Chapter 8
The Case for Using Wide-Area Monitoring and Control to Improve the Resilience and Capacity of the Electric Power Grid

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Abstract It is important for power grids to become flexible to accommodate diverse technologies such as intermittent renewables and power electronic conversion sources, while conventional generation resources are becoming more volatile with market forces and political directions. Environmentally, building new transmission is challenging. With smart grid technologies, there is a great deal of potential to control the power system using many widely distributed resources, but there is a considerable challenge in making use of the control capabilities in a novel way. This nascent volatility versus reliability demand makes operational decision-making and execution more challenging than in any other time in history. This chapter will explore modern techniques to improve grid reliability by enhancing and extending control center capabilities and substation capabilities. The use of automatic, wide-area protection schemes to mitigate cascading blackouts will be examined. Also explored will be the use of: wide-area control strategies, new and emerging technologies and communications, software and hardware architectures, and state-of-the art Energy Management System (EMS) technologies as the keys to more reliable operations. Additional focus will be placed on the positive impacts of synchronized phasor measurements.

8.1 Introduction

The high-voltage electric power grid was designed to operate in a stable condition. And, historically, that is how the grid has been typically operated. As per its intended design, the grid uses high-voltage transmission lines to transport electricity across thousands of miles. The power starts at various geographically dispersed generating units and is moved to numerous substations across the grid. The substations

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transform the high-voltage energy to lower voltages, which are suitable for transfer by distribution networks to the customers.

The grid typically has sufficient capacity to transfer energy to every customer 24 h/day, 7 h/week. Scheduled maintenance may temporarily take some of the grid components (generating units, transmission lines, transformers, etc.) out of service. Additionally, unexpected failures, due to acts of nature or other causes, may take components out of service. In order to maximize safety, mitigate systems damage, and minimize downtimes to customers, the grid has established a set of stability limits.

When components of the grid are disabled, the grid's transfer capacity is reduced and the grid operates on a thin capacity margin. This means that the likelihood the grid will exceed its stability limits is greatly increased.

There are many different types of stability limits including:

- Transmission line thermal overloads
- High or low voltages, and Voltage Stability (VS)
- Transient angle stability
- Damping of oscillations

Conventional protection is designed to isolate elements of the grid that may be damaged as a fault occurs. However, designing conventional protection to address wide-area stability issues can be challenging and conservative, and constraint levels can be conservative to ensure the integrity of the power system. In order to be effective, the relay protection schemes, which are deployed all across the grid, need to be coordinated.

Responsibility for monitoring power system conditions across the grid lies with the Energy Management System (EMS) operator. The EMS receives new data every 2–4 s and sounds alarms when violations are detected. The EMS also performs a variety of network analyses and calculations to help the operator assess and manage the stability of the grid. While this human/machine team is usually capable of handling anything that arises, there are infrequent circumstances when the grid becomes unstable and some areas lose power.

Many companies have implemented remedial action schemes or special protection schemes in order to protect equipment when certain predetermined conditions are encountered. These automatic preventive control actions include reconfiguring the topology of the grid or even blacking out a portion of the grid in order to prevent the spread of a blackout across the entire grid. These schemes tend to be conservative since they are based on heuristics and off-line assumptions that have to span a wide range of power system operating conditions.

This chapter focuses on a wide-area grid control approach that is based on real-time power system operating conditions. Automated schemes that use current conditions to deploy the most rapid and effective strategies will be discussed. The primary objective of wide-area control is to protect the interconnected power grid from uncontrolled widespread failure.

The August 14, 2003 blackout and other similar critical grid failures around the world have driven the industry to develop more automatic and adaptive control systems to prevent future catastrophes. Postmortem analyses and other investigative reports have concluded that the power system planner and the EMS operator must both be provided with the data and means to avoid system-wide power failures caused by unexpected events.

Now, more than ever, electric utility companies are facing a wide range of problems. It is becoming more and more difficult to operate the power system in a stable and reliable manner. Some of the issues forcing the utilities to emphasize improved grid stability include:

- Unexpected adverse weather conditions
- Shifting of load distribution and load management
- Dispersed and intermittent generation resources
- Electricity market system initiatives that cause the grid to be utilized in a more dynamic and less predictable manner
- Generation company decisions since they have been separated from the transmission companies
- Transmission stability decisions that are based on assumptions of load forecasts, generation capacities, and margins
- Stability margin concerns, since the system is operating closer to its limits

In order to cope with these issues, companies are focusing on new technologies and techniques to take full advantage of:

- Early problem detection and warning signals identified by synchronized measurements
- Recorded data analysis
- Wide-area visualization
- Wide-area closed-loop control

It is very clear that the use of EMS applications needs to be extended in order to improve the reliability and accuracy of system condition estimation (state estimation), the reliability and accuracy of relay coordination and relay settings, the implementation of utility practices and new regulations (Giri and Avila-Rosales 2002), and the defense plans against disturbances (Avila-Rosales et al. 2004). In addition, all of these new power system operational challenges have resulted in a new set of engineering challenges.

8.2 Engineering Challenges

Nowadays, electric utilities are deploying grid stability analysis tools in their EMS architectures for power system model structures of unprecedented size. Today 50,000 bus systems are not uncommon. These deployments impose major computational challenges related to model data collection and accuracy, solution techniques, visualization of the results, and the systems architecture.

In order to be effective, the EMS needs the capability to model and simulate the behaviors of extremely large transmission systems over a wide range of time domains, frequency domains, and topological designs.

Accurate tools for transient (angular) conditions and voltage stability (VS) are required, in order to assess and simulate all sorts of scenarios for the current time and immediate future. Quick methods are needed to reduce the computational burden associated with dynamic analysis and quasi-dynamic simulations to evaluate cascading events for preventive/corrective actions. The "prediction of dangerous states" by look-ahead simulation is becoming a new requirement in the industry.

The challenges go from modeling to accurate results of simulation and monitoring tools in the EMS and market applications.

8.2.1 Accurate Modeling and Data Quality

Some of the problems in the current EMS deployments are linked to modeling errors (Meliopoulous et al. 2001) and parameters that are improperly migrated from planning models to operational databases. The operational model is a bus-branch oriented model, although almost all Supervisory Control and Data Acquisition (SCADA) information is available at the substation level. Making matters worse is the fact that not all of the SCADA information is passed to the operational model; the node-circuit breaker models are not fully considered.

The EMS therefore relies on the State Estimator (SE) to pinpoint and identify topology errors as well as parameter problems. Unfortunately, the identification of the topology problem is combinatorial in nature. The estimation algorithm can pinpoint where the problems are but a system for the fast determination of the actual status of branches, switches, and breakers has not been properly implemented yet.

To compensate, the EMS operators usually communicate with their neighbors whenever unusual behaviors are identified. External network topology errors continue to be an issue and are adjusted manually (or according to schedule) to minimize the impact on the internal part of the power system. Synchronized phasor measurements are currently in place to correct some of these modeling errors. Still, there is a lot of room in this area for research and development towards improving wide-area operations.

Special protection schemes and load shedding schemes are based on predefined scenarios with the support of off-line applications. These applications also suffer from incorrect modeling. For this reason, the planning offices spend a lot of time identifying potential problems and system conditions. They basically create problem scenarios in order to specify schemes to mitigate them.

To reduce the analysis burden, and to get realistic information, the planning engineers are studying available modes to retrieve information from real-time events and create snapshots that deserve further analysis via "what-if?" conditions.

Still, the following problems need to be addressed, spanning the time frames from planning to operations preparation, to operations, to real-time analysis and control:

- Inadequate network modeling
- Incorrect static and dynamic parameters
- Unreliable limits
- Improper protection settings
- Measurement calibration errors

These issues must be addressed as soon as they are identified and as early as possible in the implementation phases of wide-area system information technologies.

8.2.2 Very Large Simulation Models

Electricity markets span very large geographical regions and are not necessarily constrained by utility company jurisdictional boundaries. This has resulted in the need to simulate very large-scale network models that represent a larger portion of the power grid.

A 32,000 bus State Estimator was deployed in 2005 by a company in the USA and continues to be in real-time operation now. Recently, requirements for 50,000 bus models have also been proposed.

Fortunately, modern SE and network analysis software packages are readily scalable to handle tasks of these sizes. Additionally, computer-processing power has increased dramatically allowing these very large equations to be solved in 30–45 s on average.

These large-scale SE solutions pose challenges for:

- Accurate and consistent input data
- Voluminous output data, which need to be quickly summarized as decision-making information for the operator

8.2.3 Accurate State Estimation

SE is considered a fundamental component of the modern EMS capabilities. As a matter of course, SE is periodically executed in order to calculate and provide a consistent and reliable state of the system based on SCADA, synchronized measurements, and other relevant information. SE is expected to calculate very large models, and with a higher frequency rate of execution, impose hard-performance requirements on existing algorithmic methods.

SE nowadays takes full advantage of distributed/parallel processing, given the advancements in available computer technologies. The steady-state estimation must also provide a valid, accurate, and robust solution under a wide variety of normal and emergency conditions.

Market applications and deregulation practices are aggressively requiring much faster, more precise, and more accurate results from SE. In the market context, financial settlements are based on sensitivities obtained from SE. If these sensitivities are incorrect, or unavailable, they translate into significant errors in the settling of market transactions.

Under severe emergency conditions, the estimation process should rely on all vital data available including historical data, recent recordings, and recent results. In this way, it is possible to monitor the grid backbone and adapt automatically. The operators have a critical reliance on SE under these circumstances to provide meaningful results under stressed conditions.

Furthermore, SE is the foundation of all subsequent network analyses such as N-1 Contingency Analysis (CA), optimal power flow calculations, stability enhancement assessments, etc. If SE fails to provide a valid solution, the rest of the network analysis cannot run.

8.2.4 Fast Stability Assessment

Near-real-time stability assessments are extremely desirable at major transmission companies (Avila-Rosales et al. 2003), particularly for wide-area control-room applications. These applications are executed based on current snapshots of the power system from the SE and the latest Phasor Measurement Unit (PMU) measurements. The results of the stability assessment flag the system as operating normally, alarmed, or under emergency conditions. The following types of limits determine these states of operational condition:

- Thermal condition
- Voltage Stability
- Angular stability
- Frequency stability
- Steady-state stability
- Available Transfer Capacity (ATC)
- Market congestion

Multiprocessing applications and appropriate hardware architecture can reduce calculation time to simulate stability problems accurately (Avila-Rosales et al. 2004). Master/slave multilayered configurations are appropriate to handle hundreds of events. There is still room, however, to reduce the burden by using information such as recent violations and an adaptive, up-to-date list of contingencies based on violation histories.

8.2.5 A Comprehensive View of EMS and Stability Results

Most operator information is based on alarms, EMS applications displays, and map board information. There is a vast amount of data available, yet there is often no easy way to provide useful information in a meaningful way to the operator. There is an urgent need for all operators to have better ways to visualize voltages, frequencies, contingency violations due to transactions, and early stability warnings. Under the pressures of cascading outages, rapid frequency changes, and voltage deterioration, an operator will sometimes rely more on instincts and past experiences than on data streams. Needless to say, this is not the optimal way to assess anomalies, fix problems, and prevent imminent catastrophes.

All operators need an easy-to-use, intuitive, geographic visualization system for both steady-state and dynamic stability assessments. Such a system should incorporate all types of warning signals and system violations. Advanced EMS applications are also needed to identify problems more quickly and to propose control actions to mitigate imminent catastrophes. Along with the visualization, operational procedures and use-case scenarios are critical to empower an operator to take a well-informed response to an emerging critical situation.

