the design to reduce the EMF.

Nevertheless, increasing the line height and or using a triangular phase configuration are the most effective ways of reducing the maximum electric fields at ground level. Opportunities to minimize magnetic fields also include phase reversal for double circuit overhead lines, screening conductors and employing split phasing. In some cases, the right of way width may be increased to allow lower EMF at the edge of the right of way.

18.5.4.5 Induction Mitigation

As human habitation development continues particularly in urban fringe areas and restrictions are placed on the flexibility to select linear routes for infrastructure, the likelihood and community pressure for cohabitation of linear assets will increase. As a result, it has become common for overhead lines, pipelines, conveyors, rail traction systems and metallic telecommunication networks to coexist in infrastructure corridors.

There are three electromagnetic interference mechanisms between an overhead line and coexisting long conductive infrastructure and are inductive, conductive and capacitive coupling. The induced voltage due to inductive and conductive coupling is directly proportional to the overhead line current. The induced voltage due to capacitive coupling is proportional to the operating voltage of the overhead line. The level of induced voltages is influenced by the overhead line and other infrastructure separation distance and the parallel length. Other factors include:

- earthing of the parallel infrastructure and the overhead line;
- soil resistivity;
- conductivity of the parallel infrastructure;
- cathodic protection equipment install on the parallel infrastructure;
- presence of shielding of the parallel infrastructure
- presence of isolating joints in the parallel infrastructure;
- level of insulation on the parallel infrastructure.

The opportunities for the implementation of mitigation strategies on existing overhead lines are limited. Some options to be considered are magnetic field shielding, relocation of structure earthing as the structure earthing should be separated from the adjacent infrastructure as far as practical, minimizing earth currents by introducing conductor transpositions and or the isolation of shielding earth wires and finally the reconfiguration of the overhead line phase conductor geometry.

18.6 Highlights

Uprating and upgrading overhead lines is a very complex planning, technical and economical process. There are many economic considerations and many technical options and the planning and implementation of overhead line uprating and or upgrading may involve considerable amount of time to formulate an appropriate cost and technically effective solution.

The Chapter describes in some detail the range of economic considerations coupled with an extensive range of uprating and upgrading options. Most importantly the Chapter highlights various design options and associated verification considerations to provide guidance on practical solutions to uprating and upgrading overhead.

18.7 Outlook

From about the early 90's and onwards many countries with major electrical infrastructure were frequently confronted with four coinciding critical issues, much of this infrastructure was constructed in the 50's and 60's, which results in the age of the assets being over 50 years; the design life of much of the infrastructure was in many cases about 50 years and has matured beyond the engineering serviceability and or economic life and required some form of life extension; the need to increase capacity of the existing infrastructure places extraordinary demands on utilities to establish strategies to uprate the existing infrastructure; and the approvals for the construction of new overhead lines are often difficult to obtain and in many cases result in critical delays to meet network capacity needs.

Since about 2000, further consideration of renewal energy is also having a significant influence of network design and capacity needs. Some planning forecasts projected to 2050 even suggest energy storage will be economical for domestic energy consumers and "leaving the Grid" may be a viable option.

Accordingly, given the considerable uncertainty about "future network design and topography," coupled with the cost of newly constructed overhead lines and the associated environmental impediments, is anticipated that there will be further and increased emphasis on increasing the utilisation of existing electrical infrastructure and this will included overhead lines. And thus upgrading and uprating of overhead lines will continue to be one of the major planning options considered.

The future will also see further development in insulation properties and conductor materials and construction techniques which will enhance the range of uprating and upgrading options currently available.

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Gary Brennan ME(Hons) BE(Hons) Grad Dip Mgt, FIE Aust, MIEEE, Chartered Professional Engineer and has worked in the electrical supply industry for over 40 years including 20 years in overhead line planning, environmental assessment, optimization, design, construction, maintenance & operation. Experience ranges from 500 to 11 kV lines & includes lattice steel towers, concrete & wood poles. ME was by thesis on "Methodology for the Assessment of the Serviceability of Aged Transmission Line Conductors" 1989. Cigré Australian Panel Convenor & Cigré Australian member Study Committee B2 Overhead Lines 2000–2008. Cigré TF leader WG 13.1 "Guidelines for increased utilization of existing overhead transmission lines." Received Cigré Technical Committee Award in 2008 & Australian National Committee of Cigré Award of Merit in 2009. Committed to continuing education of young engineers.

Zibby Kieloch has MSc in Civil Engineering from Warsaw University of Technology. He has been designing overhead transmission lines at voltages up to 500 kV at Manitoba Hydro, Canada for over 25 years. Most recently, he is responsible for one of the largest HVdc projects in North America – Bipole III Transmission Line Project. He has been a Cigré member and the Canadian Representative on the Study Committee B2 since 2005, making contributions to a number of Working Groups. Since 2012, he has been the Convenor of the SC B2 Customer Advisory Group. He is also an active member of the Canadian Standards Association technical committees responsible for overhead line design and conductor design standards.

