**ERCOT Synchrophasor Technology Assessment**

***A Report by the Phasor Measurement Task Force (PMTF)***

**Background**

Synchrophasor technology involves the retrieval of GPS time-stamped data from Phasor Measurement Units (PMUs) at various points on the electrical system. Voltage and current magnitude and angle data, plus frequency is made available for applications to utilize at a rate of up to 60 times a second. Common utility industry applications include wide area visualization, state estimator enhancement, model validation, and the implementation of certain protective relaying or control schemes. PMUs act as a *complement* to traditional SCADA systems and provide enhanced visibility of certain phenomena, such as oscillatory behavior.

In November 2013, the ERCOT ROS authorized the development of the Phasor Measurement Task Force and developed a charter with the following scope of work:

* + - 1. How will synchrophasor data be used in ERCOT (real-time monitoring, unit model validation, etc.)? What are the current and planned uses by ERCOT? What are current and planned uses by TSPs and generators?
      2. What kinds of locations of PMUs are needed to meet this use(s)? How will these locations be determined?
      3. What are the data latency and quality requirements and other specifications, in order to meet the intended uses? Should these vary depending on the kind of PMU location?
      4. Who should install and own the PMUs? Who should be responsible for the communications from the PMUs?
      5. How should synchrophasor data be treated in terms of confidentiality?
      6. What reporting should be established for synchrophasor data? ROS/DWG/SPWG/PDCWG etc.
      7. What data retention should be established for synchrophasor data?
      8. What are the CIP implications/requirements for the use of this data?
      9. What is the application of synchrophasor data in the area of Ancillary Services?[[1]](#footnote-1)

In addition to the nine items assigned above, the PMTF identified two additional noteworthy areas to address:

1. Impact of related NERC Reliability Standards and FERC rulings on synchrophasor data usage in ERCOT
   1. MOD-026, *Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions*
   2. MOD-027, *Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions*
   3. PRC-002, *Disturbance Monitoring and Reporting Requirements*
   4. FERC Ruling in the Southwest 2011 blackout
2. Review of other Interconnections’ efforts in this area.
   1. MISO
   2. PJM
   3. WECC

Based on these assigned tasks and other background research, the PMTF developed an Issues List with associated action items and deliverables in each area. In many instances, existing binding language with a similar scope has been examined for its applicability to Synchrophasor data. For example, in many ways ICCP data traffic is similar to Synchrophasor data traffic with respect to a need for certain levels of data quality, availability, and observability. Also, PMU requirements are similar to Disturbance Monitoring Equipment (DME) requirements in terms of their optimal location on the grid, and composition of data channels. Where possible, new language/recommendations/requirements have attempted to model analogous and existing binding language.

This report, along with other supporting documents and related language revision requests, is the key deliverable provided by the PMTF in response to the ROS request.

**Key Benefits for ERCOT (IL #1)**

Within the ERCOT region, the three most beneficial applications, or “use cases”, identified by ERCOT are:

1. Oscillation detection and alarming
   1. Generator or Flexible AC Transmission System (FACTS) device
   2. Adds functionality not provided by SCADA or State Estimator
   3. Addresses Reliability Coordinator (RC) visibility for localized and Inter-area oscillations
2. Generator model validation
   1. Supports [MOD-026-1](http://www.nerc.com/files/MOD-026-1.pdf) Exciter model verification
   2. Supports [MOD-027-1](http://www.nerc.com/files/MOD-027-1.pdf) Turbine/governor model verification
   3. Addresses requirements for TPs and GOs
3. Post-disturbance analysis and reporting
   1. Supports (future) [PRC-002-2](http://www.nerc.com/pa/Stand/Pages/Project_2007-11_Disturbance_Monitoring.aspx) Disturbance monitoring and reporting requirements
   2. Applies to TOs, GOs, ERCOT

These applications have been chosen based on (A) overall potential to improve system reliability, (B) overall potential to improve system model validation, and (C) compliance with present or future NERC requirements. Consequently, the PMTF’s work has focused in these areas. Above and beyond these three primary applications, the CCET Synchrophasor project group has identified a more complete set of eleven use cases. PMU installations and synchrophasor measurement system architecture additions to support the three primary cases may also provide benefits among the broader set of use cases.

The following sections of this report examine additional questions and concerns in specific areas related to the ERCOT-identified PMU applications. It should be noted that this is not an exclusive list, and other potential applications (such as certain Ancillary Services identified by FAST, setting line angle alarm limits or operator visibility of black start paths) also benefit from the availability of PMU data.

NERC Cost Effective Analysis Process (CEAP)[[2]](#footnote-2)

Some high-level cost vs. benefit information in this area was recently provided by NERC in response to a continent-wide survey associated with PRC-002-2. With respect to costs:

*For DDR capability the respondents noted a very broad range of methods to capture fault data. Phasor Measurement Units (PMU) seem to represent the preferred equipment solution to meeting the capability requirements in the standard. PMUs seem to be the most cost effective means of achieving the standard’s requirements for DDR capability.*

*For DDR capability, the respondents identified the estimated costs of DDR monitoring devices which was averaged to be $50K ‐ $60K (with a high of $100K to $200K) per device. The respondents identified the estimated costs of installation of the DDR monitoring devices which was averaged to be $50K to $60K (with a high of $200K) per installation. Respondents identified the estimated costs per maintenance cycle which were averaged to be $3K (with a high of $6K) per installation.*

With respect to benefits:

*Benefits identified during the CEAP consist, in some cases, of mitigated reliability risk statistics from the NERC Reliability Assessment and Performance Analysis (RAPA) department and/or a potential resource savings. The following was developed in collaboration with NERC’s Reliability Initiatives and System Analysis department:*

*The benefits of having sufficient DM capability placed appropriately throughout the power system is best illustrated by the difference in the analyses of the 2003 Northeast Blackout and the 2011 Arizona‐Southern California Disturbance. In 2003, NERC determined there were insufficient time‐synchronized DM data in the footprint of the power system disturbance. As a result, fault records and data had to be “daisy‐chained” to form a synchronized detailed sequence of events by comparing sub‐second frequency, voltage, and current recordings from several disparate traces to develop time offsets between devices. The process involved several thousand traces and took five (5) subject matter experts (SME) about four (4) months to complete. Preparing graphics was virtually impossible and very time consuming. Even the rudimentary pre‐dynamics period timeline took 3 months to develop.*

