NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Recommended Oscillation Analysis for Monitoring and Mitigation Reference Document

Synchronized Measurement Working Group

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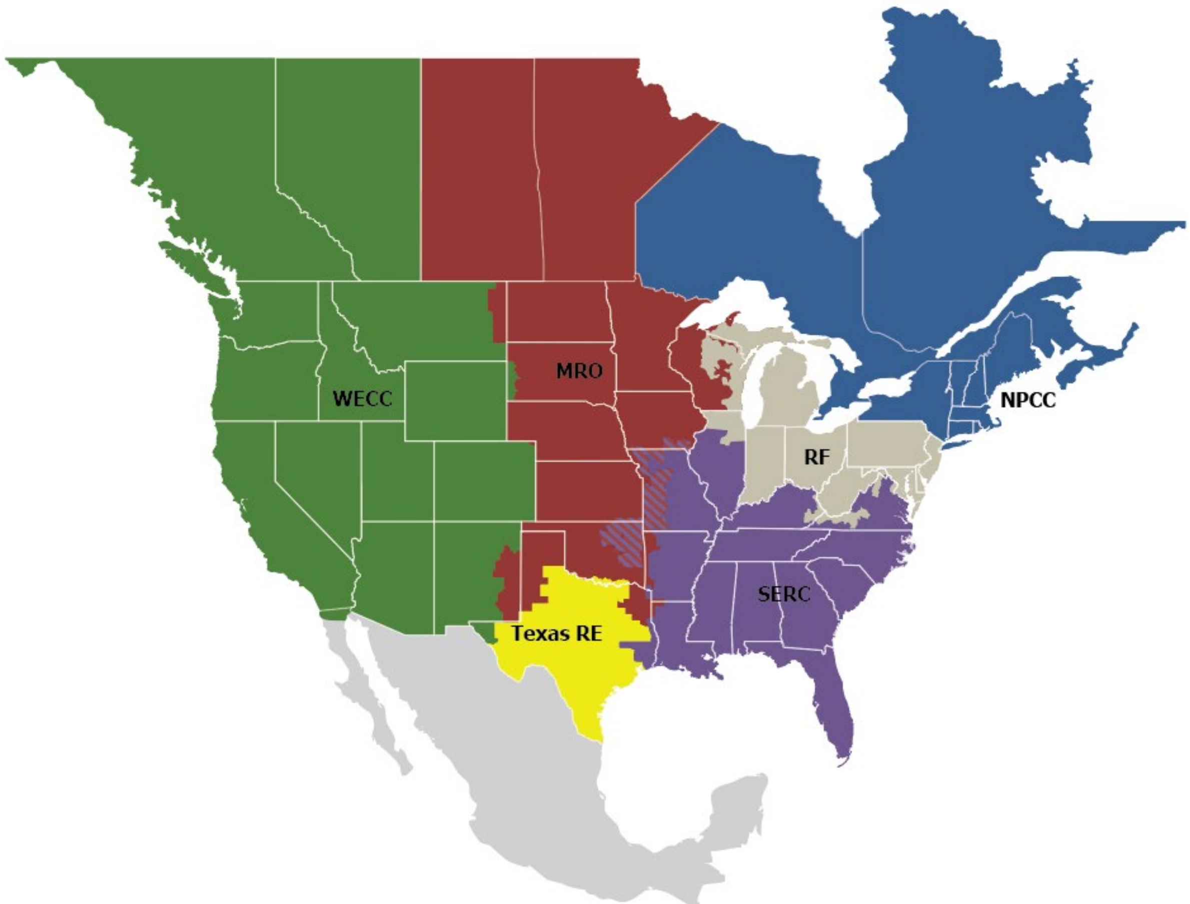
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators (TO/TOP) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

Recent oscillation events, such as the January 11, 2019, forced oscillation event in Florida that interacted with a natural system mode of the Eastern Interconnection and led to propagation of the oscillation across the Interconnection, have highlighted the need for increased monitoring and consistency in the monitoring of oscillation disturbances. Some of the key recommendations from the report[1] on the event included the need for Reliability Coordinators (RCs) and TOPs to utilize real-time oscillation detection tools. RCs and TOPs should have real-time oscillation detection tools in place to identify when oscillations are occurring and determine if the oscillations are limited locally within their footprint or are more widespread. Equally important is to be able to distinguish between forced oscillations, poorly damped natural system modes, or scenarios where forced oscillations may be propagating across a wider area due to resonance conditions. In addition, there was a recognition that RCs should improve their communication with RCs in the event of widespread oscillation disturbances in BPS and when operating procedures could be an effective means of ensuring this coordination upon the identification of an oscillation.

The NERC Synchronized Measurement Working Group (SMWG) was also requested to develop guidance on oscillation analysis methods to encourage consistency in the system quantities that are monitored for oscillation events and the respective thresholds for alarms. The detection and alarming of oscillations and their classification in a consistent manner is critical in ensuring coordinated mitigation of both local and widespread oscillation disturbances in BPS.

In addition, it is also important to identify what kind of operator actions are necessary for different kind of oscillations. These actions can range from locating the source of forced oscillations to reducing power transfers across major transmission paths. Actions can also include making topological changes to improve damping of widespread natural system oscillations or combinations of those actions if there is interaction of the forced oscillations with natural system modes that result in propagation across the Interconnection.

The following are key findings and recommendations of this technical reference document:

- For monitoring of inter-area or natural oscillations, various methods exist that can utilize ambient or post-disturbance data to determine the system modes that are significant. These assessments are recommended to be done annually or based on significant changes in the system. After identifying the significant modes, additional analyses can be performed to determine the locations where the modes are observable and the respective thresholds for alarming or operator action based on damping and the energy of the modes. In addition, analyses using powerflow cases and the associated dynamic models can be utilized to validate the modeling of the observed significant modes and to determine what mitigation actions might be effective in improving the damping of those modes.
- Forced oscillations can be detected using various methods that utilize thresholds established by prior analyses to differentiate between sustained forced oscillations and normal ambient changes in system conditions. Once the forced oscillations are detected, various methods exist to determine the locations from where the forced oscillations originate.
- Under certain conditions, forced oscillations can propagate across an Interconnection due to resonance with a natural system mode. Mitigation of such wide spread oscillations can require a combination of mitigation actions ranging from locating and eliminating the source of the oscillation to taking actions to reduce the impacts across the system by improving the damping of the impacted system mode.
- Mitigation of local and widespread oscillation disturbances and their impact requires effective tools and coordination between RCs and TOPs to determine the type of oscillation and the appropriate mitigation actions.

[1] Lesson Learned: Interconnection Oscillation Disturbances: https://www.nerc.com/pa/rrm/ea/Lessons Learned Document Library/LL20210501_Interconnection_Oscillation_Disturbances.pdf

Introduction

The SMWG, formerly the Synchronized Measurement Subcommittee, has provided well-accepted guidance on what oscillations are, why they occur, and what are the various tools to monitor them. Various previously published reports on Interconnection oscillation analyses[2] and forced oscillation events[3] provide recommendations on what RC and TOPs should do to monitor oscillations, emphasizing the need to coordinate and develop tools. Monitoring of oscillations requires the setup and configuration of real-time tools that require a certain level of analyses and preparation to determine the quantities for monitoring, what should be their respective thresholds for alarms, and the respective operator actions.

The analysis that is required can vary depending on whether a tool is being set up to monitor a natural inter-area oscillation or a forced oscillation. The levels at which operator actions are necessary to intervene and mitigate for any potential reliability impacts of oscillations can also vary based on the type and location of oscillation. RCs and TOPs are in the process of developing operating procedures to supplement the monitoring of oscillations. These operating procedures contain specific actions for operators to follow during critical oscillatory conditions. Model-based simulations provide an opportunity to determine required mitigation actions for consistency in developed operating procedures and mitigation plans.

This technical reference document addresses two distinct types of power system oscillations, natural and forced and is divided into five distinct chapters:

- **Chapter 1** addresses inter-area electromechanical oscillations. These oscillations are often referred to as natural oscillations because they arise from the dynamics inherent to any power system. A system's inter-area modes of oscillation govern the periodic exchange of energy between generators in different parts of the system. Natural oscillations can take on different forms depending on how the system's dynamics are excited: ambient oscillations resulting from continuous perturbation by random load changes and ringdown oscillations caused by an impulsive disturbance, such as a generator tripping off-line.
- **Chapter 2** addresses forced oscillations, which are the response of a system to a particular periodic input, such as a generator with a steam valve cycling on and off continuously.
- **Chapter 3** discusses the case where a forced oscillation becomes observable across a wide area.
- **Chapter 4** provides recommended guidelines for operators to address wide-area oscillations.
- **Chapter 5** discusses examples of existing practices by RCs and operators.

In summary, the chapters of this technical reference document aim at providing a framework of methods to do the following:

- Conduct natural-mode-related and forced oscillation analysis by using examples to illustrate what is normal and what is not
- Determine quantities to be monitored and quantify their boundaries and how to implement these boundaries as monitoring thresholds in tools
- Determine and validate mitigation actions and establish distinction between local and system issues

[2] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf
[3] Eastern Interconnection Oscillation Disturbance: https://www.nerc.com/pa/rrm/ea/Documents/January_11_Oscillation_Event_Report.pdf

Chapter 1: Inter-Area Electromechanical Oscillations

As demonstrated by the *2019 Interconnection Oscillation Analysis Reliability Assessment* [4] different Interconnections have different known modes. In fact, there are a large number of modes, but they can be reduced to only a handful that are dominant, important, and observable and actually have a noticeable effect on electrical signal dynamics of the system. This reduction usually leads to roughly a half dozen or so modes in each Interconnection (depending on grid size and complexity) that are worth understanding and tracking. Some of the commonly known modes are shown in **Table 1.1**, which demonstrates the differences between the Interconnections and the expected Hz range for these oscillations.

Table 1.1: Major Modes in Various Interconnections

Interconnection	Mode Name	Mode Frequency Range (Hz)
Eastern	N–S	0.16–0.22
	NW–S	0.29–0.32
	NE–NW–S	0.23–0.24
Texas	N–SE	0.62–0.73
Western	North-South A (NSA)	0.20–0.30
	North-South B (NSB)	0.35–0.45
	East-West A (EWA)	0.35-0.45
	British Columbia (BC)	0.50-0.72
	Montana	0.70-0.90

The next section provides a summary of known methods that help determine the following:

- The modes of significance in an Interconnection that are recommended to be monitored, for a given system topology and operating condition, typically appear as consistent peaks in the signal spectrum (see **Figure 1.1**). When mode monitoring algorithms (both ringdown and ambient measurement-based) are used, the estimated modes tend to form clusters (as shown in **Figure 1.2**) over time or across multiple signals on a complex plane. In addition, significant modes tend to have much higher pseudo modal energy[5] compared to all other estimated modes from the same measurement window. This can be verified by looking at curve fitting errors from a small subset of the estimated modes.
- Methods for determining the effective mitigation actions should be used to increase damping of the determined modes.
- Methods for determining the measurements should be used to monitor the significant modes.

[4] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf
[5] Trudnowski, Daniel J., John W. Pierre, Ning Zhou, John F. Hauer, and Manu Parashar. "Performance of three mode-meter block-processing algorithms for automated dynamic stability assessment." IEEE Transactions on Power Systems 23, no. 2 (2008): 680–690.

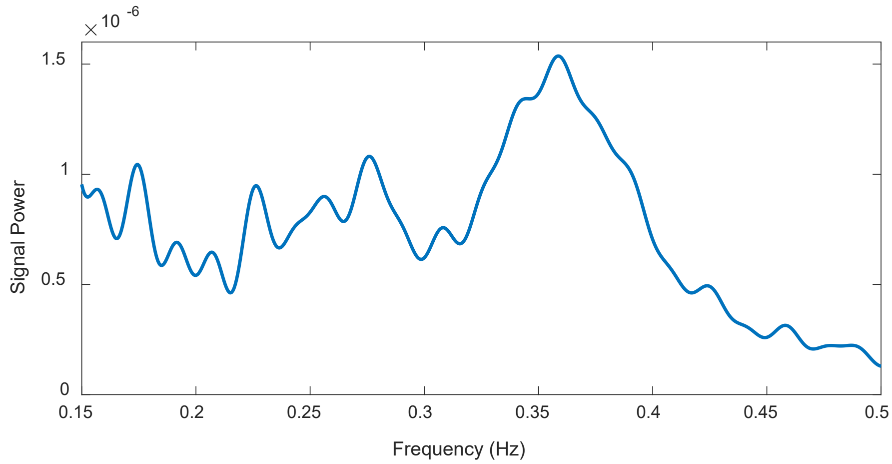


Figure 1.1: Estimate of the Spectral Content of the Frequency Signal

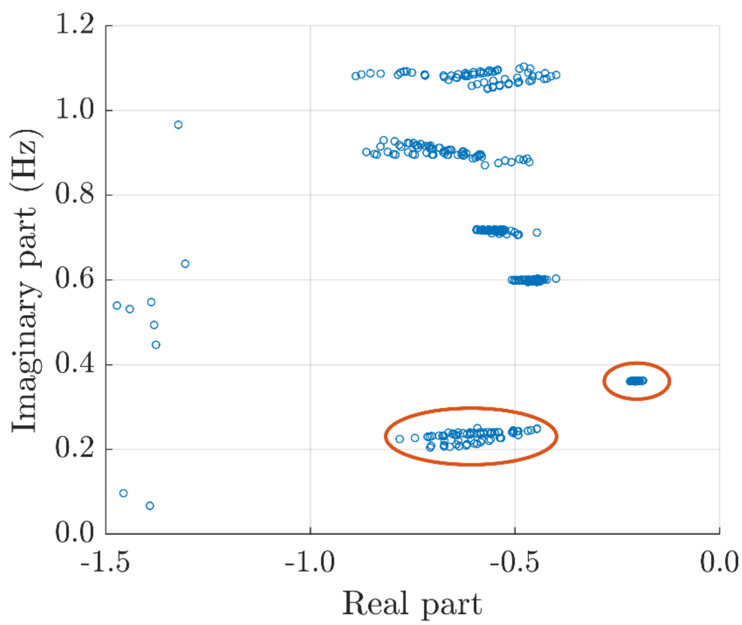


Figure 1.2: Example of clusters formed by eigenvalue estimates

1.1 Interconnection-Wide Analysis to Determine Significant Modes

This section provides a framework of known small-signal stability analysis methods to determine the inter-area modes of significance, input data, and any other information required to do these analyses. Guidance is also provided on the recommended frequencies of these studies. The *2019 Interconnection Oscillation Analysis*[6] report presented various types of oscillation analysis techniques for modal identification. In addition, more comprehensive details on these methods are available in the IEEE Power and Energy Society (PES) developed technical report: *Identification of Electromechanical Modes in Power Systems*.[7] Several of the methods described in this section have been deployed in commercial tools and deployed by system operators. Examples are provided in **Chapter 5**.

These methods fall into three main categories:

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[6] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf

[7] IEEE Task Force on Identification of Electromechanical Modes, *Identification of Electromechanical Modes in Power Systems*, *IEEE Technical Report PES-TR15*, June 2012 (http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PESTR15*)*.

Ringdown Methods: These are used to analyze natural oscillations that result from large disturbances on the BPS. These methods can be utilized with phasor measurement data or simulated data from offline powerflow dynamic simulations. The post-disturbance trajectories of relevant power system states, or sometimes combinations of statements, are commonly referred to as "ringdowns." Analysis of ringdowns provides valuable insight into the frequency, damping ratio, and shape of the system's inter-area modes of oscillation. It can also serve as a useful tool in model validation (i.e., ensuring that the modal characteristics of real-time or planning base cases match those of the actual system). There are various algorithms and methods employed for modal analysis of disturbance data that are distinct from the techniques used to analyze ambient data.

Ambient Methods: These are used to analyze signals during normal, steady-state conditions where the primary excitation to the system is random load changes. These methods are typically in real-time tools or offline tools for analysis of phasor measurement data. They can be used to track the frequency, damping ratio, shape of specific modes of oscillation, or to identify periods of low damping in any mode. They can also be used to analyze ambient periods surrounding disturbance data to provide validation for ringdown methods.

Eigenvalue Analysis Method: This method can be implemented by using powerflow cases along with the associated dynamic data to determine the modes that exist in a system. The mode frequency, damping and associated mode shape, controllability, and participation factor of participating generators can be determined. The method can be utilized on offline powerflow base-cases used for transmission planning and operational planning studies or with real-time state estimator snapshots.

Table 1.2 shows a summary of the methods along with the type of data or model where the methods are applicable.

Table 1.2: Methods for Modal Analysis

Data Type	Ringdown Methods	Ambient Methods	Eigenvalue Analysis
Synchrophasor Data (Ambient Data)		X	
Synchrophasor Data (Post-Disturbance Data)	X		
Powerflow Base-Cases (Offline Planning Models or Real-Time State Estimator Snapshots) with associated dynamic data	X		X

The results of the analyses will help to determine the modes that are important from a monitoring perspective. The modes are typically defined by a frequency and a mode shape that lists the participating generators and the respective areas in the mode. The analysis also provides the damping[8] of the respective modes that can vary significantly based on system operating conditions and generator controller configurations. These methods are summarized in Table 1.3 for a quick comparison of the approaches and data requirements.

[8] Modes are often represented as complex numbers in rectangular form: $\lambda = \sigma + j\omega$. A mode's frequency is given by $f = \frac{\omega}{2\pi}\ Hz$ and its damping ratio is often expressed in percent as $\zeta = \frac{-\sigma}{\sqrt{\sigma^2+\omega^2}} \times 100\%$. A system maintains small-signal stability as long as all of its modes have a positive damping ratio.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
Prony Methods[9]	• Estimates damped sinusoidal components in a linear system response • Expressing the system outputs as linear combinations of fundamental sinusoidal modal components • Singular Value Decompositions (SVDs) for handling the measurement noise and for reducing the computational burden	Post-Disturbance Data
Eigensystem Realization Algorithm (ERA)[10]	• Singular value decomposition of a matrix whose entries are samples of the system impulse response (Hankel matrix) • Using the decomposition, a reduced linear system realization is computed (i.e., the system state matrices)	Post-Disturbance Data
Matrix Pencil[11]	• Compute a pseudo-inverse of a matrix using an SVD technique (This also includes a built-in filter for leaving out noise related phenomena in the SVD formulation.)	Post-Disturbance Data
Variable Projection (VARPRO)[12]	• General nonlinear least-squares optimization technique	Post-Disturbance Data
Hankel Total Least Squares (HTLS)[13]	• Formulate a Hankel matrix from the observed Phasor Measurement Unit (PMU) measurements of the event • Use a Total Least Squares approach for evaluating the eigenvalues again using a SVD computation	Post-Disturbance Data

[9] D. J. Trudnowski, J. M. Johnson and J. F. Hauer, "Making Prony analysis more accurate using multiple signals," in IEEE Transactions on Power Systems, vol. 14, no. 1, pp. 226-231, Feb. 1999.

[10] J. J. Sanchez-Gasca, "Identification of power system low order linear models using the ERA/OBS method," in IEEE PES Power and Systems Conference and Exposition, 2004.

[11] Guoping Liu, J. Quintero and V. M. Venkatasubramanian, "Oscillation monitoring system based on wide-area synchrophasors in power systems," 2007 iREP Symposium - Bulk Power System Dynamics and Control - VII. Revitalizing Operational Reliability, Charleston, SC, 2007, pp. 1–13.

[12] A. R. Borden and B. C. Lesieutre, "Variable Projection Method for Power System Modal Identification," in IEEE Transactions on Power Systems, vol. 29, no. 6, pp. 2613–2620, Nov. 2014.

[13] J. J. Sanchez-Gasca and J. H. Chow, "Computation of power system low-order models from time domain simulations using a Hankel matrix," in IEEE Transactions on Power Systems, vol. 12, no. 4, pp. 1461–1467, Nov. 1997.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
Yule Walker[14]	• Method operates by first estimating the autocovariance sequence of the measured data • It then fits a model that describes the relationship between the autocovariance sequence at different lag values • The parameters of this model are associated with a rational polynomial whose poles correspond to the power system's electromechanical modes • An extension allows the parameters of electromechanical modes and forced oscillations to be identified simultaneously[15]	Ambient synchrophasor measurements
Least Squares[16]	• Fits a model that describes the current measurement in terms of past measurements and the current random input • This model parameterized as a rational polynomial whose poles correspond to the power system's electromechanical modes • An extension allows the parameters of electromechanical modes and forced oscillations to be identified simultaneously[17]	Ambient synchrophasor measurements
Frequency Domain Decomposition[18]	• Power spectral density (PSD) functions of the ambient measurements are first estimated in the frequency domain • Singular value decomposition (SVD) then used to combine and extract the principal singular values of the multiple PSD estimates	Ambient synchrophasor measurements

[14] R. W. Wies, J. W. Pierre and D. J. Trudnowski, "Use of ARMA block processing for estimating stationary low-frequency electromechanical modes of power systems," in IEEE Transactions on Power Systems, vol. 18, no. 1, pp. 167–173, Feb. 2003, doi: 10.1109/TPWRS.2002.807116.
[15] U. Agrawal, J. Follum, J. W. Pierre and D. Duan, "Electromechanical Mode Estimation in the Presence of Periodic Forced Oscillations," in IEEE Transactions on Power Systems, vol. 34, no. 2, pp. 1579–1588, March 2019.
[16] N. Zhou, J. W. Pierre, D. J. Trudnowski and R. T. Guttromson, "Robust RLS Methods for Online Estimation of Power System Electromechanical Modes," in IEEE Transactions on Power Systems, vol. 22, no. 3, pp. 1240–1249, Aug. 2007.
[17] J. Follum, J. W. Pierre and R. Martin, "Simultaneous Estimation of Electromechanical Modes and Forced Oscillations," in IEEE Transactions on Power Systems, vol. 32, no. 5, pp. 3958–3967, Sept. 2017.
[18] Guoping Liu and V. Venkatasubramanian, "Oscillation monitoring from ambient PMU measurements by Frequency Domain Decomposition," 2008 IEEE International Symposium on Circuits and Systems, Seattle, WA, 2008, pp. 2821–2824.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
	• Local peaks among the singular values to correspond to frequencies of system modes and oscillations observed in the data • Modal properties estimated by analyzing these principal singular values near the peak frequencies	
Stochastic subspace identification (SSI)[19]	• Formulate the PMU measurements as outputs of a linear system being excited by unknown random load fluctuations, modeled as independent white noise inputs. • Essential features of the linear system model describing the power system can then be estimated	Ambient synchrophasor measurements
Eigenvalue Analysis	• QR-based methods for complete eigenvalue decomposition • Arnoldi-based methods for partial eigenvalue decomposition • Provides information on observability, controllability, and participation factor of generators along with frequency and damping ratio of respective modes	Powerflow case and dynamic data

The recommendation is to perform these analyses on a regular basis after events by using the post-mortem analysis methods and by using the powerflow base cases and associated dynamic data on a seasonal or yearly basis. Significant system changes can also be used as triggers for performing these analyses, such as the following:

- Changes in system
- Retirement of generation facilities
- Changes in power system injection points due to an increase in renewable resources penetration or generation dispatch patterns and inverter-based resource
- Other significant changes in generation dispatch patterns

In addition, the modes can also be validated by using post-mortem analysis through planned signal tests in the Interconnection. The annual Chief Joseph Brake insertion test in the Western Interconnection (WI) is an example of a signal test allowing the validation and update of some of the known modes.

[19] S. A. Nezam Sarmadi and V. Venkatasubramanian, "Electromechanical Mode Estimation Using Recursive Adaptive Stochastic Subspace Identification," in IEEE Transactions on Power Systems, vol. 29, no. 1, pp. 349–358, Jan. 2014

1.1.1 Commonalities on Interconnection Oscillation Analysis using Modal Analysis of Ringdowns

This section presents an example of modal analysis performed using power system data collected during a disturbance, either observed or simulated. The ringdown method is used as an example. The intent of this section is to discuss concepts that are generally applicable to all ringdown methods. The notion of curve fitting is central to modal analysis of ringdowns. In broad terms, curve fitting is the process of specifying a model whose output provides the best fit to measured data under some mathematical criteria. The model identified by a curve-fitting routine can then be used to extract information about the resonant properties of the system. Specifically, the identified model permits estimation of the eigenvalues and eigenvectors of a linearized representation of the system dynamics that correspond to a particular operating point. For studying electro-mechanical oscillations, measurements of rotor speed, bus frequency, and intertie active power flows provide useful input data.

A crucial step in any curve fitting procedure is to specify the structure of the model being fit to the data. For power system applications, common choices include autoregressive models and discrete-time state-space models. Often, choosing a specific model structure helps to determine which algorithm is best suited to the problem. For instance, Prony's method identifies an autoregressive model to determine the coefficients of the characteristic polynomial. In contrast, the Eigensystem Realization Algorithm identifies a discrete-time state-space model. Often (but not always), autoregressive models are used for single-channel analysis whereas state-space models are inherently multi-channel. In this context, "single-channel" refers to the analysis of one ringdown while "multi-channel" refers to the simultaneous analysis of multiple ringdowns.

Data Collection and Pre-Processing

In general, it may not be possible to analyze all of the modes of interest by using data collected for a single disturbance. The reason for this limitation is that a given disturbance may not excite all of the modes, or it may not excite them enough to permit estimation with the desired accuracy. For example, following a Chief Joseph Brake insertion in the WI, it may be possible to estimate the frequency and damping of the North-South B mode but not the East-West A mode. When characterizing dynamic models, this limitation can be mitigated by simulating multiple disturbances that originate from various points in the system. The data for each simulated disturbance can then be used to estimate a subset of the system modes.

Modal analysis may be performed by using data collected during a wide variety of disturbances; however, special considerations arise in the case of transient disturbances during which the operating point of the system may move from one equilibrium to another. For example, following the loss of a transmission line, the active power transfer on the remaining ac lines may change. If these power transfer measurements are used as inputs to a modal analysis framework, the dc offset corresponding to the post-disturbance power flow must be subtracted from the original signal. In the case of generator trips, the trajectories of rotor speeds and bus frequency measurements contain considerable low-frequency content that lies below the range of the electromechanical modes. It is generally desirable to remove this very low frequency component of the system response to better highlight oscillatory phenomena. This may be done by forming pairs of relative signals that represent the difference in bus frequency (or rotor speed) measured at two different points in the system. If an estimate of a particular mode is sought, these pairs may be selected based on knowledge of its shape. Alternatively, the center-of-inertia frequency (or speed) may be subtracted from each individual frequency (or speed) signal. This is a useful technique when the mode shapes are not known in advance. If the subsequent deviations after detrending the data are small, scaling (or normalizing) the data may improve numerical performance, if it is done in a consistent manner.

In order to get the best possible results from any modal analysis technique, care must be taken in collecting and preparing the input data. When analyzing data collected from actual disturbances, it is often beneficial to use a lowpass filter to mitigate the impact of high-frequency measurement noise and/or process noise. When circumstances allow, as in a posteriori analysis, high-order finite impulse response filters are preferred because they can be designed with a linear phase response, preserving a constant group delay across the entire frequency band.

The corner of this lowpass filter should be placed such that the oscillatory phenomena of interest falls firmly within the passband. This step may be omitted when analyzing simulated data arising from real-time or planning base cases when noise is not present.

