NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

PMU Placement and Installation

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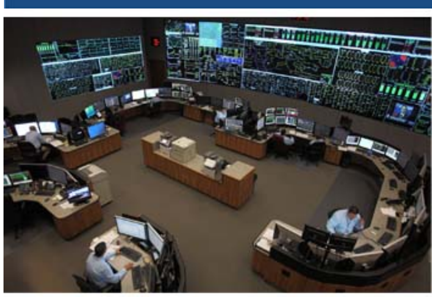
RELIABILITY | ACCOUNTABILITY

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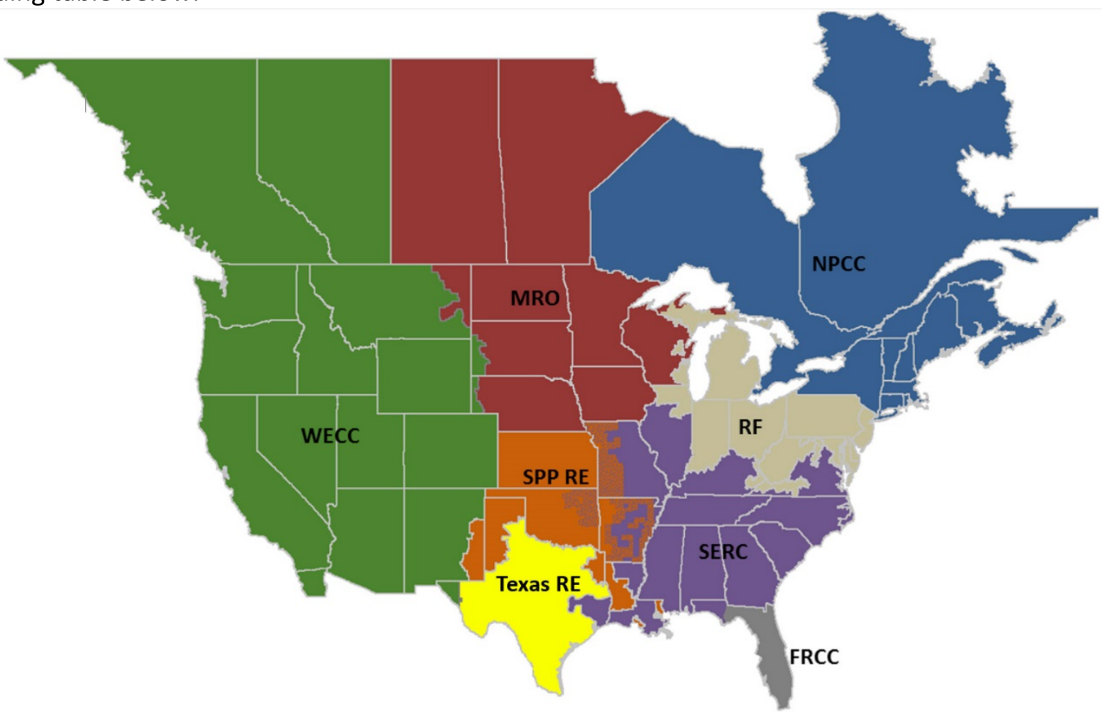
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

NERC, as the FERC-certified Electric Reliability Organization (ERO),[1] is responsible for the reliability of the Bulk Electric System (BES) and has a suite of tools to accomplish this responsibility, including but not limited to the following: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program, and Reliability Standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the Reliability Standards to maintain the reliability of their portions of the BES.

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the BES. The NERC Technical Committees—the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)—are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines per their charters.[2] These guidelines establish voluntary recommendations, considerations, and industry best practices on particular topics for use by users, owners, and operators of the BES to help assess and ensure BES reliability. These guidelines are prepared in coordination between NERC Staff and the NERC Technical Committees. As a result, these guidelines represent the collective experience, expertise, and judgment of the industry.

The objective of each reliability guideline is to distribute key practices and information on specific issues to support high levels of BES reliability. Reliability guidelines do not provide binding norms and are not subject to compliance and enforcement (unlike Reliability Standards that are monitored and subject to enforcement). Guidelines are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to support reliability for the BES. Further, guidelines are not intended to take precedence over Reliability Standards, regional procedures, or regional requirements. Entities should review this guideline in conjunction with Reliability Standards and periodic review of their internal processes and procedures, and make any needed changes based on their system design, configuration, and business practices.

[1] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

[2] http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf
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Purpose

This Reliability Guideline is intended to address recommended practices for placement and installation of Phasor Measurement Units (PMUs) and the collection of synchronized phasor measurement (“synchrophasor”) data. It is meant to provide utilities with existing synchrophasor networks as well as utilities exploring synchrophasor capability with sufficient technical basis to support efficient and effective placement decisions. The strategies set forth in this Reliability Guideline center around the needs of the PMU-based applications for which the data is expected to be used. The concepts presented here are generally agnostic to specific implementations or algorithms within the applications deployed; rather, the goal is to provide technical background for practitioners seeking to deploy PMUs for specific applications for their system. The Reliability Guideline does not provide binding norms or create parameters by which compliance to NERC Reliability Standards is monitored or enforced. However, it does provide insight into those Reliability Standards that encourage use of PMU equipment and synchrophasor data.

The Reliability Guideline applies primarily to Transmission Owners (TOs) and Generator Owners (GOs) who own or operate the physical assets. It also applies to the broader audience of data owners or users who may use or rely on PMU data. These entities include Transmission Operators (TOPs), Balancing Authorities (BAs), and Reliability Coordinators (RCs) for real-time applications as well as Transmission Planners (TPs) and Planning Coordinators (PCs) for offline analysis. In addition, this Reliability Guideline aligns with the NERC function of interconnection-wide event analysis and disturbance monitoring.

PMU Installation

The installation of PMUs generally follows standard utility practice[3] for planning, design, installation, and commissioning of instrumentation in a substation. The planning stage determines the measurements to be made, signals required, and usually the signal sources for the PMU. PMU design considers the equipment required as well as equipment location, circuit wiring, communication interface, and designation of auxiliary equipment such as routers and timing receivers. Equipment installation usually requires wiring changes and coordination with other activities such as scheduling equipment outages. Commissioning should include tests with instrumentation in the substation where the PMU is installed as well as places where the data is used or recorded. Substation instrumentation can provide very accurate measurements that assure the PMU is calibrated and the scaling is correct. Comparisons with other data acquisition systems, including SCADA, assures that the PMU measurements are correctly identified and scaled and also that they are close to values that have been in use and are accepted values. Commissioning tests should include verifying communication adequacy with standard test equipment as well as an intensive monitoring period of usually multiple weeks to check for dropouts, corruption, or other data problems. These overall considerations are considered in more detail in the following sections.

PMUs and their installation are one aspect of a robust synchrophasor network that includes PMUs, Phasor Data Concentrators (PDCs), GPS receivers, clocks, network infrastructure, and data storage. A generalized data flow schematic is shown in Figure 1. This guideline focuses primarily on the placement and installation of PMUs; however, the entire system plays a key role in ensuring reliability and available PMU data reaches the synchrophasor applications. Figure 1 simply highlights the integration of many aspects of a synchrophasor network between system equipment, TOs, RCs, and Wide Area Networks (WANs).

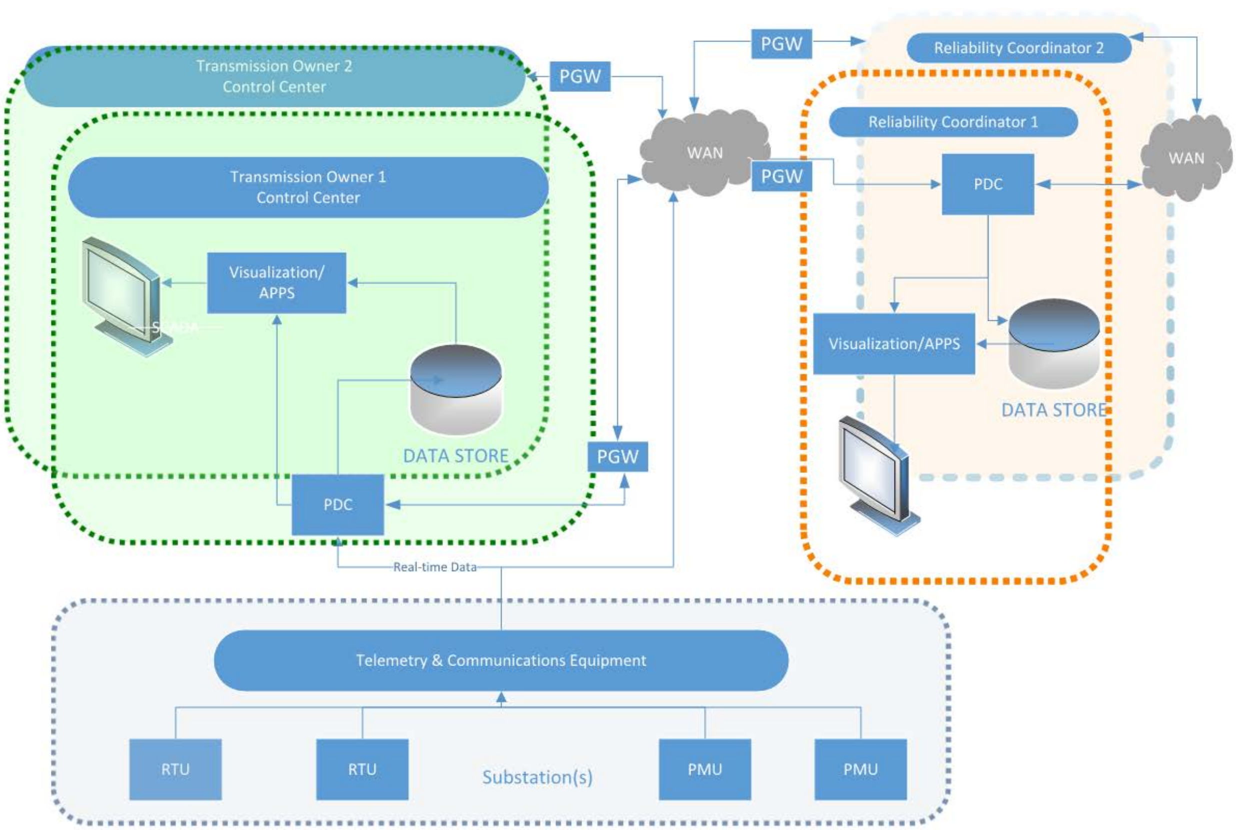

Figure 1: Flow Diagram of Synchrophasor Data

[3] While the technology may be relatively new, the installation of these types of devices is similar to many other digital relays, digital fault recorders, etc., in a substation.

Equipment Considerations

The PMU is the essential piece of equipment synchrophasor network. It can be provided as a stand-alone device or as a function within another device such as a digital relay or digital fault recorder (DFR). The main considerations for the PMU are:

1. **Number and Type of Inputs**: Planning should designate the required measurements including voltage, current, analog values and digital indications. Typically planners require at least one transmission level bus voltage and circuit currents. Some circuits may not be included in the set of measurements due to PMU measurement capability (i.e., number of inputs). Alternatively, more than one PMU may be deployed. If necessary, the PMU must be equipped to handle analog inputs with suitable signal conditioning and A/D conversion or digital Datacom input. Also, Boolean status inputs require single point sensing.
2. **Input Characteristics:** Voltage and current secondaries are provided at several standardized levels. The PMU should be equipped for the appropriate ones. Like other substation equipment, the PMU should have appropriate input protection for dealing with transients and interference. Equipment power should be DC at the correct voltage so the PMU will operate reliably through extreme events. One issue is current levels. PMUs are expected to operate accurately at normal load levels rather than at extreme fault levels. Scaling designed for fault level performance may not give very good load level resolution. The user needs to scale the input so the PMU will be accurate at the maximum current needed for measurements so it will provide good measurements at normal operation levels. Of course the input should be protected to prevent damage during extreme voltage and/or current conditions such as faults.
3. **Signal Availability:** Substations may have voltage and current secondaries all brought to a central control house or distributed to a number of relay houses. These secondary circuits should be available to the PMU as inputs to the A/D converter in the device. If distributed, the PMU should have distributed sensing units with digital reporting to the central PMU. Alternatively, separate PMUs may be installed at each signal location and then data combined by a substation PDC or reported from multiple PMUs to a central PDC.
4. **Timing Signal:** A PMU requires a precise timing signal for phase angle measurement and the time tag. This timing is most often provided by a clock that receives synchronization from the GPS system. This clock can be internal or external to the PMU. If internal, an antenna and cable is required. In some cases, the signal from a single antenna can be split if more than one PMU is installed. The advantage of an internal receiver is that delays are compensated and synchronization quality is directly available to the PMU. If the GPS clock is external to the PMU, the signal can be distributed by IRIG-B, unmodulated 1 PPS RS232, or another time distribution signal. Recently IEEE 1588 distribution over Ethernet has become available and capable of time distribution at the required accuracy level (within 5 µs). It is important that a time source quality indicator is provided along with the time signal itself. Incidents have occurred where phase angle was in error due to a bad timing signal although the data indicated the timing was good. In addition to the signal and timing quality indication, delay compensation may be required for longer cable lengths between the GPS receiver to the PMU.
5. **Output Capability:** The IEEE Standard C37.118 series specifies class of performance (M or P), reporting rates, and data representation (polar/rectangular, integer/floating point) that can be used. PMUs have attributes configurable by the user as well as fixed attributes that the user cannot change. A PMU should be selected that can be configured to meet all user requirements.
6. **Local Access to PMU Data in Substation:** Depending on company procedures, local access to PMU data and local indications from the device while in the substation may be required. Such access simplifies commissioning and troubleshooting. It can also be useful for other substation testing procedures. However, some utilities may not use or require this feature for security reasons.
7. **Communication Interface:** A PMU needs to be able to output the measured data (see Communications and IT Considerations Section below). This is usually done through an Ethernet port that connects to a

local network. The usual configuration and testing considerations apply including addressing, speed, and security.

8. **Certification:** The IEEE ICAP C37.118 certification program[4] certifies PMU equipment according to the latest IEEE C37.118 standard. This certification program is continuing to evolve and certify PMU equipment to tested specifications. While this does not preclude the use of existing PMUs installed on the system, it is recommended to consider the IEEE ICAP certification program when deploying a PMU network.

Dual Function Digital Relays as PMUs

Integrating synchrophasor settings into digital relays may enable a faster and more cost-effective wide-spread deployment of synchrophasors. Many utilities have moved towards this approach because of the massive deployment of existing digital relays which helps minimize the number of devices[5] in the field with minimal added complexity to the existing digital relays themselves. Standardizing synchrophasor technology as part of the digital relay package or upgrades allows a utility to make PMU measurements a core part of the business similar to protective relaying. As substation projects occur and new digital relays are installed, synchrophasors in these relays are essentially free; most modern digital relays can also provide synchrophasor outputs. The only significant item that should be considered is connecting time synchronization to the digital relays if they currently do not already have one (satellite clock, IRIG-B connection, etc.). Refer to IEEE Std. C37.242[6] for more information related to enabling PMU functionality in digital relays.

If a substation does not yet have high speed communication, installing a digital relay with PMU output enabled or upgrading an existing relay to include a PMU data stream can still save time and money over the long run. There is no need to go back to the devices later to change settings, which requires outage of equipment to take the relays offline for these settings changes and other modifications. Once high speed communication gets added to the substation, the PMU can start streaming synchrophasors with minimal changes that typically do not require energized equipment outages. Even without high speed communications, the relay can store a limited amount of synchrophasor data locally at the substation for later retrieval and analysis, if needed. Cybersecurity concerns should be evaluated and addressed as appropriate; however, cybersecurity matters may be affected by how the PMU data is used for decision making by the system operators.

An important recommendation here is here is standardization of synchrophasor settings, to the extent feasible. Each utility has standard settings for their digital relays, so these standards can be updated to enable synchrophasors when the relay engineers create the setting files. This would prevent non-standard settings from getting turned on and also help ensure uniformity for all settings to be made to the fleet of devices. For example, the additional PMU settings should include:

- Enabling PMU functionality
- Configuring the data stream parameters (signals, names, ID codes, PMU name, etc.)
- Setting communications parameters (UDP vs. TCP, etc.)
- Verifying instrument transformer settings
- Configuring time source settings and connecting a time source

[4] IEEE, “IEEE Conformity Assessment Program (ICAP): Phasor Measurement Units”, 2016. Available: http://standards.ieee.org/about/icap/37.118.html

[5] This may also decrease O&M costs as well.

[6] *IEEE Guide for Synchronization, Calibration, Testing, and Installation of Phasor Measurement Units (PMUs) for Power System Protection and Control*, IEEE Std. C37.242-2013, 2013.