Some utilities are already using advanced visualization technologies in their control rooms, where they can see at a glance shaded voltage clusters, coloring, and pie charts fed with live SCADA data. This is certainly an area where the EMS applications can improve operations. Visualizing a stability trend is invaluable. Also, showing the operator the grid's immediate history and imminent future conditions can truly help. Advanced visualization is an enabling technology with a significant potential for developing advisory control techniques that would eventually move towards automated closed-loop control in the field.

Some visualization techniques show two-dimensional stability regions where all of the dynamic and thermal readings are displayed. These are continually updated as the system evolves. Going forward, the utilities define what specific data and monitoring information would be beneficial to them in order to improve system stability.

Many consortia have been formed to address specific grid stability operational issues and improved information visualization. These consortia are comprised of utilities, universities, software vendors, and hardware vendors.

8.3 Recent Technology Advances

8.3.1 Faster and More Economical Computer Power

Computer processor speeds and parallelization techniques, along with reducing costs, lead to much greater computer power accessible to utilities. As a result, these centers can perform more complex and computationally intensive tasks.

Distributed processing is now being utilized at control centers to speed up the solution process of certain computationally intensive functions such as CA and Dynamic Stability Analysis (DSA).

8.3.2 Substation Automation: Decentralized Processing

Another ongoing trend is to add more processing capability and intelligence at the substations (Apostolov 2004). Data from these processors can be used locally to optimize substation operations. This information can also be used to improve system-wide optimization and operator decision-making by providing more consistent and valid data for analysis at the control center.

Many utilities are now deploying PC-based SCADA systems at major substations. In addition to basic SCADA-type functions, new applications are being added to improve monitoring and control locally.

8.3.2.1 Substation-Based State Estimation

Current substation technologies already have infrastructure to handle the PMU work. This is done through relays in feeders and devices connected to the high sides and low sides of the transformers. PMU technologies can be integrated with other systems in order to provide operators with a wide range of network applications and data correction methods.

The use of substation technologies will change the way that the Regional Transmission Organization (RTO) business is modeled. A lot of data filtering and data cleanup can take place before the final data are actually used at the transmission level. The whole configuration, including switches, breakers, flows, etc., can be monitored and recorded. The local control and coordination of protection tasks during load shed is one of the most important operations during emergency conditions and there is a lot that can be done at this level.

8.3.3 State Estimation Robustness

Nowadays, SE is becoming a critical function at the control center. Market settlements and revenue calculations are based on subtle details and key data from the SE systems. The newer, very large models have also been focusing on improved SE functions. Furthermore, SE is the foundation of all subsequent network analysis calculations. All network-oriented applications (steady-state and dynamic) need the initial conditions as the starting point.

Therefore, if the SE fails, the rest of the network sequence does not have a valid base number. These technical drivers have resulted in a closer scrutiny of SE methodologies and algorithms. They have also resulted in the development of a more accurate, efficient, and reliable SE application at the control center. In the end, the SE solution must be guaranteed by any means necessary, either by using approximated solutions or by reducing the scope through utilizing new measurements and algorithms.

8.3.3.1 Wide-Area State Estimation

The possibility of running SE at the scan-rate level (substation level) and less-than-a-minute level (wide-area level) is one of the most exciting lines of power grid research today. The ability to take advantage of the existing substation infrastructure in order to identify and correct problems for more accurate readings at the wide-area level can now be implemented.

One reason for this progress could be the fact that the RTO business lacks detailed models in some areas (breaker node). Other areas like the substation level, however, provide all of the necessary details. The usual error problems in the vicinity of failures could be avoided through the use of substation-based applications. Topology problems could also be quickly identified.

8.3.4 Improvements in Visualization Techniques

Experience of blackouts globally emphasizes the need for improving control center capabilities for better "situational awareness." This means that the operators need to constantly be aware of current system conditions. The information needs to be presented rapidly, reliably, and meaningfully so that decision-making is expedited. Accompanying situational awareness is the need for operational response guidance that defines the actions that would relieve wide-area stress and dynamic threats. Specific guidance is key to taking real-time action in response to an alarm.

8.3.5 Globally Synchronized Phasor Measurements

Synchrophasor (or phasor) measurement involves deriving a phasor representation of measured waveform, referenced to an ideal 50- or 60-Hz sine wave with peaks on precisely timed second boundaries (Fig. 8.1). The ability to represent a voltage or current waveform concisely as a magnitude and angle means that the measurements can be streamed from the substation to a central unit where geographically separate measurements can be time-aligned and compared.

Phasor measurements are increasingly being deployed across power grids worldwide. In North America, under the Smart Grid Investment Grants (SGIG), the number of PMU installations has grown fivefold over the past 4 years. Since 2004, 1200 PMUs have been installed on the US grid. This trend has energized the industry—the next large-scale deployments of PMUs are expected to happen in India and Brazil. India is committed to deploying more than 1700 PMUs across the entire country beginning in 2014.

Each PMU typically monitors 6–36 phasor quantities, digitals, frequency, and frequency rate-of-change, and all of the data are time-tagged using the Global

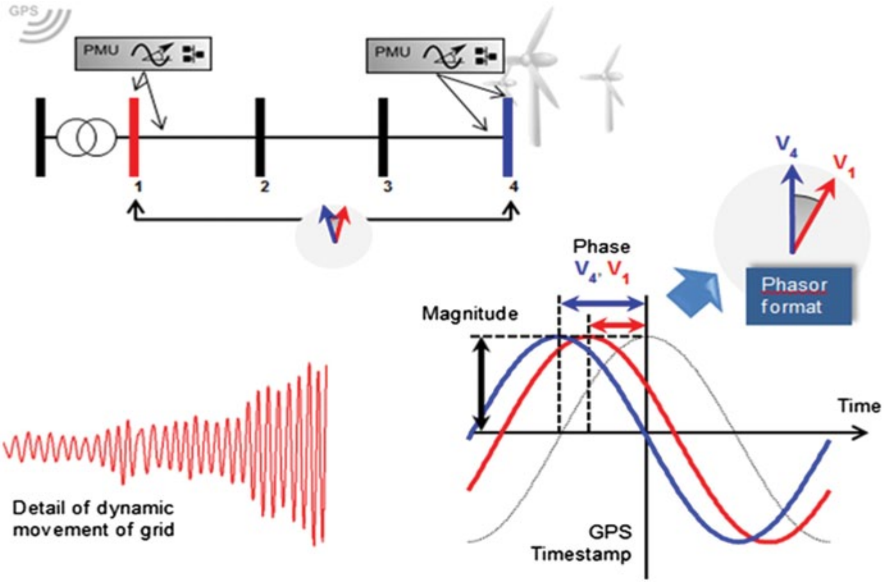

Fig. 8.1 Phasor measurement units (PMUs) and synchrophasors

Positioning System (GPS) to insert a global time stamp. There is also a growing trend of incorporating synchrophasor capability into relays and other IEDs. These synchronized phasor measurements are transmitted at very fast rates: from 10 to 120 samples per second. The information is captured at the millisecond time frame, and includes voltage, current, and frequency values.

8.3.5.1 PMU Instrumentation

Timely, synchronized PMU measurements are available to operators nowadays. Most utilities worldwide have some form of PMU project, in either research or commercial application. As illustrated above, PMU devices measure synchronized voltage and current, and transmit data to a central location where they are compared, analyzed, and processed. The PMU hardware is normally based on platforms built for disturbance recording or protection relays, and are equipped with a GPS receiver and Inter-Range Instrumentation Group-B (IRIG-B) time-code generator. While GPS is currently used exclusively as the time source, there is an industry direction to reduce dependence on continuous GPS availability through the use of Institute of Electrical and Electronics Engineers (IEEE) 1588 Point-to-Point time protocol and highly stable master clocks.

The ability of PMUs to provide synchronized information offers operators a lot of advantages, like dynamic trending. This facilitates the prediction of frequency behaviors, active load changes, and reactive power changes immediately after dis-

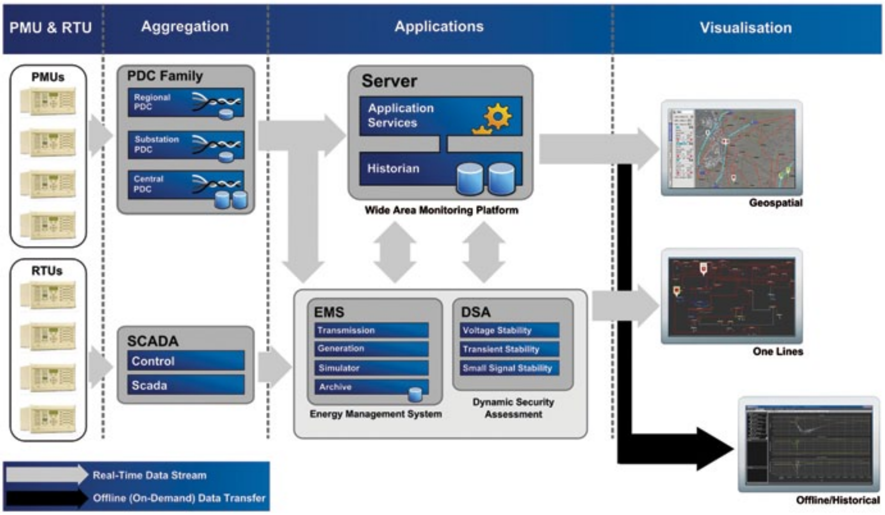

Fig. 8.2 PMU–PDC and application integration layers

turbances. This gives the operators a better chance to accurately assess both grid stability and overall stability.

Most utilities are currently considering the following integration layers for monitoring:

- *Measurements:* This may consist of a set of PMUs from different vendors and Intelligent Electronic Devices (IEDs) passing information to a Phasor Data Concentrator (PDC) at the substation level.
- *Data processing:* This involves analysis algorithms applied to incoming data to extract information such as oscillation frequency and damping, and disturbance event occurrence and impact. The information is displayed and stored by the WAMS Datacenter, and can be forwarded to the EMS or other clients.
- *Data management:* This consists of information being accessed normally via dedicated communications using a variety of protocols to exchange information between several databases, data archiving systems, planning model validation programs, SCADA systems, and SE systems.

The accuracy of PMU data has been considered in some detail, relating to the PMU processing itself and the instrumentation channels. While the hardware solution is not being completely discarded, there are software alternatives now under consideration in the North American Synchrophasor Project (NASPI) consortium. A lot has been learned from the off-line applications experiences in the PMU/PDC environments. This can be seen as the first step towards online applications.

Figure 8.2 details the different integration layers and the data management tools available to the EMS.

8.3.5.2 Emerging PMU Standards

As PMUs become mainstream technology, there is a need for industry standards around performance and data exchange to ensure measurement accuracy and interoperability across different manufacturer offerings. Since 2005, IEEE C37.118 had been the de facto standard for real-time synchrophasor data exchange between PMUs, PDCs, data management systems, and applications. The standard was updated in 2011, and its component parts C37.118.1 and C37.118.2 now dictate the requirements for synchrophasors.

In particular, the C37.118.1-2011 addresses the measurement aspects for phasor, frequency, and rate-of-change of frequency (ROCOF)—it retains the steady-state requirements from the 2005 standard, and adds performance requirements for dynamic conditions. Additionally, it distinguishes these requirements between "M-class" (i.e., analytic applications that could be adversely effected by aliased signals and do not require the fastest reporting speed) and "P-class" (i.e., protection applications requiring fast response). The C37.118.2 addresses the communication aspects for synchrophasor data exchange.