*In analysis of the 2011 event, through the use of data from 5 PMUs, the key timeline traces were completed in 2.5 hours and the sequence of events was developed by five (5) SME over a five (5) day period, including graphics of the event. The greater detail available also provided a much deeper understanding of the interacting elements of the disturbance. That is a savings of about 4,400 SME hours for the analysis.*

*The CEA industry responses indicated that there would be little incremental reliability benefit from the standard because entities believed that there was sufficient DM installed on the power system already. The entities did recognize the importance of being able to effectively analyze disturbances, however, believed that the standard was not needed.*

In summary:

*The Survey Response observations developed by the CEAP Team follow:*

* *A significant portion of the DM capability already exists on the power system that satisfies the draft standard’s requirements.*
* *Survey responses indicate that when new equipment is installed, it allows the opportunity to install multifunctional equipment that provides capability for more than one task, therefore is clearly more cost effective.*
* *Survey responses indicate an increase in EFTE was minimal or averaging about 2.*
* *The Implementation period seems to be satisfactory for those with capability already installed.*
* *Some entities responded that a standard was not needed in their Region, however continent wide, there may be some benefit to having a standard that identifies minimum DM capabilities and guidance to determine locations on the power system.*
* *No egregious costs per individual installation, which ranged typically from $100K to $160K, were identified by entities for the draft standard when considering the need and potential benefit of having sufficient equipment on the power system.*
* *GOs believe, in general, that there will be little reliability benefit and the costs will be difficult to recover. TOs that file tariffs and through legislation have more certain recovery through rates if costs are incurred due to implementation and future compliance with standards.*

*The CEAP Team, upon review of the data submitted and giving due weight to the costs vs. benefits of implementation of the standard: (a) does not opine on whether a standard is the appropriate method to address the perceived need; but (b), if it is determined that a standard is the appropriate path forward, is of the opinion that the proposed standard (1) provides a cost effective means compared to other alternatives for providing disturbance monitoring capability, and (2) will support the efficient and effective collection of disturbance data continent‐wide on the BES.*

Furthermore, experience in WECC in the area of generator model validation has shown Synchrophasor data based model verification to be cost-effective when compared to generator re-testing. In the WECC region, generating unit model *validation* criteria has been in effect since 1996, and model *verification* requirements have been in place since 2006.[[3]](#footnote-3)

**Recommended Action(s)**

None at this time.

**PMU Locations and Placement (IL #2)**

**Current Status**

In the ERCOT region, there are presently around 100 PMUs voluntarily installed by several entities, primarily TSPs. Most of these PMUs presently provide voltage, current, and frequency data at a rate of 30 samples per second. Of these, as of 8/20/14 nearly 70 PMUs at 40 distinct locations are networked and providing real-time data to ERCOT on a 24x7 basis. ERCOT has installed the Electric Power Group (EPG) developed RTDMS visualization and alarming platform. ERCOT engineering staff presently utilizes this application outside of the control room to inform Operators of detected oscillations and for post-event analysis, and there are plans to introduce this functionality to the control room staff by mid-2014.

Several entities have installed PMUs and are utilizing or plan to utilize them in the following manner:

|  |  |
| --- | --- |
| Entity | Application Area(s) |
| AEP/ETT | CCET participant\* |
| LCRA TSC | RTDMS-based Operator visualization & alarming, load model validation, post-disturbance analysis, transmission line impedance validation, EMS integration, post-contingency line voltage angle monitoring |
| Oncor | CCET participant\*; operator angle visualization |
| Sharyland | CCET participant\* |

*\* Refer to* [*http://www.electrictechnologycenter.com/synchrophasor.html*](http://www.electrictechnologycenter.com/synchrophasor.html) *for more details on the CCET Synchrophasor project.*

With respect to PMU placement, options above and beyond NERC requirements in this area that support the top three ERCOT applications presently identified, include the following list. This list of *possible* options was developed by the PMTF in the process of crafting language for ROS to consider.

1. Continue PMU placement based on voluntary efforts (default)
2. Require targeted PMU placement based on operational experience/history (ERCOT-requested)
3. Require mandatory PMU placement at existing facilities with a phased-in timeframe
   1. Require mandatory PMU placement at major transmission facilities
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
   2. Require mandatory PMU placement at facilities with a FACTS device
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
   3. Require mandatory PMU placement at generator terminal
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
   4. Require mandatory PMU placement at TSP point of interconnection
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
4. Require mandatory PMU placement only for new or upgraded facilities
   1. Require mandatory PMU placement at “major” transmission facilities
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
   2. Require mandatory PMU placement at facilities with a FACTS device
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
   3. Require mandatory PMU placement at generator terminal
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
   4. Require mandatory PMU placement at TSP point of interconnection
      1. Off-line (local storage & alarming)
      2. Networked directly (allows for ERCOT monitoring & operator action)
5. A hybrid combination of the above options.

The recommended PMU placement guidelines are contained within the Nodal Operating Guide section 6 language changes proposed by the PMTF.

**Recommended Actions**

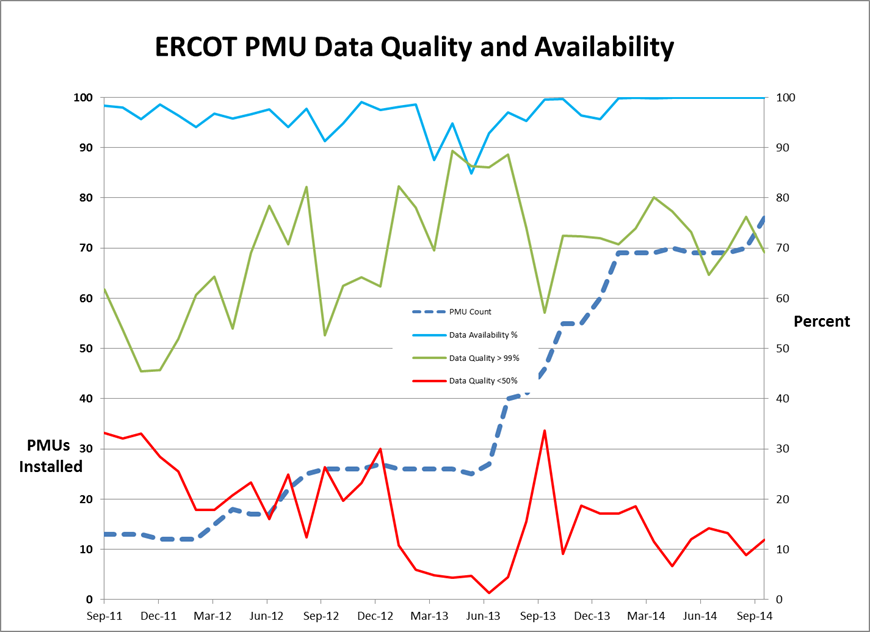
Task 1: Develop application-based guidelines for locating PMUs within the ERCOT region.

