NASPI SYNCHROPHASOR STARTER KIT

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NOTE TO READERS – this is very much a work in progress. We invite your feedback about what to include in this document to make it more useful for you and your colleagues. Please send feedback and suggestions to:
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NASPI North American SynchroPhasor Initiative

DOE credit and disclaimer

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Synchrophasor Starter Kit

Purpose

This package is intended to summarize the information needed to undertake a new synchrophasor project or upgrade an existing project. It documents many of the lessons learned and best practices gleaned from the North American synchrophasor projects over the past five years.

The Starter Kit offers summary information and links to more detailed resources on each of the topics addressed. The Starter Kit contents and contributors are listed below.

Outline

1) Synchrophasor Background – Alison Silverstein (NASPI)
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10) PMU Commissioning –
11) Communications System Requirements – Jim McNierney (NYISO)
12) Cyber-security – Tony Johnson (SCE)
13) Phasor Data Concentrator -- ?
14) Relevant NERC Standards – Ryan Quint (NERC)
15) Data Classes & Characteristics – Frank Tuffner (PNNL)
16) Data Quality – Ken Martin (EPG)
17) Data Interpretation – Jim Kleitsch (ATC)
18) Model Validation – Silverstein (NASPI)
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21) Glossary, Acronyms & Definitions --

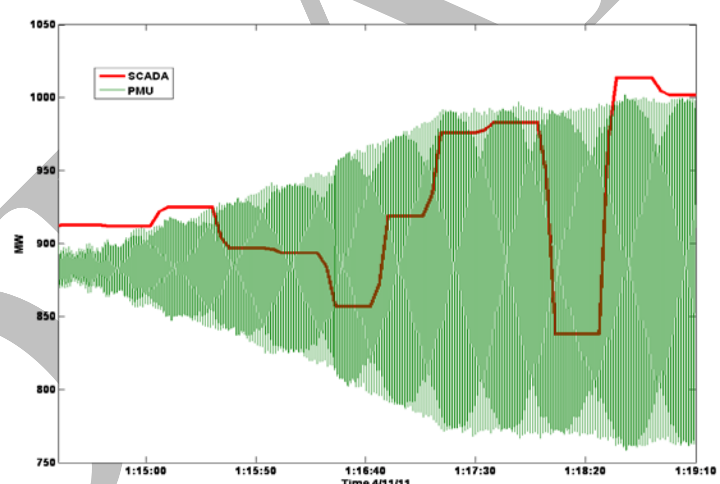
1) Introduction – Synchrophasor Background

A synchrophasor is a time-synchronized measurement of a quantity described by a phasor. Like a vector, a phasor has magnitude and phase information. Devices called phasor measurement units (PMU) measure voltage and current and with these measurements calculate parameters such as frequency and phase angle. Data reporting rates are typically 30 to 60 records per second, and may be higher; in contrast, current supervisory control and data acquisition (SCADA) systems often report data every four to six seconds – over a hundred times slower than PMUs.

PMU measurements are time-stamped to an accuracy of a microsecond, synchronized using the timing signal available from global positioning system (GPS) satellites or other equivalent time sources. Measurements taken by PMUs in different locations are therefore accurately synchronized with each other and can be time-aligned. This makes the relative phase angles between different points in the system available as directly-measured quantities. Synchrophasor measurements can thus be combined to provide a precise and comprehensive "view" of an entire interconnection.

The accurate time resolution of synchrophasor measurements allows unprecedented visibility into system conditions, including rapid identification of details such as oscillations and voltage instability that cannot be seen from SCADA measurements. Complex data networks and sophisticated data analytics and applications convert PMU field data into high-value operational and planning information.

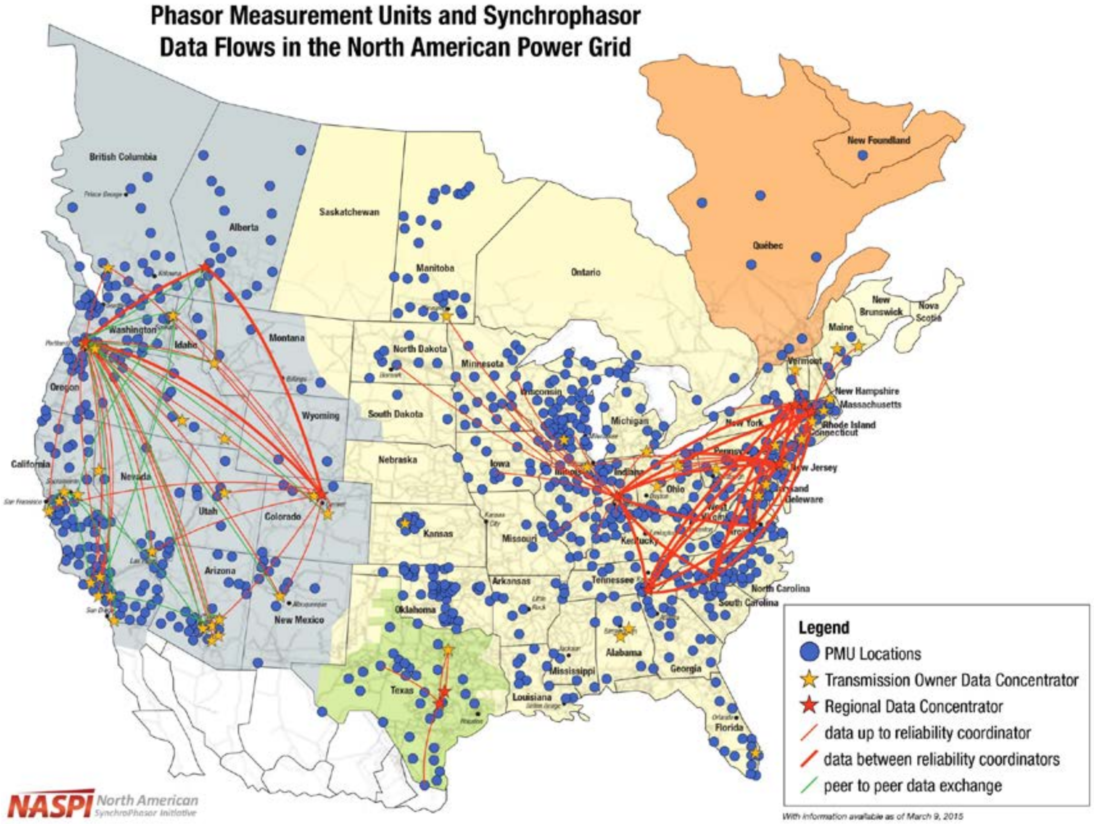
Power plant un-damped oscillations



PMU Deployments and the Federal ARRA Grants

In 2009, there were only 200 research-grade PMUs networked across North America. Today there are almost 1,700 production-grade PMUs deployed across the U.S. and Canada, streaming data and providing almost 100% visibility into the bulk power system. Most were installed using $165 million in federal grants authorized by the American Recovery and Reinvestment Act of 2009, matched by private industry funds. The DOE and industry investments also funded installation of high-speed synchrophasor data networks, development of technology interoperability standards for PMU measurement, functionality and data formats. At the same time, DOE funded a variety of R&D projects to develop advanced synchrophasor data applications and analysis tools.

PMUs and Synchrophasor Data Flows in North America as of October 2014



Principal applications and benefits of synchrophasor technology

Situational awareness and wide-area monitoring: The network of PMUs enable grid operators to see the bulk power system across an entire interconnection, understand grid conditions in real time, and diagnose and react to emerging problems. Analysts believe that synchrophasor-enabled visibility could have prevented the 2003 Northeast and the 1996 Western blackouts. As synchrophasor data quality improves, those data are being integrated into some existing control room visualization tools based on EMS and SCADA data, gaining acceptance for synchrophasor-enhanced wide-area monitoring.

Real-time operations: Synchrophasor data is being used to improve state estimator models for better understanding of real-time grid conditions. It is being used to detect and address grid oscillations and voltage instability, and integrated with SCADA and EMS data to drive real-time alarms and alerts. Analysts are looking at PMU data to expedite resolution of operating events such as fault location, and quickly diagnose equipment problems such as failing instrument transformers and system imbalances.

More advanced applications use PMU data as an input to Special Protection Systems (SPS) or Remedial Action Schemes (RAS), and can trigger automated equipment controls. PMU data can be used to monitor and manage system islanding and black-start restoration. ERCOT is using PMUs to verify customers' performance in demand response events.

Power system planning: Good dynamic models allow a better understanding of how power systems respond to grid disturbances; better prediction enables better system planning with better grid and financial asset utilization. Synchrophasor data are particularly useful for validating and calibrating models of power plants, FACTS devices and other grid equipment, letting generators and grid operators comply with NERC Modeling standards with better results at lower cost. These data are also being used to improve system models, calibrating state estimators and dynamic system models and simulations. The Western Interconnection of North America has been a leader in using synchrophasor data for planning applications.

Forensic event analysis: Phasor data is invaluable for post-event analysis of disturbances and blackouts. Because synchrophasor data is time-stamped, it can be used to quickly determine the sequence of events in a grid disturbance, and facilitate better model analysis and reconstruction of the disturbance. These enable a faster and deeper understanding of the disturbance causes and inform development of ways to avert such events in the future.

Synchrophasor System Elements

A synchrophasor system begins in the substation. PMUs there collect real-time data, usually from existing potential and current transformers. The PMUs are connected to a high-speed communications system to deliver the data to a phasor data concentrator (PDC). Typically, the PDC performs a number of functions that reject bad data, and package the incoming data into sets based on the time-stamp. The data at the PDC are then relayed on a high-speed wide-area communications network to a higher-capability PDC. PDCs typically feed the aggregated data received into a data archive, and to analytical applications such as wide- area visualization tools, state estimators, and alarm processors. The details of these installations can vary greatly, depending on the complexity and scale of the synchrophasor system, and application requirements dictate the rigor of system redundancy, cyber-security, and other implementation details.

Today PMUs are deployed primarily on the transmission system, but the industry is beginning to explore the use of PMUs at the distribution level for power quality, demand response, microgrid operation, distributed generation integration, and enhanced distribution system visibility.

The international engineering community has recently adopted several key technical interoperability standards pertaining to synchrophasor technology, including IEEE C37.118.1 (phasor measurement units and synchrophasor measurements), IEEE C37.118.2 and IEC 61850-90-5 (synchrophasor data communications and protocols), IEEE PC 37.244 (phasor data concentrator requirements), IEEE C37.238 (use of PTP over Ethernet for power system applications), and IEEE 27.242 (guide for PMU synchronization, testing, and calibration).

The NASPI Task Force on Testing and Certification has recommended that users of synchrophasor measurements require that the PMUs producing those measurements be certified compliant with IEEE C37.118.1. The IEEE Standards Association has developed a synchrophasor conformity assessment program for testing PMU compliance with respect to the IEEE standard.

International synchrophasor technology use

Several nations began deploying PMUs in the 2000s, including several European Transmission System Operators, the Nordic System, and several Latin American utilities. China has built an extensive synchrophasor system in combination with its high voltage power grid and generation build-out, using thie synchrophasor system for wide-area monitoring and dynamic security control. In India, the Power System Operation Corporation Ltd. is building a national-scale wide-area monitoring system with over 1,700 PMUs that will feed a broad suite of real-time grid security applications and off-line uses.

North American SynchroPhasor Initiative

NASPI brings together the utility industry, manufacturers and vendors, academia, national laboratories, government experts and standards-making bodies. This large volunteer community dedicated to synchrophasor technology advancement has collaborated to address and solve technical, institutional, standards development, and other strategic issues and obstacles. NASPI works to accelerate the maturity and capabilities of synchrophasor technology, to improve the reliability and efficiency of the bulk power system. The NASPI Work Group meets twice a year, with financial support from the United States Department of Energy and the Electric Power Research Institute. NASPI has compiled a large collection of synchrophasor resource information and success stories from North American and international sources, available at www.naspi.org.

Source: NASPI October 2014
Image sources: Map -- NASPI; oscillation -- Dominion Virginia Power; photo – BPA

References:

- J. Dagle, "Synchrophasor Technology and Systems," October 19, 2014, CIGRE-NASPI Synchrophasor Technology Tutorial, at CIGRE-NASPI Symposium: Grid of the Future
- M. Paolone, "Synchrophasor Fundamentals: from Computation to Implementation," July 21, 2013, IEEE-PES General Meeting Tutorial, at Synchrophasor Fundamentals: from Computation to Implementation, IEEE PES General Meeting, Prof. Mario Paolone
- North American Synchrophasor Initiative – www.naspi.org
- U.S. Smart Grid.gov resource center, at https://www.smartgrid.gov/library/search.html
- IEEE Power & Engineering Society (although much of their material is behind a pay-wall and only accessible if you pay for PES membership or a fee for individual materials.

2) Synchrophasor Use Cases

A use case is a list of actions, steps, tasks and interactions that a user would take in using a specific system to achieve a particular goal. In the case of a new technology project such as synchrophasors, it is helpful to itemize the ways that the users want to use the system in order to identify the functionality and design requirements for the new system. An effective investment proposal should include a thorough set of use cases that indicate the priority needs and uses that the project will constructively address.

Use cases can be highly complicated or relatively simple.

The CAISO developed a highly detailed use case for its 2010 synchrophasor system use[1]:

ERCOT developed its SGIG project around a set of use cases summarized in the tables below and detailed at CCET Use Case Examples[2] (2014) and in the CCET SGDP Final Report (2015). These are shown in Figures 2.1, 2.2 and 2.3; ERCOT's use cases are representative of the broad community of synchrophasor users and address most of the widely used applications.

[1] See CAISO at https://www.caiso.com/Documents/IP-1-ISOUsesSynchrophasorData_GridOperations_Control_AnalysisandModeling.pdf

[2] Ballance, Palayam & Nuthalap, "Synchrophasor Technology – PMU Use Case Examples," presentation, 11/5/2014.

Figure 2.1 – CCET (ERCOT) Synchrophasor Use Case Overview
(Source: Ballance, Palayam & Nuthalapati [2014]; permission from ERCOT)

USE CASE OVERVIEW

Use Case	Grid Scope	Streaming 30 samples/sec	Slow Speed 3 samples/min	Local Event Capture	Example of Application on ERCOT Grid
High Stress Across System (High Phase Angle) Observed	Wide Area	Yes	Yes		High Phase Angle from Valley - November 13, 2013
Small Signal Stability – Damping is Low	Wide Area	Yes			Control system oscillations from wind plant - January 9, 2014
Small Signal Stability – Emerging Oscillation Observed	Wide Area and Local	Yes			Slow System Oscillation Detected October 12,2014
Voltage Oscillation Observed	Regional	Yes			Wind Control System Oscillations in Valley - April 12-13, 2013
Voltage Instability Monitoring (real-time P-V or Q-V curve)	Regional	Yes			High Phase Angle in Valley - November 13, 2013
Detection of Subsynchronous Interactions (Not necessarily resonance, just below 60 hz)	Local Regional	Yes			
Integrate PMU Data Into State Estimator	Wide Area	Yes	Yes		Baselining Study confirmed correlation between PMU and State Estimator data
System Disturbance – Capture and Interpretation	Regional	Yes	Yes, not high resolution	Yes	Enhanced Event Analysis Capabilities - numerous examples
Generator Parameter Determination	Local	Yes		Yes	Wind plant oscillation and trip following line outage - September 2011, reported in 2012 IEEE PES paper
Major Load Parameter Determination	Local	Yes		Yes	
PMU-Based Fault Location	Local Regional	Yes		Yes	
Phase Angle Across Breaker for Reclosing Action		Yes	Yes		ERCOT operating studies identify need for monitoring phase angles
Subsynchronous Resonance Identification and Mitigation (PGRR027)	Regional	Yes			
Transmission Characteristics Determination	Regional	Yes		Yes	
Dynamic Transmission Line Ratings using PMU monitoring	Regional	Yes			
Validation of Control Devices (e.g. SVC) performance	Regional	Yes		Yes	

Electric Power Group

Figure 2.2 -- CCET-ERCOT SGDP Synchrophasor Use Cases
(From CCET SGDP Final Technical Report, pp. 98-100)

Table 13. Synchrophasor Use Cases

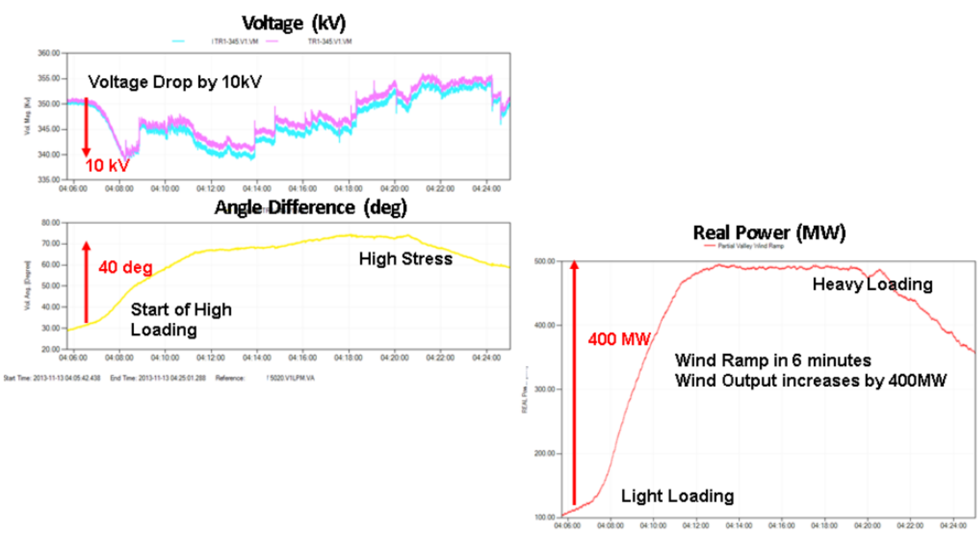
Use Case	Need	Grid Scope	Streaming 30 Samples/Sec	Slow Speed 3 Samples/Min	Local Event Capture
High Stress Across System (High Phase Angle) Observed	Wide area metric that uses phase angle as a measure of the degree of power flow from one region to another, or from one station to another. PMU phase angle data can advise the Shift Engineer about the measured angle across wide area to provide early warnings on high power flow (high grid stress)	Wide Area	Yes	Yes	
Small Signal Stability – Damping is Low	Small signal oscillation is generally across a large area of the grid, and can be noted with a low damping ratio. PMU data can advise the Shift Engineer about both known and unknown oscillations at location(s)	Wide Area	Yes		
Small Signal Stability – Emerging Oscillation Observed	Small signal oscillation is generally across a large area of the grid, and can be noted as a new oscillation frequency or mode not seen before. PMU data can advise the Shift Engineer about both known and unknown oscillations at location(s)	Wide Area	Yes		
Voltage Oscillation Observed	This is a regional phenomenon in one area of the ERCOT grid. The cause may be over-control of generator exciters or reactive controls in low electrical strength areas of the grid. PMU voltage phasor can advise the Shift Engineer about the voltage oscillations at location(s) due to fast voltage controllers at wind generators and other control devices in the grid	Regional	Yes		
Voltage Instability Monitoring (real-time P-V or Q-V curve)	This involves regional voltage instability based on deteriorating grid conditions noted with real-time tracking of P-V or Q-V curves. PMU data (real, reactive power and voltage) can advise the Shift Engineer indirectly on high grid stress under low voltage deteriorating conditions	Regional	Yes		
Detection of Subsynchronous Interactions (not necessarily resonance, just below 60 Hz)	Detection of subsynchronous (<60 Hz) interactions at a higher frequency than those with small signal stability or emerging oscillation. Oscillation frequency can advise Shift Engineer	Local Regional	Yes		
Integrate PMU Data into State Estimator	PMU phase angles can be used to validate the state estimator results used in control rooms (locates differences which reflects anomalies in models used for state estimation)	Wide Area	Yes	Yes	
System Disturbance – Capture and Interpretation	PMU data is useful for event analysis and for determining the root cause of events and their locations	Regional	Yes	Yes, not high resolution	Yes
Generator Parameter Determination	Generator parameters in actual settings versus models used in stability studies don't always match actual transient behavior in system events. PMU data (voltage, phasor, P&Q) can advise generator dynamic response following a nearby transient, compares results to simulated response (based on system planning models), and alerts if differences are significant (meaning that the generator response to the transient event was different from what was expected)	Local	Yes		Yes
Major Load Parameter Determination	Similar to generator parameter determination, but this addresses load models that behave differently than models being used.	Local	Yes		Yes

PMU-Based Fault Location	PMU data is used to detect a fault on the network, and algorithms provide grid operator with estimate of likely location of the fault, and the fault characteristics. Shift Engineer reviews fault information and determines need for reclosing test	Local Regional	Yes		Yes
Phase Angle Across Breaker for Reclosing Action	PMU data is useful during an event to identify stress across system, and validate safe restoration actions. System operator reviews phase angle and voltage on both sides of an open breaker and determines need and ability to successfully reclose the breaker		Yes	Yes	
Synchronous Resonance Identification and Mitigation	ERCOT planning guide revision request (PGRR) 027 needs subsynchronous resonance (SSR) detection algorithms related to series capacitors to determine what capacitors to swap out	Regional	Yes		
Transmission Characteristics Determination	PMU voltage magnitude and phase angle measurements at the two ends of a transmission line can be used to compute the characteristics of the transmission line, and to validate the modeling used for studies	Regional	Yes		Yes
Dynamic Transmission Line Ratings using PMU Monitoring	PMU data will be used to monitor the change in transmission line resistance versus temperature. For example, at x temperature, the resistance deviation is y at this z sag level. The temperature will be independent and used in an offline study which will use apparent resistance to determine the sag	Regional	Yes		
Validation of Control Devices (e.g. SVC) Performance	PMU data can be used to validate the performance of control devices, such as SVCs, following grid events. The Shift Engineer reviews the measured performance, and compares it to expected performance	Regional	Yes		Yes

Figure 2.3 – Example of ERCOT Use Case
(from Ballance, Palayam & Nuthalapati [2014])

Use Case - High Stress Across System (High Phase Angle) Observed

Event Analysis – Impact of High Wind on System Performance Following Wind Ramp



Reference Angle: North 7

3) Essential Synchrophasor Applications

What you want to accomplish with your synchrophasor system should determine the applications you need. Transmission operations, generation, and reliability coordinators all have different needs and priorities. The recommendations here are sorted by the type of user and application readiness. These are listed in summary tables for the three user categories above.

- The first "essential applications" are basic, commercially available, and offer immediate value to the host entity every day.
- The "do these later" applications require more customization for your entity, are commercially available (or near-commercial), and offer additional value for the user.
- Most of the "do these in the future" applications are in development or testing, and are not yet easy to implement.

The section on specific applications summarizes for each application:

- What you use the generic application for
- Why would you do this
- Lists (alphabetically by vendor) some of the commercial and other provider application options available
- A few useful references for more information.

3.1 ESSENTIAL APPLICATIONS

3.1.1 Essential applications for a Transmission Owner or Operator

STAGES	APPLICATION
ESSENTIALS -- DO THESE FIRST	1) Model validation 2) Event analysis 3) Frequency monitoring 4) Asset management -- equipment mis-operations and health monitoring 5) Equipment commissioning 6) EMS back-up 7) Breaker reclosing with phase angles
DO THESE LATER	1) Operator training & simulation 2) Fault location 3) Visualization & wide-area situational awareness
DO THESE IN THE FUTURE	1) Automated Special Protection Schemes 2) Linear state estimation 3) Data conditioning

3.1.2 Essential applications for a Reliability Coordinator

STAGES	APPLICATIONS
ESSENTIALS -- DO THESE FIRST	1) Model validation 2) Event analysis 3) Forensic event analysis 4) Frequency monitoring 5) Verify equipment and asset operations 6) Oscillation detection and mode meter 7) Phase angle monitoring and alarming 8) Wide-area situational awareness and visualization 9) Set alarms & alerts
DO THESE LATER	1) Operator training & simulation 2) Voltage stability monitoring 3) System restoration & black-start with phase angle monitoring 4) Wide-area situational awareness with common view in emergencies 5) Voltage monitoring for renewables integration
DO THESE IN THE FUTURE	1) Automated Special Protection Schemes and islanding 2) Linear state estimation 3) Data conditioning 4) Load models

3.1.3 Essential applications for a Generation Owner

STAGES	APPLICATION
ESSENTIALS -- DO THESE FIRST	1) Model validation 2) Generator settings verification 3) Equipment commissioning
DO THESE LATER	
DO THESE IN THE FUTURE	1) Monitoring system current unbalance to protect large generator rotors 2) Turbine monitoring

3.2 APPLICATIONS DESCRIPTIONS (ordered alphabetically)

3.2.1 Alarms and alerts

What:
How:
Applications:
References:

- J. Dyer, “Establishing Alarm Limits and Using Them in Real-time Operations,” October 8, 2013, at https://www.electricpowergroup.net/epg_events/eventIntro.aspx?qsel=t1Y4VkICPZo=
- Megan Vutsinas, Duke Energy Carolinas, “Insights on Operations Solutions,” October 22, 2014, presentation at NASPI Work Group meeting, at Wide-Area Visualization, Integrated Alarms, and State Estimation - Megan Vutsinas
-

3.2.2 Asset management through event analysis

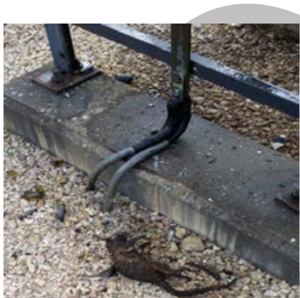
PMU data can be used for analysis of routine operating events; these analyses often identify a wide variety of asset problems and can be used for asset management.

