Model Validation Using Phasor Measurement Unit Data

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Preface

This report was coauthored by Alison Silverstein (independent consultant and NASPI Project Manager), Eric Andersen (Pacific Northwest National Laboratory), Frank Tuffner (PNNL), and Dmitry Kosterev (Bonneville Power Administration). Tom King, Jr. was the project manager at the Oak Ridge National Laboratory (ORNL) and Jeff Dagle was the project manager at PNNL.

The North American Synchrophasor Initiative is a collaboration between the electric industry, manufacturers and vendors, academia, national laboratories, government experts and standards bodies. The group works to accelerate the maturity, capabilities, and use of synchrophasor technology to improve the reliability and efficiency of the bulk power system. NASPI receives financial support from the United States Department of Energy and the Electric Power Research Institute and is managed through the Battelle Pacific Northwest National Laboratory.

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Questions regarding the report may be directed to Alison Silverstein, NASPI Project Manager (alisonsilverstein@mac.com) or Teresa Carlon at PNNL (Teresa.carlon@pnl.gov).

Disclaimer

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The Department of Energy's Office of Electricity Delivery and Energy Reliability, through the Consortium for Electric Reliability Technology Solutions, has worked with Bonneville Power Administration (BPA) to fund extensive work by BPA and the University of Wisconsin on model validation. This work used both DOE research and development funding and American Reinvestment and Recovery Act (ARRA) grants.

Many of the insights in this report were gained from the PMU projects installed as part of the ARRA Smart Grid Investment Grants and Smart Grid Demonstration Projects. Those grants required at least a 50 percent cost match from their private partners.

This report benefited from information, guidance, or critical technical review from Joe Paladino (DOE), Phil Overholt (DOE), David Ortiz (DOE), Steve Yang (BPA), Joe Gracia (ORNL), Harold Kirkham (PNNL), Pavel Etingov (PNNL), Ryan Quint (Dominion Virginia Power), Pouyan Pourbeik (Electric Power Research Institute), Jim Kleitsch (American Transmission Company), Bernie Lesieutre (University of Wisconsin), Bill Blevins (Electric Reliability Council of Texas), and Michael Esposito and Shripad Chandrachood (MathWorks®).

Executive summary

Power systems are designed and operated using mathematical models that characterize the expected behavior of power plants, grid elements, and the grid as a whole. These models support decisions about what types of equipment to invest in, where to put it, and how to use it in second-to-second, minute-to-minute, hourly, daily, and long-term operations. When a generator, load, or other element of the system does not act in the way that its model predicts, the mismatch between reality and model-based expectations can degrade reliability and efficiency. Inaccurate models have contributed to a number of major North American power outages, including, for example, the August 1996 Western Interconnection outage.

The behavior of power plants and electric grids change over time and should be checked and updated to assure that they remain accurate. Engineers use the processes of validation and calibration to make sure that a model can accurately predict the behavior of the modeled object. Validation assures that the model accurately represents the operation of the real system—including model structure, correct assumptions, and that the output matches actual events. Once the model is validated, a calibration process is used to make minor adjustments to the model and its parameters so that the model continues to provide accurate outputs. High-speed, time-synchronized data, collected using phasor measurement units (PMUs), are essential for model validation of the dynamic response to grid events. Grid operators like the Bonneville Power Administration are already using PMU data recorded during normal plant operations and grid events to validate grid and power plant models quickly and at lower cost.

To reduce the possibility of inaccurate models contributing to another large-scale system event, the North American Electricity Reliability Corporation (NERC) recently adopted four Reliability Standards for periodic model validation and calibration. The scope of these standards primarily covers generator models and requires regular checks to ensure the modeled behavior matches reality.

This report describes the use of PMU data for model validation. It introduces some basic concepts of electric asset models, reviews the benefits of synchrophasor-based model validation, and provides an overview of the model validation process. It offers some examples of how industry members have been using synchrophasor-based model validation to improve the accuracy of their models and improve grid reliability. Last, this report summarizes the new NERC modeling standards, which can be met using synchrophasor-based model validation methods.

The primary benefits of using PMU data for model validation and calibration include the following:

- PMU data contain real operating ranges and operational relationships among grid assets more accurately than stand-alone testing of individual physical assets. This produces better models of grid assets and their interactions, which improve overall system reliability.
- Models validated and calibrated using PMU data improve asset and system efficiency by setting more accurate operating limits for grid assets, which may enhance asset utilization.

- Once a good model is developed, engineers can use PMU data with the model to detect equipment mis-operations and predict failures, enabling better asset maintenance. This may prevent more substantial equipment damage and could potentially have safety benefits.
- Synchrophasor-based model validation and calibration methods are more economical, timely, and accurate than validation methods that take a generator offline for performance testing. Validation and calibration using PMU data enable the asset owner to continue operating the plant and realizing revenue without stopping operations to conduct testing for model validation purposes.
- Synchrophasor-based model validation and calibration are an accepted and cost-effective way to satisfy the requirements of NERC Reliability Standards MOD-26, MOD-27, MOD-32, and MOD-33 to verify generator real and reactive power capability and control systems, and to assure their appropriate responses during system disturbances [1].

The benefits of synchrophasor-based model validation listed above provide power system asset owners and operators many advantages over traditional offline generator testing. These include the ability to meet the NERC Standards, and potentially to operate the grid in a more reliable and efficient manner. Already, several grid operators mandate PMU placement at generator interconnections so that data can be used to validate generator and system models.

Acronyms

ACE	area control error
ARRA	American Reinvestment and Recovery Act of 2009
BPA	Bonneville Power Administration
COI	California-Oregon Intertie, a set of three 500 kV alternating current power lines connecting California and Oregon
DFR	digital fault recorder
DOE	U.S. Department of Energy
DOE-OE	U.S. Department of Energy, Office of Energy Delivery and Electric Reliability
EIMA	Energy Infrastructure Modeling and Analysis, a division of DOE-OE
EMS	energy management system
EPG	Electric Power Group, a consulting and software firm
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas, a reliability coordinator serving most of Texas
FACTS	Flexible Alternating Current Transmission System
FERC	Federal Energy Regulatory Commission
FNET	frequency monitoring network
GE	General Electric, an electrical equipment provider and software developer
GPS	Global Positioning System
HVDC	high-voltage direct current
Hz	Hertz, the unit of frequency, defined as one cycle per second; the North American grid operates at 60 Hz.
IEEE	Institute of Electrical and Electronics Engineers, a standards organization
ISO-NE	Independent System Operator – New England
MATLAB®	Mathematical modeling software by MathWorks®
MISO	Midcontinent Independent System Operator, the reliability coordinator and market operator serving fifteen Midwestern states and Manitoba, Canada
MVAr	mega volt-ampere reactive, a measure of reactive power in an electrical circuit
MVA	megavolt ampere(s), a measure of real or active power in an electrical circuit
NASPI	North American Synchrophasor Initiative
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator, the reliability coordinator and wholesale market operator serving New York State
NYPA	New York Power Authority
PG&E	Pacific Gas and Electric
PJM	PJM Interconnection, LLC, the reliability coordinator and wholesale market operator serving fourteen Mid-Atlantic and Midwest states and the District of Columbia
PMU	phasor measurement unit
PNNL	Pacific Northwest National Laboratory

PPMV	Power Plant Model Validation
PPPD	Power Plant Parameter Derivation
PSLF	General Electric's Positive Sequence Load Flow power flow software
PSS®/E	Power System Simulator for Engineering, a Siemens modeling tool
RAS	remedial action scheme (also called a Special Protection System), an automatic protection system designed to detect abnormal or pre-specified system conditions and take pre-arranged corrective actions to maintain system reliability.
SCADA	Supervisory Control and Data Acquisition
SGIG	Smart Grid Investment Grant, 4-year narrow-focus technology grants funded under the ARRA, awarded by the U.S. Department of Energy for a variety of electric grid technology projects
STATCOM	Static Synchronous Compensator
SVC	static VAr compensator
VAr	volt-ampere(s) reactive, a measure of reactive power
WAMS	wide-area measurements system
WECC	Western Electricity Coordinating Council, the reliability coordinator serving the Western Interconnection
WISP	Western Interconnection Synchrophasor Program

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1. Introduction

Power systems are designed and operated based on mathematical models that characterize the expected behavior of power plants, grid elements, and the system as a whole. Many mathematical models are used in power systems: they are used to estimate asset costs and capabilities, they predict how different assets will work together within a system of loads and resources, they inform the planning and design of the system, and operators use them to guide real-time operations.

The level of detail in models of power system elements varies by application. Some models represent the transmission lines and switching stations that form the electrical grid, converting the electrical measurements into indications of physical conditions such as thermal loading and ground clearances. Other models represent a high-level summary of the grid and how larger balancing areas are exchanging power to maintain a consistent frequency across the system. Often, the result of one model can feed into another to provide even greater system observability. Nearly every single function in a modern grid control center has some form of underlying model that actively interprets the current state of the grid, extracts additional indicators of performance and reliability, or predicts imminent future grid conditions.

Given the many models associated with electric power planning and operations, the need for accurate models has never been greater. With accurate, validated models, abnormal behaviors or pending equipment failures can be detected and rectified before larger outages occur. Good models boost confidence in the measurements being received, and may reveal behaviors that are not directly observable in the raw measurements. For example, in the Western Electricity Coordinating Council (WECC) operating region, models use phasor measurement unit (PMU) data to estimate the properties of small signal stability on the western interconnected power system. If these mode monitors detect a low damping condition, operators can act to reduce the stress on the grid and prevent a large-scale outage. This reliability protection would not be feasible without an accurate underlying model and real-time PMU data.

