Chapter 8
Oscillation Detection and Mitigation Using Synchrophasor Technology in the Indian Power Grid

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8.1 Introduction

Any electrical grid is susceptible to low-frequency oscillations as these are inherently present in the system. However, such low-frequency oscillations are non-observable due to high positive damping. These oscillations are observed only if some power system control interact in a way causing excitation of the oscillation modes by reducing their damping. Indian grid has also been experiencing low-frequency oscillations since early days. However, their observability is now better with the introduction of Synchrophasor technology [1, 2]. In earlier days, these oscillations were known to the system operator only after being reported by any generating station. For example, in Western Regional (WR) grid of India, oscillations between Vindhyachal and Korba regions were observed when the transmission linkage between the Eastern and Western part of the Western grid was weaker. Further, during large grid synchronizations, the Thyristor Controlled Series Compensators (TCSCs) were used in order to suppress the inter-area oscillations after synchronization. For example, synchronization of Eastern Regional (ER) grid and Western Regional (WR) grid in 2003 was done using tie links having TCSC for damping the low-frequency oscillations [3]. Similar was the case while synchronizing the Eastern Regional grid with the Northern Regional grid wherein TCSC installed tie lines were used to damp out the inter-area oscillations [4, 5]. Oscillations were also observed after synchronization of NEW (North-East-North East-West) grid with the Southern Regional grid since December 2013 [6–9]. Long inter-regional synchronizing tie lines require TCSCs to suppress the oscillations as

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used in ER-WR and ER-NR grids synchronization. Since NEW grid and SR grids were synchronized over a 208-km-long 765 kV 2*S/C lines, no FSC plus TCSC was envisaged in the planning horizon of synchronization of NEW and SR grids.

In recent years, Indian system operator has to operate power systems closer to its stability limits because of rapid growth in demand. Furthermore, large regions being connected by few lines has resulted in lightly damped modes becoming prominent and observable to the system operator. Technology and operating philosophy are being sought for increasing the power transfer over existing (possibly weak) interconnections, thereby reducing the damping of the already lightly damped modes which increases the operator's challenges. Consequently, ensuring that the damping of modes of rotor oscillation in power systems provides adequate margins of stability has been and still is of concern to system planners and operators. In order to damp oscillations, firstly there is a need to classify the modes under various categories based on the observation and literature.

A. Classification of Oscillation

Based on the literature survey [10–17], the low-frequency oscillations can be broadly classified into the following categories:

1. Inter-area mode: 0.05-0.3 Hz
2. Intra-area mode: 0.4–1.0 Hz
3. Inter-plant mode: 1.0–2.0 Hz
4. Intra-plant mode: 1.5–3.0 Hz
5. Control mode: not defined
6. Torsional mode: 10–46 Hz.

The associated oscillations in the above classifications are the characteristic or natural modes of the system. The frequency and damping of such modes generally change with the operating conditions, i.e. changes in the system configuration and load/generation in the grid. Such changes in operating condition may cause the electrical power system to drift or be forced towards a small-signal stability limit. These conditions result in negative damping of modes which is seen as growing oscillation in various electrical parameters. Such negative damped oscillations have huge repercussions on the power system and can even cause blackouts.

B. Impact of Low-Frequency Oscillation

It is well known to the power system engineers that the oscillations have played an important role in the world famous blackouts [18]. These include the following:

1. 1996 WSCC Blackout
2. 2003 Blackout in USA and Canada
3. 2003 Blackout in Denmark–Sweden
4. 2003 Italy Blackout
5. 2011 Chile Blackout

So, there is a need of systematic study and planning required for small-signal stability in power system to avoid such blackouts. Inter-area oscillation causing System Protection Scheme (SPS) triggering due to negative damping has also been observed in the Indian power system. The observability of oscillation has placed new dilemmas with regard to the type, nature, source and impact of the oscillations in front of the operator. In due course of time, the operator gradually is now able to comprehend more about the oscillations using Synchrophasor measurements along with conventional SCADA.

C. Observability of Low-Frequency Oscillations in the Indian Grid

Earlier, the SCADA data available with the system operator and/or the data from generators were used for the study of oscillations which had its own limitations due to low resolution. With the introduction of Synchrophasor measurements units in Indian grid, the oscillations in the grid can now be easily monitored with precision at national control room and each regional control room in real time. This has helped the system operator in giving feedback to the planners regarding weak interconnections where LFO is observable. Based on the various observations and analysis of the data from the Synchrophasor based Oscillation Monitoring System (OMS), baselining of the modes in present Indian power system has also been done and is given below [1]:

- Mode 0.2–0.25 Hz: Southern grid and NEW grid
- Mode 0.7–0.75 Hz: Eastern, North-Eastern and Western grid
- Mode 0.6 Hz: Eastern, North-Eastern and Western grid
- Mode 0.5 Hz: North-Eastern grid with rest of the grid.

8.2 Cases of Low-Frequency Oscillation in the Indian Grid and Measures Taken/Required for Their Improved Damping

Various cases of low-frequency oscillation and few cases of sub-synchronous oscillation have been observed in the Indian grid during last few years. Such high observability of oscillation was possible only with the availability of Synchrophasor data at the desk of system operator [1]. Among these incidents, the cases of sub-synchronous resonance observation at HVDC terminal, oscillation in the area of southern part of Eastern grid, oscillation in the North-Eastern grid, etc., are of interest. These oscillation cases analysis based on the Synchrophasor data, SCADA data and other data sources is presented in this chapter. However, a summary of these case studies is given below in order to familiarize the readers.

- The sub-synchronous resonance (SSR) and sub-synchronous torsional interaction (SSTI) phenomenon in the electrical grid can be due to the proximity of a fixed series capacitor or an HVDC link to a generating station. Both the situations are disastrous for the generator rotor which gets damaged after experiencing sub-synchronous oscillations. There are very few cases in Indian system on SSR and SSTI out of which one has been monitored through Synchrophasor and the same has been explained in this chapter.
- Oscillation cases in the Eastern and North-Eastern regions are prominent. The areas in Eastern Region near to Southern Regional grid boundary have shown highest observability in terms of oscillations. Significant inter- and intra-plant oscillations have been seen in North-Eastern region which have resulted in tripping of units and lines [19]. One case from North-Eastern system has been explained in this chapter in order to show how the low-frequency oscillation affects the system stability and protection operation.
- Based on experience, it is observed that oscillations when excited by a single unit can be easily monitored and concluded and after this the remedial action can also be planned to take suitable measures. During such cases, oscillations have either initiated when these units were brought in service or when they were taken out or have tripped abruptly during oscillations. Further, the oscillations have been observed to die out in a short span of time. These cases have provided various lessons during system operation to avoid such oscillations. Few such case studies have been included in this chapter for the benefit of the readers.
- The interesting observation during many of the cases of oscillations was their observability aspect. Even though in many cases oscillation frequency lies in the category of inter-area or intra-area oscillation, their observability was local in nature.

Few case studies have been presented below to understand how Synchrophasor data has helped operators in understanding the very nature of low-frequency oscillations (LFO) and planning of various remedial measures.

A. Low-Frequency Oscillations at Generating Plant due to Switching of a Nearby High Capacity Transmission Line

Low-frequency oscillation in a generating plant may get excited due to the malfunction of its controller when there is a change in the grid parameter by virtue of any nearby switching activity. In one of the cases, it was found that generating unit started hunting and caused oscillation in the grid during the switching of a 765 kV long line which was connected from the adjacent substation near to the generating station. The observed low-frequency oscillation has subsided after the tripping of the unit which was hunting. The detailed description of the event is given in the next paragraph.