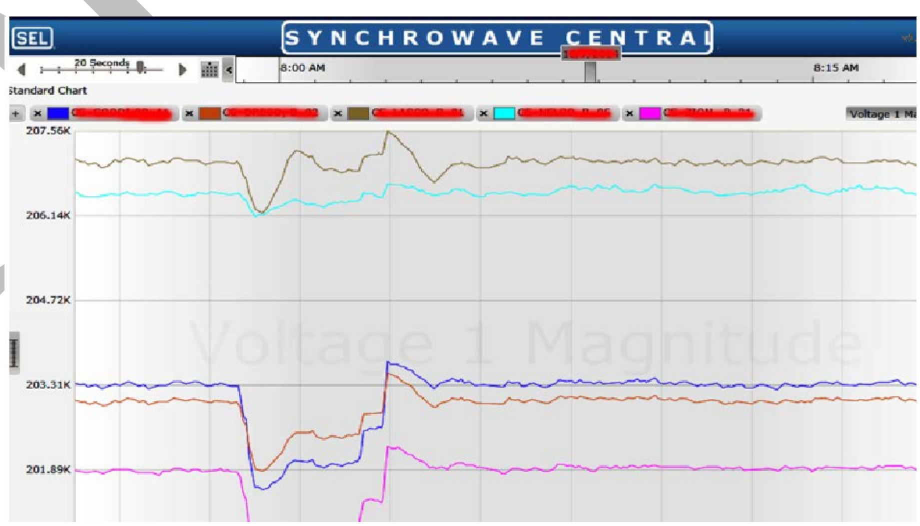
What -- Purposes include equipment monitoring, diagnosing equipment health and mis-operations, and equipment commissioning.

Why – Synchrophasor-based monitoring and event analysis enable better information about assets’ real-time condition, enables better active and proactive maintenance, makes field crews more productive, can prevent asset-caused outages, and speeds service restoration.

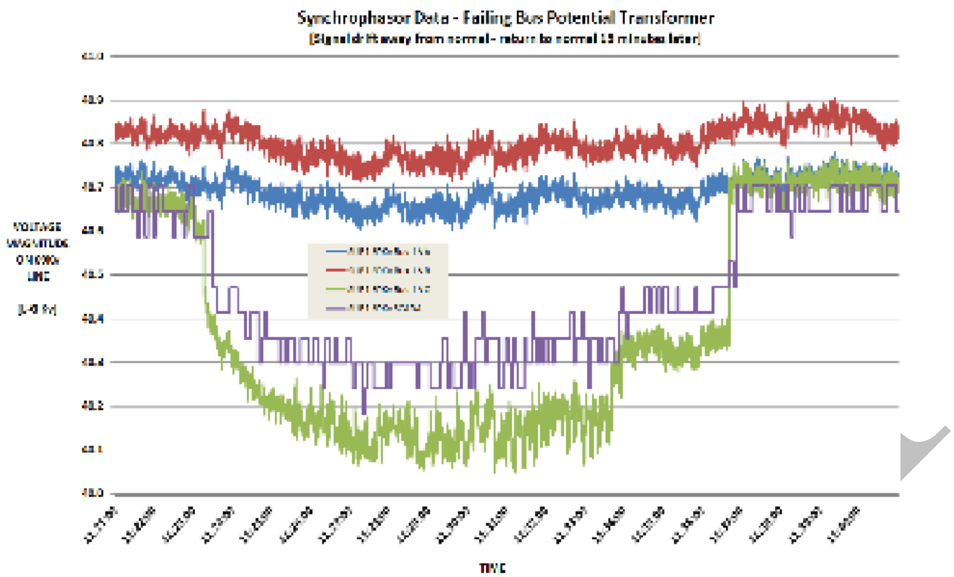
Here are some examples of how analysis of grid events (including at the distribution level) can reveal asset problems.

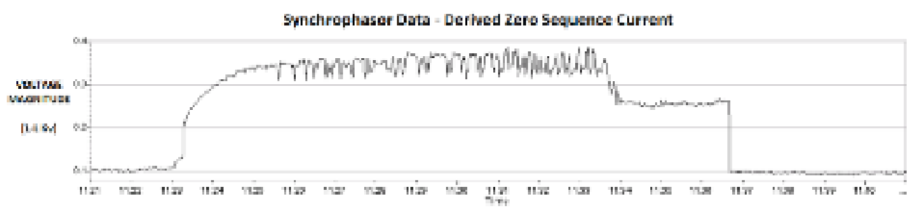
- A transient seen on Commonwealth Edison’s transmission system was caused by a squirrel in a 12kV bus (Source: D. Schooley, ComEd, “Synchrophasors,” athttp://www.ece.iit.edu/~flueck/chicago_pes/2014/PES-May13-Synchrophasors-Schooley.pdf)





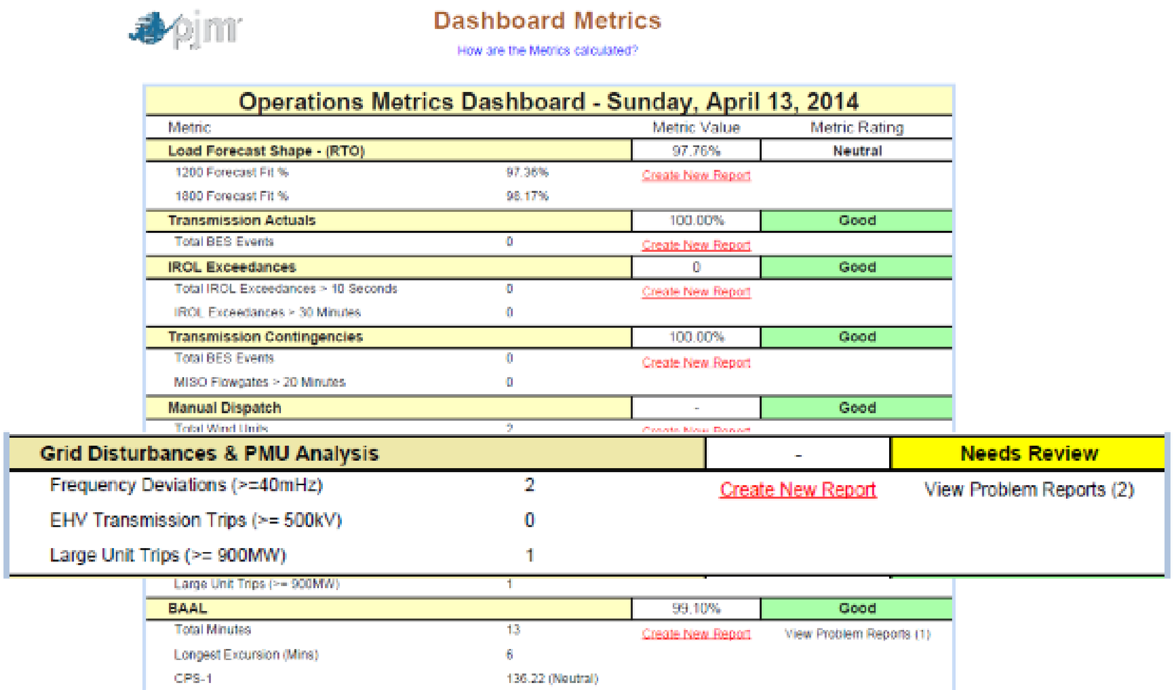
- ATC spotted a failing PT winding through PMU data, and took the bus out of service for repair BEFORE it failed.





How: PJM uses PMUs to leverage NERC event criteria. They look for the following events and discuss them in the daily operations review team morning meeting. PJM uses a "dashboard report" (shown below) for these discussions.

- Frequency deviations > 40mHz in any rolling 16-second interval (BAL-003 Frequency Response)
- EHV transmission trips and outages – monitoring EHV lines that are components of IROL transfer interfaces
- Large generator trips >900 MW (BAL-002 Disturbance Control Performance



Source: F. Robinson, "Daily Visualization, Daily Operations Review and Event Analysis," NASPI Meeting 10/14, at https://www.naspi.org/Badger/content/File/FileService.aspx?fileID=1334

Application tools available – There are few commercially available tools at this time that process streaming real-time or stored PMU data and compare patterns to known event patterns and indicators. However, a number of TOs and RCs use PMU data for off-line investigation into events occurring in real-time (to identify disturbance cause and develop mitigation options). Others have established a routine (sometimes automated) scan of PMU data to look for anomalies and include review of those findings in morning operations reviews.

References:

- NASPI CRSTT video event library at https://www.naspi.org/crstt
- A. Silverstein, "Diagnosing Equipment Health and Mis-operations with PMU Data, May 2015" (PDF 3,414KB)
- NASPI Control Room Solutions Task Team, "Using Synchrophasor Data to Diagnose Equipment Health and Mis-operations Event Summary Table" (PDF 136KB).
- White A., S. Jacobs. August 2014, "Use of Synchrophasors at Oklahoma Gas and Electric Company", (PDF 1,300KB).
- SEL SynchroWAVe Event 2015 visualization software for disturbance analysis, at https://www.naspi.org/synchrophasorsoftwaresearch .

3.2.3 Automated Remedial Action Schemes (Special Protection Schemes)

What:
How:
Applications:
References:

3.2.4 Equipment Commissioning

What: Use PMU data when commissioning equipment during installation or after maintenance, to verify in real time that the equipment is performing as desired.

How: Install equipment, run equipment tests and watch equipment performance in real-time using data from a near-by PMU to verify that the equipment is performing as it should, and communicate any problems (or confirmation) to the field crew so they can fix it and complete the task correctly before they leave the work site.

Applications: None specific

References: None

3.2.5 EMS back-up

What: EMS/SCADA systems monitor and collect grid condition data every 4 to 6 seconds.

- If you lose your SCADA feed, you can use the independent PMU data network feed as an alternative data source.
- Caution – if the synchrophasor data network is independent from SCADA/EMS network, you can't use it for asset control functions

How: If your PMU data use a separate communications network distinct from your EMS, if you lose EMS you can route PMU data feeds into your SCADA system applications, down-sampling as necessary rather than using all incoming PMU data.

Applications: None dedicated for this purpose

References: None

3.2.7 Event Analysis

What: Use PMU data and analytics to identify disturbances and anomalies occurring on the grid and determine the cause and consequences of the disturbance or event by using the insights offered through the high-speed PMU data.

How: See descriptions in 2.2.2, Asset Management through Event Analysis (above).

Applications:

References:

- NASPI CRSTT video event library at https://www.naspi.org/crstt
- A. Silverstein, "Diagnosing Equipment Health and Mis-operations with PMU Data, May 2015" (PDF 3,414KB)
- NASPI Control Room Solutions Task Team, "Using Synchrophasor Data to Diagnose Equipment Health and Mis-operations Event Summary Table" (PDF 136KB).
- White A., S. Jacobs. August 2014, "Use of Synchrophasors at Oklahoma Gas and Electric Company", (PDF 1,300KB).
- SEL SynchroWAVe Event 2015 visualization software for disturbance analysis, at https://www.naspi.org/synchrophasorsoftwaresearch .

3.2.8 Fault Location

What:
How:
Applications:
References:

- S. Picard, M.S. Adamiak & V. Madani, "Fast and Accurate Fault Location using Synchrophasors," CIGRE Grid of the Future presentation, October 2014, at http://cigre.wpengine.com/wp-content/uploads/2015/06/Fast-and-Accurate-Fault-Location-using-Synchrophasors.pdf
- OG&E

3.2.9 Forensic Event Analysis

What:
How:
Applications:

References:

- NERC, "Standard PRC-002-NPCC-01 – Disturbance Monitoring," approved by Federal Energy Regulatory Commission," at http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-002-NPCC-01&title=Disturbance%20Monitoring&jurisdiction=United%20States
- M. Adamiak & R. Hunt, "Application of Phasor Measurement Units for Disturbance Recording," at https://www.gedigitalenergy.com/smartgrid/Aug07/PMU_disturbance_recording.pdf

3.2.10 Frequency Monitoring

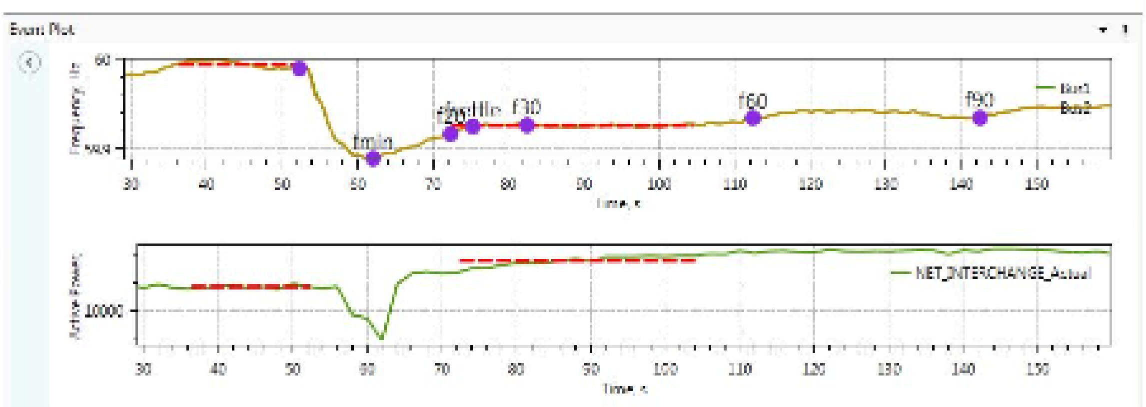
What -- NERC Standard BAL-001 requires monitoring a Balancing Authority or Interconnection's ability to stabilize frequency immediately following the sudden loss of generation.

- Frequency response measure (FRM) = MW/0.1 Hz, computed from single event frequency response data

The desired functionality for PMU-based frequency measurement analysis tools includes:

- Detect under-frequency events
- Detect areas where the generation loss occurred
- Frequency response baselining – interconnection-wide or for balancing authority
- Compliance with NERC BAL-003 Frequency Response Reliability Standard

Example (from PNNL FRAT):



Applications

- EPG RTDMS
- BPA-PNNL FRAT
- Dominion Virginia Power

References

- PNNL Frequency Analysis Tool at https://www.naspi.org/synchrophasorsoftwaresearch
- P.V. Etingov, D. Kosterev & T. Dai, "Frequency Response Analysis Tool," December 2014, at http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23954.pdf
- D. Kosterev, D. Davies et al., "Using Synchrophasors for Frequency Response Analysis in the Western Interconnection," CIGRE Grid of the Future presentation, October 2014 at http://cigre.wpengine.com/wp-content/uploads/2015/06/Using-Synchrophasors-for-Frequency-Response-Analysis-in-the-Western-Interconnection.pdf

3.2.11 Generator settings verification

What:
How:
Applications:
References:

- S. Yang
- NASPI Model Validation paper

3.2.12 Linear State Estimation

What: State estimation is a process using statistical analysis methods to estimate power system operating conditions based on measurements of grid conditions. It estimates voltage magnitude and phase of system buses, deriving P and Q flows and injections. The state estimator runs using SCADA data and extends and corrects measured quantities for system monitoring. State estimator results are used as the basis for dynamic security assessments, real-time contingency analysis, and other operational functions. State estimation can also be used to detect and reject bad data from condition assessments (if the underlying SCADA data provide sufficient measurement redundancy).

With the availability of time-synchronized PMU data sampled at speeds 100 times faster than SCADA, classic non-linear state estimation can be supplemented or replaced by linear state estimation and other improved solutions:

- Linear state estimation using three-phase PMU data directly solves for system conditions and unknowns.
- Hybrid state estimation supplements traditional SCADA measurements in non-linear analysis with phasor measurements of voltage and current phasors, improving the accuracy and robustness of non-linear estimation.
- PMU data can be used to validate a state estimator and improve its performance.
- PMU data used with state estimation can improve detection of bad data.

- Distributed state estimation can be performed in a decentralized architecture at the area or substation level, for faster computation, lower latency and easier data validation, enabling local control of automated system protection schemes.
- Dynamic state estimation (using differential rather than algebraic equations) using PMU data will be feasible in the future.

How: PJM, NYPA, WECC, MISO, Dominion Virginia Power, ERCOT, and others are using PMUs for various types of state estimation.

Applications:
- Alstom
- EPG
- EPRI
- Siemens
- V&R Energy

References:

- NASPI, "State Estimation Technical Workshop," March 25, 2015, covering the basics of state estimation and the ways that state estimation is changing with the availability of synchrophasor data, at NASPI State Estimation Technical Workshop, San Mateo, CA

3.2.13 Load Modeling

What: Use PMUs to collect information on load performance and use that data to update and modify current load models used for long-term system planning and short-term event analysis. Current load modeling efforts are paying particular attention to the phenomenon of Fault-induced Delayed Voltage Recovery (FIDVR), a transmission-level disturbance that can result from residential air conditioner motor stalling.

How:

Applications:
- WECC Composite Load Model

References:

- D. Kosterev, "System Model Validation," October 2013, presentation at NASPI Technical Workshop on Model Validation, at WECC Modeling Workshop Load Model - NASPI
- WECC Model Validation Working Group, "WECC Composite Load Model," presentation at WECC MVWG meeting, August 25, 2011, at

http://docslide.us/documents/wecc-composite-load-model-wecc-mvwg-meeting-bellevue-wa-august-25-2011.html
- P. Etingov, "FIDVR Load Modeling Tool," June 11, 2015 presentation at DOE/OE Transmission Reliability Program Review, at http://energy.gov/sites/prod/files/2015/07/f24/19.%20Etingov%20LMTD.pdf
- R. Bravo, "FIDVR Distribution System Monitors," October 23, 2014, presentation at NASPI Work Group Meeting, at https://www.naspi.org/Badger/content/File/FileService.aspx?fileID=1345

3.2.14 Model validation

What: Use PMU data of asset or system response to actual events to verify or calibrate asset models. Add paragraphs

Why:
- Approved method for complying with NERC MOD-026 and MOD-027
- Saves money – avoids having to take generator off-line for testing, saving as much as $100k/test in lost revenues and consultant fees
- More accurate results, robust against a wider range of actual system conditions, so contributes to system reliability
- Easier and faster – can be automated for better staff productivity

Application tools available:
- EPG RTDA
- EPRI RTDMS
- GE PSLF
- Mathworks MathLab
- Siemens PTI PSSE

References:
- P. Overholt, D. Kosterev, et al., "Improving Reliability Through Better Models," IEEE Power & Energy Magazine, April 2014, at http://magazine.ieee-pes.org/files/2014/04/12mpe03-overholt-2301533.pdf
- Silverstein, A., E. Andersen & F. Tuffner, "Model Validation Using PMU Data," NASPI Technical Report (March 2015), at PDF 995KB
- NASPI Technical Report, "Model Validation Using Synchrophasors, NASPI Technical Workshop," October 22, 2013, at http://energy.gov/sites/prod/files/2014/07/f17/NASPI-TechRpt-ModelValidation-Oct2013.pdf
- Martin, K., "EPG Model Validation Webinar," March 2014, at https://www.electricpowergroup.net/epg_events/eventIntro.aspx?qsel=Y8WQDewUU2Q
- NERC Model Validation Task Force, "Power System Model Validation," December 2010, at http://www.nerc.com/docs/pc/mvwg/MV%20White%20Paper_Final.pdf
- NERC, Reliability Standard MOD-026-1, "Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions," at

http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-026-1&title=Verification%20of%20Models%20and%20Data%20for%20Generator%20Excitation%20Control%20System%20or%20Plant%20Volt/Var%20Control%20Functions&jurisdiction=United%20States

- NERC, Reliability Standard MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions," at http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-027-1&title=Verification%20of%20Models%20and%20Data%20for%20Turbine/Governor%20and%20Load%20Control%20or%20Active%20Power/Frequency%20Control%20Functions&jurisdiction=United%20States

3.2.15 Monitoring system current unbalance to protect large generator rotors

What:
How:
Applications:
References:

3.2.16 Operator Training & Simulation

What:
How:
Applications:
References:

- R. Avila-Rosales, R. Fairchild, J. Giri, et al., "An Advanced Training Simulator for Synchrophasor Applications," at http://cigre.wpengine.com/wp-content/uploads/2015/06/An-Advanced-Training-Stimulator-for-Synchrophasor-Applications.pdf
- EPG, "Phasor Simulations – How Can They Be Used in Operations?" November 19, 2013 at https://www.electricpowergroup.net/epg_events/eventIntro.aspx?qsel=yaC/g/d1wJA

3.2.17 Oscillation Detection & Modal Analysis

What: High-speed, time-synchronized PMU data allow detection and analysis of grid oscillations that were not detectable before widespread PMU deployment. Both local and interconnection-wide oscillations have the potential to harm grid assets and could set off wide-scale blackouts. A number of software applications have been developed to monitor synchrophasor data in real time and diagnose oscillations. Mode meters use small signal analysis look at oscillation data and identify the frequency modes of each oscillation.

The desired functionality for PMU-based oscillation detection tools includes:

- Scans voltages, power and frequency at interties, power plants, DC ties, wind hubs for sustained oscillations in key frequency bands
- Alarms when a sustained oscillation is detected with detailed modal analysis
- Trend displays available for problem drill-down
- Facilitate decision support tools for grid management
- Engineering support applications for baselining and setting alarm thresholds

Example --

Recent oscillations identified within the western interconnection
(Source: WECC JSIS)

Mode	Freq. (Hz)	Shape	Interaction Path(s)	Controllability	Grade	Comments
NS A	0.25	Alberta vs System. BC and PNW swing with Alberta	Alberta Interconnect. COI. Cust.	Alberta	A	An Alberta trip causes NSA and NSB to combine into one NS mode with reduced damping. Need to understand damping better.
NS B	0.38	Alberta vs (BC + N. US) vs (S. US).	Alberta Interconnect. COI. Cust. Boundary.	Wide-spread. PDCI	A	This is the most wide spread mode in the system. Need to understand damping better.
EW A	0.5	(SW US) vs (Mid W. - CO)	Unkown	Unkown	C	Need PMUs in east part of loop.
MT	0.55 to 0.8, 0.8 typical	MT vs system.	Garrison.	Colstrip	B	Sometimes MT swings against BC.
BC	0.6	BC (Kemano) vs system. Ripples to S. Cal.	Cust. ?	Kemano?	B	Strong interactions with PDCI and PNW.
EW B	0.7	Unknown	Unkown	Unkown	F	

NOTE: "Grade" is a measure of how well we currently understand this mode.

Applications:

- ABB
- Alstom
- EPG
- OSIsoft
- Schweitzer
- Space-Time Insight
- Washington State University

References:

- M. Venkatasubramanian, "Power System Oscillatory Stability," presentation at NERC Operating Committee Meeting, September 15, 2015, presentation 9f in http://www.nerc.com/comm/OC/AgendasHighlightsMinutes/OC_Meeting_Presentations_September_2015.pdf
- NASPI Oscillation Detection & Voltage Stability Technical Workshop, October 22, 2014, at https://www.naspi.org/techworkshops , including videos

- WECC JSIS, “Modes of Inter-Area Power Oscillations in the Western Interconnection,” November 30, 2013, at https://www.wecc.biz/Reliability/WECC%20JSIS%20Modes%20of%20Inter-Area%20Oscillations-2013-12-REV1.1.pdf
- D. Trudnowski & J. Pierre, “Measurement Based Stability Assessment,” June 3, 2014 presentation at DOE/OE Transmission Reliability Program Review Meeting, at http://energy.gov/sites/prod/files/2014/09/f18/07-2014TR-PeerReview-Pierre.pdf

3.2.18 Phase angle monitoring

What:
How:
Applications:

References:

- EPG Webinar, “Using Phase Angle Differences – What they mean and how to use them in operations,” September 17, 2013, at https://www.electricpowergroup.net/epg_events/eventIntro.aspx?qsel=Y8WQDewUU2Q
- B. Blevins & A. Das, “ERCOT Synchrophasor Data Baselining Study,” presentation to NASPI, March 11, 2014, at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CB4QFjAAahUKEwiRhM-M76TIAhVBjw0KHYc8C3M&url=https%3A%2F%2Fwww.naspi.org%2FBadger%2Fcontent%2FFile%2FFileService.aspx%3FfileID%3D1244&usg=AFQjCNEOJEDBXRNPA4VvHmUm5IdhN7oOEA&sig2=F7tYIuSjwxnzjiCpkfS0zA
- B. Bhargava, “Eastern Interconnection Phase Angle Baselining Study,” June 11, 2015, at http://energy.gov/sites/prod/files/2015/07/f24/20.%20Bhargava%20EI%20Baselining%20Analysis.pdf

3.2.19 Turbine monitoring

What:

How:

Applications: None commercially available yet

References:
- T. Rahman, “SDG&E Experience with Advanced Generator Monitoring,” October 22, 2014, presentation at NASPI Work Group meeting, at https://www.naspi.org/Badger/content/File/FileService.aspx?fileID=1347

3.2.20 Verify equipment operations

What:

How:

Applications:

- Alstom e-Terravision
- EPG RTDMS
- Schweitzer SynchroWAVe

References:

- J. Ballance, EPG – "Phase angle differences – what they mean and how to use them in operations," September 2013, at https://www.electricpowergroup.net/epg_events/eventIntro.aspx?qsel=Y8WQDewUU2Q=
- NASPI CRSTT "Phase Angle Monitoring" white paper DRAFT, October 2015, at https://www.naspi.org/File.aspx?fileID=1567 .