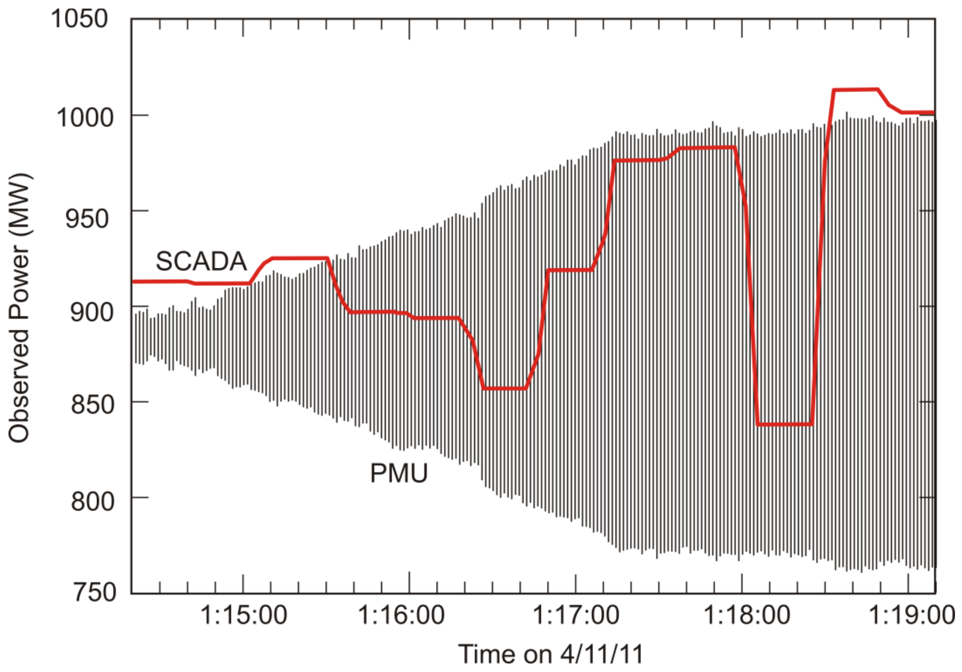
In contrast, when a model does not accurately predict the performance of a component of the system, the mismatch between model-based expectations and actual performance may lead to unexpected violations of the system stability, power outages, power system disturbances, generation tripping, and/or costly equipment damage. Inaccurate models have contributed to a number of major North American power outages. One notable example includes the 1996 Western Interconnection blackout. Planning models being used during the 1996 blackout could not accurately predict the significant instabilities of the actual power system that caused the blackout; a more accurate model might have caused a different system design and operations that did not collapse as a result of the set of causes that occurred in 1996.

One way to make power system models more accurate is to use data collected by PMUs to validate them. PMUs typically measure grid conditions at least 30 times per second, 100 times faster than the 2- to 4-second reporting rate typically associated with Supervisory Control and Data Acquisition (SCADA) systems. These high sampling rates are necessary to observe dynamic power system phenomena. Also, PMU measurements are time-synchronized and time-stamped right at the moment of measurement, providing a synchronized view of the power system dynamic state that is unavailable from SCADA measurements.

For the purposes of this document, the terms "PMU" and "synchrophasor" are not used interchangeably. Strictly speaking, a synchrophasor is a "synchronized phasor," which is created by a device that assigns synchronized time-stamps to measured quantities. Within the power system community, some use the term "synchrophasor" to mean the PMU device as well as the calculated measurement. This report uses the term "PMU" to mean any member of a suite of grid monitoring devices that produce and store high-speed, time-synchronized measurements of grid conditions. That group includes digital fault recorders (DFRs), frequency monitoring network (FNET) devices, digital relays upgraded to full PMU capability, and dedicated PMUs.

A PMU measures current, voltage, and frequency, which are also measured by SCADA devices. However, a PMU also calculates the phase angle of voltages and currents at these locations in the power system. PMUs record the data at much higher measurement and reporting rates than SCADA, offering more granular visibility into grid and asset conditions. Furthermore, PMU data are time-synchronized at the moment of measurement using universal time sources such as Global Position Systems (GPS). This time synchronization allows measurements from many grid locations to be time-aligned and combined, creating wide-area views of the grid. Traditional SCADA-based measurements time-stamp the data upon receipt at the control center or data collection point, not at the location of the measurement. Because of communications network latencies, SCADA data are not consistently time-stamped and when used to represent wide-area grid conditions, may mis-represent the state of the power system. Although most current grid operations models use SCADA data, opportunities exist to improve model accuracy using PMU data.

A power plant oscillation event in 2011 shows the insights to be gained from looking at PMU rather than SCADA measurements only. Figure 1 shows a 2011 oscillating event on a power plant owned by Dominion Virginia Power [2], recorded with both SCADA (red line) and PMU (black line) monitors. In this event, real power in this generator was fluctuating up and down by a few hundred megawatts every few seconds due to a malfunctioning power system stabilizer on a nearby power plant. The SCADA system showed changes in power over the course of a few minutes, but the PMU data show the speed and magnitude of the oscillatory behavior in precise detail. The greater visibility afforded by PMUs improve operations staff ability to identify and diagnose operational problems, and then take action to address those problems. In this case (and in many others), the SCADA data do not reveal the full nature of the problem and offer less insight into possible solutions.



Source: Adapted from Thorp and Gardner 2014 [2]

Figure 1. Comparison of SCADA and PMU measurements for grid oscillation event

The U.S. Department of Energy's (DOE's) Smart Grid Investment Grants and Smart Grid Demonstration Program grants, authorized under the American Recovery and Reinvestment Act (ARRA) of 2009, funded a number of PMU technology projects, matched by private sector efforts and funds. Those projects spurred the deployment of more than 1,700 PMUs across North America, and the development of numerous applications and analytical effort to use the synchrophasor data now being collected.

With the widespread deployment of PMUs, the data they produce can be used to improve and validate power system models. Model validation represents the process of comparing model predictions to a trusted source, such as PMU measurements of actual system events, and comparing the results. If the difference between the two responses is within acceptable margins, then the model is deemed valid and it can be used for the appropriate application. But if the difference is outside some acceptable range, then the model is deemed inaccurate and it must be corrected. Once a model is validated, it may require periodic calibration to fine-tune the parameters within the model to reduce error. Calibration uses a known reference to adjust the model's parameters to accurately predict known outcomes in response to actual operating conditions and disturbances.

Model validation and calibration using PMU data are now recognized as appropriate and successful uses of synchrophasor data. Calibrating asset models using PMU data, increases the likelihood that the models will perform accurately under a wide range of grid and asset conditions. Rather than performing offline testing of grid assets and using historic data from such tests, PMUs allow the creation and validation of models representing grid assets under normal operating conditions and in near-real time (data are usually available within milliseconds). The PMU-based model allows for more efficient operation of the grid by better reflecting the actual behavior of the system, not based on a physical asset test conducted months or years past. Furthermore, model testing and improvement using actual grid performance information collected by PMUs is more precise, time-efficient, and can be more economical than traditional offline asset testing. Transmission operators like PJM and BPA are requiring PMU installations on the generator side of interconnections to leverage the benefits of synchrophasor-based model validation.

This report explains the value of PMUs in validating power system models. The report is organized as follows:

- Section 2 discusses power system models in general and provides some background on model validation and calibration.
- Section 3 discusses the explicit advantages of PMU-based model validation.
- Section 4 describes how to perform the model validation process.
- Section 5 provides some brief examples of model validation using PMUs.
- Section 6 concludes the report.
- Appendix A describes the new NERC model validation requirements.
- Appendix B describes automated model validation and calibration tools using synchrophasor data.

2. Power system models

Electric system planning and operations require extensive modeling and analysis to operate successfully. Models and simulations are used to predict how individual grid elements, and the grid as a whole, will behave and respond to grid events under various circumstances. Power systems are planned, designed, and operated to withstand contingencies and power system events without interrupting service to customers. Model representations are often used in lieu of actual grid tests because it is impractical or impossible to test all of the possible operational conditions or resource commitments, including combinations that can occur in grid operations. Better models of individual grid assets, and of the grid as a whole, can reduce uncertainties, improve reliability, and yield more economical operational and investment decisions.

Power system model characteristics

On a fundamental level, all power system models are sets of mathematical equations representing physical systems. A model may represent a set of differential equations defining the magnetic field in a generator, or calculate the power flowing from one region to another. Many different types and scales of power system model exist, representing the different requirements and complexities of different conditions and operational requirements of the power system. For simplicity and the purposes of this document, models are qualified by a set of three characteristics. These characteristics define the scope of the model, its typical use, and the timescale of the modeled behavior.

The scope of the model defines the scope and extent of the elements the model represents—this could range from a single device (e.g., a transformer), a set of devices that perform as a single asset (e.g., a power plant), or a set of assets that perform within a region (e.g., a regional system that includes many transmission lines and generators). The way a specific device or asset is modeled may vary according to its typical use; for example, the model of a power plant used for power production and revenue forecasting is very different than the model of a plant that is used for short-term system dispatch or longer-term protection and control studies. For the purposes of this document, the scope of the model is divided into device-level and system-level impacts.

- **Device-level model** – These models typically encompass a single piece of equipment and very localized observations. Device-level models often include explicit representations of finer detail of the asset, such as magnetic flux in coils or positions of individual steam valves. They often represent a specific control device on an asset (e.g., governor) or a single asset in a larger aggregation (e.g., a single turbine in a hydrogeneration facility).
- **System-level model** – These models typically encompass a larger geographic region that can vary from something as small as a town to as large as a whole transmission interconnection or reliability region. System-level models can represent a collection of device-level models, or an aggregated behavior of smaller components. Observations from various points in the larger power system represent inputs and expected outputs of these models. System-level models often aim to capture larger-scale behaviors, such as power flowing through a corridor or the electrical frequency of the entire grid. They often represent many devices and assets and use aggregations or simplifications of asset behavior (e.g., model a power plant as one single, larger source, instead of individual generating units or compound devices).

Models can also be categorized as offline and online models:

- **Offline model** – These models are used in system planning studies or post-event analyses. They represent models where execution time is not a primary concern and may explore specific or future conditions of the power system. Offline models can represent the present grid, but are often not updated very quickly and may include simplifications to capture larger, system-level impacts. Archived measurements or statistical approximations may be used to validate and adjust these models. Long-term transmission planning models, seasonal operational models, and day-ahead market models are typically offline models.
- **Online model** – These models are used in near-term planning studies (e.g., within the next hour) and for system real-time operations (e.g., supporting decisions within the next several seconds). Execution time is a significant concern for online models, as is receiving timely information. PMU data are fed into the model and outputs are expected before the next change in the state of the system. These models often represent the present power system and provide indications of system conditions (e.g., state estimation) or are performing near-term forecasts to estimate real-time system operating limits. These models may vary from system-level impacts to individual generator conditions or outputs. State estimation models and real-time contingency analysis are examples of online models.

The final classifier for models in this document concerns the timescale they represent. PMU data can be used to validate both static and dynamic models. However, because dynamic models by definition address high-speed system behavior, high-speed, time-synchronized PMU data are uniquely suited and necessary for use in dynamic models.

- **Static model** – These models represent the slower behaviors of the power system, often with minute- to hour-level granularity. Static models typically represent larger, steady-state behaviors of the system such as power flow and generator economic dispatch. Faster behaviors of the system are either ignored or averaged out in static model mathematical representations. Longer time steps mean that both SCADA and PMU data can be used to validate and calibrate most static models.
- **Dynamic model** – These models represent the faster behaviors of the power system and its assets, often on the millisecond to second timescale. Dynamic models represent transient behavior as the system transitions between different states and equilibria. Dynamic models often use differential equations and direct physical representations of power system elements, with significant complexity and computational requirements relative to static models. These models are used to study near-term stability conditions of the grid such as frequency regulation, voltage stability, and small signal stability. SCADA measurements do not capture dynamic events well (as shown in Figure 1) and are not time-synchronized; therefore, PMU data are better suited for measuring dynamic phenomena than SCADA devices.