Similarly, the recently developed IEC 61850-90-5 report on Routed Generic Object Oriented Substation Event (GOOSE) and Sample Value (SV) datasets is an upgrade to the IEC 61850 GOOSE and SV profiles respectively to accommodate synchrophasor measurements. The GOOSE is a user-defined dataset that is sent primarily on detection of a change of any value in the dataset. SV is also a user-defined dataset; however, the data are streamed at a user-defined rate (e.g., the reporting rate of the synchrophasors). The new profile takes either a GOOSE or SV dataset and wraps it in a UDP/Multi-cast IP wrapper. Security is a key element in any communication system. To this end, the 90-5 profile implements authentication of a transmitted message and optional encryption of the same message (Parashar et al. 2012).

8.3.5.3 PMU Allocation, Redundancy, and Communication Cost

As utilities transition from Research and Development (R&D)-grade PMU installations to production-grade deployments, some issues that need to be addressed include:

- Resource allocation
- System redundancy
- Data quality
- High-speed communication facilities
- PMU–PDC communication backup for failures

For wide-area control, a redundant set of measurements is desirable so that, in the event of the failure of one PMU, other adjacent PMUs and information from connected devices can provide reasonable results.

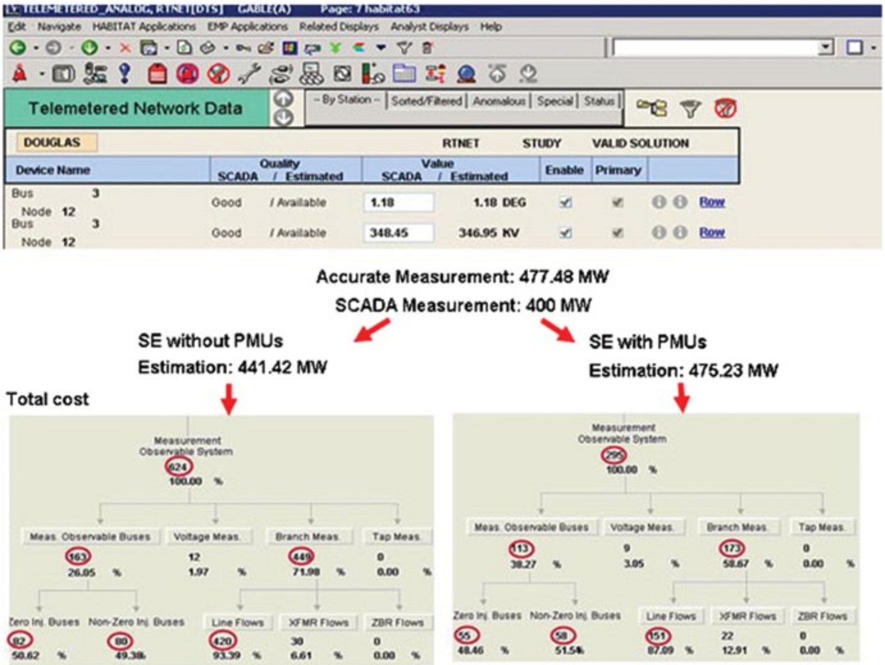

Fig. 8.3 PMU impact on state estimation

The PMU allocation problem is being analyzed in order to determine a meaningful allocation standard. Such a standard will seek to minimize the costs of communications while maximizing the ability to leverage the EMS applications particularly the SE. Some of the allocation tests seek to find a baseline through graph theory, observability (Baldwin et al. 1993; Nuqui and Phadke 2002; Xu and Abur 2004), and the costs of communication. Other utilities focus on oscillation patterns to improve the system damping as part of the wide-area stabilization process.

Regardless of the scope of the work, there is a tendency now to allocate the devices as if they were building blocks that will remain in the same place along the installation plan. In the end, however, PMU allocation will likely be constrained by the installation and communications cost.

Several studies have been conducted and the findings are under consideration to evaluate the benefit of the synchronized measurements in SE. The study results are very positive and as the number of PMUs increases a better accuracy of SE results are expected. Figure 8.3 shows a sample of a process during the benefit analysis of SE with and without PMU devices.

8.4 Techniques for Improving the Reliability of Power Grid Operations

8.4.1 Direct Stability Measurements and PMU-Based Analytics

The advent and growth of PMU data at the control center has spawned a new suite of purely measurement-based synchrophasor analytics. This paves the path to being able to monitor and analyze grid behavior at a sub-second rate, which in turn makes online grid stability analysis a practical reality. Furthermore, these applications do not have the overhead burden of the large network model (along with uncertainties in the model data and SCADA data), but rather are based on digital signal processing techniques to characterize the power grid's dynamic behavior. Operational benefits of adding synchrophasor applications at the control center include:

- Maximizing utilization of existing transmission capacity by confidently operating the grid closer to its actual, "true" operating limit
- Providing an early warning system to quickly identify grid disturbances to guard against blackouts
- Monitoring for undesirable grid dynamics and oscillations
- Identifying islanding conditions
- Enabling efficient forensic post-disturbance analysis to find out what just happened, where, and why

Some of the emerging PMU-based analytics are discussed below.

8.4.1.1 Phase Angle Separation to Assess Steady-State Stress

Using "phase angle differences" within an expression of stability margins (as opposed to just megawatt, MW, flows) is a more direct indicator of grid stress between key source and sink regions, for two reasons. Firstly, because it not just monitors MW flow problems but also encapsulates impedance changes due to line outages which weaken the transmission paths. Secondly, noting that stability-constrained corridors are not simple impedances, but include loads and power injections along the length of the corridor, the angle difference is a useful indication of the overall loading of the corridor and the effect of this loading on the physical stability limit. In practice, it can be beneficial to introduce angle difference limits in combination with power limits, so that the power limit can be exceeded if the angle is within the boundary (Fig. 8.4).

A scenario that has been studied for power-angle constraints is related to a Transient Stability (TS) constraint in a corridor that has a large infeed of low-inertia renewable energy that contributes to power flow without participating in the TS problem. Some indicative results suggest 10–12% uplift in the TS limit could be achieved through the use of the power-angle constraint (Wang et al. 2014).

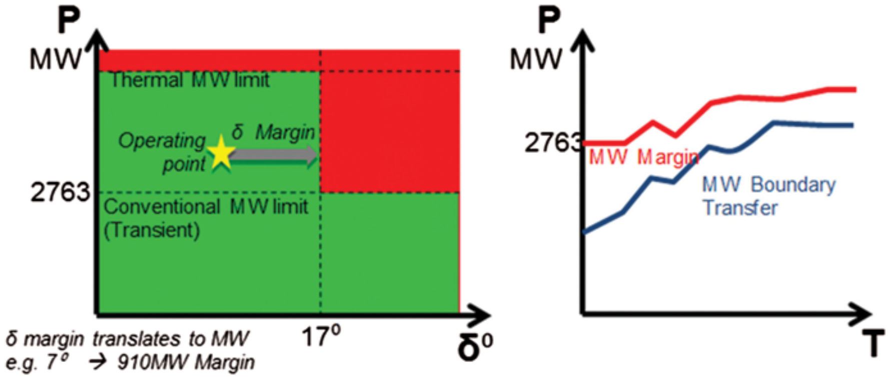

Fig. 8.4 Operating constraints based on angle difference and power, showing *operating point* and *margins*

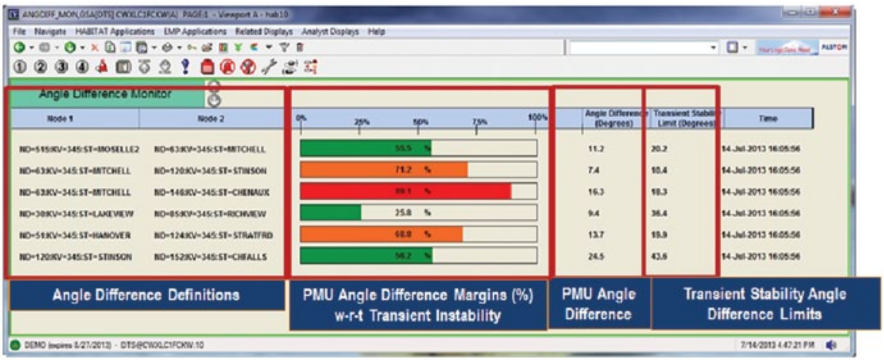

Fig. 8.5 Angle difference monitoring: against the EMS transient stability limits

Increased MW flows or weakening of transmission paths both result in greater stress on the grid. Additionally, since topology changes are reflected in the monitored angle differences themselves, the angle limit will tend to be more constant than the limit based on summation of MW flows. The traditional approach of prorating the MW limits to account for outages on the grid is therefore no longer necessary when moving to an “angle difference” approach; this is a significant benefit to managing and operating the grid more reliably and effectively (Fig. 8.5).

8.4.1.2 Oscillation Monitoring

The power grid experiences a variety of power oscillations, including:

- Slow-power oscillations related to governors or improperly tuned AGC bias (typically 10–100 s period, or 0.01–0.1 Hz)

- Inter-area electromechanical power oscillations (typically 1–5 s period, or 0.2–1.0 Hz)
- Power plant and individual generator oscillations
- Wind turbine torsional oscillations (usually about 1.5–2.5 Hz)
- Control issues in generator, SVC, and High-Voltage Direct Current (HVDC) systems
- Steam generator torsional oscillations (about 5–50 Hz, etc.)

Grid oscillations are always present. If the system is stable, normal power imbalances excite oscillations that are damped and return to a steady state. However, oscillations can become negatively damped and grow in amplitude. The growing oscillations can result from power system stress, unusual operating conditions, or failed controllers (PSS, excitation, etc.), or unintended control interactions between devices in the network. Also, cyclical mechanical power or local control instability can inject a forced oscillations into the grid, which can be amplified through the network if it coincides with a network oscillation.

Growing power oscillations can cause line opening and generator tripping, and in the worst case, lead to cascading power blackouts. Another risk is that the interactions between oscillations can lead to major equipment damage. One interaction phenomenon is sub-synchronous resonance when a generator torsional oscillation resonates with the LC circuit natural frequency of series compensated lines, and there is a risk of breaking a generator shaft or causing large over-voltages on the transmission system. Recently, a similar interaction between wind farm control and series compensated lines was observed, known as sub-synchronous control interaction. Higher-frequency phenomena can be added to a WAMS system, but may require adapted measurements.

With PMU measurements, it is possible to characterize the stability of the various oscillatory modes in real time based on the reaction of the power grid to random perturbations in loads or generation (Fig. 8.6). The information provided by such a measurement-based application is analogous to eigenvalue analysis of dynamic models and includes:

- Mode frequency, amplitude (energy), and damping trends (which are useful indicators of power-system stress, usually declining with increased load or reduced grid capacity)
- Mode shape information, typically presented on a geographic display (to identity observability of that mode across the power grid)

The lower-frequency dynamics, typically up to 10 Hz phenomena, can be extracted from standard PMU measurements. Also, the sources contributing to poor damping can be found from measurements (Arango et al. 2010; Al-Ashwal et al. 2014).