Jan Lundquist received his MSc in Electrical Engineering from Chalmers University of Technology, Göteborg, Sweden, in 1976. From 1976 to 1978, he was with the Swedish State Power Board in a system planning department. In 1978, he joined the Dept. of High Voltage Engineering at Chalmers University of Technology for post-graduate studies and research work in the field of AC transmission line Corona effects, receiving his PhD in 1986. From 1986 to 1999 he was with ABB Switchgear, working on development and application of metal-oxide surge arresters and compact switchgear modules. Since 1999 he has been with STRI, working on insulation coordination, Corona effects, substation reliability and software development. He has been the convener of Cigré WG B2.41 on AC to DC conversion of transmission lines.

Overhead Lines and Underground Cables

19

Herbert Lugschitz

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H. Lugschitz (✉)
Vienna, Austria
e-mail: Herbert.Lugschitz@apg.at

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19.1 Introduction

19.1.1 Background

This chapter deals with cables on land, exceeding 220 kV, both AC and DC. The scope is to give an overview and comparison between Overhead Lines (OHL) and Underground Cables (UGC) regarding technique, costs, lifetime and others.

The objective is also to provide a sound technical base for discussions, to show the newest developments and outlooks for both technologies. It is not the objective to give a technical course on OHL or UGC – such information can be found in other chapters of this green book or the green book from SC B1 or in the papers mentioned in the references at the end of the chapter. OHL are the oldest and most commonly used transmission method worldwide to transport bulk electrical energy over big distances on land. Extra high voltage lines may exceed a length of 1000 km for the transport of several 1000 MW per circuit in AC or DC. Subsea cables cross distances up to 600 km so far with capacities near 1000 MW per circuit.

At present the percentage of UGC on land is rather small. Cigré TB 338 "Statistics of AC underground cables in Power networks" gives information in Table A5 about the installed lengths of AC underground cables and overhead lines and the percentage of total circuit length which is underground at 315–500 kV. Information was received from 28 countries worldwide, showing a percentage of approximately 0.5 % UGC (2007) at this voltage levels. Table A6 of Cigré TB 338 which gives the values for voltages 501–764 kV shows that no UGC exist (2007).

The European 400 kV-grid of entso-e has currently approximately 1.3 % of cables (on land and subsea). Of this 400 kV- cables on land contribute to approximately 0.3 % to the grid of entso-e (mainly in cities).

In future the big majority of new lines will be built overhead. The Ten Years Network Development Plan "TYNDP" 2014 of entso-e estimates the development for the next ten years and amounts to approximately 48.000 km of new or upgraded lines. The following text is an excerpt from the TYNDP 2014.

AC – with about 21.000 km of new lines planned – is expected to remain the prominent technology. Around 10% of the investments actually consist of upgrades or refurbishments of existing AC assets. Most new overhead lines planned will be built using AC technology, which is still the easiest to implement for inland applications. Partial undergrounding of sensitive areas will increasingly complement overhead lines.

However, DC is now heavily utilised, with about 20.000 km of new HVDC lines in the Plan, i.e. more than 40% of the total additional infrastructure. The main drivers for the HVDC choice are:

- *The connection of some offshore RES, especially in the North Sea area (but most offshore connections still being AC);*
- *The integration of the Iberian peninsula, Italy, the Baltic States, Ireland and the UK with mainland Europe in line with the IEM;*
- *The need to bring power generated far from the consumption to cities and industrialised areas (e.g. wind in Scotland, wind in the north of Germany leading to the setting up of German corridors, etc.).*

The expected growth of new cables almost corresponds to the development of the new HVDC projects included in the TYNDP 2014. More than 75% of the total amount of HVDC lines will be built using cables. Submarine cables will represent the greatest length planned, although almost 5.000 km of HVDC projects are planned onshore.

Submarine HVDC cables in the North Sea build an offshore grid, even though they are point to point or in a few cases three-terminal devices.

A significant number of kilometres of HVDC overhead lines has been planned as well.

The question “Overhead or Underground?” is posed frequently in public discussion, from landowners, politicians and other stakeholders. Both have their advantages and disadvantages and have their typical fields of application. High voltage grids are complex systems. Many aspects must be observed during their construction and service and simple answers to this question are not possible. Each project must be seen on a case by case basis.