Within Nodal Operating Guide section 6, section 6.1.3 titled “Dynamic Disturbance Recording Equipment” has been reserved as a placeholder. This location is appropriate to document PMU placement and equipment requirements. The language shall be drafted in a similar fashion to the Fault Recording Equipment requirements covered in section 6.1.2.

**Phasor Data Quality of Service Requirements (IL #3)**

**Current Status**

In the ERCOT region, configuration changes made in early 2014 have improved overall data availability, as shown in the figure below. The data availability improvement is documented in the NASPI presentation located at: <https://www.naspi.org/File.aspx?fileID=1232>. There is still room to improve in terms of the data quality, particularly as new PMUs are brought on-line. This trend is also shown in the figure below.



Data quality is monitored on a daily basis by ERCOT staff and concerns (such as high latency, excessive data drop-outs, etc.) are addressed with the individual asset owner on an as-needed basis.

Analogous ICCP data transfers are governed by the ERCOT ICCP handbook. PMU data traffic may be transmitted over existing data networks also used for ICCP traffic.

**Recommended Actions**

Task 1: Establish Minimum Data Latency Requirements

Latency is the time delay it takes from the first data bit to be transmitted until the last data bit is received. Latency includes the physical delay of the communication channel and equipment being used for the signaling, where the channel latency could be insignificant depending upon the media being used. Data latency may also be increased due to the PMU filtering algorithm, and some latency is also added via any intermediate Phasor Data Concentrator (PDC) processing.

Acceptable latency is highly dependent on the application. Data used for off-line applications, such as generator model validation and post-event analysis, can be delayed substantially without degrading system performance. Applications used for real-time displays and operator awareness can usually tolerate 2-10 seconds of delay through the data transmission network from PMU data source to application end-use without significant impact to the end-user. Latency requirements for the top three applications identified by ERCOT *today* are summarized below.

|  |  |
| --- | --- |
| ERCOT Use Case | Application  Latency Requirement |
| Oscillation Detection | 2 – 10 seconds |
| Generator Model Validation[[4]](#footnote-4) | N/A |
| Post-Event Analysis[[5]](#footnote-5) | N/A |

Task 2: Establish Minimum Sampling Rate Requirements

Like Data Latency, Sampling Rates are highly dependent upon application requirements. For real-time detection of oscillations, a minimum sampling rate of 6 samples per second may be sufficient, although 30 samples per second offers greater resolution of higher-frequency oscillations. For post-event analysis, the output recording rate required by NERC draft standard PRC-002-2 of 30 samples per second is advisable. A 30 or greater sample per second rate is consistent with generator modeling practices and tools commonly used in industry for generator model validation purposes. Recommended sampling rates for the top three applications identified by ERCOT are summarized below. PMU sampling rates may be higher than what is required for the application, and the lower sampling rate may be forwarded from the entity’s PDC on to ERCOT.

|  |  |  |
| --- | --- | --- |
| ERCOT Use Case | Output Recording Sampling Rate (samples/sec) | IEEE C37.118 Class |
| Oscillation Detection | 6-30 <5 Hz  60+ >5 Hz | M |
| Generator Model Validation | 30+ | M |
| Post-Event Analysis | 30-60 | M |

Practically speaking, the recommended minimum multi-application PMU sampling rate is 30 samples per second.

Task 3: Establish Minimum Bandwidth Requirements

Communications network bandwidth requirements should not be independently specified. Bandwidth is a logical function of the number of monitored phasors per PMU and sampling rate, in combination with end-use applications needs and communications network capabilities and customer requirements as formalized in service-level agreements. Therefore, bandwidth requirements are the logical result of data point and sampling rate requirements.

The IEEE C37.118.2 Synchrophasor Protocol includes standards for PMU communications systems. Data is transmitted in frames that consist of several measurements that correspond to a specific time. Frames are sent at a rate of 1 to 60 per second. The data can be transported over asynchronous serial (such as RS232), synchronous serial (such as RS422), or network communications using raw packet transmission or a stacked protocol such as IP. Bandwidth requirements vary depending on the data rate and the amount of data being transmitted. The following table summarizes the data transmission speed requirements using this protocol. The rates in the table are based on 10 bits/byte of information which is required for RS232. UDP/IP or TCP/IP bandwidth requirements need to include overheads for TCP/IP (22 bytes/packet) and UDP/IP (28 bytes/packet).

**Bandwidth needed for data transmission of synchrophasor data using the C37.118 protocol (unencrypted)**

|  |  |  |  |
| --- | --- | --- | --- |
| Data rate  Frames/s | 5 Phasors  1 Analog,  (integer) | 10 Phasors,  4 Analog,  2 digital,  (integer) | 10 Phasors,  4 Analog,  2 digital,  (floating point) |
| 12 | 4800 bps | 8400 bps | 14160 bps |
| 30 | 12000 bps | 21000 bps | 35400 bps |
| 50 | 20000 bps | 35000 bps | 59000 bps |
| 60 | 24000 bps | 42000 bps | 70800 bps |

Data encryption will increase bandwidth requirements, potentially by a factor of 50-150% (assuming a PDC to PDC data transfer over a VPN connection).

An increase in the amount of synchrophasor data streamed by Market Participants will require addressing future ERCOT WAN bandwidth needs.