Table 1 shows a few of the major types of models that are used in for specific grid planning and management functions. It categorizes these models using the distinctions above and indicates which of these models can use SCADA or PMU data.

Table 1. Some types and uses for power system models

Model Type	Typical Use	Preferred Input Data	System/ Asset/ Device	Online/ Offline/ both	Static/ Dynamic/ Both
Generator capacity models	Predict machine capabilities for market bid limitations	SCADA	Device	Both	Static
Generator performance models	Predict machine response to system events and conditions	PMU	Asset	Both	Dynamic
Interconnection-wide model	Line thermal limits	SCADA	System	Both	Static
	Voltage stability, rotor angle stability, small signal stability, frequency compliance	PMU			Dynamic
Remedial Action Scheme trigger model	Detect and implement proactive protection for certain grid conditions	PMU	System	Both	Both

Power plant model development

Under NERC Reliability Standards, every large generation plant owner is required to provide a mathematical model of that plant to its transmission provider, so the transmission provider can understand how the plant will behave relative to the rest of the bulk power system [3, 4]. A power plant developer usually provides an "as built" model to the plant owner.[1] The model for a new plant is initially developed based on physical testing of the plant. The initial (or baseline)

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[1] The Institute of Electrical and Electronics Engineers (IEEE) maintains a catalog of generic models characterizing power plant and transmission equipment; the user can customize a generic model to represent a specific generator or asset.

plant model establishes the basic model structure and offers an initial set of values for key model parameters of that system (e.g., type of generator, capacity, and control settings). This manufacturer-supplied model should produce accurate predictions of the plant's performance for a certain range of inputs [5].

However, initial testing of a power plant does not always yield a model that accurately describes the plant's behavior under a broad span of grid conditions and unplanned system disturbances. The Bonneville Power Administration (BPA) has found that for many power plant models, the key plant components, such as power system stabilizers and turbine governors, have deficient models even after the baseline plant testing has been performed and applied to customize the initial plant model. BPA's experience testing models developed by generation owners suggests that 60 to 70 percent of the power plant models did not accurately predict actual plant performance (as was recorded with PMUs under actual system disturbances) [5], particularly for plants with analog controls.

In 2006, the WECC adopted the Generating Unit Model Validation Policy [6], officially allowing and encouraging the use of PMU-enabled disturbance recordings for power plant model validation. For effective performance monitoring, WECC recommends that generator owners install disturbance monitors (such as PMUs) in a power plant to collect high-speed data on stator voltages and currents, field voltage and current, and governor valve position. These data can be used to supplement plant inspections and support later model validation.

There are several stages in the process of validating generator or system models:

1. Obtain the reference data for the validation process, typically measurement data from the point of interconnection or a nearby PMU.
2. Select the appropriate device model structure.
3. Set the model to simulate the operation of the generator or system under the specific grid conditions and inputs (power and voltage).
4. Run the model.
5. Compare the results against the actual PMU measurements. There are two possible outcomes:
    - If the differences are within pre-defined limits, the model is valid.
    - If the differences between the model's prediction and the plant's actual performance do not match, the model will either need calibration, or revision. A model revision requires revalidation.
6. Replicate this process to account for multiple disturbances over a range of operating conditions.

These steps are explored further in Section 4.

While validating a model is an important process to ensure it properly represents reality, this is only one step in the overall maintenance of the asset model. Periodic calibration and parameter update mechanisms are also key items of the modeling process. These model maintenance tasks help keep the model relevant to the current system conditions and aid in the ability to maintain validity. A brief discussion of model maintenance is also discussed further in Section 4.

WECC adopted a model validation standard in 2006. The success of that effort formed the basis for others to consider adopting similar policies and standards. NERC recently updated and expanded its modeling standards to assure that all power system models (including both static and dynamic models) and data used to predict system performance will be accurate and up to date. The four Reliability Standards are summarized below; more detail is provided in Appendix A. These MOD standards will take effect over the next 3 years, so the North American electric industry is preparing now for their adoption. None of these standards explicitly requires the use of synchrophasor data for compliance with the standard, but using PMUs to collect these data will be an effective and cost-efficient path to compliance.

- **MOD−026−1, "Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAr Control Functions"** – This is intended to make sure that models and data used in dynamic simulations accurately represent generators' voltage and reactive power capabilities. Most of its requirements became effective on July 1, 2014; the requirement to provide the verified generator model and data becomes effective on July 1, 2018 [3].
- **MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions"** – This is intended to make sure that there is an accurate, well-calibrated model for each generator's real power response to system frequency variations. Most of the provisions of MOD-027-1 became effective in July 2014; Requirement 2, for submittal of a fully verified model and associated data, will take effect on July 1, 2018 [4].
- **MOD-032-1, "Data for Power System Modeling and Analysis"** − This standard establishes consistent modeling data requirements and reporting procedures for development of "planning horizon cases necessary for analysis" of the interconnected grid. Requirement R1, for sharing data between planning entities and operating entities, will become enforceable on July 1, 2015. The other provisions will become effective on July 1, 2016 [7].
- **MOD-033-1, "Steady-State and Dynamic System Model Validation"** – This requires planning coordinators to develop a documented data and model validation process and transmission owners to provide actual system behavior data. It will take effect on July 1, 2017 [7].

While NERC's MOD standards will require model verification every 10 years, WECC has adopted a regional policy requiring that models be updated every 5 years. More frequent validation allows detection of the control system failures and errors, particularly power system stabilizers, and operating status changes. WECC also lowers the model validation threshold to 20 MVA per plant, thus applying its requirement to a wider range of power plants than are covered under the 75 MVA rating in the NERC standard [8].

Many transmission planners and transmission operators believe that using synchrophasor-based disturbance recordings for model validation and calibration is the most effective way to comply with these requirements—not just once every 10 years, but also for routine performance assessment and updating of power plant models. PMU technology allows power plant model validation to be performed many times per year instead of once every 10 years. As Section 5 shows, an increasing number of generation owners and transmission planners have gained experience with and confidence in this method.

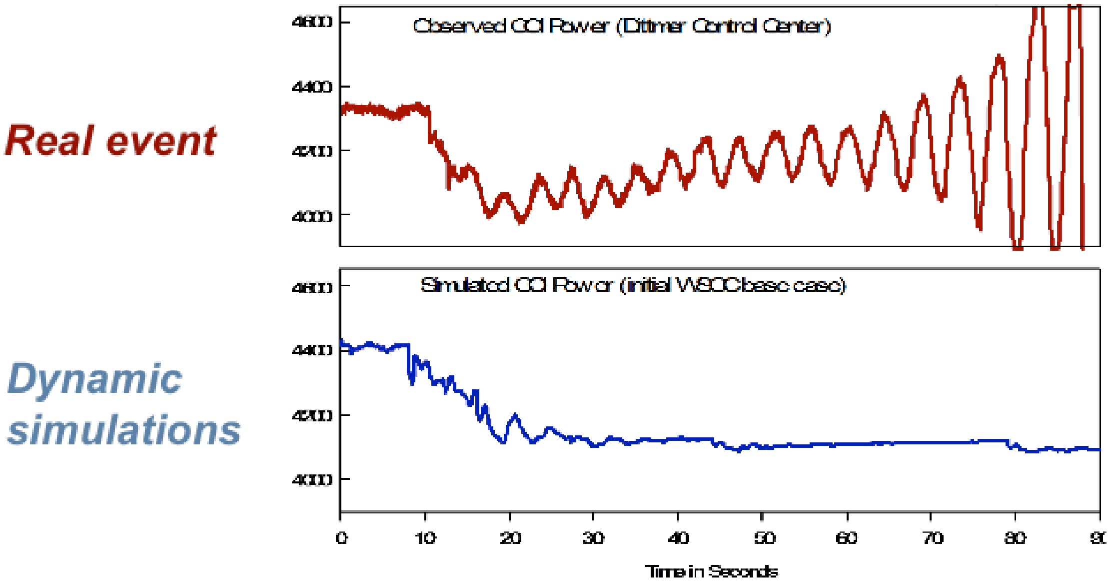
Accurate models and inaccurate models

Given the many ways that utilities, generating entities, and grid operators use models, the accuracy and speed of those models can have multi-million or billion dollar consequences for grid operators, owners, and customers. Accurate models are those that reflect reality sufficiently for the intended application. Inaccurate models predict system or device behaviors that do not match their true response under specific conditions. Accurate models produce results that match the true state of the device or system (validated under a wide variety of grid conditions and events). Inaccurate models can lead to dangerous situations where grid behavior is unexpected because it does not match what the models predicted; such situations can end up in outages and equipment damage.

One such example is the August 1996 outage in the Western Interconnection. A number of equipment failures and local outages culminated in a grid separation that caused blackouts affecting millions of people across several western states. The system models of the time predicted that under this complicated set of conditions, the system would remain in a stable condition, as shown by the power flow on the California-Oregon Intertie in the bottom portion of Figure 2. However, the actual occurrences shown in the top portion of Figure 2 reveal that the system actually became unstable, moving into a large-scale oscillation that caused a system breakup and blackout. Had the dynamic models been accurate, operators might have better understood system limitations and might have prevented the blackout.

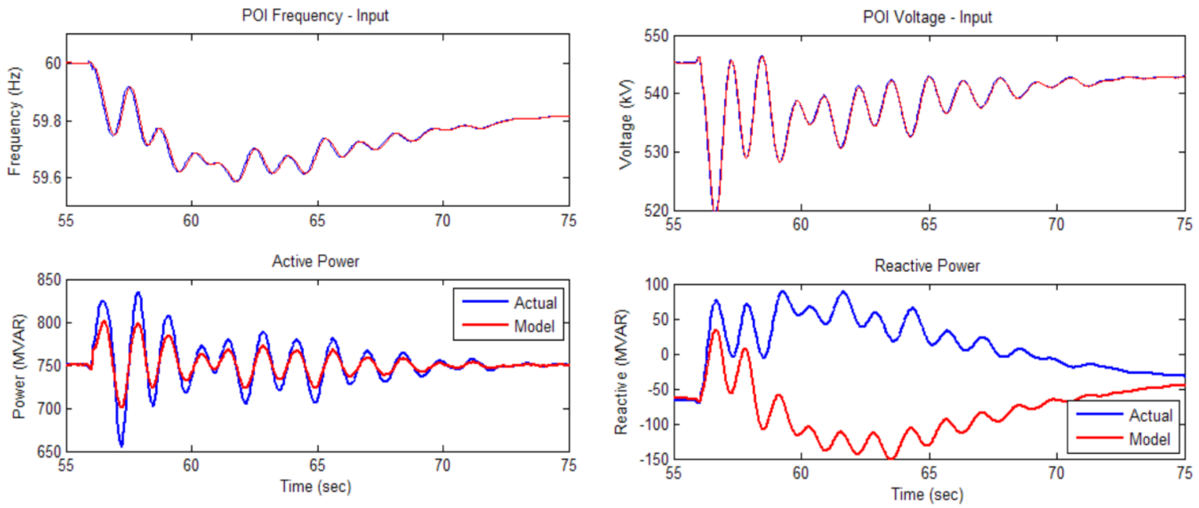
Inaccurate models can be improved to become more trusted, accurate models. The 1996 Western Interconnection blackout led to the discovery that the WECC planning models then in use could not predict the voltage changes that led to the blackout. Based on this insight, the WECC instituted baseline performance testing requirements for western power plants to validate and improve the generator models in the system. This validation process includes mandatory 5-year model updates and testing or regular comparisons of generator responses to system events.