3.2.21 Visualization, Wide-Area Monitoring & Situational Awareness

What:
How:
Applications:
References:

3.2.22 Voltage Stability Monitoring

What:
How:
Applications:
References:

4) Synchrophasor value proposition

Types of benefits

- Reliability
- Throughput and efficiency
- Cost savings
- Environmental

List some of the biggest impact benefits measurable today

References and more material

- NASPI Technical Report, "The Synchrophasor Value Proposition – Itemizing and Calculating the Benefits from Synchrophasor Technology," October 2015, at https://www.naspi.org/File.aspx?fileID=1571.
- Several docs from the SGIG awardees and NASPI presentations
- NASPI eqpt mis-ops and model val papers

Synchrophasor benefits and value metrics

Synchrophasor Benefit	Synchrophasor Value Metrics
Reliability benefits	
Reduction in major outages	Number major outages
Reduction in minor outages	Number minor outages
Fewer customers affected by outages	Number customers
Fewer equipment failures and catastrophic emergencies	Number of equipment failures Number of catastrophic equipment emergencies
Faster service restoration	Number of outage hours avoided
Faster line reclosing	Hours saved MWh energy flows enabled
Smoother generator synchronization	?
Faster blackstart restoration and synchronization	Hours saved Customers affected
Faster island restoration	Hours saved Customers affected
Faster forensic event analysis and lessons learned	NQ
Back-up communications network and data for loss of SCADA system	NQ
Cost savings	
Congestion reduction	$ value of more efficient dispatch
Labor cost reductions	Staff hours saved $ value of worker hours saved
Reduced energy use	MWh and value of MWh saved

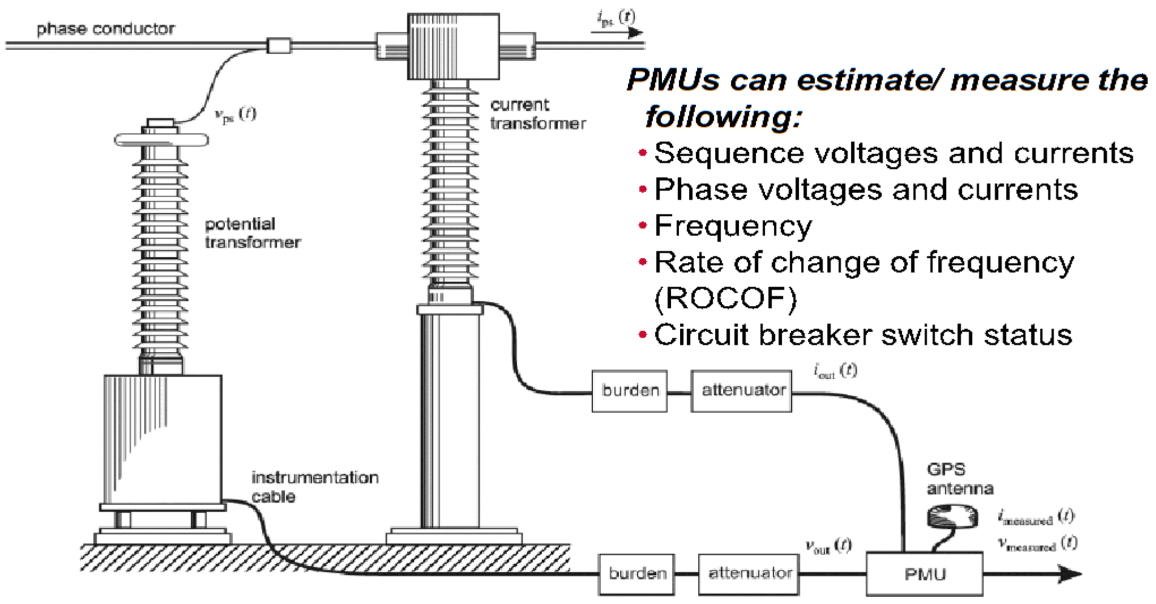
Fuel and hydro savings (includes O&M costs)	MWh realized from generation efficiency
	$ value of fuel savings
	$ value of O&M savings

Capital savings	Assets not built $ net present value of capital investments delayed

Grid throughput and efficiency benefits	
Enhanced energy flows	Bottleneck facilities relieved MWh of incremental flows from bottlenecks reduced
Better reactive power management	NQ
Environmental and policy benefits	
Increased delivery and use of renewable generation	Incremental renewable MWh
Decrease in net carbon emissions	Incremental tonnes pollutants not issued from fossil generation

5) Phasor Measurement Units

5.1 The PMU



5.2 PMU capabilities

PJM's description of the information to be recorded about a PMU in the PJM PMU Registry summarizes much of the relevant information about a PMU's functionality and performance requirements. See https://www.pjm.com/~/media/committees-groups/committees/oc/20140408/20140408-item-06-attachment-m-to-registry-file-template.ashx

PG&E developed compliance tests to be sure that the PMUs it selected would be able to perform according to the utility's requirements. Those test requirements are summarized here.

PG&E PMU Compliance tests
(used with permission from V. Madani, PG&E)

TEST	REFERENCE STANDARD	TEST LEVEL
Dielectric voltage withstand	EN60255-5	2.3KV
Impulse voltage withstand		5KV
Damped Oscillatory	IEC61000-4-18IEC60255-22-1	2.5KV CM, 1KV DM
Electrostatic Discharge	EN61000-4-2/IEC60255-22-2	Level 3
RF immunity	EN61000-4-3/IEC60255-22-3	Level 3
Fast Transient Disturbance	EN61000-4-4/IEC60255-22-4	Class A and B
Surge Immunity	EN61000-4-5/IEC60255-22-5	Level 3 & 4
Conducted RF Immunity	EN61000-4-6/IEC60255-22-6	Level 3
Power Frequency Immunity	EN61000-4-7/IEC60255-22-7	Class A & B
Voltage interruption and Ripple DC	IEC60255-11	12% ripple, 200ms interrupts
Radiated & Conducted Emissions	CISPR11 /CISPR22/ IEC60255-25	Class A
Sinusoidal Vibration	IEC60255-21-1	Class 1
Shock & Bump	IEC60255-21-2	Class 1
Seismic	IEC60255-21-3	Class 1
Power magnetic Immunity	IEC61000-4-8	Level 5
Pulse Magnetic Immunity	IEC61000-4-9	Level 4
Damped Magnetic Immunity	IEC61000-4-10	Level 4
Voltage Dip & interruption	IEC61000-4-11	0,40,70,80% dips,250/300cycle interrupts
Damped Oscillatory	IEC61000-4-12	2.5KV CM, 1KV DM
Conducted RF Immunity 0-150khz	IEC61000-4-16	Level 4
Voltage Ripple	IEC61000-4-17	15% ripple
Ingress Protection	IEC60529	IP40 front, IP20 Back
Environmental (Cold)	IEC60068-2-1	-40C 16 hrs
Environmental (Dry heat)	IEC60068-2-2	85C 16hrs
Relative Humidity Cyclic	IEC60068-2-30	6day variant 1
Damped Oscillatory	IEEE/ANSI C37.90.1	2.5KV, 1Mhz
RF Immunity	IEEE/ANSIC37.90.2	20V/m 80-1Ghz
Synchrophasors Standard & Prtotocols	IEEE C37.118.1, C37.118.2 IEC61850-90-5, C 37.238, C 37.242, C 37.244	Config. 2 file in C37.118.2 format Data: UDP Multicast, IGMP V2 and V3, & IP V4 & V6
Required streaming frames	60, 120 per second	"P" class and "M" Class

BPA's 2009 PMU test plan (developed before IEEE 37.118.1-2011 was adopted) indicates the key performance characteristics of PMUs for the applications discussed in Section 2, including dynamic performance requirements for rise time and overshoot.

BPA 2009 PMU Performance Specifications
(Used with permission from T. Faris, BPA)

Element	Required	Preferred
Basic		
A/D Sampling Resolution	16 bit	___________
UTC Synchronization	10E-6 sec	
Phasor Reporting Rate	60 sps	
Nyquist Frequency = 1⁄2 of Reporting Rate	30 Hz	
Phase angle error not to exceed	+/– 1° at +/–5Hz	
Filtering		
Frequency Response to -0.5 dB (94.5%)	±5 Hz	___________
Frequency Response to -3.0 dB (70.7%)	±10 Hz	___________
Gain at Nyquist Frequency	–40dB (1%)	–60dB (0.1%)
Max. Gain above Nyquist Frequency	–40dB (1%)	–60dB (0.1%)
Max. Gain at harmonics of n(60 +/–1)Hz	–60dB (0.1%)	
Max. Phase delay at ±0.25 Hz	3°	
Max. Phase delay at ±2.0 Hz	15°	
Step Response		
Response time from 0 to 95% not to exceed	50 ms	
Response time from 10 to 90% not to exceed	32 ms	
Response overshoot not to exceed	7.5%	5%
Input Capabilities		___________
Number of Voltage Phasors	2	___________
Number of Current Phasors	6	
+/– 20 Volt floating DC voltage		4
4-20mA DC control current		4
Digital status	8	
Output Capabilities		
Fiber-Optic	X	
Interoperability		
C37.118 standard support	X	
IEC 61850		X

A few of BPA's test considerations and methods and considerations may illuminate what PMUs measure and calculate and how they should perform:[3]

- Setup and configuration -- This category covers the initial set up of the device, including physical connection of AC signals, power source, and communications. In

[3] Used with permission from Tony Faris, BPA.

addition, the ease of use in setting PT/CT ratios, selecting phasors for the data stream, and setting output data rates will be assessed, as well as the front panel and any displays or indicators that are included.

- Time synchronization -- All devices will be classified as using either IRIG-B or a GPS signal for time synchronization. Also, the amount of time required to synchronize on startup will be recorded, both in terms of the "status" field in the 37.118 stream and any front panel indication of synchronization. After the unit is locked and running for an extended period of time, the source of synchronization will be removed and the time required to lose and to subsequently regain synchronization will be recorded.

- Interoperability – 37.118 support PMUs will be tested for interoperability and support of the IEEE C37.118 standard by checking compatibility with common software, including TVA PMU Connection Tester and BPA Streamreader. Data packets will be assessed for correct length, and all fields within a packet will be examined for appropriate values in multiple conditions. Flexibility in output formats (floating point versus integer, polar versus rectangular, network protocols) will also be addressed. PMUs will be connected to existing Phasor Data Concentrators to ensure compatibility with other devices.

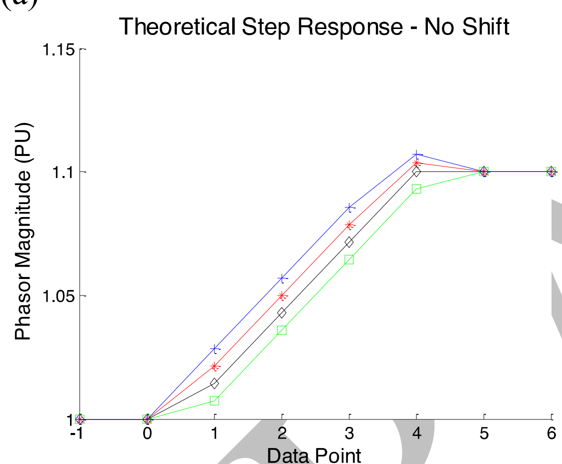
- Steady state tests -- Multiple tests will be performed to investigate performance of PMUs under steady state conditions. In each of these tests, Total Vector Error (TVE) is not the primary indicator of performance. However, TVE will be used, where appropriate, as a supplemental value representing measurement error of the PMU and to ensure compliance to 37.118 standards.
    - Phasor magnitude – balanced, three phase voltage and current tested at a range of magnitudes
    - Phase angle – phase angle of balanced, three phase voltage and current relative to UTC
    - Phase angle versus frequency – absolute phase angle error measured at off-nominal frequencies
    - Frequency response – phasor magnitude measured at off-nominal frequencies
    - Frequency accuracy – frequency error measured at a range of input frequencies
    - Unbalanced amplitude – amplitude of one of three voltage and current phases is varied, and magnitude error is measured
    - Unbalanced phase – phase angle of one of three voltage and current phases is varied, and phase angle error is measured

- Step tests -- Amplitude, phase and frequency step tests all follow the same general methodology. A playback file is generated with a series of steps, each delayed by a short interval within the data output interval (16.7 ms for 60 samples per second). The file has an interval of constant signal at nominal level, a step to the new value at a defined time, an interval at the new value, and a return to the nominal level. For a 60 sps data rate, the 16.7 ms sample interval is divided into multiple equal intervals, and steps are placed at each of these intervals. In this way, the steps occur at various times within the measurement window, so multiple responses are recorded from a test file. In the analysis stage, each of these delayed steps is shifted back by a time corresponding to the delay in which each step occurred.

An example of this process for an amplitude step test is shown in Figure 1, using four steps, each delayed by 1⁄4 of the measurement interval. Figure 1(a) shows the recorded data before analysis. Note that the PMU response is highly dependent on the time of the input step relative to the timestamp. Figures 1(b) and 1(c) show the overall step response as each step is shifted in time back to a common point. Figure 1(d) shows the final step response after analysis is complete. In this final plot, a single curve characterizes the step response of the PMU, allowing for calculation of overshoot, rise time, and delay from the input step to the output step.

BPA PMU Tests – Theoretical step response after each shift in amplitude

(a)



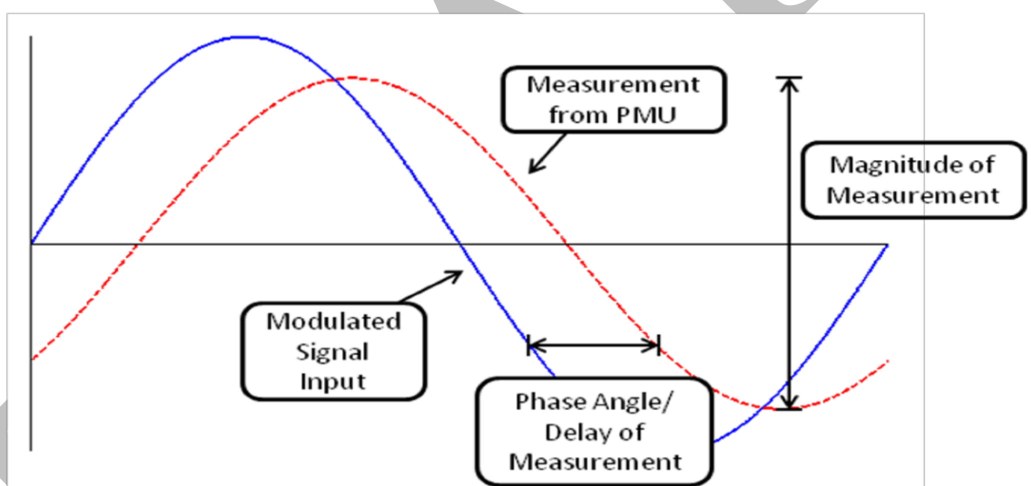
(b)

- Structured signal tests -- Structured signal tests include modulated and mixed-signal tests, where distortion is introduced, with the goal of determining group delay and filter effects. These tests include:
  - o Mixed signal harmonic rejection – distortion at harmonics of the carrier frequency is

mixed into the base signal to determine the level at which PMU filtering rejects this distortion

- Single frequency, out-of-band rejection – distortion at frequencies outside of the Nyquist is mixed into the base signal at nominal frequency to determine the level at which PMU filtering rejects this distortion
- Modulation tests – amplitude, phase, or frequency is modulated at a wide range of modulation frequencies to measure rejection of the modulation and group delay of the measurement. The goal of modulation tests is to determine the relationship between a signal modulated in amplitude, phase, or frequency applied to the input of a PMU and the corresponding characteristic of the phasor measurement reported. For example, in an amplitude modulation test, a comparison is made between the magnitude of the oscillation of the magnitude measurement provided by the PMU and the magnitude of the modulation signal applied. In addition, a comparison is made between the phase angle of the magnitude measurement and the phase angle of the input modulation signal to calculate the group delay in the measurement. Figure 2 shows a typical response of a PMU when the input signal is modulated. Depending on the test performed, the dashed sinusoidal response can represent the magnitude, phase, or frequency measurement.

Figure 2. Typical response of PMU to modulated signal



Using a curve-fitting algorithm, BPA's analysis program will estimate an RMS magnitude of the measurement from the discrete data points at 60 samples/second and the delay from the input modulation to the output. The RMS magnitude is a reflection of the filtering performed by the PMU, while the delay represents the overall group delay of the device.

The Indian electric transmission company Posoco, recently undertook a major regional synchrophasor project. The table below shows Posoco's PMU specifications for the project for its three regions.

[table from p35 at "POSOCO, Synchrophasor Initiative in India," 2012]

5.3 P class v. M class PMUs

P class (protection)
Minimal filtering

- Possible aliasing of higher frequency components
- Less delay in estimation
- Important for real-time controls requiring minimum delay

M class (measurement)

- Some anti-alias protection
- Wider frequency response, lower noise
- Latency longer (depends on reporting rate)
- Important for situations with higher frequencies present

Both classes conduct essentially the same measurement in all other respects.

5.4 New PMUs v. upgrading existing relays

Relay conversion to PMU (Cite Lafayette)

Using DFRs as PMUs -- Older DFRs can be used as PMUs, but some users have found conversion challenges. (See J. Kleitsch, H. Mehta & J. Hackett, "Using Digital Fault Recorders and Phasor Measurement Unit Devices," NASPI Meeting June 2012)

5.5 PMU Manufacturers:

- ABB
- Alstom
- Beijing Sifang Automation
- Macrodyne
- MehtaTech
- National Instruments
- PQube
- Schweitzer Engineering Laboratory

References:

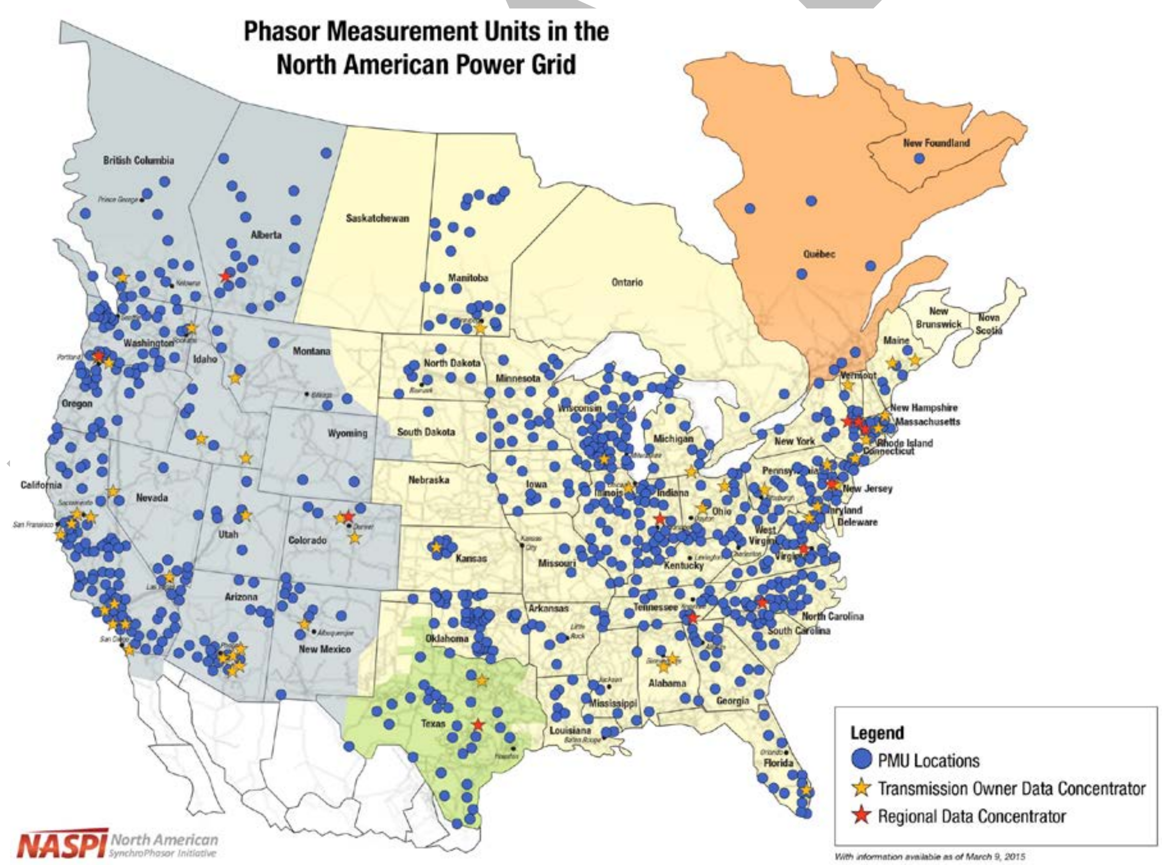
- K. Martin, "Synchrophasor Characteristics & Terminology," presentation to ERCOT on March 7, 2014, at (PDF 754KB)
- NASPI PRSVTT, "Guide for Installation of Multi-Function PMUs," presentation to NASPI Work Group, October 23, 2014, at Guide for Installation of Multi-Function Phasor Measurement Units (MF-PMU)

6) PMU Placement

PMU placement should be driven primarily by system and applications needs, then by installation feasibility and cost. In the early days of synchrophasor technology development and deployment, it was very costly to deploy individual PMUs using specialized crews for installation and substation designs modified to accommodate the PMU. This led to the view that PMU placement should be optimized to maximize the value and usefulness of the limited data collected given the relatively high cost of undertaking the PMU and software deployment effort.

Today, in contrast, many companies have significant experience with PMU design and installation and there are over 2,000 PMUs deployed across North America. PMU acquisition and installation costs have diminished significantly (see section ___ on PMU Installation Costs). Most new PMU installations place many PMUs in a single coordinated effort, and do in-fill with later installations as additional targeted substations become available for work associated with maintenance or upgrade projects. Thus in most areas, there is little need to optimize placement of individual or a small number of PMUs and a growing trend to install PMUs as part of routine transmission program upgrades and new construction.

PMUs across North America, October 2014



Additionally, many existing digital relays already installed on the grid are actually multi-function devices that can be converted (using existing firm-ware) to turn on phasor measurement capability without compromising the relay's performance. This has been done by a number of transmission owners (PG&E, Lafayette Municipal Utilities, and more). This removes much of the cost of PMU set-up.

PMU placement considerations include:

- System needs are to monitor critical assets and potential trouble points (loads, key transmission paths and constraints, and key generators).
- Application needs dictate different placement considerations – e.g., voltage stability monitoring points may differ from linear state estimator monitoring points or automated system protection schemes.
- Feasibility considerations include communications facilities, timing of substation or site work activity, and capital and crew availability.
- The more PMUs you already have, the less incremental value to the next PMUs installed for uses like wide-area situational awareness and state estimation and – unless the new PMU will serve a specific asset or application need.
- There are formal mathematical methods for PMU siting, but in most cases practical guidelines and criteria are more useful.

<u>PMU Placement Example – NYISO Guidelines</u> -- Initial applications were for wide-area visualization and phasor-enhanced state estimation. The PMU placement guidelines for NYISO transmission owners under the NYISO Smart Grid Investment Grant synchrophasor project were to put the PMUs at:

- Critical interfaces, control area ties and zonal tie lines
- Generating stations > 500 MW
- Wind power plants > 100 MW
- Major load centers
- Thermal and voltage constraints
- Power system stabilizer location
- Phase angle regulator location
- FACTS devices
- Future wind installations.[4]

PMU Placement – Interconnection requirements

Several Reliability Coordinators and Transmission Owners have tariff requirements for new generators to put a PMU at the point of interconnection with the transmission system. Common features of those tariff requirements include:

- The PMU should take 30 samples/second or faster

[4] McNierney & Cano, "State Estimation & Wide-area Visualization," 10/14 NASPI Meeting, at https://www.naspi.org/Badger/content/File/FileService.aspx?fileID=1332

- Be installed on customer side of generator step-up transformer
- Have communications equipment to deliver data to transmission provider
- Provide 10 to 30 days or better of local data storage for the PMU data
- Measure
    - Gross MW and MVAR
    - Generator terminal voltage & frequency
    - Generator field voltage & current
- The host generator should have up to three years of event data retention for model validation and event analysis purposes.