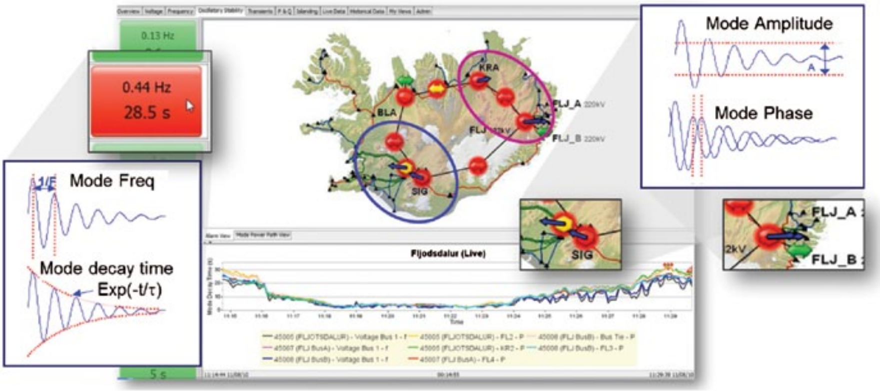

Fig. 8.6 Oscillatory stability monitoring and visualization in the control room

8.4.1.3 Islanding Detection, Resynchronization, and Blackstart

The cardinal symptoms of electrical separation of parts of a power system include: (1) a sustained difference in the frequency across the system and (2) freely rotating phase angles.

PMU-based voltage phasor measurements, together with frequency measurements, can provide an immediate indication of the separation of a system into two or more electrical islands. They can also provide valuable information for operators to prepare the system for resynchronization and supervise the process of synchronizing the system and subsequent network strengthening. It is very useful for operators to have a supervisory indication of the frequency and angle so that islands can be balanced before a resynchronization is attempted. It is also useful for immediate diagnosis if the check-sync relay fails to close, or if the breaker reopens.

This PMU-based geographic view of the system is also useful in the blackstart process. A blackstart plan normally involves energizing the system from a few generators at strategic positions in the grid, then re-energizing the network islands around the generators and finally reconnecting the islands. The network can be quite insecure during this process, and view of the stability of frequency and angle in real time is valuable (Fig. 8.7).

8.4.1.4 System Disturbance Detection and Characterization

PMU measurements make it possible to promptly detect sudden disturbances on the grid and to identify the nearest points of measurement to the source of the disturbance. Such a disturbance could be a trip of a major generator, loss of a major load, or a line trip. Because of the inertia of rotating machines, angles of generators

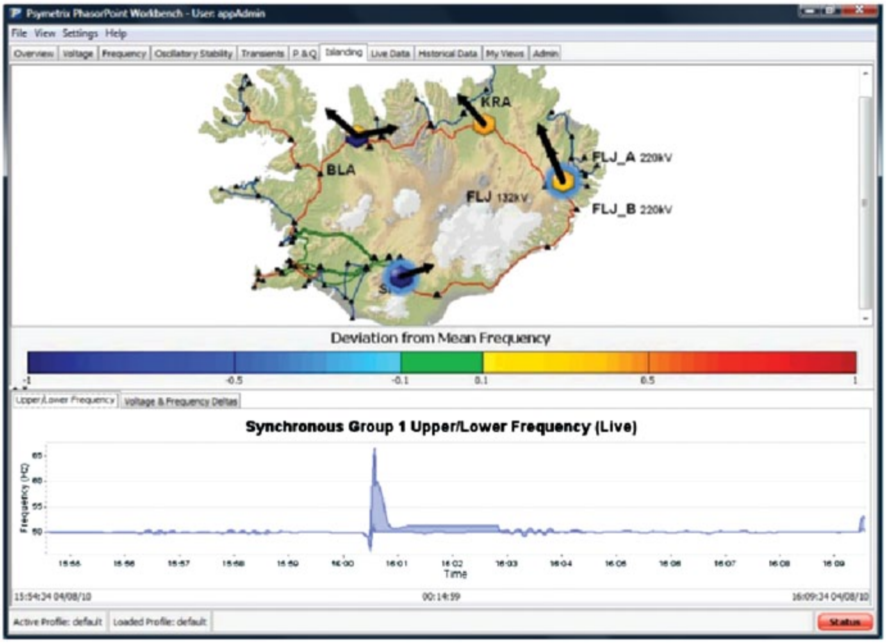

Fig. 8.7 Islanding visualization in the control room

cannot change instantaneously, and the angles and instantaneous frequency will change more rapidly close to the source of a problem than at a distant location.

Furthermore, based on the emerging frequency and phase angle patterns following the disturbance, it is possible to characterize it as a line trip or a generator/load loss. In the case of generator trip or load loss, it is also possible to quantify the MW amount based on drop in frequency shortly after the event. Such applications are also capable of triggering event data captures with a user-defined pre- and post-event period, which are automatically stored in the long-term event storage archive for post-disturbance analysis.

Even if such disturbances may occur outside the utility's jurisdictional footprint, since the grid is interconnected, the impact is felt across the entire power system. Hence, such a PMU-based application is especially valuable to grid operators as it provides observability across the larger system, for which traditional SCADA measurements may not be available.

8.4.1.5 Voltage Stability (VS) Monitoring

A wide variety of purely PMU-based VS indices that serve as a measure of the proximity to the voltage instability (degree of system stability) have been proposed. In principle, such a stability index maps the current system state into a single (usually scalar) value with a predictable shape that can be monitored as system operating conditions and parameters change (Parniani et al. 2006). Some of these approaches include:

- Monitoring voltage magnitudes at critical locations (i.e., key load center and bulk transmission buses): This is the simplest approach and consists of monitoring voltage magnitudes at critical locations and their comparison with predetermined thresholds. Voltage magnitude is not a good indicator of the security margin available at an operating point. However, when the system enters an emergency situation low voltage of the affected buses is the first indication of an approaching collapse.
- Sensitivity-based VS indices: These indices relate changes in some system quantities to the changes in others, such as a change in voltage magnitude per change in MW/MVAr flows, which can directly be computed by tracking the PMU measurements.
- VS indices derived from Thévenin impedance matching condition (Vu et al. 1999): They measure stability degree of individual load buses (or a transmission corridor) by monitoring the equivalent Thévenin impedance of the system and equivalent impedance of local load (magnitude of these values are equal at the voltage instability point). Furthermore, stability degree can be expressed in terms of local voltage magnitude and voltage drop across the transmission path as well as in terms of power margin (MW or MVA). The use of these indices must in some way address contingencies, as the impedance can instantaneously change by nearby generation or voltage support tripping.
- Reactive power reserve monitoring: A considerable decrease in reactive power reserves of system's key generators is a good indicator of system stress. Computation of reactive power reserves requires placement of measurement devices at several locations, does not require system model, and in principle can make use of both SCADA and PMU-based measurements (Bao et al. 2003).
- Singular Value Decomposition (SVD) applied to a measurement matrix: This approach focuses on computing and tracking the largest singular value of the matrix. Measurement matrix is constructed from PMU measurements such that each column is a stacked vector of the available PMU measurements over a time window (two to three times the number of available PMUs; Overbye et al. 2010).

8.4.2 Positive Impacts of PMUs on the EMS

Integration of the new synchrophasor solutions with modern-day EMS analytics is our best promise for implementing a practical production-grade online stability solution at the EMS.

In Fig. 8.8, on the left, we have the traditional EMS analytics (SCADA, State Estimator, etc.) that have been developed over the past 5 decades. More recently, we have integrated "model-based" stability analytics which use the network model and the State Estimator solution to run dynamic stability studies. These are called Dy-

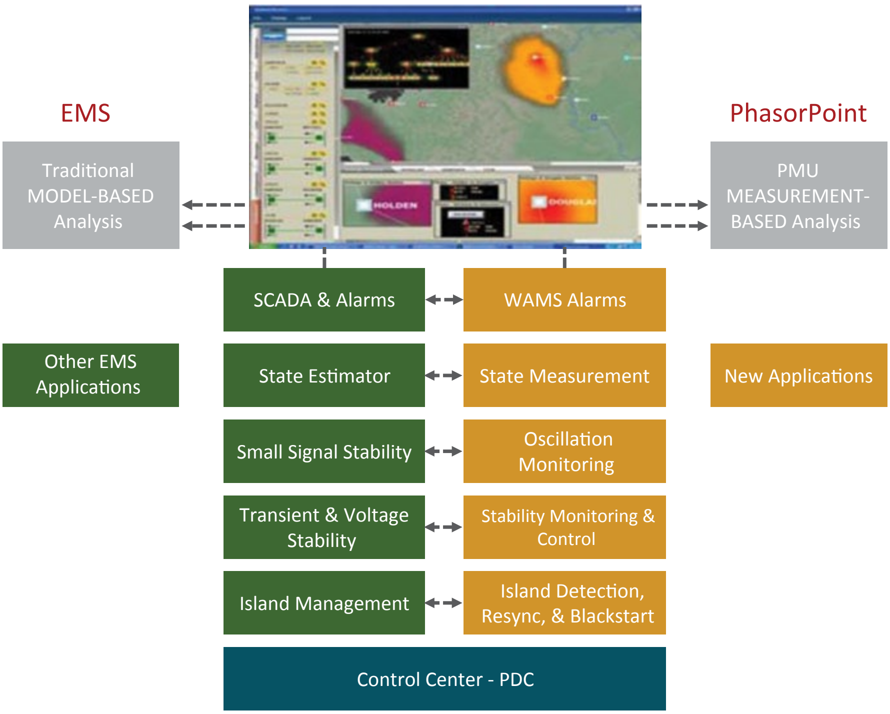

Fig. 8.8 The next-generation energy management system

namic Security Assessment (DSA) and include assessments of Small-Signal Stability (SSS), VS, and TS. These have traditionally been off-line planning functions since they are computationally very intensive. More recently, with faster computing processors, algorithmic approach changes and DSA software performance enhancements, these functions have migrated into the online EMS and can now run in "close to real time," with the advantage of assessing stability risks and constraints based on the actual operating conditions rather than conservative planning assumptions.

8.4.2.1 PMUs in State Estimation

The most immediate benefit of combining PMUs with model-based applications is the use of the PMU data to improve the accuracy of existing topologies and State Estimators (SEs). This benefit can be used as a migration path towards more comprehensive installations. The operators see the benefits at the monitoring levels so they wish to use the information as much as possible to get better solutions. SE is capable of running at the scan rate at the substation level and less frequently at the wide-area control center level. This is done in order to assess the stability of the grid with the latest information from the field. PMU technology has the potential for a positive impact on SE in a number of key areas including:

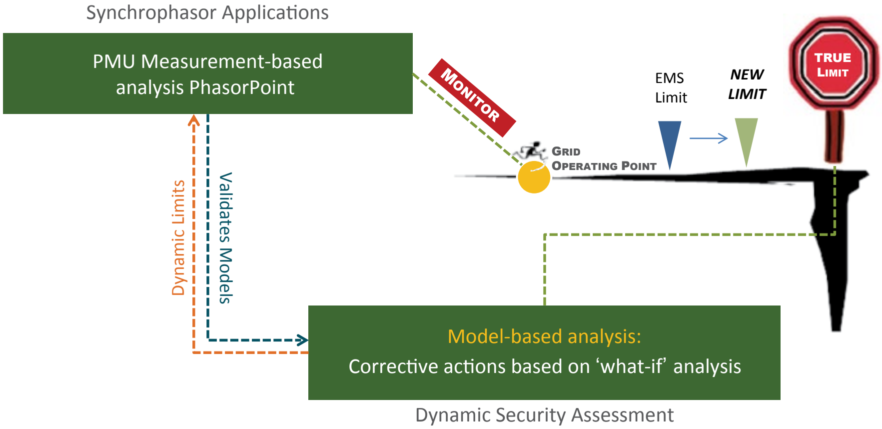

Fig. 8.9 Integrating PMU measurement-based analysis with model-based DSA applications

- Increased observability
- Improved solution accuracy
- Improved convergence
- Improved detection of bad data

More recently, a purely PMU-based State Estimator has been implemented for entities that have complete PMU observability for all or a portion of their transmission network. Since this is a linear problem, this Linear State Estimator (LSE) can operate at sub-second rate of the incoming PMU data and towards dynamic state estimation.

