PNNL-35770

Offline Power Systems Applications Enabled by Phasor Measurement Units

Technical Assistance to the
Power Sectors of Southeast Asia

March 2024

Shuchismita Biswas
Kaustav Chatterjee
Jim Follum
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U.S. DEPARTMENT OF STATE

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the U.S. Department of State

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Figures

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1.0 Introduction

This report provides a brief overview of several offline (non-real-time) applications facilitated by high-resolution time-synchronized measurements recorded by phasor measurement units (PMUs). The high reporting rate and time-synchronization of PMU records provide a detailed view of power system dynamics, enabling electric utilities to obtain a better understanding of their systems. In this report, the following applications have been reviewed:

- Power plant model validation
- System model validation
- Ringdown oscillation analysis
- Frequency response analysis
- Postmortem analysis of disturbance events

Along with a brief technical background of the applications above, applicable North American Electric Reliability Corporation (NERC) standards have been discussed, and examples of implementation in North American organizations have been provided. Implementing several of the discussed applications may need a preliminary stage of data gathering from multiple entities, and several frameworks and process flows have been formulated by organizations around the world for this purpose. However, the data-gathering stage has not been considered in the scope of the present report.

For a similar review of real-time applications enabled by PMU data, see [Chatterjee et al., 2023].

2.0 Power Plant Model Validation

Power system planning and operations rely heavily on computer simulations, and hence maintaining accurate simulation models is a critical task. Model validation, i.e. ensuring simulation results agree with observations during actual events, has therefore attracted attention from power system operators around the world, and several approaches and recommendations put forth for executing this complex task. The model validation task can be broadly categorized into- a) system model validation and b) component model validation. This chapter delves into model validation for generators, a vital power system component, using PMU data, while chapter 3.0 discusses interconnection-wide system model validation. Several examples of North American organizations leveraging PMU data and commercially available tools to exhibit standards compliance and diagnose modeling issues are included.

2.1 Applicable NERC Standards

The MOD standards framework developed by NERC, as shown in Fig. 1, prescribes requirements for validating power plant and interconnection-level steady-state and dynamic models. Staged tests are recommended for establishing baseline plant models, which must then be verified periodically. The validation and verification process may involve data exchange among multiple entities like plant owners, transmission operators, and planning coordinators. Hence, the MOD-032 standard [NERC MOD-032-2, 2023] establishes consistent requirements for gathering and reporting modeling data, which are not reviewed in this report. However, the interested reader may reference [NERC, 2021] for further insights.

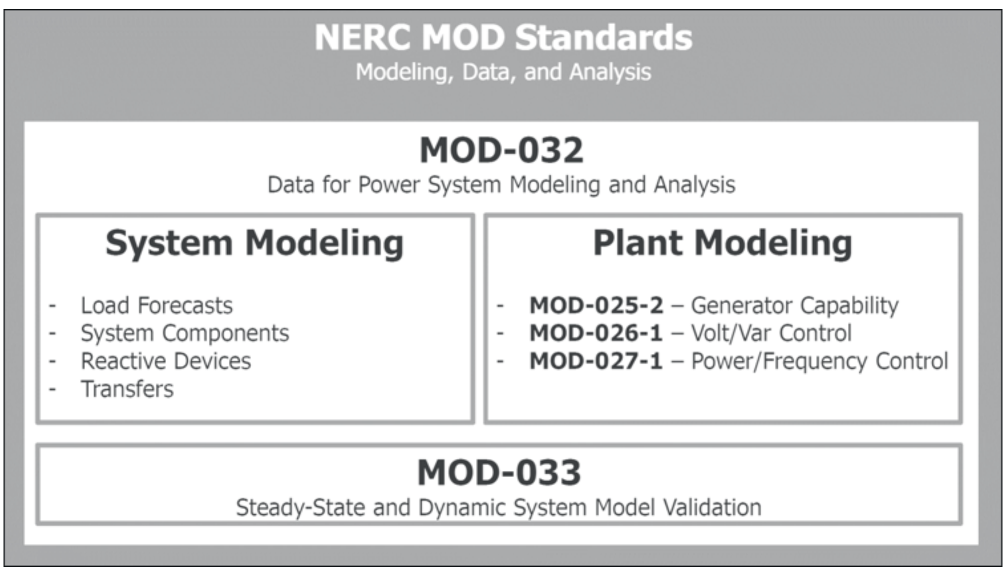


Figure 1: NERC MOD standards framework, adapted from [Quint, 2016]

Specifically relevant to the plant modeling task are the following standards:

- **MOD 025 - Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability**: The stated purpose of this standard is "*to ensure accurate information on generator gross and net reactive power capability is available for steady-state models used to assess bulk electric system reliability*" [NERC MOD-025-1, 2006]. Prescribed requirements apply to individual generators and synchronous condensers with a gross nameplate rating above 20 MVA, and to individual generating plants with multiple units directly connected at a common bulk power system (BPS) bus with a gross aggregated nameplate rating above 75 MVA.

- **MOD 026 - Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions**: This standard has been formulated "*to verify that the generator excitation control system or plant volt/var control function model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability*" [NERC MOD-026-1, 2014]. In the larger North American interconnections, requirements apply to individual and aggregated plants with a gross nameplate rating above 100 MVA (Eastern and Quebec) and 75 MVA (Western). In the smaller Texas interconnection, MOD 026 applies to individual and aggregated plants with gross nameplate ratings above 50 and 75 MVA respectively.

- **MOD 027 - Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions**: This standard aims "*to verify that the turbine/governor and load control or active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations*" [NERC MOD-027-1, 2013]. MOD 027 requirements apply to the same generator plants as MOD 026.

With the rapid growth of inverter-based resources (IBR) in the North American grid, an increasing need to have accurate IBR representations in planning models is being felt. To address this, the Federal Energy Regulatory Commission (FERC) recently issued a rule directing NERC to formulate model validation and verification standards for BPS-connected IBRs as well as aggregate representations of distributed energy resources (DERs) connected at the distribution level. Hence, model validation standards specific to inverter-interfaced resources are expected to become applicable in the near future.

2.2 Disturbance-Based Model Validation

PMU measurements of grid disturbances allow the verification and calibration of plant dynamic models using the measurement playback method shown in Figs. 2 and 3. The NERC MOD standards allow the use of measurement-based validation for compliance reporting (however, measurement-based validation cannot replace the requirement for establishing an initial baseline model), and hence generator owners can avoid costly staged testing and the revenue loss associated with a plant shutdown.

In the measurement playback method, power plants are assumed to be connected to a voltage and frequency source at the point of interconnection (POI) with the BPS. Detailed models of generator units and other auxiliary plant equipment up to the POI are needed, while the BPS is abstracted away. Voltage and frequency measurements recorded by a PMU at the POI during an event are played into a simulation software and the resultant changes in plant active and reactive power outputs are noted. If the simulated plant's output of active and reactive power closely match the recorded PMU measurements, then the existing plant model can be validated. Validation using multiple events is important to ensure model consistency. Most of the major commercially available simulation softwares used in the industry such as PSS/E, PSLF, TSAT, etc. offer disturbance play-in functionalities, making the playback method convenient to implement.

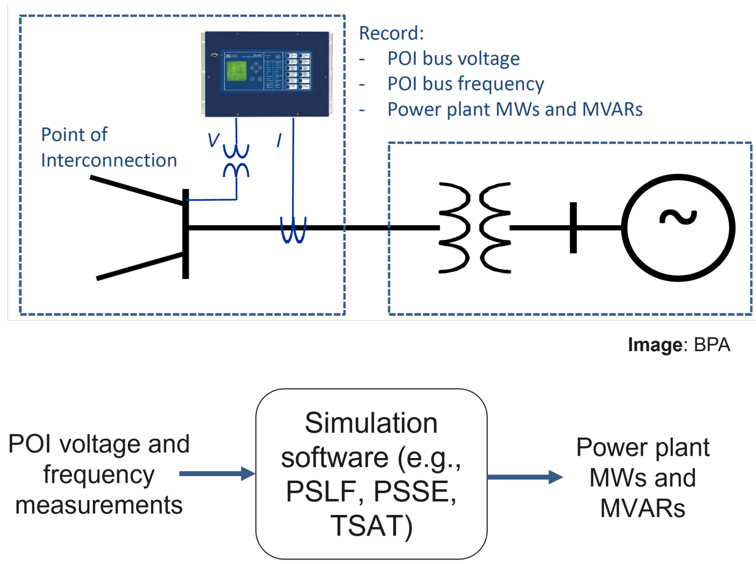


Figure 2: Conceptual illustration of the measurement-playback method for model validation, adapted from [NERC, 2018b]

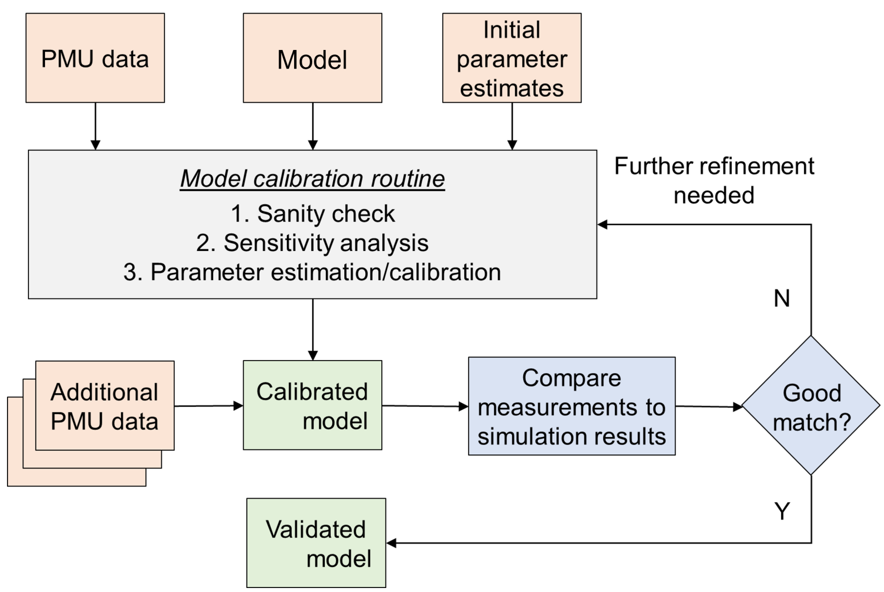


Figure 3: Measurement-based model validation and calibration platform, adapted from [Biswas et al., 2023]

In addition to the cost savings realized by avoiding staged tests, data-based model validation offers several other benefits. First, as disturbances are encountered during normal grid operations, model verification can be performed more frequently than the minimum cadence prescribed by regulatory bodies (for example, NERC requires model verification to be performed once every 10 years, while in the Western Interconnection, the requirement is to perform validation at least once every five years). Frequent model verification can also help in the early identification and mitigation of controller failures and parameter tuning issues. Second, with measurement-based model validation, regional planning coordinators and transmission operators can independently verify generator performance, identify model limitations, and iteratively improve the overall system model.

Regional organizations like the Bonneville Power Administration (BPA) report that despite having developed baseline models, 60-70% of generator models within their footprint did not match disturbance measurements. Investigations performed by BPA personnel coordinated with generator owners have resolved many of these observed issues [Kosterev et al., 2013b]. Per BPA's experience, the most commonly encountered model issues include - power system stabilizer (PSS) models, turbine control mode of operation, governor models, generator inertia, deficiencies in model structure, and automatic generation control (AGC). Plants with digital control systems are observed to have good models that stay accurate over time, while those with legacy analog controls tend to have error-prone models whose parameter values change with time [Kosterev et al., 2013b].

2.3 Quantifying the Model-Measurement Mismatch

Acceptable differences between disturbance recordings and simulation results are often ascertained using engineering judgment. An organization in early stages of implementing measurement-based model verification may have higher mismatch tolerance than organizations that already have sophisticated practices in place. Moreover, examining how and where the simulation results and observed measurements do not align can provide clues about the source of modeling inaccuracies. For instance, if simulation results match observations well immediately after a disturbance, but start to vary in the following seconds, it could indicate limitations in the model's secondary control schemes. Fig. 4 shows examples of modeling issues and their underlying causes identified by BPA for several generators within their footprint using PMU disturbance measurements.

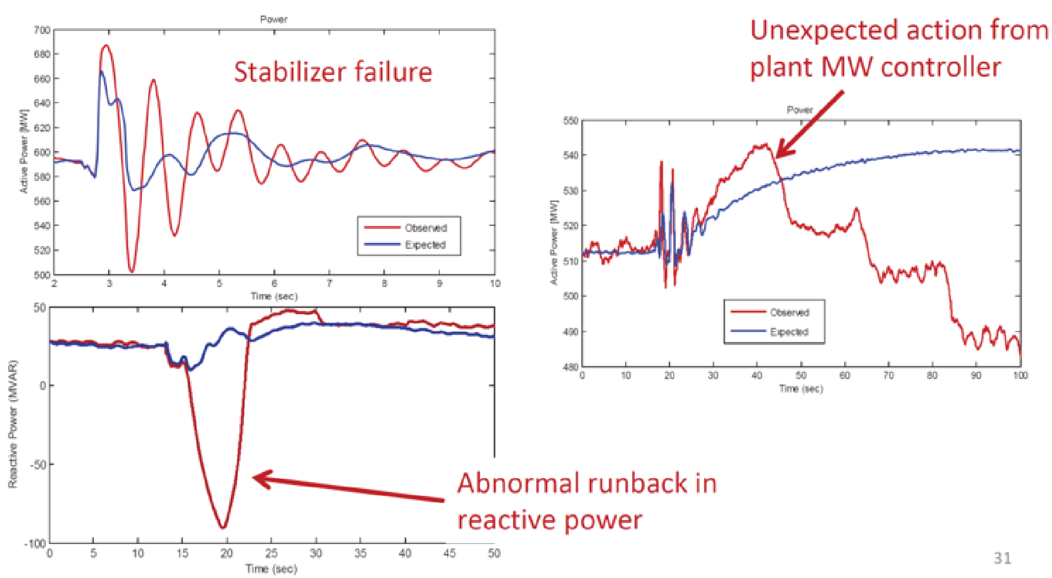


Figure 4: Examples of model inaccuracies identified for power plants in BPA's footprint using PMU data-based model validation [Kosterev et al., 2013b]

2.4 Model Parameter Calibration

Several numeric techniques have been designed to determine optimal parameter values that minimize the difference between simulation results and corresponding event measurements. Power plant models consist of many parameters, and it is important to first determine which parameters influence generator response to particular events before attempting to calibrate them. The calibration process can be broadly classified into the following two stages:

- **Trajectory sensitivity analysis**: This step determines which model parameters are identifiable using the data for a particular event.
- **Parameter tuning**: Parameters identified in the previous step are tuned to obtain the best match between the simulation and measurements. The model-measurement mismatch is quantified by some error metric (eg., [Ju et al., 2020]). Parameter tuning methods based on various approaches like Kalman filtering, heuristic optimization, pattern matching, machine learning, etc. have been proposed.