To maximize the accuracy of mode frequency estimates, the input data may be resampled via a combination of anti-aliasing and decimation. A useful rule-of-thumb is to set the sampling rate of the input data to approximately 10 times the highest frequency of interest. For example, if the highest mode frequency of interest is 1 Hz, this would imply a sampling rate in the range of 10–12 sps (samples per second). During this process, the sampling rate of the original data should also be taken into account. Resampling generally yields the best results when the final sampling rate is an integer factor of the original rate. For instance, if the original data is sampled at 60 sps, it would be advisable to resample the data at 10 or 12 sps, as opposed to 11 sps. Choosing the final sampling rate in this way obviates the need to upsample (i.e., interpolate, the original data, which is not advisable in modal analysis applications). Before downsampling the original data, it must be passed through an anti-aliasing (lowpass) filter that limits its bandwidth to satisfy the Nyquist-Shannon sampling theorem. For example, if 60 sps data is going to be resampled at 12 sps, the stopband of the anti-aliasing filter should begin at 6 Hz. As with noise reduction filters, high-order linear phase finite impulse response filters are preferred for this application where possible.

Curve Fitting Sensitivities

Most curve fitting algorithms for modal analysis are designed to operate on the so-called "free response" of the system (i.e., the period in which the input or forcing function has gone to zero). Thus, the position of the curve-fitting window must be aligned with the free response for best accuracy. For example, if the system stimulus is a dynamic brake insertion, the left endpoint of the curve-fitting window should be placed no sooner than the instant when the brake is removed. In general, it is a good practice to allow some additional time to elapse, perhaps 0.5–1s, to ensure that the dynamics within the curve-fitting window correspond to the free response. In special circumstances where the forcing function is known (such as probe testing), this rule for positioning the curve-fitting window may be relaxed; however, the analysis algorithm may require modification. The positioning of the right endpoint of the curve-fitting window is equally important. A useful rule-of-thumb is that the duration of the window should be approximately 3–4 cycles of the lowest oscillation of interest if possible. For example, if the lowest mode frequency of interest is 0.25 Hz, this would imply a curve fitting window length of approximately 12–16 s. A caveat is that the window should not include flat or nearly flat signal content. This is an indication that the system has reached a new steady state that is not helpful in characterizing its dynamics and that the right endpoint must be placed no later than the final data sample.

There are multiple ways to quantify a curve-fitting error, some of which depend on whether the analytical formulation is single-channel or multi-channel in nature. Two commonly employed approaches are the ℓ_2-norm and the closely related mean squared error (MSE). Both methods correspond to so-called least-squares error minimization. In the single-channel case, the ℓ_2-norm is given by

$$f(z,\tilde{z}) = \sqrt{\sum\nolimits_{k\in\mathcal{K}} (z_k - \tilde{z}_k)^2},$$

Where z_k the input data, and $\tilde{z}_k$ the output of the model. Here k denotes the sample index and $\mathcal{K}$ the set of points in the analysis window. Similarly, the MSE is defined as

$$f_{\mathrm{mse}}(z,\tilde{z}) = \frac{1}{|\mathcal{K}|}\sum\nolimits_{k\in\mathcal{K}} (z_k - \tilde{z}_k)^2,$$

Where $|\mathcal{K}|$ is the total number of samples in the window. These methods may be extended to the multi-channel case by summing over not only time but also the various signal channels. This type of least-squares minimization is implicit in many algorithms, such as Prony's method and dynamic mode decomposition (DMD).

When curve-fitting routines are used for modal analysis, attention must be paid not only to the fitting error but also to the estimates of the eigenvalues and eigenvectors derived from the results. These estimates are sensitive to various factors, including (but not limited to) the model order, the position of the curve-fitting window, and the value of any additional parameters. Many algorithms, such as Prony's method, require the user to specify the model order, or the number of poles, as an input. As discussed above, the user must also specify the position and duration of the curve-fitting window. Furthermore, optimization-based curve fitting routines may utilize additional parameters, such as constants allowing the user to trade-off between various terms in a multi-objective optimization formulation. All of these user-specified inputs have an impact on both the curve fitting error and the mode estimates returned by the algorithm.

When performing modal analysis of ringdowns, it is generally advisable to sample the space of possible input parameter combinations. For example, an input parameter combination may comprise a given model order, analysis window, and trade-off parameter value. At the start of the procedure, a set of possible combinations is defined that spans some portion of the space of interest. Then, the results of analysis are recorded for each combination that creates a collection of mode estimates. Eigenvalue estimates may be categorized first according to their position in the complex plane and then according to the corresponding eigenvectors. This process produces clusters of eigenvalue estimates in the complex plane, each that roughly takes the form of an ellipse. Categorizing estimates based on the eigenvectors helps to distinguish modes that are close to one another in the complex plane but have different shapes. Likewise, categorizing mode estimates purely in terms of their frequency and damping is insufficient because their mode shapes may be different. For example, the North-South B mode and the East-West A mode reside at very similar frequencies in the WI; however, they have different mode shapes. Final mode estimates may be derived by averaging individual estimates that have been confirmed to have the same shape.

Examples

This subsection presents practical examples stemming from modal analysis of a simulated Chief Joseph Brake insertion in the WI. To generate this simulated data, the dynamic brake was inserted at the 5s mark for a duration of 0.5s. In these examples, the inputs to the curve fitting routine were bus frequency measurements recorded at 26 points distributed geographically throughout the system. Each bus frequency was calculated by using a backward difference derivative approximation applied to the voltage angle. To model the effect of a bandlimited sensor, the output of the derivative approximation was then passed through a first-order lowpass filter. Modal analysis was performed by using an optimization-based, multi-channel curve-fitting algorithm. As with ERA, this method identifies a reduced-order state-space model that can then be fed into eigen analysis routines.

Figure 1.3 shows the frequency deviation (from nominal) measured at Nicola, British Columbia, and Genesee, Alberta. The dashed traces show the measured state trajectories, and the colored traces show the output of the model constructed by the algorithm. In this case, the curve-fitting window begins at the 6.5s mark and is 12s in length.

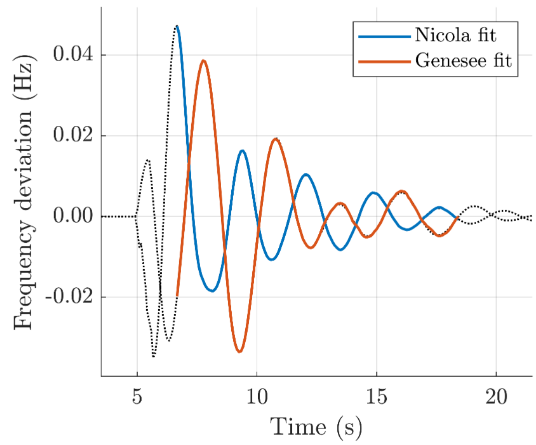


Figure 1.3: Example Curve Fit

Figure 1.4 shows the frequency difference measured between Nicola and Genesee. As explained above, computing the frequency difference between two points can make modal analysis easier by cancelling out common mode behavior. The dashed trace shows the relative frequency itself, and the colored traces show the two dominant modal components of the ringdown, the North-South A and B (NSA and NSB) modes. This decomposition can be performed by solving for the minimum-norm solution to an overdetermined system of linear equations as in Prony's method.

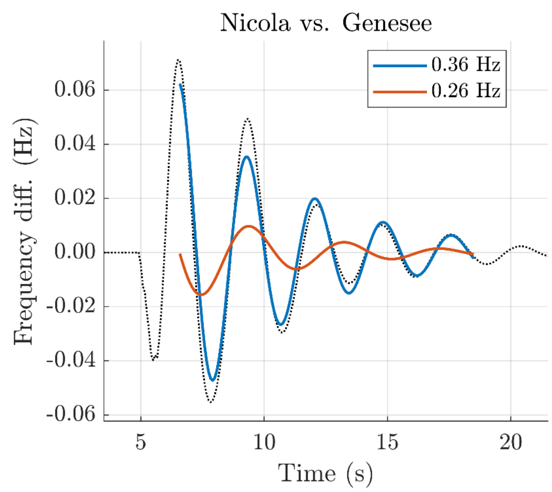


Figure 1.4: Decomposition of the Relative Frequency

The curve fitting procedure was repeated for 64 unique combinations of input parameters that spanned eight different analysis windows and eight values of a trade-off parameter used in the optimization. **Figure 1.2** shows the eigenvalue estimates generated using this approach. The orange ellipses highlight the estimates of the North-South A and B Modes generated from this disturbance. As discussed above, after the estimates were clustered according to their position in the complex plane, the eigenvectors were checked to ensure that all of the estimates within a given ellipse had matching mode shapes. In general, the variance associated with mode frequency estimates is lower than the variance associated with damping estimates. Furthermore, it is generally true that the variance associated with damping estimates increases as the true damping of the underlying mode increases. For this disturbance, the North-South B mode may be estimated with a higher degree of confidence than the North-South A mode because the variance is lower in both dimensions.

Figure 1.5 shows the shape of the North–South A mode overlaid on a map of the WI. Likewise, **Figure 1.6** shows the shape of the North–South B mode. Recall that mode shapes correspond to the right eigenvectors of the linearized state matrix. The shape of a mode provides information about how observable it is in a particular state or at a particular location. The shape also provides information about the phase of the oscillation, which can be used to determine which complexes of generators (or other components) are oscillating against one another. In the maps, the area of each marker is proportional to the magnitude of the entry of the right eigenvector corresponding to state measured at that location. Likewise, the arrow emanating from the center of each marker shows the precise phase of the oscillation. The color gradient indicates which states are oscillating against one another, as delineated in the key. This analysis is useful in verifying that the modal properties of dynamic models used in operations and planning match those of the actual system.

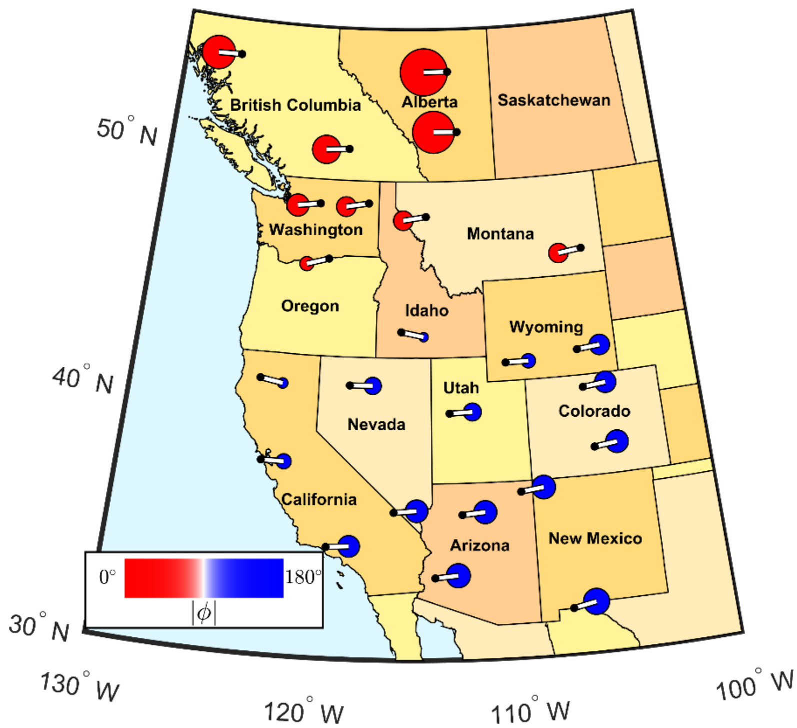


Figure 1.5: Map of the Shape for the 0.26 Hz North–South A mode

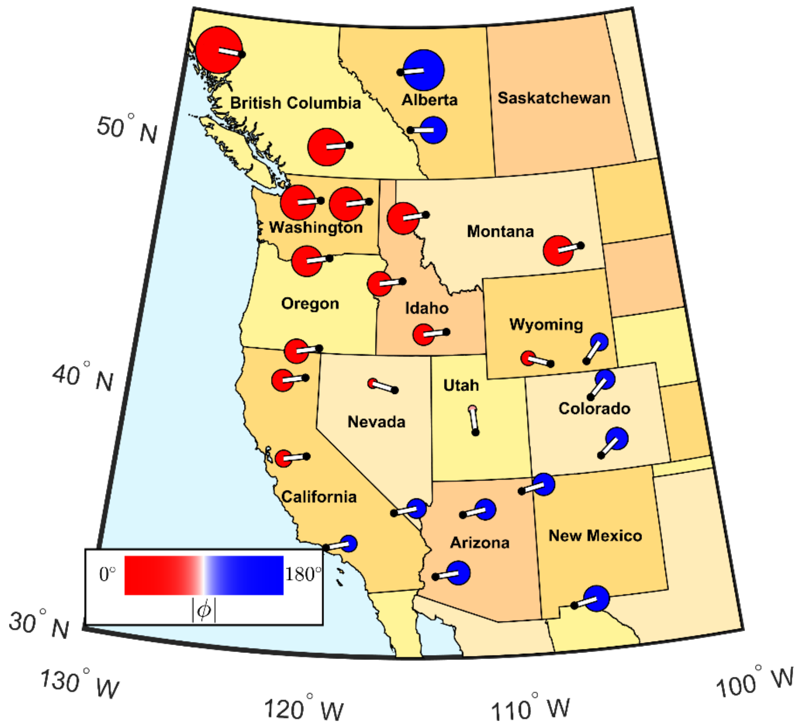


Figure 1.6: Map of the Shape for the 0.36 Hz North–South B mode

1.1.2 Commonalities on Interconnection Oscillation Analysis using Modal Analysis

This section describes ambient analysis techniques and the commonalities between them. The fundamental assertion behind modal analysis of ambient data is that the power system's dynamics are continuously excited by random load changes. Through proper analysis, the results of this excitation can be observed in synchrophasor data even during ambient conditions.

A measurement of frequency from a PMU during ambient conditions is plotted in **Figure 1.7**. Modal oscillations are not apparent from visual inspection, but the impact of the system's modes is present in the signal's random variation. To better see this, consider the estimate of the signal's frequency-domain spectrum in **Figure 1.8**. This estimate was generated by analyzing 30 minutes of data, including the 60 seconds in **Figure 1.7**, by applying a method based on the Discrete Fourier Transform (DFT). Note the spectrum's peak near 0.35 Hz. This peak corresponds to the well-known North-South B mode in the WI.

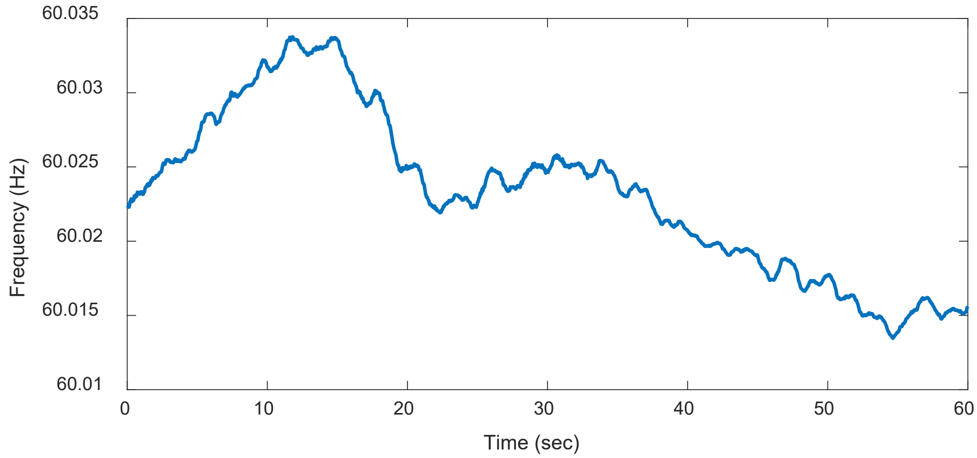


Figure 1.7: Plot of Frequency Measurements from a PMU during Ambient Conditions

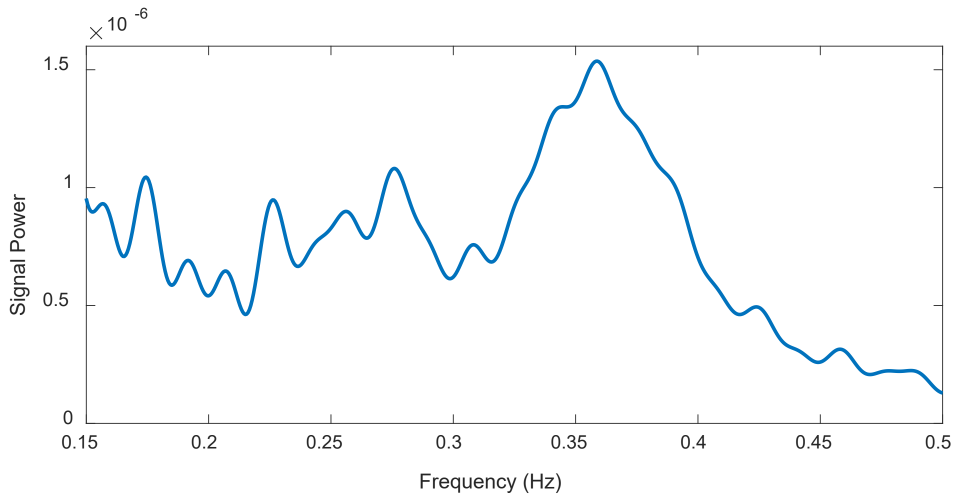


Figure 1.8: Estimate of the Spectral Content of the Frequency Signal

The observability of modes in the frequency-domain spectra of PMU measurements forms the basis for several ambient modal analysis algorithms. The Least Squares and Yule-Walker algorithms used in mode meters are actually spectral estimation methods. The methods determine model parameters to estimate the spectrum. These models can then be evaluated to extract estimates of the system's modes. Similarly, the fast frequency domain decomposition (FFDD) algorithm used in oscillation monitoring tools is based on estimation of power spectrum densities from all available PMU measurements. Further details are provided in **Section 2.1.2**.

Ambient algorithms were primarily developed to provide improved situational awareness to system operators in real-time environments. They can also be useful tools for identifying modes that need to be monitored. Ambient algorithms can be applied to historic data to obtain mode estimates that are updated regularly, even at one-minute intervals. This approach provides a much more granular view of each mode's behavior than can be obtained with transient analysis. Ambient analysis can also be used to understand how modes change during different loading conditions, system topologies, and seasons. This information can be critical in understanding of which modes need to be monitored and what conditions may lead to poor system damping.

1.2 Determination of Mitigation Actions

In addition to monitoring, operators would need guidance on how to mitigate inter-area oscillations. It is important to determine and validate mitigation actions in a consistent manner. These actions are developed ahead of time in operational planning studies and summarized in operating guides. There are two main model-based methods to determine and validate mitigation actions that can be included in the operating guidelines provided to operators:

- Eigenvalue analysis with powerflow cases and associated dynamic data
- Ringdown analysis with simulated disturbances on powerflow base cases and associated dynamic data

1.2.1 Eigenvalue Analysis with Powerflow Base Cases to Determine Mitigation Actions

Powerflow cases along with the associated dynamic data provide an opportunity to determine the significant modes along with their damping. The global positioning system (GPS) coordinates of the generating resources in the powerflow cases can help to establish the geographical mode shapes in addition to determining the participating generators in the various modes. Additionally, eigenvalue analysis also provides information on the controllability of participating generators for each mode. Using this information can help identify generators that have more control over a specific mode and therefore help with identifying strategies to improve damping ratio of that mode, such as tuning of Power System Stabilizers (PSS) of generators having high controllability for a mode to improve the damping ratio of that specific mode. This approach can be applied to both offline powerflow cases used for transmission and operational planning purposes and with real-time powerflow cases that utilize the state estimation solution and real-time conditions. The model-based approach to determine the mitigation actions provides some advantages:

- It allows for real-time validation of the provided mitigation approaches in operating guidelines provided to operators when used with real-time powerflow cases and the associated dynamic data.
- It allows testing different strategies such as varying transfers along major transmission corridors, varying topology conditions, such as status of transmission lines or series capacitors or generation redispatch.
- It allows testing the impact of contingencies on the damping of the significant modes. This can provide situational awareness to operators of the impact of contingencies when the damping of the monitored modes is below the critical levels for a sustained period.

The basic approach in this method is to calculate the eigenvalues within a certain frequency and damping range. It is recommended to pick a frequency range of 0.1 to 0.95 Hz to capture all possible inter-area modes and make the damping range large enough to capture the known significant modes. It is also recommended to filter out all modes that have a damping of more than 25% to focus on the modes of interest that show lower damping. Once a known significant mode is identified, mode tracing can be utilized to trace the impact of transfer across a path and variation of other topological conditions or equipment status, such as PSS on the damping of the known significant mode. This allows the development of guidelines for operators when developing mitigation actions for reducing damping of the monitored modes.

Figure 1.9 and **Figure 1.10** are examples of eigenvalue analysis performed by using the above approach in with the Small Signal Analysis Tool (SSAT) on the real-time state estimator snapshots along with the associated dynamic models at RC West. Mapping the GPS coordinates to each of the resources allows the development of the mode shape plots. This allows the validation of the mode shapes with state estimator cases when the damping and energy of the monitored modes reaches critical levels.

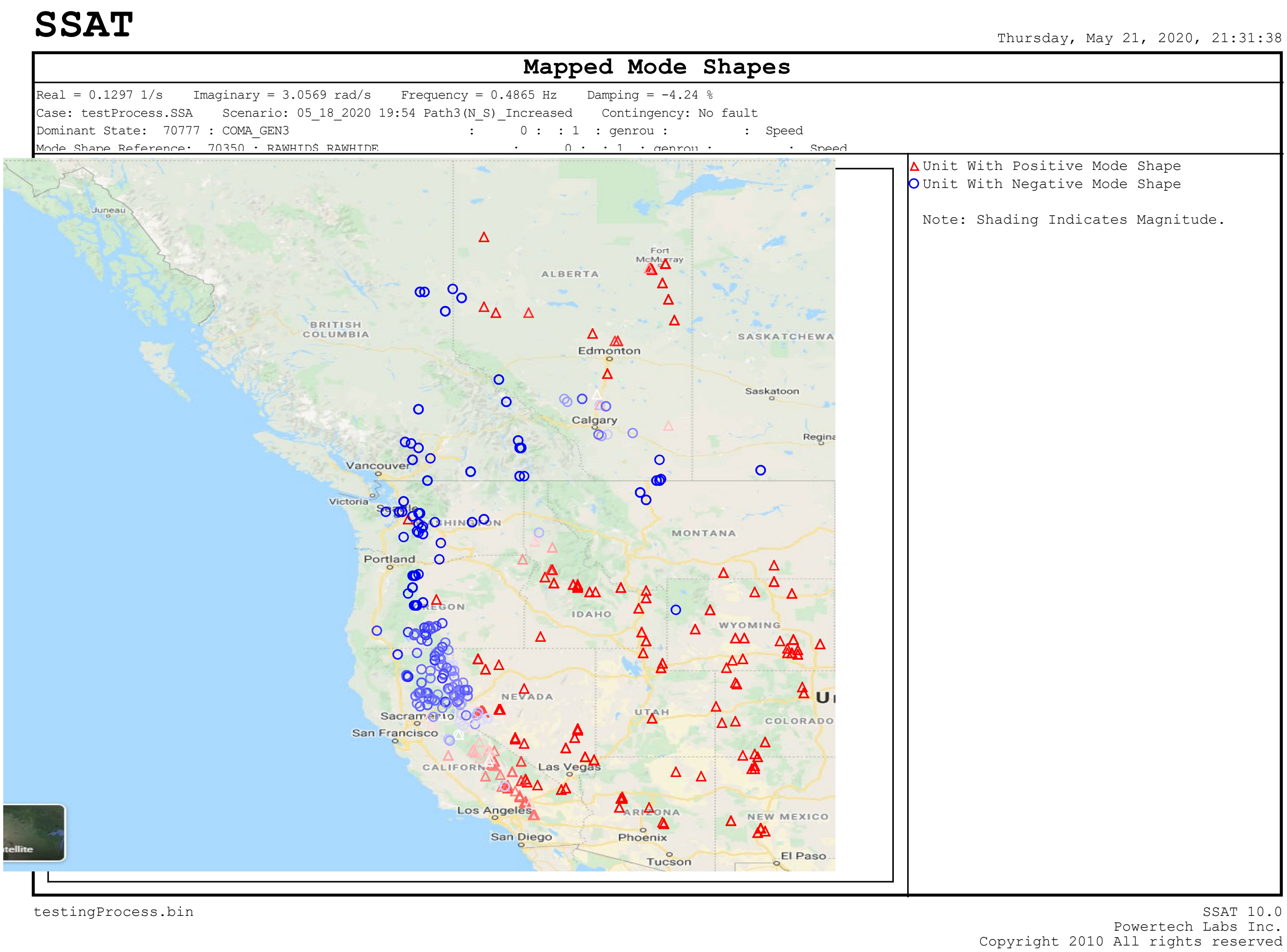


Figure 1.9: Mode Frequency Damping and Shape Estimated Using Eigenvalue Analysis

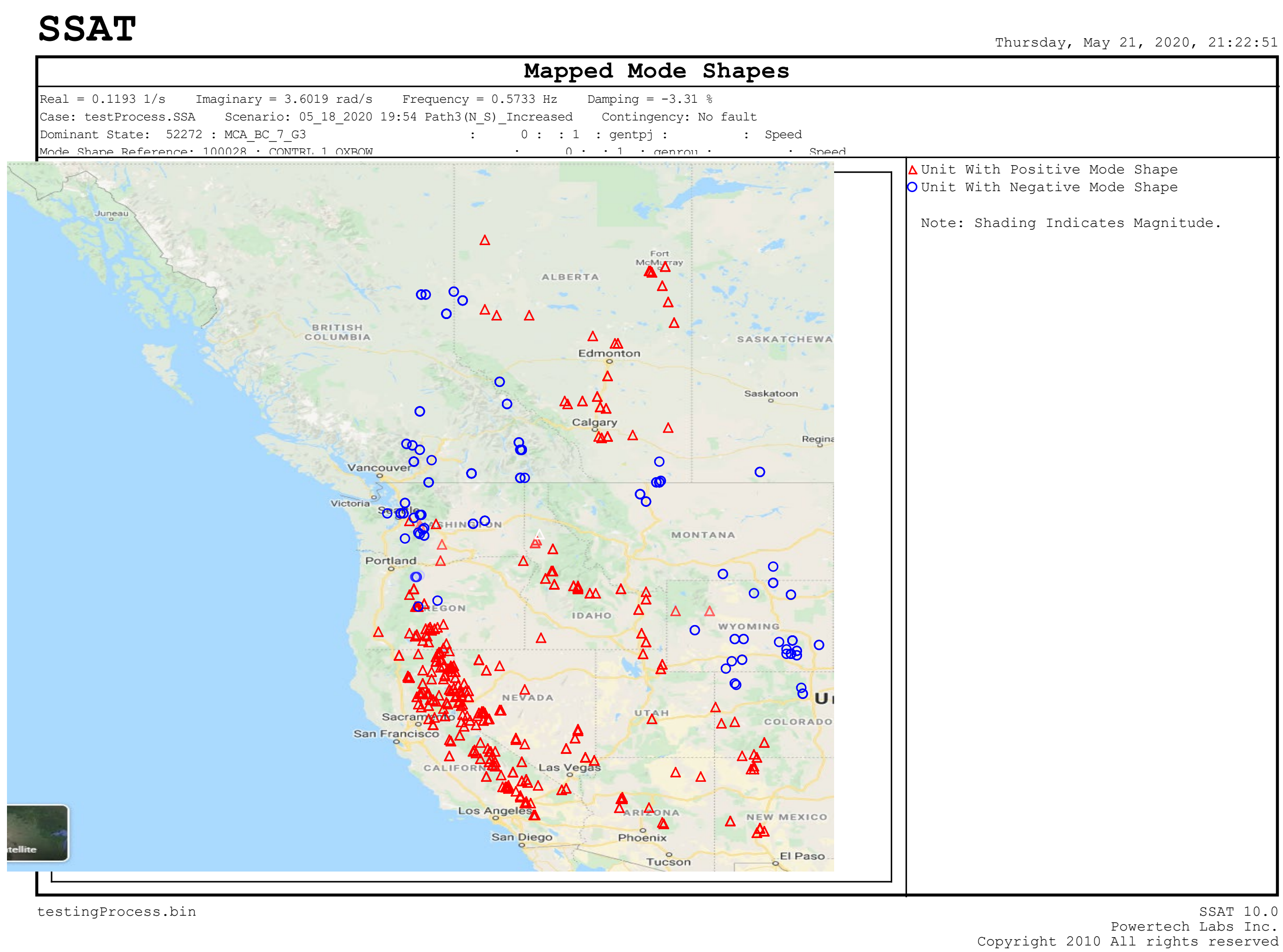


Figure 1.10: Mode Frequency Damping and Shape Estimated Using Eigenvalue Analysis

1.2.2 Ringdown Analysis with Powerflow Base Cases to Determine Mitigation Actions

Utilizing ringdown analysis with powerflow base cases using simulated disturbances is very similar to the earlier described process to determine the various modes and their associated frequencies and shapes. The proposed mitigation actions, such as change in interface MW transfer levels or change in topological conditions, would be simulated in the powerflow base cases and the ringdown analysis would be repeated to determine if there is change in the damping of the mode being tracked while also ensuring that the mode shape is more or less constant. This iterative process helps to determine and validate mitigation actions.