To overcome these uncertainties and to give reliable facts the European Commissioner for Energy in 2009 asked “entso-e” representing the European Transmission System Operators and “Europacable” representing the leading XLPE EHV cable systems manufacturers in Europe to produce a paper on the possibilities of partial undergrounding with synthetic insulated (XLPE) HV UGC. These two parties published the “joint paper” in 2011. “*The objective of the joint paper is to provide an authoritative source of information for future transmission projects, which shall be made available to any interested party.*”

19.1.2 Technical Basics and Differences Between OHL and UGC

Electrical conductors must be insulated from the earth potential and against themselves. One main difference between OHL and UGC lies in the kind of insulation used.

- OHL use air for insulation
- UGC use solid materials for insulation.

Air is an easy insulating material for OHL. In order to insulate a UGC high quality insulating material is needed. This can be a special paper over the conductor and impregnated with insulating liquid (for 400 kV used until the late 1990s, often called “oil filled cables”) or synthetic material (XLPE, most used method for new cables) (Figure 19.1).

The kind of insulation used determines the necessary geometrical dimensions of the power circuit. Due to the insulating material used with UGC the electrical phases can be laid closer to each other, than it is possible on overhead towers with air as insulation. UGC are delivered to site on cable drums which are typically 600–1000 m.- a 20 km circuit may be made up of 60 to 90 drums (for three phases). Under favourite situations the length per drum may exceed 100 m.

These single cable lengths are limited by the transport possibilities (dimensions and weight of the drums). The single lengths have to be jointed on site which is a process that needs great care.

There are many methods to lay UGC. Common laying methods are directly buried in trenches in soil, in tunnels or in ducts (Figure 19.2).

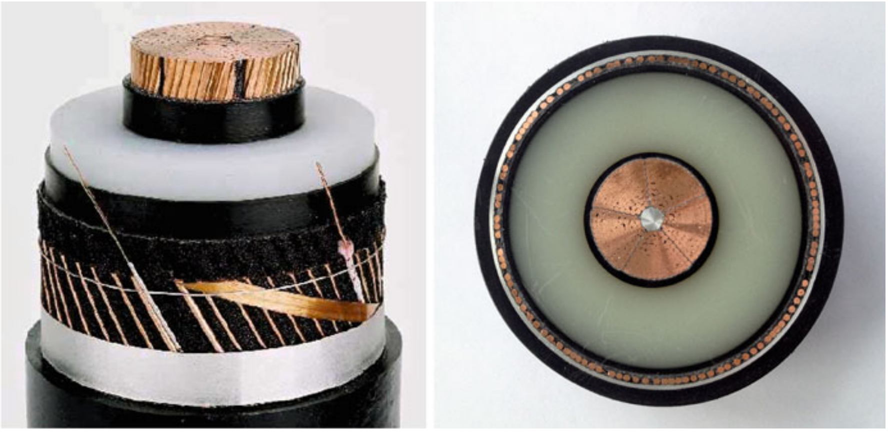

Figure 19.1 Cross linked XLPE-cables with copper conductors. *Left* from Cigré TB 247, page 17; *Right* 400 kV cable with copper conductor 1200 mm^2, 600 MVA without and 1050 MVA with forced cooling.

Figure 19.2 *Left* – one cable system direct buried in soil (from Cigré TB 338, page D.2); *Right* - two XLPE 400 kV cable systems in a ventilated tunnel, 2 × 1100 MVA, special application in cities (Berlin, picture APG).

Figure 19.3 shows a typical 400 kV AC double circuit transmission tower. If such an OHL with high ampacity is to be undergrounded, twelve UGC become necessary to replace this OHL (see Figure 19.4).

19.2 Advantages and Disadvantages of both Techniques

UGC have their specific field of application. They are normally installed when OHL are not possible or for other specific reasons. Typical examples are lines in the vicinity of airports, in densely populated areas of cities, large river crossings, or in protected areas.

Partial undergrounding of an OHL can be a part of the solution.