WECC’s model validation efforts revealed several inaccurate power plant models. Figure 3 shows the model outputs and measurements for an 800 MW steam-turbine generator during a grid event. Frequency and voltage were used as model inputs, and active and reactive power were used as measures of model accuracy. The simulated magnitude of active power oscillations did not match actual data, and the reactive power predicted does not match the actual, measured value. The power plant is located in stability-limited region of the Western Interconnection. With regular PMU-based model validation, this inaccuracy was recognized and later fixed using model calibration methods developed by the University of Wisconsin.



Source: Kosterev et al. 2013 [5]

Figure 2. WSCC August 1996 Outage: actual event (top) and the simulation (bottom)



Source: Yang and Kosterev 2012 [9]

Figure 3. Inaccurate model (800 MW steam-turbine generator)

Following the 1996 blackout, BPA began to monitor several generators using PMUs to collect high-speed data about how the plants responded to real grid disruptions. In 2000, BPA began using the collected data for generator model validation in lieu of taking the plant offline for performance testing. Because PMUs sample and calculate power, voltage magnitude, voltage phase angle, and frequency in real time, a PMU placed at the point of interconnection between a power plant and the grid will collect data about actual plant performance during a wide variety of power system conditions. These data can then be used to determine whether the plant's model is accurate or inaccurate. Traditional machine testing, conducted while the plant is offline, does not subject the generator model to the same range of operating conditions, nor does it examine any of the interactive behavior between other grid assets that may influence the generator under test. This shortcoming may lead to a model that is accurate given the physical test conditions, but inaccurate under a wider range of operational conditions.

Today, BPA has PMUs monitoring 130 synchronous generators in 12 power plants with total generating capacity of more than 21 GW. In recent years, BPA expanded PMU monitoring to wind power plants, now covering 11 plants with total generating capacity of about 1.5 GW. PMU-based model validation is the preferred method for compliance with NERC MOD Reliability Standards.

3. Benefits of PMU-based model validation

PMU-based model validation and calibration for power plants is becoming a standard practice in several areas of North America as PMU usage has increased. BPA and PJM Interconnection, LLC (PJM) have recently adopted provisions to require new generators to install PMUs at the point of interconnection between the power plant and the transmission system, and similar provisions are being considered in other regions to assure that PMU data are collected for model validation.

Before PMUs and automated computer analysis tools were available, the long-established method of collecting data for model validation was to take a plant offline. One problem with offline testing is that the plant is unable to generate power during the outage, causing lost revenues for the duration of the test. With the plant offline, extensive physical testing is conducted to determine how the plant behaves under a variety of physical and electrical conditions that simulated grid-connected events. These performance data are used to develop the plant’s initial baseline model, and later tests are run during subsequent outages to acquire updated performance data. The physical test results are then compared to the model outputs and the model is corrected if needed.

PMU-based model validation offers numerous advantages over traditional physical generator testing. These benefits include:

- PMU data capture real operating ranges and operational relationships between grid assets more accurately than stand-alone testing of individual physical assets. This produces better models of grid assets and their interactions, which improve grid reliability.
- Grid disturbances captured in PMU data enable more frequent model validation, thereby increasing system planners’ and operators’ confidence in the power system model. Western Interconnection has 10 to 15 disturbance events each year that can be used for PMU-based model validation.
- Models validated and calibrated using PMU data improve asset utilization and system efficiency by setting more accurate operating limits for grid assets.
- Models validated and adjusted using PMU data allow engineers to detect imminent generator control or equipment failures and real-time mis-operations, which can allow planned maintenance rather than equipment failure and emergency response. This may also prevent potential equipment damage.

- Synchrophasor-based model validation and calibration enable the asset owner to continue operating the plant and realizing revenues by collecting continuous data about generator performance under actual grid conditions, rather than taking costly outages solely to conduct generator testing for model calibration. Overholt (2014) and Huitt (n.d.) [10, 11] describe success stories of using disturbance data to complement the baseline model development and calibration.
- Synchrophasor-based model validation and adjustment are an accepted and cost-effective way to satisfy the requirements of NERC Reliability Standards MOD-26, MOD-27, MOD-32 and MOD-33 with respect to generator, control systems, and system models [1].
- At the resource planning timescale, accurate models help transmission owners and system planners identify and invest in the correct amounts and types of grid and generation equipment.

PMUs at or near a power plant perform continuous high-speed monitoring that records the plant’s response to actual transmission-level grid disturbances, such as generator losses, faults, or breaker operations. The PMU data capture a much wider range of plant responses than would be examined in formal physical plant testing. Furthermore, while physical testing is costly and may only be conducted every 5 years, an owner with access to PMU data can review asset performance and recalibrate the model—or spot mis-operations or erroneous settings—much more frequently. PMU disturbance recordings and automated model validation tools enable continuous, ongoing model validation and recalibration after every grid disturbance.

4. How to perform model validation using synchrophasor data

Whether working with physical test data or PMU data, the broad process of model validation first requires verifying that the basic structure and assumptions of the model are correct, and then assessing and calibrating its essential parameters if necessary. Given PMU data on generator performance during multiple grid events, an engineer can set up the generator model to match the actual grid conditions and generator settings that occurred for a specific recorded event. The model is then run to see if it can reproduce the plant’s actual behavior during the event. If the prediction is far from the actual behavior, the analyst will have to determine whether the mismatch can be addressed by calibrating the model parameters, or making changes to the underlying model structure and assumptions. It may also be necessary to adjust assumptions built into the model to match actual plant settings—for instance, the model may assume that a power system stabilizer or Automatic Voltage Regulator is in operation, when in fact operators have turned it off (or vice versa).

This section offers more detail about the model validation process and lists some potential tools to perform the validation. The types of disturbance data useful for PMU calibration are outlined in a later subsection.

The model validation process

The basics of the model validation process were covered earlier in Section 2. NERC's Model Validation Working Group explains that the process for model validation of a generator (or other grid asset) using PMU data includes the following steps [12]:

1. Obtain the reference data for the validation process, typically PMU data from the point of interconnection or a nearby location.
2. Use the manufacturer-provided model or select the appropriate model for the asset (e.g., type of generator or Flexible Alternating Current Transmission System [FACTS] device).
3. Set the model to simulate the operation of the generator or system under the specific grid conditions and inputs (power and voltage).
4. Run the model with the selected PMU data to generate a simulated output.
5. Compare the simulated output to the actual PMU-measured values and determine if the model is valid. If the differences between the model's prediction and the plant's actual performance do not match, the model will either need calibration, or revision. A model revision requires revalidation.
    a. If necessary, adjust the model by varying the settings and parameters for the asset. For a generator, the governor, exciter, stabilizer, and any other significant, plant-specific elements can affect its performance. When the simulation and the actual occurrence are within pre-defined acceptance criteria, then the model is considered validated. If a close match cannot be obtained, the structure of the model may need to be revised.
    b. If the structure of the model requires revision, use appropriate engineering troubleshooting processes and engineering judgment to evaluate the underlying assumptions and algorithms to determine how to revise the model.
6. Replicate this process to account for multiple disturbances over a range of operating conditions. A robust model will have a good match against multiple events with the same asset parameters, and will ultimately deliver better predictions of the plant's response over a wide range of grid events.

This same process can be applied to non-generator assets and, in a much more complex fashion, to power system models.

While power plant validation and calibration process can be performed manually, a set of tools has been developed to automate the process. Table 2 lists some of the model validation software tools available in late 2014. Several other applications are in research and development stages. More detailed examples for each of these tools are provided in Appendix B.

Table 2. Available tools for PMU-based model validation

TOOL	DESCRIPTION	USERS
Electric Power Research Institute (EPRI) Power Plant Parameter Derivation Tool	Performs model calibration and verification using PMU data. The tool contains all IEEE standard excitation models and many popular turbine-governor models. The user selects initial models and parameter bounds. The software then automatically iterates on model parameter adjustments until it finds the combination of settings that best match the PMU recorded event data.	MISO, NYISO, PJM, Duke Energy
BPA/PNNL Power Plant Model Validation Tool	Uses GE PSLF software, PMU data, and SCADA data to compare a list of disturbance records to the simulated output. Provides a mostly automated method to perform visual inspections and comparisons between the model and measured data. If a discrepancy is detected, BPA works with the power plant's owners to calibrate their model.	BPA, PG&E
MathWorks® Simulink®-based Tool	Performs model calibration and verification using PMU data. Uses a power system model created in Simulink and boundaries on parameter values, with a library of standard excitation systems, turbine governors, and other transmission equipment. Iteratively adjusts the model until the best match with measured data is obtained.	ERCOT, PG&E
Electric Power Group Phasor Grid Dynamics Analyzer	Compares simulated disturbance records against simulated events. It is mainly used as a visualization tool, with simulations and manual model tuning occurring externally.	MISO

What disturbances are useful for model validation?

PMU recordings of almost any noticeable grid event can be used for model validation. During grid disturbances, a device operates outside of its normal steady-state condition, providing an opportunity to observe the dynamic behavior of the asset during transients. The PMU data from these transient grid disturbances provides information that cannot be captured with SCADA. These transient disturbances often pose the most risk for grid stability and reliability.

Here are some of the grid events that can generate valuable PMU data for model validation purposes:

- **Frequency excursion event –** In a frequency excursion, a substantial loss of load or generation causes a significant shift in electrical frequency, typically outside an interconnection's standard. PMU data on a generator's response to a frequency excursion can be used to examine the settings and performance of models of governor and automatic generation control (used to adjust the power output of a generator in response to changes in frequency).
- **Voltage excursion event –** A fault on the system, a significant change in load or generation (including intermittent renewables), or the loss of a significant load or generation asset can cause voltage shifts. PMU data on a generator's response to a voltage excursion can be used to validate models of its excitation system, reactive capabilities, and automated voltage regulation settings (used to control the input voltage for the exciter of a generator to stabilize generator output voltage).