Communications & IT Considerations

Communications are generally implemented using networks rather than individual wire and channel systems. Communications considerations are described here under the assumption of digital and networked systems, and can be broken down into the general categories of bandwidth, latency, reliability, and security. Major considerations of each of these areas are:

1. **Bandwidth:** the amount of data that can be passed through a given point in a unit of time. This is usually expressed in bits per second (BPS) or some multiple (kBPS for kilobits/s). Synchrophasor data is usually communicated at a continuous rate, so there are no bursts and no buffering requirements. The rate is relatively high, with a typical PMU requiring 15-40 kBPS for 30 fps measurement reporting rate. The bandwidth is directly related to a number of factors such as the number of signals reported and the data format (e.g., floating point vs. integer). Network communications handle this well with rates of 10 MBPS and up. The biggest problem is usually the need to share circuits with other applications some of which send data in bursts. In those cases, without sufficient prioritization and buffering, synchrophasor data can be dropped. PMUs that are currently, or expected to be, used for systems that are mission-critical should plan for sufficient bandwidth.

2. **Latency:** the amount to time delay from when data is sent to when it is received. Communication circuits are fast, approaching the speed of light. However, there is delay in coding the data into the circuit and decoding data out of the circuit. There is more delay introduced by schemes for error detection, retransmission, extra decode-encode points when systems are merged, and data rates are changed. This can add up to 100’s of ms. Latency affects real time applications such as control functions and real-time system displays. Latency is not a concern for event archiving except as it may affect the data collection system. A typical PMU to control center link over fiber optic communications will have 20-50 ms of latency. Variable waiting and processing delays in data collection systems can increase overall latency to several seconds, so this should be considered in the overall application plan[7]. As more PMUs are connected to a PDC, the possibility for outliers become more frequent. PDCs forward time-aligned data based on the latest arriving data packet, so longer latencies can be expected in these situations. Missing data or dropouts can introduce these types of longer latencies for specific time stamps. Utilities should design systems to minimize these delays as much as possible. The latency in communication should be considered along with the overall timing budget which includes the PMU’s internal latency (both windowing delay and processing time), PDC transit times and application processing.

3. **Reliability:** measure of how likely a communication link is to fail, either momentarily or for longer periods. Short term failure can include contributing factors such as fading on a long microwave link or a burst of data on a link that exceeds buffering capability. Short term problems like this are known and expected, but reduced to rare occurrences by careful planning. Communication link issues cannot be entirely eliminated, but can be effectively mitigated. The less known failure modes relate to the quality of equipment and installation. Beyond planning to reduce failure modes with high quality installations, redundancy techniques are required, as with redundant interface equipment. At the lowest level, the most likely sources of failure such as interface equipment can be made redundant. The next step is making the communication path redundant with automatic path switching. A fully redundant installation will duplicate the entire measurement system from sensing through the measurement and communication; however, a practical redundancy can be achieved for many applications using functionally equivalent measurements or derived values. At this level the only single point of failure is the application itself, which can be designed for high availability.

4. **Security:** measure of how resistant the communications network is to intentional or unintentional interruption, corruption, or loss of data. Terminal equipment such as the PMU and PDC need to be secured to prevent unplanned changes to their configuration, interruptions in their operation, and unauthorized

[7] Latency requirements are driven primarily by application needs. Each application should include a latency specification or requirement.

data access. Security is a complex and ever growing concern, so this summary does not address it in detail; however, it is mentioned since physical and cybersecurity of assets on the BES are important to help ensure reliable operation of the grid.

Measurement Reporting Rates

Phasor measurements are reported at a rate that is a multiple or submultiple of the system frequency. For a 60 Hz system, the standard reporting rates are 10, 12, 15, 20, 30, 60, or 120 measurements/second, with 30 and 60 samples per second most common. The measurements are sent as a package, called a frame, where all the measurements are at the specific time represented in the time tag that is included in the message. Most systems in North America report data at 30 frames/second (fps). While this is the most common rate being used, the data requirements for applications vary. An application that determines phase angle for reporting to SCADA only needs data at around 1/2 fps to match SCADA operating speeds. Conversely, an application trying to detect subsynchronous resonance may require 120 or 240 fps reporting to enable detecting oscillations as high as 60 Hz. The primary considerations for reporting rates are:

1. **Application Requirements:**
    a. **Measurement Bandwidth:** The Nyquist rate restricts the bandwidth of the phasor quantities reported by the PMU to < ½ reporting rate. Practical filtering further restricts reasonable measurement to probably ¼ reporting rate.
    b. **Reporting Latency:** The delay between reports can be expressed as 1 over the reporting rate (e.g., 60 fps will have an inherent time between measurements of 0.016667 sec). Measurement will also have a reporting latency dependent on the time window selected. Wider window lengths such as those used for M-class PMU measurements will have a higher reporting latency because it will require more time to collect that window around the time tag and report the synchronized phasor quantity.
2. **Communication Restrictions:** The reporting rate and number of reported values determines the minimum bandwidth. Attempting to send data at a higher rate will cause overload and data loss. Maintenance information, bursts of data by applications sharing the channel, and occasional impairments restrict channels below rated capacity. The reporting rate needs to be restricted so that the requirement is below the usable channel capacity, which may be 20% to 80% lower than the nameplate capacity. Communications should be specified to overcome these restrictions to meet the synchrophasor applications' needs.
3. **Data Handling Equipment:** Usually equipment like PMUs, PDCs, and application servers are sized to handle data at the specified reporting rate. In the case that some of these items are previously designated, the reporting rate may have to be restricted to prevent overloading them. PMUs may not be equipped to provide all reporting rates, so this could further restrict reporting rate specification.
4. **Data Storage Capacity:** Synchrophasor systems are capable of producing very large volumes of data. The rate at which it is reported and stored drives the storage requirement. Storage is usually specified based on reporting rates and the number of PMU signals or tags[8] needed. Utilities should manage storage to meet the application and data retrieval needs. Another option is to move data to a long-term archive rather than throttle back data collection.

Data Quality

Synchrophasor data can include any electrical and physical quantity such as voltage, current, frequency, power, breaker position, control values, and alarm position. However, synchrophasor data only includes magnitude and phase of voltage and current, frequency, and rate of change of frequency (ROCOF). The focus here is on data quality of these measurements. Robust synchrophasor networks seek to minimize data quality issues and develop

[8] Tags refers to any unique analog or digital quantity.

applications that are immune or aware of data quality impacts on performance. Applications have their own set of data quality requirements[9] based on the needs of the computation and visualization being performed. Data quality in the context of this analysis includes all aspects of the data that relate to its presence and usability. This is a very broad aspect and can be broken down into the following categories:

1. Loss of data in communication and processing systems
2. Data not sent by the PMU
3. Corruption of data in communication and processing systems
4. Inaccuracy in its representation of real-world quantities
5. Lack of precision in the representation for use in the target application
6. Incorrect identification of measurements
7. Excessive and inconsistent latency

These categories are discussed in some detail in the following sub-sections.

Data Loss

Data loss is where data is expected but no data is received. The most common place this is experienced is in communication systems. Problems in these systems are due primarily to:

- Buffer overruns, either continuous or intermittent
- Interface mismatch – ports, connection types
- Incorrect routing
- Communication blockage due to incorrect security provisioning or errors in the circuit

The second most common area of loss occurs during data processing. These problems include:

- Uncoordinated PDC wait times
- Insufficient computer processing capability. Data loss occurs during task switching, background task activity, and other shared activity.
- Virtual servers not provisioned for real-time priority. Synchrophasor processing requires hard real-time activity while typical processing deals with blocks of data based on a scheduler.
- Redundant system switchover often causes a short data loss.
- Security between data systems can block communications if not configured and updated correctly
- Overload in data storage systems – insufficient disc space. Also excessive storage access can interrupt data storage functions.

Data Corruption

Corruption as used here refers to errors in the data representation rather than the values themselves. This kind of error includes bits that are lost or flipped, numbers that are represented in the wrong format, incomplete messages, and similar problems.

[9] Refer to the NASPI PMU Application Requirements Task Force (PARTF) report titled *PMU Data Quality: Framework for the Attributes of PMU Data Quality and a Methodology for Examining Data Quality Impacts to Synchrophasor Applications (revision November 2016)*. Available: HERE.

Bit and message format errors occur in communication and handoffs between equipment. They are usually detectable with a CRC and message format checking including message completeness, format, and length. Other checks like measurement value ranges and time stamp values add more certainty.

The representation format errors are the result of configuration miscommunication. In some cases, the error will cause obviously bad values, like using floating point for integer data. In other cases, like reversing real-imaginary, the problem will not be as clear and requires more data value checking. While this kind of error can largely be eliminated with thorough commissioning, continuing monitoring should be employed to detect unscheduled changes.

Leap seconds and PMU calibration for leap second may introduce errors if the PMU does not accurately account for the leap second when it happens. Experience shows that many existing PMUs have reported bad or corrupt data by mishandling the leap second; these are being addressed in updated firmware revisions. The result of corruption due to leap second can vary based on how the PMU handles it, but errors can range from a single data point as time crosses the leap second to persistent errors that were detected by an engineer days after observing errors in phase angle difference calculations. Engineers should be cognizant of leap seconds and ensure the software tools are built robustly and PMU vendors are appropriately handling the leap second in their devices.

Inaccuracy

Accuracy addresses whether the measurement data correctly represents the engineering quantity. This includes both the value itself and the time given for that value. Synchrophasor, Frequency, and ROCOF are measurements of AC quantities, so have to be estimated over an interval of time or "window". They can change over that window, so the reported value will be some kind of average over that interval. Factors that affect the accuracy of the estimate include:

- Time errors from either the time source or within the PMU. If the reference time is bad, the phase angle will be incorrect. If the time error is large, the magnitude measurement will not be accurate for the time as stamped. Time errors greater than 50 µs will impact phase angle calculation while time errors greater than 1 ms will also impact magnitude.
- Any translation device from the point of sensing the measured quantity to the PMU affect the accuracy. This includes the PT/CT devices, auxiliary transformers, and electronic transducers if used. These problems include poor initial calibration, aging, uncompensated equipment repairs, and temperature effects.
- Extreme changes in value during the estimation window can degrade accuracy.
- Noise and interference can degrade accuracy, particularly for Frequency and ROCOF which are derivatives of the phasor values.
- Incorrect phase sequence from the CT/PT wired to the PMU analog ports can result in inaccuracy. This can be hard to detect at the substation; however, comparison with other phase angles will quickly identify errors in phasing. This is a useful validation check to perform during installation and commissioning of new PMUs.

Once estimated, the value is in digital form and the accuracy is fixed. However, scaling and other processing can change the value and make the measurement inaccurate. Common errors include undocumented PT/CT ratio changes, phase angle adjustments incorrectly applied (e.g., Y-Δ), and scaling misapplied (e.g., l-l vs l-n).

Lack of Precision

Precision is how finely the number is resolved. For example, voltages of 1.5 V or 2.499 V would both be reported as 2 V by a meter with 1 volt resolution. If the meter had 0.01 V resolution, these voltages would be reported as 1.50 V and 2.50 V respectively, clearly different voltages.

One area PMU precision affects the measurement is the input A/D sampling. If the scaling is such that the signal level is very low compared with the A/D resolution, the waveform will be "steppy" and not very accurate. The lack of precision in this case shows up as a noisy measurement. Conversely if the scaling is set for greater precision but does not take into account the resulting limit on maximum or minimum value for the signed integer size, then clipping can occur. Users should consult the equipment instruction manuals and installation practices to ensure appropriate scaling.

Another area precision affects the measurements is in the calculations. The numbers can be in integer or floating point and with different precisions. The issues in this case are the same as with the input. If the numbers are not scaled to use the right number of bits, the calculations can be "steppy" for too few or overflow at peaks with too many. Floating point processing can alleviate this by representing all numbers with the same resolution.

Still, another area of concern is the reported values. Measurements can be transmitted in integer or floating point format. Floating point can provide all the precision of the calculation results within the PMU, so does not degrade precision. Integer format usually requires scaling from the particular engineering value. Scaling factors should use sufficient resolution so as to not degrade the precision of the estimated value prior to scaling. This is particularly true when the data is to be used for small signal and modal analysis.

The last area of concern is data storage and archiving. The least significant bits may be dropped or the data may also be compressed to reduce the storage requirement. In both cases there is a loss of precision to minimize data storage space. The tradeoff should be carefully analyzed to be sure the applications will not be adversely affected by data reduction.

Incorrect Identification

When a PMU measurement arrives at the place the measurement will be used (e.g., application, data historian, etc.), it has to be identified as to the type of measurement, where it was taken, and the particular engineering quantity it represents. If the measurement identifier, usually the measurement name (line, bus, substation, etc.) and type (voltage, current, etc.) are not correctly matched to the number, the value being used will be incorrect and misleading. This problem can easily occur because the naming and scaling are done at the substation but usually checked at the control center. A thorough process to check this identification after installation will minimize the problem, though periodic checks are still required as occasional "small" repairs can cause changes that are overlooked. Utilities are exploring PMU data registries and the C37.118.2 specification of data frame protocol to account for this information.

Latency

Latency is the time delay from when the measurement is made until the measured value is ready to be used by an application. Normally the latency for synchrophasor data is quite low (e.g., on the order of 50 ms) and is dependent on the network design, communications medium, processing time, and other infrastructure-related considerations. However, when there are problems with data communication and data processing equipment, it can become much larger, on the order of a few seconds.

The biggest problem is the configuration of the PDC. The PDC collects data from several PMUs and aligns it by time stamp before sending on to an application or another PDC. To do this, a PDC has a Wait Time in which it waits for the data for each time stamp from all the PMUs to arrive so these measurements can be time-aligned together. If a single measurement arrives late (beyond the wait time), then the aligned group is late. The PDC is designed to limit the wait so that if one measurement is missing, it does not wait forever. The challenge is setting the PDC Wait Time so it will wait the maximum reasonable time for late data but not so much as to degrade performance[10] if data is lost. If there is more than one PDC in the data processing chain, settings of the lowest PDCs in the chain

[10] This is often application specific with respect to degraded performance.

will dictate coordination of the settings and the next level, and so on. They should be carefully coordinated to prevent excessive delay for the users or excessive data loss. PDC Wait Times are dependent on (1) where in the data stream the PDC resides, and (2) the downstream applications used by the PDC. For example, substation PDCs may have very small or zero Wait Time and act as a pass-through data aggregator. Data historians, on the other hand, may have long Wait Times on the order of many seconds to allow ample time for the data to arrive.

Other drivers of latency involve the communication circuits. If they are highly loaded, buffering to handle data bursts can cause excessive latency. If they are overloaded, there will be data loss which will cause PDC latency as described above. Careful design and operation can assure the circuits are not overloaded to the point that they degrade the performance. In addition, packet fragmentation of large packet sizes may result in increased latency and possible dropped data and should be carefully addressed.

Most PDCs will display or stream the difference between the timestamp of a PMU data frame and the time that frame arrives at the PDC. This quantity will include the internal delays introduced by PMU filtering, as well as the time for the packet to traverse the network. It also largely dependent on the location of the timestamp within the measurement window (beginning, middle, or end), and the length of the window itself. Using the latency value reported by the PDC requires that the PDC is precisely synchronized to GPS. There are different methods for synchronizing the PDC. One option is use applications that occasionally (e.g., every 5-10 minutes or so) synchronize the PDC or servers with a high-accuracy internal clock to minimize timing drift between resynchronization. Installing a GPS clock to a hardware PDC will help identify the latency more accurately; however, for a software PDC, Windows Time Service does not provide suitable timing accuracy (too much drift) to measure PMU latencies. PDCs should be time synchronized to ensure Wait Times are applied correctly, regardless of whether latency is being measured.

One option for estimating PMU network latency within an organization using a software PDC is to set up a "reference" PMU at the same location as the central PDC, as shown in Figure 2. If the reference PMU uses the same configuration as the field PMU (measurement window, filtering, etc.), delays introduced by the PMU will be eliminated and the time to traverse the network will be isolated.

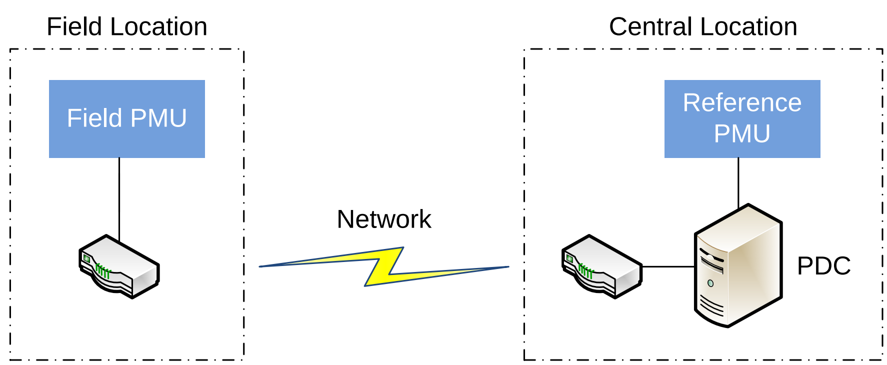

Figure 2: Basic Configuration of PMU Latency Analysis

The PDC will report latencies for both the field PMU and the reference PMU. A long-term measurement of these values can be recorded, then a sample-by-sample difference can be computed to estimate the network latency (Figure 3). This method does not require the PDC to be time-synchronized, as all latency quantities are relative to each other.