Task 4: Establish Minimum Redundancy Requirements

As the criticality of synchrophasor measurements increase in the Operator realm, the need for redundancy also increases. Depending on the use case, various levels of redundancy may also be warranted. The need for redundancy shall be taken into account in Nodal Operating Guide language recommendations.

**PMU and Telecommunications Ownership (IL #4)**

**Current Status**

Presently, most PMU data traffic is carried from the TSP facility to the TSP PDC by TSP-owned private telecommunication networks. For example, in one instance PMU data is output serially, converted to Ethernet media at the substation, and then transmitted back to a central office PDC via a private TSP-owned substation wide area network which is also utilized for other TSP data traffic (e.g. SCADA data, DFR/relay data retrieval, VOIP, etc). PMU data traffic between the TSP PDC and the ERCOT PDC is primarily carried by ERCOT Wide Area Network (WAN). The PMUs and associated telecommunication networks are owned by the asset owners, who at this time are primarily Transmission Service Providers (TSPs). The majority of the PMUs are protective relays such as the SEL-421 digital line relay, while the remaining minority are other substation IEDs such as DFRs.

Given a large enough local storage system, local retention of phasor data may, in some cases, act as a substitute for a networked data connection. This approach is particularly well-suited for off-line applications such as generator model validation and post-event analysis and/or when the cost of a networked data connection may be significant. A minimum of 10-day local storage is required in order to support post-event data retrieval per the draft PRC-002 standard. However, in the event of a communication outage or an ad-hoc data request from a non-networked PMU, a longer storage timeframe on the order of 30 days is recommended where feasible and cost-effective.

**Recommended Action**

Task 1: Develop ERCOT Synchrophasor Communication Handbook

This deliverable will document how to set up a TSP-ERCOT or QSE-ERCOT synchrophasor data (WAN) connection to provide a C37.118 compliant data stream to ERCOT and/or receive an RTDMS-compatible data stream of select PMU data in return from ERCOT.

**Phasor Data Sharing and Confidentiality (IL #5)**

**Current Status**

Within ERCOT, ERCOT’s legal staff has reviewed this topic and the opinion is that phasor data that discloses a Resource Entity operational status and/or output is treated similarly to other real-time telemetered data (e.g. ICCP) from a Resource Entity that similarly discloses its operational status and/or output. As a result of this, phasor data sharing and exchange is covered under the ERCOT Nodal Protocols section 1.3 Confidentiality.

Synchrophasor data not directly attributed to a Resource Entity (e.g. synchrophasor data obtained from a transmission switchyard) is not considered to be Protected Information.

Synchrophasor data derived directly from a Resource Entity is considered to be Protected Information per:

*(c) Status of Resources, including Outages, limitations, or scheduled or metered Resource data. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;*

Generator market-sensitive data is treated as confidential for sixty days. Transmission non-market-sensitive data is able to be shared sooner. CEII data, including PMU data designated as such, shall not be released to parties without proper authority, e.g. NERC, FERC, TRE, etc. ERCOT TSPs are able to exchange phasor data amongst themselves at their own discretion, subject to Nodal Protocol requirements governing market-sensitive data. One example of ongoing inter-utility phasor data sharing is through the CCET project, whose members are subject to an NDA which includes synchrophasor data.

Within the ERCOT working group structure, PDCWG has an ongoing non-disclosure agreement which allows it to discuss and review generator market-sensitive data.

**Recommended Action(s)**

None at this time.

**Phasor Data Reporting and Workgroup Integration (IL #6)**

**Current Status**

Presently, PMU events are included in the ERCOT Monthly Operations Report presented at each ROS meeting. The PMU Events section lists major synchrophasor events captured during the prior month along with some basic parameters such as event type, duration, frequency, and damping ratio. A sample from the March 2014 report is shown below:

*There were two synchrophasor events captured in March. Both were the result of frequency events detailed in section 2.1 above. When analyzing system disturbances, ERCOT evaluates PMU data according to industry standards. Events with an oscillating frequency of less than 1 Hz are considered to be inter-area, while higher frequencies indicate local events. Industry standards specify that damping ratio for inter-area oscillations should be 3.0% or greater. All events listed below indicate the ERCOT system met these standards and transitioned well after each disturbance.*

|  |  |  |  |
| --- | --- | --- | --- |
| Date and Time | Event Type | Duration of Event | Comments |
| *3/10/2014 18:29:21* | *Unit Trip* | *Approx. 159 sec* | *The event was caused by the loss of one unit generating 798 MW net. Following the trip, frequency dropped to 59.775 Hz. The oscillating frequency of 0.683 Hz with 9.55% damping ratio was observed.* |
| *3/19/2014 08:41:02* | *Unit Trip* | *Approx. 360 sec* | *The event was caused by the loss of one unit generating 770 MW net. Following the trip, frequency dropped to 59.795 Hz. The oscillating frequency of 0.752 Hz with 12.78% damping ratio was observed.* |

However, the use of existing synchrophasor data by ROS working groups is largely non-existent. The Critical Infrastructure Protection, NERC Reliability, Planning, Black Start, Network Data Support, Operations, Steady State, System Protection, and Resource Data Working Groups are not using existing data and have not identified uses for the data at this time.

ERCOT staff has discussed synchrophasor data pertaining to generator dynamic performance with the Performance Disturbance Compliance Working Group (PDCWG) and the Dynamics Working Group (DWG). Whereas the use of such data is not currently part of PDCWG and DWG procedures, some of the data may potentially be a useful supplement to other data sources, such as the RARF process and generator testing data. Currently, analyzing damping of oscillations is not a defined task or focus of PDCWG, but PDCWG could consider use of synchrophasor data for this purpose if this function is not duplicative of ERCOT staff, Generator Owner, and DWG functions. Neither DWG nor PDCWG have attempted to weigh the relative merit and cost-effectiveness of synchrophasors versus other ways to obtain data that could be used to evaluate oscillations, or attempted to weigh the incremental value relative to existing data sources. As a practical matter, the existing locations of PMUs at transmission switching stations is of limited value for generator model validation, because PMUs need to be placed on the generator terminals for that purpose.