- **Device trip –** Transmission devices and lines routinely trip out of service. They cause less severe impacts than a frequency or voltage excursion, but can provide similar data sets useful for model validation.
- **Remedial Action Scheme (RAS) activation –** Useful data events for model validation can be caused by a reaction to mitigate grid disturbances. Certain grid disturbances may cause a RAS activation, which will attempt to regulate the grid back to a normal operating condition. In some systems, the RAS may include switching on devices such as shunt reactors, changing FACTS devices, or inserting braking resistance. Activation of the RAS may create additional discrete disturbance events on the system, providing frequency and voltage events that can also be used for model validation.
- **Probing signal –** In the WECC, the high-voltage direct current (HVDC) station at Celilo, Oregon, has the ability to modulate its output power to a known signal, effectively serving as a signal generator into the western power system. These signals can be used to verify and calibrate system-level and generator models' frequency responses, particularly for small-signal-stability analysis.

Some entities already have standard practices in place for using PMU data for validation purposes. BPA, in particular, uses many sources of disturbance data to validate its models. BPA checks generator models after almost every event when frequency falls below 59.9 Hz, exploring the "frequency excursion events" category. BPA and WECC use the 1,400 MW dynamic braking resistor at the Chief Joseph substation to intentionally "ring" the system (the brake imposes a near-impulse event on the system). Regular insertions of this braking resistor provide a way to track generator and system responses over time, to identify parameters drifting out of calibration, and potential pending equipment failures.

Model validation maintenance

While model validation is a very important process for creating a trusted representation of the system, model maintenance is equally important. Model maintenance procedures provide some assurance that the model continues to represent the asset accurately. Therefore, a regularly scheduled maintenance process and mechanism for testing and updating the model is necessary. Model maintenance includes periodic model calibration and establishment of process for updating model parameters.

Model calibration adjusts the parameters of the model to compensate for circumstances like aging components or different operating conditions. To assure that a model remains accurate over time, calibration should occur regularly. BPA currently performs model validation and calibration for many of its generators after significant power system events. These events occur roughly once every couple of months, providing a schedule for validating and calibrating the model regularly. Good model maintenance practices entail revalidating and calibrating all power asset models after notable grid events, or doing so on a regular schedule (e.g., every 2 months).

Good model maintenance also requires a process for updating a model to reflect changes to the plant or the system. For example, if a generator's PSS is modified, then its model should be modified to reflect that change. Once a model has been modified or updated—whether to reflect an asset change or just to improve the model's accuracy—the corrected model should be used for all applications that use this plant model.

Without proper model maintenance using an established maintenance process, a fully validated model's output may slowly accumulate larger differences from actual asset behavior, eventually resulting in an inaccurate, invalid model.

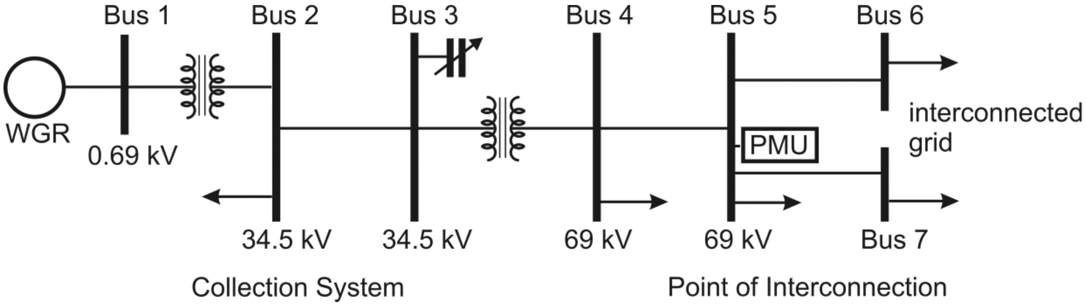
Where do the PMUs need to be located to get accurate model validation data?

Generally, a PMU that is electrically close to the asset it is monitoring can better isolate the behavior of that asset relative to other grid components. In such conditions, the model is less complex because it incorporates fewer grid elements. As a result, PJM and BPA both require installation of a PMU on the generator side of the point of interconnection (i.e., between a new generator and the transmission system). This requirement yields a PMU disturbance record that tracks only the performance of the generator, and requires modeling fewer components between the point of measurement and the generator, thereby enabling a cleaner model and validation process.

At present, however, most PMUs used for model validation are located at the substation closest to the point of interconnection for the power grid asset. This means that the PMU may collect data on the combined performance of multiple generator units, as well as a transformer and other substation equipment. To use those data to validate and calibrate the generator model, the analyst includes models for the various system components positioned between the plant and the PMU. This helps account for the predictable effects of the non-generation elements (e.g., the transformer and substation) in the validation and calibration exercise. These components have associated models and parameters as well, which may introduce inaccuracies into the power plant model.

There is an increasing interest in placing PMU-type devices within power plants. Such devices can measure not only generator stator voltages, currents, active and reactive power, but also generator field voltage and current, rotor speed and angle, as well as control signals. Technology demonstration projects are currently under way at San Diego Gas and Electric [13].

Figure 4 shows the simplified network topology of a wind power plant (marked as WGR on the left-hand side of the graphic) that is on a collector system. There are five buses between the wind generator and a PMU placed at the point of interconnection between the wind plant and the rest of the system [14]. When analysts begin working with a PMU data set for this generator, they might build a model that includes the mathematical models for the wind plant, the five buses, and the two transformers between the wind plant and the PMU. The modeling program will calculate the behavior of each of the electrical elements to separate the effects from the performance that is actually attributable to the wind plant itself. If the PMU were located on Bus 1 rather than Bus 5, the PMU data and the wind generator model would be insulated from the impact of these devices as potential sources of prediction error.



Source: Blevins 2013 [14]

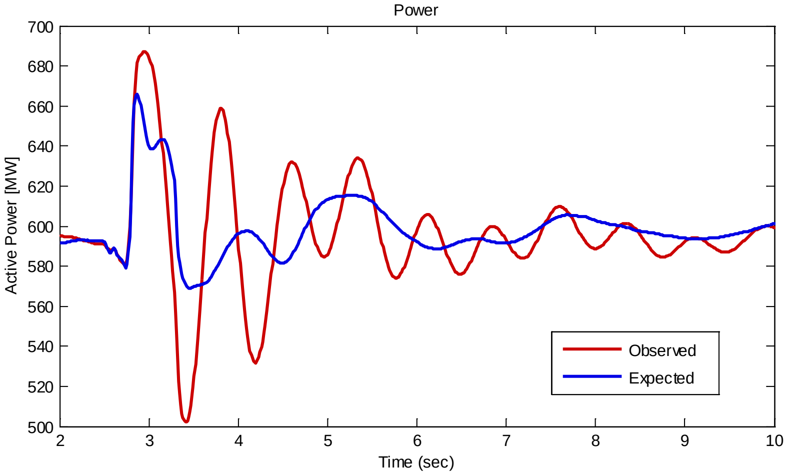
Figure 4. Simplified network topology for a wind plant (WGR) and the PMU that monitors it

5. Examples of PMU-based model validation

With the proliferation of PMUs installed under DOE's Smart Grid Investment Grants and Smart Grid Demonstration Projects (awarded in 2009 with equipment installation completed in 2014), a number of generation and transmission owners have used synchrophasor data to improve their grid models. This section summarizes recent model validation examples starting at the generator level with some of the earliest generator validation efforts—hydro, nuclear, and coal plants and more recently, wind and solar generators and FACTS devices. This section also addresses interconnection-level system models and state estimation models.

Hydroelectric generators

BPA's The Dalles hydrogenerator was the first power plant model modified using synchrophasor data in 2001. Subsequently, BPA staff members have used PMU data to develop verified baseline models of most of BPA's major generators. Such models enable identification of control abnormalities and plant mis-operations. For instance, in 2009 BPA engineers noticed that one Grand Coulee hydropower generator responded differently to a system oscillation than the power plant model would have predicted (see Figure 5). Investigation using the plant model hypothesized that the plant's power system stabilizer was not functioning; this failure was verified by the plant operator.



Source: Kosterev et al. 2013 [5]

Figure 5. Grand Coulee hydropower generator response to oscillation (red) differed from the expected baseline response (blue)

Nuclear generators

BPA used PMU data to validate and calibrate the model for the 1,100 MW Columbia Nuclear Generating Station. The model validation effort began with collection of data about the plant's actual behavior in response to four disturbance events. The plant model was later verified and recalibrated with data from 30 subsequent disturbances. BPA estimates that because the plant's owner did not have to take it offline for model validation testing, the plant yielded from $100,000 to $700,000 worth of revenues that might have otherwise been lost during the test period [15] (apart from the additional cost of the physical testing).

Independent System Operator-New England (ISO-NE) used PMU data for a ground fault that occurred 16 miles away from the Millstone Nuclear Power Plant to validate the model for that plant. The ISO-NE validation exercise yielded a model that accurately reproduces the voltage and real power output for this event for two Millstone nuclear units and two lines connecting the plant to the New England grid [16].

Coal-fired generators

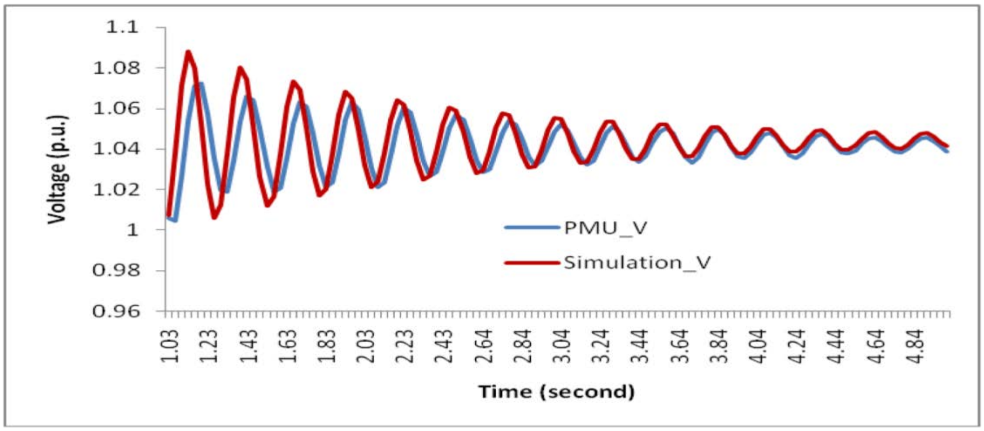
PMU data have been used to validate the models for at least two coal-fired generators, including TransAlta's 750 MW Centralia Coal Plant in 2003 [10], and the Colstrip power plant [5].