1.3 Monitored Quantities Informed by Analysis

Monitoring the modes of significance requires determining which synchrophasor data that should be utilized in tools to monitor the modes. Various quantities can be used, such as voltage angle pairs, voltages, or flows. It is important for system operators to monitor modes in a consistent manner. This section provides guidance on which quantities can be selected.

While the number of PMU measurements are limited, all the system variables' dynamics, to some extent, are affected by each mode. This means that measurements of electrical quantities, to some extent, will contain information on the modes that can be extracted/estimated for analysis and tracking purposes. This does not mean that all measurements are the same when it comes to tracking modes; some measurement points are affected by certain modes more than others are and have more unique properties that are useful for the process of tracking the stability of each mode. For example, the answer is to use signals that make the mode(s) of interest highly and easily observable and therefore easy to track when trying to track a particular mode and decide whether to use voltage, power, or frequency signals. For inter-area mode estimation/tracking, angle-pair derivative signals are a great choice because they consist of two individual PMU voltage angle measurements from different grid locations that, with proper signal choice and setup, produce a single signal that amplifies a single mode's presence and ideally attenuates all other modes. As mentioned before, this makes the tracking of individual dominant modes much easier. There are many methods for modal analysis and signal selection. Below is just one example of the process of choosing signals for a mode meter setup.

Consider the following frequency trend lines at different substations spread out through the WI over a one-hour duration in **Figure 1.11**.

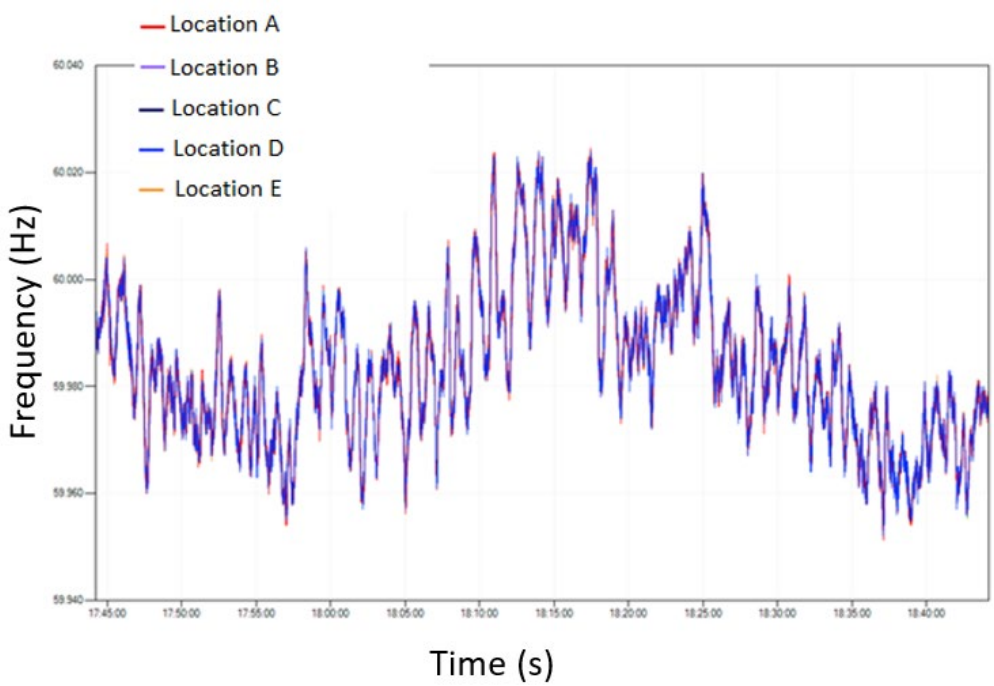


Figure 1.11: Sample Frequency Trend in the WI

At first glance, this looks like a 60 Hz frequency signal with some random ambient noise. In truth, this represents that the modes are manifesting themselves onto the frequency signal measurements at each location, but they are not apparent in the waveforms. If the signal's spectra are plotted, their energy as a function of frequency can help identify dominant modes. **Figure 1.12** conveys that dominant modes truly exist with their frequencies characterized by broad peaks.

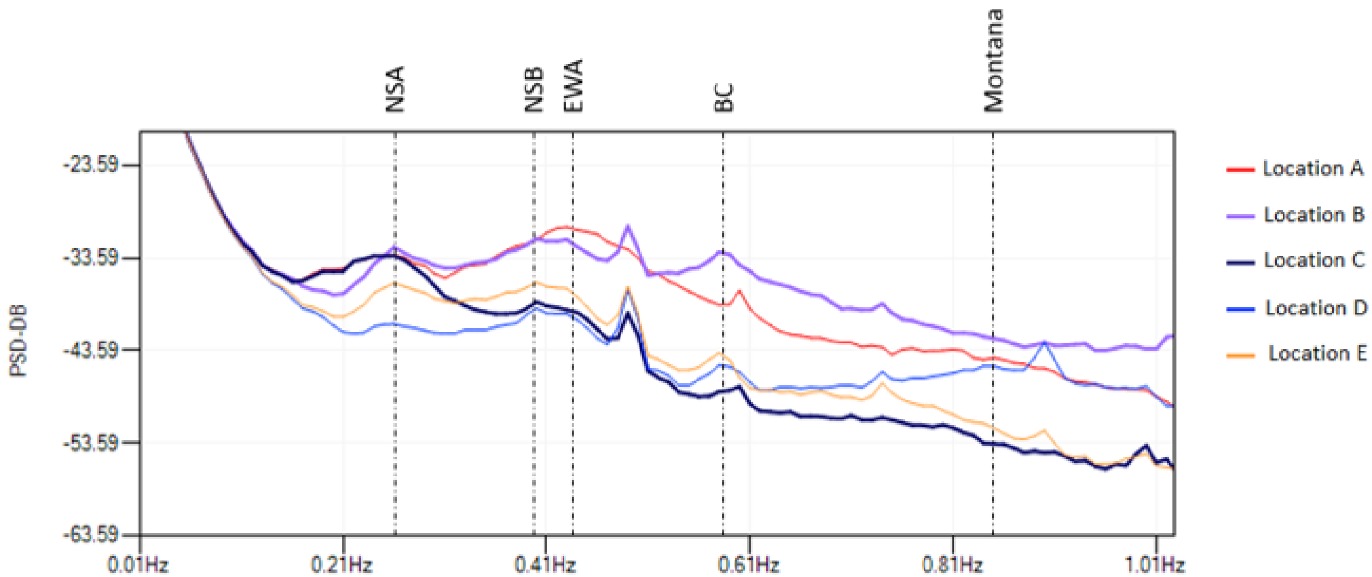


Figure 1.12: Mode Observability at different PMU locations

Upon close inspection, it becomes clear that certain modes only manifest themselves (or show themselves) in certain locations on this signal set. For example, the frequency signal spectrum at Location D shows that the Montana mode is observable in Location D's frequency signal spectrum but not in Location C's frequency signal spectrum. In addition, some locations' frequency signal spectrum (like Location A) show one mode overpowering all other modes by a considerable amount that dominates the modal contribution to the observable dynamics of the frequency signal at that location (e.g., East-West A Mode (EWA) for Location A).

From this sort of analysis, one can also extract one more piece of information, the "phase." Spectral analysis of the modes on a particular signal set at different PMU locations not only indicates what modes manifest themselves at each location for the given signal type of the signal set for each mode but also reveals the phase at one location relative to one another location when the mode ideally "shows itself" at both locations. Because the modes are linear ordinary differential equation (ODE) solutions, they are oscillatory and cause system variables to also oscillate to some extent in harmony or anti-harmony with one another. That means all of the interactions of system variables for each mode can be described by a set of sine and cosine waves that have magnitude and phase values describing their relationship to one another. The phase can be anywhere between 0 to +/-180 degrees. Essentially, the phase shows how a location's signal measurements interact with each other when under the influence of a single given mode. Locations with a phase near 0 degrees apart from one another are "in-phase." However, locations with a phase near 180 degrees apart from one another are "out-of-phase." Locations with a phase near 90 degrees apart from one another are "uncorrelated."

To put this concept into practice, consider the example scenario below. According to the power spectrum in the previous section, Location C and E are grid locations where the NSA mode clearly presents itself (~0.25Hz). According to the mode phase data shown in **Figure 1.13**, Location E is nearly -180 degrees "out-of-phase" with Location E, (approx. -157 degrees).

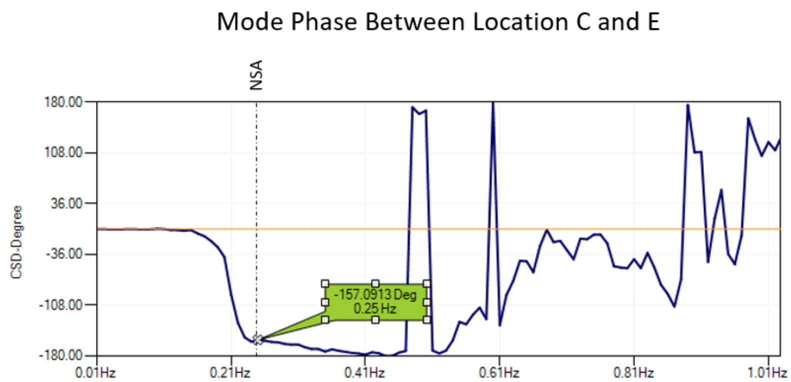


Figure 1.13: Example of Mode Phase between Two Locations

By taking the phase and mode energy data from the estimated power spectrums, a "mode shape" plot describes how all of the signals that are being influenced by the mode are related to one another. To visually show this, imagine a PMU at locations A and C that shows the ideal frequency signals of 60 Hz when suddenly the NSA mode becomes unstable and negatively damped. Consequently, a near-0.25 Hz oscillation starts to build and, due to the locations' relative mode phase as the signal at Location C swings up, the signal at Location E does exactly the opposite as shown in **Figure 1.14**. This is an example of an "inter-area oscillation" caused by an unstable and negatively damped mode.

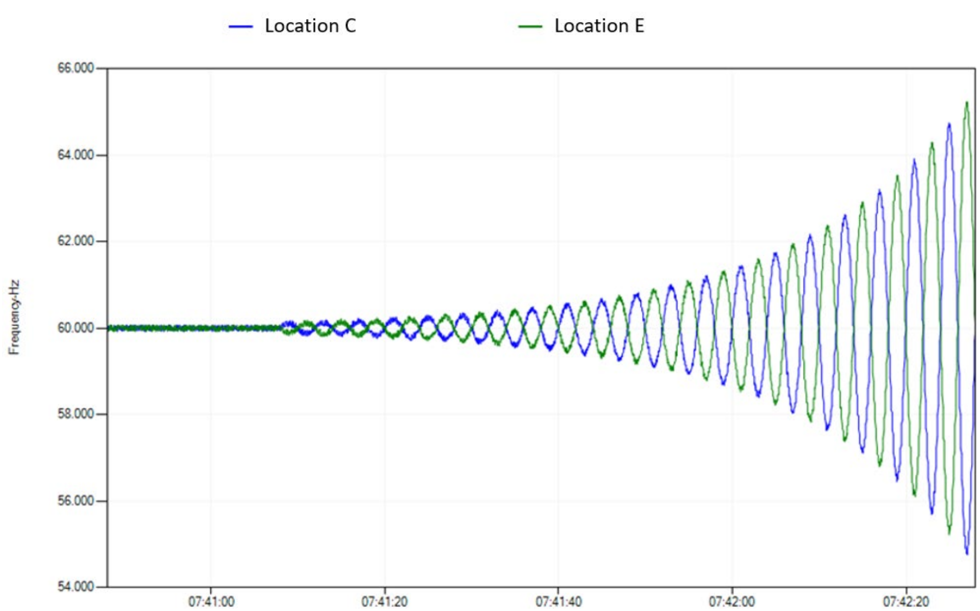


Figure 1.14: Example of Frequency at Different Locations during an Inter-area Oscillation

Since both signals exhibit the mode and have a relative mode phase near 180 degrees, these two signals can be used in a special way to gain an advantage for tracking a mode with a mode meter. Shown again in **Figure 1.15** are the sample estimated power spectrums of the frequency signals at Location C and E.

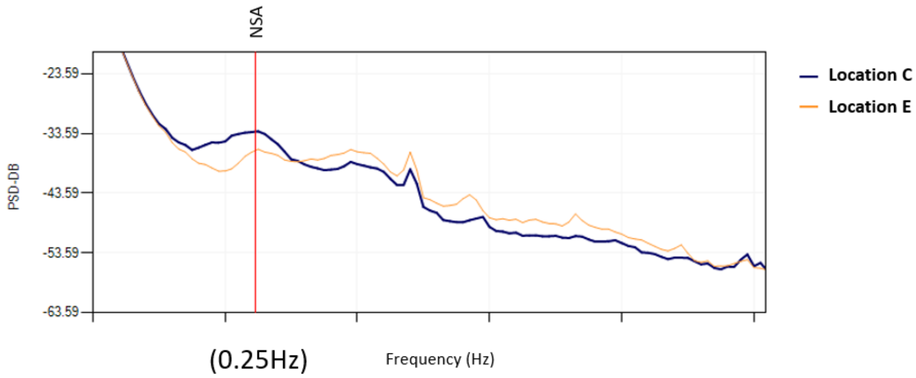


Figure 1.15: Sample Estimated Power Spectrums of Frequency Signals

By subtracting these two frequency (or numerical derivative of PMU voltage angle signal) signals at Locations E and E, creating a differential "angle pair" signal, we can see that the new signal makes the NSA mode "pop-out" as shown in **Figure 1.16** by attenuating common properties and amplifying differing properties in the Location C and E frequency signals.

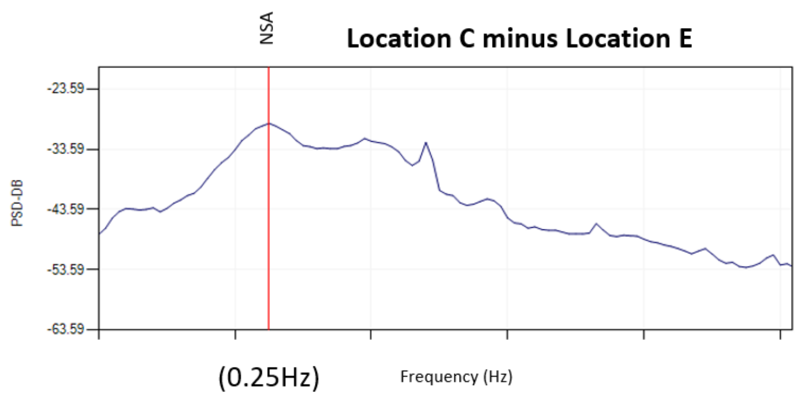


Figure 1.16: Sample Angle Pair Differential Pair Signal for North-South A Mode

As seem above, using the angle-pair differential signals can provide an effective to monitor a given mode in mode-meters. Therefore, it can more easily calculate and estimate frequency and damping ratio of a given mode if the system is in ambient conditions. If we do the same procedure over a large set of signals, we can better determine an acceptable input signal for a given mode meter. See example in **Figure 1.17**.

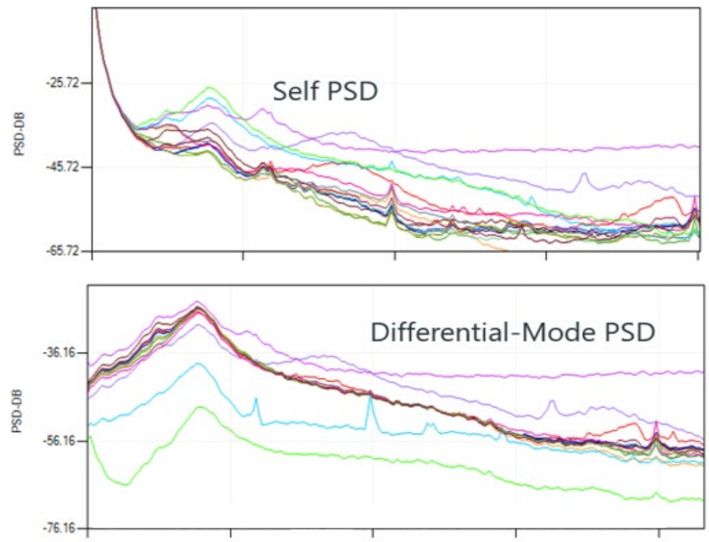


Figure 1.17: Sample Self and Differential Spectrums for Multiple Signals

So far, this paper has discussed a maximum of two signals. If two dominant modes are close in-terms of natural frequency, it might be necessary to either add more input signals to create a more unique output signal that distinguishes the two close modes or change the signal type since all signal types exhibit different network mode shapes. By utilizing the gain properties of differential and common signals, a unique signal for a given mode can be created that provides the best input to a given mode meter for a given set of available PMUs. For example, the sum of active power flows in two lines interconnecting Mexico to the rest of Central America is used to monitor and control unstable modal activities for opening the interconnection between Guatemala and El Salvador when unstable operating condition is detected.[20]

1.3.1 Thresholds for Damping and Energy

Simulation studies and review of historical mode estimates can help determine how much a contingency or credible set of contingencies can reduce a particular mode's damping ratio. This information can then be used to select alert and alarm thresholds to ensure that a sufficient stability margin is maintained in precontingency conditions to preserve stability in post-contingency. Offline studies are helpful to determine thresholds, but additional margins should be included to account for unforeseen contingencies and system conditions. Though alert and alarm thresholds should be based on studies, a damping ratio below 5% typically warrants investigation while corrective action is likely necessary if the damping ratio falls below 3%. The mode estimate should be validated before taking action to ensure that the low damping estimate is not the result of poor data quality, the presence of forced oscillations, or normal variation in the estimate. Offline modal baseline analysis can help determining the threshold for modal energy in different operating conditions.[21] Peak energy levels in the signal spectrum for a mode in a normal operating condition can be used to set the thresholds for energy.[22] As discussed next, mode shape and system conditions can also be evaluated to validate mode estimates.

[20] Espinoza, José Vicente, Armando Guzmán, Fernando Calero, Mangapathirao V. Mynam, and Eduardo Palma. "Wide-area protection and control scheme maintains Central America's power system stability." In 39th Annual Western Protective Relay Conference. 2012.

[21] Trudnowski, Daniel J., and Ferryman, Tom, Modal baseline Analysis of the WECC system for the 2008/9 Operating Season, Technical Report, September 2010

[22] Donnelly, Matt, Dan Trudnowski, James Colwell, John Pierre, and Luke Dosiek. "RMS-energy filter design for real-time oscillation detection." In 2015 IEEE Power & Energy Society General Meeting, pp. 1–5. IEEE, 2015.

1.3.2 Monitoring Mode Shape

In addition to monitoring the mode frequency and damping, it is also recommended that tools be set up to monitor the mode shapes of the various monitored modes. This will allow operators to validate that the mode where damping and energy are reaching critical levels is the same for which operators have been provided operating guidance.

1.3.3 Monitoring System Conditions

The system conditions identified for increasing damping and reducing the energy of the monitored modes should be monitored along with the damping, energy, and the mode shape. This is to ensure that system conditions are contributing to the damping and the energy of the monitored modes that reach critical levels where the next contingency can cause instability. Therefore, path flows, topology conditions (such as line status, series capacitor status, generator status) should be monitored along with damping and energy of the modes.

Chapter 2: Forced Oscillations

One among the many challenges faced by the electric power industry is the presence of forced oscillations in the power system grid and determining the source location of these forced oscillations in real-time. The existence of these oscillations is increasing as the grid characteristics change with the addition of wind, solar, and distributed technologies both on grid and behind the meter. Many oscillations have been observed in the power system over the past couple of years[23] across the North American system. Possible root-causes for forced oscillations include the following:

- Malfunctioning equipment
- Control systems with incorrect settings
- Control systems with faulty designs
- Incorrect power system stabilizer settings and governor control settings
- Incorrect dc converter station settings
- Cyclic load

The occurrence of these oscillations can be persistent or intermittent and with low energy or high energy. The presence of these oscillations may lead to undesired operation of the power system, including equipment tripping that causes further stress on the system. Therefore, the early detection and mitigation of oscillations in real-time is crucial to ensuring reliable operation of the grid.

Knowing that an oscillatory event exists in the system is the first step in the proposed methodology. In the past, many oscillation events went by unnoticed due to an inability to detect oscillations using supervisory control and data acquisition (SCADA) measurements. Synchrophasors provide the resolution necessary to capture oscillations and provide real-time alarms for oscillations that are sustained on the system. This information is important for the operators to avoid further stress and outages in the system that may degrade system reliability.

The following are different methods for detecting forced oscillations and the respective quantities that should be monitored in these methods and how the alarm thresholds should be set up for these monitored quantities. Where applicable, baselining techniques are also provided to help determine the thresholds at which forced oscillations warrant immediate mitigation or further investigation.

2.1 Forced Oscillation Detection Methods

Examples of methods available to detect forced oscillations are described below.

2.1.1 Detection Method 1: Energy Bands Monitoring Approach

Detection of oscillations in the power system requires not only identifying the existence of oscillatory signatures in the real-time measurements but also defining the thresholds to be used to differentiate oscillatory signatures from ambient changes in the measurements. Key metrics of power system oscillations can be monitored and analyzed to define the severity of oscillations and therefore establish the detection criteria. The main parameters for power system oscillations are as follows:

- **Oscillation Frequency:** Rate of change of fluctuations seen in the signal over time
- **Oscillation Energy:** indicator of severity of oscillation (high energy oscillations require operator attention)
- **Damping:** Indicator of the sustainability of oscillation over time

[23] Reliability Guideline: Forced Oscillation Monitoring & Mitigation - https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

Oscillation Frequency

It has been observed from oscillations forced on the system that similar devices lead to oscillations relatively close in frequency. Therefore, monitoring the oscillation frequency can be an indicator of type of oscillation (e.g., inter-area, local, control system problems, Flexible Alternating Current Transmission System (FACTS) device settings). In this approach, the frequency spectrum is divided in multiple bands where each band of frequency is used to indicate a common root-cause of the oscillation. Through observation of previous oscillation events and correlating the frequency to the identified root-cause, four bands of oscillations are defined corresponding to various types of oscillations. The oscillation frequency bands are useful to indicate the most likely cause of the oscillation. Frequency band details along with common causes are shown in the **Table 2.1**.

Table 2.1: Frequency Bands of Oscillations and Likely Causes

Frequency Band	Likely Cause of Oscillations
0.01–0.15 Hz	Governor, plant controller, automatic generation control
0.15–1 Hz	Electromechanical inter-area and local plant oscillations
1–5 Hz	Local plant modes, intra-plant modes, local generator control oscillations, excitation controls, dc circuit controls
>5 Hz	Torsional oscillations, sub-synchronous oscillations, fast acting controllers

Oscillation Energy

Amplitude is the most direct indicator of the severity of an oscillation at a particular frequency. When frequency bands are considered, the energy in each band can be monitored as a proxy for amplitude. Oscillations with high peak-to-peak amplitudes will result in high energy within their frequency band. Oscillations can be monitored by alerting or alarming when the energy in a band exceeds predefined thresholds. Monitoring energy in a band[24] can be more practical than estimating the amplitude of individual oscillations because oscillations may have time-varying frequencies and be accompanied by harmonics in the same frequency band.

Oscillation Damping

Oscillations are a part of every power system and can be observed every day while monitoring the dynamics of the system; however, sustained oscillations can cause reliability issues if not managed carefully. For this reason, it is important to distinguish oscillations that are normal from the ones that are of a potential concern. The damping of an oscillation is the indicator of the sustainability of oscillations over time. Highly damped oscillations dissipate quickly, meaning that the oscillation is observed over a short period before dissipating, while lower damped oscillations sustain for longer periods. Therefore, monitoring oscillations sustainability can be performed through monitoring damping or calculating oscillation continuity over time, as explained in the following sections.

This sets the stage for monitoring the oscillations in real-time. For effective real time oscillation monitoring, it is important to do the following:

- Establish frequency bands for oscillation monitoring:
  - What frequency bands to configure for monitoring?
- Establish thresholds for minimum energy:
  - At what level is an oscillation identified and detected?

[24] Real Time Dynamics Monitoring System – Electric Power Group: http://www.electricpowergroup.com/rtdms.html

In order to establish the parameters for real time oscillation monitoring, periodic analysis and baselining of key power system metrics is required to establish the proper oscillation thresholds for monitoring. The thresholds are usually system-specific and depend on the normal behavior of the power system. To identify the monitoring parameters, it is realistic to baseline the power system oscillations from a rich source of archived high-resolution phasor data. This requires mining historical phasor data to search for oscillations and gather the prerequisites required to monitor in real time. Phasor data mining studies would reveal both known and unknown oscillations. The unknown oscillations can be added to the bucket of known oscillations for additional monitoring until mitigation actions are executed to terminate the oscillations. The key steps in baselining study are as follows:

1. Access to archived phasor data
2. Data conditioning (filtering and conditioning, eliminating bad measurements)
3. Establishing mining criteria (Frequency bands, Energy, Oscillation period)
4. Scanning data and identifying events that meet mining criteria
5. Reviewing and interpreting mining results to identify types of oscillations
6. Preparing recommended parameters for real time oscillation monitoring—frequency bands, energy thresholds, damping, and key monitoring locations.