8.4.2.2 Integrated PMU Measurement-Based and Model-Based Stability Analysis

Figure 8.9 illustrates how the model-based and measurement-based analytics work together for congestion management. The synchrophasor applications tell you what the current operating state is and track its changing behavior at sub-second rates. The operator wants to know how far the current state is from the edge of the cliff or the limit at which the grid would collapse—this is called the "true limit." This "true limit" typically reflects the post-contingency operating conditions (i.e., N-1 scenario), and is therefore determined by the EMS model-based DSA tools since they are based on a network model and can perform what-if studies to increase loading and stress on the grid till its point of collapse. Traditionally, estimates of the "true limit" have come from off-line planning studies and on "worse-case scenarios" to accommodate a wide range of conceivable operating conditions and system contingencies. Furthermore, a safety margin is required to establish the "EMS limit" since the model which was used to calculate the limit has inaccuracies and uses conservative assumptions. For these very reasons, these operating limits tend to be overly conservative which only means that existing transmission assets are not being utilized at their full capabilities.

By running the DSA tools in real time based on the most recent "State Estimator" solution (i.e., current operating conditions), we are able to eliminate some of the uncertainties, and therefore imply less conservative limits.

The new limit based on real-time measurements combined with real-time model-based analysis can be less conservative for a number of reasons:

- The DSA limits are based on a real-time stability assessment (as opposed to an off-line planning study) and reflect the current operating condition.
- The measurement is more directly related to the physical phenomenon, such as angle measurements being a more direct measure of TS than MW.
- The dynamics analysis extracted from measurements relate to the actual dynamic condition of the grid and reduce uncertainties implicit in the model (e.g., whether equipment and control is operating correctly, nature of the load model, etc.).
- Actions can be defined that respond to emerging threats at an early stage, while conventional systems require a longer time frame to design a response. A shorter look-ahead time period means less conservatism in the volatility assumed between the study time and real time.

The ultimate goal is closed-loop wide-area control and protection of the grid. Current grid stability applications estimate the control signals and send them to the devices that are very far apart geographically. This type of operation can be problematic. As an alternative, it may be more efficient to concentrate on reduced portions of the network and extend the findings to wide-area implementations, at least until better and faster communication facilities are available.

8.4.2.3 Monitoring the System State

The proper use of early warning signals (Bhargava et al. 2004), dynamic simulations, and visualizations will permit operators to quickly take actions to prevent and/or correct imminent systems problems.

The following modes are suggested for wide-area systems analysis time horizons:

- On-line wide-area monitoring of current states
- System state predictions
- Planning analyses

8.4.2.3.1 Online Wide-Area Monitoring of Current States

The ability to model and simulate grid behavior over a wide range of time domains, frequency domains, and topological resolutions needs to be developed.

The applications comprise fast, dynamic tools for transient (angle) variations, VS changes, and long-term dynamics to simulate all sorts of power plants and nonlinear devices on the grid. The consideration of fast-time domain techniques, such as quasi-dynamic simulations, may help to evaluate cascading and islanding during a system recovery. The EMS will take periodic grid snapshots to update the network topology and provide information for dynamic simulation and assessment.

The extent of the network topology to be modeled needs to be adapted to handle a wide range of structures, such as RTOs, stability coordinators, transmission operators, and others. The proper identification of events and conditions in the system should trigger the right time frame over which the appropriate dynamic simulation and modeling are needed. The use of synchronized information and processing is synonymous with wide-area monitoring.

8.4.2.3.2 System State Predictions

There is definitely a need to be able to predict where the system will go before the control actions are deployed (Khatib et al. 2004). A simulation environment should be available using real-time information from the EMS in addition to historical data recordings that can be fed into the dynamic simulation. The accuracy of the system state prediction simulation environment depends on how reliable the schedules and limits are in the short-term time frame. Under catastrophic conditions, a few minutes in advance may help to significantly reduce the risks of system failure.

For fast-state prediction simulation, a change of simulation scope and region of interest may help. The state prediction could be triggered automatically or on demand to assess control movements and reconfiguration plans during disturbances. In this way, a lot of potential problems can be identified. For emergency situations, a model including only the measurements that can be delivered to the control center in the shortest possible time is required. These measurements may include items such as:

- Important generator outputs
- Frequency and voltage measurements
- Important flow measurements
- Important new measurements (angle measurements)
- Information and recent recordings

One of the goals of the system prediction environment is to estimate where the system is heading and what the stability level is going to be (Samuel et al. 1994; Savulescu 2004) when it gets there. If the events that created the condition (energy imbalance) are known, the angular and VS assessment simulation could be used to avoid further cascading (that otherwise could drive the system to total collapse). The purpose of the state prediction is to assess the long-time condition (within approximately one hour or so) before the system would reach a state where voltages might collapse and generators might lose synchronism.

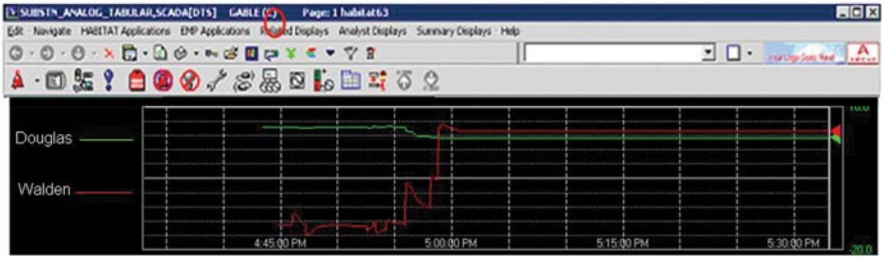

Fig. 8.10 System prediction information

Dangerous states could trigger alarms in advance. Recent SE snapshots combined with time-domain analysis and historical information could provide a good opportunity to exploit consecutive snapshots and identify any system trends. After the system prediction is done, the operator would be in a position to identify:

- Grid stability after large disturbances
- Grid movements towards unstable conditions

Figure 8.10 provides the look of the angular trend between two selected points (PMU) after the occurrence of an unanticipated outage (prediction) while the grid is experiencing heavy traffic. The substations and monitored points can be selected in advance.

8.4.2.3.3 Planning Analyses

Analytical applications run in study-mode environments and can be used as stand-alone models or incorporated into network sequence studies. The study tool is used to prepare cases, perform validations, and update the bus-branch model based on "what-if" conditions from the latest power flow results.

The study mode can be initialized from real-time snapshots or previous cases, as long as the models are consistent; otherwise, the validation task will reject the execution. The planning horizon studies are prepared using the corresponding time-point models and topologies in the study network sequences. Then a number of executions are performed and the corresponding output results are saved back to the EMS.

PMUs are of immense benefit to the planners as well. Specifically, the dynamic observability they provide along with the precise time synchronization is very valuable for after-the-fact postmortem analysis of system disturbances to identify sequence of events and associated root causes, as well as assesses power system performance and response following the events.

The synchrophasor-based observations during such disturbances are equally useful for dynamic model validation, as they offer valuable feedback to validate and fine-tune the dynamic models such that the model-based reconstructions of

Fig. 8.11 Dynamic model validation using synchrophasor measurements (*left*), along with simulated reconstructions (*right*)

these system events closely match the actual grid performance captured by PMUs. Figure 8.11 shows how synchrophasor measurements, along with simulated reconstructions of the disturbance, can be utilized in an off-line mode to verify the dynamic models.

When there is a clear discrepancy in the time domain, a modal decomposition is useful in identifying the particular mode(s) contributing to the mismatch, and the associated mode shape is helpful in identifying a particular power system element that needs validation. For example, in Fig. 8.11, the discrepancy shown can be attributed to a 1.07-Hz local mode where a positive damping (5.59 %) has been identified from the measurement recording, while a negative damping (−0.73 %) is indicated from the corresponding simulations.

8.4.2.4 Dynamic Stability State Assessment

PMU data can be analyzed and preprocessed to notify the operator about rapid changes in any of the measured electrical variables. These rapid changes could trigger recording devices to start capturing data at a faster rate and the EMS applications could be engaged. This would provide the operator with recommendations for preventive/corrective actions (Pavella et al. 1999).

The following warning signals are available at specific PMU locations:

- Sustained frequency oscillations
- Excessive angular deviations between pairs of nodes on the grid
- Slow voltage decline
- Sudden voltage dip

- Sudden current change
- Sudden current dip
- Fast frequency decline and rate
- Sudden change of active/reactive flows

8.4.2.5 Automated System Restoration

Automated system restoration has been an objective of many utilities in the past, and very recently (since the August 2003 blackout) it has been the focus of studies to avoid cascading events and even total system collapses. System recovery depends very much on the topological structure. Modern short-term, mid-term, and long-term applications provide enough simulation to support intelligent grid control actions and to avoid cascading incidents, although, again, the communications component is really the big issue in the wide-area context.

8.4.3 Online Dynamic Stability Assessment Techniques

Today's VS and TS tools (Giri and Avila-Rosales 2000; Kundur et al. 1999) are designed for online as well as off-line applications.

The voltage tools perform stability assessments using static analysis techniques. For any number of given scenarios, they determine the VS of the base case (operating point), for the given contingencies, solution/control parameters, and stability criteria (stability margin, voltage profile, and volt-amperes reactive (VAr) reserve). In addition, for each scenario that includes a transaction (power transfer from a source to a sink) it can determine the VS limit of the transaction's increase or decrease. Contingency screening and remedial action capabilities are also available.

The transient application performs stability assessments via nonlinear time-domain simulation techniques (Avila-Rosales et al. 2000). In addition, a number of post-simulation analyses can be carried out to assess the various forms of TS, including angle stability, damping, transient voltage and frequency stability, and relay margins. It can even process multiple contingencies and multiple study scenarios in a single session. Similar to its voltage counterpart, power transfer limits in defined transactions can be determined automatically. Further, these determinations comply with all forms of stability requirements.

Dynamic applications are designed to provide the operator a set of stability indices to assess the overall system stability and to provide early warnings of problems. These are all based on fast and accurate time-domain simulations (Kundur et al. 1998).

Under normal conditions, angular and voltage transient simulations provide the stability margin for a set of energy transactions and flow gates ("from and to" locations on the grid). The margins are used to determine control recommendations to maximize grid stability, while ensuring market rule compliance and maintaining sufficient active/reactive power reserves.

Small-signal analysis contributes with measurements taken to identify oscillation problems and parameter tuning to increase the system damping for certain contingencies (Kundur and Wang 2002). These early warnings help the operator to:

- Measure the impact of any event and the current stability status (sort of red, yellow, blue, and green light indicators)
- Evaluate the overall thermal, transient, voltage, and frequency limits and provide recommendations to reduce the risks of operation

8.4.3.1 Wide-Area Stability Modes

Dynamic stability assessment has always played an important role in systems operations. It has also been one of the most computationally intensive calculations in any control center. Utilities are now demanding tools that can address the challenges of competitive markets, while providing the same reliable operations as a full EMS. Specifically, utilities are requiring tools to address static and dynamic stability power system challenges. The advent of independent power producers (IPPs), multiparty energy transactions, increased transaction volumes, and new energy routing routines requires system operators to put a great emphasis on voltage control and stability changes.