Wind and solar generators

Several efforts are under way to use PMU data to improve models of wind and solar generators. The Utility Variable Generation Integration Group, an industry consortium, is doing extensive work on renewable power plant model validation, working in collaboration with the Electric Power Research Institute (EPRI), the National Renewable Energy Laboratory, Sandia National Laboratory, EnerNex, Oklahoma Gas & Electric, BPA and Idaho Power Company. Electric

Power Research Institute (EPRI) developed an application for calibrating wind power plant models using PMU data [17].

The Electric Reliability Council of Texas (ERCOT) has used voltage oscillations observed at PMUs near wind plants to tune wind plant models, recreating the oscillations using simulation tools such as MATLAB® and Powertech modeling software (see Figure 6). With a model that accurately reflects oscillations and their causes, the grid operator can diagnose the causes of operating events, such as wind-driven oscillations, and identify appropriate corrective measures before those oscillations spread to harm other assets or cause a loss of load.



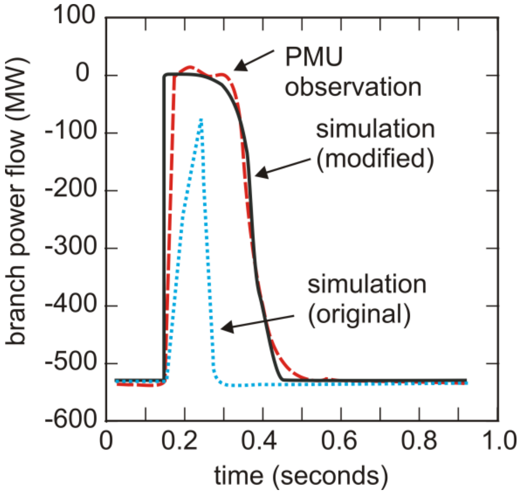
Source: Blevins 2013 [14]

Figure 6. Calibration of a wind plant model using PMU data in ERCOT

FACTS devices

FACTS and other power electronics devices are used to improve grid controllability and power transfer capability. Thus, like generators, FACTS devices need to be modeled effectively. EPRI has developed the Static VAr System Validation Model for validating FACTS device models. The New York Power Authority (NYPA) used this tool to improve the dynamic models for its Marcy STATCOM and its refurbished static VAr compensator (SVC). NYPA started with the generic SVC models developed in 2010 and 2011 and PMU data from disturbance events. NYPA then calculated the injected reactive current and reactive power for the devices and played measured voltage back into the models to fit simulated values to the measured values, using least squares estimation to optimize the models [18].

ISO-NE has automated its dynamic model validation process and is using it to validate and recalibrate models for HVDCs and SVCs [16]. Figure 7 shows how the initial New England HVDC model mis-predicted a power spike (blue dashed line) relative to the PMU-measured event (red dotted line); once the HVDC model was validated using the PMU data, the recalibrated model produced a more accurate simulation, which could reproduce the actual event almost exactly with the new simulated event (black line).



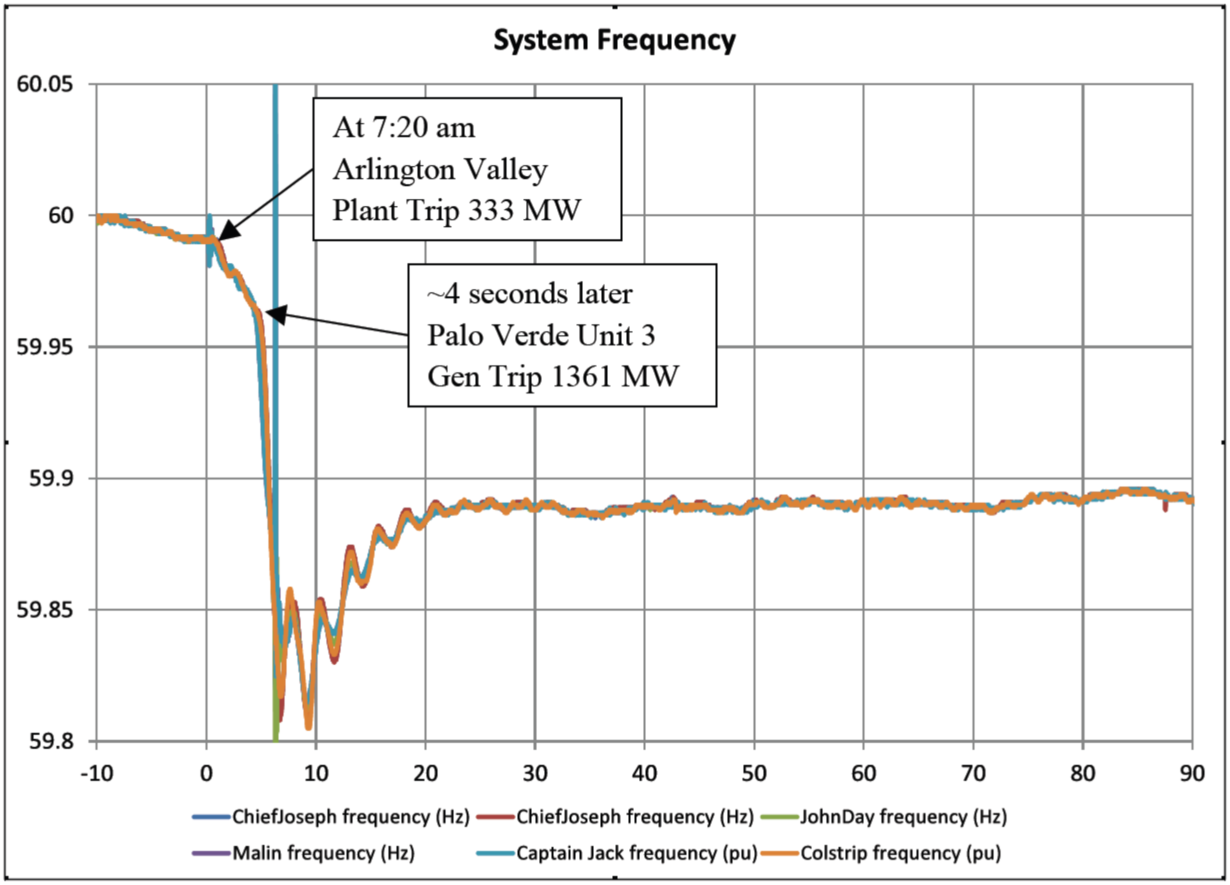
Source: Luo 2013 [16]

Figure 7. Validation of New England HVDC model using synchrophasor data comparison of pre- and post-validation simulations to actual event performance

System models

In the case of system models, engineers have been using PMU and other data in forensic efforts to understand the sequences and causes of recent grid failures. Such investigations start by using PMU data with SCADA and other information to create a "sequence of events" record to understand all of the equipment that was affected, in what ways, and at what times, during the event. PMU data is invaluable in developing the sequence of events, because the measurements are time-synchronized at the source (unlike SCADA data which is time-stamped upon receipt in a control center, and therefore is often skewed by to 2 to 5 seconds). With the sequence of events in hand, analysts then feed key parameters (generation dispatch, loads, network configuration, and operational characteristics of the case) from the sequence of events record into the system dynamic model to see whether that model can accurately reproduce the event and thus explain the "why" behind what happened on a second-by-second basis.

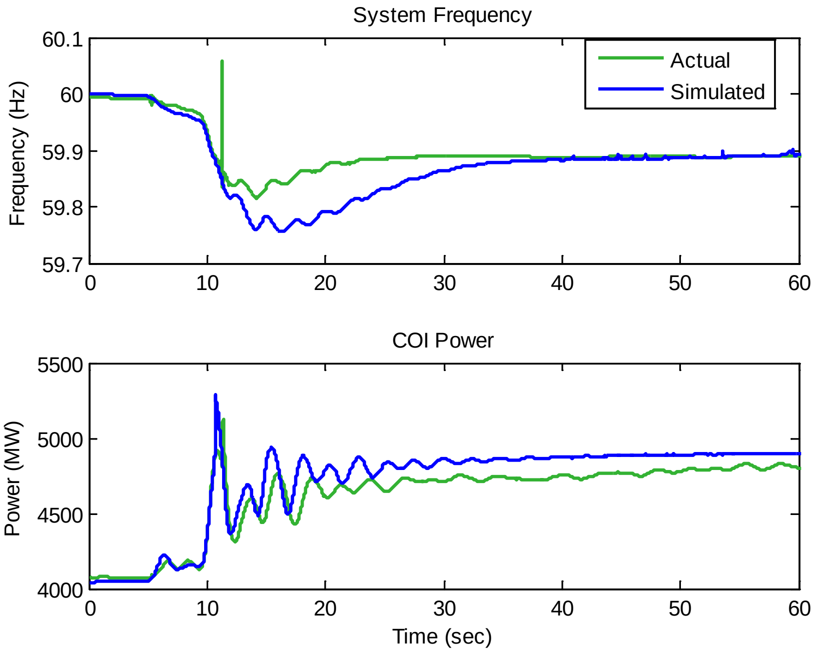
The July 4, 2012 loss of 1,700 MW of generation in Arizona is an example of one recent model validation study [19]. Figure 8 shows the actual event as frequencies recorded at several points across the western grid. While this event started with the loss of two power plants in Arizona, it triggered oscillations across much of the western interconnected system, including a power surge of 1,500 MW and a voltage drop on the California-Oregon Intertie.



Source: WECC 2013 [19]

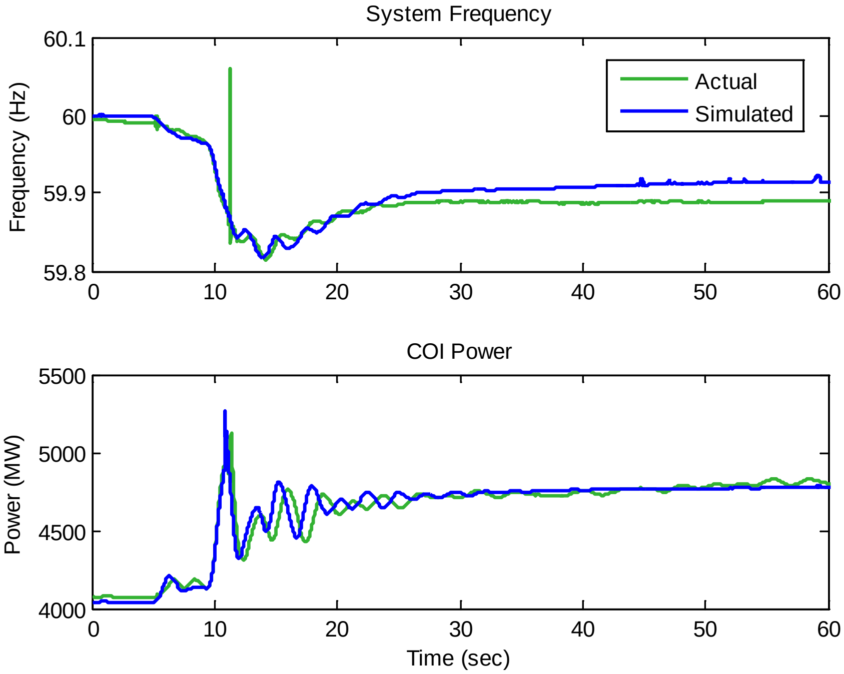
Figure 8. July 4, 2012 Western outage frequency plot

Figure 9 compares the Western Interconnection system model predictions against actual system performance on July 4, where the green lines show the actual event and the blue lines are the model results. The model could not closely predict either system frequency (top graph) or power flow (bottom graph; model results shown in blue) across the California-Oregon Intertie. Figure 10 shows that the model's performance improved once the PMU data were used to recalibrate the model's generator governor parameters to better track the actual event (except for the frequency spike 10 seconds into the event) [19]. WECC's Western Interconnect Synchrophasor Project provides the synchrophasor-based wide-area measurements necessary for model validation and reconstruction of sequence of events. WECC now automatically collects and archives PMU data for every grid event that occurs across the interconnection, so that data can be retrieved and used later for event analysis and model validation.