One of the 500 MW units of the plant was just synchronized with the grid, and it was generating 98 MW. The unit was on speed control mode. The controller mode of the generating unit was being changed from speed control mode to load control mode of the turbine. At this moment, a nearby long 765 kV line was opened by the system operator as a part of planned outage. Subsequently, the unit started hunting

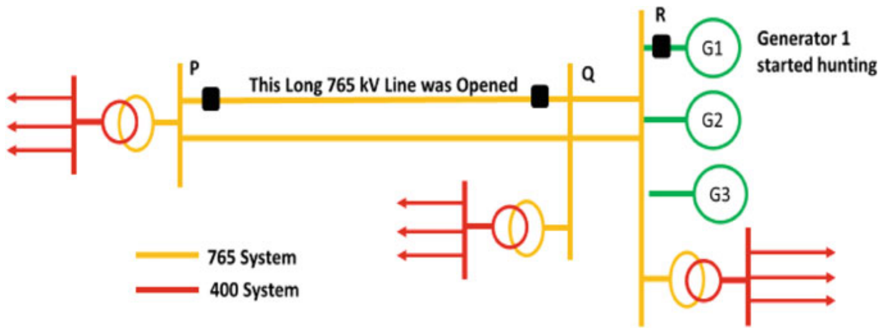

Fig. 8.1 Network schematic for the illustration of the case study 1

with wide fluctuation in its active as well as reactive power. The schematic diagram for better visualization of the event is given in Fig. 8.1.

Prior to analysing the actual cause of the oscillation, it is to be understood that the turbine prime mover control system usually has three modes of operation, i.e. speed control, load control and pressure control. Prior to synchronization, i.e. in start-up phase, any generating unit prime mover is kept on speed control mode. In this mode by adjusting the control valves, the total amount of steam flow entering steam turbine is changed, which is directly proportional to speed of rotation. Once the generator is synchronized to the grid, control system is in either load or pressure mode. In the load control mode, control error that represents input to the controller is formed as a difference between set point and actual load.

In the above case, it was found that the control was being changed from speed to load control mode to increase the power of the generating unit after synchronization. During this time, a nearby long 765 kV line was being opened by the system operator as a part of planned outage. As the line was manually tripped, it has led to 7–8 kV change in the bus voltage of the generating station. Due to this voltage dip during the line outage, there was a change in load feedback. This has resulted in toggling of turbine control between speed control to load control and eventually resulted in hunting of the real power of the unit between 17 and 250 MW causing severe oscillations in the grid. Along with real power, reactive power of the unit was also oscillating.

Figures 8.2 and 8.3 show the respective frequency and voltage observed at various nodes during the excitation of inter-area oscillation due to the local oscillation at the generator. This incident of oscillation has provided a lesson to the system operator to not perform switching near to substation while a generating unit is being synchronized. Further, it has also provided a generating station to check for planned switching operation near to its generating station which is being given by system operator on day-ahead basis to all constituents.

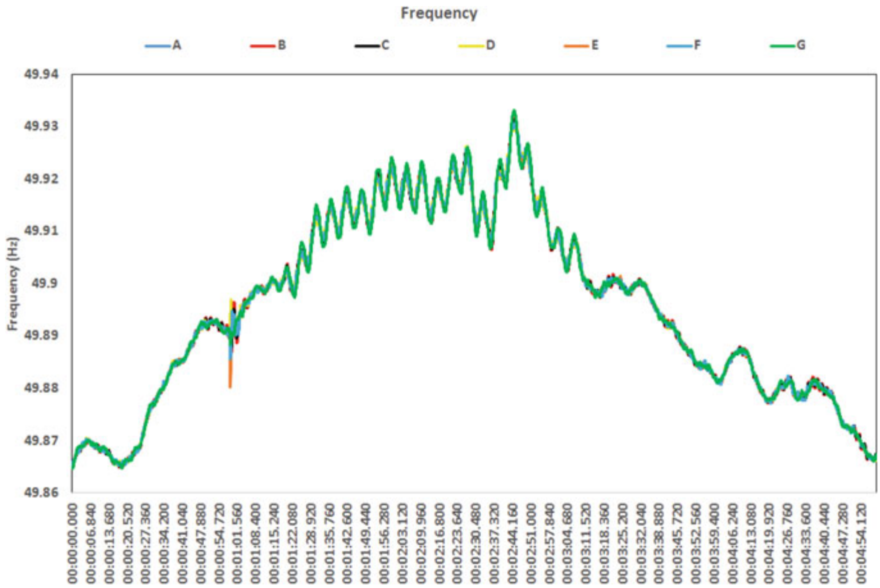

Fig. 8.2 Frequency of nearby nodes in the grid during the oscillation

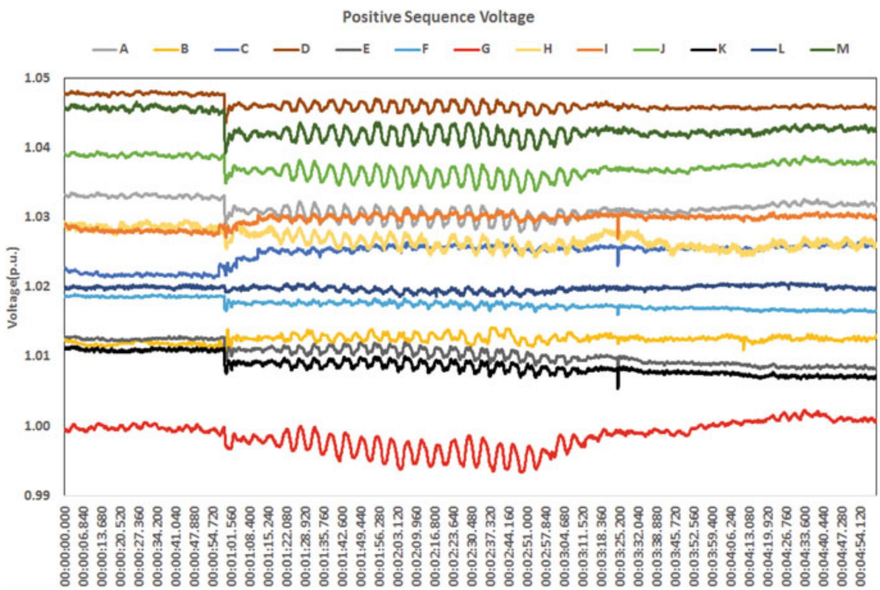

Fig. 8.3 Positive sequence voltage of nearby nodes in the grid during the oscillation

B. Sub-synchronous Torsional Interaction Near to HVDC Converter Terminal

The sub-synchronous torsional interaction (SSTI) is observed when an HVDC converter terminal is located near to a generating complex. SSTI is observed on two different operating conditions, i.e. low generation at the plant and multiple commutation failures in the HVDC due to fault on the line. A brief overview of the SSTI to understand the phenomenon is provided in the next paragraph.

The phenomenon of sub-synchronous oscillations is basically associated with synchronous machines and can be of three types:

1. The classical form of subsynchronous oscillation is subsynchronous resonance (SSR) and it occurs when a natural frequency of a series compensated transmission system interacts with a natural frequency of the turbine prime mover.
2. The second type of subsynchronous oscillation is called subsynchronous control interaction (SSCI). Such SSCI oscillations are a result of control interaction and not from the electrical resonance from SSR. The problem in such cases is primarily due to the use of mechanically derived speed signals in the feedback control system.
3. A third concern with regard to torsional modes is of sub-synchronous torsional interactions (SSTI) which originate because of other transmission equipment such as SVC, HVDC.