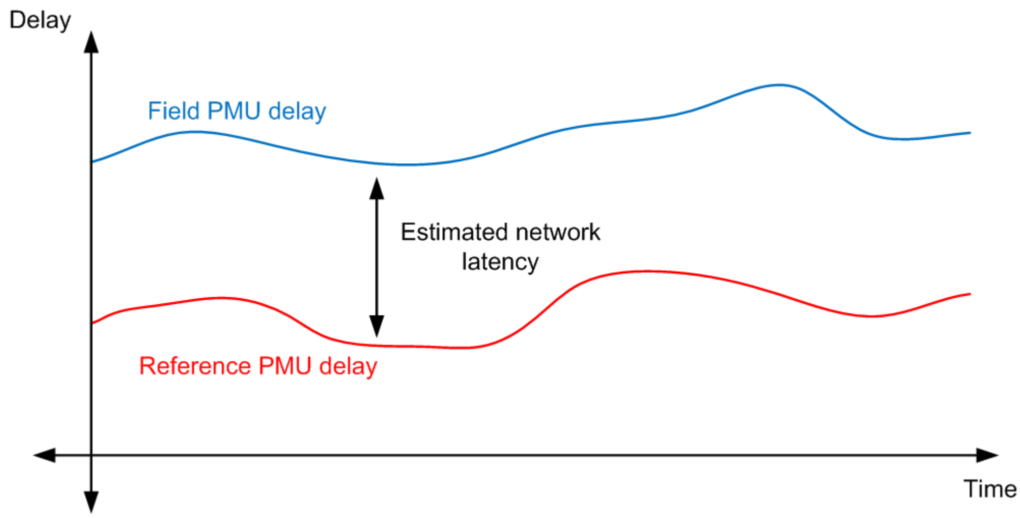

Figure 3: Estimation of Field PMU Delay

Data Storage and Retrieval

Storing synchrophasor data requires a much greater amount of disk space compared with conventional SCADA storage used by electric utilities. Due to the volume from data and significantly faster sample rates, integrating synchrophasor data with traditional SCADA data on the same historian can impact data retrieval performance and can use up remaining drive space quickly. A request for data requires that the system open the needed archive file for the timeframe of the request and sort through them to find the data that is needed. Combining synchrophasor and SCADA data in a single historian system can have a major impact on the SCADA data retrieval, not only the PMU data retrieval, since the number of archive files increased dramatically. For this reason, many utilities are using separate archives and sharing necessary data across the two systems.

For example, a utility data historian system may generate archive files of a particular size for timeframes of about a week or so. In comparison, synchrophasor archives create archive files every 6-8 hours, or about 25 times more often than the conventional SCADA system. Table 1 compares these systems for an actual utility SCADA and PMU data historian system.

Table 1: Example Comparison of Utility Data Historians

SCADA Historian System			PMU Historian System		
Number Tags	**File Size**	**Archive Frequency**	**Number Tags**	**File Size**	**Archive Frequency**
100,000	8 GB	8 – 10 days	1,500	8 GB	6 – 8 hours

Another archival option is for the application to store all data to a short-term archive at full resolution for a configurable period of time (e.g., months). Eventually the data rolls into a long-term archive with some level of compression to reduce storage requirements. Eventually the data is deleted after a pre-determined timeframe. The long-term archive can also store data for system disturbances at full resolution using pre-defined event detection logic, keeping these events indefinitely. It is recommended that long-term archives retain the data for at least 3 years to ensure forensic analysis, offline applications, and engineering tools have sufficient data available.

Many historian systems use data compression techniques to reduce the amount of information stored on disk. Historian applications allow the user to set parameters for exception and compression processing that removes noise and errors from the signal without losing any significant meaning from the data. This frees up disk space, reduces network traffic, and improves overall performance of the historian applications. They are defined as:

- **Exception Processing:** stores data if the data changes outside a pre-defined deadband limit, which should be set to a value less than the precision of the metering equipment supplying the data.
- **Compression Processing:** similar although in this case the changing data can have a slope and deviations from the slope drive what samples are stored and what samples are not stored.

The combination of exception and compression processing can significantly reduce the amount of data stored. However, some newer synchrophasor applications (e.g., oscillation detection) may require that all measurements be maintained since they use the noise in the signals to derive meaningful content that can be used by operators or engineers. Application requirements need to be addressed prior to setting compression or exception processing settings. By-exception can remove small-signal changes in the data and affect applications requiring this information. Exceptions, if used at all, should be based on the level of process noise in the measurement, not the accuracy class, thus retaining the dynamic content.

Two examples of recommended compression settings based on PMU measurement type are provided in Table 2. Utility A settings have proved to result in about 60% compression of the raw PMU data; Utility B settings have resulted in about 50% compression. Utility A uses applications such as oscillation detection and monitoring, hence the very low voltage phase angle compression setting and no compression of frequency measurements.

Table 2: Utility Compression Setting Examples

	Measurement Type	Compression (Deviation)	
Utility A	AMPS	0.100	A
	DEG-AMPS	0.100	deg
	DEG-VOLTS	0.001	deg
	MVAR	0.010	MV
	MW	0.010	MW
	VOLTS	10.000	V
Utility B	AMPS	0.200	A
	DEG-AMPS	0.050	deg
	DEG-VOLTS	0.005	Deg
	MVAR	-	MV
	MW	-	MW
	VOLTS	5.000	V
	FREQ	0.00002	Hz
	ROCOF	0.00006	Hz

The quantization of phasors using integer data format is normally comparable with the measurement process noise, and therefore there is little to be gained from the increased storage requirements for floating point phasors. However, integer format frequency has a resolution of 1 mHz, which can limit the capability to use frequency for oscillations and smaller disturbances. In our experience, using floating point for frequency retains valuable information that is lost in integer frequency.

Depending on redundancy requirements for the system disk space, costs and architecture can be significant. Most utilities use primary and backup drive hardware, doubling necessary disk space. These systems are usually redundant between control centers (primary and backup control center), again doubling the storage space. For example, a medium-sized utility currently generates 10 TBytes of primary disk space per year on their synchrophasor data archive. This results in 40 TBytes required disk space per storage year to account for redundancy. Some utilities store synchrophasor data at the substation level for shorter periods (e.g., weeks or months) so that data is not lost if there is an interruption in the communications network to the control center(s).

It is recommended to store synchrophasor data for at least one year at high resolution (minimal compression or exception processing of the data), with longer-term archives storing compressed data for a longer period of time. Data for system disturbances should be stored with no compression or exception processing of the data indefinitely for future engineering analysis. Reasonable event triggers should be set to capture events of interest to engineering staff in full resolution, including system faults and underfrequency events. Some utilities store all data indefinitely as to not throw away any data that could be of use in the future (e.g., baselining studies). Others store full resolution data online for several months and then store archive files offline for a period comparable to what they do with SCADA data. It is best to determine these requirements up front so that the data storage requirements can be specified to meet expected application needs.

PMU Placement Strategies for Real-Time Tools

Strategic placement of PMUs is critical for enabling the use of real-time applications and tools. This section addresses placement of PMUs for each application discussed.

State Estimation

State estimation is the process of deriving a best estimate of system state (voltage magnitudes and phase angles) based on a set of measurements from the system. The state estimator (SE) produces a state estimate using measured quantities and statuses such that bad data or errors are flagged through redundant measurements. Usually, state estimation is based on minimizing the sum of squares of the differences between estimated and measured values of a function. There are three primary types of commonly used state estimators:

1. **Conventional**: non-linear state estimate based on a network model and unsynchronized SCADA measurements[11] of bus voltage magnitude, active (P) and reactive (Q) power flow (lines and transformers) and injections (generators and loads), element statuses, and set points;
2. **Hybrid:** non-linear state estimate using unsynchronized SCADA measurements and time synchronized synchrophasor data[12];
3. **Linear:** direct linear (non-iterative) solution of the system state using time synchronized measurements. PMU-based state estimation includes using time synchronized PMU data including both the voltage magnitude and phase angle.

The advantage of using PMUs for state estimation may include: (1) synchronized measurements with a common time reference; (2) voltage and current phasor measurements (magnitude and phase angle) are available; and (3) very fast state estimate solution due to a direct, non-iterative technique. A PMU-based state estimator can be used to improve PMU data quality, and may serve as a backup SE solution and/or comparison check for the conventional SE.

Observability

Regardless of the solution technique used for state estimation, the concept of state observability and measurement placement remains the same. Observability analysis determines if a unique estimate for the system state can be found using the available set of measurements. The system is considered observable if the Jacobian matrix has full rank; the number of measurements should exceed the number of system states. System observability depends on the number of measurements, locations of measurements, and topology of the system. Topological, numerical, and hybrid techniques are utilized to determine the network's observability, identifying additional measurements that are needed for the system to become (more) observable. PMUs offer several advantages over conventional measurements for observability:

1. PMUs can improve system state observability both for conventional and linear SE.
2. PMUs can be placed anywhere in an unobservable island[13] to merge it with the other islands. In contrast, conventional measurements need to be installed at the boundary buses of observable islands.
3. PMUs provide a state measurements so Ohm's and Kirchhoff's Laws can directly be applied because of the direct measurement of phase angle. This allows for more effective expansion of the observable portion of the system due to the state vector measurement. Using the measured state variables (bus voltage and angle) and line current, adjacent voltages can be estimated with direct computation. This includes lines coming out of observable islands.

[11] Conventional SE does not include time synchronized synchrophasor data.
[12] There have also be proposed non-linear, synchrophasor-only state estimators that are under research and development.
[13] In this context, island refers to a cohesive set of observable buses.

4. Similar to conventional state estimation, PMU-based state estimation has similar observability impacts due to loss of data sources. In some situations, performance is improved over conventional estimation since more information can be extracted from the existing PMU measurements.

PMU placement for system observability depends on which of the following objectives are intended to be met:

1. Identifying the minimum number of PMU locations such that the system is observable using PMUs only; or
2. Placing a pre-determined number of PMUs to achieve maximum possible observability[14].

Two approaches are used for hybrid state estimation:

1. PMU and SCADA measurements are available at the same location. In this case, both types of measurements are used for state estimation at the same location, but PMU measurements should have an equal or higher weight[15] since they are time synchronized and measure phase angle directly. The greater the number of available measurements, the more accurate the results of state estimation are.
2. For locations where PMU data is available, PMU measurements are used. At locations where PMU measurements are not available, SCADA measurements are used.

PMU locations define observable states in a PMU-only Linear State Estimator (LSE). The objective function for optimal PMU placement is minimizing the number of PMU installations while achieving a sufficient level of redundancy. Excluding a redundant measurement should not affect observability of the system. PMUs have generally been placed on the bulk power system (BPS) at higher voltage levels (e.g., 345 kV or higher). A linear state estimator can be developed for the BPS system that is observable, and expanded over time as PMU measurements become available. Figure 4a shows PMU placement within a small test system (dark grey lines show redundant measurements) and Figure 4b shows the observable buses or states based on observability analysis using these select few PMUs that are available.

- Buses where PMUs are placed have a directly measured system state – these are fully observable.
- Starting from buses where PMU measurements are located, line flows are used to estimate bus voltages at buses which are directly connected to the buses with PMUs. These are also observable buses.
- Then, flows are computed and voltages at buses connected to those buses where voltages and flows have been calculated using direct computation. These are also observable buses. This process is repeated while we can expand the set of observable buses using direct computation, and depends on the power system network, and quantity and locations of PMUs.
- As a result of the above two steps, (1) bus voltages and flows in the observable part of the system are determined, and (2) non-observable parts of the network are identified where approximate values of voltages and flows are determined.
- Values of generation and loads and positions of switched shunts are computed.

It may be noted that topology needs to be known and correct for state estimation to be applied, and may be derived from RTU data. Phasor data can be useful for validating topology, in addition to carrying out state estimation.

[14] Redundant PMus and communications paths can help ensure observability.
[15] Provided that some basic data quality checks are performed on the PMU data such as correlation, statistical analysis, comparison of signals, etc.

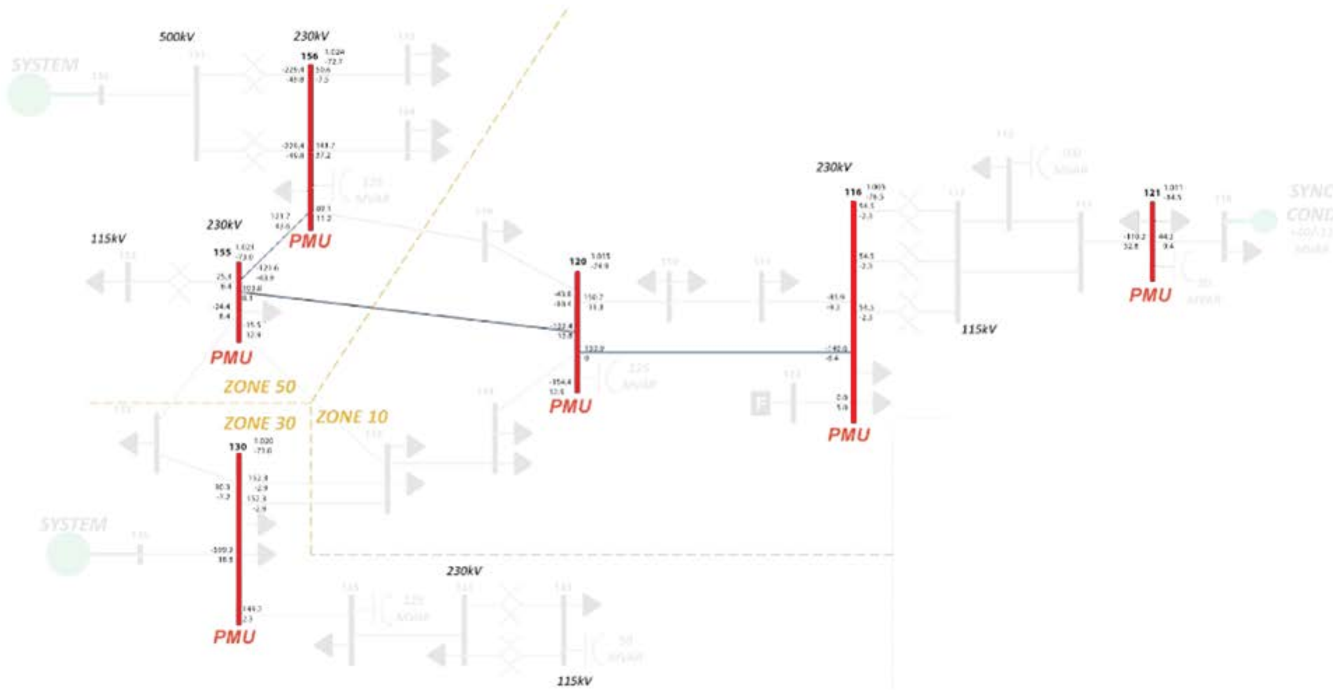

Figure 4a: Six PMU Location [Source: V&R Energy]

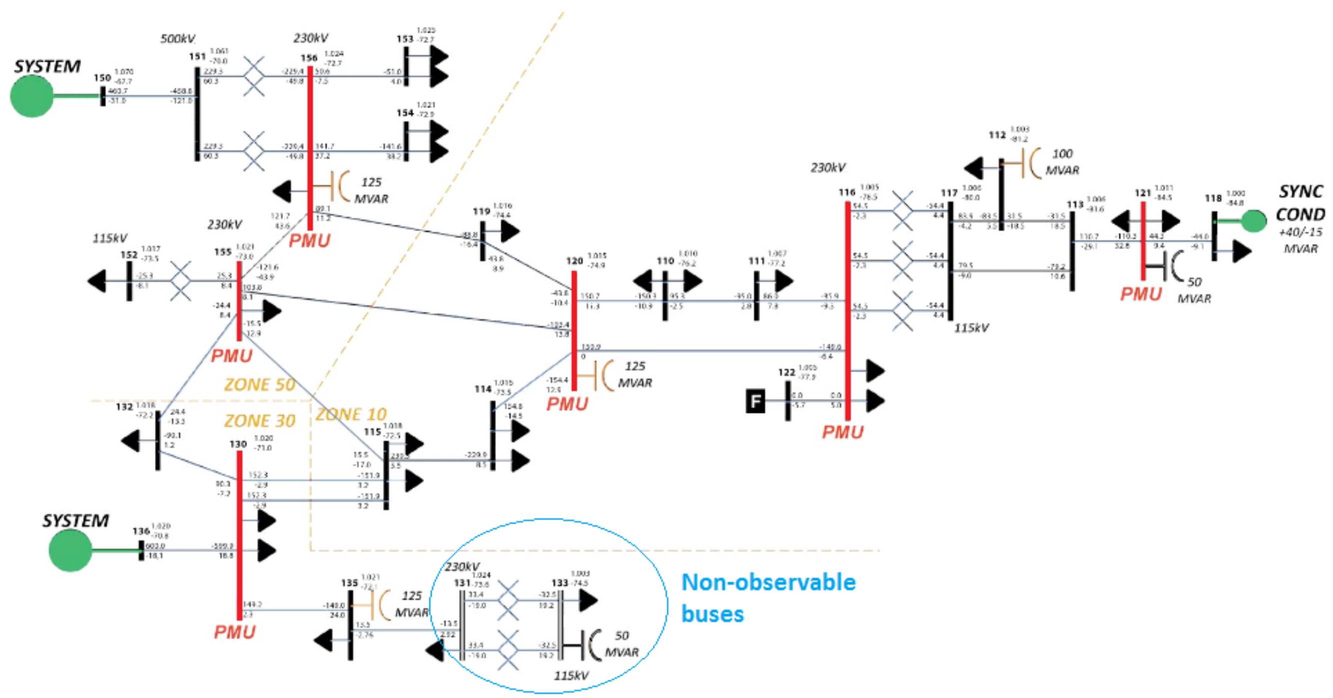

Figure 4b: Observable and Non-Observable Buses [Source: V&R Energy]

Oscillation Monitoring & Analysis

PMUs enable real-time monitoring of system oscillations. Monitoring can vary from simple detection of the existence of oscillations to tracking a particular system mode's properties. PMU placement is critical to the monitoring of oscillations, which are distinguished using the following terminology:

1. **Oscillatory Mode**: A natural property of an electromechanical system ("electromechanical mode") characterized by its frequency, damping, and shape. Inter-area modes are oscillatory modes consisting of many generators whose speeds move together cohesively.
2. **Oscillatory Mode Shape**: Relative perception of an Oscillatory Mode at different parts of a power grid. The Shape is defined by the amplitude and phase of the Mode at specific measurement locations.
3. **Transient Oscillation Response**: System response immediately following a disturbance such as a fault, line trip, generator trip, or load rejection. Oscillations in a Transient Response are characterized by the Oscillatory Modes.
4. **Forced Oscillation Response**: Response of the system associated with an external input or a malfunctioning apparatus (e.g. malfunctioning steam valve cycling on and off, arc furnace induced dynamics). Forced oscillations may include harmonics resulting from the periodicity of the external inputs. Forced oscillations are typically undamped and persist until the malfunctioning device is removed from the system.
5. **Resonance Effect**: Two natural frequencies of oscillation, involving some of the same plants, come close in frequency and interact, normally resulting in one mode being observed with very light damping.
6. **Ambient Response**: The response of the system to the small random changes within the system. These changes are typically characterized by small random load changes.