The basic requirement for data mining is high-resolution phasor data across the system from multiple locations for a minimum of three months to tabulate different oscillations based on the availability of events. The study can be extended to additional months to extend the research of new additional oscillations. The process could also be made iterative with a relatively short baseline study period to establish low thresholds and utilize prolonged periods of adjusting/increasing thresholds while learning of the system oscillatory properties.

The data mining process includes the following:

1. Scan through phasor data, detect low damped oscillations, and record the associated damping and energy value
2. Calculate statistics for each oscillation identified, including pattern of occurrence, highest energy value with timestamp, and PMU measurement
3. Record baseline oscillation characteristics: location, minimum energy level, and frequency band for additional monitoring in real-time

Data Analysis Procedure

The analysis procedure for establishing oscillations alarm thresholds steps are as follows:

1. Assess the quality of the phasor data using PMU quality flags. This step identifies the bad or unusable data (as indicated by the PMUs), which was then removed from the baselining analysis.
2. Identify additional bad data (not indicated by PMUs) using range check and stale check filters. The data dropouts in the communication links are eradicated in this step. Additionally, engineering judgment can be used to identify voltage signals that show significant deviations from the respective base voltages.
3. Perform oscillation analysis or the remaining good data. This step identifies oscillation in the data set and categorizes the events by location, severity, duration, and count to provide an event library for use in the study. Visual inspection of detected events and validation of oscillation energy detected through peak-peak oscillation variation is helpful in this step to eradicate false events.
4. Establish the oscillation alarm thresholds by calculating the oscillation energy in each frequency band for the dataset during ambient conditions. The average energy for each signal can be used to establish the suggested alarm thresholds for the bands.

Detection Procedure and Methodology

All available frequency, voltage magnitude, current magnitude, and voltage phase angle signals are to be initially used to mine for oscillation events. Bad data is to be removed prior to mining by using PMU quality flags, range check filters, and stale check filters. Oscillation events are detected based upon event filters listed in **Table 2.2** below.

Table 2.2: Example Oscillations Mining Criteria		
Event Filter Type	**Filter Value**	**Description**
Oscillation Frequency (Hz)	>= 0.1 Hz	An oscillation frequency filter is used to retain oscillation events above a certain oscillation frequency.
Duration (minutes)	>= 1 Minute	An oscillation event filter is used to retain sustained oscillations above certain duration.
Energy	> 3 times Standard Deviation	An oscillation energy filter is used to detect the significant energy in the oscillation.

Establishing Alarm Thresholds

The oscillation energy is calculated in each frequency band during ambient conditions for each of the four oscillation bands. When oscillations occur in a signal, the oscillation energy for that signal increases, indicating the existence of oscillatory signature in the signal. The mean energy and standard deviation for each signal in each of the oscillation bands is calculated to establish the suggested alarm thresholds. It is suggested that two levels of alarm threshold be established per the formulae below in **Table 2.3**. This method ensures that only significant oscillation events trigger alarms in real-time and provides multiple levels of alarms to differentiate oscillations requiring monitoring from the ones requiring mitigation. These thresholds should be evaluated using the data analysis approach described earlier on a regular basis to ensure that all significant oscillations are detected and alarms for insignificant oscillations are kept to a minimum.

Table 2.3: Example Criteria to Establish Alarm Threshold	
Alarm Level (Each Band)	**Alarm Threshold (Each Band)**
Level-1 (Less Severe)	Mean Energy of Ambient Data Set+(3×Standard Deviation of Ambient Data Set)
Level-2 (More Severe)	Mean Energy of Ambient Data Set+(4×Standard Deviation of Ambient Data Set)

Detecting and Identifying Local-Area Oscillations

Forced Oscillations can be either localized to a small footprint in the Interconnection, or wide-area, resulting in multiple regions swinging against each other. Depending on the oscillation spread, the methods that are currently available to detect and identify the source may vary. Therefore, it is important to identify whether the oscillations detected are local oscillations or inter-area in nature.

Determining whether an oscillation is local or inter-area can be achieved by answering the following questions:

- What frequency band is generating the oscillation alarm? Is the oscillation frequency detected by the oscillation detector close to one of the system modal frequencies?
- Is my PMU coverage spread-out across the system? If so, is the pattern of alarms widespread across most PMUs or is it localized to a specific geographical area? Are the other entities in the Interconnection observing similar alarms?

The first indicator of local oscillations is the range of oscillation frequency. Based on the ranges defined in **Table 1.1**, if an oscillation is detected and is sustained for a period[25], an alarm will be generated from a specific band for each PMU that detects the high-energy oscillations. Referring to **Table 1.1**, local oscillations mostly reside in Band-2 or Band-3, with oscillation frequencies in the range of 0.15 -1 Hz and 1-5 Hz respectively. Oscillation alarms can be validated by observing the oscillation energy of the band at the PMU that generated the alarm. The energy trend should be increasing to exceed the alarming threshold, indicating the existence of an oscillation in that frequency band. Further validation can be done by observing the trend of the metric, which is used by the Oscillation Detection Module (ODM) to perform calculations at the PMU locations.

Secondly, local-area oscillations are contained to a specific geographical footprint and are detected by PMUs nearby the oscillation source. Therefore, only the PMUs relatively close to the source should detect and alarm for the event. That said, detection at the individual PMU level depends not only on the oscillation energy seen by the PMU but also on the alarm levels associated with the oscillation detection for the PMU. Hence, depending on the severity of the oscillation observed from different PMU locations, some PMUs relatively close to the oscillation might not alarm for the oscillation if the energy does not exceed the defined thresholds.

2.1.2 Detection Method 2: Detection of Sustained Oscillations of Any Type

Undamped oscillations can occur in power systems either from the presence of sustained oscillations related to natural power grid dynamics (stable limit cycles) or from the introduction of forced oscillations from external sources, such as from rough zone related vortex oscillations or from control failures. Thus, algorithms initially intended to detect poorly damped modal oscillations can also be used to detect sustained forced oscillations. Subsequent analysis would be needed to distinguish whether the underlying cause of the low damping is related to poor damping of natural modes or from the presence of external forced oscillations. This is important to ensure proper application of the appropriate mitigation measures, either improving a mode's damping (**Section 1.2**) or locating and disabling the forced oscillation's source (**Section 2.2**).

Multi-dimensional methods are effective for implementing this approach since they can point to oscillations present in any of the PMU signals included in the analysis. This includes algorithms, such as the FFDD and fast stochastic subspace identification (FSSI). Specifically, a FFDD that is based on estimation of power spectrum densities from all available PMU measurements is very effective in detecting sustained oscillations.

The FFDD first estimates a net energy estimate for the system in the frequency domain, called the Complex Mode Identification Function (CMIF),[26,27] from all the available signals for each frequency value of interest. Then the local peaks in CMIF can be shown to be the dominant system modes and oscillations that are observable in the PMU data at that time in the system. Then using the shape of the CMIF near the local peaks, the FFDD associates a damping estimate for each of the peaks.

In this sense, sustained oscillations can be easily distinguished by the presence of sharp peaks in the CMIF estimate, and correspondingly, the damping estimates associated with sustained oscillation frequencies can be shown to be near zero. Therefore, the FFDD based approach can directly detect the presence of any sustained or forced oscillation in the frequency range of interest and only the oscillations that have significant energy compared to the other natural modes in the CMIF estimate are selected for detection. Therefore, the method is self-calibrating, in this sense, and does not require any baselining studies. Moreover, the FFDD directly provides the mode shape or oscillation shape

[25] Waiting period is configurable and can be set to dynamically change depending on event severity. Waiting period ensures filtering of transients and post-events ringdown behavior of the system.

[26] H. Khalilinia, L. Zhang and V. Venkatasubramanian, "Fast Frequency-Domain Decomposition for Ambient Oscillation Monitoring," in *IEEE Transactions on Power Delivery*, vol. 30, no. 3, pp. 1631–1633, June 2015

[27] G. Liu and V. Venkatasubramanian, "Oscillation monitoring from ambient PMU measurements by frequency domain decomposition", *Proc. IEEE ISCAS*, pp. 2821–2824, May 2008

directly from the power spectrum matrix as part of the FFDD estimation procedure, and the shape can be useful in understanding the nature and potential source of the sustained oscillation.

The FFDD was tested extensively at Peak Reliability as part of the Forced Oscillation Detection and Source Locator (FODSL) that used PMU based FFDD for oscillation detection and SCADA based engines for source location using generator MW and MVAR SCADA outputs. The FFDD was monitoring over a thousand current magnitude and MW power signals and was very effective at detecting hundreds of sustained oscillation events at Peak Reliability. The FFDD has been implemented as an action adapter into openPDC and has been tested at several other utilities in North America and in Europe. Figure 2.1shows an Illustration of FFDD estimates showing a forced oscillation event that occurred on September 5, 2015.

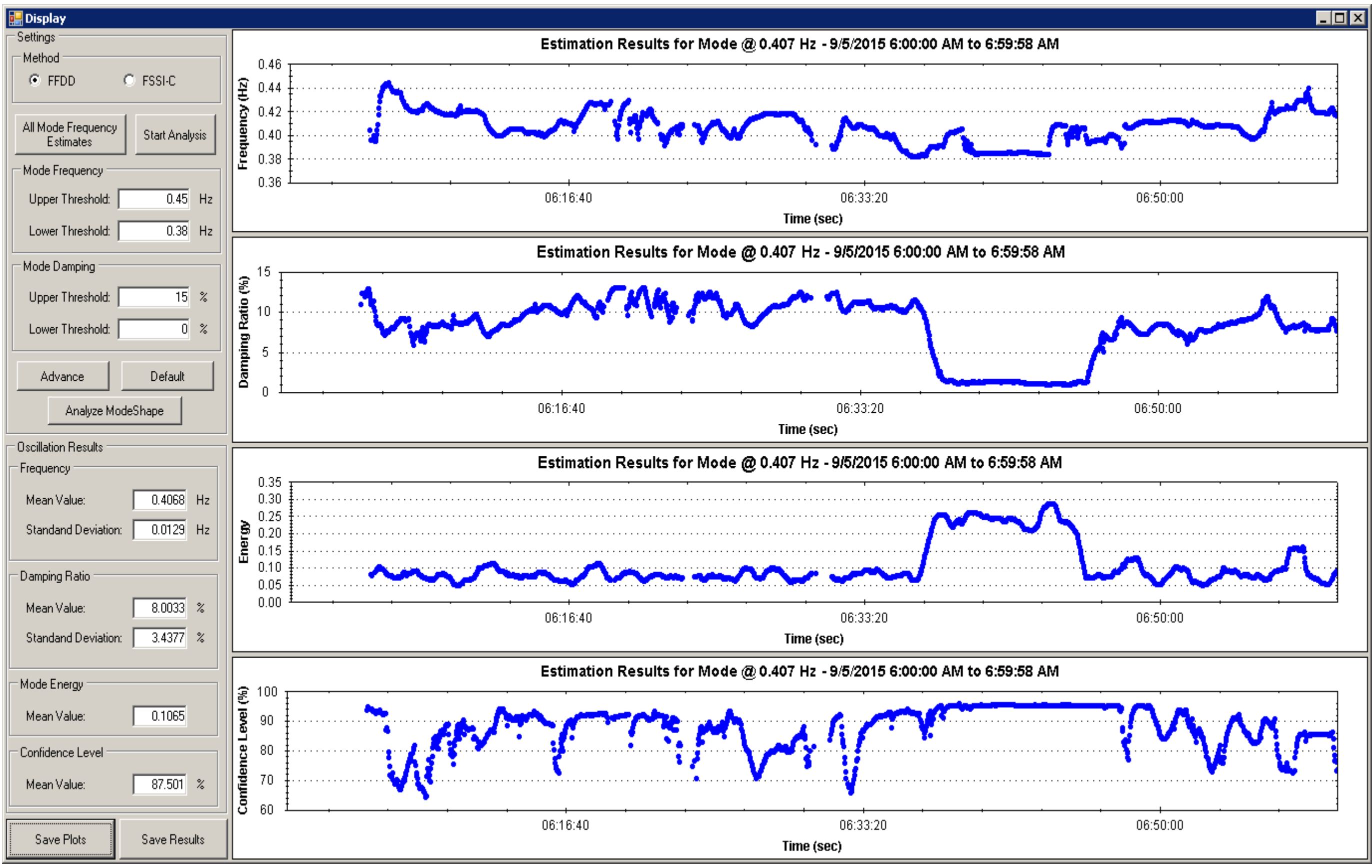


Figure 2.1: Illustration of FFDD Estimates Showing a Forced Oscillation Event that Occurred on September 5, 2015

2.1.3 Detection Method 3: Mode Frequency Band Monitoring Method

Interactions of different plants and controllers in power systems can result in small or large oscillations in the system. For a stable system, oscillations should decay by the passage of time. In an unstable system, oscillations can grow to dangerous levels where remedial actions are needed to mitigate the adverse effects of the oscillations.

Oscillations appear in power systems in different situations. One of the types of oscillations is forced oscillations (which are due to continuous cyclical excitation) as opposed to ambient oscillations (which are caused by white noise excitation). Forced oscillations can jeopardize the stability of the system when the amplitude of these oscillations is large or when these oscillations interact with system poorly-damped natural modes and the magnitude of the oscillations increases.

Power Dynamic Extraction (PDX)

Power Dynamics Extraction (PDX)[28] analysis method processes power system PMU signals to determine the presence of oscillatory components or system modes and their key parameters. For each oscillatory component, PDX determines these key parameters: frequency, damping ratio, mode shape, and amplitude of the mode. PDX down-samples the input signals with any sampling frequency to 10 Hz. The algorithm uses autoregressive model to obtain characteristics of the modes. PDX processing is applied to a window of the most recent data, and the dynamic characteristics of the system are derived for that time window. The analysis is updated at regular intervals. There are two variations of the algorithm:

- PDX-1 uses a short window (3 minutes) and updates every 5 seconds. This window is used for alarming as it can respond quickly to changes in amplitude and damping ratio.
- PDX-2 uses a longer window (more than 20 minutes) and updates every 20 seconds. This window gives more accurate and stable results. This could be used for model validation or for comparing different cases of well damped modes.

Mode Bands Management

In order to track modes in the frequency range of interest, mode bands should be defined. For example, a range may be constructed to contain a single persistently occurring low frequency mode. Defining effective mode boundaries is facilitated by collecting prior PDX1 and PDX2 processed data. Histograms containing large timespans of data (up to three days) can then be used to decide initial mode boundaries.

Alarms and Alerts

For each frequency band and each signal, some thresholds for estimated modes characteristics can be set for alarms and alerts. Damping ratio and amplitude thresholds are the most important limits. Alerts or alarms are issued when the damping ratio of a mode is below the threshold and the amplitude is larger than the threshold. There is another threshold by means of which the modes with small amplitudes are removed from alarming, regardless of their damping ratio. Similar threshold for damping ratio exists, very well-damped modes with high damping ratios are excluded from alarming regardless of the amplitude. Hysteresis limits can be set for alert and alarm events by requiring the threshold breach to persist for a defined period of time (in seconds) before an alert or alarm event is triggered.

Sustained Oscillation Detection

Any type of sustained oscillation, such as natural near zero damping mode or forced oscillation, can be detected by PDX method. These types of sustained oscillations are detected and presented by a near zero damping ratio mode by the PDX engine. However, for an appropriate mitigation plan, further analysis and investigation are required to understand whether the sustained oscillation is the result of a zero damping natural mode or a forced oscillation.

In the following simulation example, the understudy system is ESCA60 and a forced oscillation with the frequency of 0.5 Hz is injected to the system from a generator at Douglas substation. In **Figure 2.2**, it can be seen that a poorly-damped oscillation with the frequency of about 0.5 Hz is identified and an alarm is issued for this oscillation.

[28] PhaorPoint, GE Digital: https://www.ge.com/digital/applications/transmission/phasorpoint

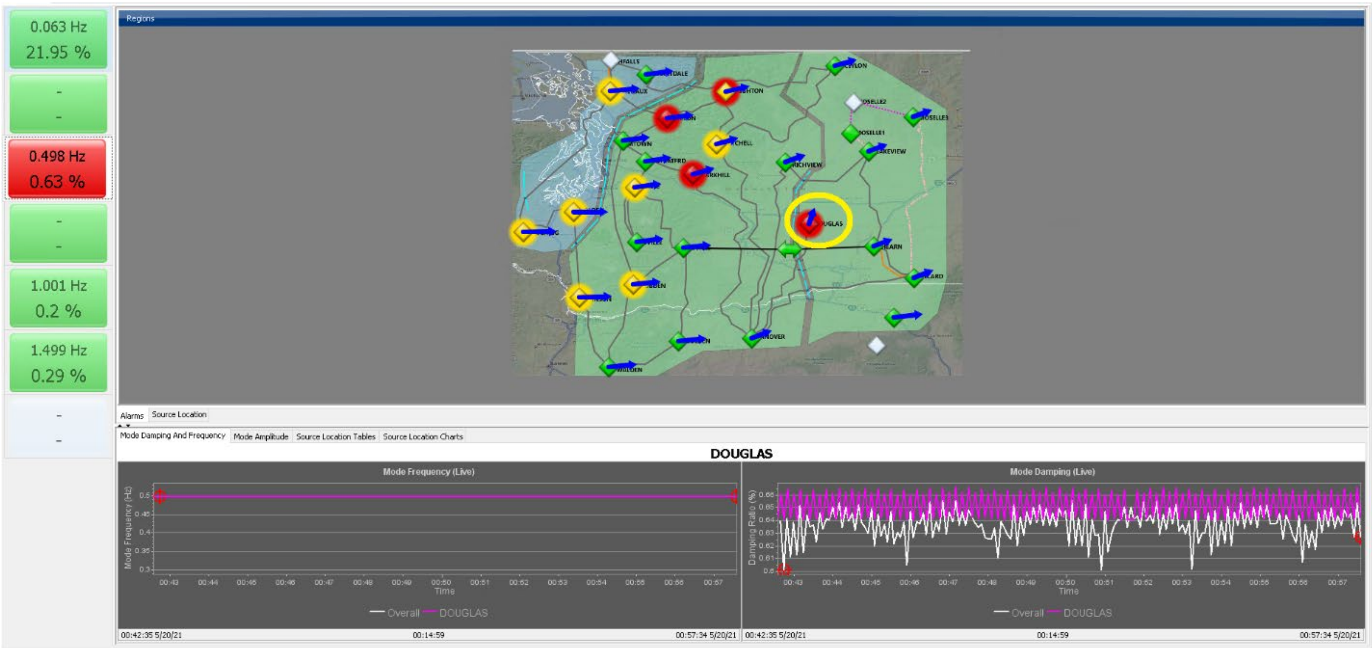


Figure 2.2: Identification of Forced Oscillation and Triggering an Alarm by PDX Method

From estimated modes, it can be seen that there are poorly-damped oscillations at 1 Hz and 1.5 Hz. These oscillations, which are harmonics of the forced oscillation at 0.5 Hz, are other indications of the presence of forced oscillation in the system. PDX could identify the forced oscillation and its harmonics that helps operators to validate the presence of forced oscillation and distinguish forced oscillation from system inter-area electromechanical oscillation.

As can be seen in **Figure 2.2**, the alarm is issued only for the estimated poorly-damped oscillation at 0.5 Hz (the estimate that corresponds to the main forced oscillation) and not for the 1 Hz and 1.5 Hz (harmonics). **Figure 2.3** illustrates the estimated damping ratio and amplitude (at the location of source) for 0.5 Hz oscillation along with the alarms and alerts thresholds. Both time plots and locus plot show that the estimated damping ratio and amplitude are in the alarm zone. In contrast, alarms or alerts are not triggered for harmonics at 1 Hz and 1.5 Hz despite their near zero damping ratio. **Figure 2.4** shows the time plots and the locus plot of estimated damping ratio and amplitude (at the location of source) for the oscillation at 1 Hz. As is evident in **Figure 2.4**, for the estimated oscillation at 1 Hz, the amplitude is below the alert and alarm thresholds.

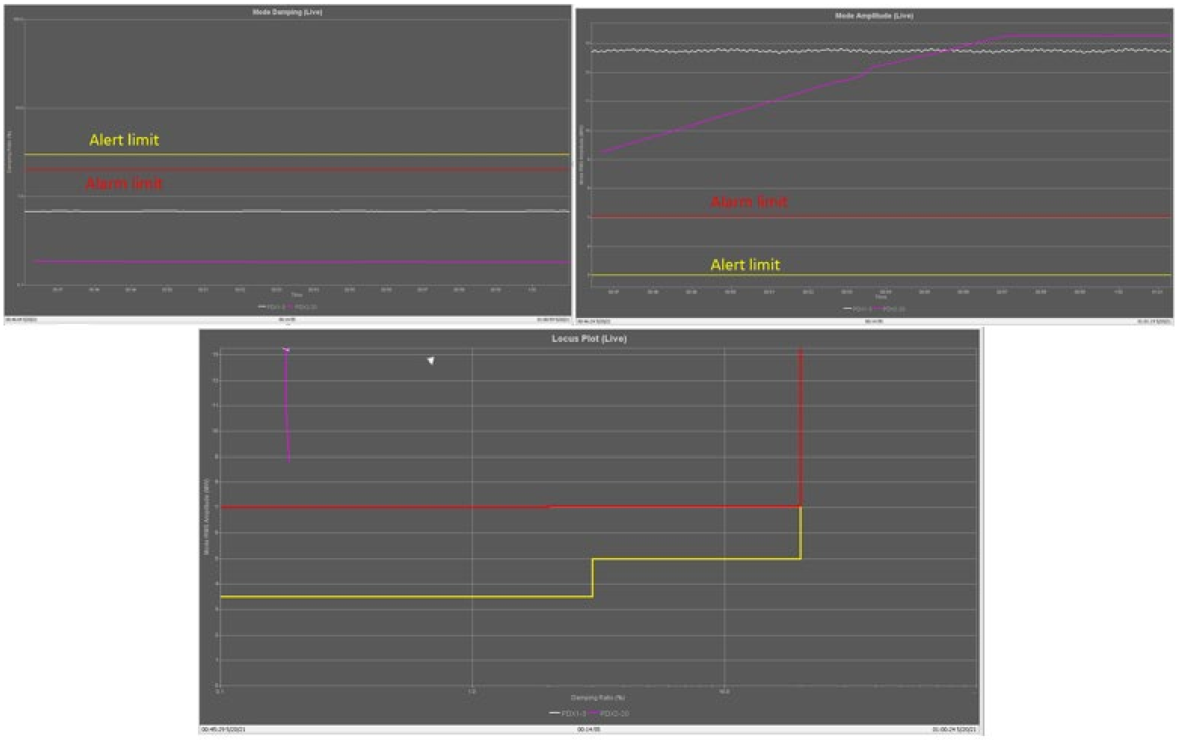


Figure 2.3: Example of Estimated Damping Ratio and Amplitude of Forced Oscillations

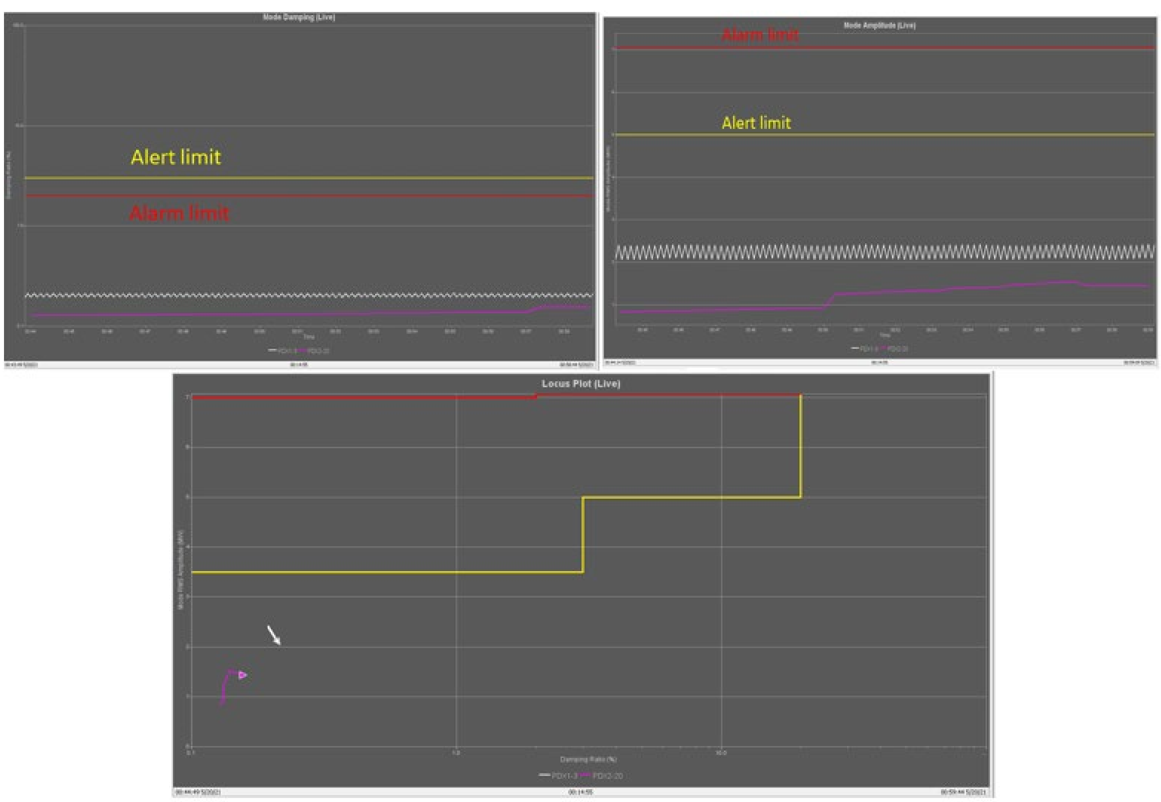


Figure 2.4: Time Plot and Locus Plot of Estimated Damping Ratio and Amplitude of the Harmonic of Forced Oscillation at 1 Hz Along with Alarm and Alert Limits

2.2 Determination of Oscillation Source

Determining the location of the source of forced oscillations can be challenging especially when the oscillation is widespread or there may not be sufficient PMU coverage to locate the exact source. For example, a RC may only be monitoring BPS level synchrophasor data, which would be utilized for alarming the operators. However, the RCs can always coordinate with the impacted TOPs to determine the source. The impacted TOPs would have a more granular view as they would be monitoring more synchrophasor data specific to the respective TOP area. In scenarios where the synchrophasor data itself is scarce, the available synchrophasor data can help to locate the local area from the oscillations originate; however, determining the exact source location would require further review of SCADA data and coordination and communication with the impacted TOPs, Balancing Authorities, and Generator Owners (GO).

When synchrophasor or telemetered data are available, the following methods help to determine the exact source location of forced oscillations or the local regions from where the oscillations originate.

2.2.1 Local Forced Oscillations

Figure 2.5 shows an example of a local forced oscillation where the source of the oscillation can be easily traced to a single location. The unit causing the oscillation may exist either at the location shown on the operator dashboard or may be in the underlying system connected to the location with the alarm if the operator dashboard does not have every location shown since synchrophasor data may not be available from every generator location. This gives the impacted RC and TOP a starting point to coordinate to determine the source.