The power transmitted by HVDC system is in general constant current or constant power control scheme, which is independent of frequency. Therefore, the HVDC rectifier tries to maintain the constant value of the current through current controller amplifier (CCA) function. The current error of HVDC and accelerating power of generator are related to each other's closed loop control. The HVDC current order may change due to fault on converter end or fault on inverter end. To keep the error in current at HVDC terminal to be zero, the generator has to accelerate/decelerate accordingly. Any disturbance in the system resulting in current error will have a wide frequency range, and so it includes frequency in SSR range. If this frequency in SSR range is excited in the HVDC control system, then the accelerating power reflected to the generator rotor is also in the same frequency. If this frequency matches with the resonance frequency or the natural modes of the turbine shaft, then it will result in SSR. Therefore, HVDC current control can cause sub-synchronous torsional interaction with rectifier end connected generators. The gain of the constant current regulator will increase when the control angle (α) increases, so generators near to HVDC are prone to sub-synchronous oscillation at larger α, for example, when HVDC is running at lower voltage.

Two oscillation cases on sub-synchronous torsional interaction were observed in a generating plant connected to the converter terminal of HVDC system under two different scenarios. The first case was when multiple commutation failures occurred in HVDC during faults near to the inverter substation under inclement weather. These faults were reflected on the converter end of the HVDC as dip in the voltage and rise in the current. With these commutation failures, HVDC power flow was also varying and the current controller was trying to keep the power constant. As explained above, the HVDC current order would change due to fault on either converter end or on inverter end, and to keep the error in current at HVDC terminal to zero, the generators have to accelerate/decelerate accordingly. During these faults, voltage dip is observed, and in order to keep the current same, α has to be increased, and with this, SSTI was observed in the grid near to converter terminal from PMUs.

Figure 8.4 shows the converter end AC side voltage where the generator is connected which have experienced the sub-synchronous oscillation. Subsequently, the SSTI damping controller got activated; however, the extent of SSTI was high and even after damping controller activation it has resulted in tripping of both poles as per the design with subsequent SPS operation leading to tripping of some of the designated units. In principle, damping of the sub-synchronous oscillations due to SSTI can be achieved by modulation of the current order or the firing angle, which gets activated after detection of SSTI after recovery of the fault. Figure 8.5 shows the zoomed plot of the SSTI as measured from the digital fault recorder device from the field at the inverter end of the HVDC terminal. The frequency of the sub-synchronous oscillation in general ranges from 10 to 40 Hz. In this case, it was observed to be around 6.69 Hz from the RMS values of electrical parameter from the disturbance recorder. Further from the PMU installed at the converter terminal of the HVDC, SSR frequency comes out to be 6.69 Hz as shown in Fig. 8.6. This mode was observed in frequency, voltage and current measured from PMU.

A thorough analysis on the available data was done by the HVDC team and system operator for this event and some interesting facts came out. The SSR frequencies deduced from the AC side instantaneous voltage by the damping controller were 15.55 Hz and 11.15 Hz. This can be seen in Figs. 8.7 and 8.8. These two frequencies were superimposed on each other, and thus, the average frequency observed was 13.35 Hz. However, the same was observed as 6.69 Hz frequency when measured on the RMS values of parameters from fault recorder as shown in Figs. 8.9 and 8.10.

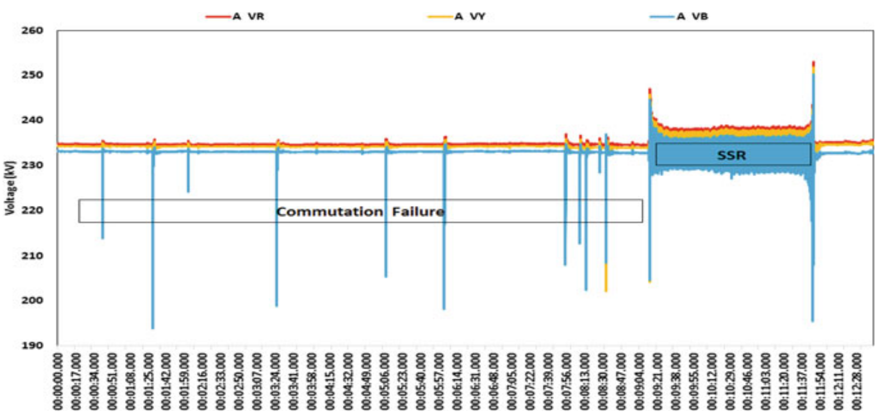

Fig. 8.4 Voltage of AC side on the HVDC converter end. Multiple commutation failures followed by SSR can be observed

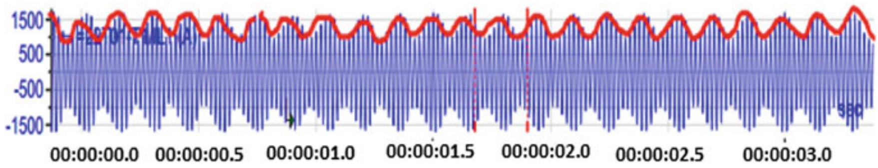

Fig. 8.5 DFR from the inverter terminal of HVDC which provides 6.69 Hz as SSR frequency

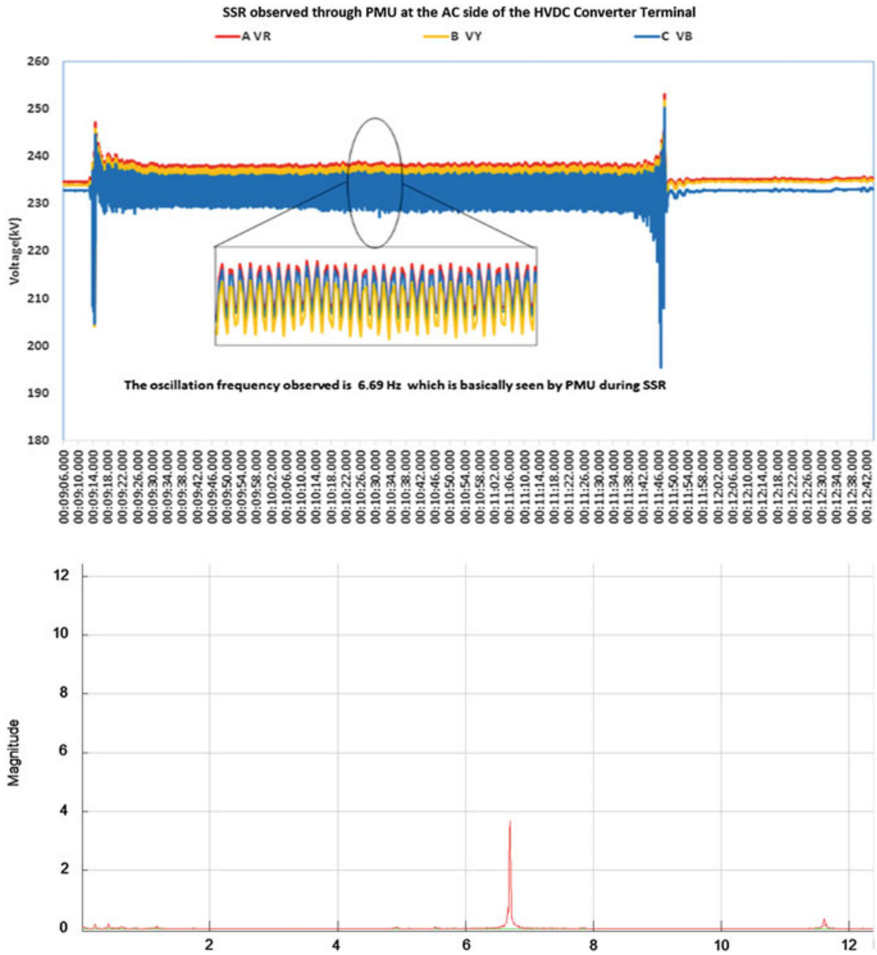

Fig. 8.6 Voltage of AC bus of converter terminal of HVDC and its Fourier transform indicating 6.69 Hz oscillation