Figure 5 exemplifies typical responses in these oscillatory states. Ambient response is caused by unknown, small random inputs; transient response is caused by a sudden disturbance; forced response is caused by a cyclic input.

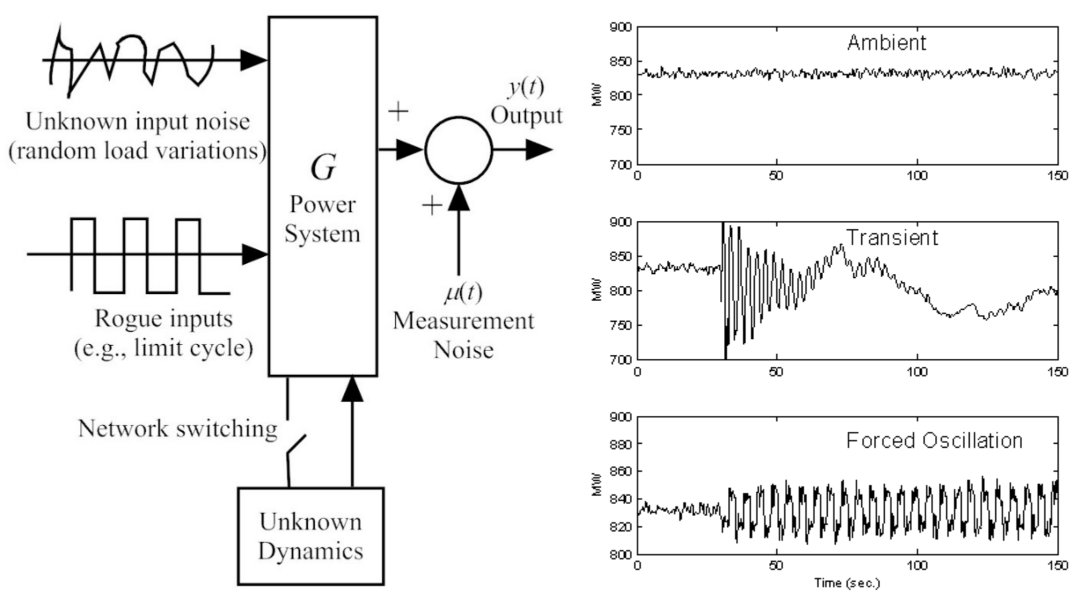

Figure 5: Types of System Response – Ambient, Transient, Forced Oscillation [Source: Montana Tech]

It is recommended to configure PMUs used for oscillation monitoring as M-class[16] devices to avoid signal aliasing.

[16] *IEEE Standard for Synchrophasor Measurements for Power Systems*, IEEE Standard C37.118.1-2011, 2011.

Forced Oscillation Detection

The goal in detecting Forced Oscillations (FO) is to quantify the oscillation amplitude, frequency(ies), and location of the root cause of the FO. As such, a PMU should be located near the source of the FO. Unfortunately, one cannot predict where FOs will come from *a priori*; therefore, one should consider typical sources of FOs. Recent research has shown that FOs typically come from the following types of sources:

1. **Synchronous Generators:** Power plants such as fossil, hydro, and nuclear power plants have many controls, with the primary electric generator functions maintaining mechanical power to the generator and generator field current at the desired level. FOs often result from malfunctioning power plant controls and/or devices[17].
2. **Wind Generation:** Unintended FOs induced by the turbine or plant-level control systems for wind turbines have been observed at high levels of wind power output.
3. **Cyclic Loading:** Industrial loads are highly cyclic in nature[18] and can induce FOs into the BPS.
4. **Malfunctioning Grid Controls:** Devices such as switched capacitors, SVCs, and series compensation devices can misoperate. Periodic malfunctioning can induce FOs into the system.

PMUs should be placed near[19] significant generating plants generally above 100 MVA[20] (including wind and solar), large load buses, and grid control devices in order to capture the location of FOs. A FO with an oscillation frequency near a system-wide oscillatory mode will be amplified by the system (i.e. a resonance effect). Therefore, even small generation plants can induce larger system-wide FOs. To identify the exact location of FO sources requires considerably wide PMU coverage across a particular interconnection which is not always practical; however, PMUs in the vicinity of these resources can often help pinpoint the general location of the oscillation and further forensic analysis can help locate the source.

In most cases, FO are monitored in real power flows, frequency signals, and voltage magnitude signals from the PMU as these quantities provide physical perspective to grid operators. For example, if a monitoring device states that a particular generator is oscillating with an RMS magnitude of 50 MW, this provides physical perspective and alarm limits to the operator. One approach is to alert/alarm operators on FOs that are above the normal[21] ambient level by a given threshold and are persisting for more than some period of time (e.g., 10 MW for 20 seconds).

Inter-Area Mode Monitoring & Analysis

Unlike forced oscillations, the behavior from an inter-area mode is more predictable. The characteristics of the oscillation are primarily dictated by the system grid topology and generation pattern over the entire interconnection. Transient stability simulations and eigenanalysis help engineers baseline expected oscillation properties. Certain locations will have very high observability of the mode while other locations will have no observability. System simulation and linear analysis studies are used to find these general locations. The goal of monitoring an inter-area mode is to track the mode's frequency, damping, and shape. Sophisticated signal processing algorithms are needed to accurately estimate these quantities along with properly-placed PMU measurements.

[17] Examples of malfunctioning controls include misoperation or abnormal valve controls swinging in a limit cycle and hydroelectric generation plants operating in a "rough zone" resulting in resonance effects linked to the turbine penstock.

[18] Such as electrolytic process in aluminum smelting.

[19] It is recommended that PMUs monitor the current and voltage at either the high- or low-side of the GSU transformer.

[20] This may be modified by individual utilities based on their system needs and types of interconnecting resources.

[21] The normal ambient level of oscillatory behavior on the system can be determined by offline analysis of ambient (no disturbance) synchrophasor data under different operating conditions.

Monitoring a particular mode requires PMU placement at points where a particular mode can be observable with the PMU data (e.g., higher amplitude of oscillation). Two levels are recommended. For the first, the few highest points of observability are required to monitor the frequency and damping of the mode. To monitor the shape of the mode requires a higher level of placement with PMUs located at many observability points within the interconnection. In general, it has been found that mode shapes rarely change unless major grid topology or change in generation dispatch occur.

Subsynchronous Resonance & Subsynchronous Control Interaction

Subsynchronous resonance (SSR) is a condition where the electrical power system exchanges energy with a turbine generator due to a resonance effect. SSR has conventionally been associated with steam turbine generators such as nuclear and coal-fired generating facilities[22], and has primarily been associated with power plants near heavily series compensated transmission lines and potential radial connections to the grid. Generally, SSR is categorized by:

- **Induction Generator Effect (IGE):** A purely electrical phenomenon for which at subsynchronous frequencies, the generator can have a negative resistance; at subsynchronous frequency, the generator appears to be an induction generator since the slip is negative. This results in the generator injecting energy into the system during a disturbance. If the system net resistance is also negative, this amplifies the action over time, causing instability and potential damage to the machine.
- **Torsional Interaction (TI):** Interaction between the electrical system (generator and transmission network) and mechanical system (turbine shaft and masses) when the complement of electrical resonance frequency ($60 - f_n$), where f_n is the subsynchronous network natural frequency, is close to one or more natural frequencies of the mechanical turbine shaft system. This can result in severe induced currents and torques on the generator shaft, causing shaft fatigue and potential damage.

Subsynchronous Control Interaction (SSCI) is a condition in which turbine controls such as power electronic converters associated with Type 3 wind turbines (doubly-fed induction generators) cause negative damping, effectively amplifying subsynchronous currents in the stator windings of the machine. Wind generation is a primary concern because it is often located far from the transmission system, necessitating series compensated transmission lines to the wind power plant.

The subsynchronous resonance and control interaction effects described above are by nature an interaction between natural frequencies of oscillation. Resonance occurs when these modes involve participation by the same plant and coincide at close frequencies. A continuous monitoring approach offers the ability to monitor the subsynchronous oscillations that occur without a resonant condition, useful for analysis, modelling and risk assessment. Furthermore, it facilitates warning of the early signs of resonance – raised amplitude, poorer damping and wider area of participation.

Using PMUs to capture SSR is challenging since typical mechanical resonance frequencies are in the range of 15-30 Hz. For example, the risk of SSR-TI occurs when the electrical resonance frequency is equal to the nominal system frequency minus the natural frequency of the mechanical system ($f_e \approx f_0 - f_m$). Therefore, the electrical resonance frequencies of concern are from 30 Hz to 45 Hz. For a PMU reporting synchrophasor data at 60 samples per second, these frequencies are outside the Nyquist rate and cannot be accurately detected. While some PMUs report at rates of 120 samples per second and can extend the observable bandwidth beyond that of a 60 sample per second reporting rate, there is a fundamental limitation that computing an accurate phasor calculation requires a data window that is typically one cycle or more, and the phasor computation itself will act to remove higher frequency components.

[22] Although this would apply to any steam turbine generator as it relates to the natural torsional frequencies of the shaft.

The PMU filter settings, filter computation window, and roll-off of the frequency response will determine if the PMU can effectively capture the frequencies of interest. For example, consider Figure 6 which shows the frequency response for an amplitude modulation test for three different PMUs sampling at 60 sps. Two of the PMUs (5 and 7) have a roll-off that heavily filters out higher frequencies but does an excellent job of anti-aliasing. PMU 6, on the other hand, provides minimal filtering for higher frequencies but runs the risk of aliasing effects. Some of these issues may be mitigated with higher sampling rates, shorter phasor computation window length and appropriate filter settings.

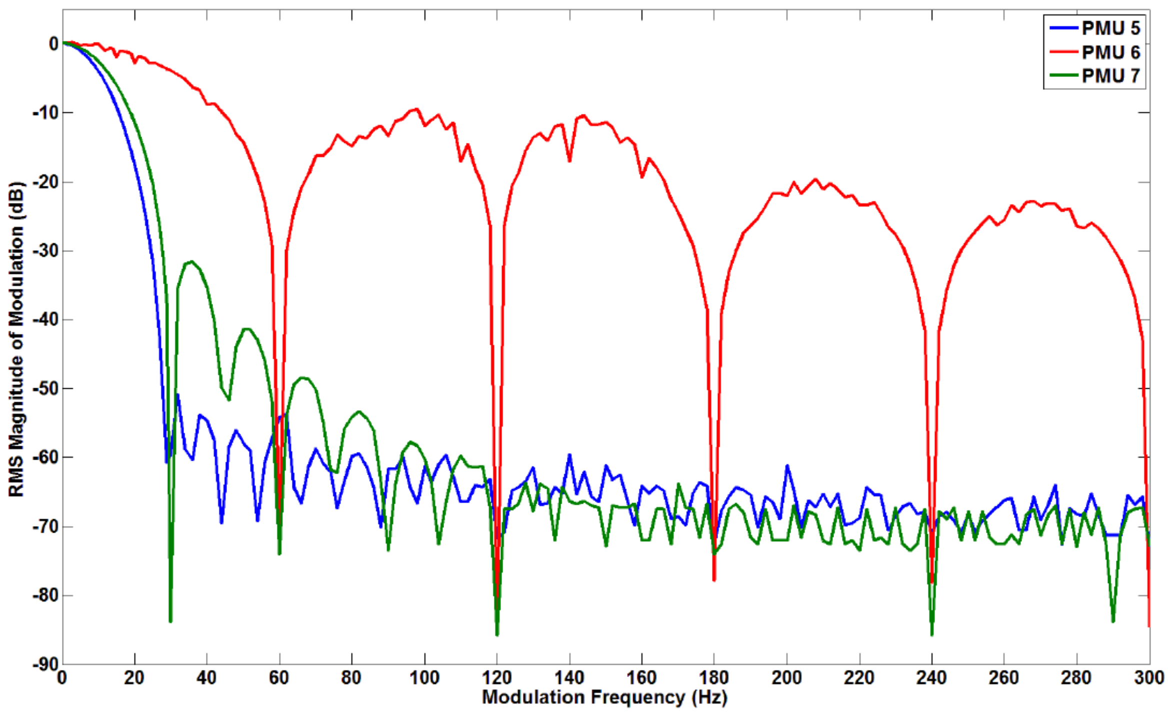

Figure 6. Amplitude Modulation Response [Source: BPA]

A promising alternative approach to sub-synchronous oscillation monitoring has been successfully trialed[23] where the raw high speed waveform measurements acquired by the same hardware as a PMU are filtered, down-sampled and streamed out as analog values (instead of phasors) at a rate of four times the nominal grid frequency (240Hz or 200Hz). This approach can use the same hardware as PMUs and communicates using the IEEE C37.118 protocol. A simple filter applied to the raw data with 80Hz cut-off avoids problems with aliasing, while providing visibility of the sub-synchronous oscillation range without attenuation.

PMUs (or Waveform Measurement Units, WMUs) capable of capturing the electrical resonance frequencies of interest should ideally be located at the terminals of equipment that may be involved in the resonance. Examples of measurement points include series capacitor terminals, the electrical generator or Point of Interconnection (POI) of the power plant to be monitored for SSR or SSCI, and FACTS devices in which control modes may be significant. Where possible, generator shaft speed measurement can be incorporated. A wide-area view of the interacting plant is important for real-time and off-line diagnostics and response, with potential for triggering automated responses such as filter switching and series capacitor bypass.

[23] Clark S., et al: "Addressing Emerging Network Management Needs with Enhanced WAMS in the GB VISOR Project", Power Systems Computation Conference (PSCC), Genoa, Italy, June 2016

Angle Difference Monitoring

A PMU estimates synchrophasor phase angle based on the nominal system frequency synchronized to UTC (GPS). The PMU estimates the sinusoidal component of the AC waveform from a voltage or current input. Using a time input, usually from a GPS source, it constructs a synchronized reference cosine waveform at the nominal system frequency (60 Hz) such that positive peak is at a UTC second rollover. The synchrophasor phase angle is the phase difference between these signals at the given reporting time.

Phase angle difference refers to the difference between two phase angles reported from individual PMUs. This angle difference between bus voltage phase angles[24] is directly related to power system conditions, as shown in the equation[25] for real power flow across a short transmission line:

$$P_R = \frac{V_S * V_R}{X} \sin(\delta_S - \delta_R)$$

Phase angle difference $(\delta_S - \delta_R)$ is primarily a factor of 1) real power flow across the transmission line (P_R) or interface, and 2) the electrical impedance (X) across the sending and receiving ends. Increasing phase angle (wide-area or line-based) indicates these forms of system stress, which can be monitored using PMU measurements.

There are two main uses of PMUs for angle difference monitoring, and placement of PMUs for these purposes is discussed in the following subsections.

1. **Line-Base Angle Difference:** The phase angle difference across a line provides useful information to a system operator, particularly for the application of angle reclosing.
2. **Wide-Area Angle Difference:** Wide-area angle differences may be indicative of system stress, and can be used to complement conventional power flow-based limits or constraints.

Angle difference monitoring for wide-area situational awareness is mostly a steady-state function so M-class PMUs are generally used.