Of course, data-driven model calibration faces several limitations. For instance, if the model structure is not accurately represented, parameter estimation using numeric curve fitting techniques can result in misleading conclusions. Hence, practitioners caution against absolute reliance on curve fitting methods; engineering supervision is still required to ensure that estimates obtained using estimation algorithms are physically explainable. Another limitation is the existence of non-unique solutions. Estimates that deviate significantly from true values can still produce model behavior well-aligned with field observations [Kosterev et al., 2013a]. This may be overcome to some extent by using multiple events capturing diverse system conditions for the calibration task.

2.5 Commercial Solutions

The model validation/calibration process (including event detection, data suitability determination, report generation, etc.) can be quite labor-intensive, and hence several commercial solutions have been developed to streamline the end-to-end process. Several of these tools can run continuously as a service in the online environment, automatically generating reports suitable for NERC MOD compliance reporting. Although engineering intervention may still be required, especially at the initial deployment stage, these tools can greatly reduce engineering burden and task execution time. Some available commercial solutions are discussed in this section, with examples of their implementation in US organizations.

2.5.1 Automated Generator Model Validation (AGMV)

Electric Power Group (EPG) offers a generator model validation solution that detects system-wide events suitable for calibrating generator models, implements customizable validation criteria (in terms of composite error metric thresholds), and automatically generates reports for NERC compliance reporting. Two versions of the tool are available - a) an online version that can perform validation in near real-time; and b) an offline version that also has an option for performing parameter tuning. Examples of model validation for different generator models and a generated NERC compliance report obtained using AGMV deployed at PJM Interconnection are shown in Figs. 5 and 6, respectively.

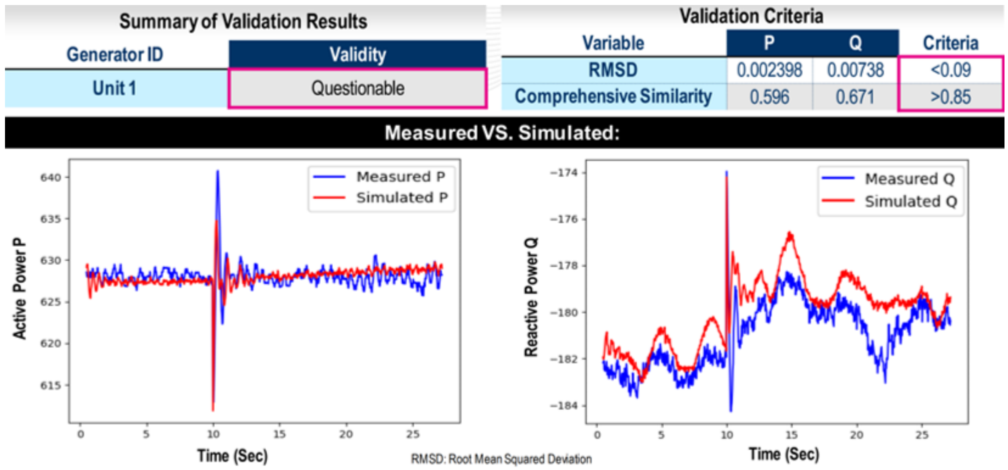
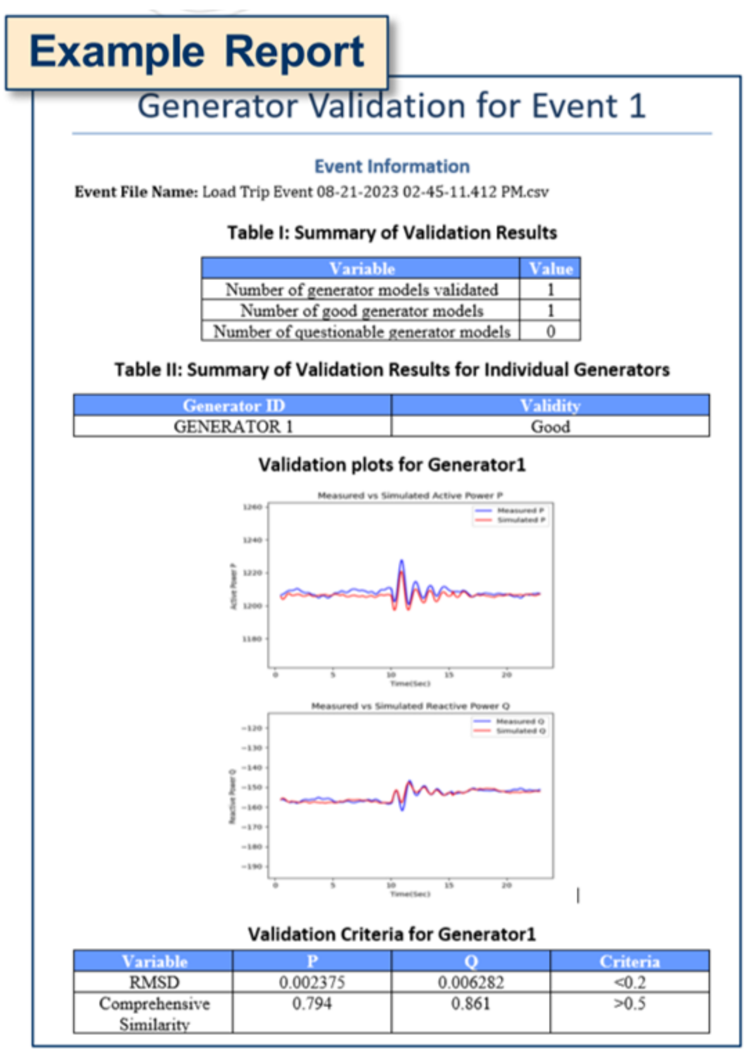


Figure 5: Model verification for two generators in PJM Interconnection's footprint using the AGMV tool [Chen and Nayak, 2023]



Example Report

Generator Validation for Event 1

Event Information

Event File Name: Load Trip Event 08-21-2023 02-45-11.412 PM.csv

Table I: Summary of Validation Results

Variable	Value
Number of generator models validated	1
Number of good generator models	1
Number of questionable generator models	0

Table II: Summary of Validation Results for Individual Generators

Generator ID	Validity
GENERATOR 1	Good

Validation plots for Generator1

Validation Criteria for Generator1

Variable	P	Q	Criteria
RMSD	0.002375	0.006282	<0.2
Comprehensive Similarity	0.794	0.861	>0.5

Figure 6: Example generator model validation report produced by AGMV [Chen and Nayak, 2023]

2.5.2 Power Plant Model Validation (PPMV)

The open-source Power Plant Model Validation (PPMV) tool discussed in [Etingov et al., 2018] was developed collaboratively by PNNL and BPA to automate generator model validation using PMU measurements. PPMV allows the easy import of data in various popular formats like CSV and COMTRADE. Databases of historic events and plant models can be maintained, making it easy to benchmark model performance against field measurements. The tool interfaces with the play-in functionalities of commercial solvers like GE PSLF and Siemens PTI PSS/E, and can be configured to interface with external parameter calibration modules. A conceptual illustration of the application framework is shown in Fig. 7. PPMV also provides advanced visualization and report generation capabilities. A screenshot of PPMV's user interface depicting the verification of a plant model is shown in Fig. 8. PPMV functionalities have been commercialized and are available within V&R Energy's POM/ROSE platform.

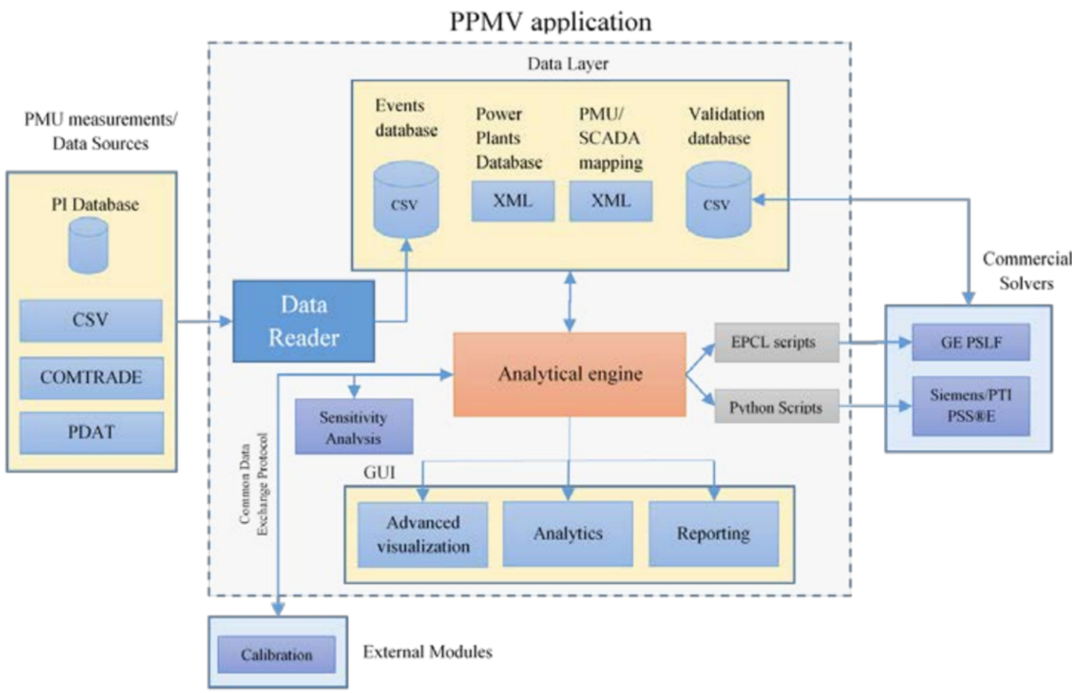


Figure 7: PPMV tool framework [Etingov et al., 2018]

2.5.3 PhasorAnalytics

GE offers a model validation and calibration module within its PhasorAnalytics suite that interfaces with commercial simulation engines PSLF and TSAT [Wang, 2019]. It performs sequential model validation with data from multiple events, implements parameter tuning algorithms, and provides interactive visualization and report generation capabilities. The tool has been used in several organizations such as Pacific Gas & Electric (PG&E) and Independent System Operator - New England (ISO-NE). An example of model validation performed using the PhasorAnalytics module in PG&E is shown in Fig. 9.