Current regional interconnection requirements include:

- BPA – wind generators > 230 kV; tariff requirement; also http://www.bpa.gov/Doing%20Business/TechnologyInnovation/ConferencesVoltageControlTechnical/SummaryWindDataPMURequirementsBPA.pdf
- PJM – generation >100 MW http://www.pjm.com/~/media/committees-groups/subcommittees/sos/20140326/20140326-item-06b-pjm-pmu-requirment-in-tariff.ashx
- ERCOT Nodal Operating Guide, Phasor Measurement Recording Equipment – aggregated generation > 20kVA, at published Generic Transmission Constraints, FACTS >100kV, after June 1, 2015 http://www.ercot.com/content/wcm/key_documents_lists/29850/142NOGRR_10_TAC_Report_052815.doc

References

- NASPI RITT, "Guidelines for Siting Phasor Measurement Units," June 2011, at https://www.naspi.org/File.aspx?fileID=518
- V. Madani, "PMU Placement Considerations," June 2010, at https://www.naspi.org/Badger/content/File/FileService.aspx?fileID=103
- J. Chow, "PMU Placement Guidelines," June 2013, at https://www.wecc.biz/Reliability/2013 06 JSIS Chow PMU Placement 2013 0612.pdf
- MISO – "Midwest ISO Placement Approach Whitepaper", October 2011, at https://www.misoenergy.org/Library/Repository/Project Material/Project Documentation/Synchrophasor Project/MISO PMU Placement Approach White Paper.pdf
- WECC Joint Synchronized Information Subcommittee, "WECC Process for Placing Synchronized Data Recorders," June 13, 2013, at https://www.wecc.biz/Reliability/WECC%20JSIS%20Placement%20of%20Synchronized%20Dynamic%20Monitoring%20Equipment-2013-06-13-APPROVED.pdf
- "Optimal PMU placement: A comprehensive literature review" – W. Yuill, A. Edwards, et al., IEEE-PES General Meeting, July 2011, at http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=6039376&url=http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6039376

NASPI Synchrophasor Starter Kit, Part 2

DRAFT October 9, 2015

NOTE TO READERS – this is very much a work in progress. We invite your feedback about what to include in this document to make it more useful for you and your colleagues. Please send feedback and suggestions to: alisonsilverstein@mac.com

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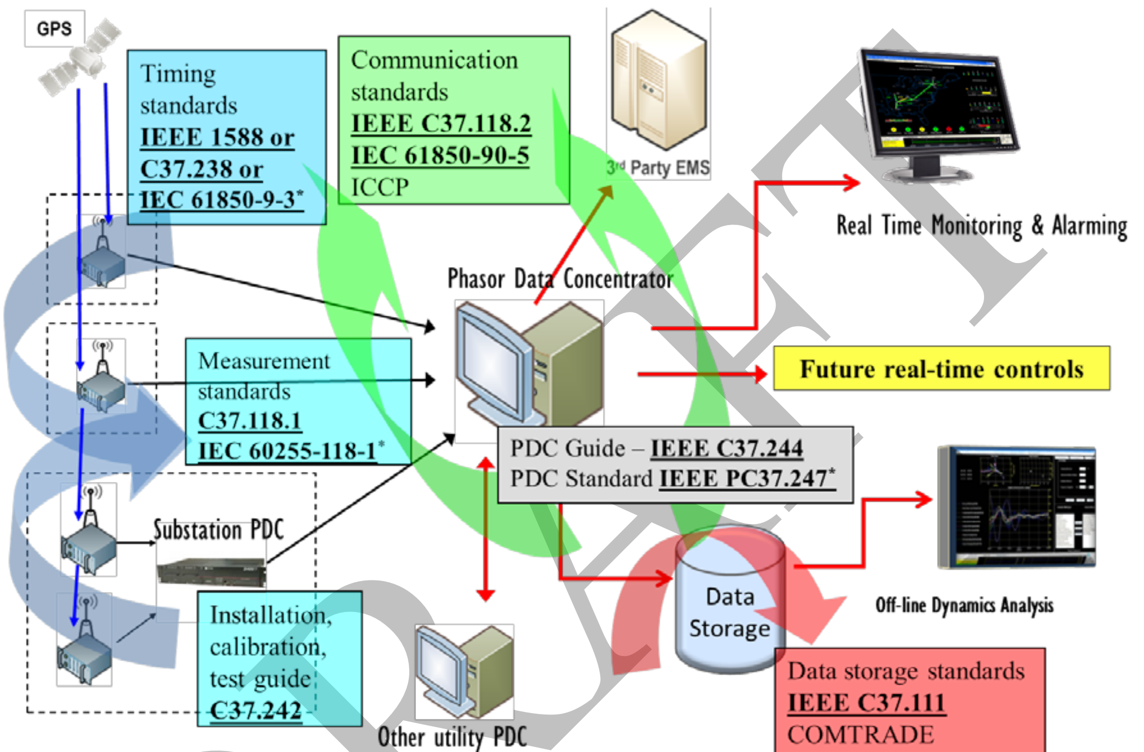
7) Relevant technical standards

Figure 1 provides a visual summary of synchrophasor-related standards and guides and their relevance to various element of a synchrophasor system. All of these standards have been developed and adopted by the IEEE or the IEC.

Figure 1 – Summary of synchrophasor-related standards and guides and their relevance to various element of a synchrophasor system



* denotes documents that are not released as of August 2015.

- IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Portale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse (http://www.iec.ch/). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA.
- IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (http://standards.ieee.org/).

The following is a brief description of the standards relevant to synchrophasor technology:

- IEEE C37.118.1-2011 and IEEE C37.118.1a-2014: Covers synchrophasor measurement requirements including dynamic performance -- Includes performance and accuracy requirements for PMU measurements of synchrophasors, frequency, & rate of change of frequency (ROCOF). Introduces different requirements for M Class (Measurement Class) and P Class (Protection Class) synchrophasor data. C37.118.1-2011 (together with C37.118.2-2011) replaces the synchrophasor standard C37.118-2005.

- C37.118.1-2011: This standard is for synchronized phasor measurement systems in power systems. It defines a synchronized phasor (synchrophasor), frequency, and rate of change of frequency (ROCOF) measurements. It describes time tag and synchronization requirements for measurement of all three of these quantities. It specifies methods for evaluating these measurements and requirements for compliance with the standard under both static and dynamic conditions. It defines a phasor measurement unit (PMU), which can be a stand-alone physical unit or a functional unit within another physical unit. This standard does not specify hardware, software, or a method for computing phasors, frequency, or ROCOF.

- C37.118.1a-2014 includes changes to ROCOF requirements. It fixes typos and clarifies wording. It relaxes or suspends ROCOF. It fixes the ramp test & further defines procedure for better consistency. It simplifies & clarifies latency tests and makes small changes in a few performance requirements. It improves the model in annex, which now meets all requirements.

- IEEE C37.118.2-2011: This standard defines a method for exchange of synchronized phasor measurement data between power system equipment. It specifies messaging including types, use, contents, and data formats for real-time communication between phasor measurement units (PMU), phasor data concentrators (PDC), and other applications.addresses the synchrophasor data transfer requirements used for communication of phasor measurements, message format, etc. It is based on IEEE C37.118-2005 with modifications and extensions. It is not a complete communication protocol, but rather a data transfer requirements standard.

- IEEE Std. C37.118-2005 – This standard is obsolete, replaced by C37.118.1-2011 and C37.118.2-2011.

- IEEE C37.238-2011: This specifies the standard profile for use of Precision Time Protocol (IEEE 1588 Ver. 2) for transferring precise time over Ethernet for power system applications. This standard specifies a common profile for the use of IEEE Std 1588™-2008 IEEE Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems in power system protection, control, automation, and data communication applications utilizing an Ethernet communications architecture. The profile specifies a well-defined subset of IEEE 1588 mechanisms and settings aimed at enabling device interoperability, robust response to network failures, and deterministic control of delivered time quality. It specifies the preferred physical layer, Ethernet; the higher level protocol used for message exchange, PTP; and the PTP protocol configuration parameters. Special attention is given to ensuring consistent and reliable time distribution within substations, between substations, and across wide geographic areas. The standard is under revision as of summer 2015 to modify the standard profile for use of Precision Time Protocol (IEEE 1588 Ver. 2) for transferring precise time over Ethernet for power system applications. Unlike IEC/IEEE 61850-9-3, IEEE PC37.238 includes: Time Inaccuracy TLV and explicit support for reduced accuracy slaves, not supporting peer delay mechanism, and/or hardware time-stamping. There are efforts to harmonize PC37.238 and the new IEC/IEEE 61850-9-3 by including the above 2 key difference in 61850-9-3.

- IEEE C37.111-2013 (also named IEC 60255-24, Edition 2): The IEEE COMTRADE standard is a file format designed for time series data that is established world-wide and is supported by standards-making bodies. It is a common format for transient data exchange (COMTRADE) for power systems. With some extension, COMTRADE is useful for formatting synchrophasor data to be stored. Annex H of C37.111-2013 presents a schema for using the COMTRADE format for recorded phasor data by making synchrophasor specific assignments to the standard COMTRADE parameters. The parameters are used in the standard, prescribed manner, but with specific uses that allow some automatic (machine) processing. This recommendation is for use with COMTRADE starting with the 1999 version. This schema can be readily adapted to the new COMTRADE version (2013).
- IEC 61850-90-5: Use of IEC 61850 to transmit synchrophasor information according to IEEE C37.118. This addresses new communication requirements for synchrophasor data to take advantage of IEC 61850 environment (includes cyber security features). It has been developed under joint efforts by IEC, IEEE, DOE, NIST, NASPI PSTT, users and vendors. This part of IEC 61850 provides a way to exchange synchrophasor data between PMUs, PDCs WAMPAC (Wide Area Monitoring, Protection, and Control), and between control center applications. The data, to the extent covered in IEEE C37.118-2005, is transported in a way that is compliant to the concepts of IEC 61850. However, given the primary scope and use cases, this document also provides routable profiles for IEC 61850-8-1 GOOSE and IEC 61850-9-2 SV packets. These routable packets can be utilized to transport general IEC 61850 data as well as synchrophasor data.

- IEEE C37.242-2013: Guide for Synchronization, Testing, Calibration and Installation of PMUs. This includes a number of useful tips for installing and commissioning PMUs.

References:

- IEEE-PES Synchrophasor Standards Suite at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0CCMQFjABahUKEwjeiaHB2aTIAhWRpYgKHQn4Aj8&url=http%3A%2F%2Fstandards.ieee.org%2Femail%2F2014_12_synchrophasor_tss_web.html&usg=AF

QjCNFGMzcAp5RE382usI2KgZpHevTwlQ&sig2=jyyqVTomKFfA6sbXDUqkNQ

- IEEE Standards Association Uniform Test Plan for C37.118.1 Conformance of Synchrophasors for Power Grid, January 2015 at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=7&ved=0CD4QFjAGahUKEwjZrZP52KTIAhUDlogKHeQmA38&url=http%3A%2F%2Fstandards.ieee.org%2Fnews%2F2015%2Fsynchrophasor-test-plan.html&usg=AFQjCNFcMGEfb_E6ynzud0NLnmLMH5Qx_g&sig2=rOWjMX3cBy_e-076FCqDTg NASPI Technical Workshop and Tutorial, "Use of IEC 61850 to Transmit Synchrophasor Information According to IEEE 73.118 [sic], August 2014 Report on July 2012 Tutorial, at https://www.smartgrid.gov/document/use_iec_61850_90_5_transmit_synchrophasor_information_according_ieee_73118_naspi_tutorial.html

8) Big picture PMU installation cost factors -- Marcus Young (ORNL)

This section summarizes research conducted in 2014 of PMU installation cost experiences by several transmission owners over the 2011-2014 period, covering project planning, PMU acquisition and installation costs. While the cost factors and best practices identified in that study and summarized below remain accurate, it should be recognized that PMU device costs have dropped further since that date, and PMU installation costs have dropped markedly relative to those reported here.

Big Picture PMU Costs

Installing synchrophasor systems involves a number of strategic and tactical decisions for which there is little empirical data. The Oak Ridge National Laboratory (ORNL) performed a DOE-funded study in 2014 on PMU installation cost experiences of several of the synchrophasor project participants to identify the major decision points and collect qualitative information regarding the cost impacts of those decisions.[1]

Because the data regarding cost accounting and functional requirements varied greatly, the study involved conducting interviews with nine transmission owners and reliability coordinators that were part of the SGIG/SGDP projects.

[1] M. Young & A. Silverstein, "Factors Affecting PMU Installation Costs," October 2014, at https://www.smartgrid.gov/files/PMU-cost-study-final-10162014_1.pdf identifies the major decision points and provides qualitative information regarding cost impacts of those decisions. It also documents some good practices and lessons learned regarding synchrophasor system installations.

Participants of Synchrophasor System Cost Study

NERC Regions	Entity
Western Electricity Coordinating Council (WECC)	Bonneville Power Administration (BPA) Idaho Power Company (Idaho Power) Pacific Gas and Electric Company (PG&E)
SERC Reliability Corporation	Duke Energy Carolinas (Duke) Entergy Corporation (Entergy)
Midwest Reliability Corporation, Reliability First Corporation	Midcontinent ISO (MISO) American Transmission Company (ATC) Manitoba Hydro
Texas Reliability Entity	Oncor Electric Delivery Company

Interviews with the participants revealed several themes explaining how project design, procurement, and installation decisions drove total installed costs of PMUs. Specifically, each utility's plans for how to use the synchrophasor system drove their choices with respect to communications requirements, security requirements, management of installation crews, and equipment requirements. Collectively, those factors were the primary cost drivers for PMU acquisition and installation.

Key Cost Drivers

The participants identified four key cost drivers. Listed in order of significance, these drivers are:

Communications: Communications upgrades for the new synchrophasor systems were identified by the participant utilities as the largest cost driver, and one that required significant strategic planning. From a practical standpoint, substation communications capabilities range from almost non-existent available bandwidth (usually in older substations) to high-bandwidth fiber-optic connectivity. One utility reported that, absent adequate existing communications, upgrades to communications infrastructure increased the cost of installing PMUs by a factor of seven. However, once a high-speed backbone telecommunications network is installed, the cost of installing additional PMUs is relatively low.

Security: Cyber-security requirements were the second most significant factor affecting PMU acquisition and installation costs. The participants used two approaches:

- Mission-critical systems -- Used for making operational decisions or to drive automatic control actions.
- Mission-support systems -- Used for monitoring system conditions and for offline capabilities that do not directly affect operations.

Three of the participants built mission-critical synchrophasor systems and designated them as critical cyber assets, complying with all appropriate NERC Critical Infrastructure

Protection (CIP) requirements. The remaining participants built mission-support synchrophasor systems that require adherence to a less demanding set of CIP requirements. One utility estimated that deploying a mission-critical PMU system increased its PMU installation costs by a factor of two over the amount required for deploying a mission-support PMU system.

Labor: To install and commission PMUs, the participants used two approaches:

- Specialized crew — Specialized training and tools were provided to a single crew that handled all of the installations (minimizes learning curve).
- Decentralized crews — Training was provided to technical personnel across the system where PMUs were being deployed (minimizes travel time to and from installation sites).

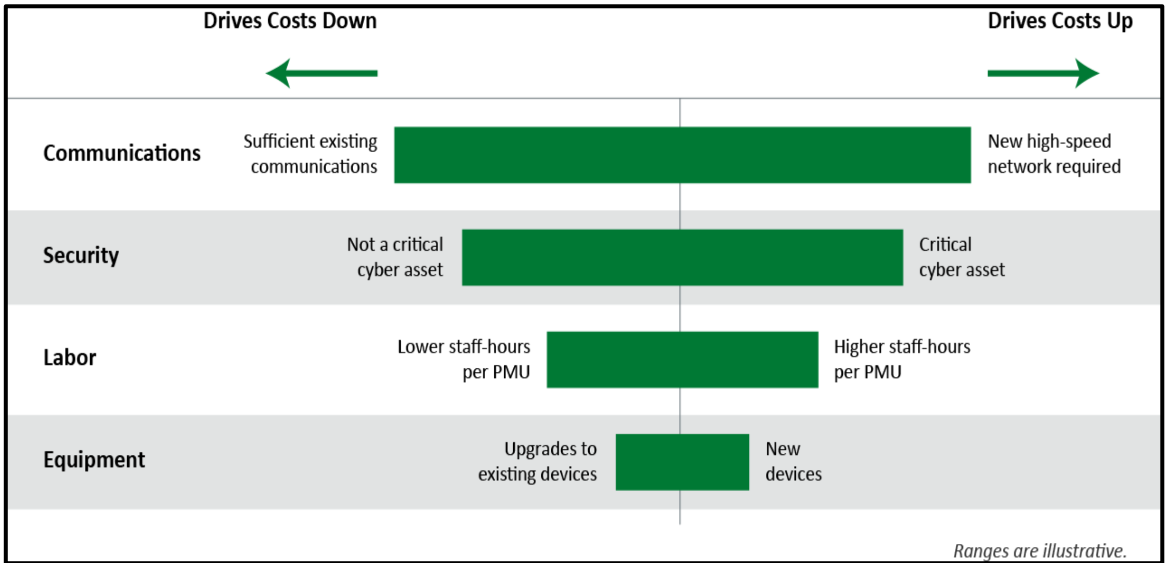
While labor was a significant cost driver, neither the specialized nor the decentralized crew strategy emerged as a good or lowest cost practice. Rather, the optimum choice between these two approaches depended on the number of miles to be driven by the installers and the number of PMUs to be installed. Regardless of approach, the participants agreed that PMU installations are more efficient when coordinated and scheduled with other work orders within a substation. By doing so, the existing substation assets are not taken out of service solely for the PMU installation. Also, if the PMU installation is assigned to crews that are already performing other work on-site, the incremental travel and set-up time for the PMU installation is minimized. This has the added logistical benefit of reducing the number of outage requests—a major advantage in situations where systems are highly utilized and outage windows require long lead times to obtain.

Equipment: Equipment was the least significant factor identified by the participants, as the typical cost of PMU devices was less than 5% of the overall installed cost (this includes acquisition and installation). In one case, a participant's PMU device was about 30% of the installed costs only because its overall installed costs were at the low end of the range reported by the participating utilities.

Phasor measurement functionality is built into many digital relays, DFRs, and other dual-function devices.

The key decision regarding equipment is whether to field stand-alone PMUs or to enable the PMU functionality in dual-function devices that are already installed in the field.
In the process of interviewing the participants, some cost trends became evident. However, differences among utility systems, practices, and synchrophasor applications prevent quantifying the precise extent to which each cost driver affects the overall cost of acquiring and installing PMUs. The impact diagram in Figure 1 provides a qualitative indication of these cost trends presented in order of relative impact.

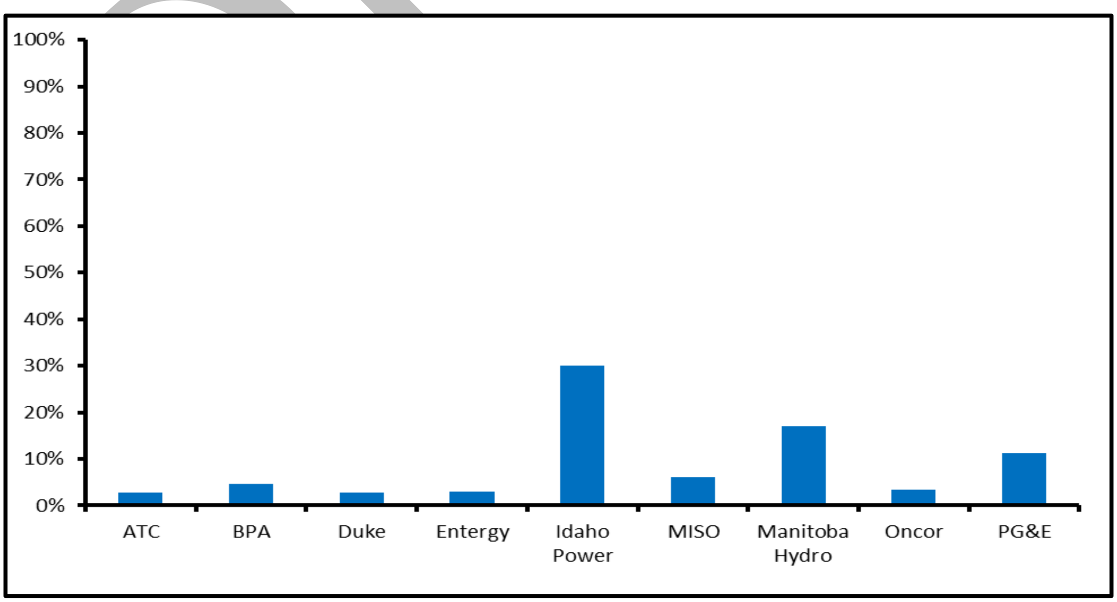
Relative impact of Key Factors on Cost of Acquiring and Installing PMUs



Average PMU Device Cost

The bar chart below compares the average PMU device cost to the average overall installed cost (cost of acquisition and installation) for each participant. The study revealed that the cost of a PMU device is usually less than 10% of the overall installed costs. In fact, more than half of the recipients indicated purchase costs of less than 5% of the overall installed costs. Idaho Power and Manitoba Hydro represent cases where the overall installed costs were comparatively low, thereby making the PMU device cost appear higher than usual.

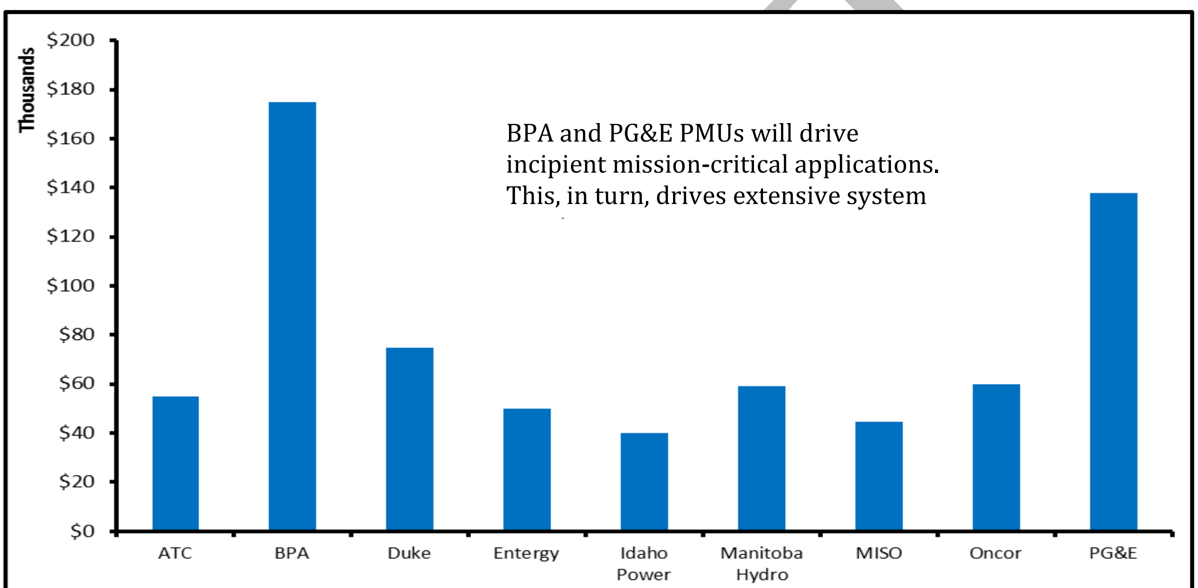
Relative Cost of PMU Devices Compared to Total Acquisition and Installation Costs



Overall Cost

The average overall installed cost per PMU, shown below, ranged from $40,000 to $180,000. The averages include cost of communications, security, labor, and other factors that each participant allocated to their PMUs. The overall installed costs are driven primarily by the intended use (both present and future) of the synchrophasor system. For instance, synchrophasor systems used for making operational decisions or that drive automatic control actions have the most extensive system requirements and thus incur the highest costs.

Overall Installed Costs per PMU



Major determinants of the overall costs were: 1) the existing infrastructure to support synchrophasor systems, and 2) the applications and capabilities associated with each synchrophasor system. As an illustrative example of the value of having synchrophasor-ready infrastructure, PG&E provided cost breakdowns for the installation of new PMUs and device upgrades. It stated that once the infrastructure is in place to support PMUs, the cost of installing additional PMUs is approximately 35% of these initial costs.

Conclusion

Installing synchrophasor systems involve a number of strategic and tactical decisions for which there is little empirical data. A DOE-sponsored study revealed four key cost factors (communications, security, labor, and equipment) and compared their qualitative impacts on overall installed cost. Ultimately, each participant's plan for synchrophasor use drove requirements, and thus the costs.
In addition, participants with prior experience with PMUs were able to leverage past experience to obtain:

- more precision in specifying goals for synchrophasor applications and hardware performance requirements
- better understanding of the cost drivers
- improved capability to trade off costs versus capabilities when deciding among options
- more cost-effective and efficient approaches to crew selection and training for PMU installations.

Sharing information through the North American SynchroPhasor Initiative and other forums served to improve practices across the industry for assessing synchrophasor requirements, developing procurement specifications, installing and commissioning PMUs, and validating PMU data.

9) Hands-on PMU installation in the field (pending)

Definitions – PMU, multi-function PMU, stuff that acts like PMUs (DFR, DDR, Fnet)
Installation steps
PMU Installation

References:

- NASPI PRSVTT – Guide for Installation of Multi-function Phasor Measurement Units (10/14) https://www.naspi.org/File.aspx?fileID=1327

10) GPS installation (pending)

Why PMUs need universal timing source for synch (cite relevant standards)
GPS – what kind of GPS devices to use (e.g., specific specs or capabilities? Can I buy this at Walmart or does it need special capabilities?); relevant technical standard or spec
Embedded v. external GPS?
How to connect GPS unit to PMU
GPS vulnerabilities (ways to lose the connection or good data)

- Cite to NASPI 10/xx session on GPS
- Spoofing at substation or satellite
- Geomagnetic interference
- Need for back-up timing sources; source options

References:

– https://www.selinc.com/TheSynchrophasorReport.aspx?id=106437

11) PMU commissioning (pending)

Topics

- How do you tell it's working
- Troubleshooting
- Applications for testing
- GPA PMU connection tester (https://pmuconnectiontester.codeplex.com/)
- Other tools?

References

12) Identifying and Naming PMUs

Consistent PMU identification and naming is essential for PMU data to be delivered and tracked effectively across a multi-owner synchrophasor system. Several reliability coordinators have developed relatively similar PMU naming conventions. Many of the regional synchrophasor systems use a PMU Registry to collect and store information on the PMUs sharing information within that system. A new PMU owner should check with its regional entity to find the latest PMU naming instructions.

References:

- MISO, "Updated PMU Naming Convention," July 31, 2012, at https://www.naspi.org/File.aspx?fileID=1322
- D. Brancaccio, April 27, 2012, "PMU Identification Numbers: Unique 16-Bit Identifiers Assigned to the PMU Registry," (PDF 2,714KB)

13) Communications system requirements – Jim McNierney (NYISO)

What are the communications systems characteristics and requirements for synchrophasor data systems?

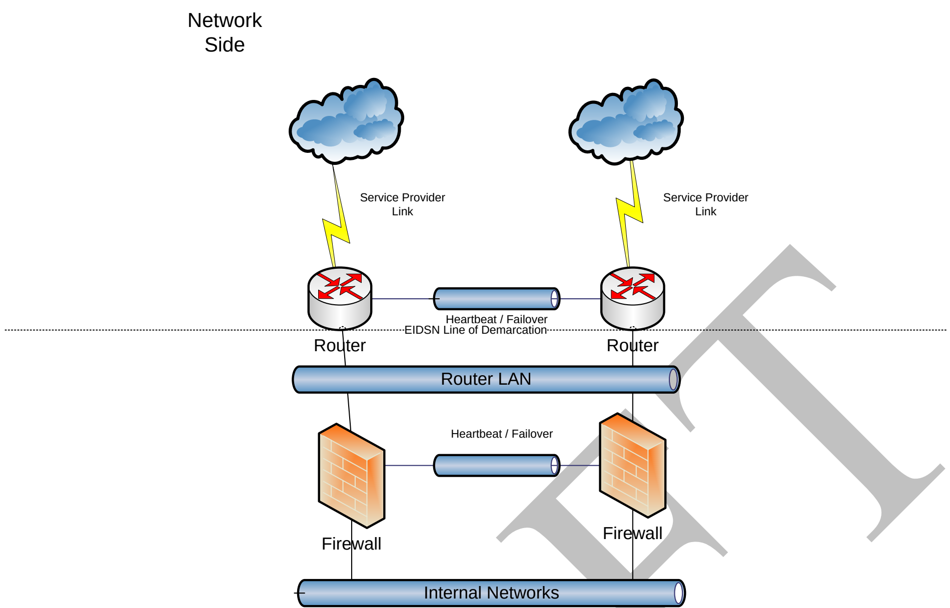
As with any communication network, the network design needs to account for the needs of the applications that the network will be supporting. The individual requirements must take into account both the exchange and collection of the synchrophasor data and / or user based sessions that will be running across it.