Line-Based Phase Angle Difference Monitoring

PMUs located at both terminals of a transmission circuit allow for monitoring of phase angle difference across that circuit; in particular, enabling PMU-based line reclosing[26] and line restoration[27] supervision. Synchronism check relays are used in the protection system for actual reclosing; however, the PMUs can provide system operators with real-time visualization of the phase angle difference across the circuit and across circuit breaker(s) at each line terminal for pre- and post-contingency conditions. There are, in essence, two version of reclosing or restoration monitoring:

- **Basic Monitoring:** PMUs measuring voltage magnitude and angle on the *bus-side of the circuit breaker(s)* will provide the operators with the phase angle difference across the entire circuit. In the event of an out-of-service line, this provides the operators with insight into whether the synchronism check relays will be impacted upon attempted reclosing. The potential transformers (PTs) for this capability are shown as the red measurement points in Figure 7.
- **Comprehensive Monitoring:** PMUs measuring voltage magnitude and angle on the *bus-side and line-side of the circuit breaker(s)* of the circuit provide the operators with exactly the same measurement that the synchronism check relay would be experiencing (with some measurement error differences). The operator would know exactly the angle difference across each breaker as the line is reclosed or returned to service.

[24] Generally, the voltage measurement is used to report the phase angle within the PMU.
[25] 'S' and 'R' refer to sending and receiving end of the transmission line.
[26] Referred to here as the automatic closing of a circuit breaker after it has been opened due to a fault.
[27] Referred to here as the re-establishment of network flows between two terminals of a transmission circuit.

The PTs for this capability are shown as the blue measurement points in Figure 7, which would be in addition to the red points as well.

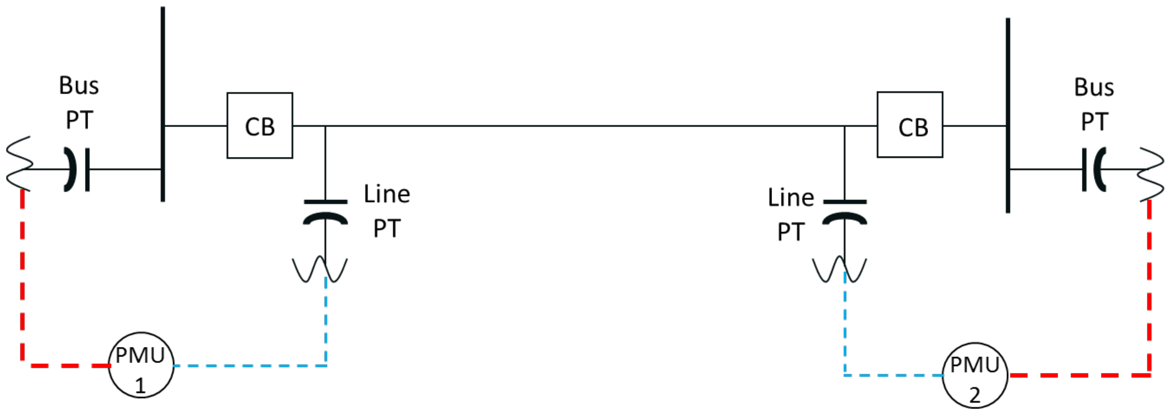

Figure 7: Line Reclosing & Restoration Supervision

Instantaneous reclosing (generally less than 50 cycles) is outside the purview of PMU capabilities; however, PMUs can provide operational insights for time-delayed reclosing (generally 10-100 seconds). From the system operator's perspective, if they do not have synchronism check relay SCADA points, they no longer would need to wait for the next state estimator solution to obtain the angle difference across the opened line or breaker.

If a reclosure is unsuccessful, the operator can use a PMU-based capability to interpret why the operation was unsuccessful. Examples of real-time diagnostic information from real events include:

- Breaker closes and re-opens. Frequency difference is too large and the network post-closure is too weak to bring the areas into synchronism. The operator will need to improve frequency match between areas.
- Frequency in one area is unstable, normally due to governor instability in lightly loaded island conditions. Some units may be removed from frequency control duty before re-trying.
- Frequency is very close between islands, and the checksync relay times out before closure is achieved.

Wide-Area Phase Angle Difference Monitoring

Phase angle difference is directly correlated with system stress, and can be used as a strategic measurement of grid security both pre- and post-contingency. For improved wide-area phase angle difference monitoring and situational awareness, the following recommendations are provided:

- **Major interfaces:** It is useful to monitoring the angle difference across major transmission interfaces across the grid, including both on a local- and wide-area basis. These interfaces are defined by key stress patterns driving the need to monitor these interfaces. Often times, a nomogram or operating limit is defined in terms of a real power (MW) transfer level. However, these limits can be defined in terms of angle difference, which is more illustrative of actual system stress.
- **Baselining:** Which PMUs will be the most valuable for angle difference monitoring requires significant baselining analysis, both using actual system data as well as offline system studies.
- **Visualization:** Wide-area angle displays such as angle contours or angle difference maps and trends provide system operators with increased awareness into the current state of the system (Figure 8). Visualization of angles is particularly useful after major system events. The impedance between source and sink increases due to line tripping and redistribution of real power flows. The angle difference between the source and sink will likely increase and can be visualized using PMU data to identify the level of system stress, complementing flow-based measurements.

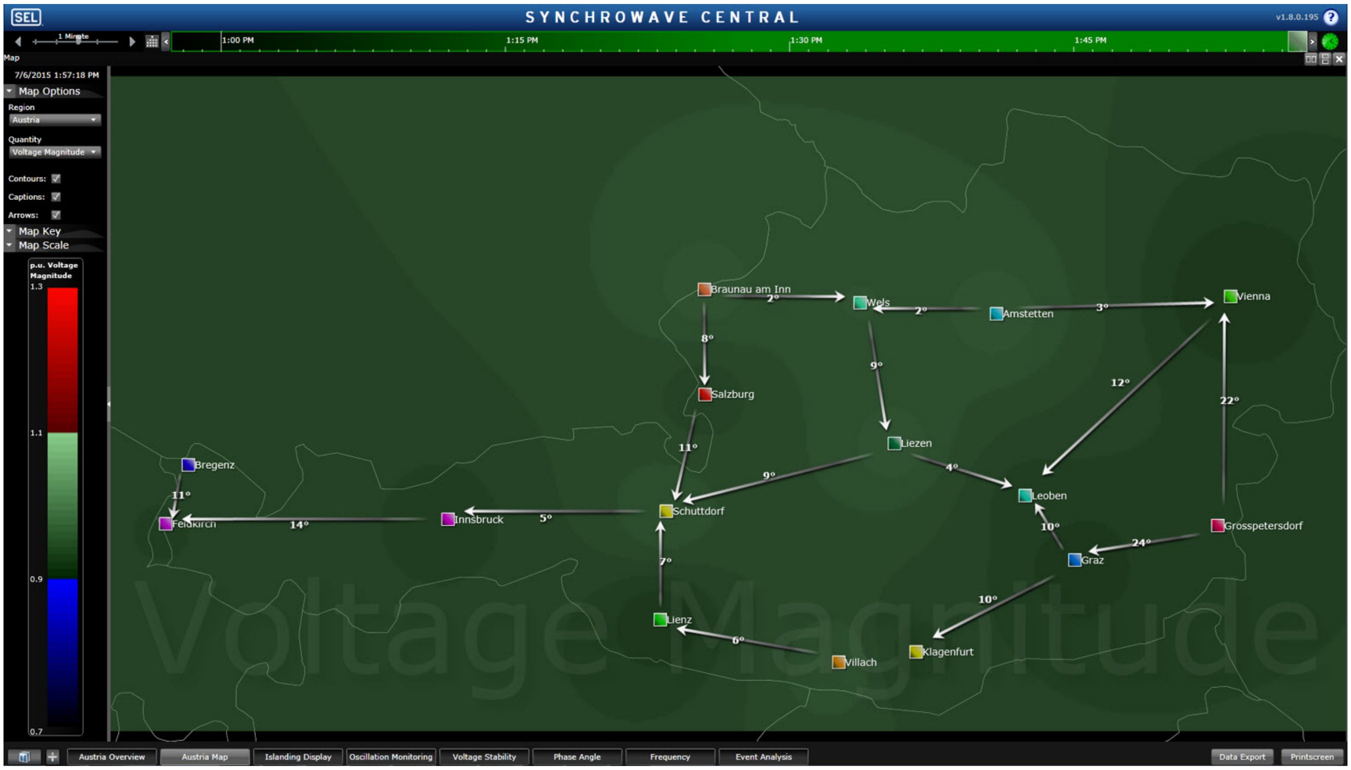

Figure 8: Wide-Area Angle Difference Monitoring [Source: SEL]

Wide area phase angle differences can be particularly useful to represent transient stability constraints between weakly connected areas of a grid, as the measurement closely represents the underlying phenomenon of angular separation. A variant of the angle difference representation is to use a composite angle to represent each area, and to express the boundary constraint as power and angle limits. Thus, raised power flow can be sustained as long as the composite angle is within a limit. In the case of wide area composite phase angle differences, the PMUs should be placed at the major centers of inertia at both sides of the boundary.

Voltage Stability

Voltage stability refers to "the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition"[28], and is a fundamental concept of power system stability analysis. System dynamics influencing voltage stability are usually slow, therefore steady-state (power flow) analysis offers an effective way to perform Voltage Stability Assessment (VSA). Power – Voltage (PV) and Voltage – Reactive Power (VQ) curves are the most frequently used steady-state techniques for voltage stability assessment.

Voltage Stability Assessment is generally a scenario-based analysis. A VSA scenario includes specification of source and sink locations (e.g. injection groups), monitored interface, a set of contingencies, monitored elements, and buses to plot PV- and VQ-curves. Placement of PMUs to perform VSA or monitor VSA system conditions should consider the following:

- **VSA Operating Condition Awareness:** Synchrophasor data enables high-resolution monitoring of actual system voltages, which can be used for advanced real-time visualization of current operating conditions and voltage stability limits to better assess the power system's proximity to system collapse. For improved VSA awareness using synchrophasor data, PMUs should be placed to enable scenario-based analysis including locating PMUs at the following locations:
  - **PV Interfaces:** PMUs located on the interface can be used to compare current operating conditions (pre- or post-contingency) to the stability limits determined using scenario-based tools.
  - **Monitored Elements:** Voltage stability limited interfaces are often defined by a low voltage condition on critical monitored elements in the post-contingency operating condition. A PMU placed at or near these critical monitored elements can help provide awareness of stability limits compared with simulation results to derive the limits.
  - **Injection Groups:** PMUs located in the source and sink areas of the injection groups used to derive the VSA limits can provide additional VSA awareness.
- **PMU-based VSA:** An effective approach to performing VSA using synchrophasor data is based on LSE to derive a PMU-based power flow base case at PMU data rates (i.e. 60 times per second). Then, the LSE-based power flow case is used to perform VSA and identify active and reactive power margins and limiting contingencies. Computation of operating margins can occur at much higher rates than conventional VSA using SCADA measurements and SE solutions. This is beneficial immediately following a major contingency such that VSA margins and limits can be updated immediately rather than waiting for the next SCADA-based SE solution.

Figure 9 shows an example application for voltage stability analysis of a PV interface observable using PMUs installed at a 26-bus network (same sample system described in the state estimation section). PMUs are located at six substations in Figure 10 (yellow buses in oneline diagram). Voltage stability analysis can be performed on the PV interface between Zones 30 and 50 and Zone 10. Figure 10 shows an example of a set of PV curves that are plotted at user-defined buses, regardless of whether a PMU is installed at that bus.

[28] IEEE/CIGRE Joint Task Force on Stability Terms and Definitions (P. Kundur et al), "Definitions and Classification of Power System Stability," IEEE Trans. on Power Systems, vol. 19, no. 2, August 2004, pp. 1387-1401.

Figure 9: Voltage Stability Assessment (VSA) using PMUs [Source: V&R Energy]

Figure 10: PV-Curves at User-Defined Buses Based on PMU Data [Source: V&R Energy]

Major Transmission Interfaces

Major transmission interfaces are often characterized by transfer paths defined as a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL). NERC Reliability Standards extensively use these terms for developing operating and planning criteria. These limits are defined as[29]:

- **System Operating Limit:** The value (such as MW, MVar, Amperes, Hertz, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:
  - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
  - Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
  - Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability Limits)
  - System Voltage Limits (Applicable pre- and post-Contingency Contingency Voltage Limits)
- **Interconnection Reliability Operating Limit:** The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

The BPS is operated within pre- and post-Contingency operating limits defined by the criteria listed above. A number of tools can be deployed to reliably operate within these limits; however, major transmission interfaces are a commonly used means of characterizing system state for large interconnected power systems. These major interfaces may have limits defined either offline or in real-time that represent the criteria listed above. In these cases, there are likely two components of the SOL or IROL:

1. **Transmission Interface:** the defined interface used to represent the system state in real-time; and
2. **Contingency Element:** the Element or set of Elements that are known to violate the operating criteria.

PMU monitoring for major transmission interfaces is useful for measuring the interface itself as well as monitoring the Contingent Element. PMU measurements covering all Elements of a major transmission interface provide a real-time measurement of system flows and voltages at strategic locations used by system operators to assess system stress. PMU-based interface calculations can provide a backup to the SCADA system as well as provide a much higher resolution, time-synchronized measurement immediately following the Contingency event. Immediately after the event, it can be helpful to examine and understand the dynamic nature of the system to ensure a new steady-state operating condition is achieved. The high-resolution data from PMUs can be effectively visualized and useful information can be provided to system operators in a meaningful and efficient way. This may be useful in situations where operators would otherwise need to wait for the next RTCA results to determine if there is an overload. For example, a major transmission interface may consist of three 500 kV transmission circuits. An N-1 or N-2 Contingency event could result in low voltages in a region of the system or overload of a lower voltage 230 kV parallel path or Element. In this case, real-time monitoring on the three circuits as well as PMU monitoring in the low voltage area or on the overloaded Element would be valuable for real-time situational awareness. These concepts are particularly useful for stability-related operating limits.

Electrical quantities to be monitored for the interface are generally defined by active power (MW), so PMU voltage and current phasors are required. For the Contingent Element, the electrical quantities to be monitored are dependent on the interface definition and the type of SOL or IROL exceedance, as shown in Table 3.

[29] NERC Glossary of Terms. Available: http://www.nerc.com/files/glossary_of_terms.pdf

Table 3: Types of SOLs and Electrical Quantities	
SOL Exceedance Type	**Electrical Quantities to be Monitored for Contingent Element**
Facility Ratings	*I,P,Q*: Elements' active and reactive power flow
Voltage Limits	V_{mag}: Element or group of Elements' voltage magnitude
Transient Stability Limits	δ: Phase angle difference (either referenced to "slack bus" or representative phase angle difference across Element
Voltage Stability Limits	V_{mag},*P*,*Q*: Elements' voltage magnitude and active/reactive power transfers nearby to verify transfer level, if applicable.

Phase angles reported by PMUs add a unique perspective for SOL and IROL monitoring and exceedance determination. Stress patterns have conventionally been monitored using active power transfer using SCADA data; however, wide area bus phase angle separation is strongly correlated to active power transfer and can complement SCADA monitoring effectively. Figure 11 shows an example of a major transmission interface monitored by SCADA MW Flow and the representative phase angle difference related to the interface. Note the correlation between the signals as well as situations where phase angle difference may be more indicative of system stress than the MW Flow value.