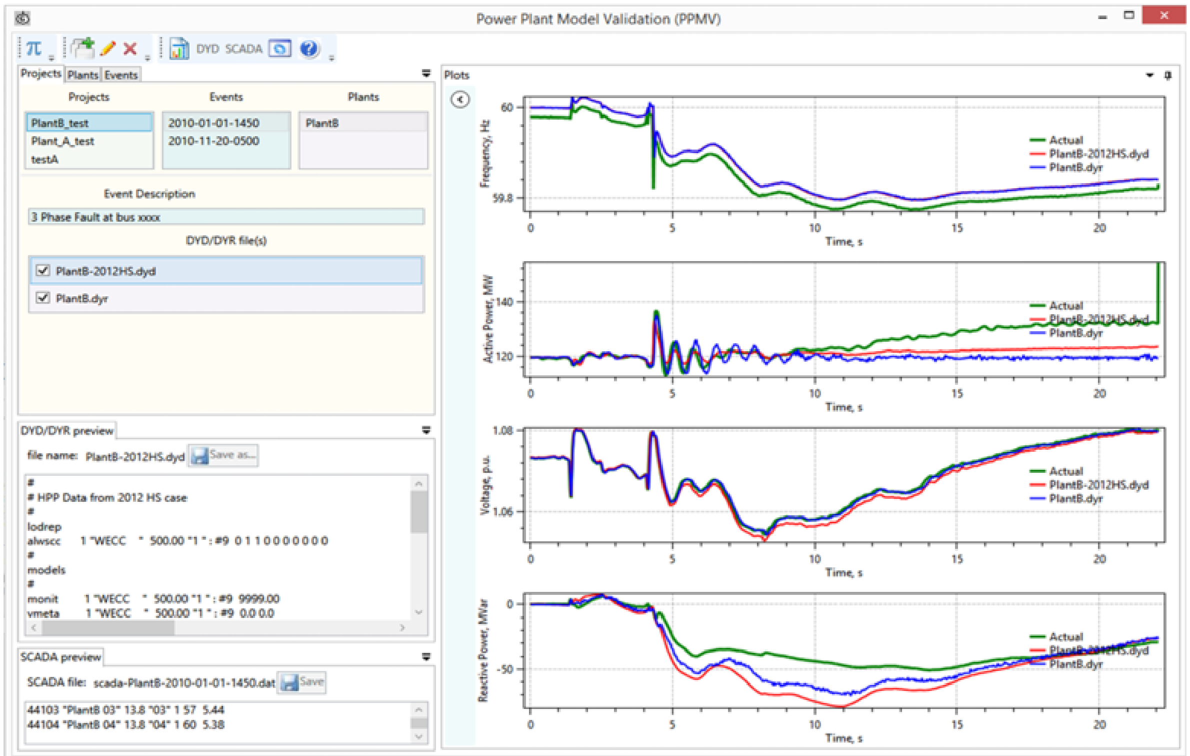
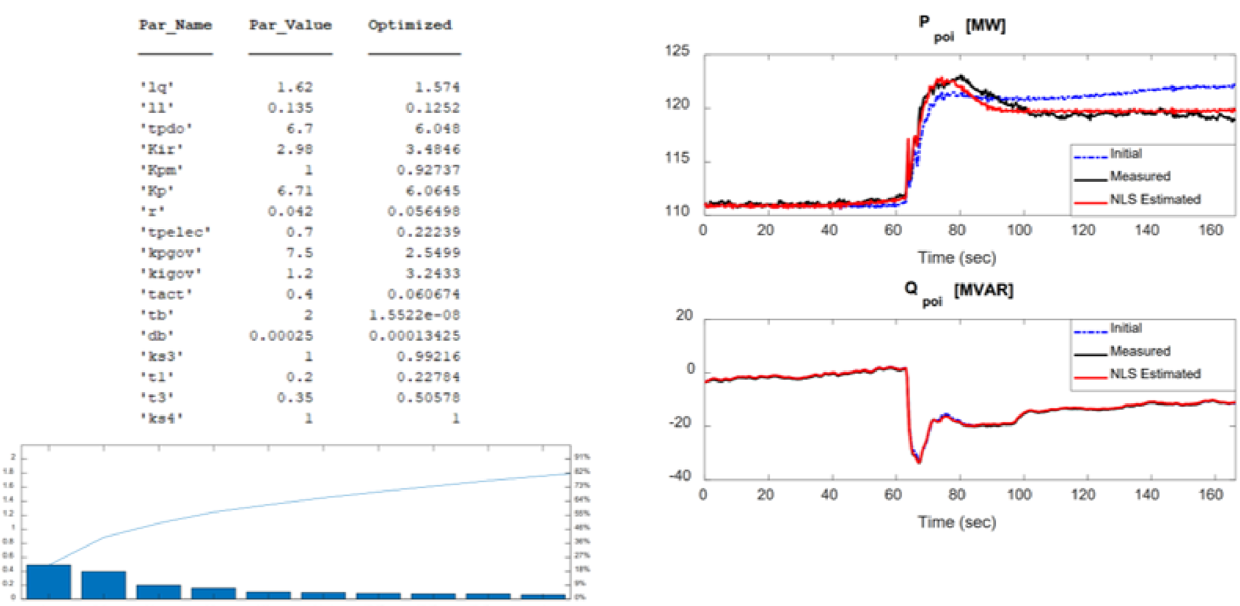


Figure 8: Screenshot of the PPMV user interface [Etingov et al., 2018]



Par_Name	Par_Value	Optimized
'lq'	1.62	1.574
'll'	0.135	0.1252
'tpdo'	6.7	6.048
'Kir'	2.98	3.4846
'Kpm'	1	0.92737
'Kp'	6.71	6.0645
'r'	0.042	0.056498
'tpelec'	0.7	0.22239
'kpgov'	7.5	2.5499
'kigov'	1.2	3.2433
'tact'	0.4	0.060674
'tb'	2	1.5522e-08
'db'	0.00025	0.00013425
'ks3'	1	0.99216
't1'	0.2	0.22784
't3'	0.35	0.50578
'ks4'	1	1

Figure 9: Model validation example using PhasorAnalytics [Wang, 2019]

3.0 System Model Validation

Interconnection-wide system model validation is a complex, iterative, and time-intensive task that relies on collaboration among several organizations and engineering judgment [Gong et al., 2019, Decker et al., 2010, Fan et al., 2021]. The availability of accurate baseline models of individual components can improve model quality, making the verification task easier. In the three North American interconnections, working groups comprising representatives from different utilities and reliability coordinators (Modeling and Validation Subcommittee (MVS) in the Western Interconnection, Multiregional Modeling Working Group (MMWG) in the Eastern Interconnection, and Steady State Working Group (SSWG) in the Texas Interconnection) perform the validation of steady-state and dynamic planning models, identify and resolve existing issues, and track changes in model performance over time.

While system-wide model validation can be quite arduous and cannot be performed without significant engineering effort. Automation routines can help streamline the processes for model adjustment and comparison of simulation results, thereby reducing task execution time. This chapter briefly reviews some best practices shared and lessons learned by US organizations. Unlike the generator model validation tools discussed in Chapter 2.0, commercial solutions for end-to-end system model validation are not widely available.

3.1 Applicable NERC Standards

Within the NERC MOD framework of standards (see Fig. 1), the Steady-State and Dynamic System Model Validation Standard, MOD-033, establishes consistent validation requirements to facilitate the collection and validation of accurate data and building of planning models to analyze the reliability of the interconnected transmission system [NERC MOD-033-2, 2021]. Accurate planning models enable effective studies on resource adequacy, The Standard assigns the following responsibilities to regional planning coordinators (PCs) for the data validation process:

1.1. Comparison of system performance in a planning power flow model against the actual system;
1.2. Comparison of system performance in a planning dynamic model against the actual system response;
1.3. Guidelines to determine unacceptable differences in performance under 1.1 and 1.2;
1.4. Guidelines to resolve unacceptable differences identified under 1.3.

The broad steps involved in the model validation process are shown in Fig. 10. Technical reference documents like [NATF, 2017] and [NERC, 2018a] provide detailed insights into methodologies implemented by different US organizations.

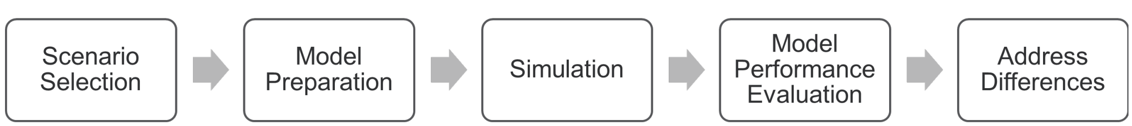


Figure 10: Broad overview of the steps in the system-wide model validation process

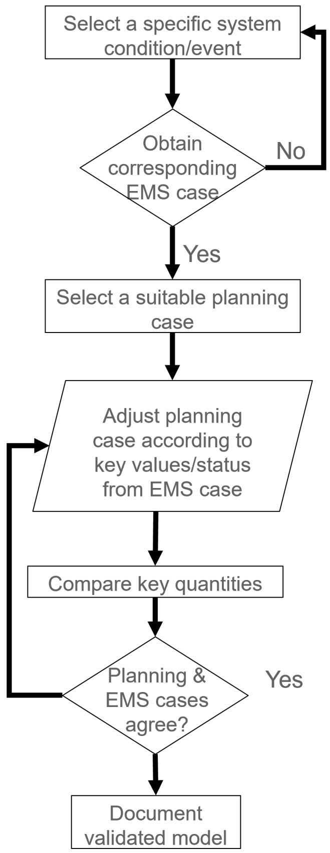


Figure 11: Process for comparing steady-state planning model to actual system conditions, adapted from [NATF, 2017]

3.2 Steady-State Model Validation

Planning model validation involves evaluating both the steady-state (often termed *powerflow case*) and dynamics cases. A powerflow case can be described as "*a collection of steady-state models for system topology, load, generation, dispatch, and interchange that constitute a snapshot of expected system performance for the selected set of operating conditions*" [NERC, 2018a]. The dynamics case, on the other hand, is "*a collection of dynamics models used in conjunction with a powerflow model to perform a transient stability analysis of system performance*" [NERC, 2018a]. Thus, a validated steady-state model is a prerequisite for proceeding with subsequent dynamic model validation.

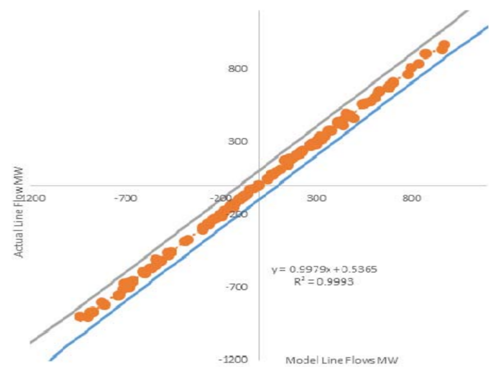
A high-level overview of the steady-state model validation process is shown in Fig. 11. Here, an existing planning powerflow case is modified to match a real system case obtained from the Energy Management System (EMS), and simulation results are compared to measurements aggregated from various sources like SCADA and generator reporting systems. Starting from an existing powerflow case is preferred for large interconnections as this may help avoid running into solution convergence problems. It is important to ensure that the load distribution and power factor in the actual system are reproduced in the planning models, because deficiencies in load representation can significantly impact model quality.

Before choosing an EMS case, some initial checks must be performed to ensure its validity. This includes checking for solution convergence and reviewing the state estimation solution to ensure that the total system power mismatch and largest bus mismatch are small compared to actual load values. The next step is to map bus numbers from the EMS to planning models. Differences may exist due to several reasons such as - (a) operation models use a node-breaker representation, but planning models use a bus-branch representation; (b) multiple generating units may be lumped into a single unit in the EMS, etc. Data mapping may be laborious, and many entities have developed automation processes.

Short-term operation changes must be recreated in the planning models to facilitate comparison with the EMS case. Some components that commonly need adjustments include - transmission/generation outages, topology changes, area interchange values, generation dispatch, generator scheduled voltages, loads, switched shunts, transformer tap positions, etc. Once the case is adjusted, the powerflow results obtained can be compared with actual measurements. Most simulation softwares allow comparing load flow results from two steady-state cases and flag differences if they exceed a specified threshold. Thresholds may be specified for active/reactive power flows on critical branches and bus voltages; tolerances may depend on voltage levels. Example tolerance limits used by regional entities in the US Pacific Northwest are shown in Fig. 12a. It may be difficult to inspect individual quantities for large systems, and various visual inspection methods have been developed to improve the efficiency of this process. One example is shown in Fig. 12b, where the simulated and measured values are plotted against each other. If many quantities deviate outside the tolerance band (indicated by blue and gray lines in Fig. 12b), then the model quality may be judged as poor, requiring significant effort to reconcile differences.

Parameters for Comparison	Bandwidth for Comparison				
	115 kV	*230kV*	*300kV*	*345kV*	*500kV*
Real Power Flow: • Line and transformer • Generator • HVDC, series cap, etc.	+/-10% (AC) or 10 MW, whichever is larger	+/-10% (AC) or 20 MW, whichever is larger	+/-10% (AC) Or 30 MW, whichever is larger	+/-10% (AC) or 50 MW, whichever is larger	+/-10% (AC) or 100 MW, whichever is larger
Voltage • Bus	+/-4%	+/-3%	+/-3%	+/-3%	+/-2%

(a) Criteria for steady-state model validation



(b) Visual comparison of actual power flows on 500 kV branches and model predictions.

Figure 12: Example metrics used by regional utilities in the Pacific Northwest to determine if planning models faithfully represent system behavior. Visual inspection of mismatches provides an efficient way to determine if a large number of quantities deviate significantly outside tolerance bands, thereby conveying model quality [Gong et al., 2019].

3.3 Dynamic Model Validation

Validating powerflow cases is the first step in the dynamic model evaluation process. However, system operators may not always maintain planning models that exactly match the initial conditions preceding an event (the normal practice is to maintain planning models for seasonal peak conditions, and light-load scenarios for shoulder seasons). A popular approach is to start with a planning case close to the seasonal conditions during an event and then adjust model components. In evaluating dynamics models, four major questions need to be addressed:

- Which events should be chosen to benchmark the model response against system conditions?
- How should the difference between the model response and system behavior be quantified?
- Which components or model parameters contribute to the observed mismatches?
- Which data/component owner should be notified?

3.3.1 Event Selection for System Model Validation

The MOD 33 standard allows the use of local disturbances for verifying the dynamic models of regional planning coordinators (PC), as the scope of the standard is limited to the PCs. However, it may be advantageous to use wide-area disturbances as this allows the same base cases to be used by multiple system operators within the same interconnection, thus facilitating coordination among entities and the sharing of engineering resources. This approach has two main drawbacks: (a) if an event causes large perturbations in certain areas while others remain relatively unaffected, then diagnosing modeling issues in the latter areas becomes difficult; and (b) a PC may not be able to resolve simulation-measurement mismatches observed within their footprints if modeling errors exist in other parts of the interconnection. Thus, a recommended practice is to use a combination of local and wide-area disturbances to implement system model validation.

Events that cause a significant change in system states can be used for dynamic model verification. Some such examples include- AC/HVDC line switching without fault, generator tripping/oscillations, transmission system faults, large frequency events, and system islanding/loss of synchronism. System operators may often use well-understood contingencies known to be visible across wide areas. For example, in the WI, the loss of the Pacific DC Intertie (PDCI), a critical transmission line, is known to trigger remedial action schemes (RAS) that trip a large number of generators. This event is commonly used to benchmark the response of WI planning models. Some examples of unsuitable events are asymmetric events that may cause sustained unbalanced flows (e.g. single pole reclosing), and events that occurred when generating units are ramping up or down. This is because while initializing dynamic simulations it is assumed that all generator output set-points remain fixed for the duration of the simulation.

3.3.2 Running the Simulations

Once an event has been selected, the corresponding measurement data need to be collected from various sources like PMUs, dynamic disturbance recorders (DDRs), state estimators, and SCADA. Without high temporal resolution data such as those collected by PMUs and DDRs, model dynamic behavior cannot be verified. To recreate the observed disturbance in a simulation environment, the sequence of events and corresponding timestamps need to be collected as well. PMU data offers rich information that can be used to further refine the event sequence timestamps.