Source: WECC 2013 [19]

Figure 9. Comparison of actual versus simulated July 4, 2012 Westwing event using the pre-event system model



Source: WECC 2013 [19]

Figure 10. Comparison of actual versus simulated July 4, 2012 Westwing event using the post-event, synchrophasor data-calibrated system model

State estimation models

A state estimation model is a specific type of system model that uses grid measurements (principally from SCADA and EMSs) to estimate the voltages and angles (the "states") across the system. It is used to compensate for limited visibility across the grid and as a way of confirming whether the measured data are accurate. Accurate state estimation is essential for power system operation. PMUs provide bus voltage angle information and calculate phase angles and synchrophasors in real time; phase angles cannot be determined from SCADA measurements.

Initially, power system analysts used phase angles from PMUs to benchmark state estimation solutions and calibrate the underlying system models. Most of the grid operators and transmission owners—including PJM, Peak Reliability Coordinator, California Independent System Operator (CAISO), BPA, New York ISO, Duke Carolinas, Florida Power and Light, and ERCOT—that received Smart Grid Investment Grants for PMU projects have used their new PMU data to validate and calibrate the system models built inside their state estimators.

New advanced state estimators can use PMU data in the estimation process, thus improving solution accuracy. Dominion Virginia Power and Virginia Technical University have developed a three-phase state estimator for calibrating the parameters of Dominion's transmission lines. Several other utilities are evaluating PMU-based state estimators for SCADA data calibration and error detection.

Pacific Gas and Electric (PG&E) (a partner in the Western Interconnection Synchrophasor Project) is using its PMUs with new state estimation tools, including distributed state estimation that pushes state estimation from a central control room out to the substation. This tool could enable swift automated assessment of grid conditions and trigger automated operation of distributed grid devices to mitigate potential grid disturbances. These experimental efforts were conducted under their DOE ARRA Smart Grid Investment Grant (SGIG) project awards.

In 2013, General Electric Company, Peak RC and several utilities in WECC joined efforts to streamline processes for system model validation of disturbance events in the Western Interconnection, and to improve tools for compliance with NERC MOD-033 Reliability Standard. Peak RC produces a West-wide System Model (WSM), which is an online state estimator model for the entire Western Interconnection in breaker-node format. The model is then exported to General Electric's PSLF simulator, where the sequence of events can be simulated. The new process is very efficient and reduces the model validation setup from weeks to hours. In 2014, WECC performed system model validation studies for five system events, including large generation trips and Chief Joseph brake operations.

6. Conclusion

Accurate models of electric power systems and their components are critical for reliable, economic grid operations. ARRA-funded investments have increased the number of PMUs deployed across North America. As a result, the electric industry now has access to accurate, high-speed PMU data that document the actual performance of the power system and its component assets. PMU data are transforming the practice of model validation, with dramatic improvements in the accuracy of power plant and bulk power system models.

The process of model validation has changed significantly. PMUs record high-speed data on the power plant and the system response to grid disturbances. These PMU data records can be fed directly into model validation software to determine whether the power plant model accurately predicts the plant's response to the disturbance. If the comparison shows that the model is a poor predictor relative to the known event, the PMU data can be used in automated software to tune or recalibrate the model to improve its predictive capability. If the model appears to be structurally deficient, the analyst can use these software tools to revise the model structure to improve its predictive capability.

Given constant PMU monitoring, analysts can establish automated, ongoing model testing and improvement for any generator that has a PMU installed at or near its point of interconnection to the grid. This means that the generator model is checked and validated against every notable grid event, becoming more accurate and robust relative to a wider set of grid conditions with every event and validation check. As the plant model becomes a better predictor of its actual performance, it contributes to greater reliability in both real-time operations and longer-term grid planning.

The long-established practice for power plant model validation is to take a power plant offline and run physical tests to collect data for model validation and calibration on a 5- or 10-year cycle. In contrast, PMU-based model validation costs less than physical plant testing and can be practiced continuously, yielding ongoing improvements in model accuracy for a growing range of grid conditions that cannot be matched through physical testing.

Synchrophasor-based model validation offers many other benefits. More accurate models improve grid reliability and system efficiency, allowing more accurate and economic grid operation. Synchrophasor-based model validation is an accepted, cost-effective way to comply with the requirements of new NERC modeling requirements.

Generator models are the most often used application of synchrophasor-based validation because their data are easier to obtain than other assets or from the overall power system. Similar analytical methods are being used to validate and calibrate overall power system models, including state estimators, and will soon be extended to load models.

In sum, synchrophasor-based model validation offers reliability and economic value for transmission owners, power plant owners, grid operators, and their electricity customers across North America.

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Appendix A – NERC model validation requirements

MOD-026-1, "Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAr Control Functions," is intended to make sure that models and data used in dynamic simulations accurately represent generators' voltage and reactive power capabilities. The owner of a generation unit larger than 100 MVA (East), 75 MVA (West), or 50 MVA (ERCOT) must provide "a verified generator excitation control system or plant volt/VAr control function model, including documentation and data," to its Transmission Planner, and update these models if there are any changes to the plant controls that change the plant's response characteristics. Acceptable model verification methods include "documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance," and the entire model and relevant data must be provided to the Transmission Planner. The Transmission Planner is responsible for determining whether the submitted plant model and data are "usable," or explaining why they are not usable. Model verification under MOD-026-1 must be performed at minimum every 10 years. MOD-026-01 was approved by the Federal Energy Regulatory Commission (FERC) on March 20, 2014, and most of its requirements became effective on July 1, 2014; the requirement to provide the verified generator model and data becomes effective on July 1, 2018 [3].

MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions," is intended to make sure that there is an accurate, well-calibrated model for each generator's real power response to system frequency variations. The owner of a generator larger than 100 MVA (East), 75 MVA (West), or 50 MW (ERCOT) must provide to its Transmission Planner a verified model and parameters that accurately simulate its turbine/governor and load control or active power/frequency control, so that the model can be used in dynamic simulations. As with MOD-026-01, the Generator Owner must verify the model at least every 10 years, and verify the model if there are any significant changes to the plant that modify its response capabilities, and the Transmission Owner must check the model to be sure that it is "usable." Most of the provisions of MOD-027-1 became effective in July 2014; Requirement 2, for submittal of a fully verified model and associated data, will take effect on July 1, 2018 [4].

MOD-032-1, "Data for Power System Modeling and Analysis," establishes "consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary for analysis of the reliability of the interconnected transmission system." It consolidates current standards MOD-010 through MOD-015 into a single standard and requires "data submission by applicable data owners to their respective transmission planners and planning coordinators to support the interconnection model building process in their interconnection." Requirement R1, which will become enforceable on July 1, 2015, will require the exchange of data requirements and reporting procedures between the planning entities and the owning and operating entities. The other provisions will become effective on July 1, 2016 [7].

MOD-033-1, "Steady-State and Dynamic System Model Validation," aims to "establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system." It requires planning coordinators to "implement a documented data validation process" and requires Reliability Coordinators and Transmission Operators to provide "actual system behavior data" to any Planning Coordinator performing validation within 30 days of a written request. MOD-033-01 will be implemented on July 1, 2017[7].

Appendix B – Automated model validation and calibration tools using PMU data

Several organizations and vendors have developed automated tools for conducting model validation and calibration of power plant models using PMU data. These tools use a similar feature in that the user can take the recorded data on the asset's real-time response to an actual system disturbance and force that data stream into the model to see how the model prediction compares to the real event. As Figure B.1 shows, the system (shown in the middle of the graphic) is represented by a simplified infinite bus representation, while the plant or generating unit under study is modeled explicitly (shown at the far right of the graphic). The simulation tools inject recorded phasor measurement unit (PMU) voltage and frequency measurements for an actual grid event (injection shown on the left-hand side of the graphic), and compare the simulated response of the generating resource (real and reactive power) to the recorded response. This is generally referred to as a "play-in" or "playback" function, which can be built directly into the simulation tools [5]. Play-in capability is the centerpiece of all of the model validation and calibration tools discussed below.

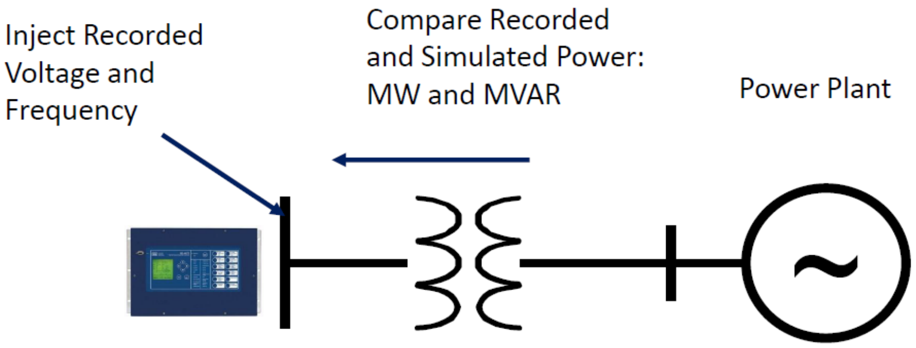


Figure B.1. Disturbance "play-in" process for PMU data to compare simulation result to actual event [5]

In 2009, the Electric Power Research Institute (IEEE) developed the Power Plant Parameter Derivation (PPPD) tool for synchrophasor data-based model validation and calibration. PPPD is a software system that contains all of the IEEE standard models for excitation systems as well as many of the commonly used turbine-governor models. The user first normalizes and then inputs the PMU data for a specific grid disturbance and plant into the PPPD tool, selects the appropriate plant type and model, specifies an initial set of upper and lower bounds for the plant parameters, and starts the PPPD analysis. PPPD then begins an iterative process of running simulations against the data to derive and optimize the model parameters. The tuned or recalibrated model resulting from this process has been shown to be an effective predictor of the plant's performance under later grid disturbances.