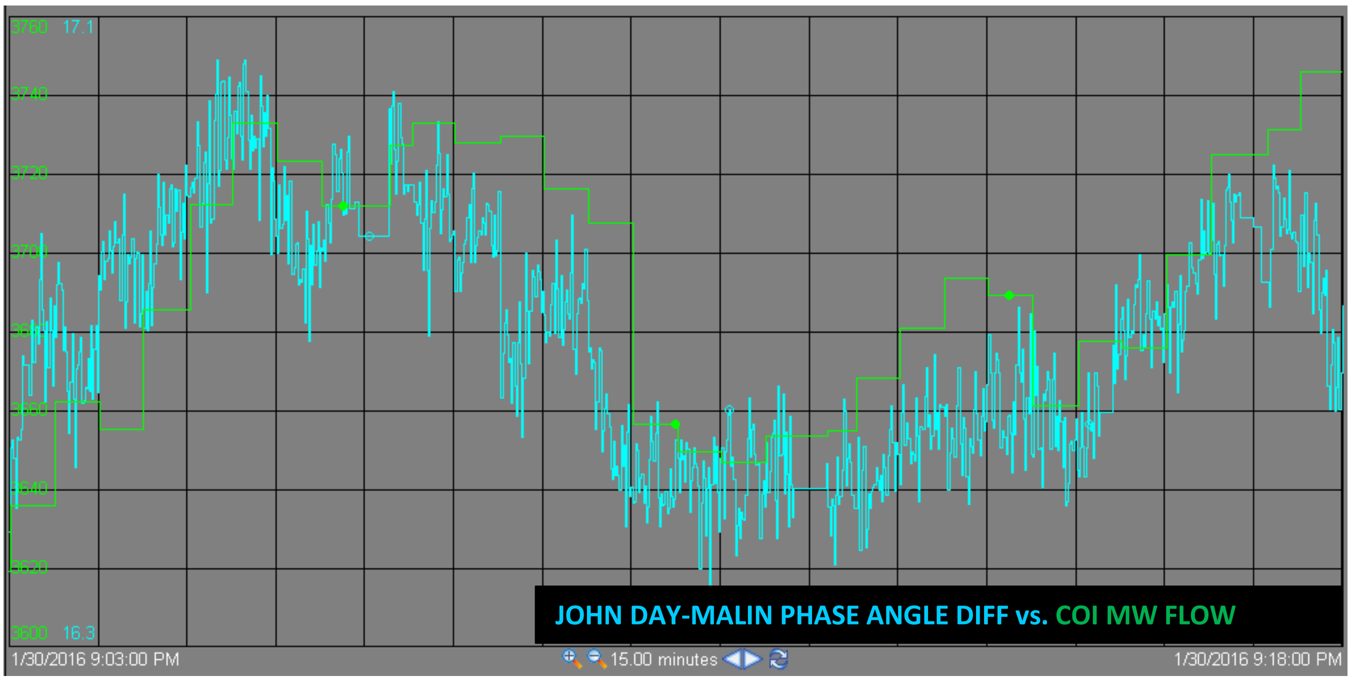

Figure 11: Interface MW Flow (SCADA) vs. Phase Angle Difference (PMU)
[Source: Peak Reliability]

Remedial Action Schemes

Remedial Action Schemes (RAS) accomplish a number of reliability goals ranging from mitigation of thermal overloads post-contingency to maintaining transient stability on a system-wide level. Examples of RAS include:

- Wide-area generation tripping based on EHV line tripping (e.g., system-wide stability)
- Local generation tripping based on connecting line outages (e.g., first swing stability)
- Load rejection (e.g., voltage stability)
- Shunt reactive compensation insertion (e.g., voltage stability)
- Braking resistors or load insertion (e.g., transient stability)
- Generator runbacks (e.g., thermal overloads)
- HVDC Controls or Modulation (e.g., stability or overloading)

RAS are generally grouped into two separate categories based on their implementation:

- **Event-driven:** RAS which require a pre-defined set of events (e.g., certain units/lines out) to transpire for any corrective action to be taken. These RAS are often armed based on current operating conditions for potential contingency events.
- **Response-based:** RAS which operate when a given set of conditions (e.g., power flows, voltages, etc.) occur on the system for a given duration to trigger the initiation of a corrective or supporting action automatically. These RAS are often armed more frequently or continually to mitigate reliability risks due to contingency events.

Synchrophasor-based RAS (SP RAS) can be incorporated in any of the ways listed above, particularly for RAS that require multiple monitoring locations in a time-synchronized, low latency manner. Figure 12 shows a conceptual diagram of a proposed response-based RAS using PMU measurements from across the Bonneville Power Administration (BPA) network. The SP RAS works in tandem with the other RAS controllers ("AC RAS Controller") and wide-area situational awareness (WASA) systems. It is intended to monitor system conditions and detect significant changes in system state using MW flows, angle differences, and rate of change these quantities to identify transient swings. Large contingencies outside their service territory may pose a reliability risk and the goals of the SP RAS is to maintain adequate transient voltages via fast-switched reactive devices to provide a safety net over existing RAS operations in the event of failure. This type of RAS is considered "do no harm" as it does not take corrective actions that are expected to cause any negative effects on the system (particularly for false operations).

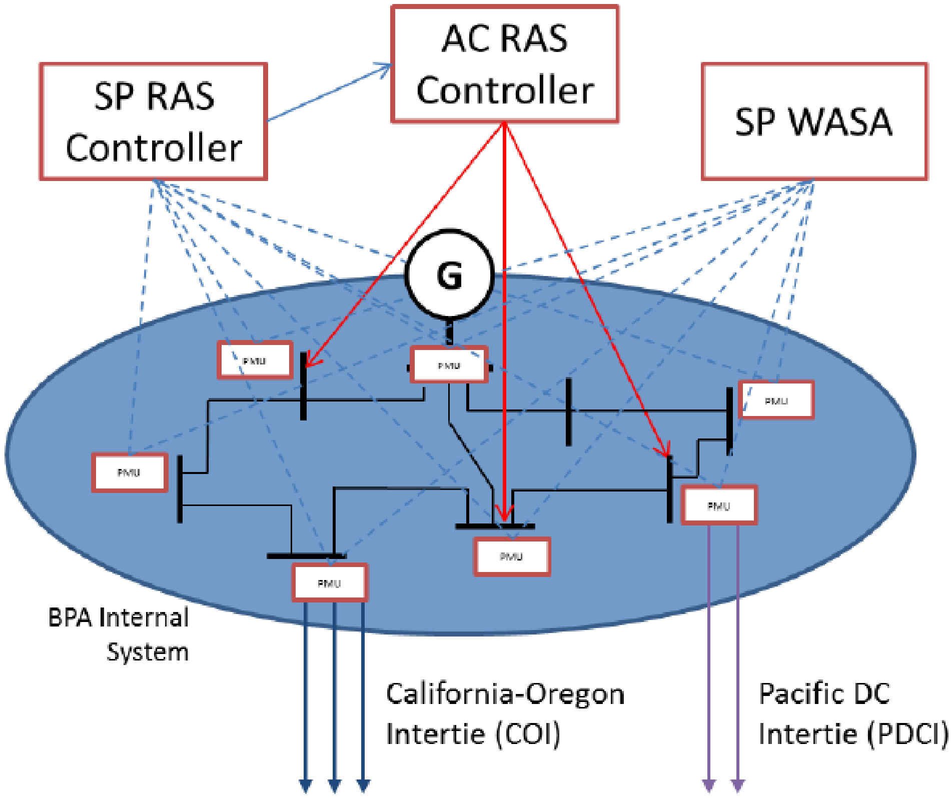

Figure 12: Synchrophasor-Based RAS – BPA RAS Concept [Source: Virginia Tech]

While this is one example of SP RAS, other RAS can be designed similarly to detect operating conditions that are considered adverse or insecure based on offline criteria (study-based) or online (real-time) monitoring. PMUs can be used to initiate the RAS (response-based) or monitor RAS action in a supervisory way (event-driven) as well automatically arm RAS pre-event. In any case, data quality and security should be accounted for in any operational decision making using this technology. Due to the complex nature of RAS and the different types of RAS in existence today, there are no clear guidelines for using PMUs as part of RAS. In any case, the algorithms deployed should be able to handle bad data, dropouts, poor latency, and not cause adverse effects such as misoperations.

Wide-Area Visualization & Alarming

Situational awareness encompasses a vast array of tools and applications used by system operators and real-time engineering staff for deeper understanding and visibility into current and future system conditions. PMU data provides high resolution visibility into system conditions, including dynamic behavior of the system following system events. Many of the tools used for situational awareness are encompassed within this report in greater detail; however, a high-value use of PMU data is simply enabling improved visualization and advanced alarming techniques. The primary forms of synchrophasor-based visualization and alarming include the following:

- **Phase angle difference monitoring & alarming:**
  - **System-wide:** PMUs located across the system at strategic EHV bus locations
  - **Interface-based:** PMUs located on either end of major transmission interfaces
  - **Line-based:** PMUs located at both terminals of a transmission circuit
- **High-resolution frequency monitoring:** System-wide frequency measurements across electrically diverse locations provides a much clearer and accurate representation of “system frequency” than conventional single-location measurements of local frequency.
- **Voltage trends and contouring:** System-wide or local voltage measurements at major EHV buses for bulk system voltage monitoring; key EHV or lower voltage buses for local voltage monitoring.
- **Interface real and reactive power flow monitoring:** PMU measurements covering ***all*** Elements of a major transmission interface provide the greatest visibility and accuracy of capturing the interface flows; measurements at either end of the interface are generally acceptable.

Alarming is a function of the monitoring capability. There are no common industry practices for placement of PMUs specifically for advanced or improved system operator alarming. However, increased visibility of the system using PMUs increases the operator’s awareness, hence improving system reliability. Nearly all PMU measurements can be employed to some advantage for wide-area visualization, regardless of the exact measurement location. General spread and coverage of measurement locations will tend to improve wide-area visualization with more detailed rendering of system conditions.

Variable Energy Resource (VER) Integration

PMUs have been applied for various reasons for integrating variable energy resources (VER) into the BPS. This section provides some examples of how PMUs have been used for VER integration and the PMU location and monitoring requirements employed. While these examples focus on wind resources, the same principles apply to other VER and inverter-based resources such as solar and battery storage.

PMU data at the POI of a VER plant can ensure the power plant is operating in the correct control mode based on plant- or TOP requirements. For example, wind farms are often operated in either a power factor control (constant or range) or voltage control mode. These modes can be monitored using the PMU data measured at the POI (voltage magnitude, active and reactive power flow). Figure 13 shows two different wind farms – one is operated in a power factor mode (MVAR injection from the plant is not correlated with POI voltage) and the other is operated in a voltage control mode with droop control.

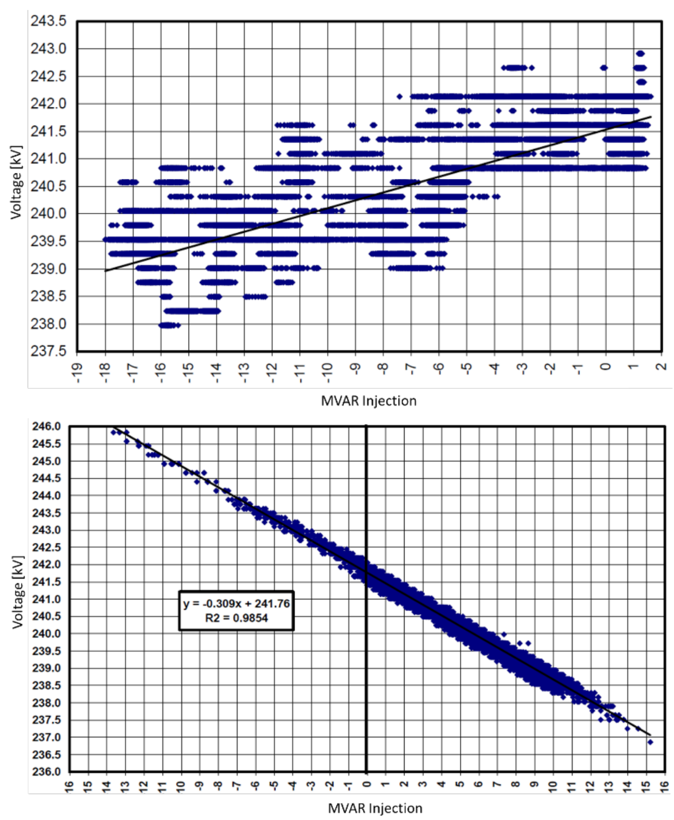

Figure 13: Wind Farm Operating Modes – Power Factor (Top) and Voltage Control (Bottom) [Source: BPA]

BPA requires[30] that large wind power projects (POI voltage >= 230 kV) have a PMU installed with specific requirements to capture data unique to large-scale wind farm operation and control. This is required for all new wind projects to provide operational awareness and to validate dynamic generator models. Figure 14 shows the monitoring points for a typical wind farm interconnected to the BPA system. High- and low-side current and voltages are required at the power plant step-up transformer as well as the current of each dynamic reactive Element and the status of all switched shunt reactive Elements on the plant-side.

[30] See Appendix A for a link to the BPA Technical Requirements for Interconnection document.

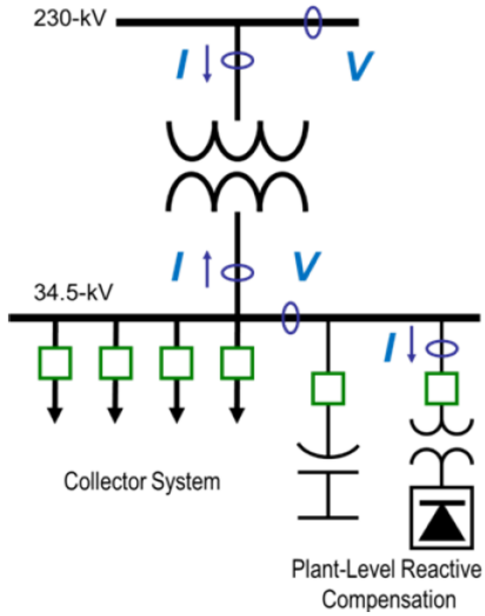

Figure 14: PMU Monitoring Locations for Wind Power Plants in BPA Footprint [Source: BPA]

Section 6.1.3 of the ERCOT Nodal Operating Guides[31] describes requirements for Phasor Measurement Recording equipment. Per the Guide, "New generation Facilities over 20 MVA aggregated at a single site placed into service after January 1, 2017" will be required to have a PMU installed. This will help assess and safely integrate VER as they proliferate in the BPS. Oscillation identification, particularly of high frequency oscillations commonly seen in renewable energy resources, has been a high value application for integrating renewables. Figure 15 shows an observed oscillation by the ERCOT grid operators. The plant was dispatched down to 40 MW output and the oscillation was mitigated. By quickly identifying the issue and taking action, synchrophasor technology improved grid reliability. The plant owner and operator were able to identify the problem and correct the malfunctioning equipment.

Figure 15: ERCOT Oscillation Identified at Wind Plant [Source: ERCOT]

[31] ERCOT Nodal Operating Guides. Available: http://www.ercot.com/mktrules/guides/noperating/

Islanding Detection and Monitoring

Islanding is when a portion of the BPS becomes completely disconnected from other portions (an "electrical island"). In an AC system, all areas are held together to the same synchronized frequency and power will flow from areas with excess generation to areas with deficit generation to maintain synchronism. Controls keep the generation and load balanced so frequency does not vary much. However, islanding conditions generally exhibit extreme power swings due to lower synchronized inertia and load. Detection of islanding involves two essential processes: detecting the occurrence of an islanding event has occurred and identifying what elements the island covers. The frequency of an electrical island will generally deviate from the rest of the system, particularly when the newly formed island has a significant discrepancy in generation and load. In the event of a large frequency difference from the interconnected system, the islanded portion can be identified by looking at bus frequency measurements. If the frequency difference is small, monitoring phase angles that drift from the coherent set of synchronized angles will identify the islanded portion. For effective islanding detection, PMUs need to be located on a wide-area basis across the interconnected BPS. Several PMUs in each area guards against false alarms generated by errors or failures. In the case of an islanded region, PMUs in each area of the region can help define the interconnected areas and determine where the boundaries of separation have occurred.

Islanding is particularly a concern when a portion of loads and a generating unit or units connected through local transmission system elements unintentionally become isolated from the rest of the electric grid. This islanding condition forms an uncontrolled area that can potentially expose customers and the generation unit(s) to significant power quality issues. Upon an unintentional island being created, the islanded generator(s) may not be suited to maintain the voltage and frequency in the islanded region within permissible ranges due to the mismatch in active and reactive power balance between the islanded generation and load. The loss of active power balance causes frequency excursions and oscillations, while the loss of reactive power balance leads to voltage deviations (sag and swells). This means that power quality is not guaranteed for the islanded loads/customers. The voltage and frequency excursions that occur can cause damage to the generator and customer equipment inside the islanded region, and can pose major safety concerns for utility personnel working in the islanded region. Another area of concern with unintentional islanding is the automatic reclosing of the transmission lines connected to the islanded generation facilities. If the islanded area remains energized for some period of time after being islanded, the islanded region might become out of phase with respect to the main electric grid. If the transmission lines connected to the islanded area perform any automatic reclosing attempts, an out-of-phase reclose condition could occur that has a significant chance of causing damage to the generator facilities and customer equipment.

Utilities have deployed anti-islanding protection and control schemes at some generation facilities that interconnect with the transmission grid through a substation with two or fewer transmission lines, and where customers are directly fed from the substation or the involved transmission lines. These anti-islanding protection and control schemes are designed to detect island conditions if they occur and immediately trip the islanded generation facilities offline. These existing schemes utilize a complex matrix of circuit breaker and switch statuses to determine when an island is created, with manually updates by operators and field personnel to indicate maintenance activities of the breakers and switches. Entities such as Dominion Virginia Power are currently investigating whether strategically placed PMUs can be used to create a new type of anti-islanding control scheme to detect an island and trip islanded generators. PMU placement for this application should include:

- Generating stations (high-side of the generator step-up (GSU) transformer) that interconnect with the transmission grid through a substation with two or fewer transmission lines, and where customers are directly fed from the substation or the involved transmission lines. Circuit breaker statuses in the PMU are recommended
- Terminals of all the transmission lines that connect a generation station with concerns about islanding with customers. Circuit breaker statuses in the PMU are recommended

- PMUs should be placed throughout the regional transmission grid near the generating stations with concerns about islanding with customers
- PMUs should also be placed at the nodes where likelihood of system islanding under significant contingency conditions based on system studies has been determined and out-of-step relaying has been enabled.

Reconnection of Alberta to WECC

The Western Interconnection experiences relatively frequent islanding conditions when Alberta separates from the rest of the larger WECC grid. Although this does not represent a full restoration from complete blackout, the reconnection of Alberta provides useful insight into the visibility of island reconnection. Figure 16 shows expected execution of the Alberta separation scheme due to a forced transmission outage on the tie lines connecting Alberta to British Columbia. It is clear the system re-stabilizes at different frequencies following the contingency. Figure 17 shows resynchronization of the island, which shows an oscillation ringdown after reconnection back to WECC grid. High resolution visibility of system frequency and phase angle difference provides immediate situational awareness for the operator to be prepared for a subsequent event post-synchronization such as small signal instability resulting in undamped oscillations.