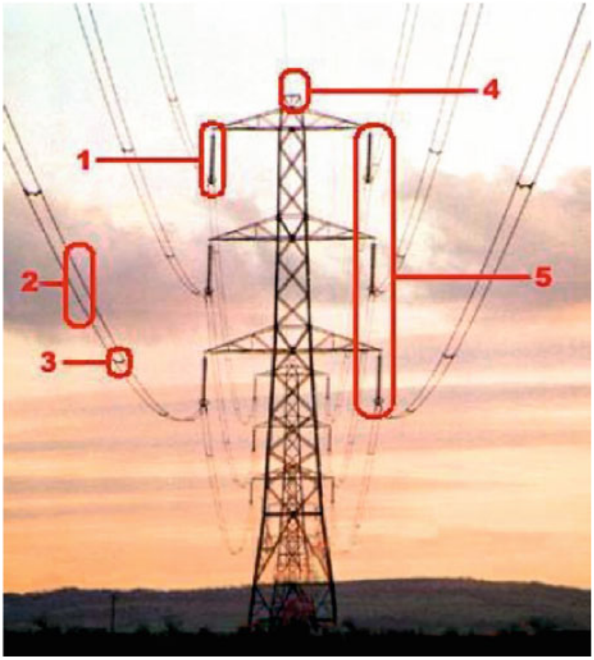

Figure 19.3 Lattice steel tower with two 400 kV electrical circuits (5), Figure 3.1 from Cigré publication 338. *Remark: typical thermal capacity with 2 sub-conductors aluminium 800 mm2 app. 2× 1500 MVA, with 3 sub-conductors app 2×2250MVA*. (*1*) Insulator. (*2*) Phase conductor low-power lines often have a single conductor; higher power lines may use multiple sub-conductors. (*3*) Spacer to hold the two sub-conductors apart. (*4*) Earth to hold of the tower or pylon. (*5*) The three phase conductors on one side of the tower make up one electrical circuit. Most lines have two circuits, one on each side.

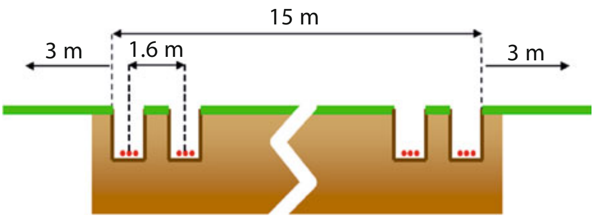

Figure 19.4 Trench cross-section for two 400 kV AC circuits, two "double cables" = 12 conductors (Figure 3.14 from Cigré TB 338) (possible laying arrangement). *Remark: capacity with copper conductors 2500 mm2 app. 2×2200 MVA*.

19.2.1 Costs

Costs are an important and sensitive aspect of a project. A distinction must be made between investment costs which cover the investment only and full costs (lifetime costs) which consider investments plus expenses over the envisaged lifetime of the line -such as maintenance, losses, new investments at the end of the lifetime, inflation, etc. It is important to note that a comparison of costs between OHL and UGC must be done under similar headings (e.g. ampacity, lifetime, availability, the same route length, repair time and cost, etc.

Cigré TB 338 "Statistics of AC underground cables in Power networks" is focussing this problem when it says: "*Cost ratios are often thought of a simple way of comparing costs, for example saying an underground cable is 10 times as expensive as overhead line. In reality there can be a wide range of values quoted for apparently similar circuits and this leads to confusion and mistrust between the various stakeholders*"………"*The only reliable method of comparing overhead and underground costs is on a case by case basis. Generic values of cost ratio are of very limited use and should be avoided. Estimates for the costs of underground and overhead options for a specific project must be calculated and then weighed against the advantages and disadvantages of each option.*"

The "joint paper" from entso-e and Europacable speaks about the following ratios of costs having this approach in mind*: "On 400 kV XLPE projects buried in soil and completed in Europe over the past 10 years the range of* ***investment cost*** *has been generally between 5 and 10 times compared to an overhead line. These cost ratios are directly related to the capacity of the link. Factors down to 3 can be reached for links with limited rating and under special favourable conditions for cable laying or in cases of expensive OHL. Factors above 10 can be reached for high capacity double circuit links and if specific structures are needed like projects involving the construction of cable tunnels (factors above 15 are expected in these cases) due to the cost for civil works. Higher ratios are also observed when compared to OHL consisting of guyed towers*.

For full costs the "joint paper states: "*When* ***lifetime costs*** *and other costs are taken into consideration, cost factor compared to overhead lines (based on self supporting tower structures) can vary between 3 and 10 times for direct burying. Where partial undergrounding is considered, the above multiples apply only to the undergrounded part of the link. This factor needs to be verified against the specific requirements of the project taking also into account the costs of the transition stations and compensation equipment, if required.*"

Recent projects and studies in several countries confirm these factors in principle.

For long AC UGC the additional costs and locations of reactors must also be considered.

In case of a DC line the converter stations at each end of the line add costs to both – OHL and UGC – and may shift the ratio.

19.2.2 Reliability and Repair Time

Cigré has issued TB 379 "*Update of Service Experience of HV Underground Cable Systems*". The paper reports failures in the years 2000–2005. It seems outdated as since 2005 several UGC on 400 kV level have been installed. Nevertheless, no more comprehensive and up to date data has been published in the meantime. Outage times less than 1 day and longer than 6 months were not considered in the survey. In any case, the paper states that the failure rate of OHL and UGC on land is approximately the same (a little higher for OHL), but the repair time for OHL is less - on average 8 hours per fault and is higher for UGC with 600 hours repair time per fault. All these statistics have the problem of small quantities of 400 kV UGC on land compared with the large number of 400 kV OHL.