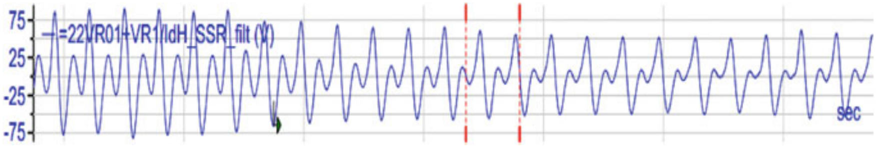

Fig. 8.7 SSR frequency filtered from voltage oscillation indicating presence of two frequencies superimposed on each other

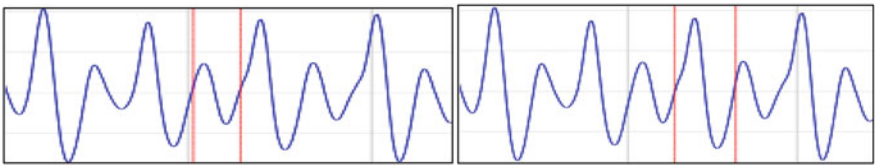

Fig. 8.8 SSR frequency filtered from voltage oscillation representing **a** 15.55 and **b** 11.15 Hz

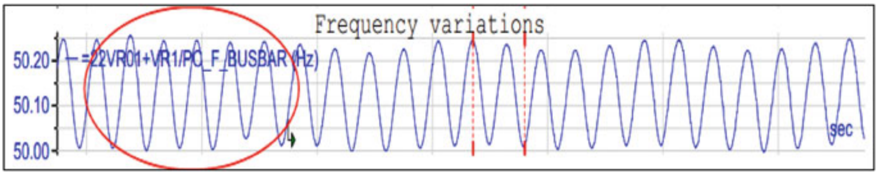

Fig. 8.9 Bus frequency measured from fault recorder indicating 6.69 Hz oscillation

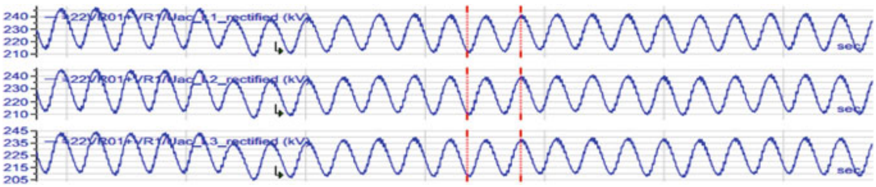

Fig. 8.10 RMS bus voltage of individual phase from fault recorder indicating 6.69 Hz oscillation

So, in the above case of SSTI, two frequencies were present, i.e. 15.55 Hz and 11.15 Hz, which is due to the presence of units of two different capacities at the generating station. While the observability from instantaneous data has shown these two frequencies, the RMS quantities were showing only one frequency which was half of the average frequency of these two modes. The same frequency was measured from fault recorder and PMU data also. Such type of measurement-related changes and their reason need to be further analysed from the signal processing techniques.

The second case of oscillation appeared when HVDC was running at reduced power order (1000–1200 MW), and there was a low generation of 300–400 MW at

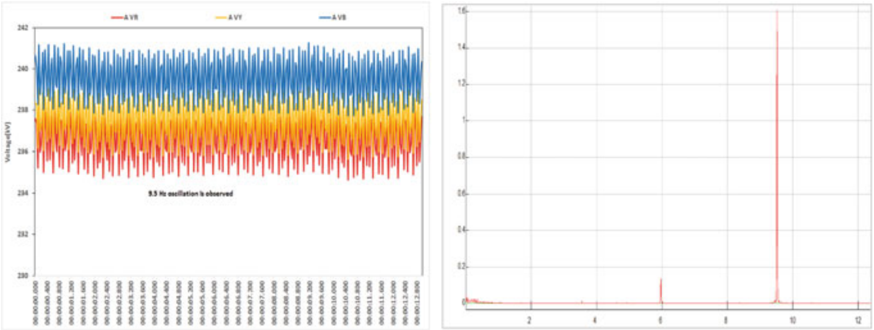

Fig. 8.11 Voltage of AC bus of converter terminal of HVDC and its Fourier transform indicating 9.5 Hz oscillation

the generating station with only one type of unit running out of the two different capacities of units present there. During this period, sub-synchronous torsional oscillations were observed on several occasions. The reason for sub-synchronous oscillation during low generation without any power system fault could not be ascertained. The oscillation frequency which was observed from Synchrophasor data was around 9.5 Hz (Fig. 8.11). The frequency of actual oscillation can be either 9.5 Hz or higher frequency like 15.5–34.5 Hz based on aliasing observed in Synchrophasor. It can be seen that 15.5 Hz oscillation was present in the earlier case also. This suggests the presence of 15.55 Hz oscillation in present scenario when only one type of unit is running.

Learnings from the above two cases of SSTI can be summarized as follows:

- From the above two cases, it was found that two different SSR frequencies are present when two different capacity units are running at the generating station. However, only one frequency is present when only one type of unit is running at the station. The oscillatory mode corresponding to one type of unit is 15.5 Hz and for other 11.15 Hz.
- Whether PMU can measure SSTI or SSR oscillation is a matter of discussion. PMU, which is reporting at 25 samples per second, can measure the oscillation up to 12.5 Hz as per the Nyquist criteria. Any higher frequency beyond 12.5 Hz will be reported as 25-F_o in the Synchrophasor due to aliasing. So a SSR having frequency of 15 Hz will be observed in PMU as 10 Hz.

C. Low-Frequency Oscillation at Nuclear Power Station

The oscillation due to the malfunction of emergency stop and control valve of nuclear power plant has been observed in the Indian grid in the past [1]. It was attributed to the failure of the relay governing the valve. Further, one more case of low-frequency oscillation was observed at a nuclear station where such behaviour was observed. This had resulted in wide variation in the power flow of the nuclear unit. This case gives a good overview of observability aspect from the Synchrophasor during the oscillation in the grid.

System operator on one occasion observed that in two of the PMUs (located near each other) few of the electrical parameters (Voltage/MVAR) started oscillating with respect to each other. These oscillations were observable only in the voltage and reactive power at these two locations. Real power and frequency have not shown much of variation. On enquiry, it was found that one the nuclear units located near to these nodes has shown large change in its reactive power as well as real power. Further, from the SCADA data for this unit, it was found that initially the real power of the unit has been reduced following which the oscillation in reactive power of the unit has started in the range of 50–200 MVAr. The owner entity of the nuclear plant had responded that they had observed steam leakage in one of the two emergency stop and control valve (ESCV) of the turbines. To rectify the steam leak process, isolation of this ESCV was required. Hence, turbine output was reduced to 350 MW in order to isolate the ESCV where leakage was observed. After isolation of ESCV, the entire steam load was shifted to the other ESCV, and with this, hunting has started in the unit. This hunting was damped after increasing the generation to 440 MW.