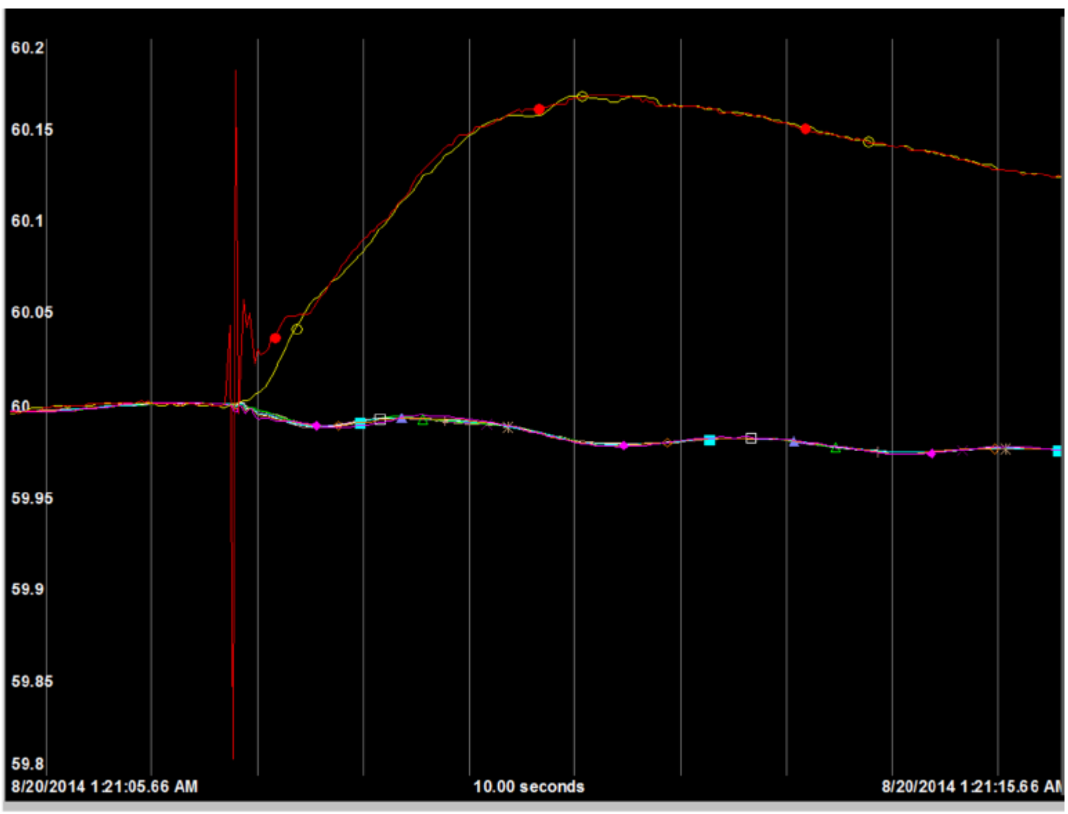

Figure 16: Alberta Separation from WECC System [Source: BPA]

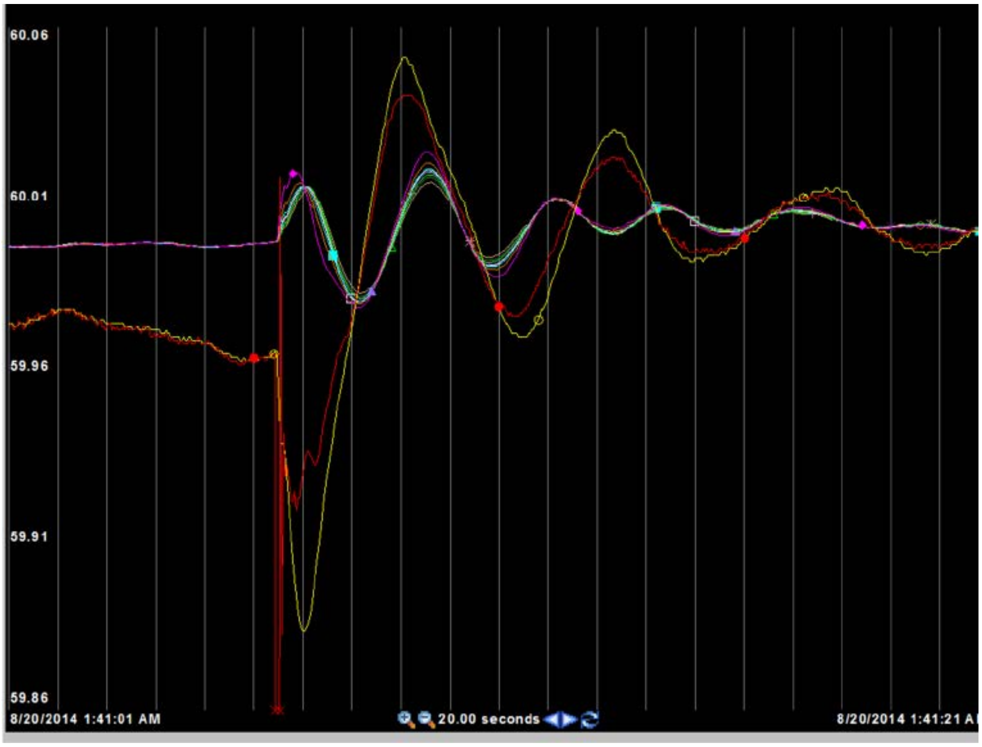

Figure 17: Alberta Reconnection to WECC System [Source: BPA]

Reconnection following Hurricane Gustav

Another example of island resynchronization is the Hurricane Gustav event, in which an electrical island was formed in the New Orleans-Baton Rouge area for over 33 hours. Over fourteen (14) transmission circuits tripped out of service, resulting in the island. Entergy PMUs alerted the system operators of the island formation by monitoring high resolution frequency signals. In addition, the PMU in service within the electrical island warned of generator hunting among three major generating units when one of the units' control modes was changed inadvertently. Lastly, resynchronization of the island with the Eastern Interconnection was accomplished using a synchroscope; PMUs were used to monitor and capture the event. Figure 18 shows successful reconnection of the two grids. Notice the marginally damped oscillations following resynchronization; visibility into these oscillations is crucial for ensuring the system remains stable.

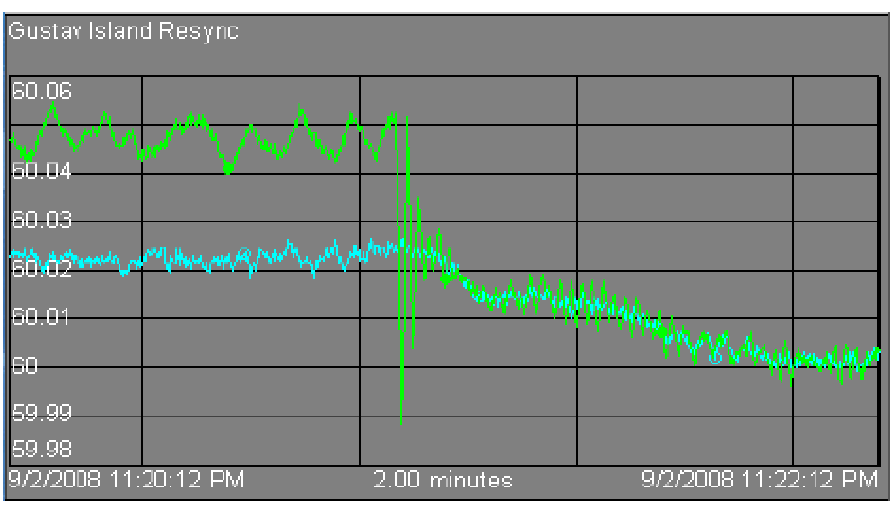

Figure 18: System Reconnection during Hurricane Gustav [Source: Entergy]

Blackstart & System Restoration

Utilities have blackstart system restoration plans that detail the sequence of events to fully restore their electric grid from a total blackout of the grid. These blackstart plans are created and practiced through periodic training and simulations in traditional SCADA and EMS systems. Some utilities including ERCOT and Dominion Virginia Power are working on incorporating synchrophasors into the blackstart restoration to enhance and improve the plan itself and execution of the plan if an event were to occur.

Incorporating synchrophasors into a blackstart plan can assist in the execution of a blackstart plan by providing high resolution voltages, currents, and frequency measurements during very complex restoration activities. As the various blackstart generators are turned online throughout the system, there will be significant dynamic and steady state challenges as the various grid equipment and loads are re-energized. Having synchrophasor data available for real-time operators and engineering support will allow a significant improvement in real-time evaluation and post-switching troubleshooting during the execution of a blackstart plan.

PMU placement for this application should include:

- Every blackstart generation station (high-side or low-side of GSU) in a blackstart restoration plan
- Every substation along the blackstart cranking paths in a blackstart restoration plan
- Key substations, lines, and breakers that will synchronize the multiple blackstart islands created during the blackstart restoration plan

ERCOT plans to demonstrate load pick during blackstart system restoration using transient stability simulators and simulated PMU measurements. Simulated demonstrations of good and bad load pick up using a PMU simulator are expected to improve understanding of island building and how loads need to be picked up during restoration.

The Indian Power system (POSOCO) has demonstrated the use of PMUs for controlled system separation and synchronization. PMU placement plays a role in these control actions. Some considerations for PMU placement in that system includes:

- The blackstart or restoration path, or synchronizing tie lines, should have line voltage as well as bus voltages measured.
- Availability of control room applications for synchronization or a digital synchroscope where the bus and line voltage, bus and line frequency, and phase rotation can be displayed for operators to allow synchronization in the field.

In the Indian power system under the Unified Real Time Dynamic State Measurement (URTDSM) system, all EHV buses have PMUs, providing full observability. However, at one voltage level it was decided to mostly utilize line voltages. This has created the issue for blackstart and synchronizing tie lines. If only bus voltage is taken, then the PMUs cannot effectively be used for synchronization due to unavailability of line voltage across the synchronizing breaker. The angular separation cannot be directly known across the breaker in this case.

PMU Placement Strategies for Offline Analysis

Strategic placement of PMUs can facilitate effective use of offline tools and analysis. This section highlights high-value offline applications and the PMU placement strategies used for those respective applications.

Power Plant Model Verification

PMU-based power plant model verification (PPMV) is the process of comparing actual power plant or unit-level response to grid disturbances against modeled response. Online PPMV provides a cost-effective and efficient way to help responsible entities comply with MOD-026[32] and MOD-027[33], which focus on the exciter and turbine-governor functions, including plant-level volt/var and load controls, respectively.

PMU placement and measurement capability are essential for disturbance-based power plant model validation using PMUs. PMUs should be located such that the generator is radially connected to the location at which the PMU is monitoring. Multiple PMUs establishing a radial-like local network of the generator connected to the external grid can also be used to perform playback since they are time-synchronized to one another. Generally, the PMU is placed at the terminals of the generator(s) at either the high- or low-side of the GSU transformer (Figure 19). PMUs are often installed at the POI, which is the jurisdictional boundary between the GO and TO, such as the TO's interconnecting substation (Figure 20). This is an acceptable practice assuming the radial nature of connection to the rest of the system is maintained. GOs may use PMUs to aid in their verification efforts related to MOD-026 and MOD-027 analysis. PCs, TPs, and TOs are not required to provide PMU data to the GO for these purposes; however, this is encouraged to support effective model verification and use in system reliability studies.

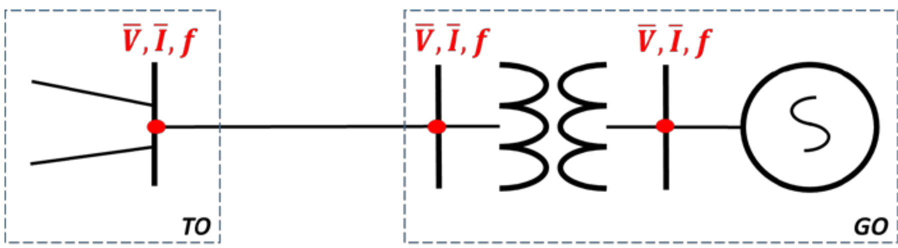

Figure 19: PMU Recordings at GSU High- or Low-Side or Plant POI

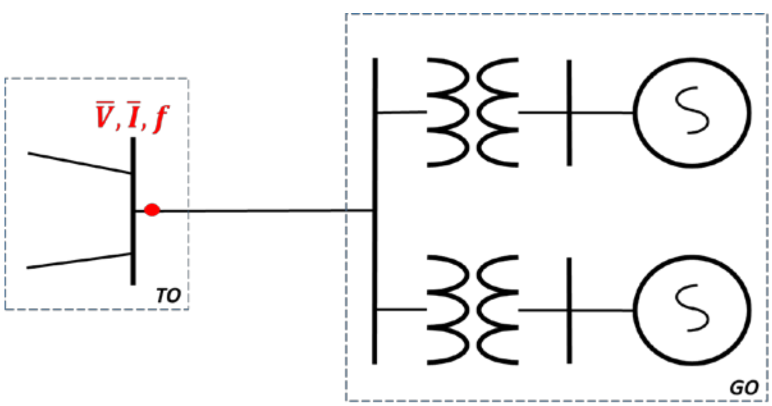

Figure 20: PMU Recordings at Plant POI for Multi-Unit

At the point of PMU placement, the following electrical quantities need to be measured:

- Bus voltage magnitude

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[32] NERC, MOD-026-1, "Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions".
[33] NERC, MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions".

- Line real power (MW) and reactive power (MVARs), measured on a three-phase basis
- Bus frequency or phase angle

These quantities can be used with the playback function to perform the disturbance-based verification process. In the case where modeled response does not reasonably match the actual response, additional steps should be taken to obtain a verified model such as offline testing or collection of additional signals such as field quantities, shaft speed, etc.

System Model Validation

System model validation is the process of comparing modeled system conditions with actual conditions during steady-state and disturbance events on the system. Unlike generator model validation, system model validation focuses on the performance of the aggregate model of the interconnected system. NERC Reliability Standard MOD-033[34] serves the purpose of establishing consistent validation requirements for the construction and utilization of planning models for analyzing the reliability of the BPS. MOD-033 incorporates both steady-state and dynamic model validation; however, PMUs play an essential role in validation of dynamic models specifically due to the continuous recording and high resolution data available. Quantities to be compared include bus voltage magnitude, phase angle, and frequency; generator real and reactive power outputs, line and transformer flows, dynamic reactive power resources, and HVDC response. Aspects to compare include inter-area oscillations, pre- and post-contingency conditions, and frequency response.

PMU placement for the purposes of improving system model validation include capturing the response of:

- Large power plants or generating units;
- Dynamic reactive power resources such as STATCOMs, SVCs, or synchronous condensers
- Major transmission interfaces – SOLs, IROLs, major transfer paths
- Cohesive load zones – capture aggregate load response
- Major system loads – large industrial or block loads
- Terminals of HVDC resources (on the AC side of the transformer)
- Automatically controls resources such as Under-Load Tap Changers (ULTC), phase-shifting transformers, and switched shunt devices
- Remedial action schemes

Capturing the dynamic response of these resources enables validation of the dynamic models behind these resources such as governors, excitation systems, power system stabilizers (PSS), FACTS and HVDC controls, RAS, and transformer controls.

Load Model Validation

High resolution data can also be used to validate the performance of dynamic load models, and has been successfully performed by many utilities. End use loads are located, generally, at the distribution system; however, these loads are often modeled at the transmission system. Therefore, it is important to understand the effects that the system disturbances have on the end use loads, and vice versa. To accomplish this, it is necessary to have data sources at as many of these locations, from the transmission system down to the individual feeders and end

[34] NERC, MOD-033-1, “Steady-State and Dynamic System Model Validation”.

use loads, as possible. Data is not limited to synchrophasor data and many data sources are used in this process, including:

- Phasor measurement units
- Digital fault recorders
- Power quality meters
- PQube® devices
- Sequence of event recorders
- Relay oscillography records
- SCADA data

PMUs at the transmission and sub-transmission voltage levels provide a time synchronized reference and are often used to time align the unsynchronized data sources from various measurement locations. Figure 21 shows an example load pocket and the placement of different measurement devices (transmission PMUs, distribution records, and end-use load PQube® monitors).