Another aspect is how important the circuit is for the supply of energy. It is therefore essential to consider the destination of the circuit in question and how the line is embedded in the grid. In other words: is the line a city-feeder, a line from a power station, a distribution or a transmission line, in a meshed grid (many connections between the lines) or not. Depending on these aspects the question of reliability and repair time may or may not be essential. It is important again to consider on a case-by-case-basis and not to generalise.

19.2.3 Lifetime

The cable industry estimates the lifetime of 400 kV XLPE cables to be about 40 years, based on tests in laboratories (the first 400 kV XLPE cable in Europa was installed 1996 in Copenhagen/DK). The replacement of a cable in a tunnel or duct is easier and cheaper compared to directly buried.

OHL have a lifetime of 80–120 years, if well maintained, though some components may need to be replaced (e.g. conductors and fittings after 40–60 years, corrosion protection 25–35 years). In addition, OHL are more accessible for maintenance work or in case of faults, emergency restoration structures can be used.

19.3 Operational Aspects

Due to the different components, electric characteristics and structure of an UGC line compared to an OHL, differences exist for their operation.

UGC produce reactive current. When exceeding a certain length of UGC, compensation measures become necessary to reduce this reactive current. Otherwise the ampacity of the line would be reduced. This is done by reactors. The order of switching must be kept according to a given concept (e.g. which substation and which reactor first, etc.).

The protection of an OHL allows automatic re-closure which results in fault clearance in most of the cases. A mixed line (OHL with partial UGC) needs a reliable protection concept which allows to be distinguished between failures in the OHL section and in the UGC section. Depending on this, automatic reclosure is possible or not.

The different impedances of OHL and UGC can lead to load shifting in the grid depending on the actual load.

Modern UGC use optical fibres either in the sheath of the cable or in separate ducts. They can indicate the temperature distribution along the route and can assist the load dispatcher in his decisions.

19.4 New Techniques (Superconducting Cables, Gas Insulated Lines "GIL", High Temperature Conductors for OHL, AC to DC, New Tower Design, DC with VCS)

19.4.1 UGC: Superconducting Cables

Superconducting cables use the effect, that special materials have a very low electrical resistance below a certain temperature, which is typically below minus 170 °C for so called "high temperature superconductors". This allows the transport of electricity with reduced losses. The conductors must be permanently cooled down to this low temperature.

Demonstration projects of such systems have been running for many years in several countries all over the world. The first applications in grids are in service now. The results of these experiences are awaited with much interest (Figure 19.5).

Typical applications will be to upgrade existing urban grids in places with limited space requirements over some hundred meters. A promising 10 kV superconductivity cable project is installed in Germany with approximately 1 km route length (2014). Presently such cables are not foreseen for long distances nor very high voltages (from Cigré TB 538: highest voltage so far 138 kV installed in Long Island USA over 600 m).

Figure 19.5 Example of superconductor cables; *Left* - single core cable, *Middle* - three core cable, *Right* - triaxial cable; (Pictures from Cigré TB 538).

19.4.2 Gas Insulated Line "GIL"

GIL use SF6 gas for insulation. Each phase conductor is made of an aluminium tube, fixed in a larger outer aluminium tube with app. 0.6 m diameter (for 400 kV). Typical transport lengths of the tubes are 12–15 m. GIL have a similar electrical behaviour as OHL (e.g. operation, ampacity, capacitive load).

Costs of GIL are by factors higher than for OHL, but can be an economic alternative to UGC in cases where double cables would become necessary.

Modern GIL of the "2nd generation" use a mixture of SF_6 and N_2 instead of pure SF_6 and their elements are welded. Experiences with GIL exist from the 1970ies.

Present typical GIL are used in power stations, substations and power plants over some hundred meters route length. GIL for partial undergrounding of OHL exists in Geneva/CH for 220 kV, Frankfurt-Kelsterbach/DE (with app 1000 m the longest GIL as partial undergrounding, 2×1800MVA) and Munich/DE, both 400 kV. GIL are mostly built in tunnels or overhead, seldom directly embedded in soil (Figures 19.6 and 19.7).

19.4.3 OHL: High Temperature Conductors

High temperature conductors are made of special alloys and can be used at temperatures of up to 210 °C. Such conductors can carry more electric current than standard conductors with an allowable temperature of 80-90 °C. These materials limit the sag and conductor pull to prevent resp. minimize adaptions of towers including replacements by higher towers. Such high temperature conductors are used for reconductoring as well, as for new lines (Figure 19.8).

19.4.4 OHL: Conversion AC to DC

The conversion of an existing AC overhead line to DC can increase the ampacity. The big advantage is in general the better control of the grid with a DC line. The

Figure 19.6 220kV GIL in Geneva/CH, energized in 2001, two electric systems in a tunnel, welded GIL of "2nd generation", 2×760MVA (Picture APG).

Figure 19.7 400kV GIL in Saudi Arabia, 780 MVA per system, installation above ground, connection of a power plant with the GIS (Cigré TB 218).