**Recommended Action(s)**

Task 1: Reporting of Oscillations Detected by ERCOT

Prospectively, synchrophasor data used by ERCOT to detect and mitigate oscillations would be reported to ROS or ROS working groups on an as-needed basis as part of the description of the event. An existing ERCOT guideline related to the event damping ratio governs what constitutes a “defined event”.

Task 2: Reporting Generator Model Validation

Existing PMU data is not currently used to validate generator dynamic models and the existing placement of PMUs at transmission switching stations is of limited value for validating generator models. However, to the extent such data is used prospectively, the data will be shared with ERCOT dynamics modeling staff and the Dynamics Working Group (DWG). If ERCOT staff, in consultation with DWG, determines that changes are needed to generator submitted RARF modeling data based upon the PMU data, ERCOT shall use established processes to modify such data in the ERCOT dynamic models. Generally, the established process would be similar to the process used if generator tests indicate results that are materially different from generator-submitted RARF data.

Task 3: Reporting PMU data to support Event Post Analysis

Existing PMU data is not routinely used in post-event analysis by ERCOT working groups. However, to the extent such data is used prospectively, the data will be shared upon request with any ROS working group (e.g. SPWG, PDCWG, etc) assigned to analyze the event.

Task 4: Report on Lessons Learned

Lessons learned via Synchrophasor data capture and/or event analysis should be circulated to the appropriate working groups (e.g. PDCWG, Seminar Working Group, etc) and other forums within ERCOT so that others may benefit from this knowledge. This is a similar approach to the NERC Lessons Learned effort (<http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx>).

**Phasor Data Retention (IL #7)**

**Current Status**

Phasor data retention is required to allow for post-disturbance analysis and establishing a history of generator model validation. Phasor data may be retained locally at the TSP or GO level as well as by ERCOT. Data retention by individual TSPs typically ranges from 90 to 180 days. ERCOT data retention consists of maintaining 400 days of full fidelity phasor data. ERCOT data retention of full fidelity phasor data gathered during system events extends indefinitely.

Data archiving by exception for certain applications such as generator model validation may also extend indefinitely in order to establish a long-term history for that particular unit.

The future NERC PRC-002-2 Reliability Standard will require a minimum 10 calendar day data retention window, as it is presently drafted.

The NERC MOD-026 and MOD-027 Reliability Standards require a minimum 3 year data retention window.

ERCOT Nodal Operating Guide section 6 requires disturbance data retention for three years.

Revenue metering and settlement data has a longer data retention period, as driven by PUC requirements.

**Recommended Action(s)**

Task 1: Draft recommended (minimum) guidelines for trended phasor data retention including parameters such as:

1. Voltage magnitude/angle data (phase)
2. Voltage magnitude/angle data (sequence)
3. Current magnitude/angle data (phase)
4. Current magnitude/angle data (sequence)
5. Frequency and df/dt
6. Real power (calculated value)
7. Reactive power (calculated value)

Task 2: Draft recommended (minimum) guidelines for phasor data retention by exception including parameters such as:

1. Data capture driven by system events
   1. Voltage magnitude/angle triggers
   2. Current magnitude/angle triggers
   3. Oscillation triggers
   4. Frequency and df/dt triggers
2. Data capture required for generator model validation
   1. Mirror retention of generator test reports, up to the life of the unit

As covered previously, data confidentiality requirements may also cover the retained data up to a period of time, e.g. less than 60 days or potentially longer if CEII data.

**Cyber Security and NERC CIP Implications (IL #8)**

**Current Status**

CIP version 5 will go into effect April 1, 2016 (high and medium impact) and April 1, 2017 (low impact).

Each individual entity subject to NERC CIP Reliability Standards is responsible for complying with those standards.

Within ERCOT, synchrophasor data tends to exhibit the following characteristics:

* Phasor data is not presently used for Bulk Electric System (BES) control purposes or automated actions.
* Phasor data may be used for observability in a sub-15 minute timeframe, similar to RTU data traffic or other telemetry.
* Some PMU data is serially transmitted, some may be transmitted via Ethernet. IEEE C37.118 describes a data structure that may be transmitted serially or routed over a network connection.
* Some PMUs may be located at critical facilities; some PMUs may be located at non-critical facilities.
* A PDC and/or PMU transmitting data on a communications network with other BES Cyber Assets may dictate the PDC and/or PMU be treated in a similar fashion.

In summary, it is up to the individual PMU and communications network owner to determine specifically whether and how the NERC CIP standards apply, particularly where the PMU data is used for operational purposes (based on the NERC Functional Model descriptions for “real-time” operations, including situational awareness). If Synchrophasor data is being relied on to make real-time operational decisions, then the PMUs themselves would be considered no differently than other relays or RTUs providing similar operational data to an operator. Refer to <https://www.naspi.org/File.aspx?fileID=533> for further details on this topic. Best practice is to proactively design and implement installations that build in a basic level of CIP protection that can be upgraded as the synchrophasor data moves into real-time operational usage.

**Recommended Action(s)**

Task 1: Educate entities on CIP considerations of Synchrophasor data through forums such as the ERCOT CIPWG.

**Impact on Ancillary Services (IL #9)**

**Current Status**

Ancillary Services (AS) involve the response of the system during a loss of generation or generation shortage scenario. A key indicator of system response is frequency and the rate of change of frequency. The current AS framework for the ERCOT Region was designed when large steam generators were the predominant generation type in ERCOT. These units have certain inherent characteristics and the Ancillary Services framework was designed around those characteristics. This framework has gradually, but significantly, evolved as gas-fired combined cycle plants and wind generators have become larger portions of the generation mix.

The Future Ancillary Services Team (FAST) is presently reviewing concepts and proposals for a new framework for AS in ERCOT. ERCOT has strived to propose a revised AS framework that is based on the fundamental needs of the power system to maintain frequency control, is as neutral as possible to the technology types that are able to provide the services, and avoids unnecessary restrictions that limit the provision of the fundamental AS requirements by as broad a set of resources as possible.