Figures 8.12 and 8.13 show the four parameters, i.e. voltage, frequency, active power and reactive power during the oscillation. It can be seen that the observability of this mode was more in voltage and reactive power. In addition, the observable oscillatory frequency was 0.2 Hz (an inter-area mode) but observable at only two nearby nodes to generators only. Therefore, the controller behaviour in the nuclear unit has excited the 0.2 Hz which is a global mode but the observability of this mode was only local.

D. Low-Frequency Oscillation in the North-Eastern Grid

Cases of low-frequency oscillations due to switching operation of transmission elements have been observed in the Indian grid, prominently in regions with weak interconnection and having small generating units (50 MW and below). The low-frequency oscillation modes in these regions get excited on account of nearby

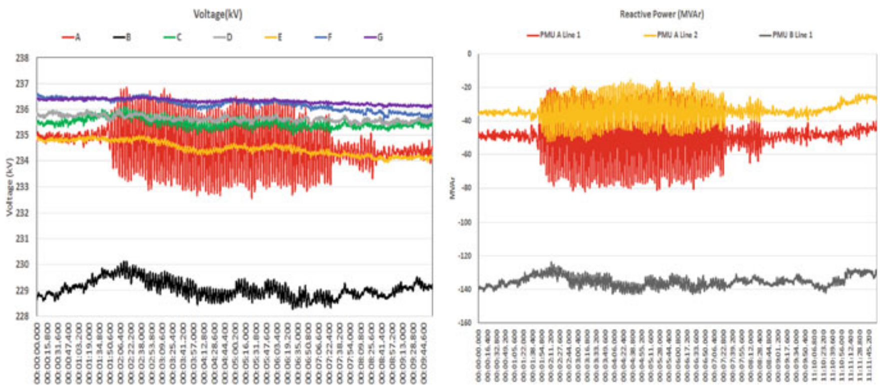

Fig. 8.12 Voltage of nodes in the grid and reactive power of lines from the nodes where maximum magnitude in voltage oscillation are observed

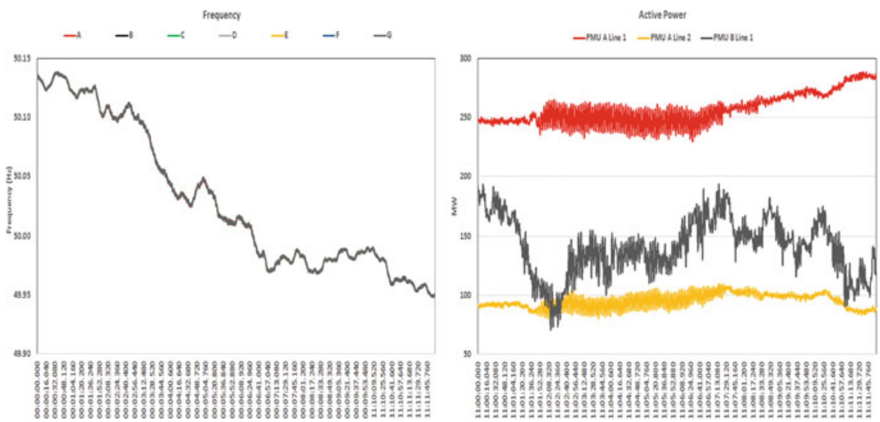

Fig. 8.13 Frequency of nodes in the grid and real power of lines from the nodes where maximum magnitude in voltage oscillation are observed

switching operation and resulting malfunction of generator controls. In absence of PSS tuning, the oscillations do not die out fast due to insufficient local damping. In the first case study, it was shown that switching operation can have effect on generation control and result in controller malfunctioning. Such oscillations on account of switching operations have been prominently observed in the North-Eastern Regional (NER) grid of the Indian Power System. A description of one such event observed in North-Eastern grid in India is explained in this case study.

Small hydro-generators having unit sizes of 50 MW and below are connected through 132 kV tie lines to load centres in the North-Eastern region having low fault levels. The area surrounding these units and the load centres is known to be prone to bad weather conditions, resulting in tripping of one or more transmission elements. Further, damage to protection equipment on account of the lightning surge and high earth resistance on account of prevailing soil conditions has also been reported from this area.

The hydro-generating plants A, B, C and D were generating 44 MW, 96 MW, 39 MW and 19 MW, respectively, where generating plants C and D are connected to the same bus. At this point in time, a nearby 132 kV transmission line supplying radial load developed a fault and the fault had a delayed clearing. This incident triggered low-frequency oscillations modes around 1.2 Hz (inter-plant) and its harmonic mode at 2.4 Hz (intra-plant). The units at generating stations A, C and D started hunting prominently, and the phenomenon was visible to power system operators at generating stations as well as regional control centre.

The oscillations were prominent in frequency and active power flows rather than voltage and reactive power flows. The oscillations continued for a total duration of about 8 min in the grid and were captured by all PMUs of NER grid, most prominently being captured by PMUs located in proximity to generators. Plots depicting the oscillation and mode frequency are shown in Fig. 8.14 and Fig. 8.15, respectively.