Figure 19.8 Different types of High Temperature Conductors (from left: 3 M, CTC, Lumpi-Berndorf).

efforts for adaptions on the line, including the new built AC/DC- and DC/AC-converter stations at the ends of the connection must be counterbalanced with the advantages gained. In general DC lines are used to transport large quantities of energy over long distances (typically exceeding 600 km). For shorter lengths AC lines are usually more economic.

A pilot-project with a so called "hybrid line" (one circuit at an existing OHL changed to DC, the other one remaining AC) is planned in Germany to check technical possibilities and electrical influences (Figure 19.9).

19.4.5 OHL: New Tower Design

Over the decades of OHL industry typical standard tower configurations have been developed, which are optimized in terms of material, transportation, erection, maintenance, costs, lifetime and appearance. Many utilities started considerations for a new tower design to get or to increase the acceptance for new OHL. Several towers

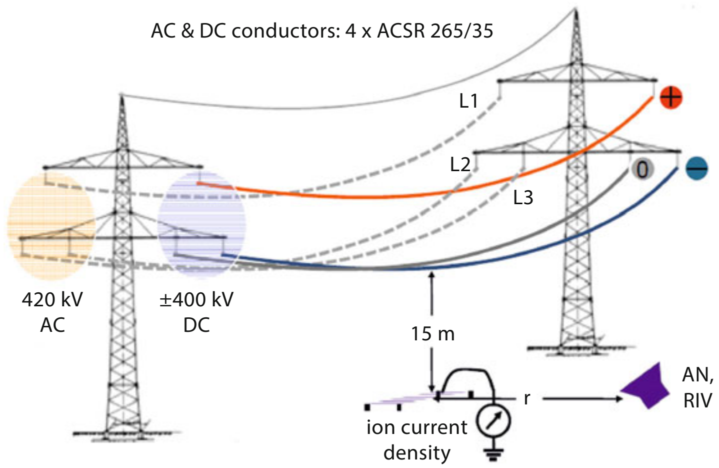

Figure 19.9 Line configuration for AC-DC conversion, one system AC, the other one DC (Source: B2 Session 2013 Auckland, Symposium papers 141, 142).

in alternative design are known from countries all over the world. Most of them are single solutions, some even have the function as eye-catchers. The Cigré TB 416 shows examples (Figure 19.10).

Only a few new designs are suitable as new standard configurations. One of them is built in The Netherlands, where this "wintrack tower" will be erected more frequently in the future (Figure 19.11).

19.4.6 UGC: DC with Voltage Source Converters

The technology DC with VSC is actually used on applications for connections of offshore wind resources. VSC is used for the underground connection between France and Spain with XLPE DC cables. It has financial advantages compared with traditional UGC lines in DC.

19.5 Mitigation Measures

19.5.1 Visual Impact

As with many other aspects, different points of view of visual impact must be considered. UGC in general have less visual impact than OHL. On the other hand OHL can be camouflaged by appropriate coating of towers and even conductors, or can be "hidden" if the landscape allows this. The picture shows a "camouflage line" in the Austrian Alps with coated towers and coated conductors (Figure 19.12).

Figure 19.10 New tower design; from left: Finland, France, USA, Finland, Spain (Source: Cigré TB 416).

Figure 19.11 Wintrack tower in the Netherlands (APG).

Figure 19.12 Two 400 kV towers can be seen. *Left*: galvanized steel tower, clearly visible. *Right*: "camouflage line" with *dark green* coated tower and conductors, nearly invisible (APG).

19.5.2 Electric and Magnetic Fields (EMF)

During the operation of a line electric fields are produced by the voltage, and magnetic fields are produced by the current. Due to the metallic sheath of an UGC there is no electric field outside the cables.

There is a magnetic field for both OHL and UGC and it depends on the magnitude of the current flowing through the circuit. These values vary with the phase arrangement as well as the clearance to ground for OHL and the depth of cables for UGC. Under normal construction conditions the magnetic field has approximately the same value above an UGC as under an OHL, when both are carrying the same current. The lateral values of the magnetic field decreases faster for UGC when moving away from the axis of the link.

Methods to reduce EMF for OHL are optimisation of the configuration of towers and phases, and for UGC optimization of the laying geometry, or shielding.

19.5.3 Audible Noise, Induced Voltages, Impact on Other Services

OHL may produce audible noise under unfavourable weather conditions. Methods are available to reduce this (e.g. multiple subconductors, phase arrangement, see chapter "environmental issues" in this green book). UGC do not produce audible noise.

Induced voltages are created by the electric field. Appropriate measures at objects in question ensure that the level of such voltages does not exceed given values. As UGC do not create electric fields, there are no induced voltages from cables, but are from OHL.