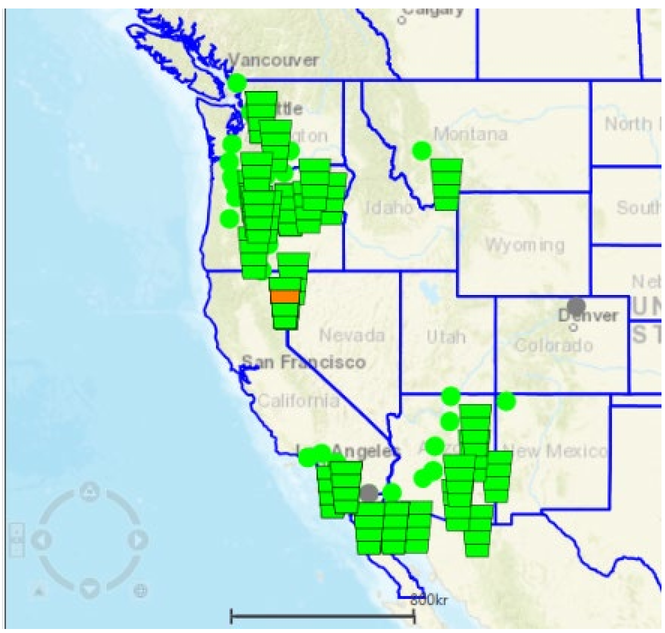


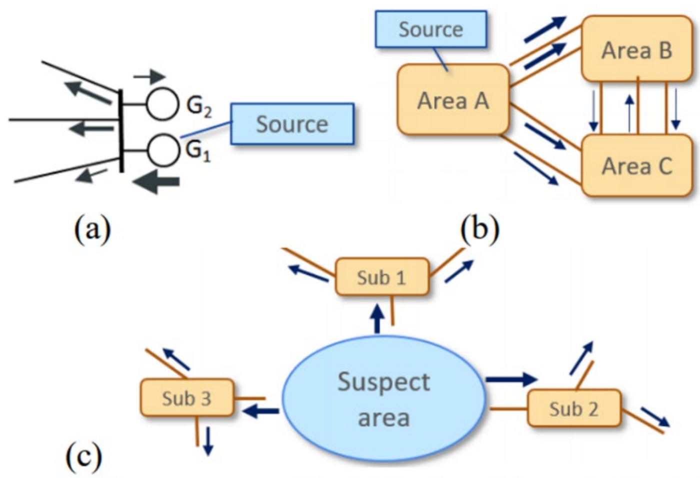
Figure 2.5: Example of Local Forced Oscillation

2.2.2 Forced Oscillations Impacting a Wide Area

When forced oscillations are observable over a wider area, location of the oscillation source can be more challenging. In certain cases, an oscillating unit can cause another unit to oscillate, which makes it difficult to pinpoint the suspect unit. The following methods help to locate oscillation sources when the forced oscillation is observable over a wider area.

Dissipating Energy Method

The method is based on tracing the flow of transient dissipating energy through the power system network (Maslennikov & Litvinov, 2020). By tracing the flow of energy back to its source, the equipment generating the oscillation is identified. When synchrophasor data is available at sufficient number of units, the method can point to the exact source of oscillation; the source will have the unique characteristic of dissipating energy flowing out of the generator. Similarly, when sufficient synchrophasor data does not exist at the terminals of generator, the suspect area can be localized by utilizing synchrophasor data from line flows. Examples of the interpretation of dissipating energy flow (DEF) results are presented in **Figure 2.6**. This method was developed and is in use at ISO New England.



The use cases of the DE pattern interpretation (a) PMU monitors POI of a power plant, (b) PMU monitor tie-lines between areas, (c) localization of suspect area non-observable by PMUs

Figure 2.6: Use Cases of the Dissipation Energy Method

Source Location Using the Phase of Oscillation

For the oscillation source location (OSL), voltage angle measurements are used to identify the PMU in the substation or region that is the closest to the sources of oscillations. This is achieved by analysing the phase of oscillations in the voltage angles from around the system. A leading phase indicates less damping contribution and the source is the location with the lowest damping contribution.[29]

Figure 2.7 shows an example of an oscillation source location map. As is evident, the source is identified and shown by the yellow circled area in the map.

[29] Al-Ashwal, N., D. Wilson, and M. Parashar. "Identifying sources of oscillations using wide-area measurements." *Proceedings of the CIGRE US National Committee 2014 grid of the future symposium, Houston*. Vol. 19. 2014.

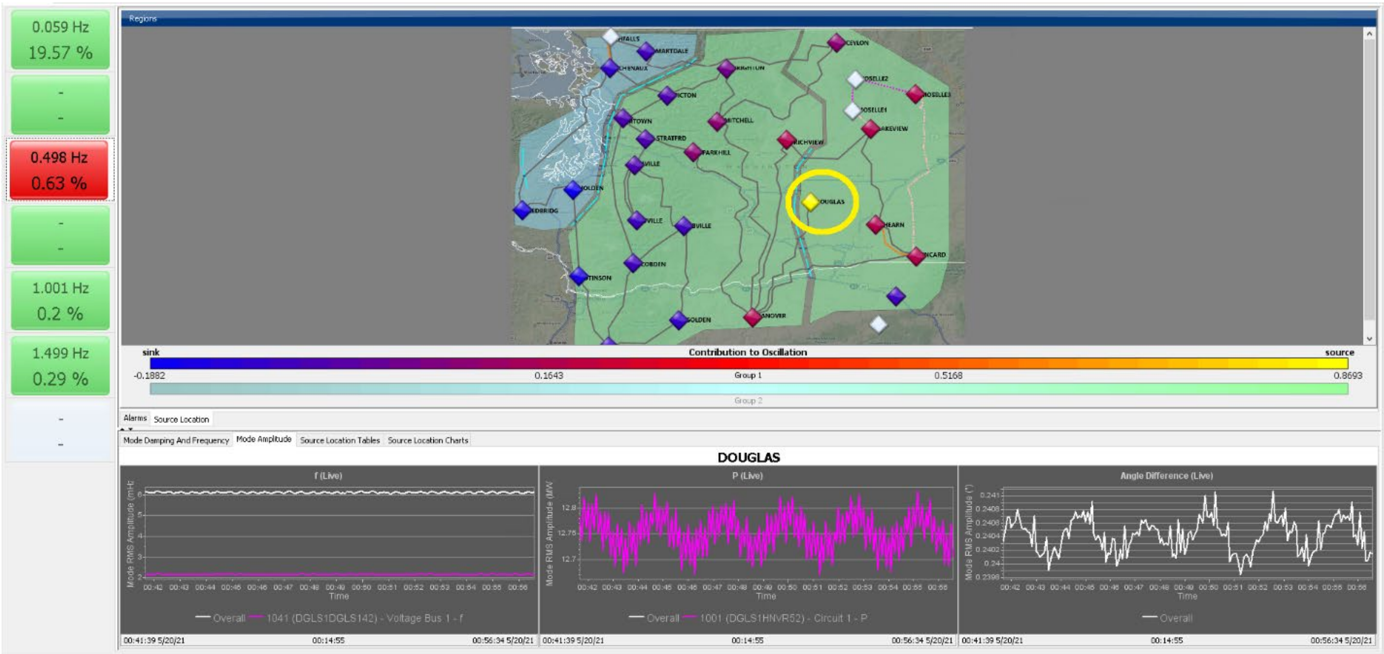


Figure 2.7: Identification of the Source of Forced Oscillation

SCADA Data Based Source Location

SCADA data can also be used to detect potential oscillation locations through the use of generator MW and MVAR telemetered data. SCADA data is easily available and, despite the lower resolution, SCADA data can help to point to the potential sources of oscillation based on the magnitude of the oscillation. This was one of the methods deployed at Peak Reliability for identifying sources of oscillation and validated with generator operators (GO) for real events.[30]

Other Oscillation Source Location Methods

Several other oscillation location methods have been developed to identify source locations under various imperfect signal conditions and practical event scenarios. These include a method[31] that combines dissipated energy flow (DEF) with a dynamic state estimator (DSE), a machine-learning pattern recognition (ML-PR) method[32] that uses DEF results as inputs, and a cross power spectral density (CPSD) based method.[33]

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[30] Source Location of Forced Oscillations Using Synchrophasor and SCADA Data, https://pdfs.semanticscholar.org/97a8/48ae894edec07f462ccefe89db54a93ebf52.pdf

[31] Combined Dissipated Energy Flow Method, https://www.naspi.org/sites/default/files/2021-10/D3S8_02_estevez_fiuba.pdf

[32] Machine-LearningPpattern Recognition method, https://www.naspi.org/sites/default/files/2021-10/D3S8_03_zheng_ge_20211007_0.pdf

[33] Cross Power Spectral Density based Method, https://www.naspi.org/sites/default/files/2021-10/D3S8_04_osipov_rpi_20211007_0.pdf

Chapter 3: Forced Oscillations Causing Inter-Area Oscillations

This section addresses the phenomenon that lead to widespread impact of forced oscillations due to resonance conditions involving system modes. Also described is an example of how model-based simulations can be utilized to observe the impact of widespread oscillations during resonance conditions.

3.1 Conditions that Lead to this Phenomenon

A forced oscillation whose frequency is the same or very close to the frequency of an inter-area mode can lead to resonance that can potentially cause amplification of the oscillation across an Interconnection. Three major conditions are necessary for the resonance effect to be high:[34] [35]

- The forced oscillation frequency should be at or near a system mode frequency.
- The system mode should be poorly damped.
- The source is near a strong participation location of that system mode, such as the distant ends of the system mode. The distant end locations are the strongest participants in the system mode.

The forced oscillation event of January 11, 2019, had two of the above conditions leading to a high resonance effect. The frequency of the forced oscillation was exactly matching one of the inter-area modes at 0.25 Hz and the source was near a strong participation location. The natural system mode was well damped; however, the oscillation amplified in magnitude across the Interconnection. Oscillations higher in magnitude than the source (Florida) oscillation magnitude were observed in the Northeastern area and the rest of the Interconnection of tie-line flows leading to impact on automatic generation control operations.

3.2 Testing Possible Mitigations

Appendix A provides an example of how the impact of the January 11, 2019, forced oscillations can be determined by using model-based simulations and how possible mitigation plans can be determined for utilization in guidance provided to operators.

Since wide-area resonant forced oscillations can be simulated in dynamic analysis, the effect of various plant controls and operator actions can also be tested; see the following examples:

- Switching AVRs to manual mode
- Generation redispatch
- Curtailing power transfers
- Commissioning more PSS

The first step to the testing is to modify the load flow and dynamic cases accordingly and then perform eigenvalue analysis to determine whether the frequency of oscillation or damping of the mode being studied has been changed. Secondly, the forced oscillation should be simulated in dynamic analysis to validate changes in damping and to demonstrate any changes in the oscillation amplitude.

[34] S. Arash Nezam Sarmadi, Vaithianathan Venkatasubramanian, Armando Salazar, "Analysis of November 29, 2005 Western American Oscillation Event", *Power Systems IEEE Transactions on*, vol. 31, no. 6, pp. 5210–5211, 2016.
[35] S. A. N. Sarmadi and V. Venkatasubramanian, "Inter-area resonance in power systems from forced oscillations", *IEEE Trans. Power Syst.*, vol. 31, no. 1, pp. 378–386, Jan. 2016.

Chapter 4: Guidelines for Addressing Wide-Area Oscillations

This section addresses the analyses, tools, and procedures that RCs/TOPs need during a wide-area oscillation event. To begin, approaches for distinguishing between a natural and forced oscillation are described in **Section 4.1**. In the relatively rare case where the oscillation is due to a poorly damped inter-area electromechanical mode, the mitigation actions developed with methods described in **Section 1.2** should be implemented. If the oscillation is identified as forced, the second step is to determine if action should be taken; guidelines for making this determination are described (**Section 4.1**) then followed by a discussion of potential mitigation actions and their validation. The section concludes with a summary of the tools and procedures needed within and across RCs/TOPs footprints to enable the previously described analyses and actions.

4.1 Determining if an Oscillation is Natural or Forced

As described previously, forced oscillations become widespread when they excite one or more of a power system's inter-area electromechanical modes. For this to occur, the frequency of the forced oscillation must be similar to the frequency of the system mode. Thus, when a sustained oscillation occurs in the frequency range of electromechanical modes, it may not be immediately apparent whether the oscillation is forced or natural. The appropriate responses to natural and forced oscillations differ, so it is important to either classify the oscillation as forced or natural before taking action or ensure control and operator responses are appropriate for either type of oscillation. Currently, many of the entities operating grids are doing neither because methods for classifying sustained oscillations are not yet widely available in commercial tools. Additionally, sustained oscillations from inter-area electromechanical modes are uncommon because the operating conditions leading to these oscillations are typically identified and addressed in planning studies. Though relatively uncommon, sustained inter-area electromechanical modal oscillations do occur and pose a significant threat to reliable system operation.

One readily observable difference between natural and forced oscillations that is widely agreed upon is the presence of harmonics. Forced oscillations are often accompanied by harmonics due to the periodic nature of the driving input. For example, a 0.25 Hz oscillation may be accompanied by harmonics at 0.75 Hz, 1.25 Hz, etc. The appearance of harmonics is a clear indication of a forced oscillation because inter-area electromechanical modes do not possess harmonics. Some commercial tools may provide frequency estimates for each of an oscillation's harmonics. Others may enable spectral analysis so that the harmonics can be picked out by examining a plot. However, not all forced oscillations have harmonics and they may be too small to detect if they do. Thus, harmonics are an important characteristic to consider are not sufficient to make the distinction in all cases. **Figure 4.1** shows SSI estimates during a forced oscillation event that shows the presence of harmonics as zero damping oscillation estimates and as sharp peaks in the power spectrum plot. The forced oscillation at 0.28 Hz leads to harmonic peaks at 0.56 Hz, 0.84 Hz, and 1.12 Hz in the power spectrum plot (in the lower right side) and as 0.56 Hz, zero damping oscillation estimates in the mode estimation table (in the center).

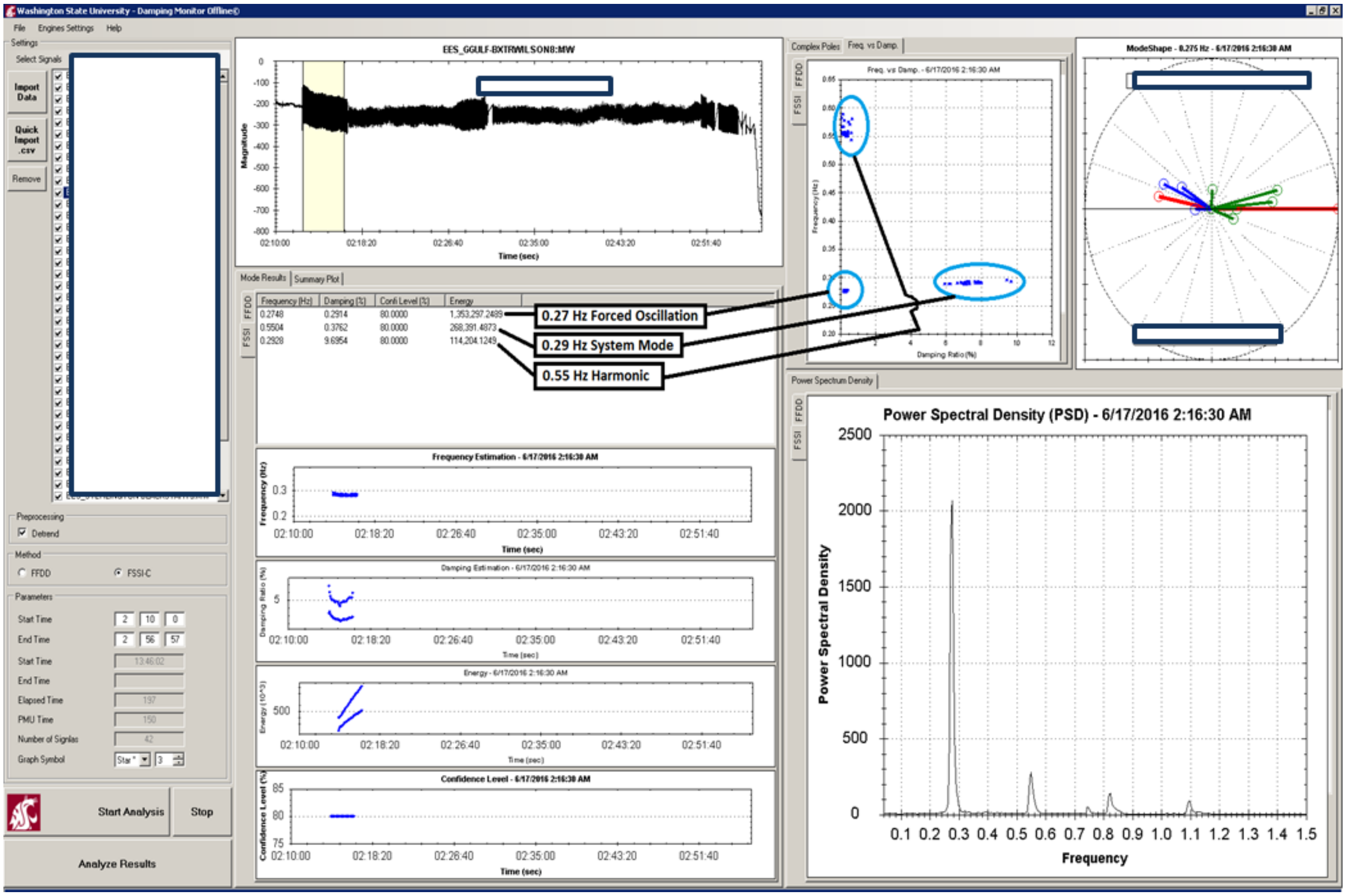

Figure 4.1: Example of Harmonics Present as Zero Damping Oscillation Estimates

The methods used to continuously monitor inter-area electromechanical modes described in **Section 1.1.2** can also help determine if an oscillation is natural or forced. These tools offer situational awareness that can help a well-trained engineer or operator understand what type of event is occurring. Forced oscillations are often (but not always) blue-sky events because they can be caused by a single piece of equipment. In contrast, poorly damped inter-area modal oscillations are often (but not always) associated with high stress conditions and/or multiple contingencies. Monitoring tools can provide an early warning of modes headed towards instability. If sustained oscillations occur following a progressive decline in a mode's damping, the oscillation is likely natural. If a sustained oscillation occurs under low-stress conditions apart from contingencies, there is a greater chance that it is forced. These are not hard and fast rules, but they can help operation staff interpret their tools appropriately.

In addition, some oscillation monitoring tools are capable of tracking forced oscillations and relatively well-damped electromechanical modes of oscillation simultaneously. If only the sustained oscillation is found at the frequency of the known electromechanical mode, there is increased likelihood that poor mode damping is leading to the oscillation. However, if the sustained oscillation and the known mode with sufficient damping are both identified, the sustained oscillation is most likely forced and has been observed before in RC operations.[36] Again, this approach requires training to help operations staff interpret results. Such approaches will be necessary while commercial tools that explicitly classify sustained oscillations as natural or forced are developed.

[36] H. Zhang, J. Ning, H. Yuan and V. Venkatasubramanian, "Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability," 2019 North American Power Symposium (NAPS), 2019, pp. 1-6

4.2 Mitigating Actions

Once an oscillation is detected, a decision about whether to take mitigating actions must be made. Defining thresholds to determine if an oscillation is a reliability threat requiring action is a nontrivial task, but the key parameter is the oscillation's amplitude. Offline dynamic studies and reviews of relay settings can be used to set well-informed thresholds. In addition, regular investigation of oscillatory events can build an institution's understanding of how oscillations of various amplitudes, durations, and frequencies may impact reliability. As much as possible, oscillation scenarios should be studied in advance through the use of measurements and models to determine appropriate action.

When a wide-area oscillation occurs, effective communication among RCs/TOPs can help maintain system reliability by ensuring that only well-coordinated and effective mitigation actions are performed. Local oscillations can typically be addressed by an RC/TOP acting alone, but if the oscillation is observed throughout an RC/TOP footprint, coordination should begin quickly. Transmission operators should contact their RC, and RCs should reach out to neighboring RCs. In this way, the affected portion of the Interconnection can be quickly identified.

Any oscillation observed across an RC/TOP footprint warrants coordination. This coordination is important even when the source is readily apparent and the oscillation is not large enough to threaten reliability within the RC/TOP footprint from which it is originating. Due to the system's dynamics, a forced oscillation may be larger in far off areas of the system. RCs in those areas need to know that the source has been identified, and the RC/TOP from which it is originating needs to adjust their response if reliability of other portions of the grid are threatened. Even oscillations too low in energy to impact system reliability may be indicative of malfunctioning or misoperating equipment. When oscillations are found to originate from a power plant, RCs/TOPs can help the power plant operator maintain reliable and safe operation by communicating with them.

With coordination efforts in place, mitigation measures can be enacted effectively. Inter-area modal oscillations should be mitigated based on the results of studies as discussed in **Section 1.2**. If the mode of oscillation is unknown, reducing flows along tie-lines may reduce system stress and improve stability. In the case of wide-area forced oscillations, the most effective mitigation measure is to identify and disable the forcing input. Disabling the input does not necessarily mean that equipment needs to be taken offline. Certain areas of operation, such as the rough zone on hydro units, may lead to oscillations. In some cases, unintended control interactions leading to oscillations can also be mitigated by adjusting an operating point. Whether the mitigating action is simply adjusting an operating point or tripping a power plant offline, the source must first be identified. Methods for identifying the source of an oscillation were discussed in **Section 2.2**.

When a severe oscillatory event occurs and reliability is threatened, a potential action is to increase the damping of the excited electromechanical mode. This action can be performed while searching for the oscillation's source, which should be the primary action of all impacted RCs/TOPs. As listed previously, the three conditions leading to widespread forced oscillations are as follows:

- Proximity of the frequencies of the forced oscillation and an electromechanical mode of oscillation
- Low damping of an electromechanical mode with similar frequency
- Controllability of an electromechanical mode with similar frequency at the source of the forced oscillation

Of these three conditions, only the damping of the electromechanical mode can be effectively adjusted by RCs/TOPs through changes in the system's operating point. Increasing the damping ratio of a mode excited by a forced oscillation will not fully address the forced oscillation, which will continue until its source is disabled. However, increasing the damping ratio of the excited mode will reduce the forced oscillation's amplitude in other parts of the system that participate in the mode.

To implement this approach, studies must be conducted ahead of time to identify the operating conditions, such as flow along transmission corridors that can be adjusted to improve the damping of each mode. When a forced oscillation occurs near the frequency of a system mode, the measures designed for that mode can be implemented to improve damping. In many cases, these actions will be similar or identical to those designed to mitigate natural oscillations due to poor system damping, as described in **Section 1.2**.

Chapter 5: Examples of Oscillation Monitoring Implemented by RCs and TOPs

In this chapter, overviews of existing tools and procedures that RCs and TOPs have put into place are discussed. PMUs and the oscillation monitoring tools provided to system operators for situational awareness of concerns that could make a 15-minute impact on BPS equipment or operational decisions should be evaluated for NERC CIP applicability

5.1 Bonneville Power Administration

Implementation and Operating Experience with Oscillation Detection - Application at Bonneville Power Administration,[37] Synchrophasor Technology at BPA: From Wide-Area Monitoring to Wide-Area Control,[38] and Reliability Guideline: Forced Oscillation Monitoring & Mitigation[39] provide an overview of the oscillation applications in use at Bonneville Power Administration (BPA). BPA's oscillation detection application has been deployed in the BPA control room since 2013, and it operates by monitoring PMU measurements for increased energy. This monitoring is performed for four frequency bands as described in **Section 2.1**. When a signal's energy exceeds the threshold, it is indicated on a geographical map in red as in **Figure 1.3**. An example where the oscillation is detected across a wide area is displayed in **Figure 5.1**. These displays provide operators with an initial indication of how widespread the oscillation is and what its type may be based on the frequency band. Once a detection is displayed, the operator can click on specific locations to obtain more detailed information as shown in **Figure 5.2** and **Figure 5.3**.

The BPA established operating procedures to accompany their oscillation detection application in 2016. If an alarm is issued for a single location, the system operator contacts the local operator or field staff to investigate further. If the alarm is issued for multiple locations, the oscillation is considered widespread. Depending on the situation, the RC may be contacted to identify the cause and develop a course of action. Potential operator actions, governed by BPA's operating procedures, include inserting series capacitors, inserting transmission lines that are out of service for voltage control, moving generation to increase system inertia, and curtailing schedules.