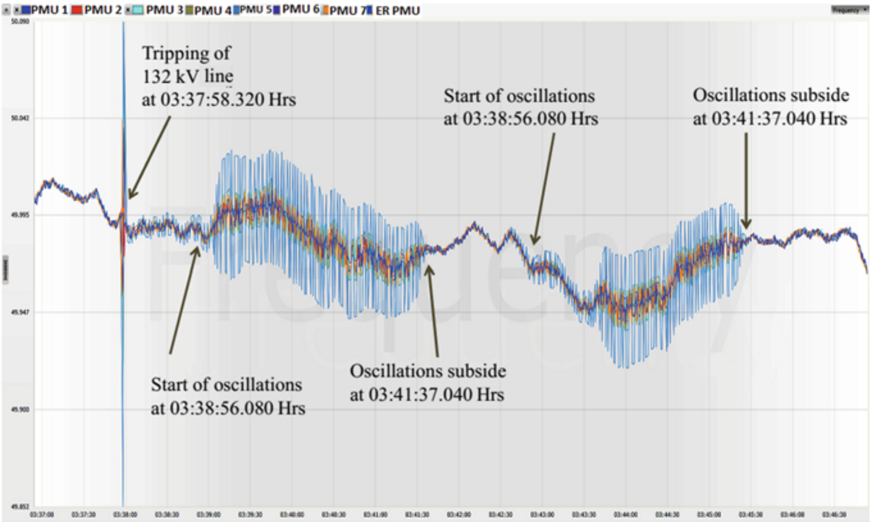

Fig. 8.14 Frequency plot from PMUs showing oscillation from PMUs of NER and ER

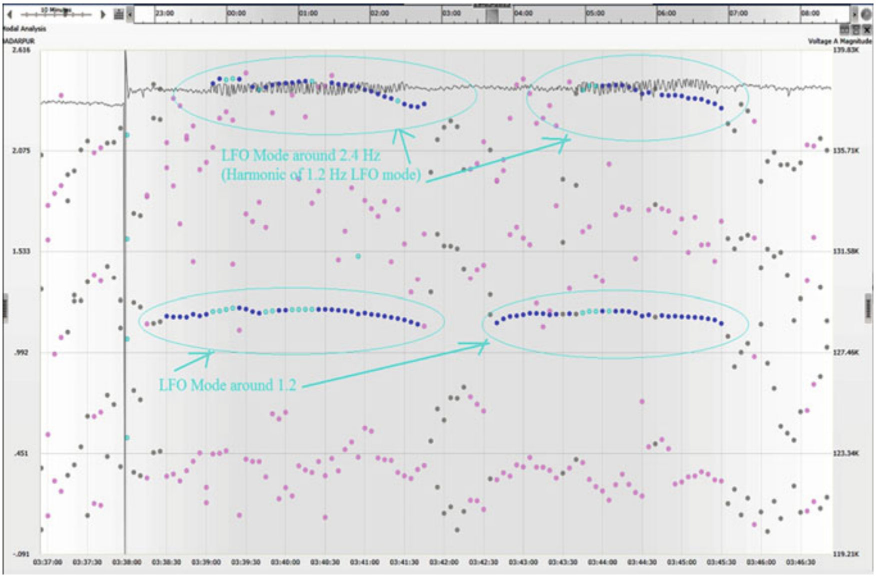

Fig. 8.15 Modal analysis plot from PMU at 132 kV node near to generating station in NER

These oscillations have resulted in tripping of units at generating stations A and C, after which the oscillations continued between units at generators B and D. This was also captured from SCADA plots shown in Fig. 8.17. In Fig. 8.15, good observability of oscillations in active power flows on the lines in NER can be observed. While in Fig. 8.17 it can be observed from SCADA plot that even the oscillating units at generating stations A and C got tripped, but oscillations kept continuing between units at generators B and D.

While the exact reason behind these oscillations is yet to be indicated by respective generators, it is clear that in the absence of adequate damping torque in the grid has led to prolonged oscillations which got damped out only after some of the participating units had tripped causing change in the system equilibrium point (Fig. 8.16).

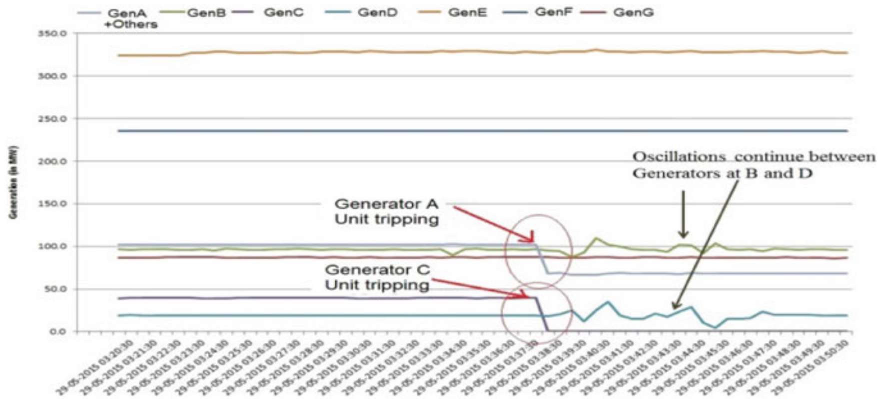

Fig. 8.16 Plot of generation from SCADA

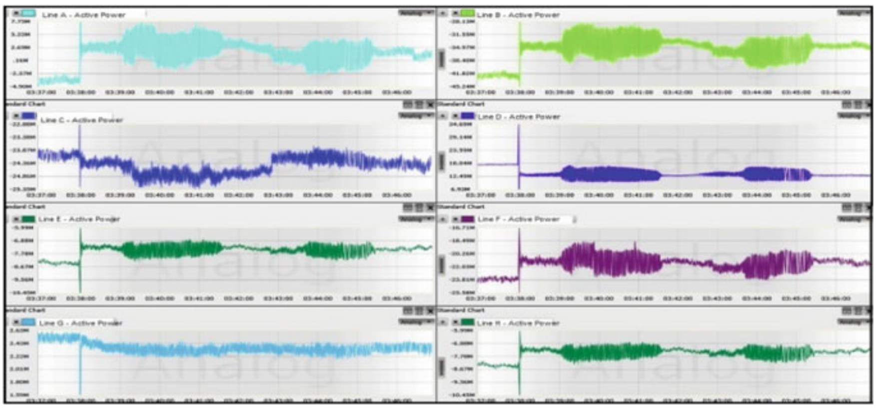

Fig. 8.17 Plot of active power flows from NER PMUs

E. Low-Frequency Oscillation and Impact of PSS Tuning

In this case, the power swing and small-signal stability issues were addressed for a generating station where units were connected at two different voltage levels. The interconnecting lines from these voltage levels were having large difference in electrical angles. The schematic diagram of the generating station is shown with the help of Fig. 8.18.

In case of contingency arising due to loss of evacuation lines from one voltage level, large swings were observed on evacuation lines at other voltage level based on Synchrophasor data from nearby PMUs supported by disturbance recorder from the station. Further, Synchrophasor measurement also provided that during such conditions, oscillations were being observed in system frequency which were inter-plant in nature as shown in Fig. 8.19.

Based on this input, SPS scheme was modified to take care of power swing criteria and PSS of generating units was tuned to take care of small-signal stability. After the PSS tuning and SPS enhancement, it was observed that under contingency, oscillation damped out very fast and had low amplitude. This can be observed in Fig. 8.20 where damping of oscillation has improved. Also, power swing was less prominent than in earlier cases.

F. Low-Frequency Oscillation due to Weak Connectivity

In this case, it is shown how a weaker connectivity of generator could result in oscillation in the grid after multiple tripping/contingencies. Units A1 and A2 of generating station A were in service with a total generation of 865 MW with all six outgoing feeders in service. However, several lines tripped simultaneously due to protection trip; consequently, it has led to the loss of generators B1 and B2 on over speed protection. The connectivity of the stations prior to this event is shown in Fig. 8.21. After these lines which are connecting generator A with the grid, i.e. A–C double circuit and A–D one circuit tripped resulting in connectivity of generator through A–D single circuit only which is also shown in Fig. 8.21.

Immediately following the line tripping which left generating station A with single evacuation line, oscillations were observed throughout the regional grid. These oscillations were prominently observed from a PMU placed at station G which is connected by a 400 kV line to station E. The oscillations have lasted for around 2 min as shown in Fig. 8.22.

On inquiry, it was found that hunting was observed in generating station A following the line tripping which led generating station with single evacuation line. The station recorder snapshot is shown in Fig. 8.23.

Hence, generation reduction was started and was maintained at 550 MW with oil support in both the units A1 and A2. Further, station load was brought down to 400 MW for better stability. This is done based on the fact that the oscillation has decayed only after the generation reduction. It was necessary to know whether the PSS was active at station. It was found that the function was activated but might have been improperly tuned.