The analysis of the current operating condition, immediate future, and several time points in advance for large systems is becoming more of an issue every day. This level of work imposes additional computational challenges, which are affected by model accuracy, solution techniques, and systems architecture. There is clearly a need for three frames of analysis to assess stability, and they are usually defined as modes of operation.

All modes depend on efficient communication and data transfer from the EMS hardware to all of the other platforms and machines. Each mode requires the validation and input/output data processing between the EMS and dedicated machines for stability; the following are some of the features:

- Data validation
- Data exchange between all dynamic engines and the EMS
- Output results and visualizations
- User interfaces and operations
- Multiprocessing system configurations

The triggering and data exchange operations between the dynamic engines and the EMS are controlled and coordinated by applications. All input data for voltage and TS are sent automatically (or upon request) to the selected dynamic parties for evaluation. A function constantly checks the availability of the results in order to retrieve the proper information from the dynamic machines. The coordinator ships the network snapshots and specific data once a validation process is executed. Multiuser capabilities can be performed since there is a unique relation between the coordinator and the corresponding dynamic instances. The coordinator knows what to send to whom and when to get the results back to the EMS.

8.4.3.2 Online Dynamic Triggering

A real-time version of the dynamic coordinator is available as part of the EMS' online sequence. This execution can be enabled or disabled from the real-time network analysis control panel. It executes on a schedule (which can be defined by the user) provided that the SE solution is valid. A function has been added to the coordinator for the purpose of exporting a bus-branch model to all dynamic engines, since the EMS is based on a node-breaker model.

The latest topology changes are reflected on the exported network snapshot. The use of web-based user interface tools (and the viewer tools available on the dynamic side) reduces the amount of data transferred back to the EMS since they are maintained until the next online execution takes place. The operating horizon, which starts in the next hour, covers the immediate short term. The planning horizon starts after the operating horizon and continues into the future. The coordinator does not allow entries from the user unless a new network model is put online.

8.4.3.3 Dynamic Stability System Configuration

The dynamic client/server configuration allows for distributed computing of any number of scenarios on any number of CPUs. The clients communicate with the EMS to receive the data and return the results. The clients also coordinate the servers for the parallel processing of scenarios received from the EMS. The overhead for distributed processing is very small and additional server machines/CPUs can be easily added to the cluster for increased computational speed.

8.4.3.4 Dynamic Stability Validation

Dynamic applications require a network model, monitored elements, selected outputs (units, branches, and buses), and transaction specification (source and sink definition, step, type, and load options). In addition, certain specific data are required for each application.

Before the dynamic applications are executed, there is a full validation that takes place to make sure the dynamic parameters and allocations are updated with the latest topology changes. The validation function validates the content of the entire dataset against the existing network contingency and translation table to maintain user-oriented descriptions. The translation table, which is automatically updated during every run, maps the EMS node-breaker model to the bus-branch model used by the dynamic engines.

Since no dynamic data are maintained on the EMS side, the bus, unit, and load sections of the translation tables must be such that the locations of the buses, the generators, and the other dynamic devices match with the numbers used in the dynamic data files.

8.4.3.5 Data Exchange Between Dynamic Analysis and the EMS

The data exchange function sends the dynamic oriented data, the network snapshots (created by either SE or power flow), the contingency data, and the translation tables in the format specified by the dynamic engines.

A shared space is used as the central location from where the EMS and the dynamic engines can exchange information; each dynamic task is tied to a PC on which the dynamic client programs run. When the dynamic executions are triggered, the clients coordinate the computation of the scenarios on available servers. A user-friendly configuration setup avoids concurrency problems. The data exchange function consists of tasks for the creation of the dynamic related files and the shipment of all files and the network snapshots to the selected systems.

8.4.3.6 Data Retrieval and Saved Scenarios

Data retrieval (or copy) is possible from real time or any other system as long as the model is the same. In particular, network data, contingency data, dynamic scenario data, and translation data can be copied from other EMS applications. Once the user executes a scenario, that user can create a saved scenario for further analysis or simply to share the information with others.

8.4.3.7 Data Exchange Definition

Data exchange is defined as the description of the current scenario, dynamic data, PC where the dynamic engine is running, and some parameters associated with waiting (and timeouts) to get results back from the dynamic tasks and out to the EMS.

8.4.3.8 Preventive/Corrective Control Recommendations

The dynamic results are posted to EMS displays with the latest status and execution flags, times of the latest executions, and plans for preventive and corrective actions based on sensitivity calculations. Most of the information can be viewed on the dynamic boxes from the EMS. The most important results are available on the dynamic machine's main windows. Output results and specific data can be transferred on request from the EMS.

8.4.3.9 Steady-State Stability Assessment

For a recent EMS project, a real-time steady-state stability analysis tool has been integrated into the online EMS environment (Avila-Rosales et al. 2004; Savulescu

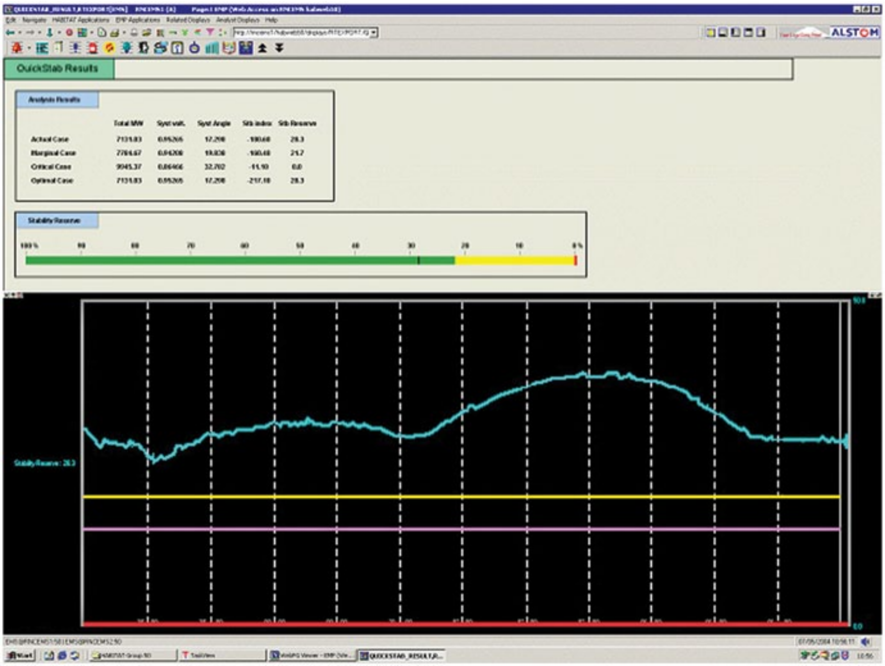

Fig. 8.12 Real-time trending of the steady-state stability margin

2004). This analysis gives the operator information on how far the system is from the critical state and also calculates a stability reserve index in percentages.

After a successful SE execution, a snapshot file in a standard format (PSS/E) is created. This file together with a local dynamic data file for generator characteristics is used as input data for the steady-state stability application. This application predicts the maximum power transfer (or MW load-ability) of the transmission network and computes the distance to the critical state where steady-state instability occurs. The distances to the stability margin state (user specified margin) and the optimal state (re-dispatching of generation to maximize the distance to critical state) are also evaluated.

Relevant information for the EMS operator is summarized in a results table display and in a bar chart providing a graphical indication of the current stability reserve as displayed in Fig. 8.12. A trend of the stability indices over several hours is also provided and provides very useful information about the stability evolution over time. This allows operators to anticipate critical systems instability conditions. Furthermore, after each analysis an alarm is sounded if the stability reserve percentage is below a user-specified danger level.

8.4.4 *Wide-Area Protection and Control*

During normal operations, the focus is always on the economics of the system. However, during an emergency (particularly with cascading conditions), the focus is on control shifts in order to guarantee grid stability. When an abnormal condition/failure is not mitigated or repaired, it can spread and lead to catastrophic conditions. The power system should be prepared to deal with the conditions created by:

- Volatility created by market rules and restructuring
- Uncertainty due to high penetration of intermittent renewables
- Power system operation very close to limits
- Transmission congestion and stressed conditions
- Weak connections
- Unexpected events
- Stability threats
- Hidden failures in protection systems

Any of the above conditions could trigger a catastrophic event, and assuming the system behaves properly the following actions will be taken:

- Monitoring will identify the location of a catastrophic failure.
- Applications will initialize and readjust controls to stop the exacerbation of the failure.
- Special protections will react to reduce the risks to operations.
- Load shedding will commence to maintain acceptable line frequency.

If the power system continues behaving in an unpredictable fashion, dynamic islanding will isolate the troubled area to avoid further grid deterioration

8.4.4.1 Special Protection Systems

The actions taken by these systems are intended to provide uninterrupted power supply by the use of "last defense" methods that should not be initiated under normal conditions. The objective is to maintain power system stability with regard to local conditions and wide-area conditions. These contingencies use data from several locations with a wide-area orientation to handle disturbances.

These systems are designed for the following purposes:

- Detect abnormal contingency system conditions
- Initiate preplanned corrective actions to mitigate the problems
- Provide acceptable system performance

The SPS controllers have some or all of the following characteristics:

- They can be armed/disarmed depending on the system conditions.
- They employ discrete controls and feed forward control laws.

- The control actions are normally predetermined.
- Some form of communication is involved in the control action.

Still, excessive reliance on these schemes may result in stability risks due to:

- Failure to respond
- Unwanted overlap with other protection systems
- Accidental operation

8.4.4.2 Wide-Area Protection and Control with PMUs

Some of the disadvantages of the current SPS systems are the fact that they work only for predefined events. This is where synchrophasor measurements provide a very useful addition to the capability to control the system to operate close to its physical limits, and also to defend the system against separation. They largely allow us to move away from predefined "event-driven" approach towards a "response-driven" approach.

The use of synchrophasor measurement in control and protection application is an expanding field and is likely to play a key role in emerging smart grid solutions.

The basic characteristics that make synchrophasor measurements attractive for protection and control solutions are as follows:

- They form a summary measure of system stress, responding to the loading and impedance between the measured points. This means that control to maintain the operation within its capability can be implemented with much fewer measurement points and communication channels than the alternatives, leading to greater robustness of the scheme.
- Angle measurements are directly related to the angular stability of the power system and its ability to remain in synchronism. The progression of a system separation can clearly be observed using synchrophasor measurements, and an automated response taken to avoid the separation. A particular benefit of using synchrophasors for angular stability, rather than more conventional event-based inter-tripping is that the synchrophasor approach is more general and can respond to unpredictable and complex event sequences.
- Since synchrophasor measurements can be streamed in real time at a rate that reflects the dynamic movement of the power system, it can be useful in improving the transient and oscillatory performance of the power system.

The applications of synchrophasor measurements apply in many different conditions to a wide range of issues. This includes both transmission and distribution applications, and distributed microgrids. Depending on the associated timescales of the grid phenomena (Fig. 8.13), the control scheme can be the following:

- Localized protection ($<$ 200 ms) at the substation where all information is captured at the substation level and is used for local control. These local actions include adjusting equipment settings, taps, power flow controllers, and more.