[37] Implementation and Operating Experience with Oscillation Detection - Application at Bonneville Power Administration: http://cigre-usnc.org/wp-content/uploads/2016/10/Kosterev.pdf

[38] Synchrophasor Technology at BPA: From Wide-Area Monitoring to Wide-Area Control: https://www.bpa.gov/Doing Business/TechnologyInnovation/Documents/2017/SYNCHROPHASORS AT BPA Nov 2017.pdf

[39] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

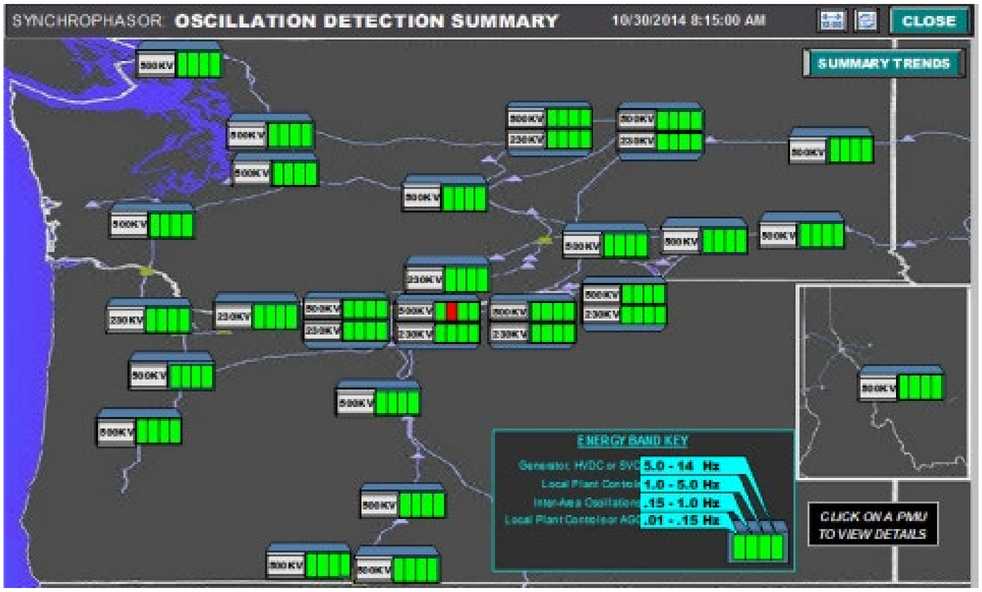

Figure 5.1: Control Room Display Indicating a Localized Oscillation in Band 2

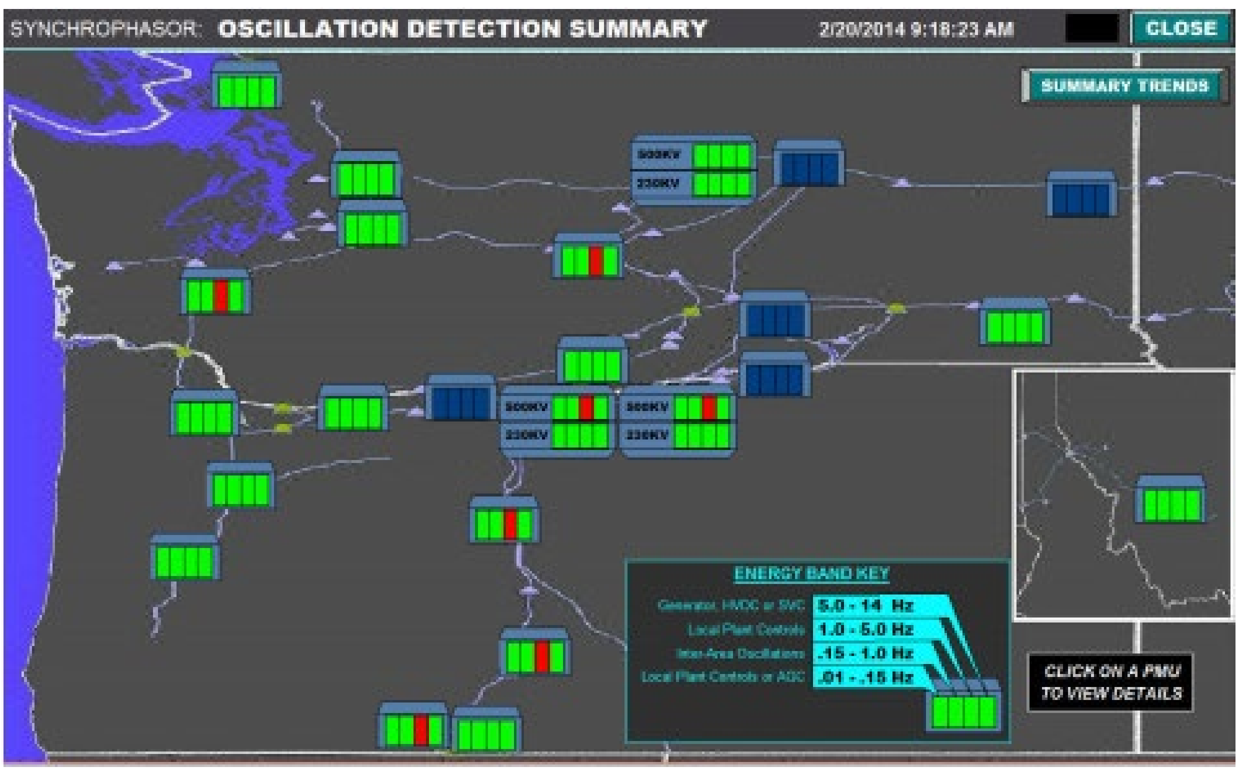

Figure 5.2: Control Room Display Indicating a Wide-Area Oscillation in Band 3

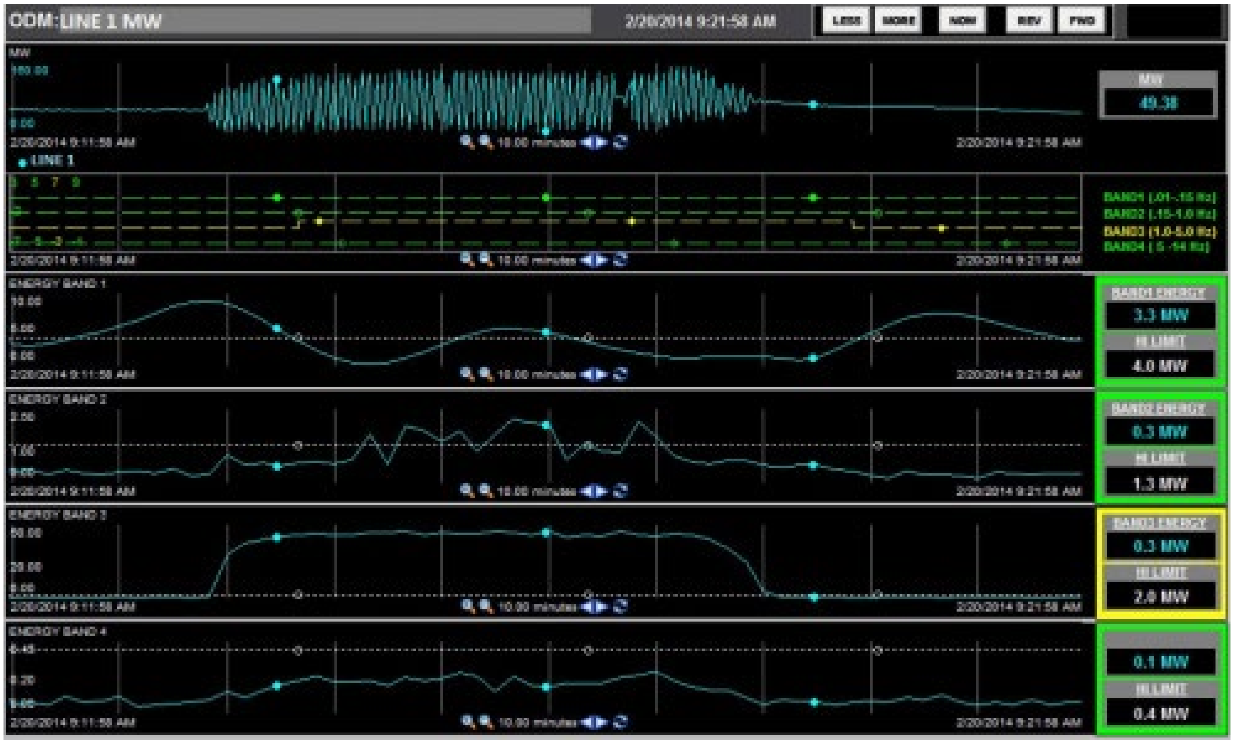

Figure 5.3: Control Room Display Providing Additional Information About a Band 3 Oscillation Alarm

BPA has also deployed a mode meter application to provide continuous tracking of known system modes. By regularly updating estimates of mode damping, the application could potentially be used to provide an early warning of inter-area oscillation problems due to high system stress; alarming and operating procedures are under development. The concept for a composite alarm that accounts for damping ratio estimates, power flows on major interfaces, and phase angle differences is displayed in **Figure 5.4**. Power flow and angle difference values have been removed from the figure.

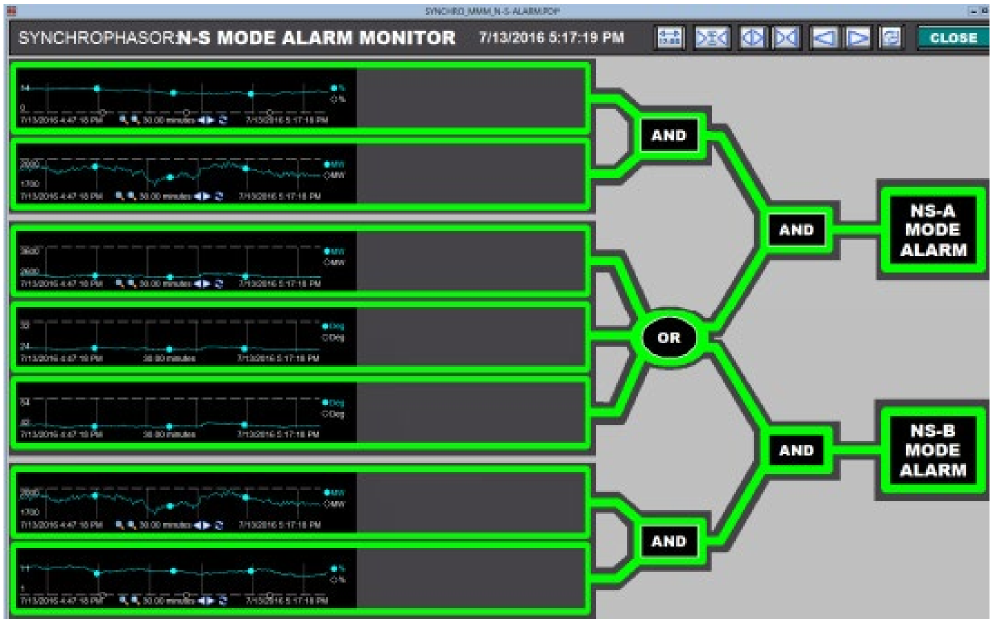

Figure 5.4: Example of a composite Alarm for Monitoring of Modes

5.2 ISO New England (ISO-NE)

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[40] and ISO New England Experience in Locating the Source of Oscillations Online[41] provide an overview of oscillation applications in use at ISO-NE. ISO-NE uses the GE PhasorPoint application to detect and characterize oscillations between 0.05 Hz and 4 Hz. This frequency range is split into sub-bands that utilize their own threshold for alerts and alarms based on the magnitude and damping of the oscillations. When a sustained oscillation of significant magnitude is detected, ISO-NE follows a similar procedure regardless of whether the oscillation is natural or forced. The key objective of this procedure is to identify the oscillation's source.

ISO-NE utilizes the online OSL application to process events. The OSL application is based on the DEF method and has processed over 1,000 oscillatory events. As mentioned earlier, the equipment generating the oscillation is identified by tracing the flow of energy back to its source. Tie-lines between ISO-NE and neighboring system operators are also monitored so that ISO-NE can determine if an oscillation is coming from outside of their territory. The OSL's pattern recognition module converts the DEF in the network into a text message identifying a specific generator, power plant, or area as the containing the source of oscillation. The pattern recognition compares the energy flow with a set of pre-defined topology-based energy flow templates for all potential oscillation sources that could be uniquely identified based on system observability with PMU measurements.

[40] Reliability Guideline: Forced Oscillation Monitoring & Mitigation:
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf
[41] S. Maslennikov and E. Litvinov, "ISO New England Experience in Locating the Source of Oscillations Online," in IEEE Transactions on Power Systems, vol. 36, no. 1, pp. 495-503, Jan. 2021

ISO-NE developed an alarm notification service to deliver the PhasorPoint and OSL results by e-mail and text messaging. An example e-mail is displayed in **Figure 5.5**.

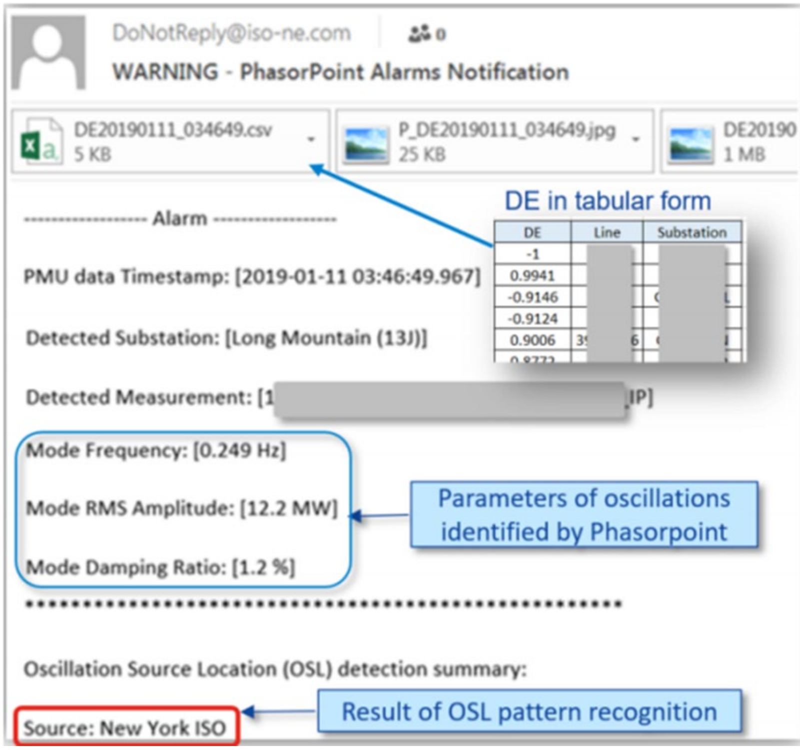

Figure 5.5: Example E-Mail from the Alarm Notification Service Detailing the Characteristics and Source of an Oscillation

E-mails from the alarm notification service are automatically generated and sent to ISO-NE control room staff and operation support engineers. If a specific power plant or generator is identified as the source, an e-mail is also sent to that generator's personnel and the local control center overseeing the generator. If the oscillation has a large magnitude, ISO-NE operational staff communicates with the operator of the source generator to apply remedial actions online. Potential mitigating measures include disconnecting the source generator from the network, adjusting the generator's MW output, or changing its control mode. If the oscillation is small, the mitigation process is shifted offline. Mitigation is again based on communication between ISO-NE personnel and the source generator's operator/owner. There is no formal distinction between a "large" and "small" oscillation at ISO-NE, but any persistent oscillation with a magnitude above the power system's ambient noise is investigated.

5.3 Oklahoma Gas & Electric (OG&E)

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[42] provides an overview of the tool and procedures developed at OG&E to address oscillations in a concentrated portion of their transmission system associated with increasing wind generation resources. In recent years, the tool's use has extended to monitor low frequency oscillations related to inter-area modes. The application's oscillation detector is based on the magnitude of the Fast Fourier Transform (FFT), which is proportional to the amplitude and duration of the oscillation. The user interface shown in **Figure 5.6** allows the user to specify the detection threshold and the frequency range of interest.

[42] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

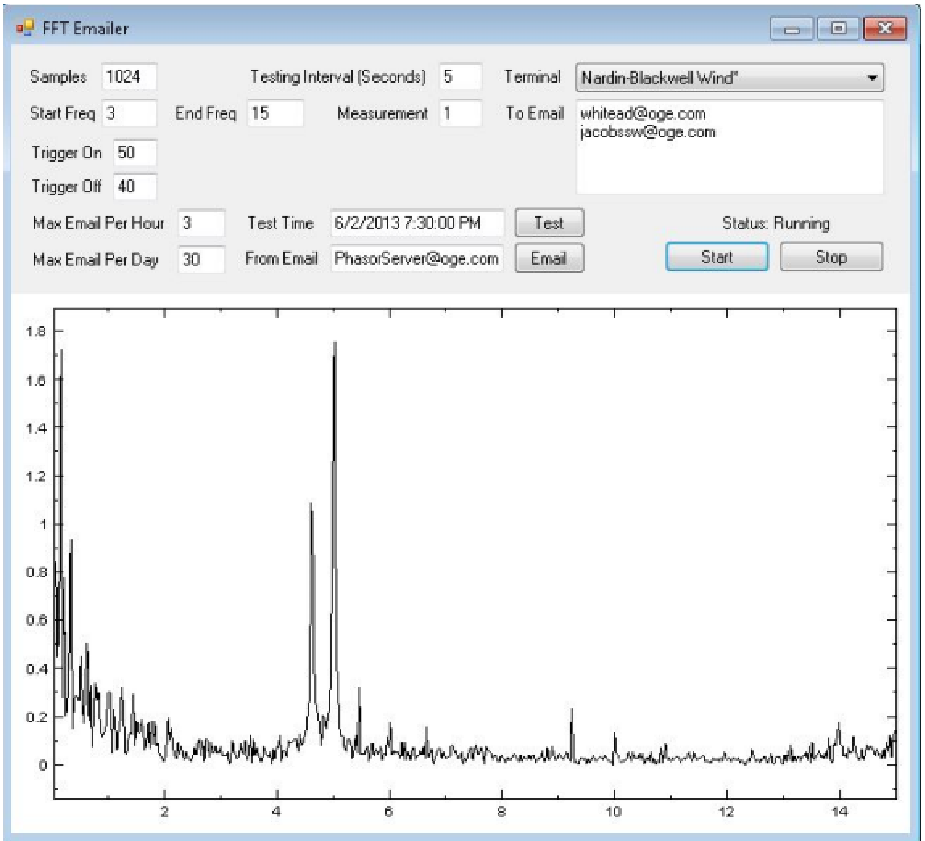

Figure 5.6: OG&E's Oscillation Detection Tool

When an oscillation is detected, the application automatically sends an e-mail like the one in **Figure 5.7** to operations support engineers. If further investigation reveals that mitigation action is necessary, the operations support engineers contact the transmission control center and recommend a mitigation strategy.

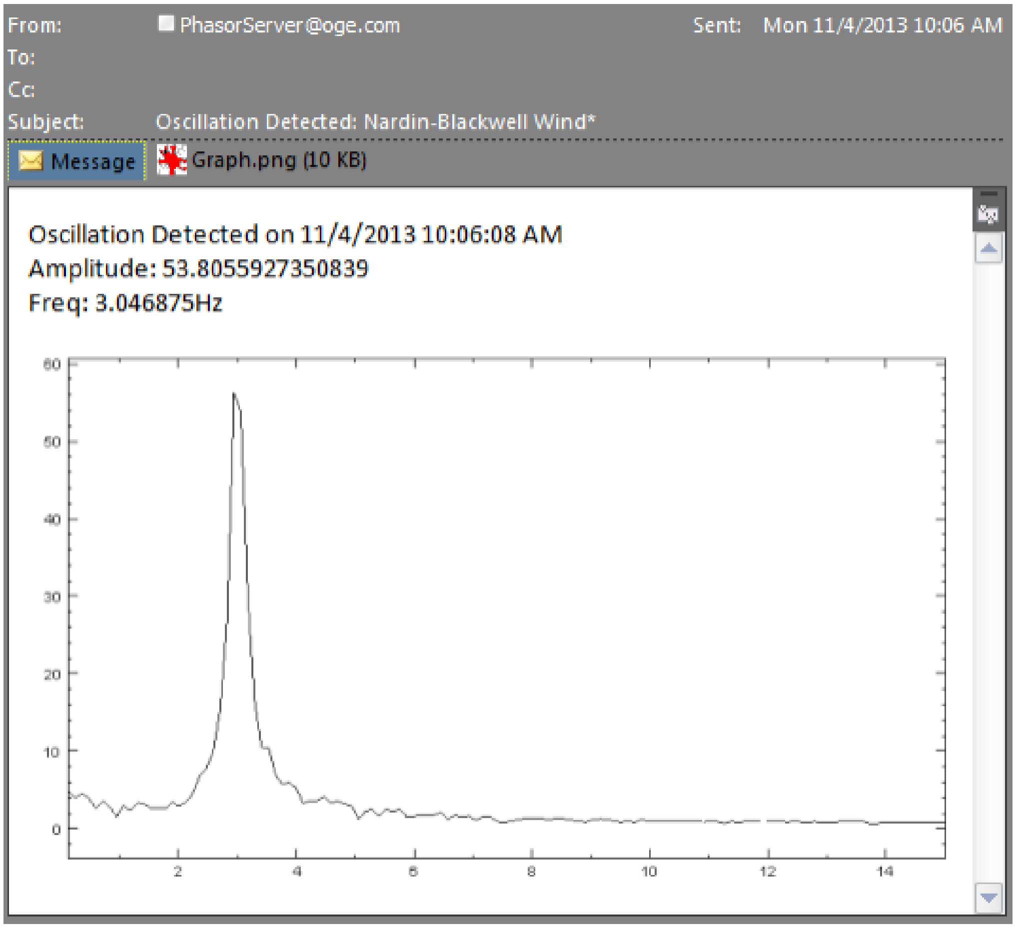

Figure 5.7: E-Mail Automatically Generated by OG&E's Oscillation Detection Tool

5.3 Peak Reliability Coordinator

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[43] and Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability[44] provide an overview of the oscillation applications used at Peak Reliability before its wind-down. These applications included both oscillation monitoring and source localization capabilities. Dominant inter-area modes of oscillation were monitored by analyzing PMU data in a mode meter application. This application provided updated frequency and damping ratio estimates every 10 seconds, much like the BPA tool described in a previous section. In addition, a PMU-based oscillation monitor was used to detect any high-energy oscillation, whether natural or forced. In addition, the frequencies, damping and energy levels, and mode shapes of inter-area modes and oscillations were estimated by analyzing hundreds of PMU signals using the FFDD, and the estimates were updated every 10 seconds.

Once an oscillation with a low damping ratio was detected with the FFDD, the source of the oscillation was identified using a SCADA-based application. SCADA measurements provided observability at many more power plants than was possible with PMU data. SCADA measurements also provide observability at generator level. SCADA measurements were collected asynchronously and updated at Peak every 10 seconds, restricting detailed oscillation analysis. Instead, the source localization application operated by identifying locations where measurements changed

[43] Reliability Guideline: Forced Oscillation Monitoring & Mitigation
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

[44] H. Zhang, J. Ning, H. Yuan and V. Venkatasubramanian, "Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability," *2019 North American Power Symposium (NAPS)*, 2019, pp. 1-6

significantly at the onset of the oscillation. In many cases, the generator exhibiting a significant change comparing to ambient condition (per ranking of normalized indices) was successfully identified as the source.

Results from the oscillation source localization application were automatically routed to network application engineers for review. After validating the results through further offline studies, engineers communicated with the corresponding entity system operator and generation plant operator to identify causes and implement mitigating actions.

5.4 RC West

RC West utilizes the Electric Power Group Real Time Dynamic Monitoring System (RTDMS) for monitoring of forced and natural oscillations. The monitoring of oscillations is supplemented with an RC operating guideline that provides guidelines to the operators for the following three scenarios:

- Forced oscillations
- Inter-area oscillations
- Forced oscillations causing Inter-area oscillations

The forced oscillation monitoring is accomplished using the ODM that monitors oscillations in the four energy bands at various locations across the RC West footprint. **Figure 5.8** and **Figure 5.9** show examples of forced oscillations observed over a wide area and a local area. **Figure 5.10** and **Figure 5.11** show examples of forced oscillations observed online flows and bus voltages.

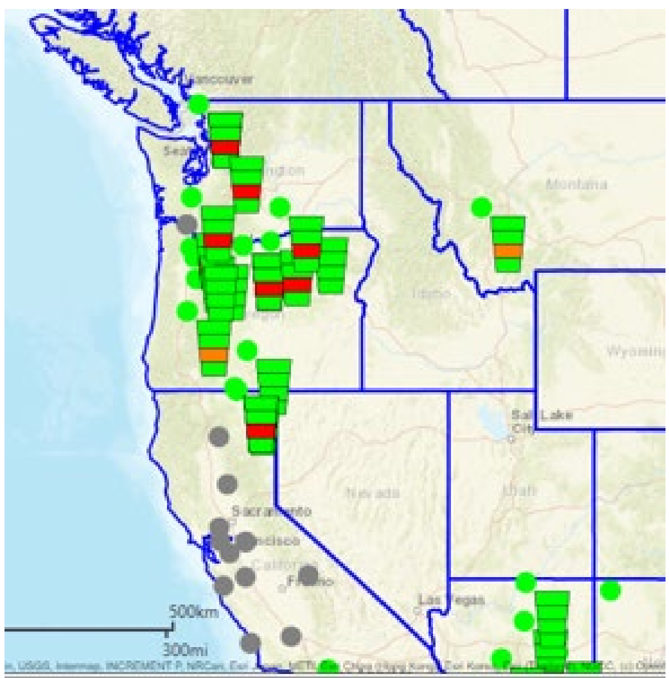

Figure 5.8: Wide-Area Forced Oscillations

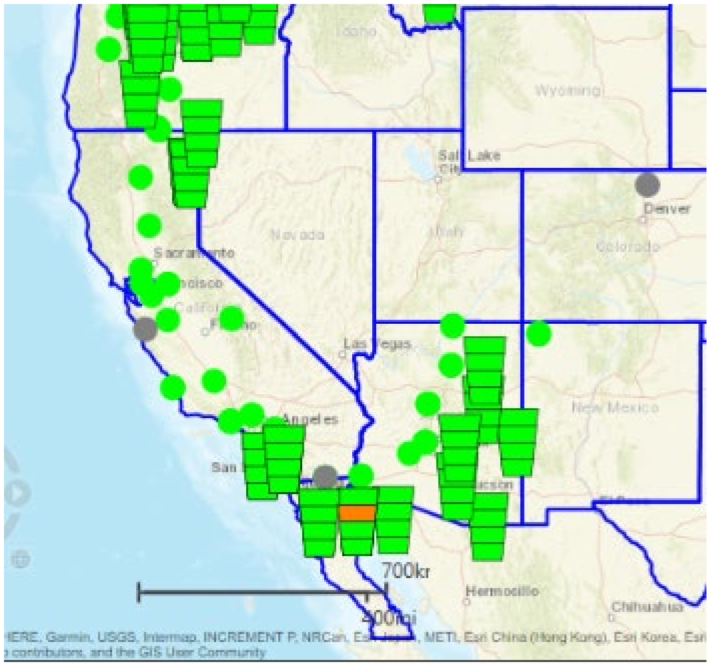

Figure 5.9: Local Forced Oscillations

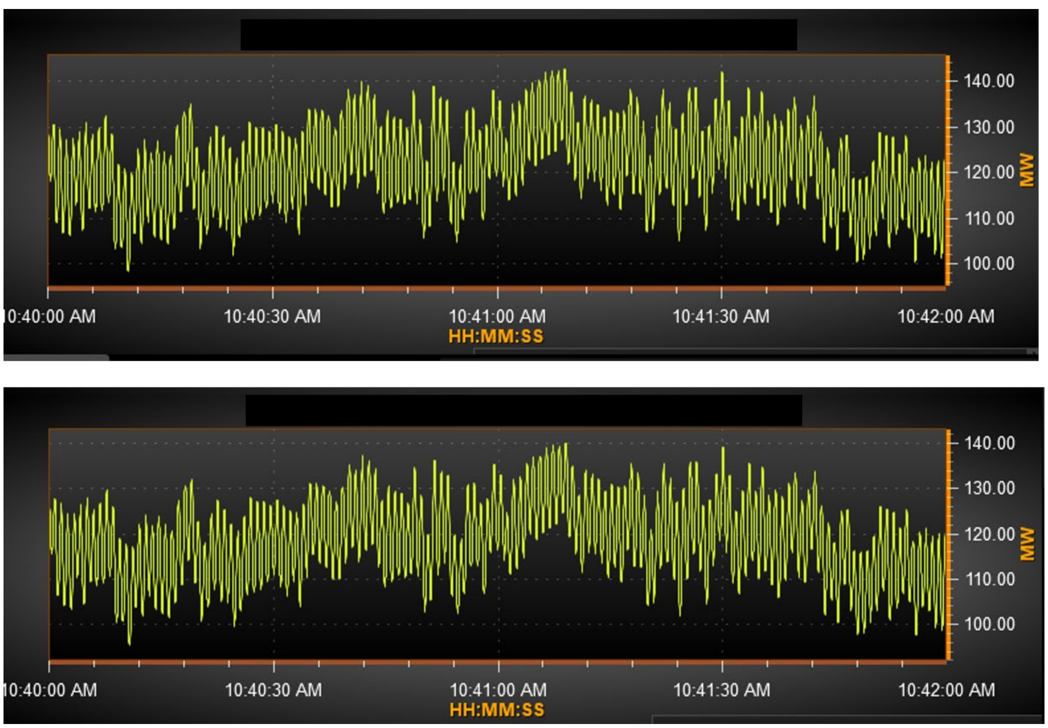

Figure 5.10: Forced Oscillations Observed on Line Flows

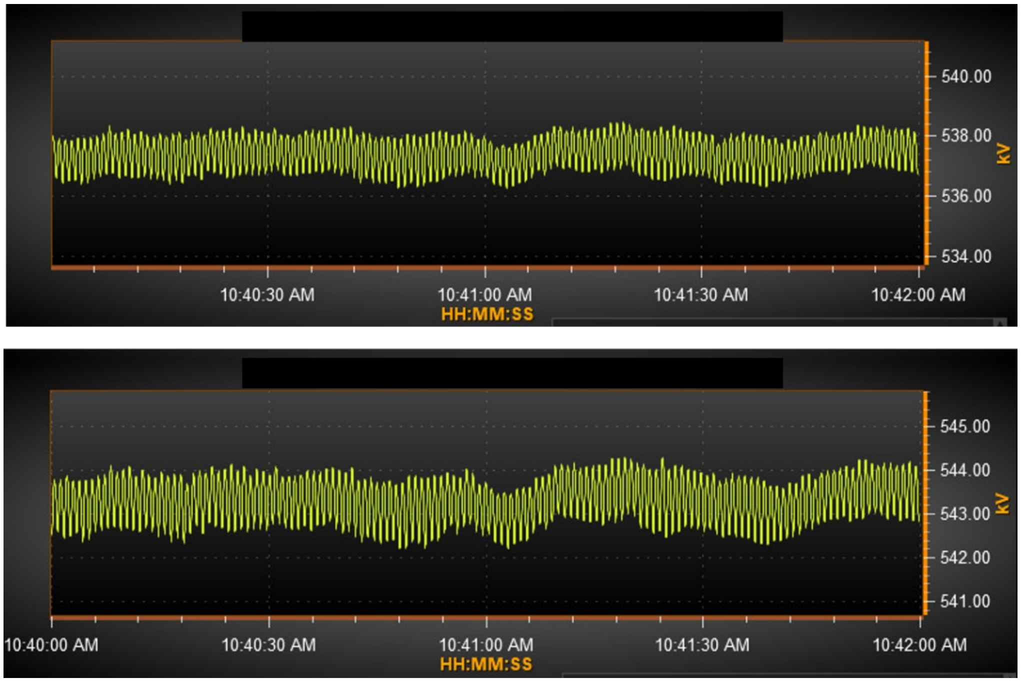

Figure 5.11: Forced Oscillations Observed on Voltages in RC West

In addition to monitoring forced oscillations, the RTDMS setup at RC West also monitors the five significant modes in the WI as shown in **Figure 5.12**: . Operators have been provided guidelines on path flows, or generators, relevant to each of these modes that can be utilized to increase damping in the event we have low sustained damping on any of these monitored modes.