Six types of AS are under consideration by the FAST:

1. Synchronous Inertial Response Service (SIR),
2. Fast Frequency Response Service (FFR),
3. Primary Frequency Response Service (PFR),
4. Up and Down Regulating Reserve Service (RR), and
5. Contingency Reserve Service (CR).
6. Supplemental Reserve Service (SR) (during transition period)

Due to a PMU’s established capabilities in recording and transmitting high-speed electric system data in a distributed, accurate, and time-synchronized manner, they are well suited to complement the adoption of certain Ancillary Services. In the published ERCOT Concept Paper on Future Ancillary Services in ERCOT[[6]](#footnote-6), it was noted that “Measurement of FFR will require a high resolution recording device, for example a Phasor Measurement Unit (PMU), to be installed at the provider’s site with appropriate communication for ERCOT.”

**Recommended Action(s)**

Task 1: Ensure the minimum PMU recording requirements meet AS requirements.

**Impact of related NERC Reliability Standards and FERC Settlements**

**Current Status**

Presently, no single NERC Reliability Standard mandates the installation of a phasor measurement unit, or the usage of synchrophasor data. However, PRC-002-2 is under review by NERC and as it is written, has several requirements related to Dynamic Disturbance Recorders (DDRs) which are functionally very similar (or equivalent even) to a PMU device. This project was initiated to address an existing “fill in the blank” standard. FERC did not approve or remand PRC-002-1 in Order 693 because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. The PRC-002-2 draft requirements as of October 1, 2014 (*in an abridged format*) include:

**R5.** Each Responsible Entity shall:

**5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required […]

**5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least […]

**5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

**5.4** Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the re-evaluated list of BES Elements as per the Implementation Plan.

**R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5 […]

**R7.** Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5 […]

**R8.** Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following […]

**R9.** Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following […]

**R10.** Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following […]

**R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following […]

**R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either […]

Following the ballot ending June 25, 2014, the PRC-002-2 standard achieved a quorum, but did not receive sufficient affirmative votes for approval. The drafting team considered industry comments and provided a new red-lined version of the draft standard on September 5, 2014. The latest formal comment period is presently open and the next ballot for this standard will be conducted October 10-21, 2014.

Additionally, the Modeling, Data, and Analysis NERC Reliability Standards MOD-026-1 and MOD-027-1 which recently went into effect on July 1, 2014 both require verification of generator component models. Specific requirements include:

**R2.** Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1.

And in MOD-027-1:

**R2.** Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1.

It is the ERCOT PMTF’s opinion that some synchrophasor data captured in response to system events (given the appropriate system event, adequate data quality, appropriate PMU location, etc) can meet and exceed all of the generator model verification requirements (whether that verification is performed by the GO or by a GO-contracted 3rd party vendor).

On July 7, 2014, in a FERC settlement related to the September 8, 2011 Southwest blackout, FERC found that a portion of Arizona Public Service (APS) Company’s $3.25 million civil penalty shall include the installation of “Phasor Measurement Units, which provide continuous, high-speed monitoring of system conditions”. These PMU installations are mandated for five facilities in Arizona (Moenkopi, Yavapai, Morgan, Pinnacle Peak, and Cholla) at both 345-kV and 500-kV voltage levels.[[7]](#footnote-7)

**Recommended Action(s)**

Task 1: Monitor the development of the draft PRC-002-2 standard and provide constructive input to the Standard Drafting Team as necessary.

Task 2: Position ERCOT binding language in this area to support and complement – yet not conflict – with the PRC-002-2 binding language.

Task 3: Pursue generator model verification techniques that utilize high fidelity, captured event data of the generator’s response to system events.

**Review of other Interconnections’ Efforts in this Area**

Other interconnections outside of the ERCOT region have installed synchrophasor technology over the past few years or are planning to do so in the near future. Each section below summarizes efforts in this area.

**Current Status**

MISO[[8]](#footnote-8)

In 2010, MISO was among 100 recipients of the U.S. Department of Energy’s (DOE) Smart Grid Investment Grant awards. MISO received a $17.25 million grant to fund the development and deployment of PMUs as part of the DOE’s effort to modernize the power grid and leads the industry in use and installation of the devices. MISO members received a one-year extension to install additional synchrophasors at no extra cost, further improving grid reliability and predictability.

Synchrophasor technologies use phasor measurement units, or PMUs, to collect data from more than 344 installed devices, 30 times per second compared to traditional technology which records measurements every four seconds. The data is GPS time-stamped, enabling measurements from different locations to be time-synchronized and combined to create a detailed, comprehensive wide-area assessment of system conditions. With this data MISO can better detect, diagnose and prevent system disruptions, in effect, creating a smarter grid.

As part of the project, MISO’s team of engineers pioneered a new feature for Control Room displays called enhanced Real-Time Display or (eRTD) to give system operators a unique geospatial visualization of grid activity. eRTD also provides two-way visualization of real-time grid activity, so now participating transmission owners have the advantage of seeing the same displays as MISO control room operators.

The three-year project came in on time and under budget, and involved 17 MISO Transmission Owners. Next, MISO intends to continue seeking new ways to extend the value gained from this technology by integrating it into our state estimator tool, incorporating use of the technology with additional transmission owners, and data sharing with the entire Eastern Interconnection.

PJM[[9]](#footnote-9)

PJM Interconnection (PJM) and 12 of its member transmission owners are deploying synchrophasor measurement devices in 81 of its high-voltage substations and are implementing a robust data collection network. This project complements existing equipment to provide the necessary information technology infrastructure and wide-area monitoring and coverage of the PJM system to support further development of more advanced applications. The project is aimed at improving electric system reliability and restoration procedures, and preventing the spread of local outages to neighboring regions. The project deploys phasor measurement units, phasor data concentrators, communication systems, and advanced transmission software applications. These devices increase grid operators’ visibility of bulk power system conditions in near real time, enable earlier detection of problems that threaten grid stability or cause outages, and facilitate information sharing with neighboring control areas. Access to better system operating information allows PJM engineers to improve power system models and analysis tools for better reliability and operating efficiency.

Through this project, PJM is implementing advanced transmission applications for the Synchrophasor system, including:

* Angle and frequency monitoring provides grid operators and engineers with detailed information about grid conditions and power flow.
* Disturbance analysis provides operators with the ability to visualize historical data trends, obtain temporal and spatial information about the disturbance, and assess the impact on system reliability and the root cause of the disturbance.
* Wide-­‐area monitoring provides PJM with additional visibility of the regional bulk transmission system. This enables better understanding of changes to system conditions.
* Oscillation monitoring allows PJM grid operators and engineers to observe power system disturbances and oscillations and to understand the impact of these conditions on the reliability of the grid.