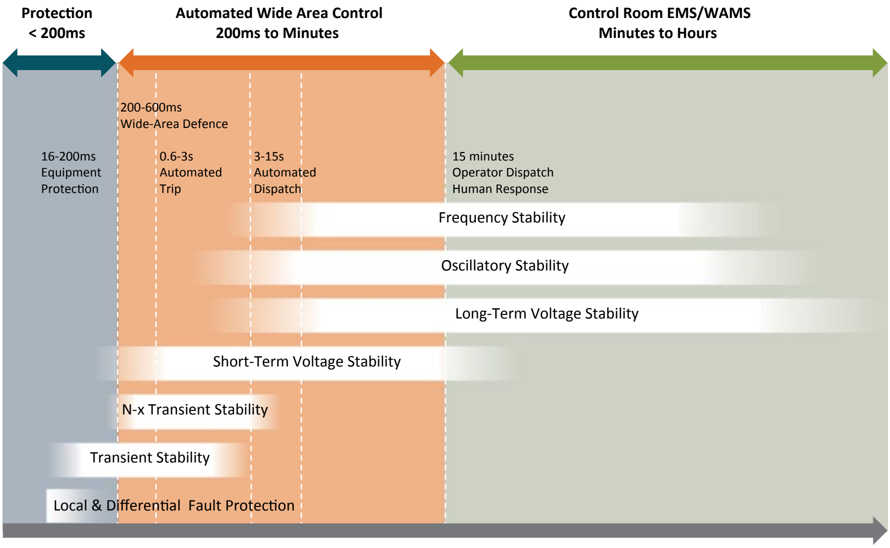

Fig. 8.13 Dynamic grid stability phenomena

- Decentralized synchrophasor-based automated wide-area control scheme (200 ms to minutes) that leverages the time synchronization property of the measurements in combination with fast processing and high speed communication between the substations to assess when a control action is needed.
- Centralized scheme that combines EMS software (including its network model-based analysis capabilities) alongside PMU information to optimize the control action. The dynamic engines are fast enough to assess the stability risks and control action evaluations for a few minutes. Operator or human intervention is likely to be part of such a centralized control scheme with minutes to hours to respond. Examples include re-dispatch to alleviate transmission congestion and/or corrective actions when the power system is operating close to its limits.

The types of control and protection mechanism include slow-speed loading optimization, high-speed stability defense, continuous control process, or discrete triggering. The options for actuation of the control include conventional or renewable generation tripping or continuous control, FACTS/SVC control, HVDC control, and voltage support.

In the various domains in which synchrophasors can be applied to control and protection, it is useful to categorize the problem in terms of:

- Defining the boundary limit: providing an expression of the capability of the relevant corridor that may be a simple angle difference, or a combined expression of measurements that best represents the limiting condition.

- Controlling to the limit: determining the control action applied at the equipment that is available to control, to operate the system up to the boundary limit. This will typically be a relatively slow control.
- Extending the limit: applying discrete or continuous control to manage the outcome of critical events such that the system can be operated beyond the N-1 limit that would apply if the control scheme was not present.

In this section, a number of examples of applications of synchrophasors in control and protection are considered.

8.4.4.2.1 Next Generation of System Integrity Protection Systems

The ability of a power system to return to a stable steady-state condition after a fault is essentially a question of angle stability. The loss of angular stability involves loss of synchronism between areas, typically resulting in an out-of-step condition followed by electrical separation between the areas. Out-of-step operation puts a great deal of stress on the network, as large cycles of electromechanical torque on generators and large voltage swing cycles. Separation across a loaded boundary leads to significant power imbalance in the areas and a risk that the areas affected will black out.

TS limits between areas of the grid is a complex problem, but a parallel can be drawn with a simple case of a single plant losing synchronism with the system. In the case of a single plant, a fault causes acceleration of the plant, and the stability criterion requires that the acceleration and angle difference between the plant to the nearest "strong" part of the network does not exceed the network's capability to extract the excess kinetic energy of the plant. The plant-to-system case is similar to the classical (but idealized) Equal Area Criterion.

The diagrams in Fig. 8.14 illustrate the basic TS problem, showing that the energy represented by Area A1 that accelerates the rotor during the fault must be less than the energy represented by Area A2 than the network can export following the fault; otherwise the system will lose synchronism. In Fig. 8.14b, the influence of generation inter-tripping is shown, increasing the energy for deceleration of the fast region.

The area-to-area loss of synchronism across several lines is more complex than the plant-to-system case, as the acceleration and angle differences immediately after the fault is cleared are different throughout the group of generators. The dynamics between the generators within the group are important for the system to return to a stable condition.

Although the process can be complex, some key influences on the TS of the boundary are:

- The accelerating energy during the fault-on period, determined by the mechanical power of generators at or close to the critical fault, and the nature of the fault
- The inertia of the area in question
- The pre-fault angle difference between the areas

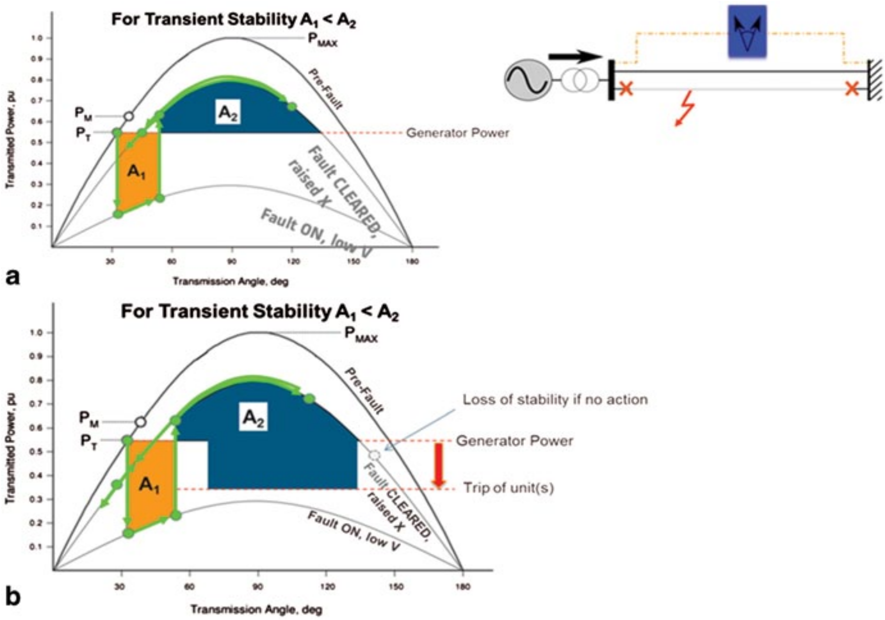

Fig. 8.14 Basic transient stability problem a) without generation shedding and b) with generation shedding

The change in the generation portfolio influences the inertia of the area. With low-inertia renewable generation capacity taking an increasing share of the operational generation mix, there may be less synchronous generation within the area to counteract the acceleration of a generator close to a critical fault. Thus, the rotor angle swings in response to a fault may be greater, and the TS constraint could become more limiting. Thus, the stability characteristics of grids are changing, and transient response is an important consideration.

8.4.4.2.2 Response-Driven Control of TS

As mentioned above, the stability of a system can be improved by inter-tripping generation in the exporting region of the grid. This has the effect of increasing the capability of the network to decelerate the exporting region and therefore pull the area back into synchronism. This is currently achieved through the use of fast-acting inter-tripping mechanisms based on predefined fault criteria. While such schemes have been successfully implemented, there are drawbacks, for example:

- Conventional inter-tripping will be over-responsive, as the worst-case fault scenario must be assumed. Practical faults will almost always be higher impedance than the defining faults which are typically three-phase short circuit at or near large generation. Thus, the scheme will trigger more generation shedding than actually necessary, and this creates a larger overall disturbance (and therefore risk) to the network.

- Conventional inter-tripping is designed for predefined fault scenarios. However, experience of large-scale disturbances shows that there are often multiple events and complex behavior, and the inter-tripping may not cover all scenarios.

8.4.4.2.3 Response-Driven Versus Event-Driven System Integrity Protection Schemes

In general, System Integrity Protection Schemes (SIPS) can be categorized as event-driven or response-driven. Event-driven action responds to a change of status in the system, such as a breaker opening, and initiates a predefined action. By contrast, a response-driven scheme creates an action that is based on the observed movement of the power system, and the action can be proportionate to the power system response.

To date, SIPS schemes have only been response-driven for relatively slow phenomena such as thermal overload. Stability problems have exclusively been event-driven in order to achieve the speed of response required to avoid separation. The response time for inter-tripping schemes, including the entire time budget from detection of initial triggering event through to the completion of breaker opening, is often required to be <200 ms. It should be noted, however, that loss of synchronism through TS is not always fast, and examples exist of the angular separation occurring 5 s after the fault.

Due to the speed of synchrophasor measurement and the direct representation of a stability problem, it introduces the possibility of response-driven action for stability. A response-driven action is slower than an event-driven action because of the finite time taken by the power system to show an angular separation (because of inertia) and the time window required for sufficiently accurate derivation of a phasor measurement. This means that there is an engineering trade-off between the speed of response achievable by an event-driven scheme and the proportionate response achievable by a response-driven scheme. A practical example of a response-driven stability SIPS is reported in Iceland (Wilson et al. 2013).

It is likely that in future, a new generation of SIPS schemes will emerge that generate a fast-acting initial event-driven response, supplemented by a response-driven component. This hybrid approach would combine the benefits of speed of response and proportionality.

8.4.4.2.4 HVDC Stability Control

There is an increasing trend to deploy HVDC links to augment a constrained Alternating Current (AC) corridor flow. Given the need for more transmission capacity and public resistance to large-scale transmission building, the greater capability of Direct Current (DC) transmission relative to AC transmission for similar visual impact, the choice of HVDC transmission embedded in the AC network can often be viable. Thus, HVDC transmission is quite frequently located across stability-constrained corridors.

HVDC technology is inherently capable of producing a fast controlled response, and is therefore capable of improving the stability characteristics of the AC system. Thus, the capacity of the AC corridor can be increased through control of the DC link, increasing the total capacity of the corridor.

A stability control capability in an HVDC corridor responds to an acceleration of the exporting region by rapidly increasing power flow from the exporting to the importing region. This has the effect of counteracting the angle difference swing between the regions. Since the critical period in a TS problem is the first swing, occurring typically within a second or two, the short-term rating of the HVDC transmission system would accommodate a substantial control capability.

Synchrophasor measurement is attractive for implementing HVDC stability control because it provides observability of the angle difference across the corridor and can be used to differentiate angle difference swings from local effects. Also, wide-area measurement can be used to introduce a continuous control that not only improves first-swing stability but also improves the damping of subsequent oscillations.

One of the benefits of using HVDC control for TS improvement above generation inter-tripping is that the control does not cause any net change in the power balance of the system. It therefore does not impact the global system frequency. By contrast, an equivalent generator inter-tripping approach results in a frequency drop, and the combination of initial disturbance and inter-trip response must be within the limits of the dimensioning generation loss that the system is designed to withstand.

8.4.4.2.5 Generation Output Control for a Transmission Boundary

Conventionally, a transmission constraint is managed by operational dispatch from the control room. This works well where the changes to load and generation are relatively slow, and there is time for an operator to take a response. However, as the penetration of intermittent renewable generation increases, the changes in power generation can be rapid. Without automated control, it is necessary for the system operator to use a safety margin that accounts for changes that may occur during the time horizon that the operator is not able to respond. Typically, an operational response initiated by an operator can take around 20 min. Thus, the constraint level of a transmission boundary must be de-rated by the extent of volatility that can occur within around 20 min.