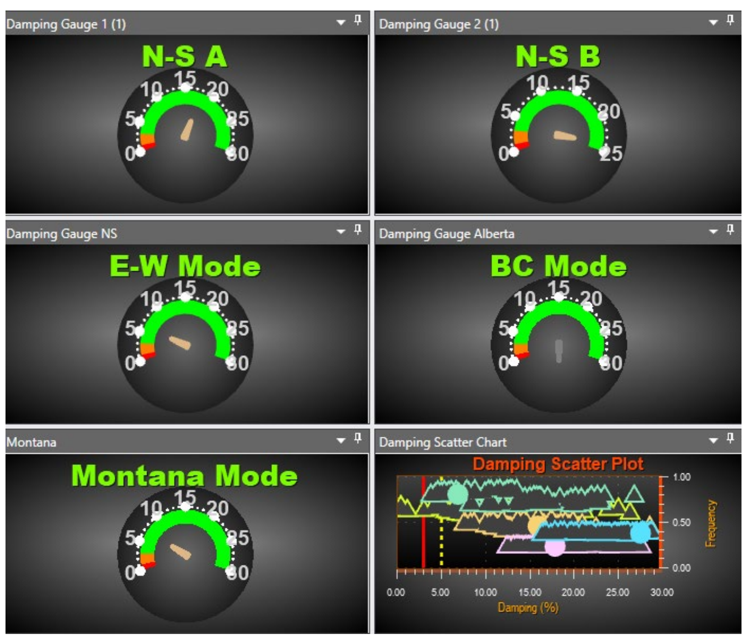

Figure 5.12: Mode Meter Monitoring

The mitigation actions for increasing damping of the modes are validated by performing SSAT analysis with real-time state estimation cases that are used along with the dynamic data applicable for the season. RC West has a running real-time transient stability analysis setup that provides the framework to perform small-signal stability analysis with the same input data from state estimation and dynamic data that is used for the transient stability analysis. The SSAT analysis, as described in **Section 1.2.1**, allows operators to determine and validate relevant path flows or status of equipment and generators that can be adjusted to mitigate observed sustained low damping on any of the monitored modes.

5.5 Southwest Power Pool (SPP)

SPP uses PMU technology and Electric Power Group RTDMS for real-time non decision-making oscillation monitoring to ensure wide-area situational awareness of Interconnection electrical signal dynamics. SPP utilizes the ODM and mode meter engines within RTDMS to extract grid dynamics information for the purposes.

ODM is used to agnostically monitor for manifested oscillations via the use of a sliding root mean square (RMS) window. An increase in signal dynamics directly translates to an increase in the RMS value. Therefore, if an oscillation occurs on a signal measurement, ODM detects this by comparing the real-time RMS value to a pre-set RMS threshold value. If the current RMS value stays above the pre-set threshold for a minimum amount of time (e.g., 60 or 120 seconds), operators are alerted of the possible oscillation event. The pre-set thresholds are set so that they represent an increase in signal dynamics above typical ambient conditions. This information can be extracted by performing statistical analysis on raw and post-processed signals and making a decision that suffices the needs of the end user. Several methods can be used (e.g., 3sigma above mean or more slightly advanced items like Dual-Dirac fitting). If there is an oscillation present and ODM detects it, internal SPP software will alert operators who then use RTDMS displays to assess the situation, such as oscillation location, signal type, oscillation frequency, and oscillation magnitude. From there, RCs will contact entities or other RCs to communicate the detection of the event. **Figure 5.13** and **Figure 5.14** shows an example of a real-time WI forced oscillation from 2019 that showed up in SPP's RTDMS system.

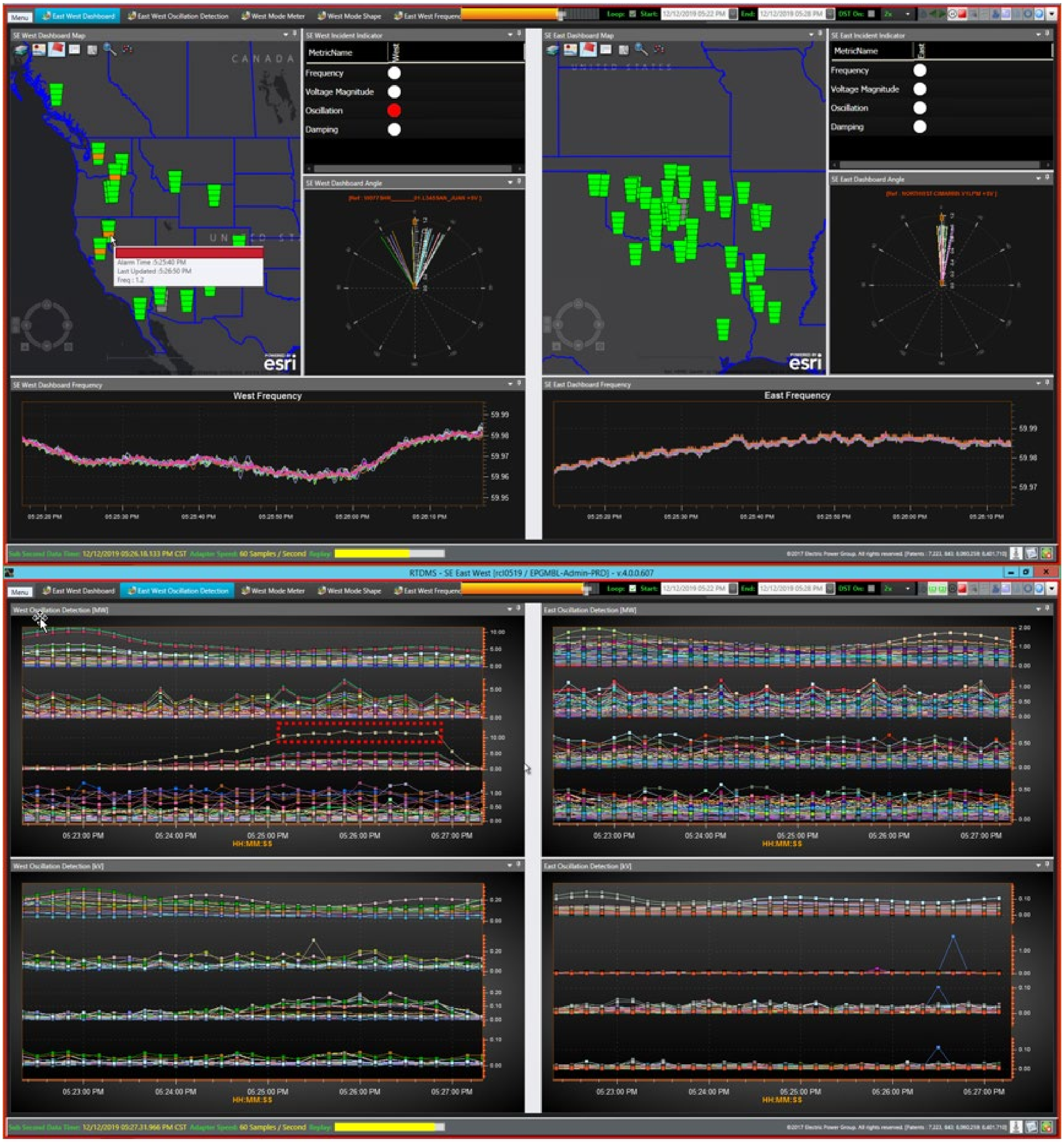

Figure 5.13: Forced Oscillation Observation in SPP

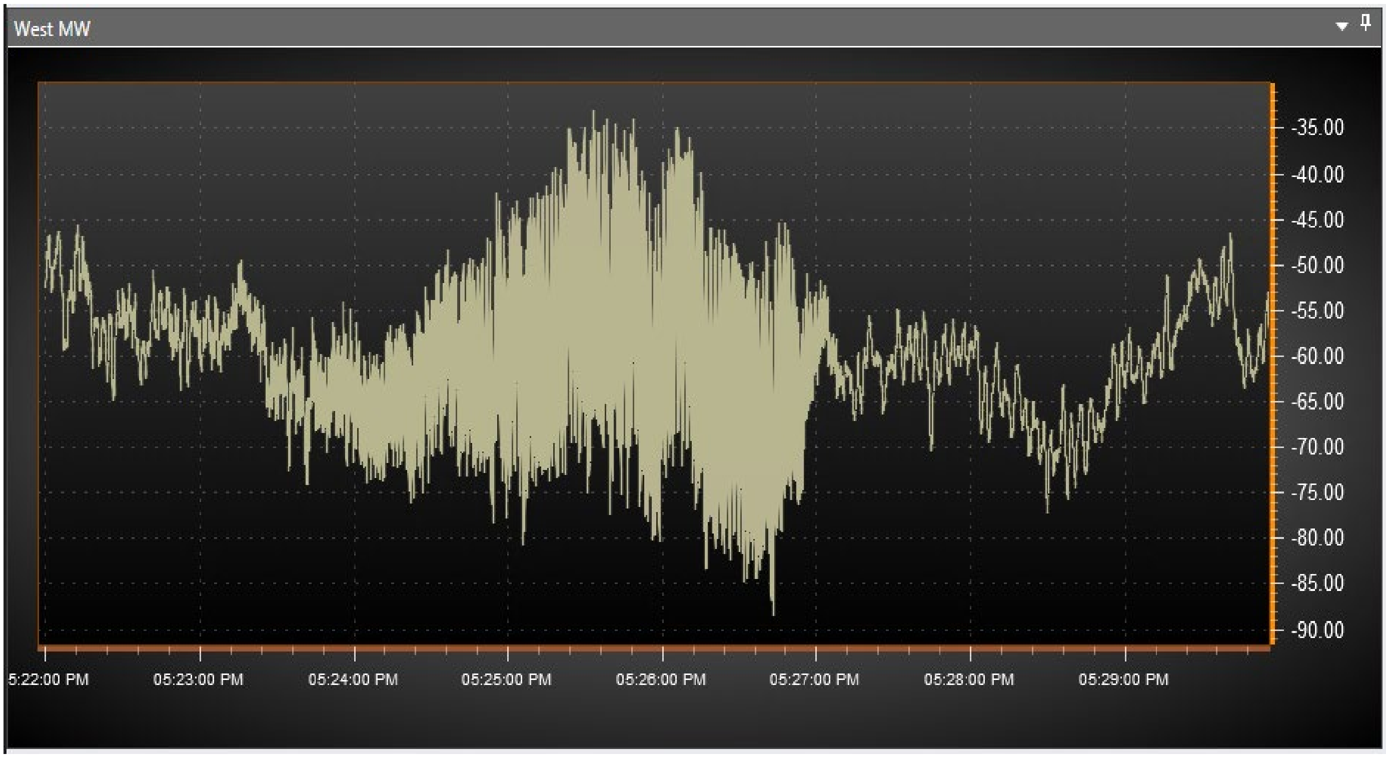

Figure 5.14: Forced Oscillation Observed on Line-Flows in SPP

On the other side of the spectrum, a mode meter is used to assess the current stability of known inter-area modes. The main outputs are the estimated damping ratio of the mode and the energy level of the composite signal used as an input to mode meter (SPP currently uses single angle pair composite signals). To assess the stability of the mode, only damping ratios are estimated and monitored in real-time. If the damping ratio of a mode drops below 3%, internal SPP software notifies the operator(s) of a potentially weakened mode. Figure 5.15 shows an example of SPP's west mode meter display, showing the real-time states of the five main WI modes.

Figure 5.15: Mode Monitoring in SPP

SPP also uses the energy values in addition to damping ratio as a quasi-ODM for detecting system oscillations pertaining to a particular system mode. This can only be done with very careful signal choices for mode meter inputs. The basic premise is that current mode meters (not just in RTDMS) typically do not work well when a forced oscillation is happening and, in that event, will generally have damping ratio estimates drop dramatically and artificially to low levels (e.g., 0% to 3%). While there are currently fixes in place, this artifact can be exploited to our advantage. By coupling a low damping ratio percent with an energy threshold (like ODM, above typical ambient conditions), a mode meter can help operators and shift engineers assess whether there is an oscillation happening that pertains to a particular system mode whether that be an unstable mode causing growing oscillations or a case where a natural mode resonance happens. In both cases, estimated damping ratios drop and energy levels rise. **Figure 5.16** is an example conveying the concept as well as a real-use case. In addition, mode shapes are also plotted as another indicator to operators that a power system oscillation pertaining to a particular system mode is in effect.

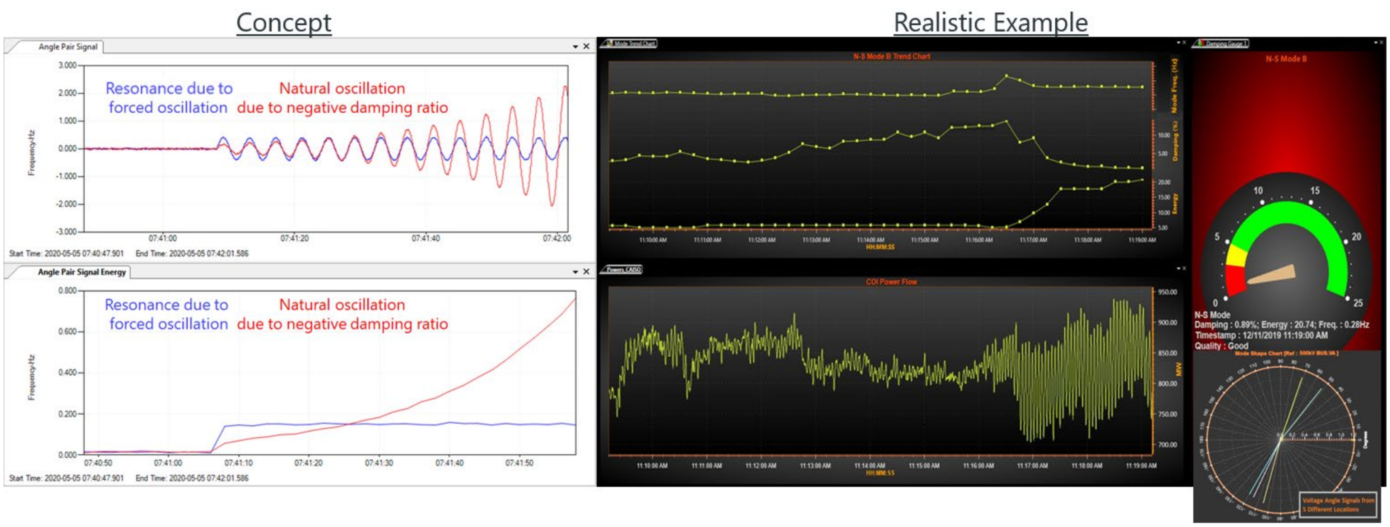

Figure 5.16: Mode Monitoring

5.6 American Electric Power (AEP)

Since early 2018, AEP has used PMU based applications for online oscillation analysis and offline event studies. Installed and maintained by AEP's protection and control team, field PMU units will stream high sampling data to an enhanced Phasor Data Concentrator (ePDC), which is a data repository. An ePDC will then dispatch PMU data streams to PhasorPoint in which real-time monitoring is enabled and alarms are generated and transmitted to energy management system (EMS) side. **Figure 5.17** illustrates the configuration of AEP's PMU system.

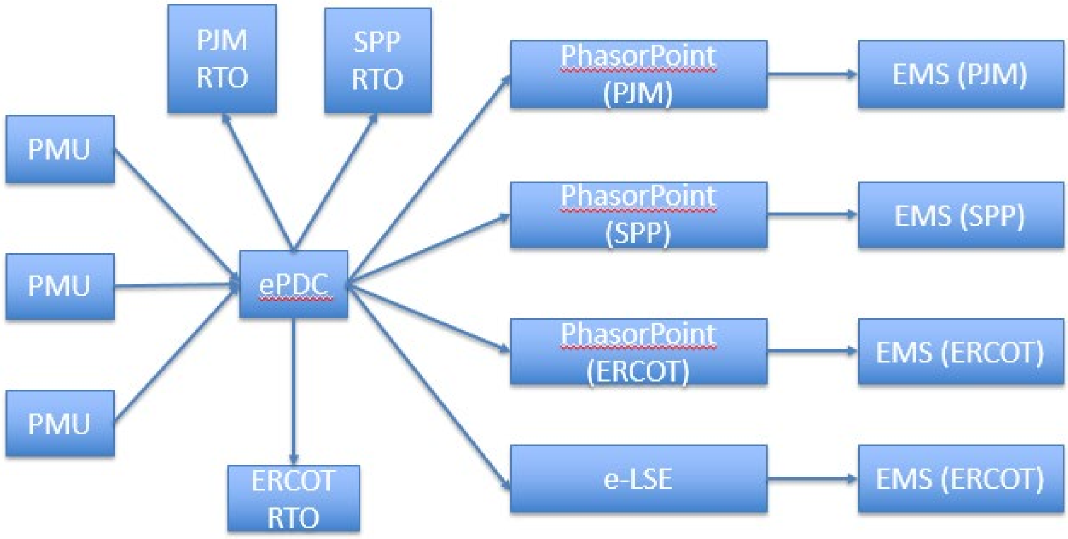

Figure 5.17: AEP's PMU Configuration

AEP has deployed close to 400 PMUs across its three footprints governed by PJM, SPP, and ERCOT. With the large amount of data accumulated, real-time oscillation event detection on frequency and active power was developed and deployed in control room to enhance situational awareness.

5.6.1 AEP Real-Time Oscillation Monitoring and Event Detection

Taking advantage of the high sampling rate of phasor measurement units, system dynamics are visualized and documented in PhasorPoint. The purpose of developing this event detection mechanism is to help control room personnel quickly identify harmful oscillations from common system variations. With online modal decomposition in PhasorPoint, system dynamics were decomposed in real time with oscillation magnitude and decay time as two critical metrics to measure the severity of the oscillation. The bigger the magnitude and longer the decay time, the more sever the oscillation will be. While it is preferred to avoid alarms on the small and quickly damped oscillations, the lingering ones with big swings are supposed to be caught by operators as quickly as possible.

With this purpose in mind, a kernel density estimation (KDE)-based methodology[45] was developed to detect oscillation events. In this methodology, a cross-validated KDE was adopted to regress historical oscillation data. As a result, a bi-variable probability density function was derived to summarize the distribution of documented oscillation data. Knowing that severe oscillatory disturbances are statistically rare, a cut-off probability initialized at three standard deviations above the mean was used to identify historical observations of oscillation events. With heuristic[46] training based on a historical event list, this cut-off probability would be finalized, and observations of past oscillation events were picked and located on Locus plot like shown in **Figure 5.18.**

[45] AEP's experience in Detecting and Analyzing Oscillation Events using PMU based applications - https://www.wecc.org/Administrative/09f_Lu_JSIS_AEP's experience in Detecting and Analyzing Oscillation Events using PMU based applications_May 2021.pdf

[46] In mathematical optimization and computer science, **heuristic** (from Greek εὑρίσκω "I find, discover") is a technique designed for solving a problem more quickly when classic methods are too slow, or for finding an approximate solution when classic methods fail to find any exact solution. This is achieved by trading optimality, completeness, accuracy, or precision for speed. In a way, it can be considered a shortcut.

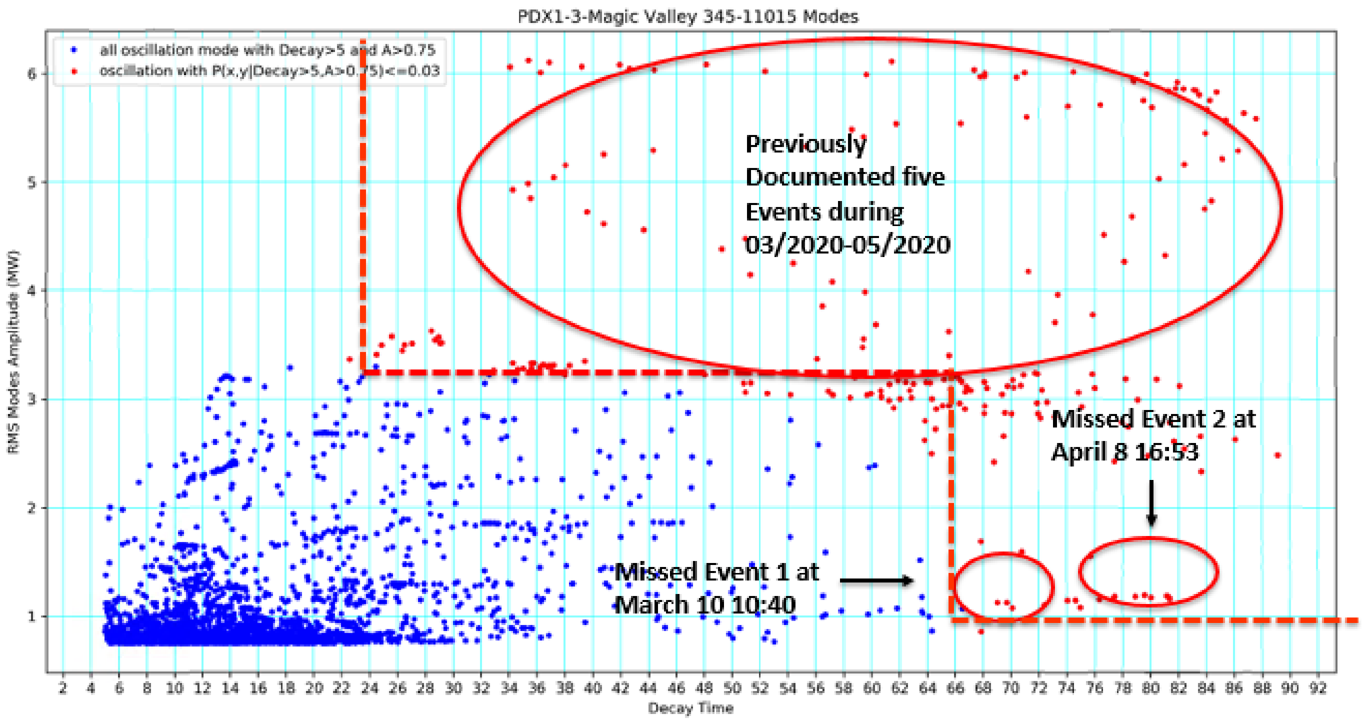

Figure 5.18: Locus Demonstration of Observations Representing an Oscillation Event

With all event observation labeled in red in **Figure 5.18**, the alarm settings concerning amplitude and decay time were configured. For the particular PMU signal demonstrated in **Figure 5.18**. Its finalized alarm configuration is listed in **Table 5.1**.

Table 5.1: Alarm Setting for PMU @Magic Valley				
	Decay Time Exclusion	**Decay Time Threshold**	**Amplitude Exclusion**	**Amplitude Threshold**
Alarm Setting	24 seconds	66 seconds	1MW	3.25MW

The alarm configurations obtained from KDE-based methodology were more reliable than the previous intuitive configurations. Historical event studies proved the method's enhanced sensitivity as the method could detect previously missed oscillation events. In addition, over one-year of control room deployment has verified long lasting reliability of the methodology as the rate of false alarms is significantly reduced. **Table 5.2** is a performance overview on the KDE-based online event detection.

Table 5.2: Performance Overview of KDE-based event detection					
Footprint	**Production Deployment**	**False Alarm Count**	**False Alarm Rate (after)**	**False Alarm Rate (before)**	**Footprint**
ERCOT	07/2020	<30	Around 6%	50+%	ERCOT
SPP	09/2020	<10	Less than 5%	45%–50%	SPP
PJM	10/2020	<20	Less than 5%	50+%	PJM

With the KDE-based event detection in place, all the oscillation events captured in PhasorPoint will be streamed in real-time to control room and documented in daily PMU reports for offline studies.

5.6.2 AEP Auto Daily PMU Report Implementation

In order to enhance the situational awareness of AEP's system for control rooms, the Daily PMU report is automatically generated as a pdf file and is archived in an internal shared folder. So far, this report includes information of the system average frequency and PMU data quality statistics and also lists the poor-quality PMUs that are in need of maintenance. In addition, the reports summarize the oscillation events and have the charts attached of event details, such as related PMU measurement waveform charts and oscillation mode information charts. More information and charts are planned to be included in future daily reports.

As shown in **Figure 5.19**, the daily reports are created by retrieving data through Phasorpoint SQL database via the Open Database Connectivity (ODBC) connector. Then python scripts have been written to access the SQL data to make necessary plots and tables, and a pdf file report containing all the information needed will be automatically generated by the script. The purpose of daily reports is to help operators and engineers have a better situational awareness of AEP's system operation. Therefore, three daily reports for each AEP's footprint (ERCOT, SPP, and PJM) are generated on a daily basis. So far, there are seven modules in the daily report that each cover the system frequency chart, the daily/monthly PMU data quality statistics pie chart, and the daily/monthly poor PMU quality list as well as the oscillation event summary list and detailed charts. Some examples of the charts in the AEP Daily PMU report are provided in **Figure 5.20–Figure 5.23**.