PPPD is now being used or studied by more than 20 generation owners and transmission system operators, including the Midcontinent Independent System Operator, New York Independent

System Operator, and PJM Interconnection. Duke Energy has used PPPD to validate the models for its entire North Carolina generation fleet.

BPA worked with Pacific Northwest National Laboratory (PNNL) staff to develop the Power Plant Model Validation (PPMV) tool, using General Electric's Positive Sequence Load Flow (PSLF) power flow software play-in function with PMU and SCADA data. The PPMV tool contains a collection of power plant models and model validation studies, as well as disturbance recordings from a number of historic grid events. The user can import PMU data from a new disturbance into the database, which converts PMU and SCADA data into PSLF format, and then run the tool to determine whether the model for a specific power plant is producing accurate results relative to its actual performance against one or numerous grid events [20]. If the model proves to be inaccurate or invalid, then BPA works with the plant owner to initiate model calibration using PMU data.

Power plant model validation is one of the deliverables of the Western Interconnection Synchrophasor Project (partially funded by the federal Smart Grid Investment Grant). To support this initiative and BPA's obligations as a transmission service provider, to date BPA has installed PMUs at 15 power plants, which account for approximately 70 generators and over 20,000 MW of generating capacity across the Pacific Northwest. BPA's goal is to use this tool, together with the many PMUs deployed across its system, to develop a model validation and performance assessment report for the entire generation fleet it serves, within hours of a disturbance.

Pacific Gas and Electric (PG&E) has been using the BPA-PNNL PPMV tool to review responses from two generators presently monitored by PMUs. PG&E reports that the PPMV tool "has made it nearly effortless to begin reviewing model performance following system events," and is looking forward to adding additional Western Interconnection Synchrophasor Project (WISP) and PG&E PMUs for greater monitoring capability. PG&E notes that when a plant model's simulated response does not match an actual event, the analyst should first look for obvious problems (e.g., the power system stabilizer is turned off), then retest the unit, and then undertake model parameter estimation (which PG&E is now exploring using MATLAB® tools) [21].

The Midcontinent Independent System Operator (MISO) uses Electric Power Group's (EPG's) Phasor Grid Dynamics Analyzer™ software for after-the-fact event analysis and model validation. MISO reports that it can use this to compare system reactions to actual events versus simulated responses and improve the planning models for better system efficiency and protection. MISO is working with the University of South Florida to automate what is now a manual model validation process [22].

ERCOT has been using MathWorks® MATLAB® Simulink® tool for model validation and calibration, applied to a wind plant. A PMU captured a voltage oscillation event when one of the two 69 kV lines connecting the wind plant to the rest of the grid was taken offline for an outage [23]. Figure B.2 shows the configuration of the wind plant, the PMU, and the rest of the grid. ERCOT staff followed the following several steps—which are essentially the same for any calibration tool—for this exercise:

1. The user selects the power plant and model to be calibrated, along with the PMU data sets for one or more disturbance events that have shown that the model is not simulating real events correctly. As an example, Figure B.3 shows the Simulink representation of Figure 4 from the earlier, PMU-siting section of the main text of this document.

2. The user identifies the model parameters to be calibrated and selects initial estimates and upper and lower bounds that will be tested for each parameter.
3. The automated calibration process begins calculating the simulation results for different combinations of parameter values, comparing each to the actual disturbance results (i.e., the recorded PMU data on plant performance).
4. The calibration tool iterates through hundreds or thousands of combinations of parameters, moving closer at each combination, until it finds a set of parameters that yields a simulated response that best matches the actual recorded response, as shown in Figure B.4.
5. If the calibration tool cannot find a set of parameters that adequately matches the model to the plant's actual performance, then the user should assess whether the model is structurally deficient relative to the plant, or whether some factor within the plant (such as the Automatic Generation Control or power system stabilizer) has been set differently in reality than was assumed in the model.
6. When model calibration has been completed successfully, the new model parameters can be exported into other power system simulation tools.

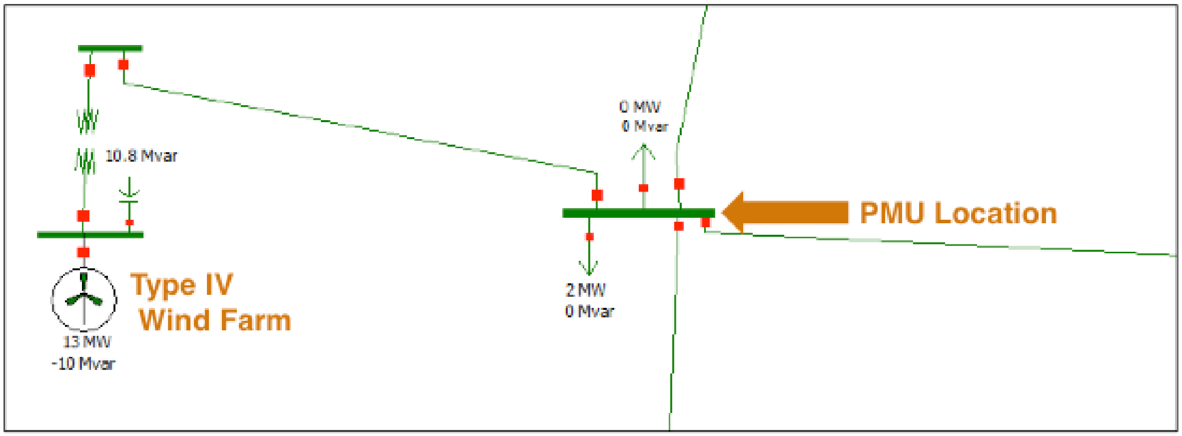


Figure B.2. Schematic of ERCOT wind plant and PMU [23]

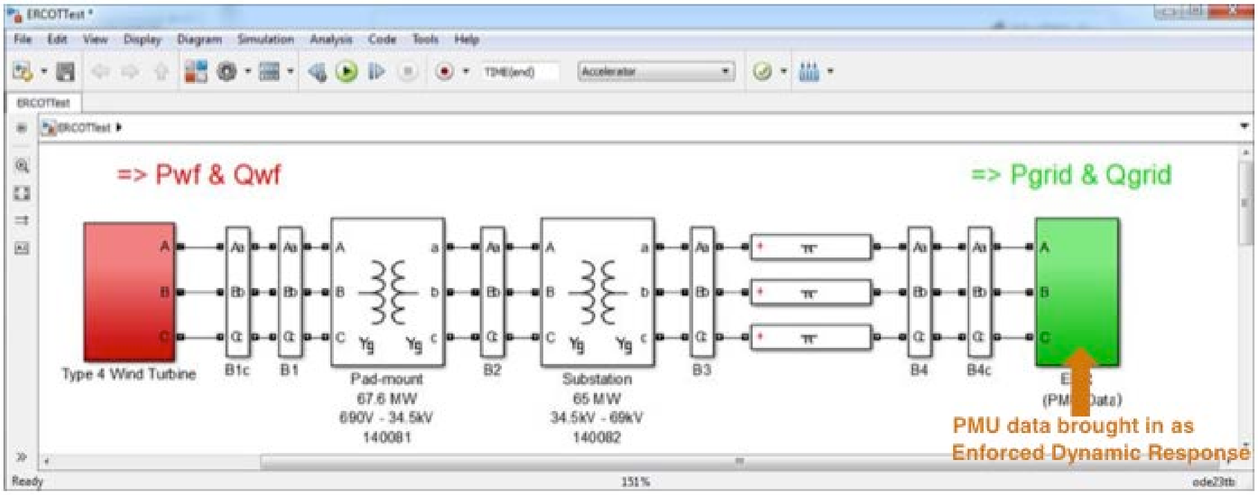
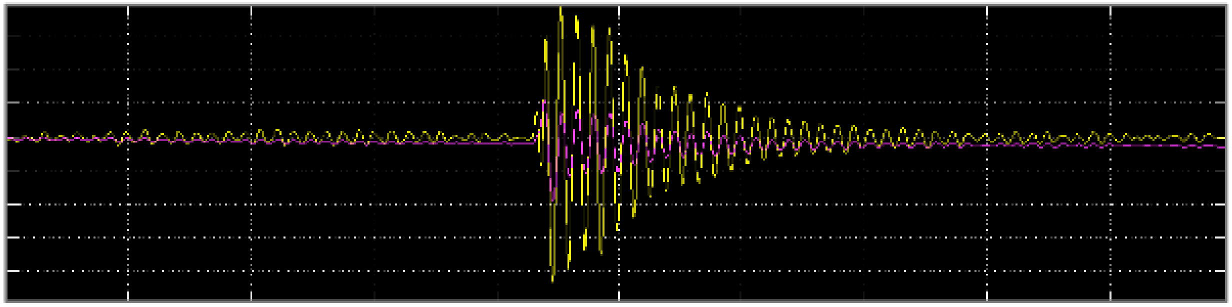
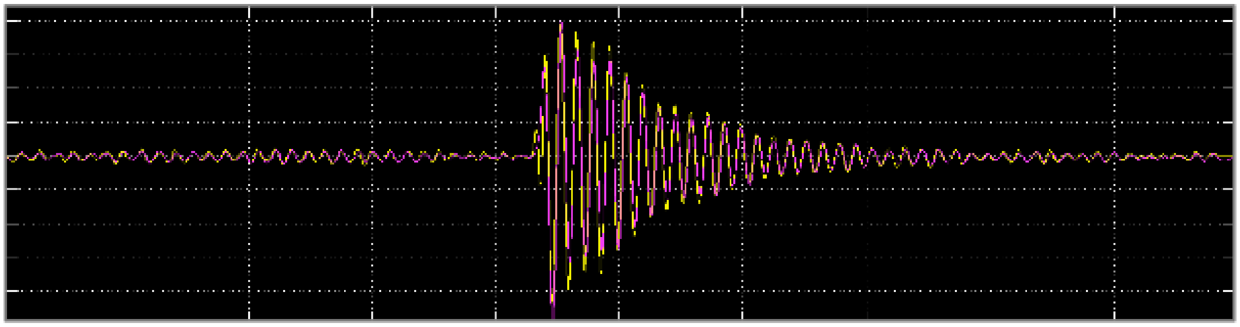


Figure B.3. Representation of wind plant system in Simulink [23]



Before MATLAB Estimation



After MATLAB Estimation

Figure B.4. Comparison of reactive power output of the ERCOT windfarm from the model before calibration (upper graph) and after calibration (lower graph). Yellow line = actual recorded reactive power output, Red line = simulated response [23].