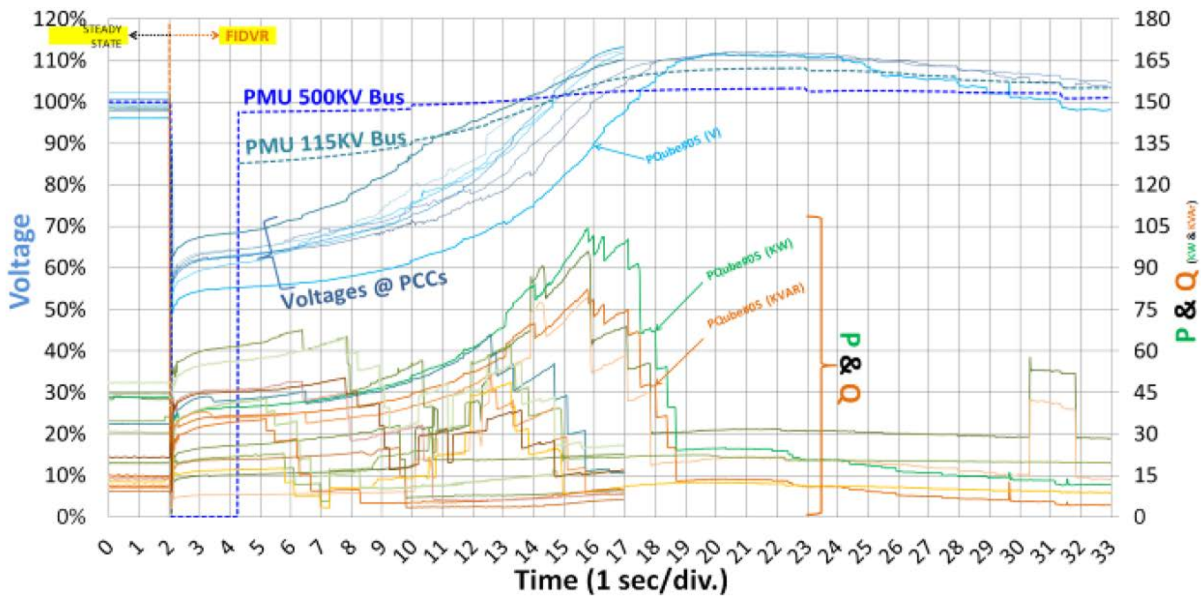

Figure 21: Load Model Data using Synchronized Measurement Data
[Source: Southern California Edison]

Disturbance Monitoring & Event Analysis

PRC-002-2 was approved by the Federal Energy Regulatory Commission (FERC) on September 17, 2015. PRC-002-2 requires that "adequate data [is] available to facilitate analysis of Bulk Electric System (BES) Disturbances", focusing on three distinct forms of disturbance monitoring data – sequence of events recording (SER) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data. PMUs are a form of DDR monitoring equipment, and generally meet the technical specifications outlined in the standard. Therefore, PMUs are expected to play a critical role in capturing the required data for event analysis for major grid disturbances moving forward. PRC-002-2 Requirement R5 outlines the BES Elements for which data is required, and includes the following:

- Generating resources with gross individual nameplate rating greater than or equal to 500 MVA; or gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA
- Any one BES Element that is part of a stability (angular or voltage) related SOL
- Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter
- One or more BES Elements that are part of an IROL
- Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program

PRC-002-2 Requirements R6 and R7 specify the electrical quantities that must be either directly measured or calculated for each BES Element specified in Requirement R5. At a high level, these requirements mandate the following quantities to be measured:

- One phase-to-neutral (or phase-to-phase for Generator Owners) or positive sequence voltage.
- The phase current of the same phase(s) at the same voltage corresponding to the voltage(s), or positive sequence current.
- Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.
- Frequency of any one of the voltage(s) specified.

PRC-002-2 Requirement R8 requires continuous recording of DDR data while Requirement R9 requires that the input data rate be greater than or equal to 960 samples per second and the output reporting rate be at least 30 samples per second. Requirement R10 of the standard defines time synchronization with accuracy of +/- 2 milliseconds, which is well within the requirements set forth in IEEE C37.118.1. Requirement R11 of PRC-002-2 focuses on data formatting for submitting data when requested and the timeframes for when that data is due to the requester.

PRC-002-2 addresses only the DDR locations which are essential to event re-creation for major grid disturbances, enforcing mandatory and enforceable requirements for the monitoring of these locations. However, some PMUs may meet the requirements of DDR and this data can play an important role in this process, and any available PMU data helps time align the sequence of events and corroborate unsynchronized measurement sources. For example, PMU data was valuable in the expeditious event recreation for the 2011 Pacific Southwest Outage event, as well as benchmarking the simulated performance against actual response (Figure 22).

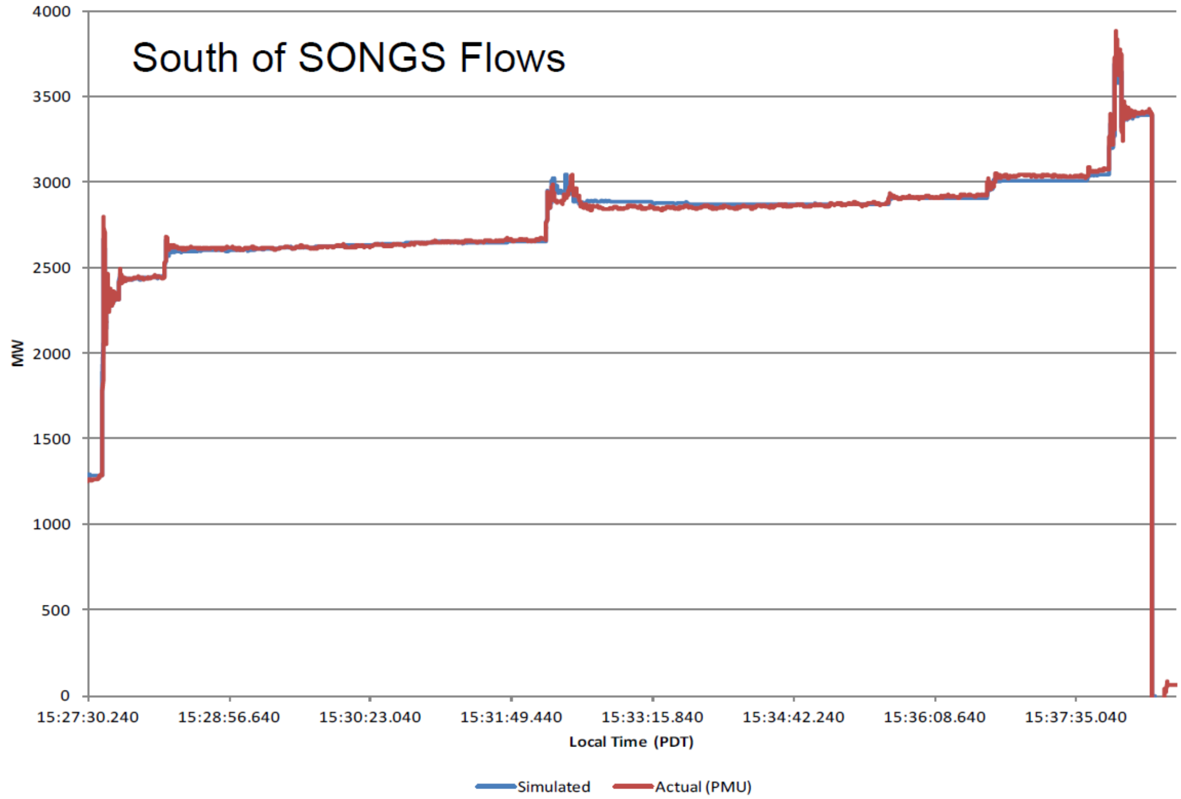

Figure 22: PMU Data used in 2011 Pacific Southwest Outage

Frequency Response Analysis

While SCADA data can be used for frequency response analysis[35] (illustrated in Figure 23), synchrophasor data provides time synchronism and higher resolution that simplifies and improves analysis. Frequency response analysis can be distinguished by three resolutions: 1) Interconnection-wide, 2) BA, and 3) plant-level.

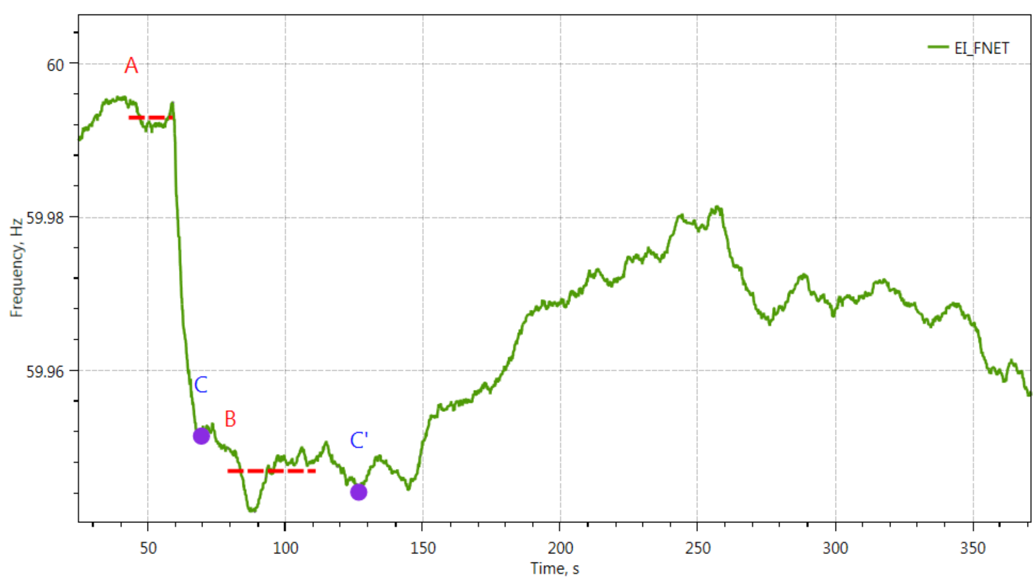

Figure 23: Frequency Excursion Event and Frequency Response Characteristic Measurements

[35] NERC, "Frequency Response Initiative Report: The Reliability Role of Frequency Response," October 30, 2012.

Interconnection-wide frequency response analysis is associated with characterizing the grid's response using a set of criteria. NERC performs extensive interconnection-wide frequency response analysis on an annual basis to define obligations for the overall system and each BA[36]. At this level, it is necessary to define a "system frequency" signal for each time stamp in the event, since frequency at any given time can be very different across an interconnected power system. In this case, it is common to use a median or average value of system frequency to define the "system frequency" on an interconnection-wide basis. Therefore, it is useful to have PMUs spread throughout the system, particularly on the edges of the system, such that a quality "system frequency" value can be defined.

On the BA level, BAs are required to monitor their BA-level frequency response according to BAL-003-1.1. This is performed by monitoring the net interchange on all tie lines with neighboring BAs for a given event. Therefore, utilities use SCADA data due to the large number of monitoring points required. However, moving forward as PMU technology continues to proliferate, frequency response analysis may also be performed by measuring the points required to calculate net actual interchange using PMUs. The higher resolution data will help capture the frequency data and frequency nadir more clearly[37].

Plant-level frequency response is a relatively new concept that focuses on comparing the plant (or unit) response to under-frequency events to monitor whether the plant responded as expected. For example, this type of analysis can be used to determine if a plant was 1) base loaded, 2) frequency responsive, or 3) under plant-level load control. For this type of analysis, the PMUs should be monitoring the terminals of the generator (or high-side of the GSU) and measurement points should consist of bus voltage phasor and frequency, and real and reactive power output of the generator or plant. These requirements are identical to those outlined for model validation purposes.

[36] NERC, "2016 Frequency Response Annual Analysis," Docket No. RM13-11-000, October 2016. [Online]. Available: http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Final_2016_FRAA_Oct_21_2016.pdf

[37] However, BA calculations for frequency response use a longer timeframe from 20 to 52 seconds following the initial disturbance time.

Other Applications for Consideration

PMUs are used in a myriad of applications and tools for both online and offline purposes. The following applications are highlighted for consideration when determining PMU placement:

- **Distribution system monitoring:** Distribution system monitoring is becoming increasingly critical for renewables integration and understanding the dynamic nature of end-use load behavior. High resolution data provides insights into the operational characteristics of these resources. Time synchronization of the data allows effective alignment between transmission-level monitoring and sub-transmission and distribution-level monitoring. Micro-PMUs and other high resolution devices such as power quality meters, digital relays, and other portable monitoring devices provide this capability. Electrical quantities to monitor include phase bus voltage magnitudes and phase currents. This enables calculation of real and reactive power flows as well.
- **Power system protection:** Using PMUs for power system protection is an evolving field; however, PMUs can be used for a variety of wide-area protection schemes such as RAS, separation schemes, safety net schemes for ensuring reliability of the BPS. Examples include coordinated undervoltage load shedding, response-based RAS, and real-time angular separation schemes. Out-of-step protection and adaptive relaying are other areas where PMU measurements can provide supervisory control over high-speed protection schemes. Today, PMU technology is limited for application to protection schemes due to the high-speed nature of protection and control and possible signal security issues.
- **Automated or supervised voltage control schemes:** Coordinating voltage control set points and schedules for dynamic and static reactive power resources is a challenge for real-time system operators. Particularly under increasingly variable system conditions resulting from a rapidly changing resource mix, the capability to automate and supervise switching of reactive power resources is becoming a critical aspect of BPS reliability. PMUs monitoring system voltages, flows, and calculation of margins can provide real-time insight that enables advanced switching schemes for steady-state and post-contingency conditions.

Prioritizing PMU Placement across Applications

Phasor measurement units measure grid conditions, including phase angles, at speeds 100 times faster than current SCADA technology. This allows unprecedented insight and analysis of grid conditions, opening up new capabilities in real-time grid management and planning. But to realize maximum value from a synchrophasor system, the network of PMUs, communications system, and software analytics need to be designed and sited with a clear plan that suits system design, acquisition, siting and installation that are tailored to the applications to be used. Synchrophasor data is used for an array of applications, and PMU placement should support the needs of these applications. This Reliability Guideline is application-centric, providing useful information regarding placement of PMUs for the purposes improving each individual application.

The following recommendations are provided for prioritizing PMU placement based on applications of interest:

1. The engineering analysis and real-time operational applications of interest should be identified and prioritized as soon as possible. Applications require different levels of accuracy, resolution, placement, and security (physical and cyber) that should be taken into account prior to concerted deployment of PMUs across a system.
2. Determine the placement required to successfully accomplish the goals of each application considered. Determine if partial coverage can suit the needs of some applications while others may require full observability or deployment prior to successfully deploy the application. This can help stage or roadmap the utilization of synchrophasor technology.
3. Identify key applications that will bring value to the organization and prioritize those PMU placements to achieve early success, adoption, and knowledge of the technology. Small successes that bring value to the organization using synchrophasor technology will help in future deployment.

   Data quality is paramount to any application. Data quality specifications and goals should be incorporated into the deployment of the technology and efforts should focus on ensuring a high availability, high accuracy, and low latency synchrophasor network. Understand the application needs related to M class and P class PMUs and incorporate this into the settings specifications as well as location prioritization.
4. An application matrix can be developed that tracks locations or buses where PMUs can meet the needs of multiple applications. These locations may be considered higher priority since they provide cross-cutting value to multiple synchrophasor-based applications.

An example of a prioritization matrix is provided in Table 4[38]. A list of different applications are represented by the columns. PMU locations are listed as the rows of the matrix. A weight is provided for each application – the higher the weight, the more important the application is considered based on the needs of the organization. The priority by location is the sum of the weight multipled by the ranking of each application. The location with the highest numerical value has the highest priority. In this example, the weights are based on a 10-point scale (e.g., in this example, oscillation monitoring, model verification, and disturbance monitoring each have a weight of ten, SSR & SSCI are weighted at six). In the table, a '1' marks PMU locations that would be used for the selected applications. The greater the number of higher-weighted applications, the higher the priority of that PMU location. lThis example is simply meant to illustrate how an entity could prioritize their PMU placement based on the applications of most value. In this case, Station A 500 kV has the highest priority. All PMU locations could be used for state estimation and disturbance monitoring while only Station A and B could be used for angle monitoring.

[38] This is based on PMU placement consideration factors developed by Pacific Gas & Electric in 2010 timeframe.

Table 4: PMU Placement Prioritization									
		Real-Time				Offline			
		State Estimation	Oscillation Monitoring	SSR & SSCI	Angle Monitoring	Model Verification	Disturbance Monitoring	Frequency Response	Priority
	Weighting	8	10	6	8	10	10	5	/10
Station Name	**Voltage Level**								
Station A	500	1		1	1	1	1	1	47
Station B	500	1	1		1		1	1	41
Station C	230	1		1		1	1		34
Station D	115	1	1				1		28

Appendix A: Interconnection Requirements and Open Access Transmission Tariffs References

This section provides useful links and reference documents related to utilities' Facility Connection Requirements (FCR) documents and Open Access Transmission Tariffs (OATT) that refer to synchrophasor technology and placement of PMUs.

PJM Interconnection (PJM)

- Open Access Transmission Tariff: http://www.pjm.com/documents/agreements.aspx
- Manual 14D: http://www.pjm.com/documents/manuals.aspx
- PJM Placement Strategy: http://www.pjm.com/~/media/markets-ops/ops-analysis/synchrophasor-tech/pmu-placement-strategy.ashx

Bonneville Power Administration (BPA)

- Technical Requirements for Interconnection: http://www.bpa.gov/transmission/Doing%20Business/Interconnection/Pages/default.aspx

Electric Reliability Council of Texas (ERCOT)

- Nodal Operating Guide: http://www.ercot.com/mktrules/guides/noperating

Alberta Electric System Operator (AESO)

- ISO Rules: http://www.aeso.ca/rulesprocedures/18592.html