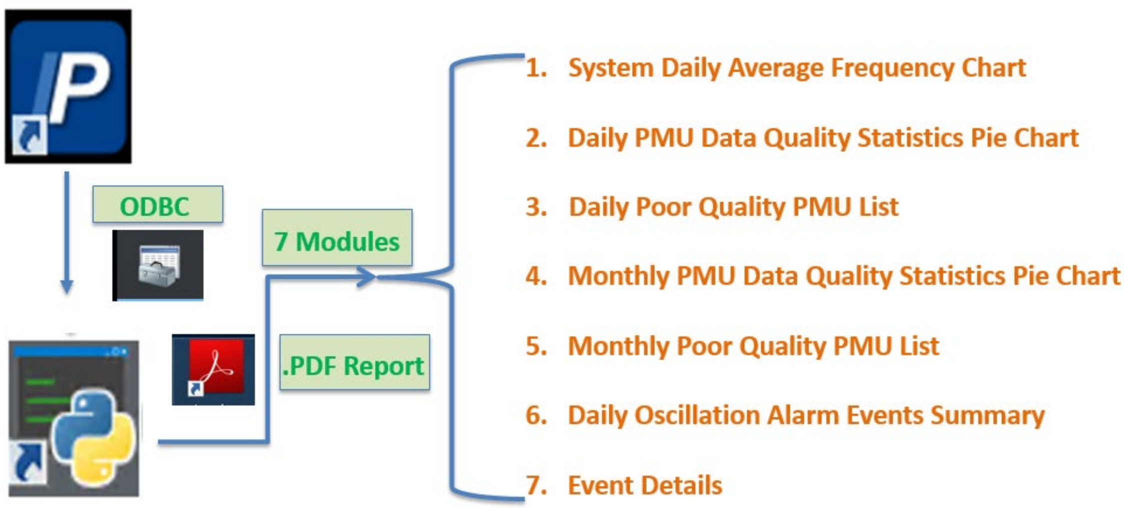

Figure 5.19: AEP Auto Daily PMU Report Deployment

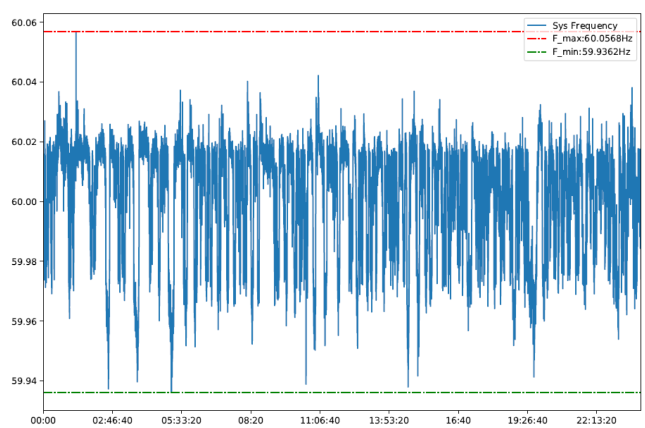

Figure 5.20: System Daily Average Frequency Chart

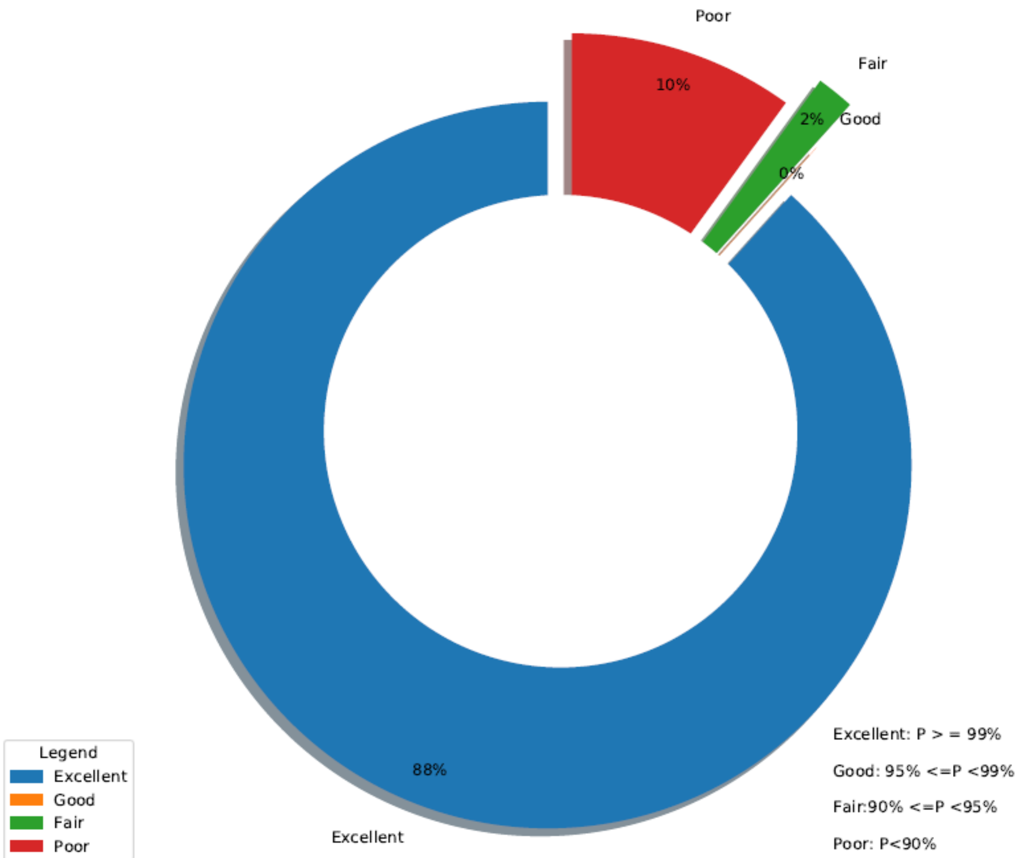

Figure 5.21: Daily PMU Data Quality Statistics

Index	Date	Time	measurement_group	measurement	parameter	message
1	2021-04-29	10:56:01	RH	12345 (ABC@RH)	P	PDX1-3 event status alarm

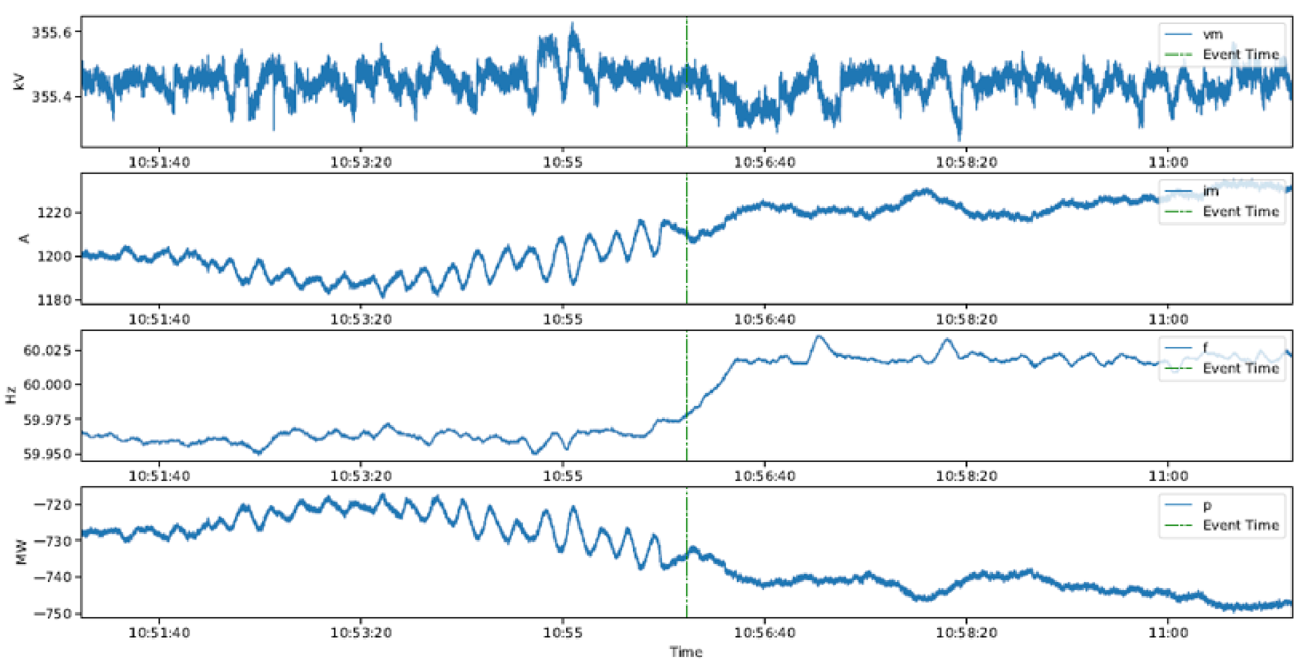

Figure 5.22: Event 1 PMU measurements

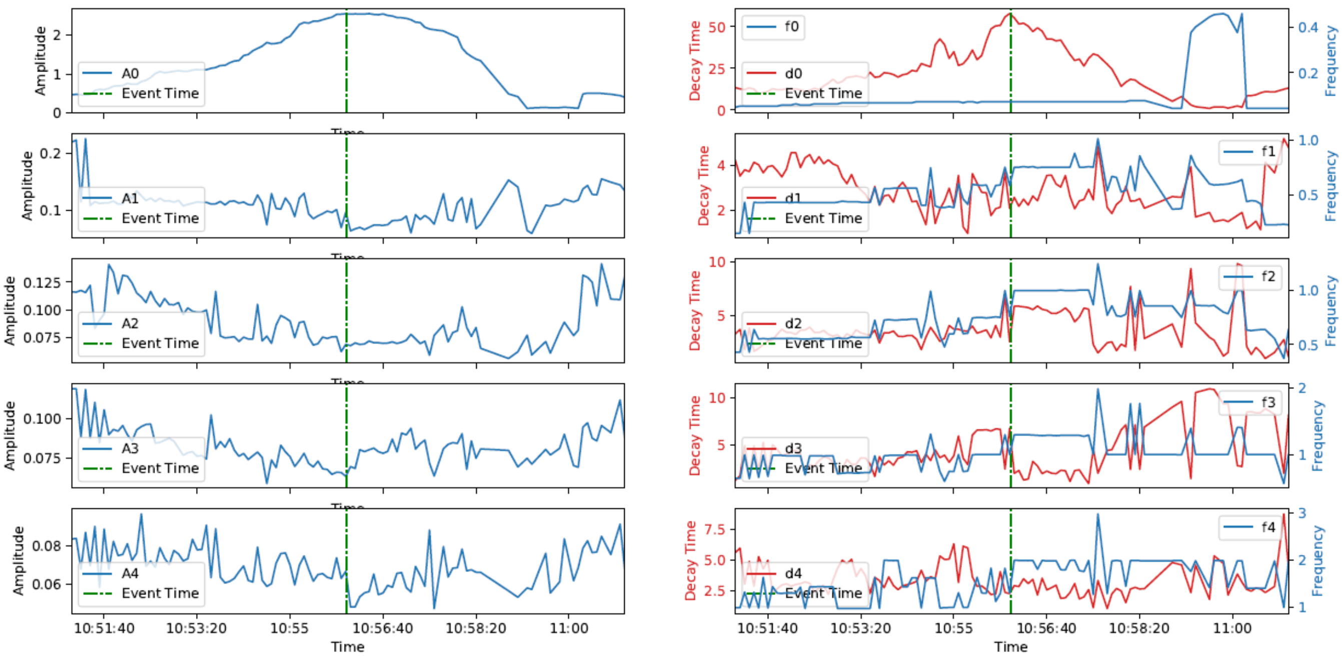

Figure 5.23: Event 1 Oscillation Mode

Appendix A: Determining the Impact of Forced Oscillations

This appendix describes through an example of how one can determine the impact of forced oscillations at frequencies closer to the inter-area modes that need to be monitored.

During the January 11, 2019, forced oscillation event, several EI GOs and System Operators set their plant AVRs to manual control and ramped down online pumped storage plants upon identifying the undamped oscillation. Following the event, there were questions on whether those were the appropriate actions and whether there were any other actions the operators could have taken to mitigate the event. This example describes how a wide-area resonant forced oscillation can be recreated in dynamic simulation and how possible mitigations can be tested. For simplicity, example simulations shown below were performed on a subset of the EI model that does not include a large enough area to capture the modes involved in the January 11, 2019, event.

Modeling of Forced Oscillations

The source of the oscillation was a steam turbine in Florida that experienced 200 MW peak-to-peak oscillations due to controller failure causing the intercept valves to open and close every four seconds. As the intercept valves cyclically open and close, they increase and decrease the flow of steam through the turbine, effectively causing the mechanical power input to the generator to oscillate between full output and zero. To represent this controller failure in dynamic simulation, a user model is needed to oscillate a generator's mechanical power at a defined amplitude and frequency. The FORTRAN code for a Power System Simulation for Engineering (PSSE) user model, named "GOV_OSCILLATE," accomplishes this as shown in **Figure A.1**.

Without delving into the details of user model writing in PSSE, the inputs to this model are as follows:

- The machine number — I
- The amplitude and frequency of the mechanical power oscillation — CON(J) and CON(J+1)
- The initial mechanical power — STATE(K)
- No used variables (VARS) or integer constants (ICONS)

Each PSSE dynamic model performs various computations at different stages of the dynamic simulation:

- In Mode 1, dynamic models are initialized. The initial mechanical power is saved in the state variable, STATE(K).
- In Mode 3, governor type models must compute the current value of mechanical power and populate the mechanical power (PMECH) arrays. As shown in line 42 of **Figure A.1**, PMECH(I) is only modified if the simulation time is greater than 1 second. After 1 second, PMECH(I) is by the equation below:

$$P_{Mech} = P_{Mech\_Initial} + \frac{Amplitude}{MVA_{base}} * \sin[2\pi f(t-1)]$$

GOV_OSCILLATE_rev2.flx

```
      SUBROUTINE GOV_OSCILLATE(I,ISLOT)
C     Logic to add a 10 MW oscillation on Pmech at time >1s
C
      INCLUDE 'COMON4.INS'
C
      INTEGER I, ISLOT
C     I     = MACHINE ARRAY INDEX
C     ISLOT = ARRAY ALLOCTION TABLE INDEX
C             J = STRTIN(1, ISLOT)  [ USES CON(J) AND CON(J+1) ]
C             K = STRTIN(2, ISLOT)  [ USES STATE(K) ]
C
      INTRINSIC SIN
      INTEGER J, K
      REAL PMECH_INITIAL
C
      IF (MODE.EQ.8)
      .  CON_DSCRPT(1) = 'Amplitude'
      .  CON_DSCRPT(2) = 'Frequency'
      .  RETURN
      ...FIN
C
C  GET STARTING 'CON' INDICES
C
      J=STRTIN(1,ISLOT)
      K=STRTIN(2,ISLOT)
C
      IF (MODE .GT. 4) GO TO 1000
C
      GO TO (100,200,300,400), MODE
C
C MODE = 1: INITIALIZE
C
 100  STATE(K) = PMECH(I)
      RETURN
C
C MODE = 2: CALCULATE DERIVATIVES
C
 200  RETURN
C
C MODE = 3: SET PMECH
C
 300  IF (TIME .GT. 1) THEN
          PMECH(I) = STATE(K) + CON(J)*SIN(6.2832*CON(J+1)*(TIME-1))/MBASE(I)
      END IF
      RETURN
C
C MODE = 4: SET NINTEG
C
 400  NINTEG=MAX(NINTEG,K+1)
      RETURN
C
 1000 RETURN
      END
```

Figure A.1: PSSE USER Model to Create Forced Oscillation

After compiling the FORTRAN code in **Figure 2.4** and creating a *.dll file the user model can be utilized using the statement in **Figure A.2**. The highlighed variables indicate that the model should be applied to machine 1 at bus 4, the amplitude of oscillation is 100MW (200 MW peak-to-peak), and the frequency of oscillation is 0.67hz. The other parameters are required for PSSE to classify it as a Turbine-Governor model and reserve the necessary space in the ICONS, CONS, STATES, and VARS arrays.

TP4_gov_oscillate_rev.dyr | GOV_OSCILLATE_rev2.flx

```
 4 'USRMDL' 1 'GOV_OSCILLATE' 5 0 0 2 1 0 100 0.67 /
```

Figure A.2: User Model Calling Statement

Figure A.3 shows the mechanical power of a unit that this model is applied to.

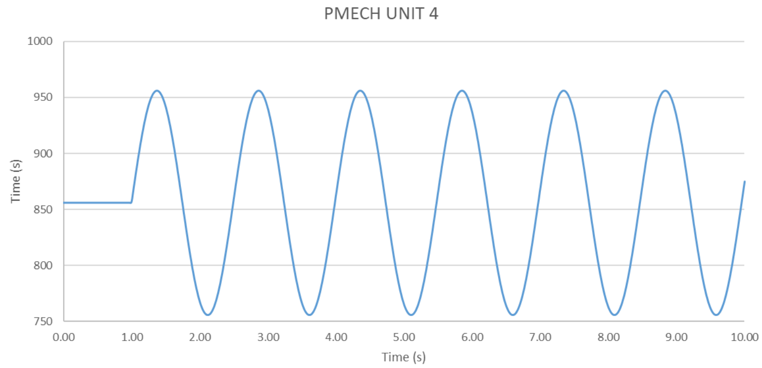

Figure A.3: Mechanical Power for Source of Forced Oscillation

Modeling Wide-area Resonant Forced Oscillations

The previous section described how a forced oscillation in mechanical power with a defined amplitude and frequency can be applied to any machine in a PSSE dynamic case. However, there are three conditions required for wide-area resonant forced oscillations:

- A source oscillating at a frequency close to a system mode
- The system mode is poorly damped
- The source is near a strong participation location of that system mode

An essential step to simulating wide-area resonant forced oscillations is to identify natural system modes that are poorly damped and determine which units strongly participate in those modes. Software packages, such as PSSE's SINCAL or Power Tech's SSAT, can be used to perform eigenvalue analysis. The software packages take the load flow and dynamic models as inputs and then provide a list of natural modes within a specified frequency range (e.g., 0.1–2 Hz). The poorly damped modes should be further analyzed to determine their mode shape and participation factors. This will illustrate which source location will most excite the poorly damped modes and which areas of the grid will experience higher oscillations.

Figure A.4 and **Figure A.5** demonstrate how wide-area resonant forced oscillations can be simulated. Eigenvalue analysis was used to identify a lightly damped natural system mode with a frequency of 0.67 Hz, that unit 4 strongly participates. **Figure 2.7** shows system variables throughout a wide area when Unit 4 experiences a cyclical failure at 0.25 Hz. The first condition for resonant forced oscillations is not well satisfied and the wide-area impact is minimal. **Figure 4.1** shows the same variables when Unit 4 experiences a cyclical failure at 0.67 Hz, such that all three conditions for resonant forced oscillations are well satisfied. The electrical power oscillations on Unit 4 are higher than the mechanical power oscillations indicating amplification or resonance. The difference between a local forced oscillation and a wide-area resonant forced oscillation is clearly demonstrated by observing oscillations in frequency and power throughout the system. Even the mode shape can be verified by observing which units oscillate against each other.

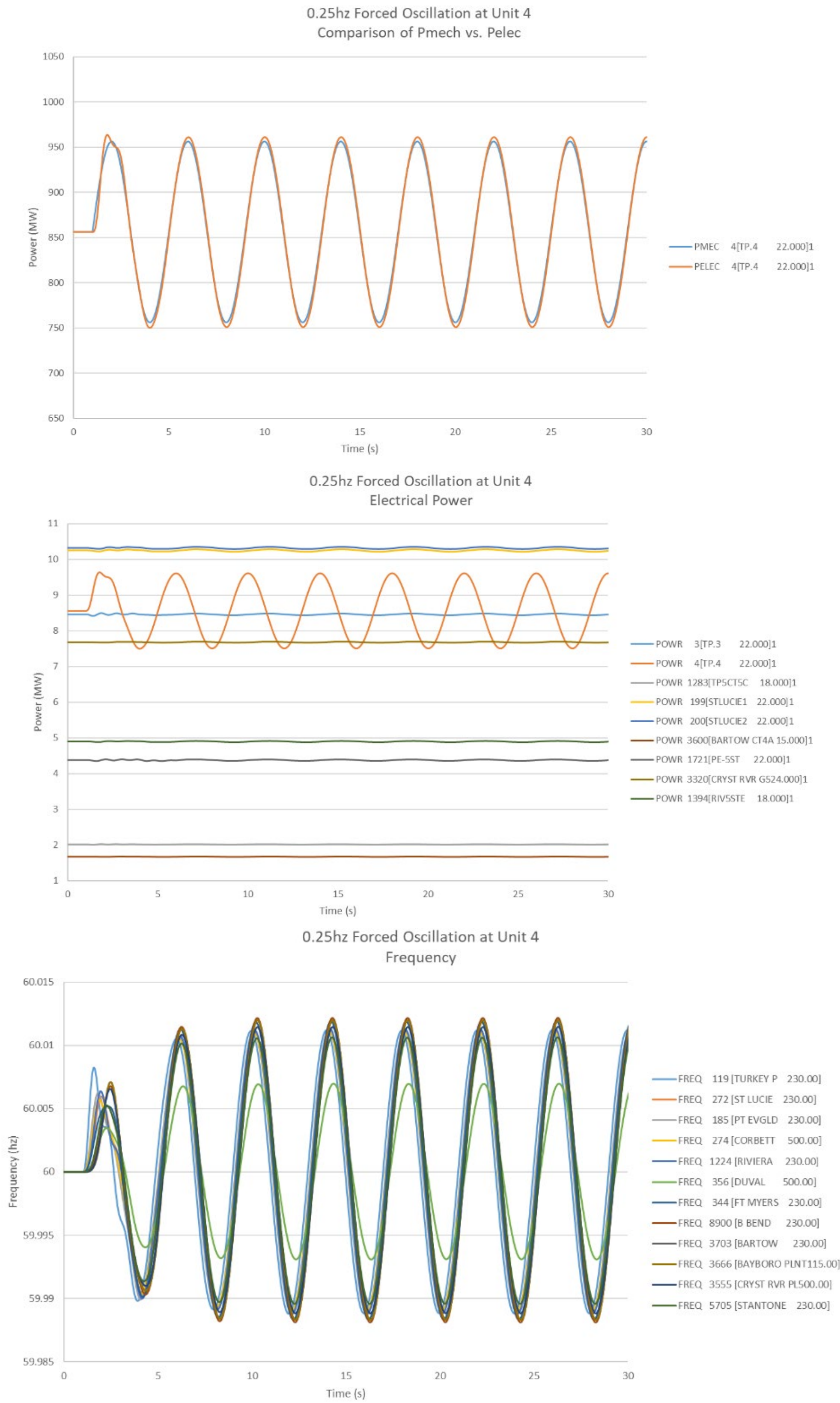

Figure A.4: Local Forced Oscillation

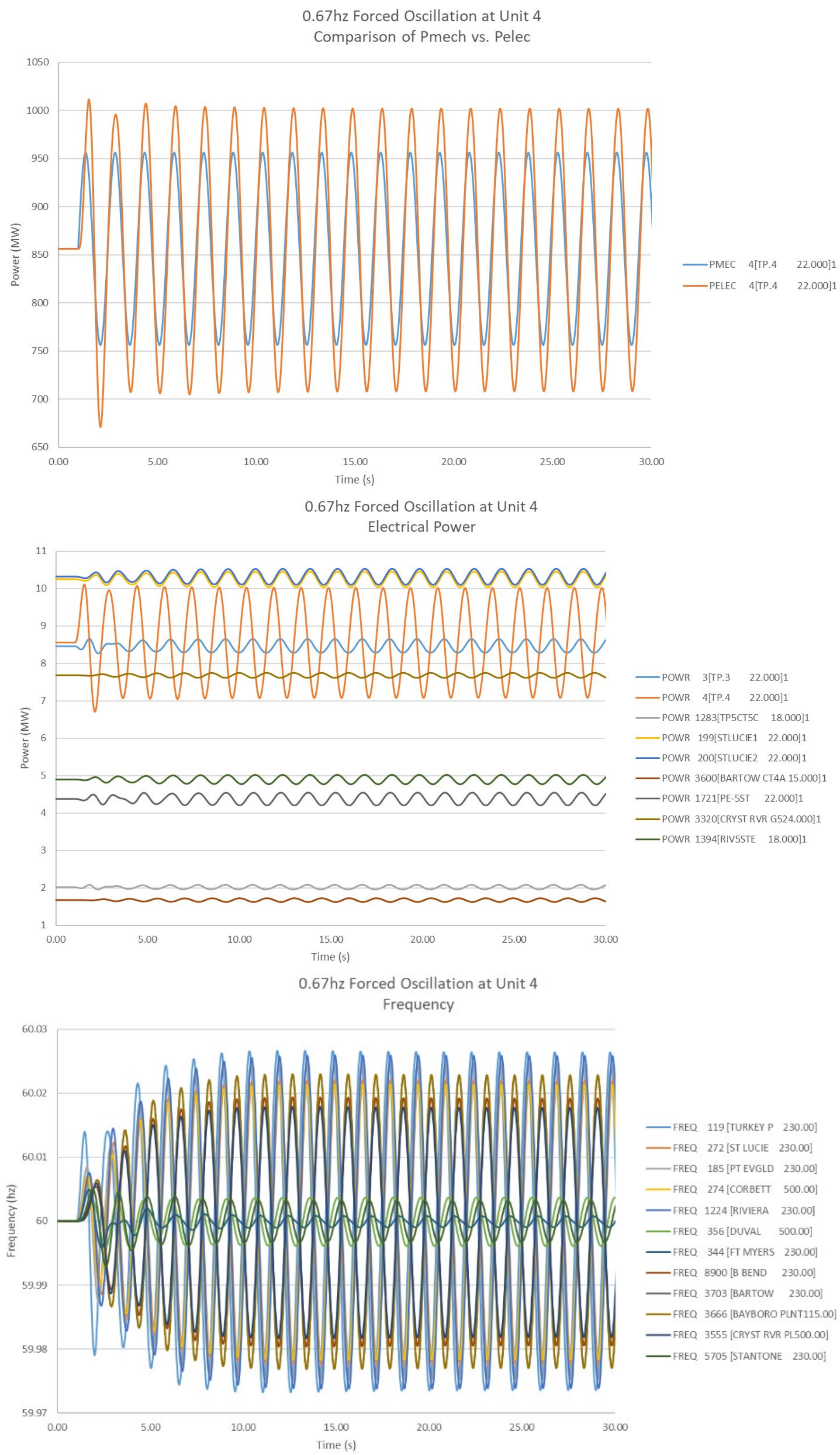

Figure A.5: Wide-Area Resonant Forced Oscillation

Appendix B: Contributors

NERC would like to thank all members of the NERC SMWG for their participation and guidance in developing this report. The following list of contributors were involved in the development of this report.

Table B.1: Contributors

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