Impacts on sensitive facilities may come from both techniques. Such influences from OHL may come from the electric and magnetic field and in case of UGC from the magnetic field only. This can lead to shielding measures or to greater clearances to objects.

Underground long distance heating pipes, pipelines for gas and oil, may cause hot spots in a UGC line if not investigated properly during the design, and vice versa UGC may create heat problems for such underground infrastructural facilities. Mitigation measures after laying are complicated and costly.

19.6 Public Debate

The discussion about OHL and UGC in the public often suffers from incorrect comparison of the facts which apply to each technology. Typical examples for such misinterpretations are cost factors related to different capacities or even different voltage levels when comparing OHL and UGC. Comparisons between different projects make no sense; each project has to be estimated separately on a case-by-case-basis. Otherwise expectations or disappointments may be triggered which can lead to completely wrong perspectives. This discrepancy is not new and can be found in many other infrastructural projects.

Many parameters need to be considered in a comparison. The following breakdown presents examples of principal design parameters for a line (OHL and UGC):

- **destination of the line**: (city) feeder, transmission grid, distribution grid, feeder from a power plant, merchant line
- **environment, topography:** urban, rural, flat/hilly/alpine, climate, other heat sources in the soil, parallel cable systems, soil conditions
- **technical requirements:** ampacity, lifetime, voltage, AC/DC, number of electric circuits, route length
- **standards:** design standards, material standards, limits for EMF and audible noise.

Here under are the parameters for UGC in addition to principal parameters above:

- **laying of cables:** directly in soil/trench, ducts, tunnel, natural/forced cooling
- **construction**: insulation fluid filled/XLPE, cross section, copper or aluminium, screen cross section, lead sheath, etc., joints, terminations
- **laying formation:** flat, triangular, delivery length per drum, single cable or double cable per electric system
- **soil**: soil conditions, other heat sources in the soil, parallel cable systems
- **electrical aspects:** compensation needed or not, configuration and dimension of transition compounds, earthing conditions
- **earthing:** earthing conditions, cross bonding

- **routing:** urban, rural, flat/hilly/alpine, climate, other heat sources in the soil, parallel cable systems, soil conditions, other services, ditches, roads, terrain suitable for cable laying
- **installation:** type of access road for cable laying,
- **flexibility:** are more developments in the area expected in the future
- **repair:** fault finding and repair.

Finally here under are the parameters for OHL in addition to principle parameters:

- **structures**: tower configuration, number of circuits per tower
- **tower material**: lattice steel, tubular steel, concrete, wood, compound
- **conductors**: cross section, number of sub-conductors per phase, material
- **corrosion protection**: galvanized, coating
- **repair**: fault finding and repair
- **weather parameters**: wind, ice.

This shows clearly that comparisons or statements about UGC or OHL make no sense without detailed and specific project information. "Cables are different and overhead lines are also different."

19.7 Main Applications of UGC, Technical Challenges

The big majority of new transmission lines worldwide will be built with OHL (planned and under construction). Especially for extra high voltage lines EHV, different and additional aspects gain more importance.

- **Economic aspects**: investment costs, losses, lifetime, financing, full costs, economic situation of the relevant country and utility
- **Environmental aspects**: visual impact, EMF, audible noise, use of land, right of way, influences from climate and topography
- **Technical aspects**: multiple systems, capacity, time for installation, length of line, influences/integration into the existing grid, reliability and repair time, access, converter stations, possible need for reactors
- **Legal aspects**: criteria for beginning and end of an OHL and a UGC section, time of authorization.

A detailed worldwide overview can be found in Appendix G of the Cigré TB 338 (data collection ended 2007) (Table 19.2).

In the last few years laws covering UGC-policy were put into force in some countries.

- 2009: Denmark: agreement between the TSO and the central politicians about transmission grid expansion policy to underground all existing lines up to and including 150 kV combined with a restructuring of the whole grid in DK. The precondition is that the envisaged development of renewable energy production plants will be built and that the financial situation will allow the additional costs

Table 19.2 Overview of main EHV AC XLPE Installations in Europe at 400 kV (source: joint paper 2011 with updates March 2014)

Location	Project	Type of Project	Cable circuits × route length (km)	Cables per Phase	Power MVA	Erection Time	Method of Laying and Cooling
Copenhagen	Elimination of overhead lines in urban area	City feeder	1 × 22	1	1 × 995	1996	Direct buried
DK			1 × 12			1999	
Berlin	Connect West/ East system	City feeder	2 × 6	1	2 × 1100	1998	Tunnel ventilated
DE			2 × 6			2000	
Madrid	Barajas Airport Expansion	Airport runway crossing	2 × 13	1	2 × 1720 winter	2002/3	Tunnel ventilated
E					2 × 1390 summer		
Jutland	Area of outstanding beauty, waterway & semi urban areas	Partial under- grounding	2 × 14 in 3 sections	1	2 × 500 nominal	2002/3	Direct buried & ducts
DK					2 × 800 temporary overload		
London	London St. Johns Wood-Elstree	City feeder	1 × 20	1	1 × 1600	2002/5	Tunnel ventilated
GB							
Rotterdam	Rhine waterway crossings	Waterway crossings	2 × 2.1	1	2 × 1470	2004/5	Direct buried & pipes
NL							