A controlled response may be applied such that the renewable generation volatility is contained such that the power transfer is clipped as it reaches the boundary limit. The boundary transfer can be dispatched much closer to the actual boundary capability, with much less need for a safety margin for generation volatility. As long as the limit can be effectively defined, and a control mechanism is in place to clip the power flow in the corridor, then greater renewable generation can be accommodated. It may be noted that the curtailment may be applied at conventional or renewable generation, and may be shared across a number of plants.

As described elsewhere in this chapter, there are advantages to defining a boundary constraint with the use of angle information. Compared with the use of a MW level to define the limit, the use of angles in the constraint definition reduces the variability of the level with respect to changes in low-inertia renewable generation and network topology changes. An angle-based constraint provides a practical approach to boundary management without the need for frequent operational updates.

8.4.4.2.6 Continuous Damping Control

Wide-area damping control can be an effective method of improving the performance of the power system, particularly for inter-area oscillations. In order for a mode of oscillation to be effectively damped, it is necessary for the mode to be both observable and controllable. Using wide-area angle monitoring as an input to damping control enables a choice of measurement inputs that emphasize inter-area oscillations that may not be strongly observed in local signals. The effectiveness of a conventional stabilizer using local measurements may be limited by the relative amplitude of low-frequency governor and local electromechanical modes. Using remote phasor input compared with a local phasor increases the stabilizer's response to the inter-area mode.

8.4.4.3 Centralized Wide-Area Control Using Dynamic Analysis Triggers in EMS

Depending on the timescales available to respond to a potential or emerging stability problem, it may be feasible to centrally optimize the corrective actions to mitigate the situation. This is especially true when operating in a preventive security control mode so as to make it able to face future events in a satisfactory way. Dynamic engines these days are fast enough to assess the stability risks and control action evaluations for a few minutes. The dynamic applications in current EMS can be triggered periodically and under specific topology conditions or scenarios prepared in advance. With the use of the latest PMU information, and considering the closed-loop operation, the applications can be triggered automatically by the following events:

- Frequency oscillations
- Slow voltage decline
- Frequency decline and rate
- Margin stability decline
- Sudden outages

The appropriate dynamic application will execute itself so that the proper control actions are recommended. There is, however, a post-processing task to coordinate and organize the set of actions to solve the specific problem.

For the same event, there will be a plan to deal with reactive issues and another to deal with frequency issues. A control could have conflicting values depending on the type of plan. Right now the operator can select the problem he or she would like to address, but for closed-loop operation the system needs to react automatically, which is one of the challenges of wide-area control.

The final recommendations will be deployed as one or more of the following defense plans:

- Protection triggering and SPS deployment (including arming of PMU-based SIPS)
- Control shifts
- Islanding protocols

The dynamic applications must be highly automated and capable of completing the tasks under varying conditions with little help (or none) from the operator.

The global and local information is available at the control center so the following triggers are possible for wide-area control:

- *Voltage decline or load level:* If this is the case, VS will execute to provide the proper set of switching/control actions considering a ~10-s time frame.
- *Phase angle separation, frequency decline, and/or rate of frequency:* Global warning signals such as considerable angle difference and global and local frequency information can trigger TS wherein time frame ranges at the millisecond level. The decision to arm the PMU-based SPS could be an outcome of the TS analysis.
- *Oscillations:* If poor damping levels for the inter-area oscillatory modes are detected, they can be addressed by the small-signal applications (e.g., dispatch to reduce stressed conditions) and/or rely on the PMU-based SPS.
- *Stability margin:* If reactive reserve is the issue, the VS engine can assess the problem. If the margin is expressed in terms of angular stability then TS will address the problem.
- *Cascading:* With the help of trending, unwanted outages and cascading can be detected so the system prediction can be initialized with the most recent real-time snapshot and disconnected equipment status. The focus is on conducting a ~10-minute-ahead simulation to detect dangerous conditions.

Figure 8.15 addresses the implementation of the dynamic applications, PMUs, PDCs, and warning signals to trigger the execution of advanced analytics.

8.4.4.4 Dynamic Adaptive Islanding

If all lines of defense are exhausted, there is another possibility: Separate the network into small *f–V*-controllable islands. The control actions should be highly automated and they should be deployed with enough intelligence to figure out the

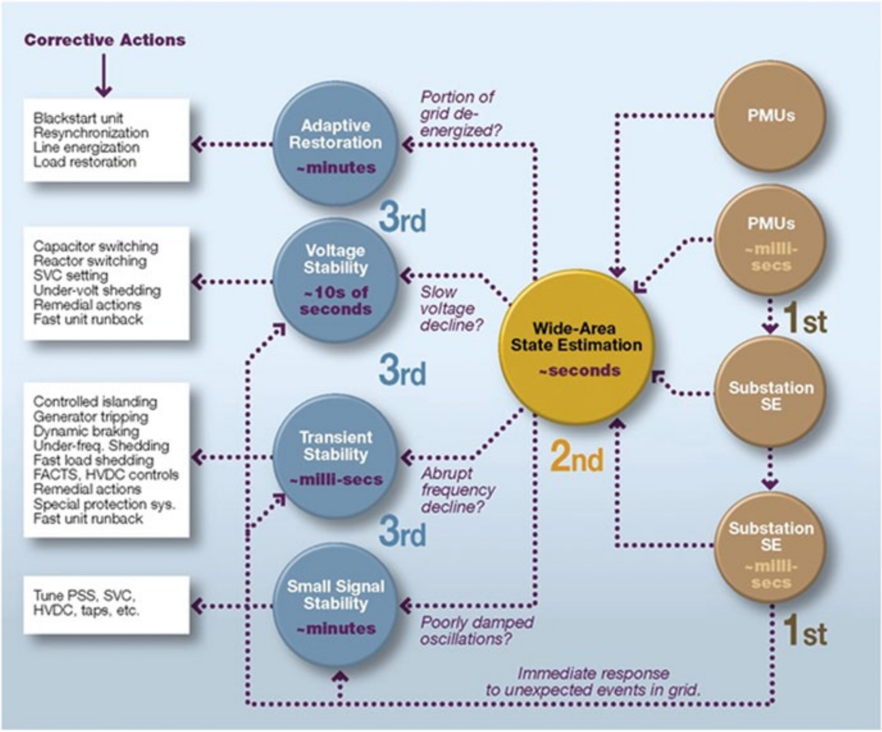

Fig. 8.15 Dynamic applications triggering and coordination

right set of alternatives to safely split the system (Vittal et al. 1998). There is a list of steps before this recommendation is ready. The steps include monitoring, trends, and finally smart network partitioning and restoration strategies. In the event that an event takes place, the following sections describe steps for dynamic islanding.

8.4.4.4.1 System Drift

The event begins and the system drifts and the generators react to it depending on its nature. They share the frequency tendency and rate of change; oscillating units are detected and grouped into critical sets. The applications process the critical datasets and provide the list of potential cut sets linking oscillating groups. System controllability and restoration guidelines are imposed to help decision making.

8.4.4.5 Trends and Triggers

The need to use recent and previous wide-area information to determine the trending of selected electrical variables (or composite indices) to identify potential problems (frequency rate, voltage rate, increased oscillations, angle and VS margins, etc.) is very important for islanding. The analysis of all PDC information will confirm or caution the operator about potential problems.

8.4.4.6 Network Partitioning

The oscillating groups define the points where the system is weak and propose where to make splits. When making grid splits, both the frequency impact and reactive impact of the various split options must be evaluated. The best choice will be the one that reduces the active power imbalance, based on the smallest generation-load imbalance to avoid further cascading. In order to be effective, the islands must be easy to restore and synchronize with the rest of the system. Optimization functions will guarantee enough active/reactive control capability to push the frequency ranges and voltages back to their nominal values.

8.4.4.7 Resynchronization

The restorative condition of the system is a state that is allowed momentarily to avoid further deterioration of the grid. Still, it is desirable to minimize the time of restoration and resynchronization. So as part of the selection for the best plan to separate the system into small islands, there is a need to consider the availability of reactive controls and sufficient resources to return the control center to a normal condition.

8.4.4.8 Infrastructure Requirements for Control and Protection Applications

It is necessary to address scheme design consideration when using synchrophasor measurements in control applications. Compared with monitoring applications, there will generally be more stringent requirements on data availability and latency. It is noted that the present IEEE C37.118 standard, both in the 2005 and 2011 versions, use Internet Protocol communication; hence, latency may require special attention for the faster requirements (Fig 8.16). The design of a protection or control scheme should account for:

- Defining the overall time budget that is available for the application to run successfully
- Ensuring that the latency at all stages including the measurement process, processing delay, communication, and actuation is within the time budget
- Defining a graceful degradation process, if required
- Identifying the need for redundancy and the implementation
- Ensuring that the static and dynamic signal qualities are appropriate for the application

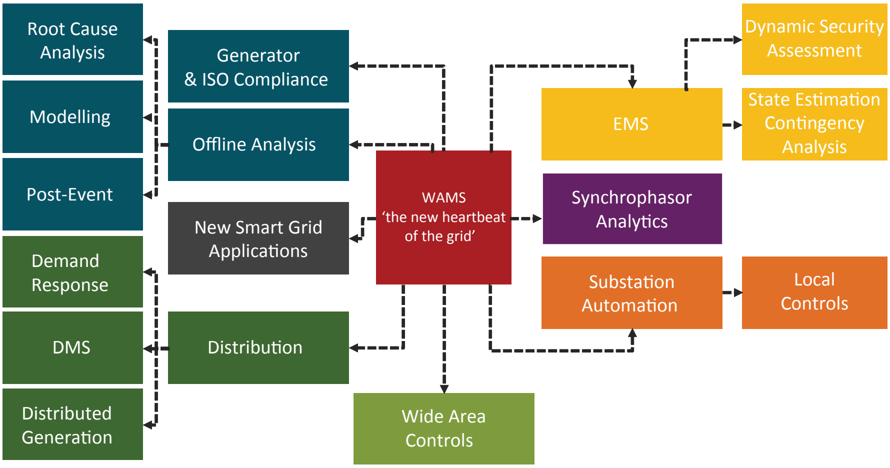

Fig. 8.16 The evolution of grid monitoring and control solutions. Illustrates how the growth of synchrophasor PMU data will facilitate a Wide-Area Monitoring System (WAMS) that becomes a rich source of fast, accurate, grid monitoring data that will drive the EMS as well as other smart grid analytics, to facilitate prompt regional, local, and wide-area controls

8.5 Conclusion

This chapter has described a high-level plan to implement a wide-area control system in an EMS. Such a system would improve power system grid stability and make recoveries easier. The primary intent of the wide-area control system is to extend the operational boundaries of the system, while protecting the electrical interconnections from a widespread collapse. In some cases, the appropriate action would be islanding and blacking out a portion of the grid in order to prevent widespread collapse.

A key element is to evaluate the optimal approach towards using PMU data in the EMS steady-state and dynamic applications. SE is the obvious first application to be leveraged, since PMUs can improve SE observability, reliability, and accuracy. Furthermore, SE forms the basis and foundation of all model-based steady-state or DSA.

PMU data are received much faster (milliseconds) than traditional SCADA data (2–4 s). This allows for faster detection of signatures of potential system problems (such as transient or oscillatory instability) and could be used to trigger dynamic analysis simulations. The dynamic simulation engines could also be deployed to directly utilize PMU data, along with the latest state-of-the-art communications and hardware to respond quickly to mitigate the spread of a system disturbance.

This approach entails analysis, prediction, and determining the appropriate wide-area control actions. Finally, communications is a challenge that needs to be addressed in order to deploy fast, automated closed-loop operations on the electric power grid.

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