WECC[[10]](#footnote-10)

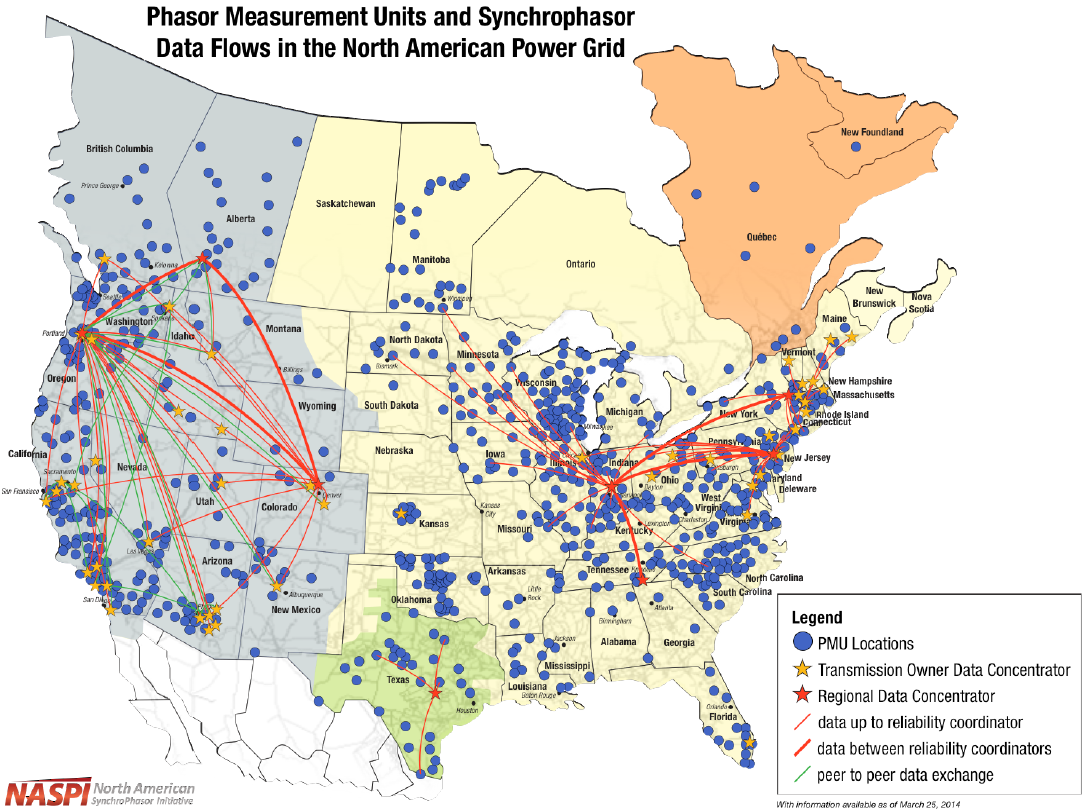
The Western Interconnection Synchrophasor Program (WISP), led by WECC and involving 18 partners, is an initiative to modernize operation of the transmission system in the Western Interconnection, increasing reliability and system performance, and enabling greater use of renewable resources such as solar, hydro, and wind.

Funded partially with $53.9 million in American Recovery and Reinvestment Act of 2009 (Recovery Act) stimulus funds awarded by the U.S. Department of Energy (DOE), WISP partners are installing an extensive network of synchrophasor technology, including more than 300 phasor measurement units (PMU) and 60 phasor data concentrators (PDC), across the Western Interconnection.

The earliest applications will focus on monitoring grid conditions and disturbances. The vast synchrophasor network will provide grid operators and reliability coordinators an unprecedented view of the Western Interconnection and dramatically improve situational awareness. Such applications will include monitoring of system frequency, voltage, and oscillations. Other applications will utilize synchrophasor information to control devices in ways that have been impossible in the past. Some applications will allow engineers to improve power system models and increase the operational efficiency of the grid.

In the near term, WISP and other projects like it will help grid operators, reliability coordinators and engineers better understand the complexities of a dynamic power system. The new information and tools should reduce the frequency and scope of outages in the bulk power system. Given the huge economic impact of blackouts, the reliability benefits are expected to be significant. With a better picture of real-time grid conditions, WECC operators will be able to more fully use the capability of the transmission system enabling it to be operated closer to its dynamic limits. Better use of the existing grid will allow transmission owners to defer other investments to increase system capacity or build new lines, yielding significant financial savings.

An overview of Synchrophasor data flows from Transmission Operators (TOs) to regional hubs, between reliability coordinators, and between TOs as of March 2014 is shown in the figure below. There is extensive TO peer-to-peer sharing of synchrophasor data across WECC, but only TO-to-RC data-sharing and limited RC-to-RC sharing across the Eastern Interconnection as of mid-2014.



**Recommended Action(s)**

Task 1: Monitor efforts in other interconnections in order to discover pertinent best practices and be aware of industry trends.

Task 2: Collaborate with WECC Joint Synchronized Information Subcommittee (JSIS) members to discover pertinent best practices and be aware of industry trends.

**Overall Summary of Key Recommendations**

This vision will be accomplished through the following tasks and related sub-tasks which have been summarized in terms of their relative priority, present status, and ownership:

| IL # | Task | Priority | Status | Owner |
| --- | --- | --- | --- | --- |
| 1 | How will synchrophasor data be used in ERCOT (real-time monitoring, unit model validation, etc.)? What are the current and planned uses by ERCOT? What are current and planned uses by TSPs and generators? | | | |
|  | *No follow-up action items required.* | | | |
| 2 | What kinds of locations of PMUs are needed to meet this use(s)? How will these locations be determined? | | | |
|  | * Develop application-based guidelines for locating PMUs within the ERCOT region. | High | Addressed by PMTF proposed NOG section 6 language. | PMTF |
| 3 | What are the data latency and quality requirements and other specifications, in order to meet the intended uses? Should these vary depending on the kind of PMU location? | | | |
|  | * Establish Minimum Data Latency Requirements | High | Addressed by PMTF proposed NOG section 6 language. | PMTF |
|  | * Establish Minimum Sampling Rate Requirements | High | Addressed by PMTF proposed NOG section 6 language. | PMTF |
|  | * Establish Minimum Bandwidth Requirements | High | Addressed by PMTF proposed NOG section 6 language. | PMTF |
|  | * Establish Minimum Redundancy Requirements | High | Addressed by PMTF proposed NOG section 6 language. | PMTF |
| 4 | Who should install and own the PMUs? Who should be responsible for the communications from the PMUs? | | | |
|  | * Develop ERCOT Synchrophasor Communication Handbook | High | Complete | PMTF (transition ownership of document to NDSWG) |
| 5 | How should synchrophasor data be treated in terms of confidentiality? | | | |
|  | *No follow-up action items required.* | | | |
| 6 | What reporting should be established for synchrophasor data? ROS/DWG/SPWG/PDCWG etc. | | | |
|  | * Reporting of Oscillations Detected by ERCOT | Medium | Ongoing via ROS Monthly Operations Report. | ERCOT staff |
|  | * Reporting Generator Model Validation | Medium | Not yet started. | ERCOT staff, DWG |
|  | * Reporting PMU data to support Event Post Analysis | Medium | Ongoing with limited WG involvement. | ERCOT staff, SPWG, PDCWG |
|  | * Report on Lessons Learned | Medium | Not yet started. | ERCOT staff, PDCWG, Seminar Working Group |
| 7 | What data retention should be established for synchrophasor data? | | | |
|  | * Draft recommended (minimum) guidelines for trended phasor data retention | Medium | Addressed by PMTF proposed NOG section 6 language. | PMTF |
|  | * Draft recommended (minimum) guidelines for phasor data retention by exception | Medium | Addressed by PMTF proposed NOG section 6 language. | PMTF |
| 8 | What are the CIP implications/requirements for the use of this data? | | | |
|  | * Educate entities on CIP considerations of Synchrophasor data through forums such as the ERCOT CIPWG. | Low | Ongoing by each asset owner. | CIPWG and individual asset owners |
| 9 | What is the application of synchrophasor data in the area of Ancillary Services? | | | |
|  | * Ensure the minimum PMU recording requirements meet AS requirements. | Medium | Not yet started. | PDCWG, FAST, ERCOT staff |
| 10 | Impact of related NERC Reliability Standards and FERC rulings on synchrophasor data usage in ERCOT | | | |
|  | * Monitor the development of the draft PRC-002-2 standard and provide constructive input to the Standard Drafting Team as necessary. | Medium | Subject to NERC & FERC timeframe. | Individual registered entities. |
|  | * Position ERCOT binding language in this area to support and complement – yet not conflict – with the PRC-002-2 binding language. | High | Subject to NERC & FERC timeframe. | ROS |
|  | * Pursue generator model verification techniques that utilize high fidelity, captured event data of the generator’s response to system events. | Medium | Ongoing | Generator Owner (GO) and Transmission Planner (TP) registered entities and ERCOT staff in a coordination role. |
| 11 | Review of other Interconnections’ Efforts in this Area | | | |
|  | * Monitor efforts in other interconnections in order to discover pertinent best practices and be aware of industry trends. | Low | Ongoing through NASPI and other forums. | ERCOT staff and individual asset owners. |
|  | * Collaborate with WECC Joint Synchronized Information Subcommittee (JSIS) members to discover pertinent best practices and be aware of industry trends. | Low | Not yet started. | ERCOT staff |

**References and Further Reading**

1. ERCOT Synchrophasor Communication Handbook
2. ERCOT Nodal Operating Guide Section 6
3. IEEE C37.118.1 – IEEE Standard for Synchrophasor Measurements for Power Systems
4. IEEE C37.118.2 – IEEE Standard for Synchrophasor Data Transfer for Power Systems
5. IEEE C37.244 – IEEE Guide for Phasor Data Concentrator Requirements for Power System Protection, Control, and Monitoring
6. NASPI list of “[Actual and Potential Phasor Data Applications](https://www.naspi.org/File.aspx?fileID=537)”
7. NERC report: “[Real-Time Application of Synchrophasors for Improving Reliability](https://www.naspi.org/File.aspx?fileID=519)”

**Acknowledgments**

The team would like to thank all the Task Force participants and all the industry guest speakers who contributed their time and talents to this report and related documents.

**Filename**

Respectfully submitted to the ERCOT ROS Subcommittee for their consideration by Kristian Koellner (Chair) and Bill Blevins (Vice Chair) on behalf of the PMTF on 10/20/14.

1. Identified at July 2014 ROS meeting [↑](#footnote-ref-1)
2. <http://www.nerc.com/pa/Stand/Project%20200711%20Disturbance%20Monitoring%20DL/NERC_CEAP_DM-CEA_Pilot_4-9-14SC_Endorsed_Version.pdf> [↑](#footnote-ref-2)
3. “Performance Monitoring and Model Validation of Power Plants Leveraging Synchrophasors”, BPA presentation to NERC PC, 12/7/10, Tampa, FL [↑](#footnote-ref-3)
4. Real-time communication not required. Generator Model Validation can be performed off-line. [↑](#footnote-ref-4)
5. Real-time communication not required. Post-Event Analysis can be performed off-line. [↑](#footnote-ref-5)
6. ERCOT Concept Paper, Future Ancillary Services in ERCOT, 9/27/2013 [↑](#footnote-ref-6)
7. <http://www.ferc.gov/media/news-releases/2014/2014-3/07-07-14.asp> and <http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order_on_APS_agreement_IN14-6_20140707.pdf> [↑](#footnote-ref-7)
8. <https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/InnovationLeaderMISOUsesReal-TimeSynchrophasorTechnologiestoEnhanceReliability.aspx> [↑](#footnote-ref-8)
9. <https://www.smartgrid.gov/project/pjm_interconnection_llc_pjm_synchrophasor_technology_deployment_project> [↑](#footnote-ref-9)
10. <http://energy.gov/sites/prod/files/Case%20Study%20-%20Western%20Electricity%20Coordinating%20Council%20-%20Smart%20Grid%20Strategy%20for%20Assuring%20Reliability%20of%20the%20Western%20Grid%20-%20August%202011.pdf> [↑](#footnote-ref-10)