Vienna	Provide power to centre of city	City feeder	2×5.5	1	2×620 without, and 2×1040 with forced cooling	2004/5	Buried in concrete block
AT							
Milan	Section of Turbigo-Rho line	City feeder	2×8.5	2	2×1100	2005/6	Direct buried & ducts
IT							
London	West Ham – Hackney	City feeder	2×6.3	1	1×1660 summer	2007/8	Tunnel ventilated
GB					1950 winter		
Switzerland/Italy	Mendrisio – Cagno	Interconnection, Merchant Line	1×8	1	1×560	2007/8	Direct buried
Randstad	Randstad South	Partial undergrounding of transmission line	2×10	2	1980	2013	Direct buried and ducts
NL					2635 short time		
Jutland	Kassø-Tjele	Partial undergrounding of new line	2×2.5	2	2×1800	2013	Direct buried
DK			2×4.5	2	2×1800	2014	
			2×1.6	2	2×1800	2014	
Jutland/Funen	Lillebælt	Partial undergrounding of two existing lines	2×5 UGC	1	2×600	2013	Direct buried
DK			2×7 Submarine	1	2×600	2013	

- 2009: a law in Germany confirms the need for more than 800 km new transmission lines respective upgrading including four 400 kV UGC - pilot projects (EnLAG). They are considered as pilot projects to gain experience with EHV UGC.

In Europe current major UGC projects on land exist in

- *The Netherlands*: 400 kV AC Randstad North OHL with 10 km partial undergroundings (4 sections), planned to be energized 2017
- *France/Spain*: crossing the Pyrenees with a 63 km ± 320 kV DC-cable, energized 2014 using VSC technology
- *Germany*: according to the EnLAG partial 400 kV AC undergrounding on pilot projects till app. 2019
- *Switzerland/Riniken*: partial undergrounding 400 kV AC app, 1.3 km, in authorization process
- *UK/London*: several 400 kV AC city cable projects, mostly in tunnels, to replace old 275 kV cables, in the next few years
- *Belgium, Stevin*: 10 km partial 400 kV undergrounding, realization planned 2018
- *Austria, Vienna*: Simmering-Wien Südost, partial 400 kV undergrounding 4.5 km, realization planned 2019
- *Denmark, Jutland*: Vejle, partial undergrounding existing 400 kV AC line, 2 × 6.9 km, 2015
- *Denmark, Jutland*: Aalborg, partial undergrounding existing 400 kV AC line, 8.6 km, 2015

19.8 Conclusions

OHL and UGC both have their fields of application. UGC are normally installed when OHL are not possible. Typical examples are lines in the vicinity of airports, lines in densely populated areas of cities, large river crossings, lines in protected areas, connections at sea including their landfalls.

The discussion about OHL and UGC in the public arena often suffers from incorrect comparison of the factors which apply to each technology. Examples for such misinterpretations are cost factors related to different capacities or even different voltage levels when comparing OHL and UGC.

The large majority of new transmission lines worldwide will be built with OHL (planned and under construction).

For both techniques new and challenging technical approaches exist (superconducting cables, GIL, high temperature overhead line conductors, change from AC to DC, new tower design).

19.9 Abbreviations

OHL: overhead line
UGC: underground cable
AC: alternating current

DC: direct current
HVDC: high voltage direct current
EMF: electric and magnetic fields
Entso-e: Association of European Transmission System Operators
Europacable, the representative of cable systems manufacturers in Europe
EHV: extra high voltage
TYNDP: Ten Years Network Development Plan
GIL: Gas Insulated Line
VSC: Voltage Source Converters for DC lines

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Herbert Lugschitz is an electrical engineer. He is employed at Austrian Power Grid APG, Vienna, Austria, and is involved in the development of the 220 kV- and 380 kV-grid since the late 1970ies. His occupation covers all aspects of the overhead line business, from foundation, structures, fittings till conductors. Herbert Lugschitz is member in Cigré since years in many WGs, as special reporter, was Austrian delegate in B2 till 2014 and is now secretary of B2. He is chairman of the Austrian, Technical Committee for Overhead Lines and the embedding of power cables" at ÖVE and is also involved in the work of CENELEC. He contributed to OHL-project studies for Albania, Tanzania, Kyrghystan, Pakistan and Zimbabwe.