Before running the dynamic simulations, it should be checked that the powerflow solution closely matches the pre-event conditions. Some initial verifications could involve checking for solution convergence and flat start. Generator outputs should be within limits, and any initialization warnings or error messages should be resolved. Moreover, transient disturbances such as generator trips could be simulated to analyze whether the resultant ringdown oscillations closely match known system properties.

Usually, dynamic simulations are run for around 10 to 20 seconds. After this time frame, automatic generation control (AGC), tap-changers, slow-acting capacitors, and other secondary controls would need to be accounted for and typically these elements are not represented in transient stability models. Additional efforts to represent these slow evolutions are unlikely to add value to the model validation exercise.

3.3.3 Comparing Simulation Results with Measurements

Due to the complexities associated with the model validation process, engineering judgment is key in ascertaining what differences between the model response and system conditions are unacceptable. Simulation results and PMU measurements are usually traced on the same plot, and visual inspection provides clues about the sources of model deficiencies. If generator model issues are observed, then the facility owners may be notified and need to calibrate the models according to MOD 26 and MOD 27 requirements. Experience with model validation exercises suggests the following as common sources behind model-measurement mismatch:

- Uncertainty in pre-contingency case
- Uncertainty in event sequence
- Post-contingency topology and dispatch changes
- Load distribution and parameters
- Behind-the-meter resources
- Secondary control actions, generator ramping, etc.

The system model validation process is iterative; the longer an organization implements model verification procedures, the better the quality of its model is expected to be. Entities that already have reasonably good system models may choose to use quantitative measures to indicate how well simulation results match actual system conditions. Other entities that are in the initial stages of deploying measurement-based model verification may choose to employ qualitative measures for determining model quality. Examples of qualitative metrics proposed for validating the model of the Brazilian interconnection are as follows [Decker et al., 2010]:

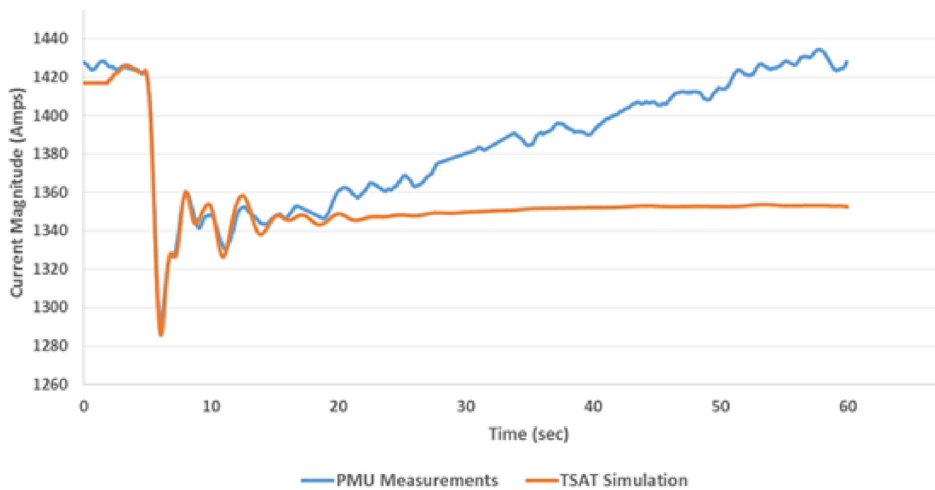
- The model predicts system stability or instability.
- The model predicts the nature of the system response, such as oscillatory behavior, lightly or heavily damped oscillations, etc.
- The model predicts a similar range of variable excursions, with maximums and minimums occurring at comparable times.

3.4 Field Examples

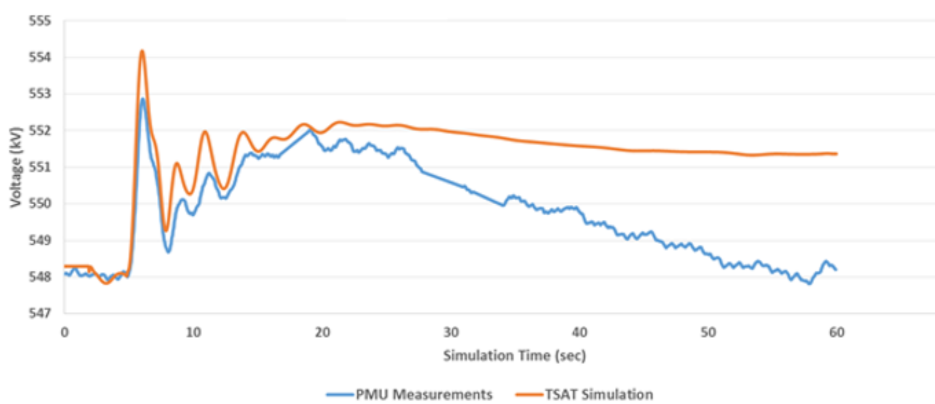
In this section, two instances of measurement-based validation of dynamics models of the WI are discussed.

3.4.1 Large Generator Trip in British Columbia

Fig. 13 shows the PMU measurements and corresponding simulation results obtained for the loss of a 525 MW generating unit in the territory of British Columbia Hydro and Power Authority (BC Hydro), located in the northwestern part of the WI [WECC, 2016]. The figure shows electrical quantities for a major 500 kV line. For the first 10 seconds after the disturbance onset (inertial and primary response), the model closely matches the event measurements. However, while the model predicts that branch flows and bus voltages settle to a constant value in about 20 seconds, measurements show a slow increase in power flow and a resultant sag in bus voltage. Engineering analysis revealed that this discrepancy can be explained by AGC actions that were not modeled in the planning case. Units responding to the loss of the generator caused an increase in power flowing across the transmission line examined. Thus, it was concluded that the existing planning model was adequate to capture the transient dynamics of the WI.



(a) Current through a major 500 kV line



(b) Bus voltage profile at the end of the line

Figure 13: Simulation results (orange) vs. PMU measurements (blue) for a 525 MW generator trip event in the BC Hydro area [WECC, 2016].

3.4.2 Remedial Action Scheme Activation

The second example described here examines the reconstruction of a wide-area event that triggered a remedial action scheme (RAS) — also known as a *special protection system* — leading to the loss of 2826 MW of generation across the WI. Investigating the mismatch between model predictions and actual system behavior revealed several modeling issues and unexpected component behavior. Fig. 14 shows how through engineering analysis differences between model and field conditions were identified and reconciled, resulting in a close agreement between the two.

Frequency values obtained from the initial system model differed from PMU measurements, as evident from Fig. 14a. Engineering personnel examined the post-contingency generator outputs from the regional generator availability data system and found several units not part of the RAS scheme that had changed their outputs. These changes were incorporated into the model, the governor units were blocked for generators whose output was higher than 95% of their maximum capacity, and large units whose power output was less than 10 MW were turned off. Capturing these changes improved the match between the model and actual system conditions, as seen from Fig. 14b and Fig. 14c.

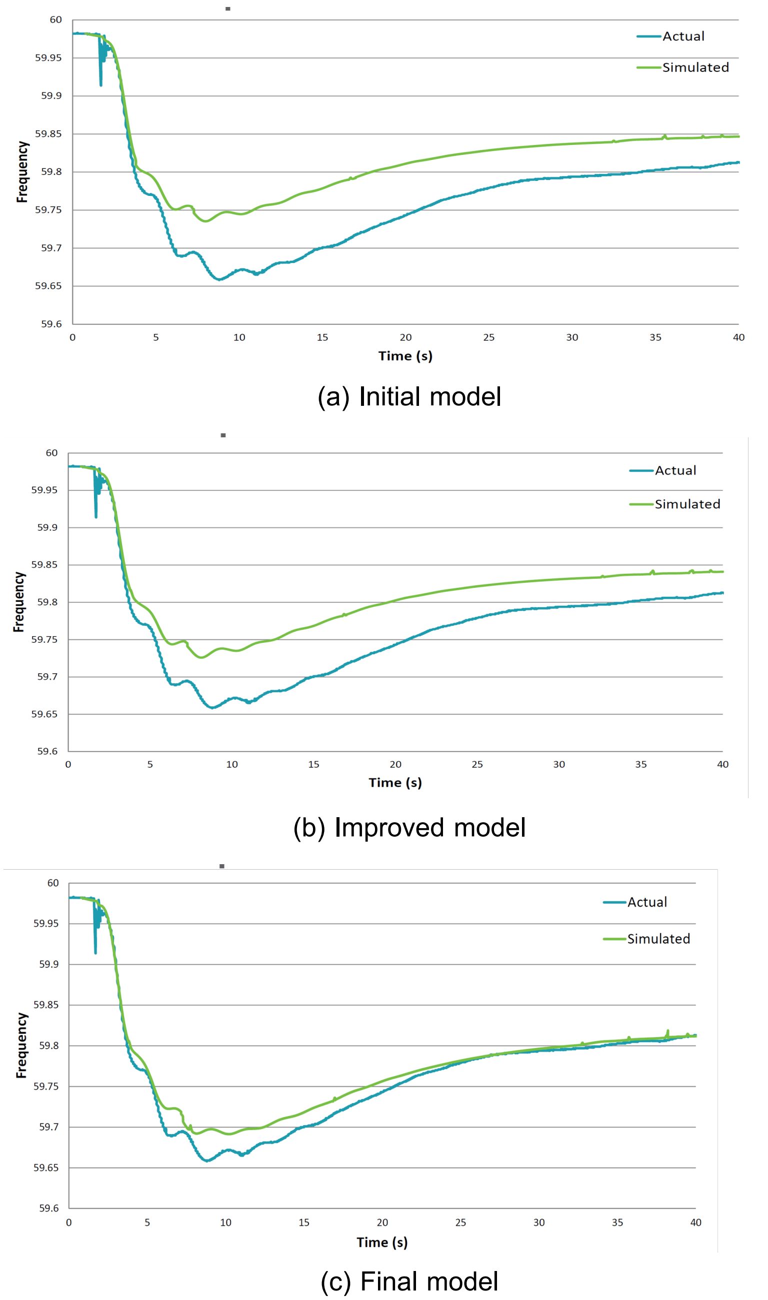


Figure 14: Frequency response obtained for a system-wide event in the WI that caused a 2826 MW generation loss throughout the interconnection [Powell, 2015]

4.0 Oscillation Baselining

In large interconnections, generators electrically close to each other tend to self-organize into groups that operate synchronously in nearly exact harmony. Such coherent groups located in different parts of the interconnection, generally separated by long distances, operate slightly out of synchronism with each other. These slight differences between generator groups create low-frequency inter-area oscillations, typically in the 0.1-1 Hz frequency range. Due to the constant perturbation of the system's modes of oscillation by random load changes, these natural oscillations are always present in the form of low-level ambient noise. An interconnection may have multiple natural oscillatory modes, but only a few of these become dominant and observable across the system, thereby requiring close monitoring. Poorly damped modes pose system stability concerns, as disturbances can trigger growing oscillations that may lead to outages.

A natural oscillation mode is characterized by its – (a) frequency: a narrow range of frequency where it is observable, (b) damping ratio (DR): a measure of how fast oscillations will dissipate following a large grid disturbance, and (c) shape: a representation of generator groups participating in an oscillation mode. A mode is considered well-damped if its DR is higher than 10%, and if the DR falls below 3-5%, the poorly damped mode is considered of concern. The properties of a mode may drift based on changing system conditions such as system load, topology, and power transfer patterns. For example, the DR of a mode may decrease in light-load conditions when fewer synchronous generators are online to contribute to damping and inter-area power transfer is high [Western Interconnection Modes Review Group, 2021, Follum et al., 2023].

Because the properties of oscillation modes vary with grid conditions, system operators need to understand which factors affect mode properties. Historical data analysis is an effective way of performing this baselining task - post-disturbance ringdown oscillations or long windows of ambient measurements can be analyzed to estimate mode properties, and statistical methods can be employed to investigate if significant correlations exist between these estimates and system conditions (e.g., output of a large generator, power transfer over a key transmission line, renewable energy generation, inter-area power transfer, etc.). Mode estimates recorded online can also be subsequently utilized for performing the correlation analyses. Examples of oscillation baselining studies performed in North American interconnections with both ringdown and ambient data are available in literature [Western Interconnection Modes Review Group, 2021, Ahmad et al., 2021, Biswas and Follum, 2024].

Identifying which factors impact mode properties provides actionable information to system operators. When the DR of specific system modes are observed to fall below a threshold, targeted remedial actions can be taken to alleviate system stress and ensure that under-/undamped oscillations do not appear. Moreover, long-term trends in mode properties can also be identified. As the generation mix changes to facilitate grid decarbonization, the characteristics of inter-area oscillations are also expected to change. Oscillation baselining studies can help flag changes before drastic transitions occur and system operators can adjust their monitoring/control strategies accordingly.

4.1 Mode Estimation using PMU Data

PMU measurements provide an effective way of analyzing power system oscillations and estimating modal properties. Measurement-based modal estimation techniques can be broadly categorized into two groups - a) ambient analysis, and b) ringdown analysis. Ambient analysis methods (e.g., Yule-Walker algorithm) estimate mode properties from low-frequency oscillations that appear as colored noise in steady-state measurements [Dosiek et al., 2013, Trudnowski et al., 2008]. Because this approach enables continuous monitoring of mode properties, they are commonly referred to as *mode meters*. The drawback of mode meters is that they require long data windows to accurately extract information from ambient noise. To properly design mode meters, prior understanding of a mode's frequency range and observability locations is required. This information can be acquired from event-driven estimates obtained from post-disturbance *ringdown* oscillations.

Ringdown analysis methods (e.g., Prony, Matrix Pencil, Dynamic Mode Decomposition, etc.) are essentially curve-fitting techniques that express the system's free-response (i.e., the period in which the input or forcing function has been removed from the system) as a linear combination of damped sinusoids, thereby yielding mode estimates [Trudnowski et al., 1999, Liu et al., 2007]. The observability of modes depends on the location of the disturbance. The disturbance may be a naturally occurring system event like a fault or planned tests. For example, the US Western Interconnection periodically evaluates modal properties by conducting tests using the 1400 MW dynamic brake at the Chief Joseph substation [Shelton et al., 1975].