With Synchrophasor data, the characteristics that are most important to consider during the design phase are both the sample rate and the sample size (# of signals that will be collected at each endpoint). There are several bandwidth estimation tools available from vendors and researchers that assist with the sizing of the circuits based on the # and types of signals that are being collected and the sample rate that will be applied at the source device. Today, the most common sample rate is 30 samples per second but can range between 30 to 120 samples per second.

The applications most commonly deployed today are basic visualization packages which carry a higher tolerance for latency than applications that might have some kind of command or control capabilities. Latency is generally defined as the time between when the measurement is taken or calculated in the field to when the data is available for use by the applications within control centers. Future application needs will likely dictate the need for much tighter controls on latency and data handling. If there is a deployment of middleware in the foreseeable future, those application functions would also need to be accounted for within the design of the network.

The most common topology and networking technologies deployed in the US today is a fully meshed network running on MPLS (Multiprotocol Label Switching). The design for these networks varies based on the need for redundancy / resiliency by the organization/s that will be deploying the network. Included below is a sample configuration of a dual-redundant network connection from an individual company (or nodal) perspective:

Standard Configuration for WAN – Node Perspective



One excellent example of networking requirements specific to the delivery of data in support of WAMS (Wide Area Monitoring Systems) is a paper that was produced by David E. Bakken, Anjan Bose, Carl H. Hauser, Edmond O. Schweitzer III, David E. Whitehead, and Gregary C. Zweigle called "Smart Generation and Transmission with Coherent, Real-Time Data." An excerpt of this document is below.

- **Requirement 1:** Hard, end-to-end (E2E) guarantees must be provided over an entire grid. If the guarantees are soft or non-existent, then it is foolish to build protection and control applications that depend on the data delivery. The guarantees must thus be deterministic: met unless the system's design criteria have been violated (e.g., traffic amount, number of failures, and severity of cyber-attack).

- **Requirement 2:** WAMS-DD must have a long-lifetime and thus be designed with future-proofing in mind. This is crucial in order to have its costs amortized over many projects, utilities, grids, etc. The goal of NASPInet, for example, is to last at least 30 years.

- **Requirement 3:** Multicast (one-to-many) is the normal mode of communications, not point-to-point. Increasingly, a given sensor value is needed by multiple power applications.

- **Requirement 4:** End-to-end guarantees must be provided for a wide range of QoS+. Data delivery for the gris is not "one size fits all".. For example, to provide very low latencies, very high rates, and very high criticality/availability to all applications would be prohibitively expensive. Fortunately, many applications do not require these stringent guarantees, but their less stringent requirements must nevertheless be met.

Examples of the wide ranges that must be provided follow:

- Latency & Rate: ten milliseconds or less up to seconds (or hours or days for bulk transfer traffic); .001 Hz to 720 Hz or more
- Criticality / Availability: IntelliGrid recommends five levels of availability of data, from Ultra to Medium.
- Cyber-security: Support a range of tradeoffs of encryption strength compared to delay induced and resources consumed.

- **Requirement 5:** Some merging and future SIPS, transient stability, and control applications require ultra-low latencies, delivered (one-way) on the order of a half or full power cycle (8-16 msec in the US) over hundreds of miles and possibly across most of a grid. Thus any forwarding protocols should not add more than a millisecond or two of latency (through all forwarding hops) on top of the speed of light in the underlying communication medium, which is roughly 100/miles/msec.

  These latencies must be provided in a way that is predictable, and guaranteed for each update message, not a much weaker aggregate guarantee over longer periods of time, applications, and locations such as provided by Mutiprotocol label switching (MPLS) technology [RFC-3031]. Each sensor update needs to arrive within its required guaranteed deadline… virtually all technologies widely deployed in today's best effort internet do not provide such per-packet guarantees.

Who runs these systems?

In the US, there are a variety of network "owners." Synchrophasor technology has been deployed at the individual utility, Transmission Owner and at Regional Transmission Owner organizations. Today, some organizations will own and operate the networking infrastructure, but the majority of large networks servicing a large number of PMU deployments are operated by established telecommunication service providers. The network "owner" organizations may choose to play a role in the operations of the network or outsource that aspect of the network to the service provider/s.

Do these things

Since latency is a key element in making sure the applications are going to perform reliably, negotiations with any service provider should focus on this element in the contracting phase. A tight SLA coupled with an "opt-out" provision would ensure (to the best of all parties' ability) that the expectation for latency is accounted for in the provisioning of the circuits that make up the network. Providing for a leased line private network over using the public Internet is desirable because of the deterministic characteristics of a private network.

Providing for encryption of the data is also a very important element in a lot of the larger networks today (those that are operated by third party service providers). The operating entity that is provisioning the network should account for encryption within its design and its operation to protect the data while in transit. The types of encryption and the PKI principles put into place for maintenance varies today. For entities that require a tighter control on this aspect of the infrastructure, might very well opt to manage the encryption keys themselves rather than contract that portion of the security infrastructure out to a service provider.

Having replacement hardware on site or a contractual SLA for hardware failures is good insurance to have in a case where mean time to repair in the event of hardware failures needs to be minimized.

Don't do these dumb things

Don't assume any contracted element of the network is in place. Test your failover scenarios (in a contracted network, work with the service provider). If the hardware is contracted for (i.e. Routers or Switches) as well, you will need to make sure that service provider can perform some hardware testing and provide you with the results.

References:

- http://tcipg.org/sites/default/files/papers/2010_Bakken_Bose_Hauser_et_al_techreport.pdf
- B. Braden et al., NASPI "2014 Survey of Synchrophasor System Networks – Results and Findings" (PDF 531KB)
- P. Myrda & S. Sternfeld, December 201, "Smart Grid Information Sharing Webcast: Synchrophasor Communications Infrastructure" (PDF 520KB).
- NASPI March 2015 PMU locations - map of PMUs with synchrophasor data flows in North America (JPG format). If you would like to use these images in research papers, articles, or journals please contact Teresa Carlon.
- ERCOT, "ERCOT Synchrophasor Communications Handbook, V 1.1," July 17, 2015, at http://www.ercot.com/content/wcm/key_documents_lists/27294/ERCOT_Synchrophasor_Communication_handbook_v1.1_07172015.pdf -- includes network description
-

14) Cyber-security – Tony Johnson (SCE)

Standards and Guides
There are several technical standards and guides that identify good cyber security practices. Additionally many regulatory agencies have identified policies that impact utilities.
Some of the better technical standards are:

1. IEEE C37.240-2014 IEEE Standard Cybersecurity Requirements for Substation Automation, Protection, and Control System
2. ANSI INCITS 359-2004 American National Standards for Information Technology - - Role Based Access Control
3. IEC 632351, Power systems management and associated information exchange – Data and communication security
4. IEEE Std. 1686, IEEE Standard for Intelligent Electronic Devices Cybersecurity Capabilities
5. IEEE Std. 1711, IEEE Trial-Use Standard for a Cryptographic Protocol for Cybersecurity of Substation Serial Links
6. IEEE Std. 1402, IEEE Guide for Electric Power Substation Physical and Electronic Security
7. NISTIR 7628, Guidelines for Smart Grid Cybersecurity: Vol. 1, Smart Grid Cyber Security Strategy, Architecture, and High-Level Requirements.

Government Regulations

1. NERC CIP, Critical Infrastructure Protection
2. EU COM(206) 786 "European Programme for Critical Infrastructure Protection" (EPCIP)

NERC
The North American Electric Reliability Corporation (NERC) has been certified as the Electric Reliability Organization by the Federal Energy Regulatory Commission (FERC). NERC has created the Critical Infrastructure Protection (CIP) Standards to provide minimum requirements for Cyber Security. The NERC CIP Version 5 standards will go into effect in April of 2016.

Bulk Electric System
A simple Bulk Electric System (BES) definition.
"All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy."[2]

BES Cyber System
NERC CIP Version 5 has moved away from the classification of individual assets to the term BES Cyber System. A simple view of this would be that the BES Cyber System is a grouping of Critical Cyber Assets as defined in the earlier versions of NERC CIP. One critical component of a BES Cyber System is the impact on the real time operation of the

[2] Note: For official language please review actual NERC definition document. This definition is for purposes of this discussion only.

BES. Real time for the purposes of this regulation is if the system would have an impact on the BES within 15 minutes.

NERC Critical Infrastructure Protection (CIP)

CIP – 002-5.1 Cyber Security – BES Cyber System Categorization

To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.[3]

CIP – 003-5 Cyber Security – Security Management Controls

To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.[4]

CIP – 004-5.1 Cyber Security – Personnel & Training

To minimize the risk against compromise that could lead to misoperation or instability in the BES from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES Cyber Systems.[5]

CIP – 005-5 – Cyber Security – Electronic Security Perimeter(s)

To manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES. [6]

CIP – 006-5 – Cyber Security – Physical Security of BES Cyber Systems

To manage physical access to BES Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.[7]

CIP – 007-5 – Cyber Security – Systems Security Management

To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.[8]

CIP – 008-5 – Cyber Security – Incident Reporting and Response Planning

To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.[9]

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[3] From NERC CIP 002-5.1 p161
[4] From NERC CIP 003-5 p206
[5] From NERC CIP 004-5.1 p275
[6] From NERC CIP 005-5 p381
[7] From NERC CIP 006-5 p411
[8] From NERC CIP 007-5 p508

CIP – 009-5 – Cyber Security – Recovery Plans for BES Cyber Systems

To recover reliability functions performed by BES Cyber Systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the BES. [10]

CIP – 010-1 – Cyber Security – Configuration Change Management and Vulnerability Assessments

To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability in the BES.[11]

CIP – 011-1 – Cyber Security – Information Protection

To prevent unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.[12]

CIP – 014-1 – Physical Security

To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.[13]

Confidentiality, Integrity, and Availability[14]

In general information security practices the order of importance is Confidentiality, Integrity, and then Availability. It is generally considered more important to protect the information from unwanted exposure than to have the data available. However, when these concepts are applied to control systems the order is somewhat different. Data availability is critical with almost equal importance given to data integrity (that the data is from the expected source). Data confidentiality is of a lower importance in these applications.

Confidentiality

In information security, confidentiality "is the property, that information is not made available or disclosed to unauthorized individuals, entities, or processes" (Excerpt ISO27000).

Integrity

In information security, data integrity means maintaining and assuring the accuracy and completeness of data over its entire life-cycle. This means that data cannot be modified in an unauthorized or undetected manner. This is not the same thing as referential integrity in databases, although it can be viewed as a special case of consistency as understood in

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[9] From NERC CIP 008-5 p629
[10] From NERC CIP 009-5 p656
[11] From NERC CIP 010-1 p709
[12] From NERC CIP 011-1 p787
[13] From NERC CIP 014 -1 p824 (note not part of Cyber security requirements)
[14] Definitions from https://en.wikipedia.org/wiki/Information_security

the classic ACID model of transaction processing. Information security systems typically provide message integrity in addition to data confidentiality.

Availability

For any information system to serve its purpose, the information must be available when it is needed. This means that the computing systems used to store and process the information, the security controls used to protect it, and the communication channels used to access it must be functioning correctly. High availability systems aim to remain available at all times, preventing service disruptions due to power outages, hardware failures, and system upgrades. Ensuring availability also involves preventing denial-of-service attacks, such as a flood of incoming messages to the target system essentially forcing it to shut down.

References:

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15) Phasor data concentrator -- ?

Topics

- Functions
- Performance requirements
- Where to put them
- Commercially available PDCs
- Hardware v. software PDCs
- References
- Hardware v. software PDCs
- PDC

References and further information

- PDC time alignment -- https://www.selinc.com/TheSynchrophasorReport.aspx?id=102815

16) Relevant NERC standards – Ryan Quint

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. One of NERC's many roles is to develop and enforce Reliability Standards using an industry-driven, ANSI-accredited process that ensures transparent and open access to all persons who are directly and materially affected by the reliability of the North American bulk power system. The NERC Reliability Standards define reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities. The Reliability Functional Model defines the functions that need to be performed to ensure the Bulk Electric System operates reliably and is the foundation upon which the Reliability Standards are based.

As synchrophasor technology, infrastructure, and applications continue to mature, the equipment and data provided by PMUs can and should be utilized to meet NERC Reliability Standards where appropriate. While there are currently no NERC Reliability Standards mandating the use of synchronized phasor measurements from PMUs, a handful of these standards can effectively be met using synchrophasor data from PMUs. Table XXX identifies the NERC Reliability Standards where synchrophasor technology is pervading into common business practice such that it can be used to meet these standards effectively; this section does not provide a comprehensive view of all NERC standards and how PMUs can be applied.

Standard Number	Title	Status
BAL-003-1	Frequency Response and Frequency Bias Setting	Subject to Enforcement
FAC-001-2	Facility Interconnection Requirements	Subject to Enforcement
IRO-003-2	Reliability Coordination – Wide-Area View	Subject to Enforcement
MOD-026-1	Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	Subject to Enforcement
MOD-027-1	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	Subject to Enforcement
MOD-033-1	Steady-State and Dynamic System Model Validation	Subject to Enforcement
PRC-002-2	Disturbance Monitoring and Reporting Requirements	Approved, pending enforcement

BAL-003-1: Frequency Response and Frequency Bias Setting

BAL-003-1 requires “sufficient Frequency Response form the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value.” The standard also provides “consistent methods for measuring Frequency Response and determining Frequency Bias Setting.”

The requirements of BAL-003-1 are written such that lower resolution data such as SCADA data can be used for frequency response analysis. The reason for this is that at the Balancing Authority level, data must be captured for all interties with neighboring BAs, and currently SCADA data is the only data source with sufficient coverage. However, PMUs measure frequency during transient events in far greater detail and many utilities are expanding their PMU coverage such that PMU data can be used in the future for capturing the Frequency Response Measure (FRM).

A number of tools exist for calculating BA FRM. One example, used by NERC Staff for their Frequency Response Annual Analysis (FRAA) determinations of Interconnection Frequency Response Obligation (IFRO) and BA FROs, is an open source software tool developed by Pacific Northwest National Laboratory (PNNL). The Frequency Response Analysis Tool (FRAT), shown in Figure XXX, enables compilation of frequency excursion events and automatically calculates the required quantities for determining the FRM and all necessary points for frequency response trending. The tool also reads data directly from OSIsoft PI data historian.

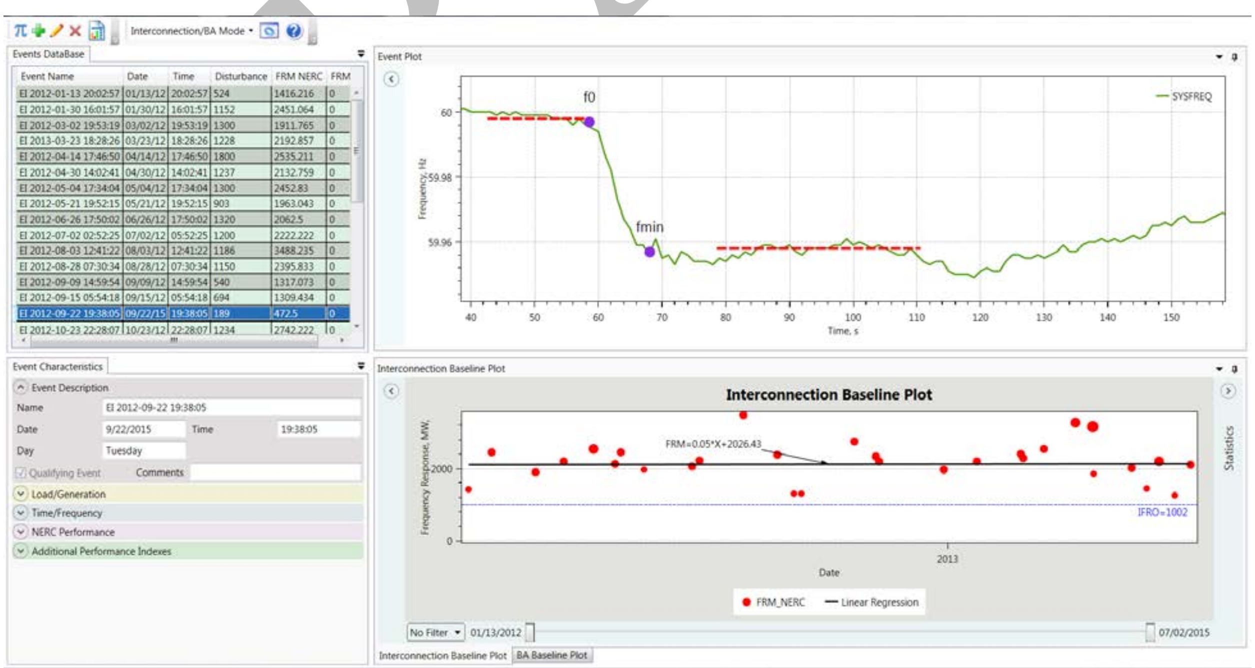


Figure XXX – Frequency Response Analysis Tool (FRAT)

FAC-001-2: Facility Interconnection Requirements

FAC-001-2 "avoid[s] adverse impacts on the reliability of the Bulk Electric System. Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information." Requirement R1 simply requires that "Transmission Owner[s] shall document Facility interconnection requirements…" And these requirements address interconnection of: 1) generation Facilities, 2) transmission Facilities, and 3) end-user Facilities.

Many utilities have realized the value in monitoring capability at the terminals of generating resources and have incorporated requirements for the installation on PMUs at new generating resource interconnections in their Facility Connection Requirements (FCR) documents and Open Access Transmission Tariffs (OATT). Examples of these utilities include:

Entity	Reference
PJM	http://www.pjm.com/documents/agreements.aspx http://www.pjm.com/documents/manuals.aspx
BPA	http://www.bpa.gov/transmission/Doing%20Business/Interconnection/Pages/default.aspx
AESO	http://www.aeso.ca/rulesprocedures/18592.html
ERCOT	http://www.ercot.com/mktrules/guides/noperating
Duke Midwest	http://www.ferc.duke-energy.com/DEW/MidwestConnection.pdf
IPC	https://www.idahopower.com/pdfs/BusinessToBusiness/facilityRequirements.pdf

IRO-003-2: Reliability Coordination – Wide-Area View

IRO-003-2 requires that each "Reliability Coordinator must have a wide-area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators." Requirement R1 focuses on monitoring "all [BES] facilities…within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area."

PMUs deployed across the grid provide high resolution monitoring capability, including measurement of voltages, phase angle differences, real and reactive power flows, and system frequency. Wide area visualization displays can provide operators with a wide-area, time synchronized view of system conditions. These conditions can include the current operating condition, transient system response due to grid disturbances, and potential contingency conditions. Not only do PMUs provide faster time synchronized data, they also provide the capability to capture phase angle differences which are indicative of system stress. The use of phase angle difference monitoring and alarming is a relatively new concept within the control room environment; however, as this application matures, utilities may be expanding use of angle monitoring and alarming. Phase angle has been shown to be an excellent indicator of system stress, particularly during light load and maintenance outage conditions where real power flows are relatively low.

Figure XXX shows an illustrative example of a wide-area visualization display that captures voltage contouring, phase angle difference monitoring, and system frequency trending within the same figure. These types of applications are continuing to mature as PMUs proliferate across the system. Advanced applications can complement visualization displays to provide the operator and real-time engineers with advanced analytics.

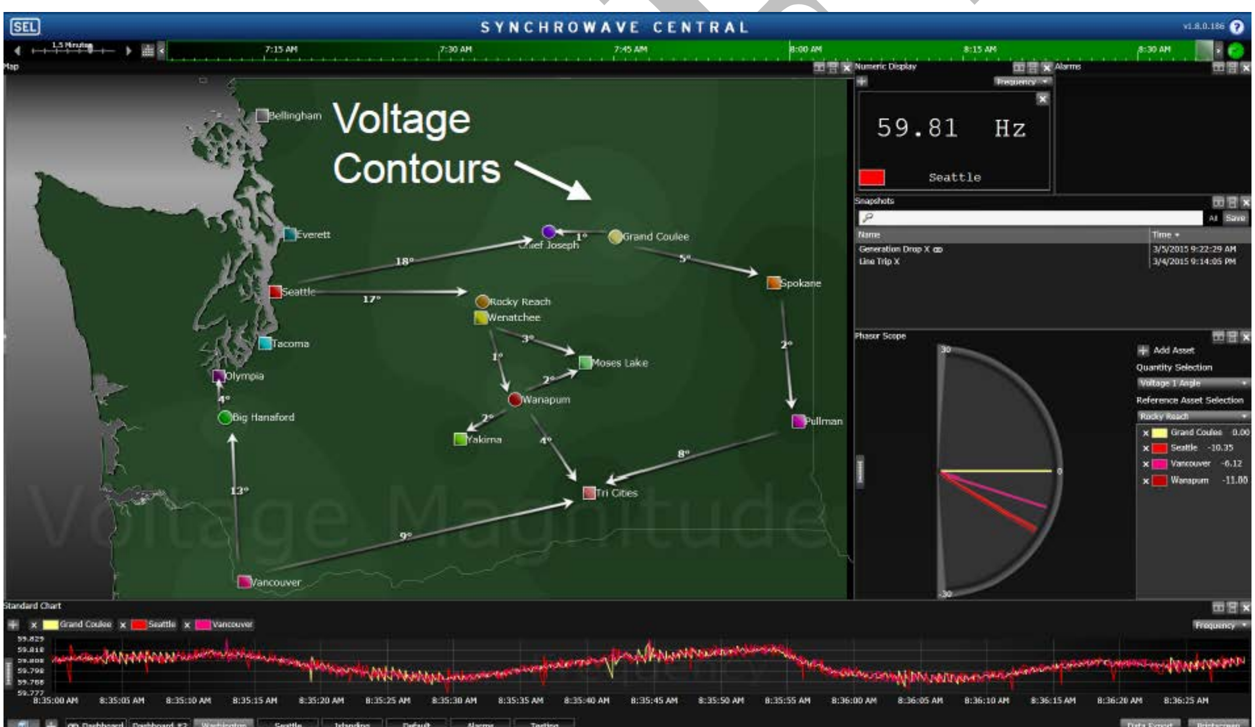


Figure XXX – Example of a Wide-Area Visualization Display

Figure XXX shows a wide-area situational awareness tool being utilized and tested by Peak Reliability Coordinator (Peak RC) for interconnection-wide awareness. The tool includes applications on:

- Islanding detection – automatic detection of system islanding
- Event detection – automated detection of grid disturbances
- Oscillation analysis – modal analysis tools for inter-area modes of oscillation

- Frequency event detection – frequency excursion alarming and visualization
- Voltage Alarming – Alarming and monitoring of bus voltage magnitudes
- Angle (Difference) Alarming – Alarming and monitoring of phasor angle difference violations
- Real and Reactive Flow – Awareness of major path flows

All the tools mentioned provide the RC with additional information to inform the System Operators of any abnormal or precursory system conditions that could lead to instability or uncontrolled cascading.