The Oscillation Monitoring System (OMS) utilizing the multi-prony method was used to analyse the above oscillations and to identify the dominant modes using the

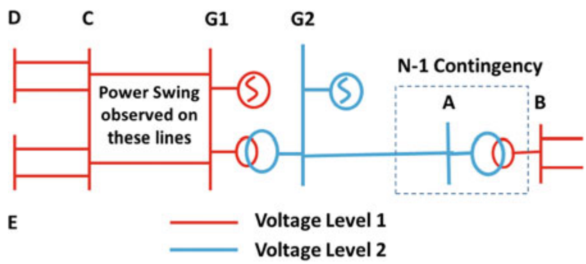

Fig. 8.18 Schematic diagram of the N-1 event causing power swing and oscillation

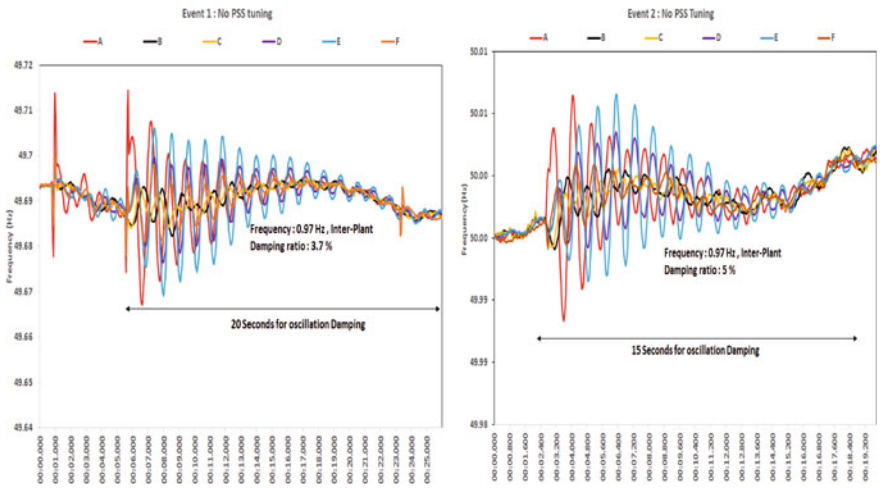

Fig. 8.19 Inter-plant oscillation at thermal station due to inadequate damping in the system

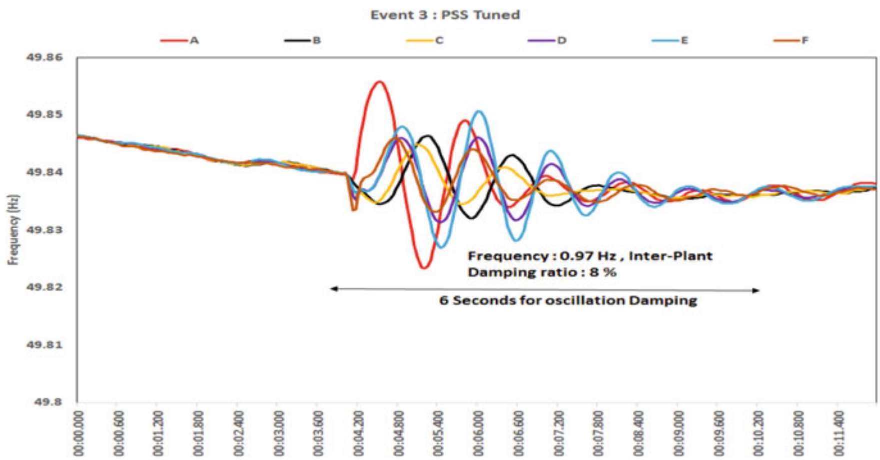

Fig. 8.20 Inter-plant oscillation damping improvement after PSS tuning

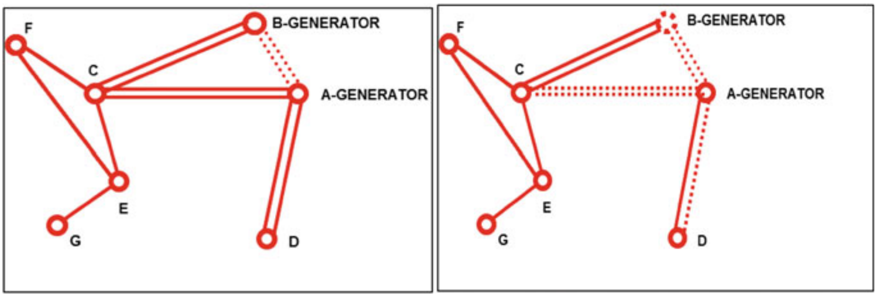

Fig. 8.21 On the left is the connectivity when units at generator B tripped, while on the right is the connectivity when units at A tripped

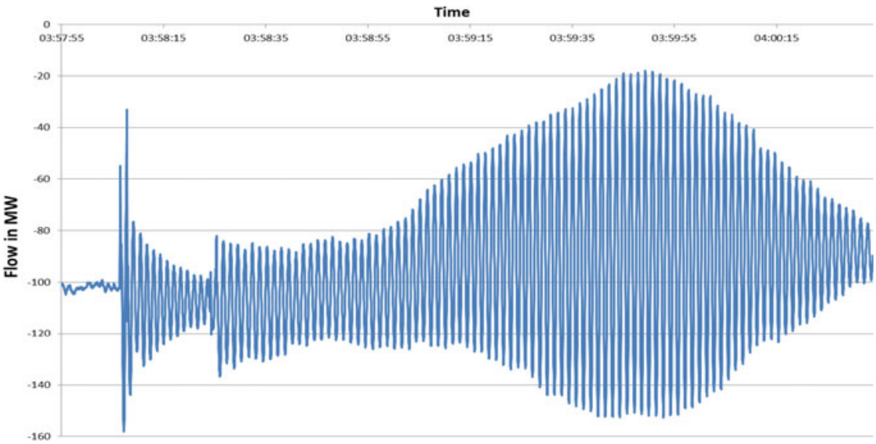

Fig. 8.22 PMU plot of active power flow in the 400 kV line G–E

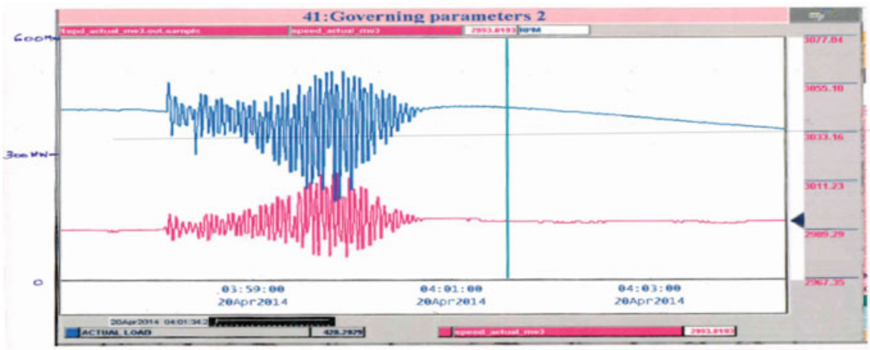

Fig. 8.23 Station recorder plot of the plant A

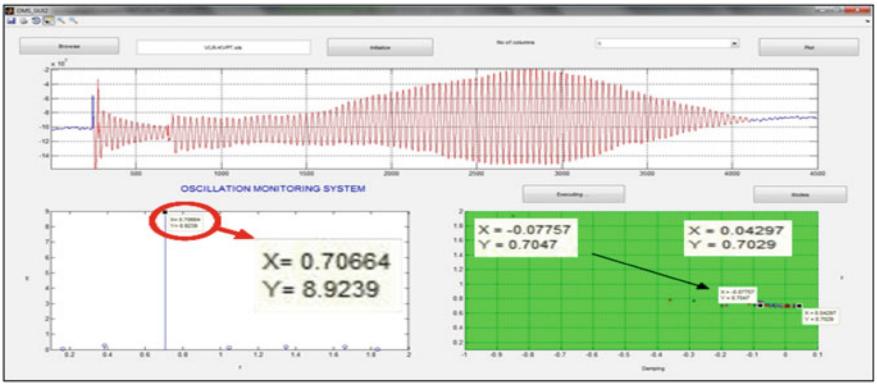

Fig. 8.24 Snapshot of OMS engine during the event indicating presence of 0.7 Hz oscillatory mode

Synchrophasor data [1]. The analysis was performed on the PMU data from station **G** and the frequency of the dominant mode of oscillation was 0.7 Hz which can be observed in Fig. 8.24. The damping ratio changed from −1 to +1.7% over the period.