The accuracy of ringdown methods depends on the data window selected for analysis. To avoid nonlinear system behavior immediately following a disturbance, a common practice is to place the left end of the analysis window after 0.5-1s has elapsed from the disturbance. Ideally, the window should consist of at least 3-4 cycles of the lowest-frequency mode of interest. Ringdown analysis methods require a good signal-to-noise ratio, so care must be taken to ensure that the analysis window ends before the oscillation decays back to the level of ambient noise. An analysis window selection example is shown in Fig. 15. The disturbance is created by simulating a brake insertion from 5-5.5 s. After the removal of the brake, 1 s is allowed to elapse before the analysis window starts. The analysis window is 12 s long, containing about 4 cycles of the $\sim$0.25 Hz mode of interest, and does not have any flat signal content.

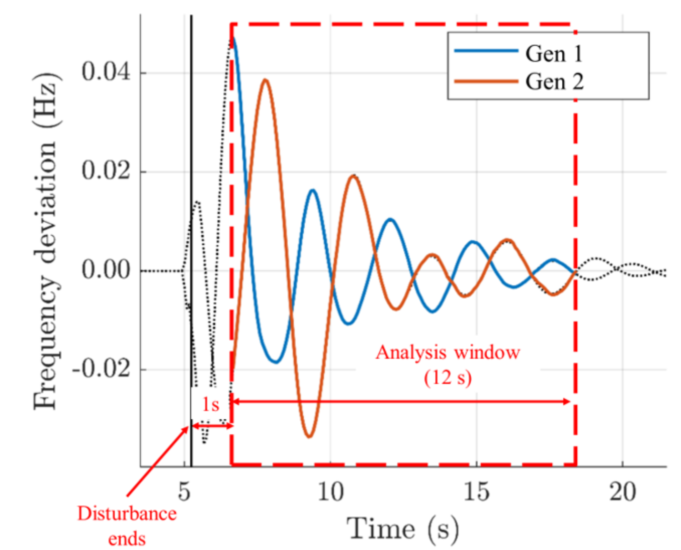


Figure 15: Example analysis window selection for ringdown analysis, adapted from [Chatterjee et al., 2023]. The red dotted rectangle shows the window selected for curve fitting.

4.2 Available Tools

Popular commercial vendors that offer online mode estimation solutions also provide solutions for implementing ringdown analysis algorithms using PMU measurements. Two popular applications include Phasor Grid Dynamic Analyzer (PGDA) (Fig. 16) developed by Electric Power

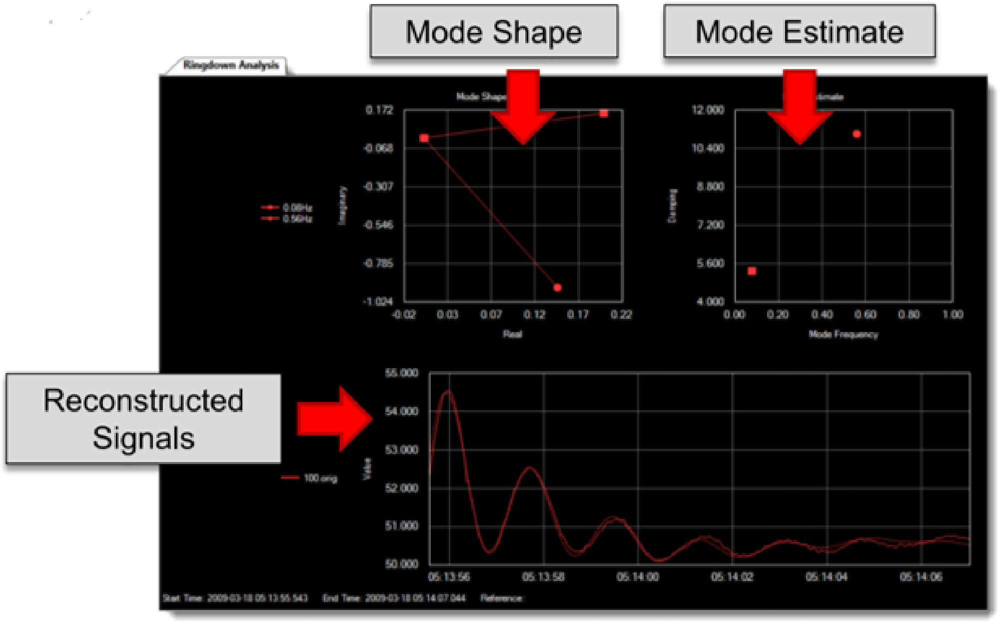


Figure 16: Ringdown analysis using EPG's Phasor Grid Dynamic Analyzer [Electric Power Group (EPG), 2014]

Group (EPG) and Synchrowave Operations (Fig. 17) by Schweitzer Engineering Laboratories (SEL). PGDA is a versatile tool for offline data mining and can perform several tasks, including oscillation detection and mode estimation, stability assessment, model validation, and frequency response analysis. The Synchrowave Operations platform includes a modal analysis application that allows users to specify which signal groups should be examined for estimating mode properties. Algorithm parameters, mode frequency bins, etc. can be specified.

Although the commercial applications described above can provide mode estimates by analyzing historic or streaming data, in-built capabilities for performing baselining studies are not present. The user needs to develop customized code for performing correlation analysis that uses estimates obtained from commercial tools as input.

Open-source tools for ringdown analysis are also available, including the Oscillation Analysis and Baselining Tool (OBAT) [1] developed collaboratively by PNNL and BPA. OBAT is a standalone Windows application that can easily interface with MATLAB and integrate external algorithms and modules. Fig. 18 shows the graphical user interface of the OBAT tool. Users can easily perform several tasks, such as retrieving previous analyses using a 'projects' panel, choosing which signals to examine, visualizing signals in the time domain, and exporting results to several data formats. Estimates obtained for the various dominant modes present in the analyzed signals are presented in tables, and users can configure different panels to visualize mode shapes. Note that several advanced visualization capabilities are available. Mode shapes can be displayed using compass plots (bottom right panel in the GUI), or mapped to the geographical location of generators (top right panel of the GUI). In the geographical mode shape plot, the circle diameters convey mode shape magnitudes at the marked locations, and generators with similar mode angles are denoted by the same color. The red generators swing together nearly 180^o out of phase with the blue generators.

Using mode estimates obtained from OBAT, correlation analysis can be performed within the tool to identify if there exists any relationship between modal properties and system conditions.

[1] https://store.pnnl.gov/content/oscillation-baselining-and-analysis-tool-obat

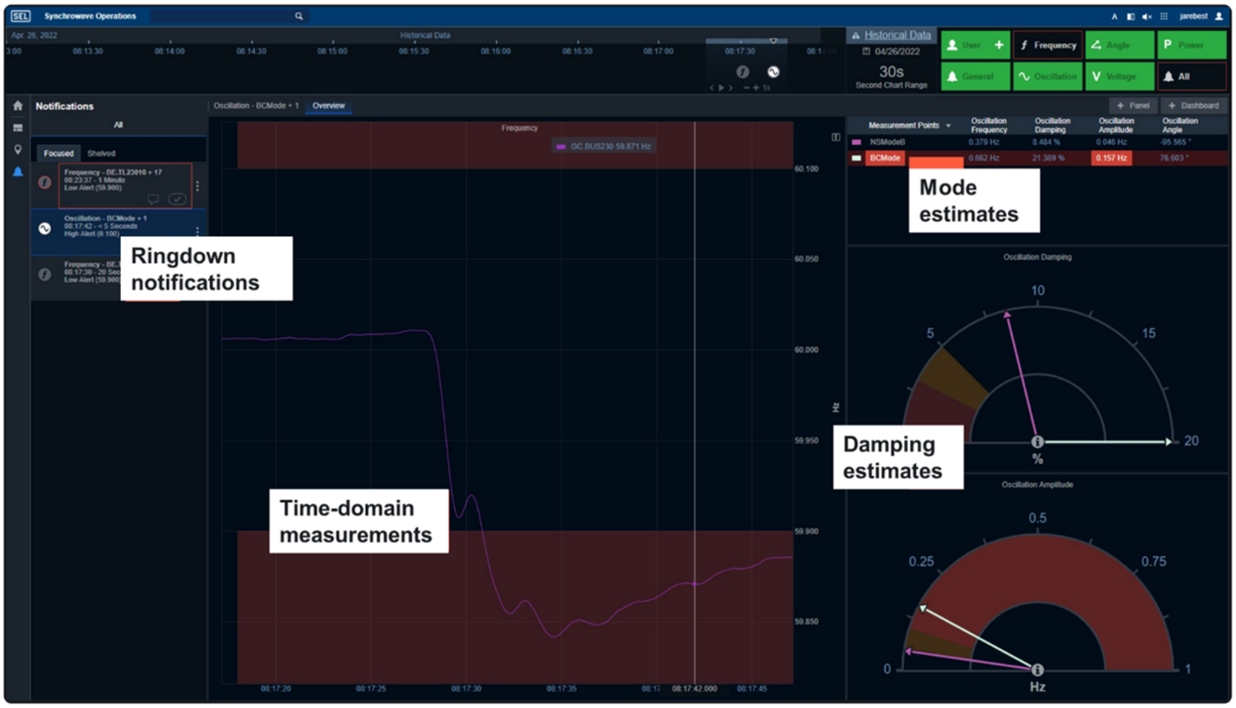


Figure 17: Ringdown analysis using SEL's Synchrowave application [Schweitzer Engineering Laboratories (SEL),]

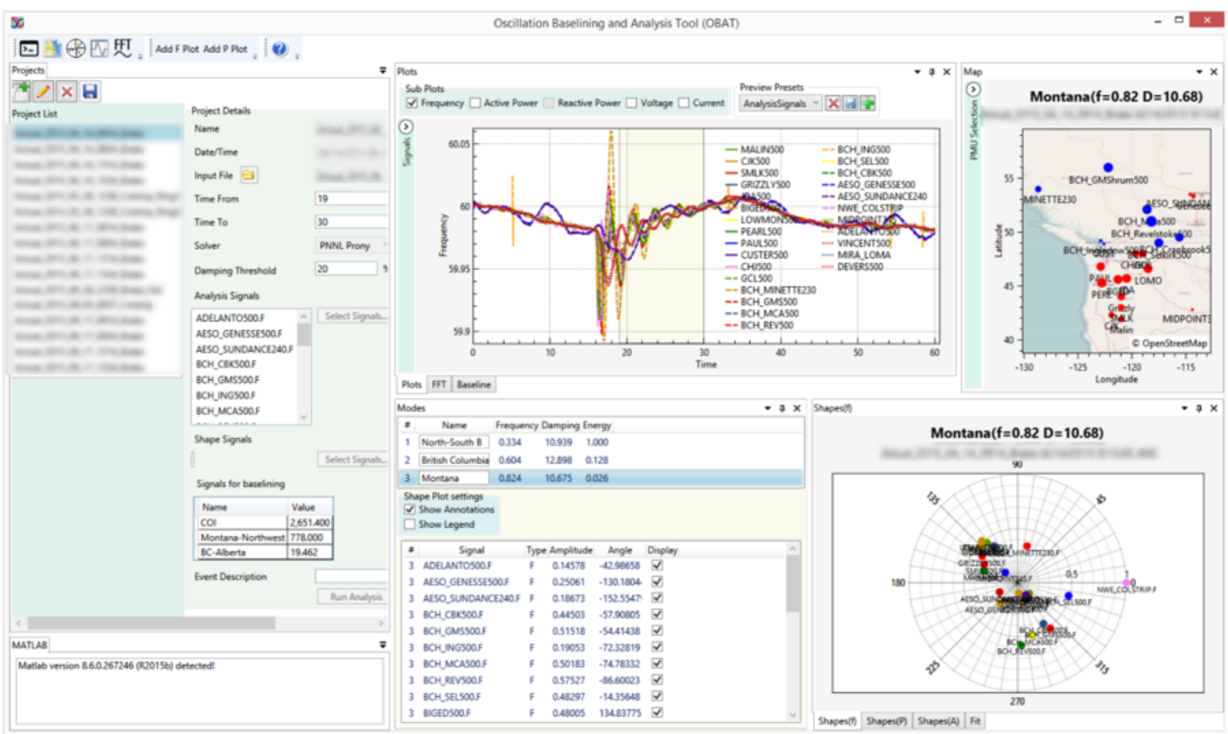
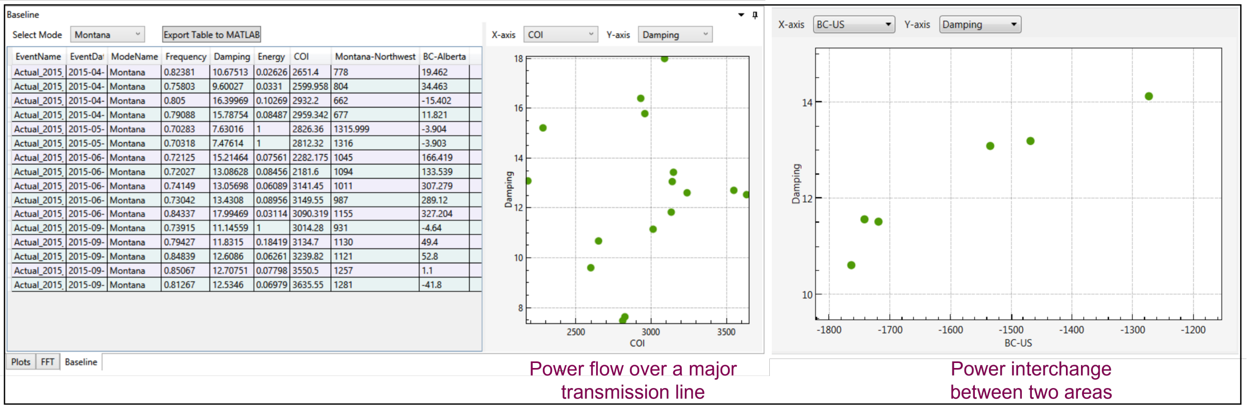