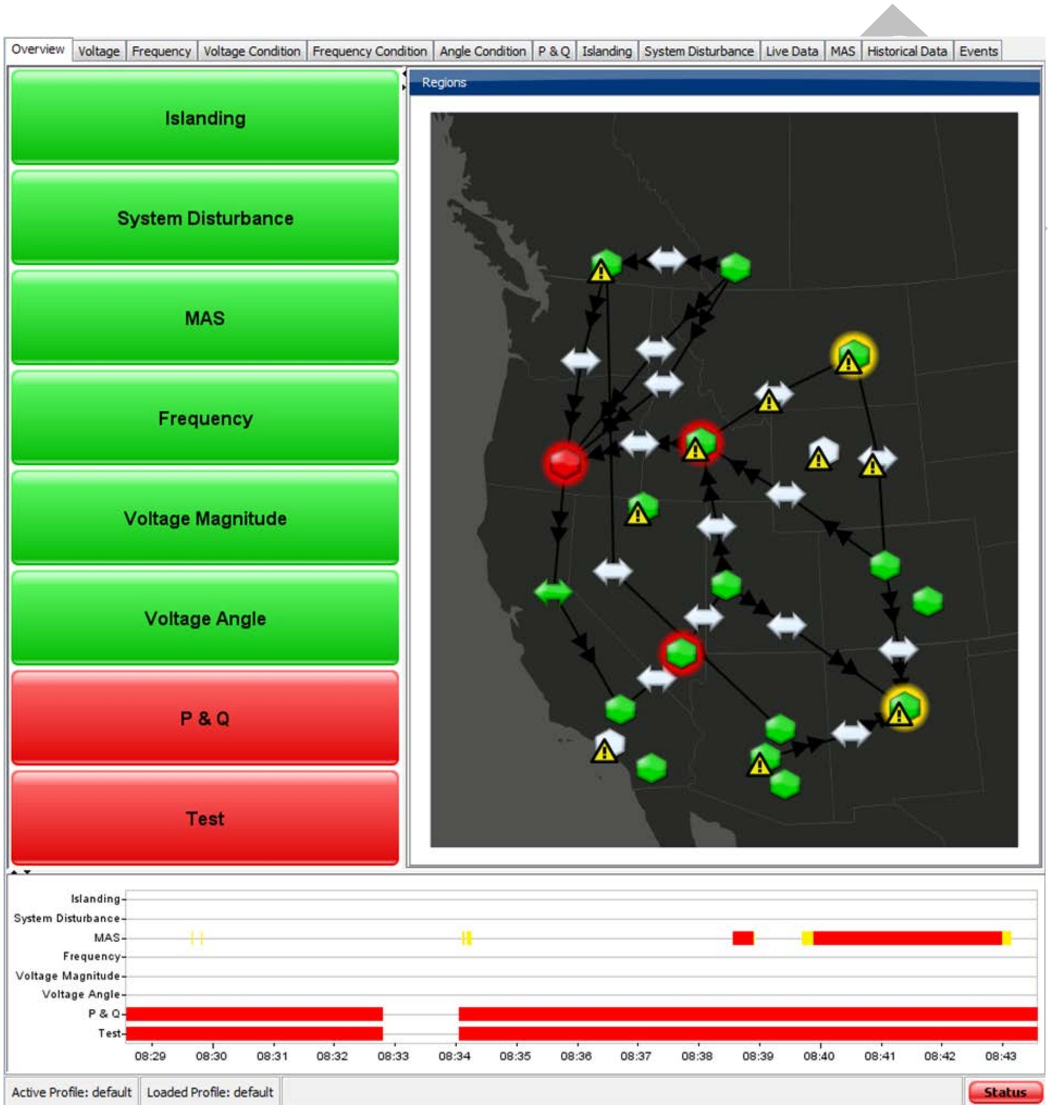


Figure XXX – Wide-Area Visualization Display & Tools

MOD-026-1 & MOD-027-1: Verification of Models

There are two NERC standards where PMU-based model verification can be applied. These include:

- **MOD-026-1:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
- **MOD-027-1:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Model verification using synchrophasor data from PMUs located at the terminals of a generating unit or point of interconnection of a power plant is one of the most mature and useful applications of PMU data[15]. Capturing online generator performance and regularly verifying that the model matches actual response has significant value for offline planning and online performance aspects of reliable operation of the bulk power system. Disturbance-based verification enables frequent verification at a significantly reduced cost to the Generator Owner. With an online disturbance-based verification approach, the generating unit may not have to be removed from service for offline testing. Furthermore, accurate generator modeling directly relates to more accurate calculation of system operating limits in the planning and operations horizons.

Figure XXX shows the process for power plant model validation. A Phasor Measurement Unit is placed at the Point of Interconnection (POI) of the power plant with the bulk power system. Note that the PMU can also be placed on individual units at the high or low side of their generator step up (GSU) transformer, which is preferred for individual unit performance verification. The PMU records the bus voltage magnitude and phase angle, bus frequency, and plant (or unit) real and reactive power outputs. In the simulation tools, the bus frequency and voltage magnitude are played-back into a simplified model and the units can be tested for their actual response (blue) as compared with the modeled response (red). Figure XXX shows an excitation system model pre- and post-verification using PMU data with tuning of identified incorrect parameters.

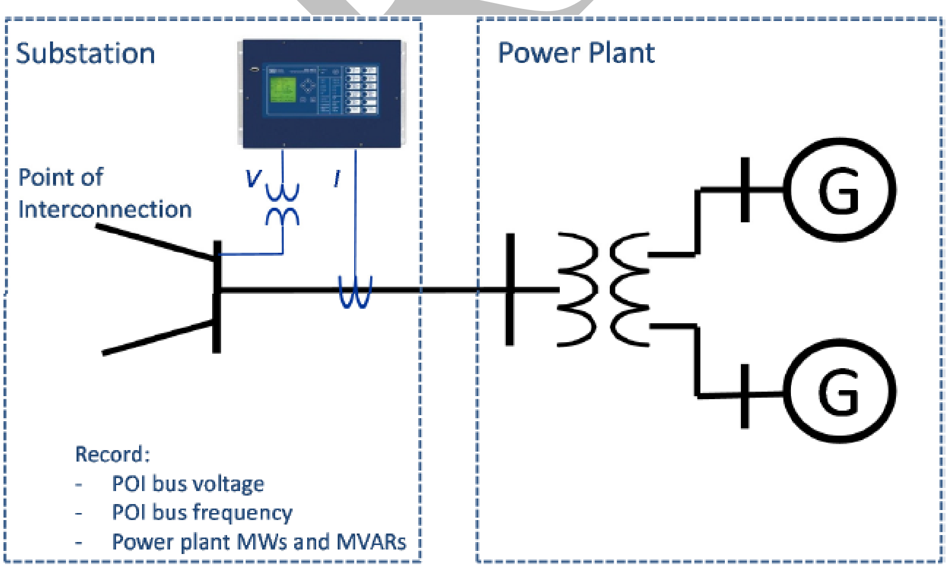


Figure XXX – PMU Monitoring for Power Plant Model Verification

[15] NASPI, "Model Validation Using Synchrophasor Data," https://www.naspi.org/documents.

Model verification using PMU data can be applied to MOD-026 and MOD-027. MOD-26 focuses on the excitation system and volt/var controls; MOD-027 focuses on the turbine-governor and load controls for active power related to speed (frequency) regulation. Figure XXX shows the model response compared with actual response pre- and post-verification.

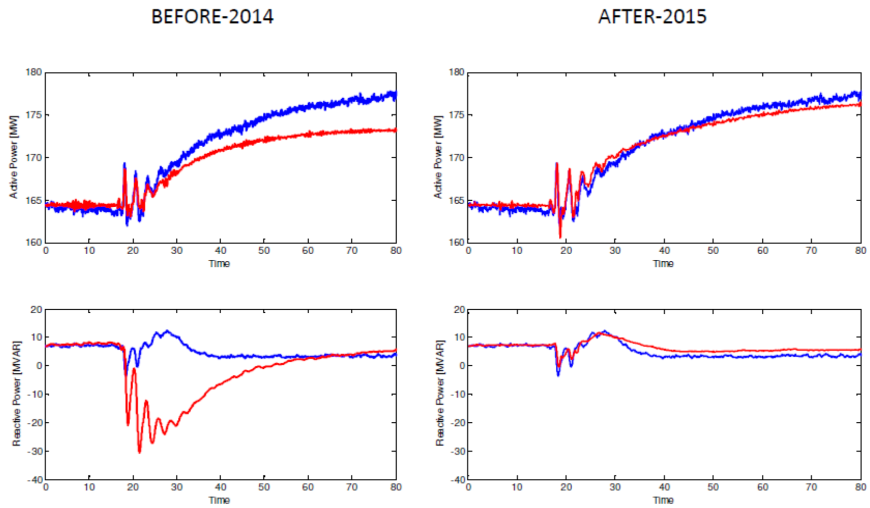


Figure XXX – Example of Pre- and Post- Verification and Calibration of Model Parameters

PMU-based model verification and performance monitoring provides an added benefit of early detection of generator control issues. Abnormal or unexpected performance of the plant can be detected quickly and resolved before they have a negative impact on the grid. Figure XXX shows examples of online generator performance not matching modeled response. In these examples, the model actually represents expected plant performance and failure within the plant equipment or controls was identified. As the figure shows, these issues can affect both the real and reactive power outputs of the plant. PMU data can effectively identify plant-level controls or equipment failures resulting in unexpected actions by the power plant.

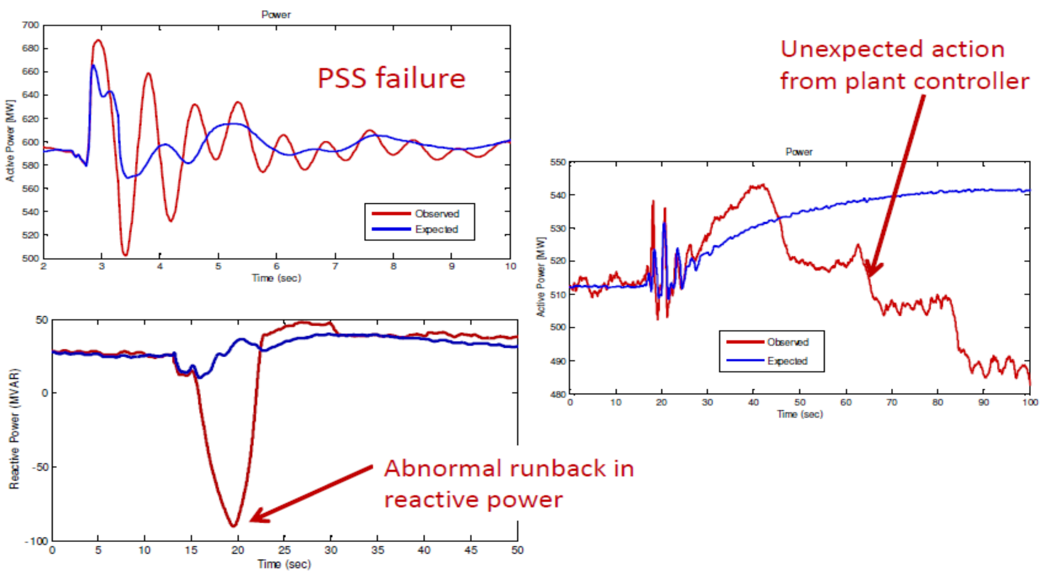


Figure XXX – Example of Plant-Level Malfunctions or Control Issues Relating to MOD-027 Performance

MOD-033-1: Steady-State and Dynamic System Model Validation

MOD-033-1 establishes "validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system." Requirement R1 requires the Planning Coordinator (PC) to implement a validation process that includes a set of attributes. Specifically, R1.2 focuses on comparison of modeled performance versus actual system performance during dynamic events.

Peak RC is actively using PMU data on major transmission paths to benchmark both their planning model (bus-branch) and operations model (node-breaker). Figure XXX shows system performance compared with model performance for a given actual and simulated event, respectively.

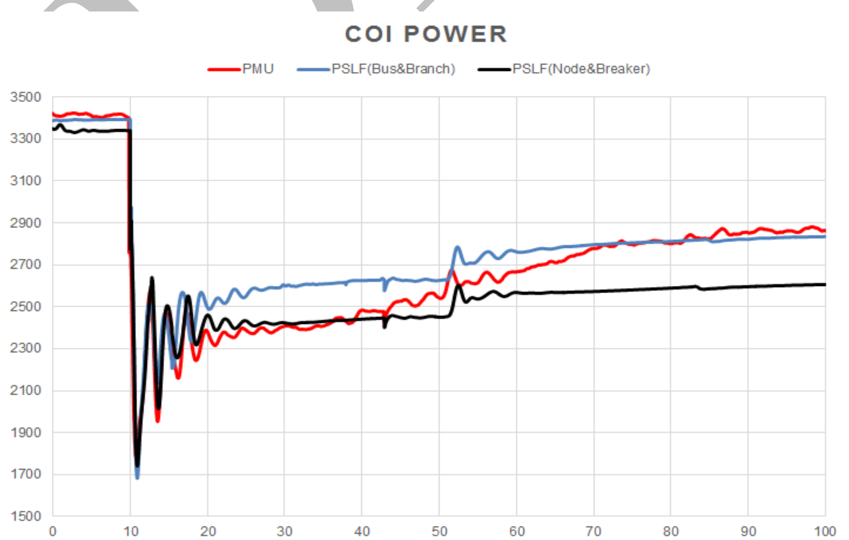


Figure XXX – Peak RC System Model Validation using PMU Data

Another example of system model validation is the use of PMUs for validating dynamic reactive resources such as STATCOMs and SVCs. New York Power Authority has used synchronized phasor measurement data to validate these types of resources after commissioning to ensure that the model matches actual response to grid disturbances. Figure XXX illustrates the playback and model comparison for a STATCOM.

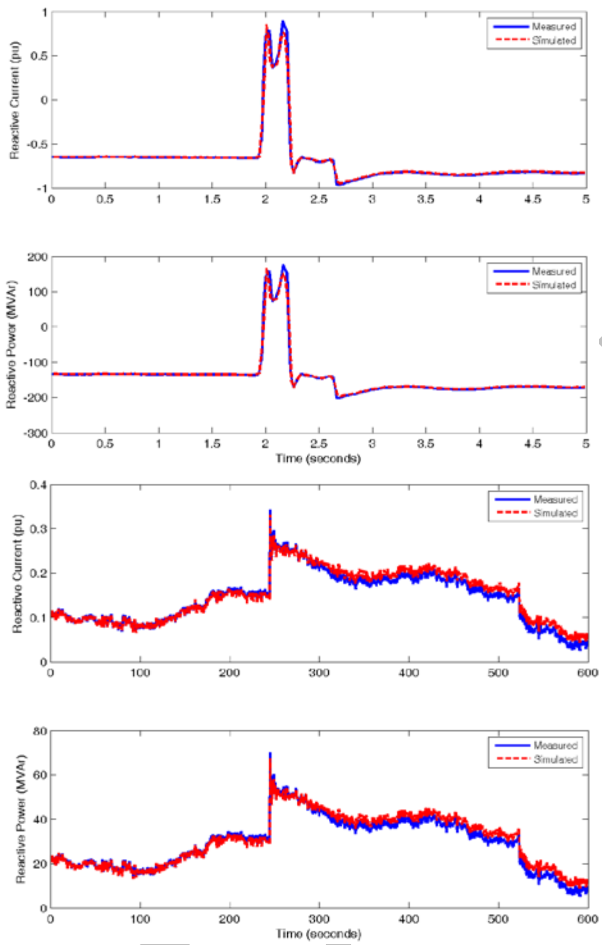


Figure XXX – STATCOM Model Validation at NYPA

PRC-002-2: Disturbance Monitoring and Reporting Requirements

PRC-002-2 was adopted by NERC Board of Trustees on November 13, 2014 and is pending regulatory approval by FERC. PRC-002-2 requires that "adequate data [is] available to facilitate analysis of Bulk Electric System (BES) Disturbances." PRC-002-2 focuses on three distinct forms of disturbance monitoring data – sequence of events recording (SER) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data. The standard and its requirements are agnostic to the type of equipment used to collect the data, so long as the equipment meets the technical specifications outlined in the requirements themselves. In fact, most if not all modern PMUs and associated wide area network infrastructure meets the requirements of PRC-002-2, and

PMUs are expected to play a critical role in capturing necessary data for event analysis for major grid disturbances moving forward. Requirement R5 outlines the locations where DDR data is required, focusing on the following major components:

- 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 System Operating Limit (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 Interconnection Reliability Operating Limit (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.

Requirements R6 and R7 specify the electrical quantities that must be either directly measured or calculated based on measurements. These apply for each of the BES Elements 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.

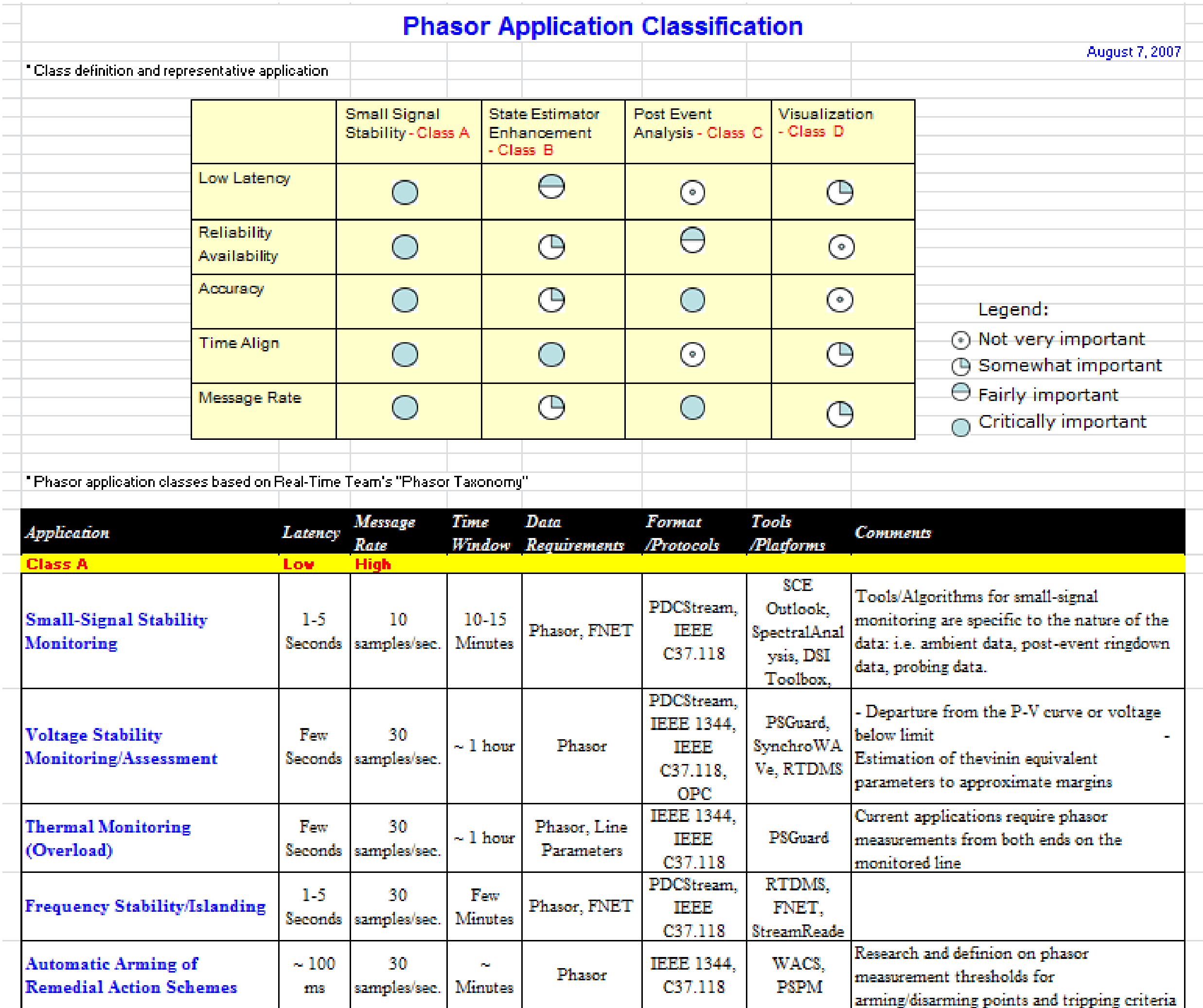
Requirement R8 requires continuous recording of DDR data while Requirement R9 defines the minimum input recording and output reporting rates of the devices used for collecting the data. Requirement R10 defines time synchronization with accuracy of +/- 2 milliseconds, which is well within the requirements set forth in IEEE C37.118.1. Requirement R11 focuses on data formatting for submitting data when requested and the timeframes for when that data is due to the requester.

17) Data classes & characteristics – Frank Tuffner

Successfully deploying and utilizing synchrophasor devices goes beyond just the physical location and installation of the synchrophasor device. The diverse application uses of synchrophasor data have different requirements and sensitivities. These requirements can influence settings on the synchrophasor device, or dictate what type of communication system is needed to get the results to the end application. Considering these requirements early prevents application failures and the need for costly upgrades at a later date.

Classification of data streams by application can obviously fall into several categories. Online or operational tools can require high data availability, with possible redundant paths to ensure higher availability values. Offline tools may not require redundant data paths, but may require extremely high accuracy in the measurements for analysis. Through two different, complementary efforts, NASPI has quantified and provided some guidance on how different applications impose different requirements on the PMU data streams. In both new synchrophasor deployments, as well as upgrades of existing deployments, these documents provide information on what types of constraints the successful deployment of PMU applications will impose on their systems. If an existing system does not have sufficient reliability or bandwidth, the installer must be aware of the required upgrades and factor that into their design. If a new system is meant to deploy operational tools, it needs to make sure the data from the PMU is reliable and accurate. Failure to account for the application requirements in both scenarios can result in poor performance, and a generally negative impression of what PMUs can provide utilities.

The original listing constructed by NASPI provides a high-level, overview version of the requirements. This table is shown in FIGXXXX1 and is available online at [REF1]. This table examines some general characteristics of PMU data streams and rates them on their importance for five application classes: feedback control, feed-forward control, visualization, post-even, and research. These different categories represented the time-frame of the data, with post-even and research typically focusing on historical data. The importance and criticality of five metrics are provided, with some numeric answers for specific applications in the subsequent table.



Phasor Application Classification

August 7, 2007

* Class definition and representative application

	Small Signal Stability - Class A	State Estimator Enhancement - Class B	Post Event Analysis - Class C	Visualization - Class D
Low Latency	Critically important	Fairly important	Not very important	Somewhat important
Reliability Availability	Critically important	Somewhat important	Fairly important	Not very important
Accuracy	Critically important	Somewhat important	Critically important	Not very important
Time Align	Critically important	Critically important	Not very important	Somewhat important
Message Rate	Critically important	Somewhat important	Critically important	Somewhat important

Legend:
- Not very important
- Somewhat important
- Fairly important
- Critically important

* Phasor application classes based on Real-Time Team's "Phasor Taxonomy"

Application	*Latency*	*Message Rate*	*Time Window*	*Data Requirements*	*Format /Protocols*	*Tools /Platforms*	*Comments*
Class A	**Low**	**High**					
Small-Signal Stability Monitoring	1-5 Seconds	10 samples/sec.	10-15 Minutes	Phasor, FNET	PDCStream, IEEE C37.118	SCE Outlook, SpectralAnalysis, DSI Toolbox,	Tools/Algorithms for small-signal monitoring are specific to the nature of the data: i.e. ambient data, post-event ringdown data, probing data.
Voltage Stability Monitoring/Assessment	Few Seconds	30 samples/sec.	~ 1 hour	Phasor	PDCStream, IEEE 1344, IEEE C37.118, OPC	PSGuard, SynchroWAVe, RTDMS	- Departure from the P-V curve or voltage below limit - Estimation of thevinin equivalent parameters to approximate margins
Thermal Monitoring (Overload)	Few Seconds	30 samples/sec.	~ 1 hour	Phasor, Line Parameters	IEEE 1344, IEEE C37.118	PSGuard	Current applications require phasor measurements from both ends on the monitored line
Frequency Stability/Islanding	1-5 Seconds	30 samples/sec.	Few Minutes	Phasor, FNET	PDCStream, IEEE C37.118	RTDMS, FNET, StreamReade	
Automatic Arming of Remedial Action Schemes	~ 100 ms	30 samples/sec.	~ Minutes	Phasor	IEEE 1344, C37.118	WACS, PSPM	Research and definion on phasor measurement thresholds for arming/disarming points and tripping criteria

[FIGXXXX1] NASPI 2008 Phasor Application Classification Table

The successful deployment of hundred more PMUs via ARRA-funded activities prompted the re-evaluation of the table from [REF1]. More concrete metrics, a greater range of characteristics, and a wider-variety of applications now need to have their requirements examined. The revitalized effort can be found at [REF2], with a snapshot of the data table shown in FIGXXXX2. The updated application table includes information on drop-out sensitivity, communication latency values, and required resolution of the data. [REF2] also includes a complementary definition document, explaining what each of the terms mean to ensure the requirements are understood.

Phasor Measurement Unit Application Data Requirements												
	PMU Measurement Parameters					Delay/Quality Parameters				Other Information		
Application	Amplitude, Angle, or Frequency Precision (p.u., degrees, mHz)	Amplitude, Angle, or Frequency Accuracy (%, absolute values)	ROCOF (Hz/s)	Frequency Range (Hz)	Time Accuracy (µs)	Measurement Transfer Time (ms)	Message Rate (Reports/sec)	Time Window (sec)	Data Loss Sensitivity (Reports or ms)	Performance Class (M/P/X/N)	Tools /Platforms	Comments
Small-Signal Stability Monitoring	0.5 degrees 0.01 Hz	TVE	STD	0.1 - 1.0 Hz	STD	50 ms	60 Reports/sec	600 seconds	10000 ms	M	EPG RTDMS, Allstom eTerra Vision	Even in real-time applications, small-signal stability often requires a long a based). Data drop outs can be tolerated and "burst data" packets can be
Voltage Stability Monitoring/Assessment	0.01 p.u. mag 0.5 degrees	TVE	STD	0.1 - 10.0 Hz	STD	500 ms	30 Reports/sec	300 seconds	10000 ms	X	EPG RTDMS, Allstom eTerra Vision	Even in real-time applications,voltage stability often requires a long analysi be tolerated and "burst data" packets can be handled by m
Thermal Monitoring (Overload)	0.5 degrees 0.1 p.u. mag	TVE	STD	0 - 0.2 Hz	STD	1000 ms	1 Report/sec	300 seconds	30 Reports	X		Significant data drop outs can be tolerated and "burst data" packets can b Thermal Monitoring (Overload) is primarily a function of fundamental fr
Frequency Stability/Islanding	0.5 degrees 0.01 Hz	TVE	STD	1.0 - 30.0 Hz	STD	50 ms	60 Reports/sec	5 seconds	1 Report	P		
Remedial Action Schemes: Automatic Arming	0.01 p.u. mag 0.5 degrees 0.01 Hz	TVE	STD	0.02 - 30.0 Hz	STD	20 ms	1 Report/sec	300 seconds	1 Report	P		RAS Arming is a low latency, steady state phenomina. The response is timing of the RAS to protect the system from inst

[FIGXXXX2] NASPI 2015 Phasor Measurement Unit Application Data Requirements

Utilizing REF1 and the more detailed REF2, the types and requirements for the different classes of PMU applications can quickly be examined. For upgrading existing deployments, this will enable the designer to know if the existing communication system and deployed PMU can handle the requirements of the new applications. For green field deployments, it provides guidance on what minimum level these applications require, to ensure things are properly sized during the requisition stage. Regardless of the deployment, some key (but not all) questions to ask relating to the application requirements and data classification are:

- What data rate does the application require? e.g., 30 frames/second, 60 frames/second, or 1 frame per 4 seconds?
- How sensitive to out-of-band interference is the application? This can help select the class of PMU, which may be useful for upgrades since existing equipment may be utilized.
- How reliable must the data stream be (how sensitive is the application to data drop outs)? If highly sensitive, higher quality channels or redundant routes may be required.
- How quickly must the data arrive at the application? If a shorter delay is required, different communication technologies, different paths, and different equipment overall may be required.
- How much data must be stored (near-term and long-term)? This can be for the direct application use, or for historic learning or comparison of the application.