The above case study has shown that a weak connectivity with grid and lack of PSS tuned response may result in oscillation in the generating the station. Further, it also provides a feedback to check for such connectivity issues at all generators in the Indian grid where a similar event could occur. The recommended action in order to mitigate such oscillation is to tune the PSS and implementing better SPS scheme for multiple contingencies.

G. Very Low-Frequency Oscillation due to Hydro-Power Plant

The case of oscillation arising during start–stop sequence in a hydro-unit has also been observed in Indian grid. This is one unique case where oscillation in hydro-units were observed by the system operator, analysed and then corrected with the help of generating station.

In this case of oscillation, it was observed that while desynchronizing the hydro-unit from the grid, the voltage plots of PMU located near the particular generating unit were observing the oscillation. The oscillation observed was of very low-frequency nature, i.e. 0.066 Hz, and the oscillations were present in all three phases of voltage in the nearest PMU as shown in Fig. 8.25. Since these oscillations were occurring repeatedly while one of the units was being desynchronized at the particular hydro-power plant, details from that generating station were sought. On investigation by the generator, it was found that improper pulse from PLC during the stop sequence was causing variation in reactive power thereby causing oscillations in voltage.

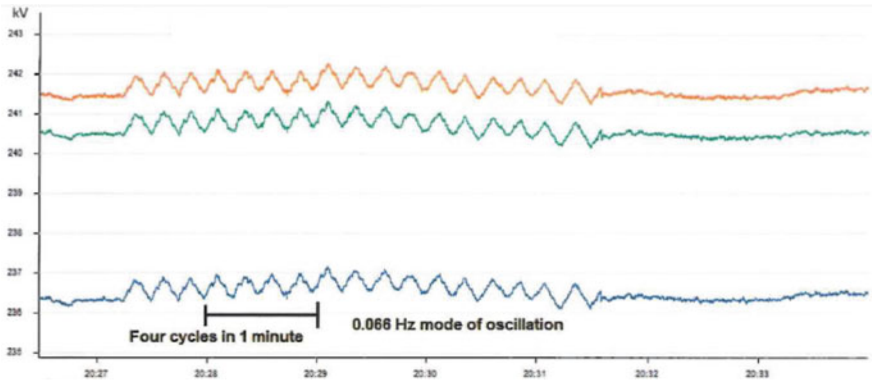

Fig. 8.25 Oscillation in the three-phase voltage of the node which is located nearest to hydro-power plant from PMU device

The generating station informed that when the following given conditions are met during stop sequence for any unit, then it automatically gets desynchronized from grid

1. Active power less than 9 MW
2. Reactive power within +3 MVAr

During automatic stop sequence execution, the PLC has been programmed to reduce the active and reactive power of the generating unit which is to be desynchronized. The PLC will give a pulse at regular intervals to reduce the active and reactive power to governor and excitation, respectively. It was observed that oscillation phenomenon was occurring when the stop command was executed for MVAR value beyond +3 MVAR (second condition not satisfied). It was observed that the automatic PLC sequence and measurement system were responding with some time gap of around 4–5 s delay. Due to this, AVR got several increase/decrease MVAR command which in turn led to large variations in MVAR (around +20 MVAR max) as shown in Fig. 8.26 from generator data acquisition system. The oscillatory frequency observed was also matching, i.e. 4 cycles/min = 0.066 Hz, as shown in Fig. 8.26.

Such large variation in MVAR was observed in the grid as oscillation in voltage, as captured by nearby PMU plot. The PLC pulse logic was modified accordingly, and the modification helped in eliminating the oscillations during the desynchronization as shown in Fig. 8.27.

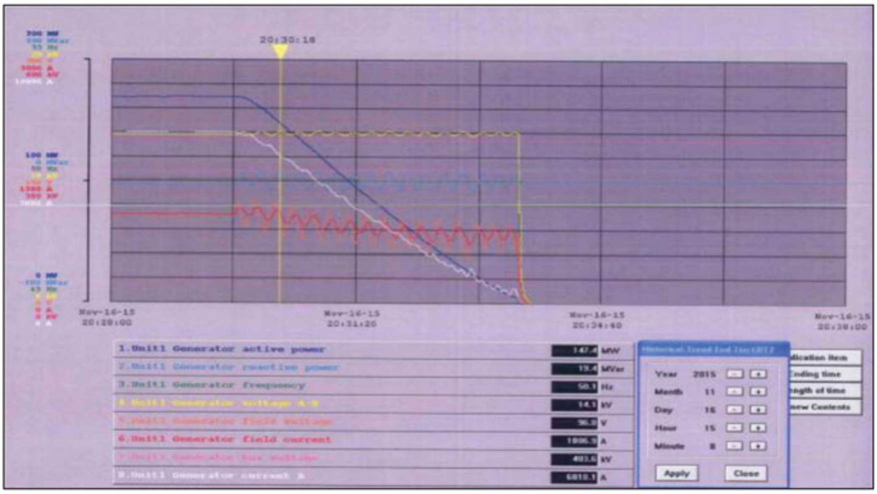

Fig. 8.26 Oscillations observed during desynchronization of unit as observed from generator SCADA (before modification in PLC pulse logic)

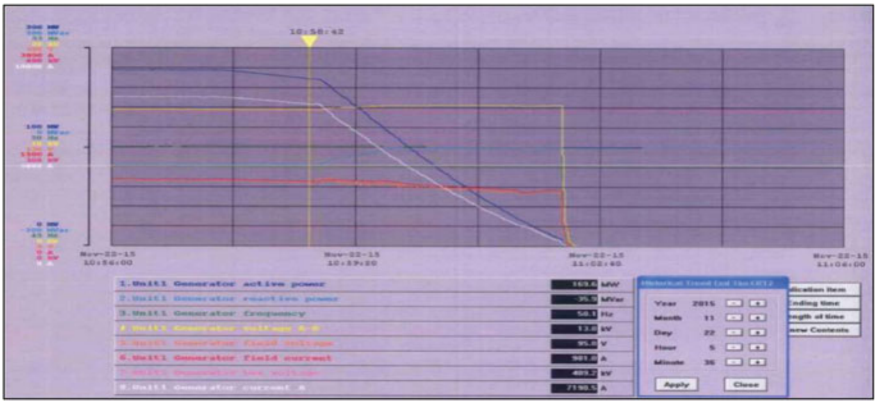

Fig. 8.27 Smooth desynchronization of unit (post-modification in PLC pulse logic)

8.3 Conclusion

In this chapter, various cases of small-signal stability have been discussed to familiarize the readers with the low-frequency oscillations occurring in Indian power system and how Synchrophasor measurements have helped operator in their observability and their mitigation after analysing the data. Based on the analysis, it can be seen that many of the local oscillations can be brought to conclusion; however, the same is not possible for inter- or intra-area mode as these require complete system study for analysis. The experience indicates that that the PSS tuning helps in damping of local nature of oscillation and affects system stability during transient.

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