Figure 18: Oscillation Baselining and Analysis Tool (OBAT) user interface showing mode estimates obtained for a ringdown event [Etingov et al., 2018]



EventName	EventDat	ModeName	Frequency	Damping	Energy	COI	Montana-Northwest	BC-Alberta
Actual_2015	2015-04-	Montana	0.82381	10.67513	0.02626	2651.4	778	19.462
Actual_2015	2015-04-	Montana	0.75803	9.60027	0.0331	2599.958	804	34.463
Actual_2015	2015-04-	Montana	0.805	16.39969	0.10269	2932.2	662	-15.402
Actual_2015	2015-04-	Montana	0.79088	15.78754	0.08487	2959.342	677	11.821
Actual_2015	2015-05-	Montana	0.70283	7.63016	1	2826.36	1315.999	-3.904
Actual_2015	2015-05-	Montana	0.70318	7.47614	1	2812.32	1316	-3.903
Actual_2015	2015-06-	Montana	0.72125	15.21464	0.07561	2282.175	1045	166.419
Actual_2015	2015-06-	Montana	0.72027	13.08628	0.08456	2181.6	1094	133.539
Actual_2015	2015-06-	Montana	0.74149	13.05698	0.06089	3141.45	1011	307.279
Actual_2015	2015-06-	Montana	0.73042	13.4308	0.08956	3149.55	987	289.12
Actual_2015	2015-06-	Montana	0.84337	17.99469	0.03114	3090.319	1155	327.204
Actual_2015	2015-09-	Montana	0.73915	11.14559	1	3014.28	931	-4.64
Actual_2015	2015-09-	Montana	0.79427	11.8315	0.18419	3134.7	1130	49.4
Actual_2015	2015-09-	Montana	0.84839	12.6086	0.06261	3239.82	1121	52.8
Actual_2015	2015-09-	Montana	0.85067	12.70751	0.07798	3550.5	1257	1.1
Actual_2015	2015-09-	Montana	0.81267	12.5346	0.06979	3635.55	1281	-41.8

Figure 19: Analyzing the relationship between mode damping estimates and system conditions using OBAT from historic event records [Etingov et al., 2018]

An example analysis is shown in Fig. 19. Here, damping estimates for several WI historic events are plotted against two system quantities - power flow over a major transmission line, and power transfer between two areas. A linear relationship is visible between the inter-area transfer and mode damping (right panel), indicating that the mode is likely to become lightly damped if the transfer increases beyond a certain value. The relationship between power flow on the transmission line and mode damping is not as clear (middle panel).

5.0 Frequency Response Analysis

The North American Electric Reliability Corporation (NERC) defines the frequency response of an interconnection as the measure of its ability to stabilize frequency immediately after a large disturbance like sudden loss of generation or load [NERC, 2023]. The measure is derived from the time-domain behavior of system frequency in different overlapping time windows following the disturbance. These windows are commonly referred to as the regimes of the frequency response (or frequency control). In each regime, the system provides distinct control actions to arrest the deviations in frequency [NERC, 2012]. These are discussed next.

The frequency profile immediately following a disturbance (i.e., a few milliseconds after a disturbance) is dominated by the inertial response of the system. During this period, the rotational inertia of the synchronous generators and synchronous motors acts to either absorb transient energy into or release stored energy from the rotating masses to arrest any change in machine speed and system frequency. The inertial support is fast and available for a very short time after which the primary frequency control comes into play. This is followed by the secondary and tertiary regimes of frequency control. Different regimes of frequency control are shown in Fig. 20 [LBNL, 2010]. The primary control begins within seconds of the disturbance and extends to a few minutes following it. The actions of primary control come from the speed governors in the generators, droop controls in the inverter-based resources, frequency response of the motor loads, and other grid components that provide frequency support based on local controls. While the primary frequency control can arrest the immediate changes in the frequency and initiate a rebound, in most cases, it by itself is unable to restore the system frequency to its pre-disturbance value. The secondary and the tertiary controls are used to that end. The secondary frequency control comes from the actions of the automatic generator controls (AGCs) that the balancing authorities (BAs) engage to restore system frequency. In North America, BAs are entities within an interconnection that ensure the generation-load balance is maintained, in real-time, within their area limits. Tertiary control involves manual adjustments of generation set points via economic dispatch [NERC, 2021].

The discussions in this chapter regarding the standards and the tools for frequency response analysis shall focus only on the contributions due to inertial response and primary frequency control.

5.1 Reliability Standard for Frequency Response Performance

In North America, NERC BAL-003-1 is the reliability standard that specifies the “amount of frequency response required in each interconnection and the allocation of frequency response obligation among balancing authorities” [NERC Std., 2014]. It also outlines the formulae for quantifying the frequency response performance of a system, both at the interconnection and the BA levels. The following are the salient points of the standard [NERC Std., 2014]:

1. It defines frequency response (FR) for an interconnection and a BA, and provides the methods for quantifying their FR (also called frequency response measure or FRM).

2. It outlines the methods for computing the reliability thresholds for the interconnection and BA FRMs, which are termed *FR Obligations (FROs)*

3. It provides the frequency bias setting for the BAs to maintain their respective FRMs within the specified FRO.

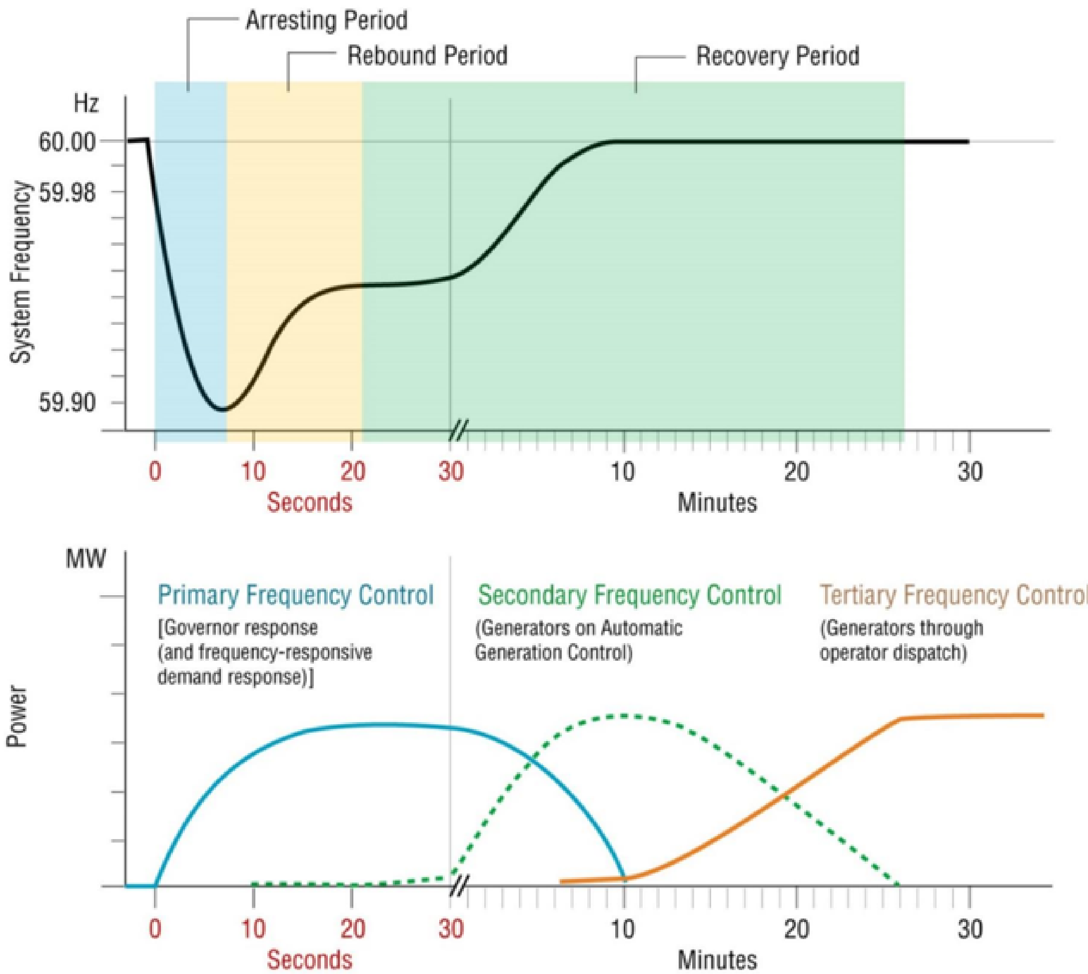


Figure 20: Primary, secondary, and tertiary regimes of frequency control. Source: [LBNL, 2010].

Before the adoption of the BAL-003-1 standard, NERC's "Frequency Response Characteristic Survey Training" document [NERC, 1989] provided the necessary guidance to the system operators and BAs to measure their frequency response behavior. It required the user to identify the net power interchanges for the BA immediately before the event and after the frequency had stabilized to a settled value. The document, however, did not provide the exact definitions of these start and end values. This led to the challenge that different people analyzing the same data could assume different instants for the event starting and the settling of the frequency. The NERC BAL-003-1 provides for this by defining the points A, B, and C on the frequency response curve as follows [NERC Std., 2014]:

- f_A (frequency at point A): this is the pre-disturbance frequency averaged over the window $t = -16$ s to $t = 0$ s.
- f_B (frequency at point B): this is the post-disturbance settling value of the frequency averaged over the window $t = 20$ s to $t = 52$ s. This time window is chosen to ensure that the transients due to the faster primary frequency control have settled while the influence of the slower secondary control is yet to make any significant impact.

- f_C (frequency at point C): this is the nadir of the frequency response due to an event like loss of generation.

The points A, B, and C on a frequency response plot for a generator trip are shown in Fig. 21 below.

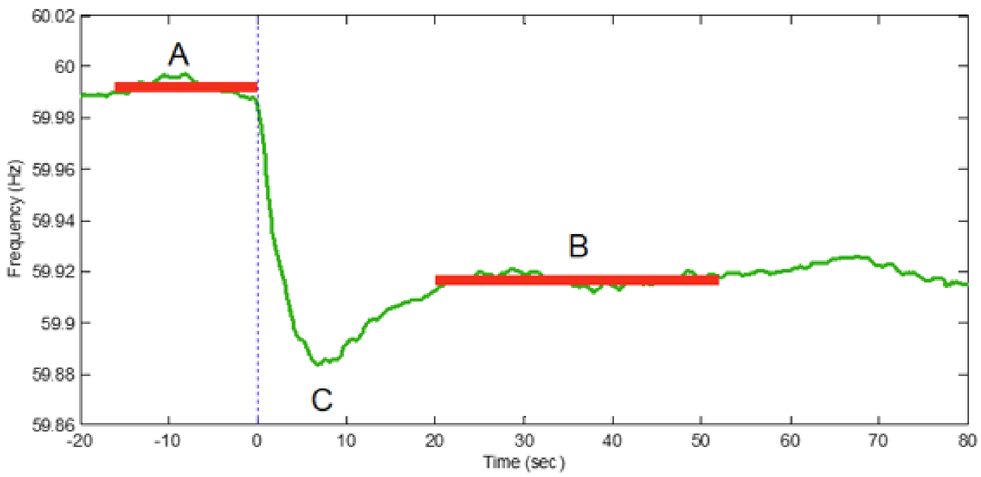


Figure 21: Points A, B, and C on a frequency response plot. Source: PNNL [PNNL, 2014].

5.1.1 Frequency Response Measure

As mentioned, NERC BAL-003-1 specifies the formulae to quantify the frequency response behavior of a system both at the interconnection level and also for the constituent BAs. The frequency response measure (FRM) for an interconnection is calculated as [NERC Std., 2014]

$$FRM_{\text{Interconn.}} = \frac{P_{\text{Gen. Loss}} - P_{\text{Load Loss}}}{10\ (f_B - f_A)} \qquad \text{(MW/0.1Hz)} \tag{1}$$

where $P_{\text{Gen. Loss}}$ and $P_{\text{Load Loss}}$ are, respectively, the net generation and load loss for the entire interconnection due to an event and f_A and f_B are the frequencies at points A and B described previously. The FRM for a BA within an interconnection is calculated as [NERC Std., 2014],

$$FRM_{\text{BA}} = \frac{(P_{\text{Int.}_B} - Adj_B) - (P_{\text{Int.}_A} - Adj_A)}{10\ (f_B - f_A)} \qquad \text{(MW/0.1Hz)} \tag{2}$$

where, $P_{\text{Int.}_A}$ and $P_{\text{Int.}_B}$ are, respectively, the net real power interchanges across the boundaries of the BA averaged over the time-windows corresponding to points A and B. A representative frequency response plot with the frequency values at A and B and the corresponding interchange powers are shown in Fig. 22. The terms Adj_A and Adj_B account for the adjustments in the power interchanges due to jointly owned units, pumped storage units, non-conforming loads, etc. The NERC BAL-003-1 standard specifies the adjustment factors for each case [NERC Std., 2014].