Additional questions can be leveraged from the tables, especially in REF2. Cognizance of the different application requirements can help ensure the PMUs deployed will provide the results desired and maintain the safe, efficient operation of the connected power grid.

References:

[REF1] NASPI Contributors, “Phasor Application Classification”. [Online]. Available: https://www.naspi.org/File.aspx?fileID=604. August 7, 2008. Accessed October 12, 2014

[REF2] NASPI Contributors, “Phasor Measurement Application Data Requirements”. [Online]. Available: FINDALINK. March 30, 2015. Accessed Sep

18) Data quality – Ken Martin

This section introduces data quality as it relates to synchrophasor measurement data. All the terms will be defined as they are introduced, though it will be assumed that the reader will have the basic background in the technology.[16]

Synchrophasor data can include any electrical and physical quantity including voltage, current, frequency, power, breaker position, control values, alarm positions, and so on. The reason this data extends well beyond synchrophasor measurements is that it is particularly useful in analysis to have data from all aspects that can affect the power system together in a time synchronized record. The defining standards for this data allow inclusion of any data type to support more comprehensive analysis. However, the basic synchrophasor data only includes complex representation of voltage and current, frequency, and rate of change of frequency (ROCOF). So the focus of data quality is on these data types.

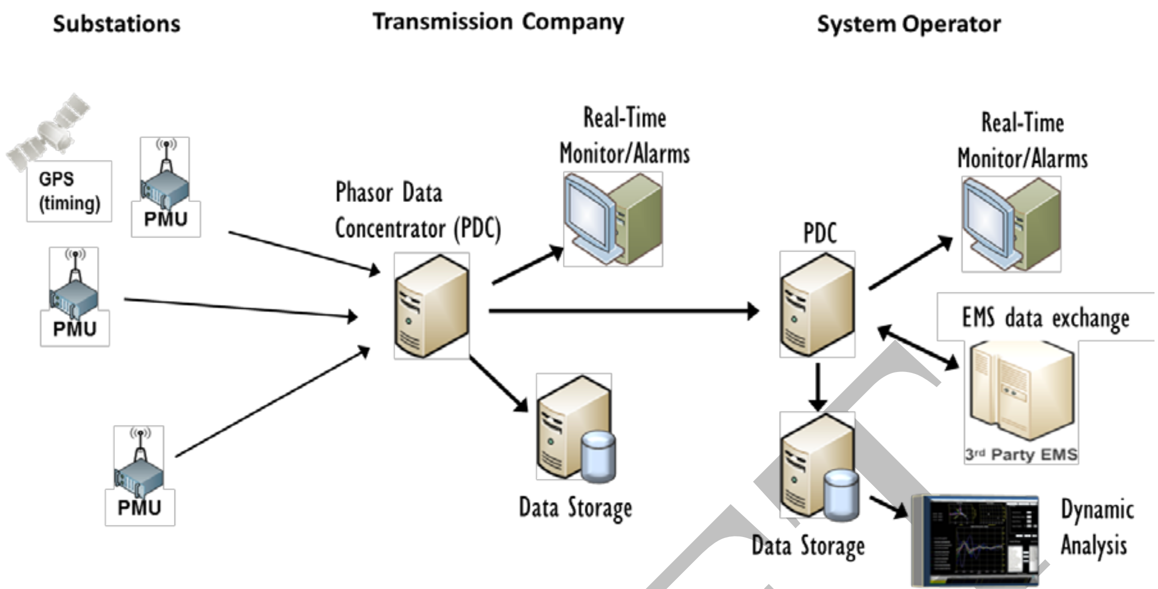
Data quality in the context of this analysis includes all aspects of the data that relate to its presence and usability. This is a very broad aspect and can be broken down into the following categories:

1. Loss of data in communication and processing systems
2. Corruption of data in communication and processing systems
3. Inaccuracy in its representation of real-world quantities
4. Lack of precision in the representation for use in the target application
5. Incorrect identification of measurements
6. Excessive and inconsistent latency

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

Typical measurement system

[16] See additional information in



The typical phasor measurement system consists of PMUs in substations to make the measurements, communications to send the data to a control center, and data gathering and processing in the control center. These are most often deployed as a hierarchy going first to the transmission owner who provides the facilities and maintains them, and then on to a regional or system operator. Another level may include higher level oversight or control functions.

In the substation the PMU must have access to the voltage and current signals which are the basis for all measurements. The analog secondaries are usually wired directly to the PMU, though in some cases electronic transducers provide the signals. The PMU must also have a source of time that is precisely synchronized to UTC. The required precision is 5 µs or better, and it needs this precision constantly. This is usually provided by a GPS receiver, though other GNSS or synchronization systems (IEEE 1588) are becoming available. The PMU produces the synchrophasor estimates from these signals. It also provides estimates of local frequency and rate of change of frequency (ROCOF). The communication protocol can also include analog signal samples and digital indications (Boolean) for which the PMU may be equipped to process.

The PMU outputs these synchrophasor estimates along with the other data listed above as a timetagged frame of data. The timetag is the time of measurement for all the values in the frame. Data frames are sent out on a timed basis, generally at a submultiple of the nominal power system frequency. In North America, data is usually sent at 30 or 60 frames/second (fps). Data is pushed rather than polled to reduce latency and overhead.

Here is an example of the basic synchrophasor data format (from ERCOT Synchrophasor Communication Handbook, v. 1.1, July 2015):

Data format:	C37.118-2011 (recommended; C37.118-2005 required)
Buffer size	30 seconds

Data rate	30 samples/second
Sort data by	Time
Maximum PDC Wait time	1 second
Maximum PMU Latency	2 seconds
Time Base	1,000,000
Communication Protocol	TCP

Data is sent using real-time communication systems to the control center where it is collected by a phasor data concentrator (PDC). The main function of the PDC is to collect the data and align it by timetag. This creates a comprehensive picture of the power system at a given point in time. It makes the measurement just like looking at a model or simulation which is done for the whole system at incremental time steps. Another important reason to time align the data is to make the angle measurements useful. The synchrophasor angle is measured in relation to absolute time, so its position and rotation is based on the power system frequency and relation to time, not to power system quantities. To be useful, phase angles have to be related to each other. Once data is aligned by timetag, all angles in the measurement are from exactly the same moment, so system angles are found just by subtraction.

Once data is time aligned, it is sent as a frame to applications that process and use the data as well as to storage functions. Real-time applications include on-line analysis, visualization of the power system, alarms for problem alerts, and any other condition that needs to be dealt with in real-time. Automatic controls based on phasor measurements are also being developed. Archived data is used for problem resolution, system performance analysis, model validation, and system planning. It may be used in near real time or for long term studies. It is also used for simulations to test visualization and control functions.

Data is typically sent from the first control center level (the TO) to the ISO or RTO since control for real time operations is at this level. Synchrophasors allow a wide-area view of the power system that can be valuable to system operators. Data may also be sent to a security coordinator as well. Real-time data distribution between utilities is also done to help by exposing problems that could spread. For all this, robust communication systems are required. The bandwidth need is easily calculated, and requirements are fairly standard specifications.

Given all the levels of processing and communication, there are many possibilities for data loss and impairments. These are detailed in the sections below based on the outline in the introduction.

Data Loss

Loss due to communication problems

- Overruns from insufficient bandwidth – calculation & examples
- Incorrect routing – ports, connection types, communications
- PMU problems with overloaded processing

Loss in processing

- Computer overloads (processing)
- Storage overloads—space required
- Routing & security

Data Corruption
Message construction
Message fragmentation & reconstruction
Incorrect representation (integer-FP, rect-polar, order reversal, more?)

Inaccuracy
Synchrophasor, Frequency, and ROCOF measurements
Accuracy addresses whether the measurement data correctly represents the engineering quantity.

- The value represents the estimated parameter for a time instant but needs an interval of signal to make the estimate. The parameters will change over the interval, so estimate represents a kind of average value over the interval. This will limit the accuracy for some situations.
- Time errors from either the time source or within the PMU affect the accuracy of representation.
- Any translation device from the point of sensing the measured quantity to the synchrophasor estimate will limit the accuracy. This includes the PT/CT devices, auxiliary transformers, and electronic transducers if used.
- Frequency and ROCOF are secondary to the original signal and are highly subject to noise and interference.

Lack of precision
Precision in data how finely the number is determined to be. For example, is a voltage is measured to be 2 volts with a meter that only measures even volts, then the actual voltage could be 1.5 or 2.4999 and the answer is the same. The precision is only +/- 0.5 volt. If however the measurement is 2.00 volts and if the actual voltage was 1.99 or 2.01 the measurement would be 1.99 or 2.01 respectively, then the precision is .01 volts.

PMU input is the analog waveform (in the current technology development). The input is sampled by an A/D converter into digital samples which are then used for phasor estimation. if the input is scaled low so that there are very few bits that are used representing the waveform, the waveform will be distorted for the phasor estimation process. This will show up primarily as noise, but can appear as a phasor distortion, depending on the input signal characteristics. A comprehensive analysis is required to determine just how the measurement would be effected. It is sufficient to say the lack of proper scaling results in a lack of precision of the signal representation which will degrade the measurement.

Phasor measurements can be calculated in integer or floating point form. As mentioned above, if the scaling for the processing is not set right, there could be an insufficient number of significant bits in the analysis resulting in excessive noise or other distortion. Processing in floating point avoids this problem since these numbers use the same number of bits of precision for all numbers. As long as the input values are scaled with sufficient precision, the synchrophasor calculations should be precise enough to provide precise estimates.

Phasor measurements can be transmitted in integer or floating point form. Floating point can provide all the precision of the calculation results within the PMU, so will not degrade precision. Integer number form usually requires scaling from the particular engineering value. If the scaling is not set to provide most of the bits of resolution, there will be a reduction in precision from the calculated value. This is particularly true when the data is to be used for small signal and modal analysis.

Reduced precision can also occur when the data is stored. If the stored data size is minimized by some types of compression or if a limited number of bits are used, some precision will be lost. It is a tradeoff with the cost of storage, so the applications need to be analyzed to be sure they will not be adversely affected by data reduction for storage.

Incorrect identification

When received at a control center or other place the measurement will be used, it has to be identified as to the type of measurement, where it is taken, and the particular engineering quantity it represents. Measurement values are sent in some kind of block of numbers. The numbers are parsed from the data block and then identified by the order in the block, tags in the block, or some other means. 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 only observed at the control center. A thorough process to check this after installation will minimize the problem, though periodic checks are still required as occasional “small” repairs can cause changes that are overlooked.

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, on the order of 50 ms. However when there are problems with data communication and data processing equipment, it can become much larger, on the order of a few seconds.

A big problem is the setting of the phasor data concentrator (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 to wait until the data for a particular time stamp from all the PMUs is present so these measurements can be aligned together. If one is late, then the aligned group is late. The PDC is designed to limit the wait so that if one is lost it does not wait forever. The challenge is setting the PDC so it will wait the maximum reasonable time for late data but not so much as to degrade performance if data is lost. If there is more than one PDC it the data processing chain, settings of the lowest PDCs in the chain will dictate coordination of the settings and the next level, and so on. They must be carefully coordinated to prevent excessive delay for the users or excessive data loss.

The other problem with latency is 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.

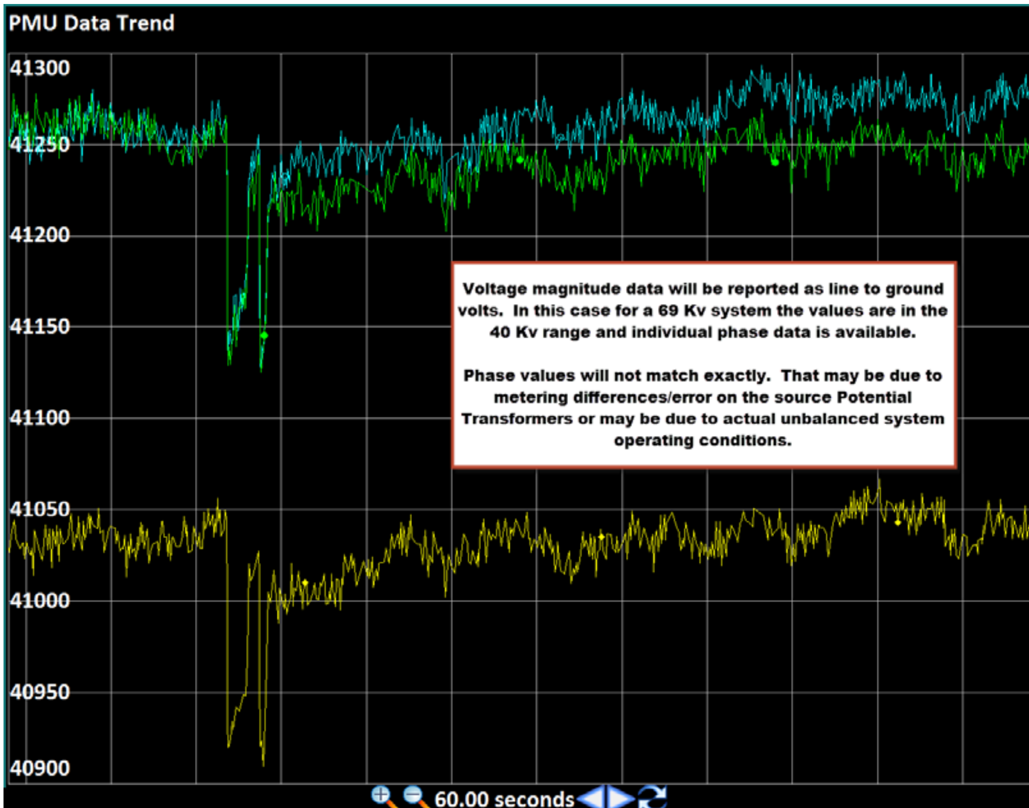
References:

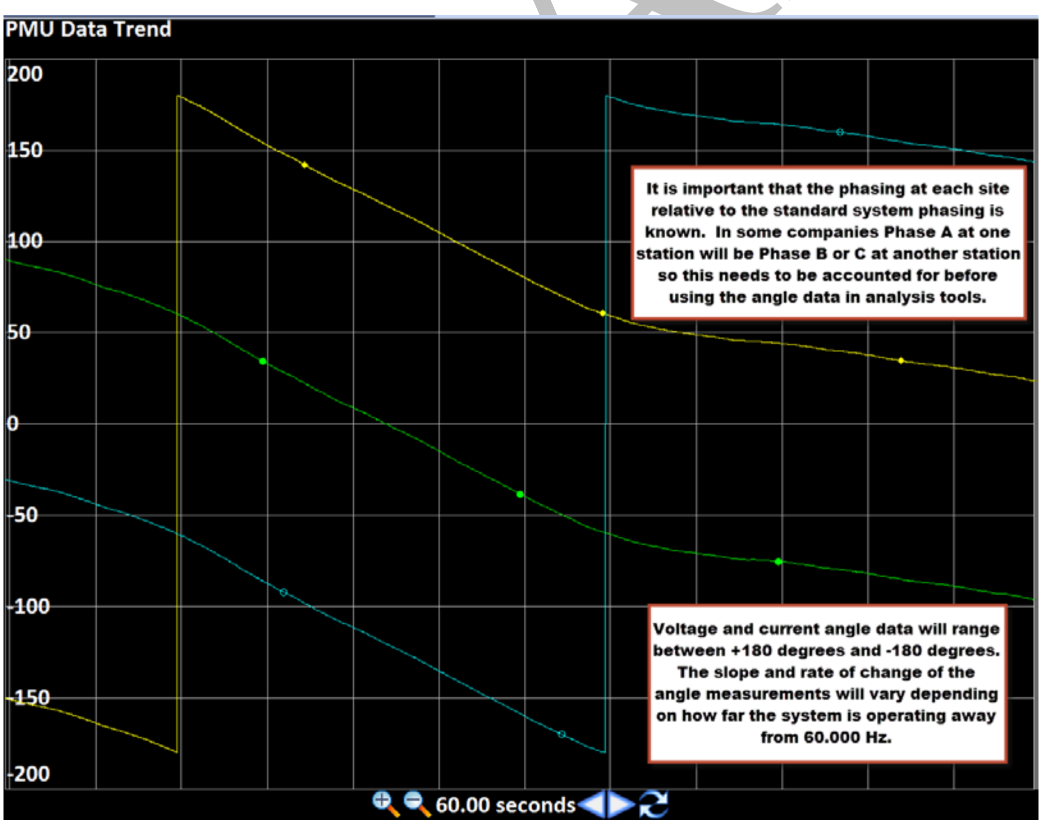
- K. Martin, "Synchrophasor Data Diagnostics: Detection & Resolution of Data Problems for Operations and Analysis," January 28, 2014, webinar recording and presentation, at https://www.electricpowergroup.net/epg_events/eventIntro.aspx?qsel=e1dJTjrtZsI
- ERCOT, "ERCOT Synchrophasor Communications Handbook, V 1.1," July 17, 2015, at http://www.ercot.com/content/wcm/key_documents_lists/27294/ERCOT_Synchrophasor_Communication_handbook_v1.1_07172015.pdf -- see data quality discussion beginning at p. 14.

19) Interpreting PMU data – Jim Kleitsch

When you first start polling and displaying synchrophasor data there are a couple things you'll notice. The first relates to the voltage values you'll be receiving. By definition the PMU provides the line to ground voltage for the facilities being monitored and provides you with a processed magnitude and angle value each scan depending on how the vendor implemented the standard. The sample plot below for voltage magnitudes is from a 69 Kv system where individual phase voltage data is being provided and the values are in the 40,000 volt range. Most vendors can provide individual phase voltage data and positive sequence data for the voltages being monitored.

Note that the three phase values in this example do not match. This can be due to differences in the metering equipment providing the data and also can be due to real system imbalances present in the grid. Trying to determine which is true is not an easy task as there's no perfect measurement available in most cases to use as a reference.

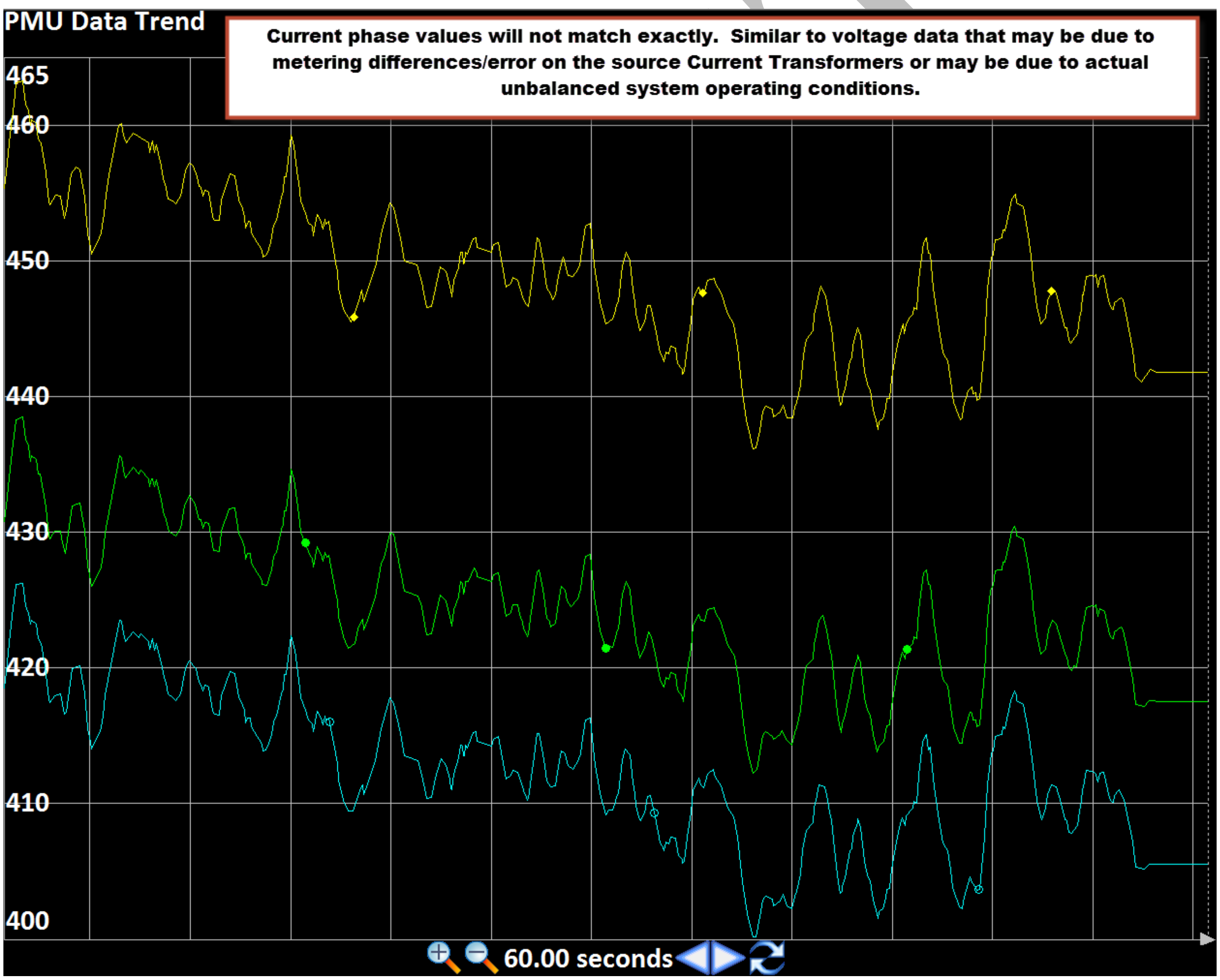

PMU Data Trend
41300
41250
41200
41150
41100
41050
41000
40950
40900
Voltage magnitude data will be reported as line to ground volts. In this case for a 69 Kv system the values are in the 40 Kv range and individual phase data is available.
Phase values will not match exactly. That may be due to metering differences/error on the source Potential Transformers or may be due to actual unbalanced system operating conditions.
60.00 seconds


PMU Data Trend
200
150
100
50
0
-50
-100
-150
-200
It is important that the phasing at each site relative to the standard system phasing is known. In some companies Phase A at one station will be Phase B or C at another station so this needs to be accounted for before using the angle data in analysis tools.
Voltage and current angle data will range between +180 degrees and -180 degrees. The slope and rate of change of the angle measurements will vary depending on how far the system is operating away from 60.000 Hz.
60.00 seconds

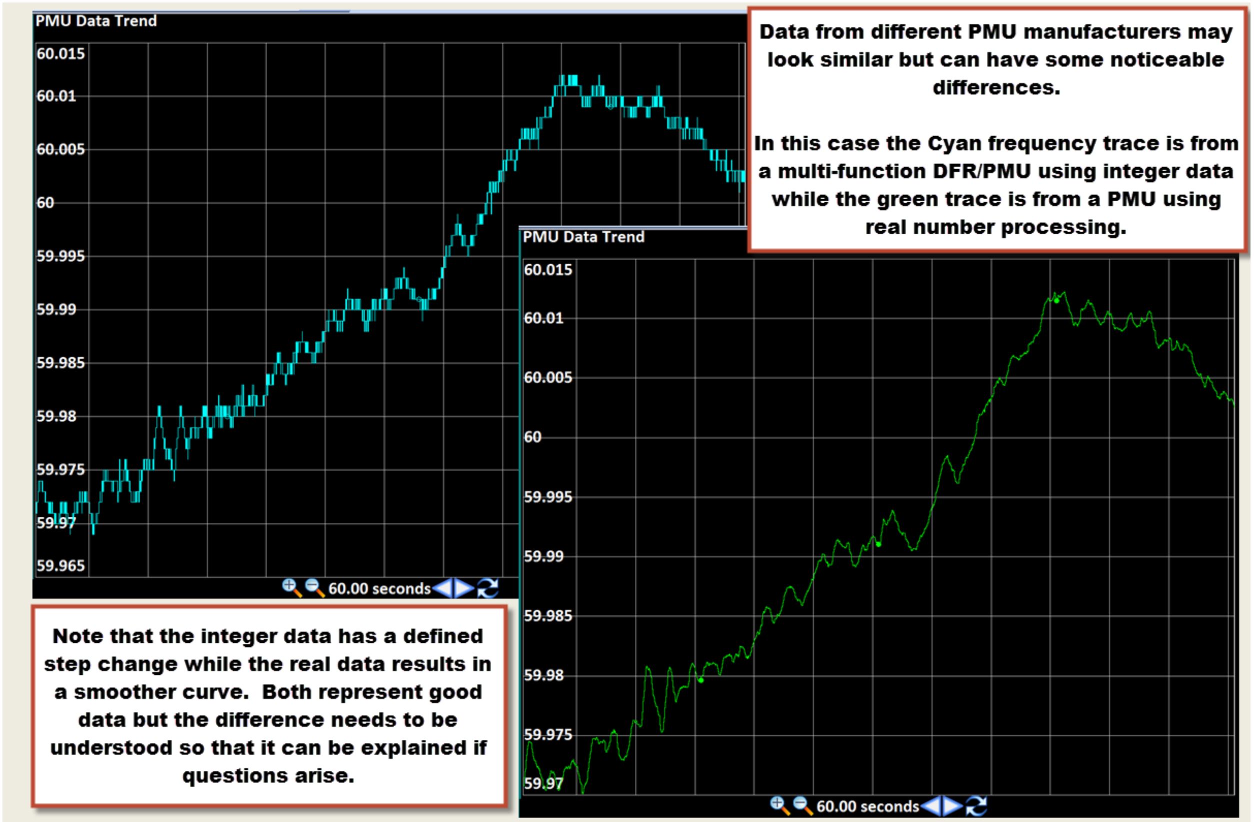
The voltage (and current) angle data is provided as a value between +180 degrees and -180 degrees. The values “jump” between these limits when they cross the thresholds as shown above. The direction of the change in the angle values is dependent on whether you’re operating above or below 60.00 Hz. The slope is dependent on how far away from 60.00 Hz the system is operating.