5.1.2 Frequency Response Obligations

Besides defining the formulae for computing the FRM from disturbance data, the NERC BAL-003-1 standard also specifies the minimum thresholds on the FRMs that ought to be maintained by

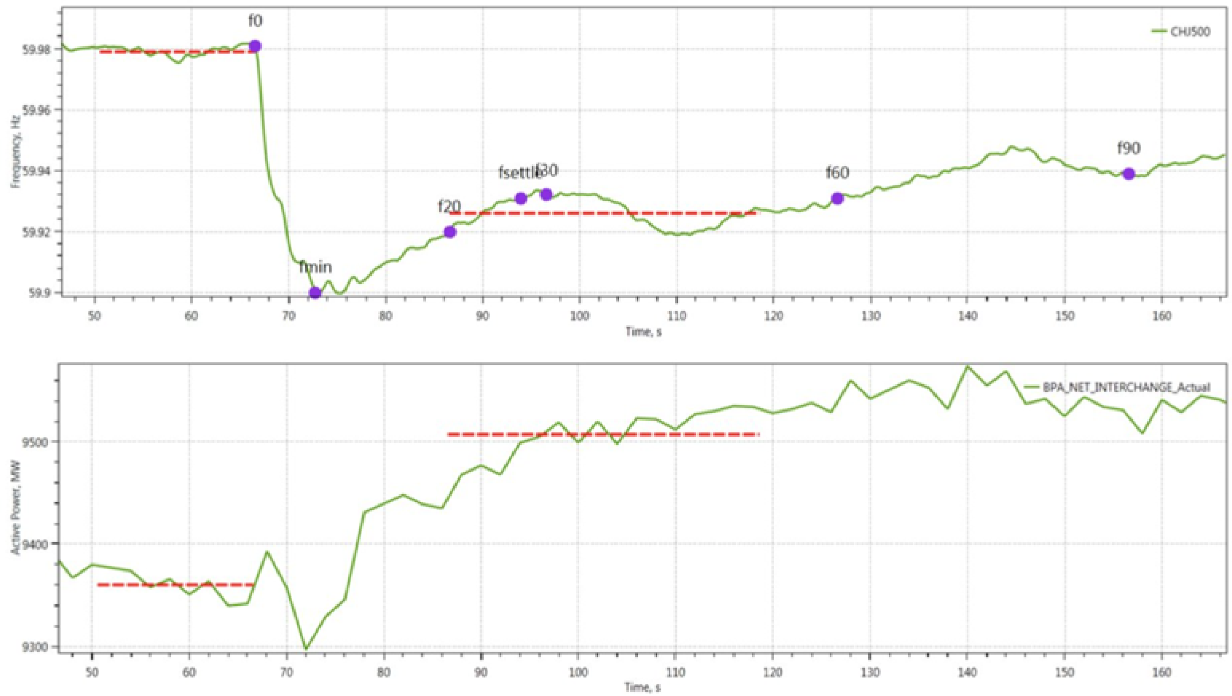


Figure 22: Frequency and interchange powers for FRM calculation in a BA. Source: PNNL [PNNL, 2014].

the interconnections and their BAs for reliable system operation from the protection standpoint. At the interconnection level, this threshold is called the Interconnection Frequency Response Obligation (IFRO) [NERC Std., 2014].

IFRO calculation involves identifying the under-frequency load-shedding (UFLS) settings for the interconnection and the largest resource contingency that could potentially violate that setting. For the Western Interconnection in North America, the largest contingency for the IFRO calculation is the simultaneous outage of two generation units (N-2) at Palo Verde, Arizona. For the Eastern Interconnection, the resource contingency used for IFRO calculation is the largest MW event recorded in the last ten years [NERC Std., 2014]. Ideally, IFRO is calculated as the amount of power lost in the contingency event divided by the maximum frequency change in the event while accounting for certain adjustments. Details on IFRO calculation can be found in [NERC Std., 2014]. Tables 1 and 2 list the IFRO values for the four interconnections in North America and the resource contingencies used in determining these values [NERC Std., 2014].

Table 1: IFRO values for four interconnections in North America [NERC Std., 2014].

	Eastern	**Western**	**Texas**	**Quebec**
IFRO (MW/0.1 Hz)	-1002	-840	-286	-179

In North America, it is the collective responsibility of the BAs to maintain a desirable frequency response behavior at the interconnection level. To that end, the NERC BAL-003-1 standard also specifies how an IFRO is to be shared among the constituent BAs. The FRO share of a BA is

Table 2: Contingencies used for IFRO calculation in different interconnections of North America.

Interconnection	Resource Contingency	Event	MW
Eastern	Largest Event in Last 10 Years	Aug 4, 2007 Disturbance	4500
Western	Largest N-2 Event	2 Palo Verde Units	2740
Texas	Largest N-2 Event	2 South Texas Units	2750

calculated as [NERC Std., 2014]

$$FRO_{\text{BA}} = IFRO \cdot \frac{\text{Annual Gen.}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen.}_{\text{Interconn.}} + \text{Annual Load}_{\text{Interconn.}}} \tag{3}$$

where Annual Gen. $_{\text{Interconn.}}$ and Annual Gen. $_{\text{BA}}$ are, respectively, the total annual generation reported within a BA and in the interconnection at large. Similarly, Annual Load $_{\text{Interconn.}}$ and Annual Load $_{\text{BA}}$ are respectively the sum of all loads in the BA and the interconnection over a year.

5.2 Tools for Frequency Response Analysis

In this section, we discuss the attributes of two software applications – the Frequency Response Analysis Tool (FRAT) [PNNL, 2014] and the Phasor Grid Dynamics Analyzer (PGDA) tool [EPG, 2024], that support frequency response analysis for utilities and BAs. FRAT is developed by PNNL and is open-source whereas PGDA is a licensed commercial tool developed by the Electric Power Group. These are presented next.

5.2.1 Frequency Response Analysis Tool (FRAT)

The Frequency Response Analysis Tool (FRAT) [PNNL, 2014] was developed by PNNL with support from the Department of Energy (DOE) and Bonneville Power Administration (BPA). The primary purpose of this tool is to support the balancing authorities and the reliability coordinators in performing FRM calculations from disturbance data consistent with NERC BAL-003-1 specifications and definitions. The tool can use both PMU (at 30 frames-per-second rate) and SCADA data from archived events. In addition to NERC FRM calculations, the FRAT tool can also perform frequency nadir calculations. The following are the main features of the tool [PNNL, 2014]:

1. visualization of system frequency for the interconnection and BA for an event from user-inputted PMU and SCADA data,

2. estimation of the initial frequency, settling frequency, and nadir frequency from the frequency response data,

3. calculation of FRM and FRO according to NERC BAL-003-1 standard

4. calculation of FRM at the nadir frequency

5. statistical analysis and baselining of FRMs from different events

6. automated generation of FR report for NERC compliance reporting

The graphical user interface of the FRAT consists of the following screens (see Fig. 23):

- *Event database screen:* This offers the user a list of frequency events to choose from. The events list has information on the time of occurrence, MW size of the disturbance, and previously computed values of FRM.
- *Event description screen:* Displays the details for the events like the initial frequency, settling frequency, nadir frequency, etc. It also shows the load and generation values, by type of units, for the interconnection and the BA and the calculated FRMs.
- *Event plot screen:* Offers graphical visualization of the time-domain plots of system frequency, active power interchange, and voltage for the selected event.
- *FRM baseline and analysis screen:* Shows the FRM values for the historic events and the baseline plot both for the interconnection and the BA. The baseline plot displays the trends and changes in FRM over a selected time range and a linear regression fit for the trend. The statistical analysis tab displays the probability distribution of the FRMs along with the mean, median, and standard deviation of the distribution.

The latest versions of FRAT also support FRM calculation for individual generation units [PNNL, 2014]. The application allows the selection of generation models within a plant and tuning of model parameters to obtain a match between the simulated frequency response results and field measurements. This is shown in Fig. 24.

5.2.2 Phasor Grid Dynamics Analyzer Tool

The Phasor Grid Dynamics Analyzer (PGDA) is an offline data analytics tool developed by the Electric Power Group (EPG). It performs analysis of disturbance data for a host of applications like model validation, oscillation detection and baselining, root-cause analysis, etc. The tool also supports frequency response analysis from archived data. It calculates both the inertial frequency response as well as primary frequency response using NERC-approved techniques. The input data can be from multiple sources like PMUs, digital fault recorders (DFRs), and system simulations. Data can be in CSV, COMTRADE, PI Historian, or any other commonly accepted data format. The tool can perform statistical analysis and generate automated compliance reports for the frequency response application. A screenshot of the tool is shown in Fig. 25.

Figure 23: Screenshot of the FRAT showing different analysis screens. Source: PNNL [PNNL, 2014].

Option to select individual plant mode

Figure 24: FRM calculation for individual power plants using FRAT. Source: PNNL [PNNL, 2014].

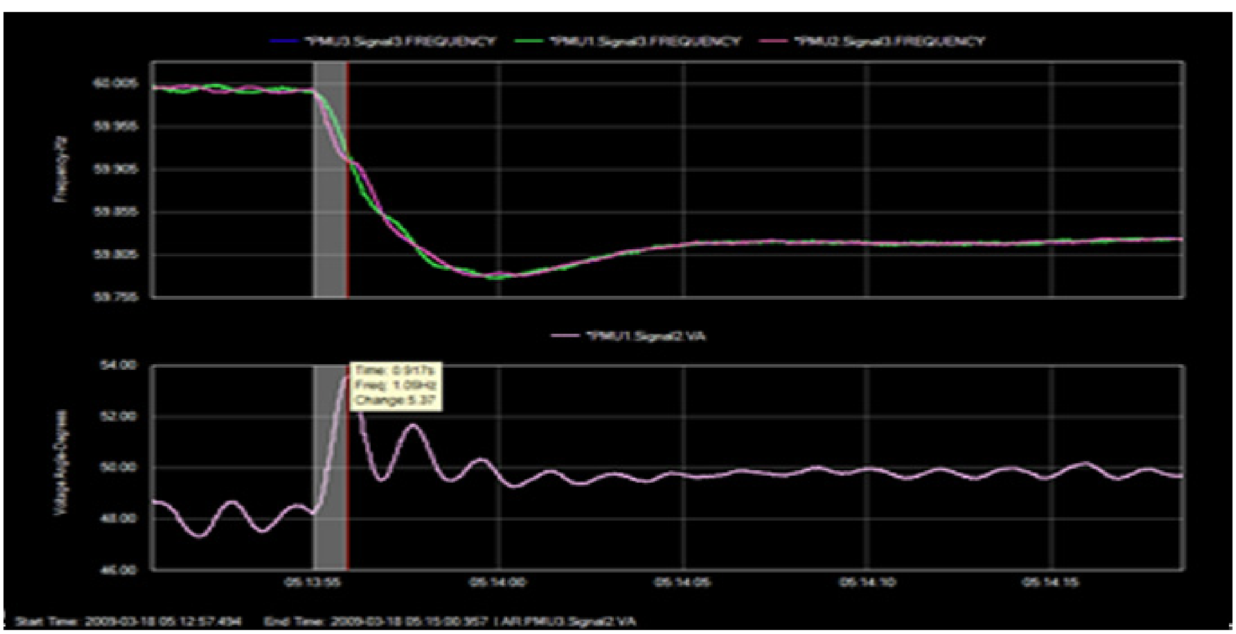


Figure 25: Screenshot of the PGDA tool for frequency response analysis. Source: EPG [EPG, 2024].

6.0 Postmortem Analysis of Disturbance Events

Postmortem analysis refers to the engineering investigation that is undertaken by the electricity reliability coordinators and other stakeholders after a major grid event to understand the root cause and conditions leading to the event. In other words, postmortem analysis seeks to answer the – 'what', 'when', 'where', 'why', and 'how' questions related to the event [Dagle, 2006]. Typically, this begins with identifying the instant of disturbance inception and tracking its propagation by accurately determining the sequence of events [Cummings, 2023]. Establishing the sequence of events requires large volumes of time-stamped measurement data from multiple sources [Dagle, 2006]. Experiences from the blackout investigations of 1996 and 2003 in North America highlight the usefulness of phasor measurements in this context. This chapter shall focus on this aspect and discuss the utility of high-resolution PMU data for disturbance analysis and their root-cause investigation.

6.1 Need for Time-synchronized Measurement Data in Post-mortem Analysis

Circuit breaker statuses and event logs play a critical role in determining the sequence of events. In transmission systems, these are typically recorded as SCADA logs. SCADA data from different locations in a large interconnection are not time-synchronized leading to time skew in recording of these statuses. The sequence of events can also be obtained from the records of the instrumentation at substations like digital fault recorders and digital relays. Many times, the internal clocks in these instruments are also not synchronized with an accurate time standard [Dagle, 2006]. This can impact the accuracy of post-mortem analysis.

In contrast, phasor measurements are GPS time-synchronized and offer a wide-area perspective concerning the inception and propagation of a disturbance event. Additionally, PMUs with their high-speed data reporting capability compared to SCADA, can capture the low-frequency transients in the system response which can be of critical importance in analyzing specific events. An important step in post-mortem analysis is to reconstruct the event signature from the simulation model to verify the validity of the hypotheses concerning its causation. The availability of high-resolution measurements from the event can offer greater insights into model calibration and root-cause validation.

The following subsections summarize key lessons learned from two notable disturbance events in North America. The limitations of traditional SCADA-based measurement systems are contrasted with the value of high-resolution time-stamped data.

6.1.1 Experiences from the 2003 North American Blackout Investigation

The real-time monitoring of the phase angle difference between adjacent areas can offer the reliability coordinators insights into detecting precursors of a system separation event. This became evident in the post-mortem analysis of the 2003 blackout in the Northeastern United States and Canada. The investigation report by NERC in the aftermath of the event suggested that if there had been the capability for phase angle monitoring in the system, it would have revealed the trends in phase angle separation between the Cleveland area and the rest of Eastern Interconnection before the relays tripped and separated the system [Cummings, 2023]. The angle separation is shown in Fig. 26. It is believed that this could have alerted the operator to shed loads in appropriate areas to prevent the cascading failure [Cummings, 2023].

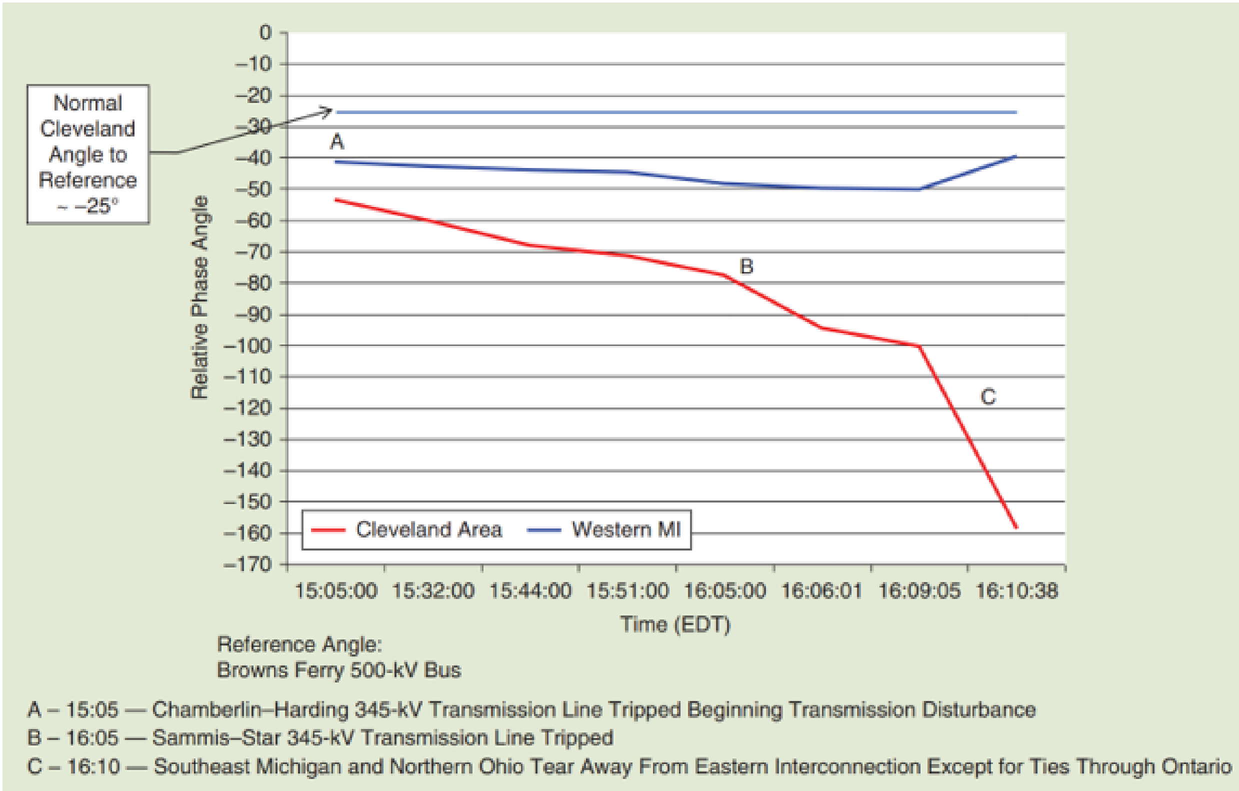


Figure 26: Phase angle difference plot showing system separation between Cleveland and Michigan leading up to the 2003 blackout. Source: IEEE/NERC [Cummings, 2023].

As discussed previously, high-speed time-synchronized measurements from PMUs and DFRs can also enable the correct identification of the sequence of events. In this case, the disturbance recorders installed on the Michigan–Ontario transmission interface gave the investigators a time anchor for understanding the inception and the propagation of the disturbance [Cummings, 2023]. For instance, in the preliminary analysis, it was believed that a 400 MW generation trip in Maine was due to the load generation mismatch in the islanded system of New England. However, with more data, it was later revealed that this tripping was a result of a remedial action scheme that initiated due to a line tripping in central Michigan [Cummings, 2023]. Time stamps also confirmed that it was this generation trip that caused the New England system to separate from the rest of the Eastern Interconnection and not the opposite. The time-stamped disturbance recording from the Michigan-Ontario interface used in the post-mortem analysis is shown in Fig. 27. The sequence of events derived from the data is shown in Fig. 28 [Cummings, 2023].

Another lesson from the 2003 blackout was that when investigating an event with the impact spread over multiple utilities and reliability coordinators, access to data in a common format may be challenging [Dagle, 2004]. Establishing a pipeline and a framework for information exchange between the stakeholders is the necessary first step in the process. Automated disturbance data reporting in a universal data format can aid the analysis to that end. Waiting for formal data requests can slow down the overall investigation [Cummings, 2023].

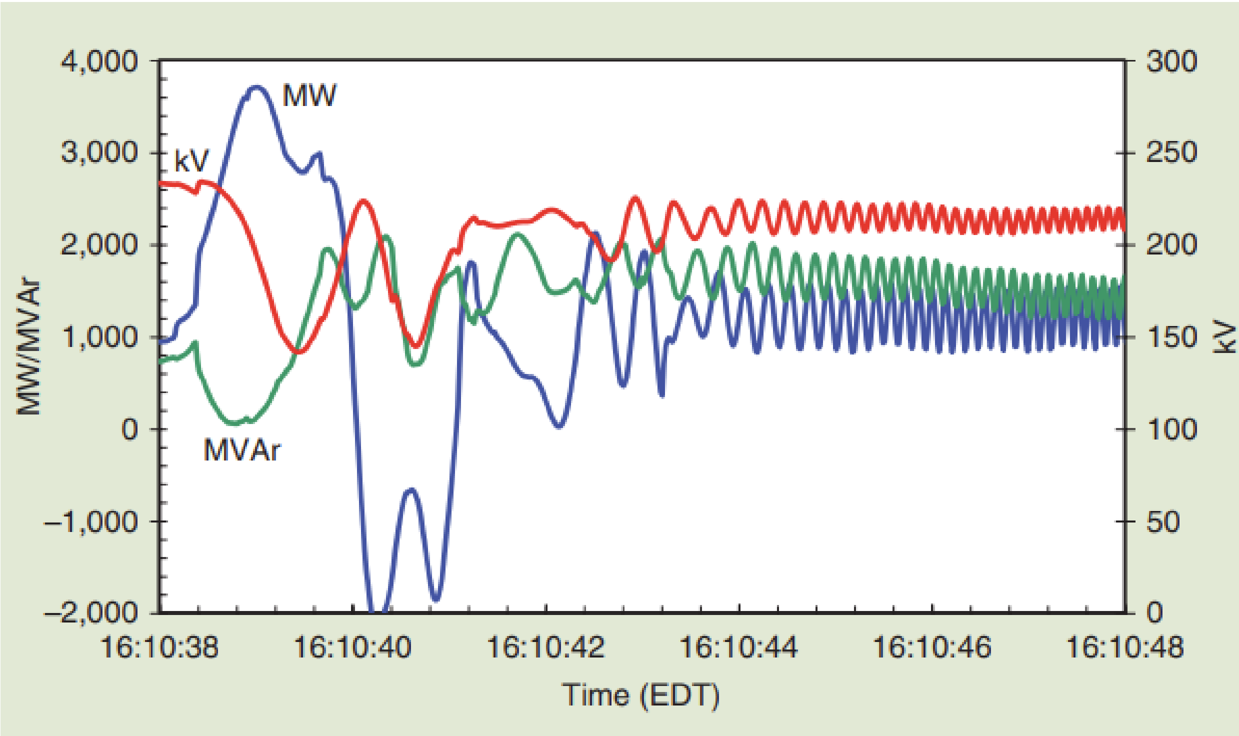


Figure 27: Disturbance recordings from the Michigan–Ontario transmission interface during the 2003 Northeast blackout. EDT: Eastern Daylight Time. Source: IEEE/NERC [Cummings, 2023].

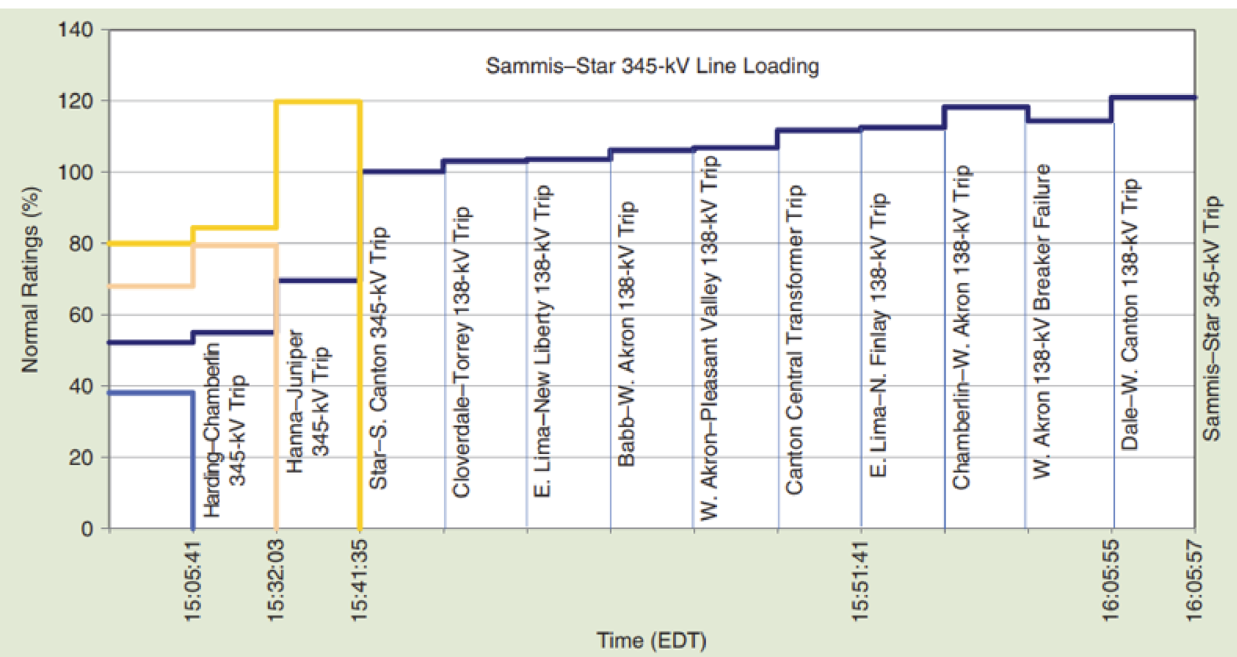


Figure 28: Sequence of events derived from time-stamped data in the 2003 blackout. Source: IEEE/NERC [Cummings, 2023].

6.1.2 Experiences from the 2019 Forced Oscillation Investigation

Another application where the availability of high-speed time-synchronized measurements can aid the post-mortem analysis is in the investigation of oscillation events for source localization and root-cause analysis. As an example, for the January 11, 2019, forced oscillation (FO) event in the Eastern Interconnection, PMU data from multiple regions and utilities were useful in locating the oscillation source in a utility in Florida [NERC, 2019]. Fig. 29 below shows the active power oscillations in the Eastern Interconnection for the January 2019 FO event derived from PMU measurements. The detection of FO frequency is also shown in Fig. 29 [NERC, 2019]. Observe that PMU data also helped in establishing the accurate time for the onset of the oscillation.

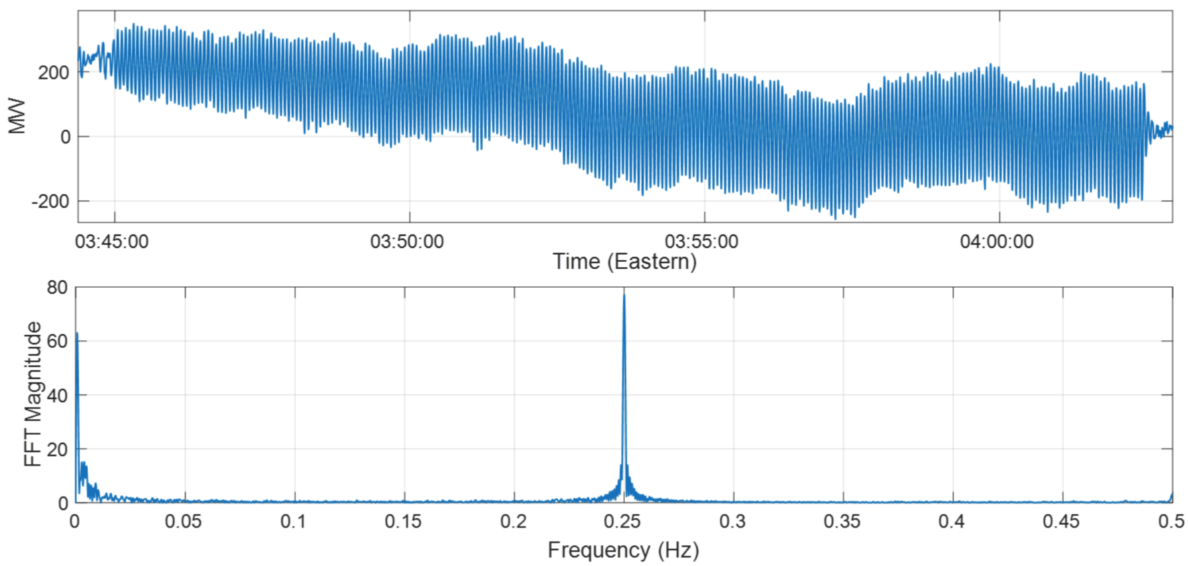


Figure 29: Active power oscillations for the January 2019 FO event (upper plot) and identification of the oscillation's frequency from PMU data (lower plot). Source: NERC [NERC, 2019].

6.2 Tools for Post-mortem Analysis

The Phasor Grid Dynamics Analyzer (PGDA) tool [EPG, 2024], developed by the Electric Power Group (EPG), supports planners and engineers in performing detailed analyses of power system disturbances and dynamic events. It offers the functionalities for identification of disturbance type, location, severity, and grid performance. The tool supports collating data from multiple sources like PMUs, DFRs, and simulation programs.

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