Displaying this data in its’ raw form does not provide much value to the real time operations group. The value of the angle data is realized when feeding it to downstream applications like islanding identification, state estimation/linear state estimator, etc…

Before using the angle data a good understanding of phasing at each site with a PMU is key. In many systems there is no consistency in phase naming, especially where companies with different conventions have merged.



Similar to voltage magnitude data, current magnitude data can also be supplied as individual phase values or derived positive sequence values. The current magnitudes are normally mismatched, again due to either metering inconsistencies or real world unbalanced operations. The above plot shows three phase current values on a 345 Kv tie line where a 30 amp difference exists between the phase readings.



Another thing you'll notice with the data is that the appearance of the data can be different for different PMU manufacturers. The plots above show frequency data for a one minute window from both a multi-function Digital fault Recorder [DFR] / PMU (the Cyan Trace) and a dedicated PMU (the green trace). The DFR based PMU uses integer processing and as such the frequency plot is comprised of small step changes. The dedicated PMU uses real number processing which results in a smother frequency curve with much smaller defined changes.

Both of these values are "good" in relation to the accuracy of the inputs but they do look different. As with any new technology, being able to understand and explain these differences is necessary to maintain confidence in the results the data feeds.

19) Model validation – Alison Silverstein & Dmitry Kosterev

Base on NASPI model val paper

20) Strategies for integrating and institutionalizing synchrophasors – Kevin Jones, PhD., Dominion Virginia Power

Synchrophasor technology is poised to shine. These time- synchronized measurements allow for precise monitoring of the vast interconnection and their high resolution sheds light on the dynamic behavior of the grid. The need for improved technologies such as phasor measurement units (PMUs) is accentuated by nationwide challenges such as aging infrastructure, flexible AC transmission systems (FACTS), and the increasing penetration levels of renewable resoruces. From a strategic perspective, there are five key dimensions to establishing a sustainable synchrophasor footprint and extract value for the business. These are standardized deployment strategies, an organizational commitment to data quality, using simple visualization tools to build trust and grow adoption, extract value using data analytics and network applications, and building a rich training program for engineers and operators alike.

This document is based on an article published in the September/October issue of the IEEE Power & Energy Magazine. The title of the original article was "Strategies for Success with Synchrophasors" and highlighted the business and technical strategies utilized by several of the leaders of synchrophasor integration in the industry. The authors of the original article were: Kevin D. Jones, Dominion Virginia Power; Edwin B. Cano, NYISO; Heng (Kevin) Chen, Electric Power Group; Fabian Robinson, PJM Interconnection; Kyle Thomas, Dominion Technical Solutions; and R. Matthew Gardner, Dominion Technical Solutions.

Organic Growth through Standardized Deployment

Over the last decade, the United States has seen substantial growth in synchrophasor deployment. While much of this growth was fueled by catalytic government grants, long term success will be found by those that can find inexpensive, non-disruptive, and efficient ways to continue to deploy synchrophasors. This can be achieved by modifying certain design standards that specify the devices that are installed or updated in a substation control house to include PMUs, PMU-enabled relays, and PDCs as part of routine production effort. These standards should involve any substation where new or routine project work is performed – resulting in the installation of hundreds of new synchrophasors across a utility's entire transmission network for fractions of a percent of total capital expenditures. Strategies like this one have the opportunity to make the number of installed PMUs from the largely structured, grant-driven, rollouts look insignificant in comparison and provide sustainable growth and updates in the future.

From the RTO perspective, other strategies can help drive standardized PMU deployment forward in an organic way. For example, requiring installation of PMUs at decidedly strategic locations such as new single unit or aggregate generator units of 100MW or greater. More generally, sites can be sought on the basis of optimal observability, locations with stability concerns, site pairs across Interconnection Reliability Operating Limit (IROL) boundaries, internal and external area ties, major generation clusters, wind and solar sites, load centers, key corridors, and locations of FACTS devices. While there are valuable applications to be implemented in all of these scenarios, the overarching goal is still to provide robust, wide-area situational awareness across the interconnection.

A Commitment to Data Quality

As synchrophasor deployment continues to proliferate through standardizations such as substation construction standards and site specific requirements, organizations have begun taking the steps necessary to operationalize their investment by making synchrophasor data available not only to real-time operations staff, but to engineering teams for off-line data analysis. While the implications of data quality vary based on the organization, the fidelity of the synchrophasor data is paramount in order for this technology to meet its potential.

Each organization has a synchrophasor footprint that may vary greatly in size and maturity. To this effect, working with partner organizations can help drive data quality metrics in a positive direction. Organizations that share PMU data can help by providing metrics and troubleshooting expertise. Even when two organizations don't share PMU data they can still mutually benefit from the exchange of lessons learned.
A commitment to high fidelity data is truly captured in the philosophy of the 'complete package' for data quality. This approach addresses the end-to-end health of the synchrophasor system – from the instrument transformers, to the PMUs, to the substation PDCs, through the fiber communications and IT transport layers, and ultimately to the central PDC. This philosophy accommodates the understanding that, even with a well-built and perfectly tuned system, there are naturally occurring levels of data loss and data quality issues that must be resolved through data conditioning. Technologies such as linear state estimator (LSE), are typically at the heart of the data conditioning strategy. The data conditioning algorithms are a crucial component of a synchrophasor data system and provide high quality synchrophasor data to end users such as engineers, operators, and network applications. Synchrophasor data is used to check for instrument transformer polarity and phase sequence reversals as well as cross-validating values with SCADA data in the EMS during both the summer and winter seasons. While vendors should work hard to design their products to be robust to data quality issues, often times the responsibility to provide good quality data to the applications still relies on the engineer to architect a system and specify algorithms that can do the job.

Visualization

Synchrophasor technology is considered to be the foundational component of improved situational awareness and wide-area monitoring systems. There is a common philosophy among the leaders in synchrophasor integration; synchrophasor data visualization should be simplistic and effective. The strategy has been to display synchrophasor data in traditional and familiar forms to drive adoption of the technology.

Data such as real-time synchrophasor data, application results, and weather data can all benefit from being displayed on a platform that visualizes the information in comfortable and familiar ways. These include superimposing data over geographical displays and electric infrastructure, customizable trends, bar charts, and oscillation mode meters.

Additionally, many agree that the value in superimposing data onto schematic one-line diagrams is quite strong as well.

The Value of Applications & Analytics

Viewing raw synchrophasor data in real-time can be an effective way to provide wide-area situational awareness. However, applications and analytics for both real-time and off-line use expand the value of synchrophasors.

Dynamic models of grid elements, such as generators, are critical for system planning analyses. Typically, these parameters are either assumed or derived from costly physical testing procedures. Therefore, validation of generator model parameters using recorded event data played back in a simulation environment is a high-value application of synchrophasor data. This technique has become increasingly common as synchrophasor technology proliferates across the power grid. This application can be used not only for generators, but also for FACTS devices such as SVCs and STATCOMS.
In addition to generators and FACTS devices, synchrophasors are often used to understand the dynamic behavior of loads. PMUs deployed at key locations in the system can monitor the behavior of various distribution system loads. This data extends existing observations of other high-resolution monitoring devices to establish parameters of a composite load model that is particularly important for modeling phenomena such as Fault-Induced Delayed Voltage Recovery (FIDVR). These techniques are becoming essential because without them, transmission planning engineers cannot account for FIDVR behavior in their studies.

Synchrophasors are now a proven tool for event detection and post-event analysis. There is a tremendous amount of operational value in knowing 'what just happened' as well as digging into post-mortem analysis to look for engineering, process, or operational improvements.

Oscillation detection and monitoring applications are mature and valuable. These applications allow engineers and operators to identify certain undesirable dynamic behavior of the grid and develop a mitigation strategy. Offline analysis of oscillations is also a valuable application for studying the characteristics of the grid in a transmission planning environment or as part of a post-mortem analysis. Many entities have found oscillation detection to be its all-star application both inside and outside of the control room because oscillations cannot be detected with legacy telemetry. In particular, organizations with wind farms have found oscillation monitoring to be supremely useful and many success stories are centered about this.

Training

As for any technology roll-out, there is tremendous value in providing training and support to, and gaining buy-in from, the full spectrum of the business. This spans from end users such as engineers and system operators to field support staff such as relay technicians that support the "nuts and bolts" of the technology. This axiom is no less valid for synchrophasor technology.

In order to foster grass-roots understanding and support for PMUs, some organizations have found success by incorporating synchrophasor related content into existing training programs such as relay technician training. The results are demonstrated in greater enthusiasm for new technologies such as synchrophasors among the technical ranks of the organizations and have the ability to foster relationships between the engineers that teach the primer modules and the up-and-coming relay technicians of the future. Additionally, searching for publicly available content and events such as webinar can provide quick, easy, and cost effective exposure to synchrophasor technology across an organization. There is also a rich community of working groups, standards teams, user's groups, etc that can help an organization begin to establish its synchrophasor presence. Lastly, vendors are often more than willing to accommodate with onsite training even in the absence of a product or license purchase. System event analyses and base line studies can also be integrated into the regular operator training to introduce analytics, alarms, and visualization.

Engineers and operators train on simulators all the time. However, these simulators are generally based on load flow simulations and therefore don't produce data that resembles the type of information provided by PMUs. Simulators and training courses for engineers and operators can be developed with the same purpose in mind using more advanced technologies such as those available in a Real-Time Digital Simulator (RTDS) machine. The simulator is a real time computing engine that the engineers can use to simulate the behavior of the electric grid in real time. Using available hardware, PMU streams from the simulation can be sent to the same visualization software that the operators might use on the real system. In this way, engineers and operators can visualize the effects of simulated events in real-time.

Conclusion

Synchrophasor technology has progressed tremendously in the eastern interconnection over the last five years. While dedicated projects to develop and deploy synchrophasor technology have been instrumental in kick-starting used and useful wide-area monitoring systems, the future relies on data quality, organic growth philosophies, business integration, and training.

21) Debunking some synchrophasor myths – Kevin Jones, PhD., Dominion Virginia Power

This document aims to highlight some of the misinformation surrounding synchrophasor technology with the hope that with a clearer picture of the what, how, and why of synchrophasors, anyone new to the field will be able to avoid many unnecessary road blocks associated with the integration and institutionalization of the technology within their respective organizations. Below are common misunderstandings associated with synchrophasors and synchrophasor deployment along with explanations as to why the statements are incorrect. Myths are written as if they are quotations using " " and italics and the explanations follow in plain text. This document is based directly on a presentation given by the author at a SERC RMWG Meeting in Atlanta, GA on July 29, 2014 entitled *Mythbusters Review of Synchrophasors (with Cultural References)* and an expanded version of the same presentation given by R. Matthew Gardner, Ph.D. at the CIGRE Grid of the Future Tutorial on Synchrophasors in Houston, TX on October 19, 2014.

Some General Myths about PMUs and Synchrophasors

"A synchrophasor is a PMU."

It is very common to hear even deeply technical individuals speak of synchrophasors and PMUs as if there were the same thing. However, the distinction between synchrophasors and PMUs is an important one. A PMU (Phasor Measurement Unit) is a device; a synchrophasor is a measured (although some would rightly argue estimated) value. To go one step further, a synchrophasor is a value that is measured/estimated by a PMU device. Therefore, to say that a PMU and a synchrophasor are the same thing is like saying that voltage and a volt-meter are the same thing. Recalling the word analogies used in standardized testing – like a multi-meter is to voltage/current/resistance/etc, a PMU is to a synchrophasor.

"PMUs are just fast SCADA."

It is also very common for individuals to over simplify the difference between PMU measurements and SCADA based measurements. Often PMU measurements are said to simply be 'fast SCADA'. However, this is a vast over simplification – one that should not be committed even when trying to explain a complex topic like synchrophasors to someone less informed on the topic. There are many dimensions in which PMUs differ from SCADA. These include: 1) PMUs utilize GPS time synchronization and SCADA does not, 2) PMUs measure at a much higher frame rate than SCADA RTUs (that's where the myth comes from), and 3) most importantly, PMUs measure a fundamentally different value – the synchrophasor, which is a complex/vector quantity that represents both the magnitude and the angle of the sinusoids at the metering point and SCADA measurements only measure scalar values. There are many other differences as well but these are the key differences.

"It's spelled 'phaser'."

Just don't. Please.

"Raw phasor angles are stationary."

Much of our training as power system engineers has taught us to think of angles as unchanging quantities as they are in a power flow. And while this definition can be helpful for computation, the way that we measure phase angles in a real power system using PMUs results in slightly different behavior. Representing a sinusoid with just a magnitude and an angle to get a Phasor requires assuming that the frequency is constant. In a real power system, this is not true. Frequency fluctuates constantly due to an ever-changing system loading and the subsequent generator response. Without diving into too much detail of the Phasor estimation algorithm, we can infer that when the frequency is steady at 60Hz, the reported angle from the PMU will remain constant. However, the Phasor measurement will rotate in the complex plane for off nominal frequency – one direction for greater than 60Hz and one direction for less than 60Hz. Phase angle referencing helps to alleviate this problem and yield relative phase angles which are constant during quasi-steady state conditions.

"PMUs are a brand new technology."

The concept of using phasors to describe sinusoids has been around for over 100 years and the concept of using phasors to understand the complete behavior of AC circuits has been around nearly as long. As far as the technology goes, the first PMUs were developed at Virginia Tech in the late 1980s. The first vendor to produce PMUs was Macrodyne. Precursor technologies include SCADA, Digital Relaying, and GPS technology. The likely reason for this misconception is that except for early adopters in progressive utilities, widespread PMU adoption didn't begin until nearly a half decade into the 21st century. However, they are not a brand new technology – it just happened to be way ahead of its time.

Myths & Misconceptions on the Funding & Management of PMU Deployment

"I need a dedicated synchrophasor project to deploy PMUs."

While many early adopters and even some late adopters have seen success with specific, structured rollouts for PMUs, this is not the only way to deploy the technology; and arguably, it is not the most optimal way. Not to say that there isn't value in pilot projects, but long term success with synchrophasor deployment requires treatment of PMUs as 'just something that we do'. It must be directly integrated with normal business practices so that deployment becomes an organic, cost effective, and efficient process.

"I need a government grant to deploy PMUs."

This myth is largely driven by the fact that many entities over the last decade have had government assistance with PMU deployment. However, like the previous myth, this can sometimes hurt just as much as it helps. Structured rollouts require dedicated resources and government grants require substantial documentation overhead. Again, an organic deployment strategy is desired. Another reason that this myth has proliferated is due to the next myth/misconception.

"PMU installations are very expensive."

At one point in history, PMU technology was extremely cost prohibitive and was relegated to only very special research initiatives or high-value niche applications. This was largely due to the cost of the crystal oscillator chip used to maintain accurate time synchronization and therefore the cost of the individual device was high. An entire science of ‘PMU Placement’ was created to optimize the locations of these installations since the individual device was so expensive. Today these chips can be purchased for less than $10. And while PMU placement techniques are still prevalent, installation locations are usually dictated by other factors such as outage scheduling. Since the cost of the device is so low, the lion’s share of the cost of PMU installation lies in the physical act of installing the device itself. Here again is another driver for installing PMUs in an organic way that takes advantage of installing PMUs where outages are already being taken.

“I only need ~20% of 1-2 full-time engineers to manage my synchrophasor data systems.”

Synchrophasor technology is not plug-and-play. In order to properly institutionalize the technology, having dedicated resources that can manage data quality, respond to unplanned outages, develop naming conventions, manage IT infrastructure and security, commission new devices as they come on line, decommission older devices as they go offline, etc. is a requirement. Forcing it on a few individuals as ‘something extra to do if you can get around to it’ is not a sustainable solution for the human resources required to maintain a synchrophasor deployment and leadership must be willing to dedicate resources to the cause.

“I need a dedicated synchrophasor team to manage my synchrophasor data systems.”

This myth is on the other end of the spectrum as the previous myth. Some organizations have created an entire team that only focuses on synchrophasors – all aspects of synchrophasors. While this is a benefit from the human resources perspective, from an organizational standpoint it can be stifling. The value proposition for synchrophasors is broad and impacts nearly every aspect of the business. Relegating the synchrophasor talent and man-hours to a specific group can likely limit the efficacy of the utilities synchrophasor efforts. An optimal scenario involves institutionalizing synchrophasor technology in as many ways as possible – creating processes and systems that require little additional effort on top of what work is currently done and spreading the dedicated engineering talent and resources across multiple business units.

“PMUs are disruptive to business operations and difficult to deploy.”

Only if you make them difficult. Only. If. You. Make. Them.

Myths & Misconceptions on the Substation Infrastructure of PMU Deployment

“ Synchrophasors can be transmitted over Power Line Carrier (PLC).”

PLC doesn’t have the bandwidth to support the transmission of synchrophasors and would be ill-suited architecturally. Even if a substation to substation connection was desired, it still couldn’t support the throughput requirements. Synchrophasor data streams require high speed communication; fiber is preferable.

“I cannot use my protective relays as PMUs.”

Many relays (with a firmware upgrade) can support multi-functions such as measuring synchrophasors. We often combine multiple relay functions into one relay so taking the additional step to add synchrophasors doesn't represent a risk that isn't already taken. Even so, the devices are designed to be able to support both functions simultaneously. In short, using protective relays as PMUs is a strategic way to increase the utility's synchrophasor footprint for little additional infrastructure or cost.

"DFRs provide all of the necessary data so I don't need PMUs."
A DFR is a completely different type of metering device than PMUs. DFRs do provide high quality data but it is not time synchronized, it is not a Phasor quantity, and it does not provide a constant stream of data.

"PMUs should only be installed in the transmission system, not generation terminals or in the distribution network."
While the transmission specific use cases have been well established for a while now, the value proposition for PMUs at generator terminals (or at the high side of GSUs) and across the distribution network is growing. On the generation side, oscillation monitoring and model validation are two key synchrophasor applications. On the distribution side, micro-PMUs are catching on as a viable technology with a myriad of use cases and the proliferation of distributed generation is only making the case for high fidelity data streams, like the ones provided by PMUs, stronger.

Myths & Misconceptions about Synchrophasor Data Quality

"Synchrophasor technology is plug & play."
Particularly in the realm of niche or single installation PMU footprints, the goal was just to 'get it to work' regardless of the longterm sustainability of the installation or downstream data architecture. Many synchrophasor data systems have been designed without the future in mind. However, in order to successful integrate synchrophasors across the business, an organization must make a commitment to ensuring data quality. In order to do this, the 'complete package' is needed. This includes but is not limited to placement of devices for optimal observability, proper configuration and tuning of the PMUs and PDCs, substation architecture design and standards, communication infrastructure, central PDC design, architecture, modeling, and work processes, and lastly, data conditioning strategies and technologies.

"Data quality isn't important."
Ensuring the quality and reliability of the synchrophasor data is foundational for long term viability of the technology within an organization. Poor data quality can manifest itself in many different dimensions. These include but are not limited to dropouts and packet loss, latency, repeated values, measurement bias, bad-missing timestamps, loss of GPS synchronization, incorrect signal mapping, planned and unplanned outages, poor server performance, and improper device configuration.

"PMUs are the most accurate measurement device."
PMUs have long been hailed for their accuracy and great potential to directly measure the state of the power system. However, they are not always the most accurate device and are

certainly not infallible. They are also still subject to a number of mechanisms which can induce error into the measurements. The largest of these are the PTs and CTs that are used to provide input signals to the PMUs and other devices in the substation. Just because PMUs can provide extremely accurate data does not mean that they will unless the utility does everything that it needs to in order to ensure quality at every stage in the measurement, transmission, and aggregation of PMU data.

"I just need to 'make it work'"

This technology isn't the equivalent of a senior design project in an undergraduate program. The long term sustainability and viability of synchrophasors is critical to the reliability of the electric grid. It is a foundational technology that should be treated with the same care that we treat our critical SCADA and EMS systems both in the substation and in the control center.

"We can sacrifice data integrity or quality to reduce data storage and network utilization."

This is the long way of saying that down-sampling and/or compression is a desirable tradeoff. In terms of data storage, PMU data requires a tremendous amount compared to its SCADA analogue. However, the cost of down-sampling and compression is high in two ways. First, it requires costly management. Second, it sacrifices the integrity of the data for future analysis. On the other side of this coin is the cost of data storage. On the surface, the cost of storage may seem large due to assumptions based on legacy storage costs. However, the exponential decrease in the cost of storage dictated by Moore's law will outpace the growth of demand for synchrophasor data storage. Therefore, when considering the long-term strategy it is better to just store all of the PMU data recorded in its original format indefinitely and simply incur the cost of scaling storage. The same principle applies to network utilization. While it is debatable when choosing, for example, between 60fps and 30fps, it is generally a poor decision to down-sample to something less than this.

"Measurement-based methods of data conditioning are just as accurate as model-based or hybrid methods of data conditioning."

While this is certainly subject to the validity of the models used, in theory, data conditioning algorithms that take advantage of the knowledge contained in models are statistically better than methods that perform data conditioning purely based on the measurement data alone. However, there are many forms of data conditioning with varying levels of performance. In the future, the lines between different kinds of data will be blurred and data quality requirements will be driven by the applications' needs. Some applications will require highly sophisticated data conditioning algorithms and others might only require some basic validation. Some applications may need data in real-time where others may be willing to wait for accuracy. So from this perspective, the 'better' method of data conditioning is always the one that meets the needs of the application with the least incurred 'system cost'.

"Existing applications are robust to bad data."

Very few existing applications were designed around the data quality problem. This is due to several reasons. First, the publicly available (or at least vendor available) synchrophasor data was not as prolific as was needed. Vendors did not have access to field data to validate their applications and were limited to simulated data. Second, because of the inexperience of the industry with respect to synchrophasor data quality, the creation of the simulated data was subject to the current understanding of how 'bad' synchrophasor data behaved. This was generally substantially different that what was experienced in the real system. In the future, applications will need to become more robust to bad data quality but will also need to have standardized specifications for what level of data fidelity is required to drive the application. Ensuring the fidelity of this input stream will be the responsibility of the system architects and the data conditioning algorithms.

"Full PMU coverage is required to do linear state estimation."
Because of the way the state equation is written, very sparse and distributed synchrophasor footprints can be conditioned using a linear state estimator.

"I need more PMUs to do linear state estimation."
Sometimes, as few as two Phasor measurements can be aggregated as a linear state estimation problem and still make sense and provide improved observability and data quality.

"I need a coherent network of measurements to do linear state estimation."
With linear state estimation, measurements can be distributed across the network and a state equation can still be formulated and make sense. While the solution quality increases as the density of measurements increase, a coherent set of measurements (i.e. all of the injections and flows at a bus) is not required to utilize the benefits of linear state estimation.

"The purpose of state estimation in general is to give me a base case."
Often the value proposition of state estimation is oversimplified by saying 'state estimator is used to give me a base case.' While this is true, it is a narrow understanding. The state estimator which is the cornerstone of modern control center applications was designed to take imperfect SCADA data and use knowledge of the network model and the statistical behavior of the signals and compute an initial condition for a power flow that can ensure convergence. So while the 'killer app' for state estimation was delivering the base case to the network applications, its core function is and always will be data conditioning.

"I already have a state estimator so linear state estimation serves no real purpose."
This misconception can be attributed to an extrapolation of the previous myth. If it is assumed that the state estimator's only purpose is to provide a base case for network applications then likely the linear state estimator doesn't provide any value unless you have a completely observable footprint. However, taking the general understanding of the purpose of state estimation, it is clear that the linear state estimator is used to provide a statistically cleansed data set for PMU only applications. Therefore, it is the desired

application which dictates whether the linear state estimator is a required component of a synchrophasor data systems portfolio of data conditioning algorithms.

Some Additional Myths and Misconceptions

"Synchrophasor visualization is completely mature."

Without question, our ability to take the vast amount of information within synchrophasor data and display it before engineers and operators is limited at best. Ultimately, there will one day be highly intuitive, informative, and interactive visualization platforms for synchrophasor data. However, these do not currently exist and there is much room for improvement in today's visualization tools. Despite this, all is not lost. In fact, it is strategic to drive adoption by using simplistic displays, sometimes as simple as trending, strip-charting, and measurement-overlaid operational one-line diagram displays, to visualize synchrophasor data. The reason this is so is because it can be intuitive to the user because it is a legacy method of displaying information. Displays that are comfortable and familiar can be adapted to display synchrophasor data in similar formats. As adoption grows, displays can evolve with the needs of the engineers and operators until we reach the advanced visualization techniques that will ultimately become invaluable.

"My operators won't know what to do with the information provided by synchrophasors."

Of all of the myths discussed in this section, this is one which is somewhat plausible. However, it is not an excuse. Developing operator training should be a key component of the institutionalizing of synchrophasor data and is a great opportunity to expose operators to new tools and information. Additionally, this myth is centered about the notion of the career-operator – an individual who has spent their entire career with the utility with much of it spent as an operator. However, the younger generation of Millennials which have grown up playing video games are much quicker to adopt new ways to digest and process information. And as retirements across the industry continue, younger and younger operators will be required to take the place of the veteran operators. In this way, there is a strategic opportunity for change that can be capitalized on.

"Synchrophasors are only valuable to ____ and not for me!"

Often times, individuals who have been doing the same thing or using the same tools find it difficult to see the value proposition of synchrophasors within their respective business unit. However, it is commonly understood that the value potential for synchrophasors is substantial across all of the business units within a transmission organization.

22) Glossary, Definitions & Acronyms