NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interconnection Oscillation Analysis

Reliability Assessment

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RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

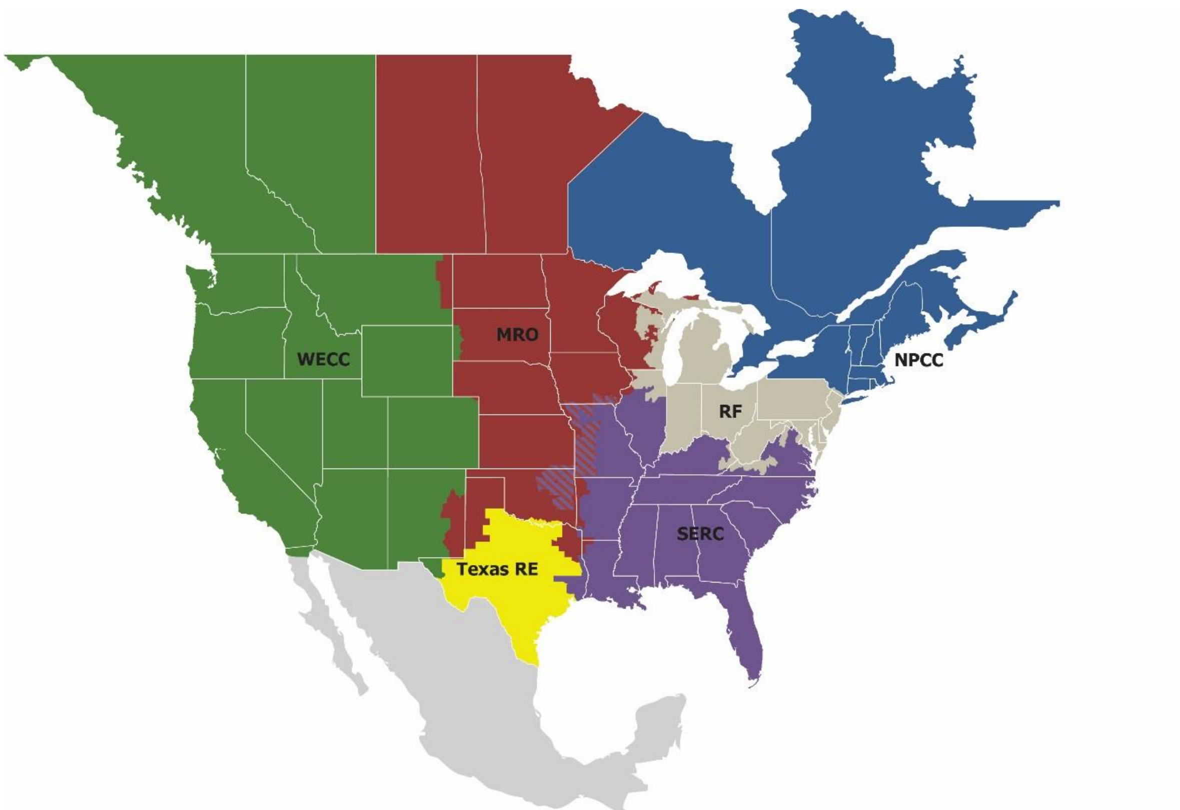
Preface

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 (REs), 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 divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



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

Executive Summary

Historically, each of the Interconnections has seen oscillatory events on the BPS with a prevailing amount of the post-event analysis constrained to specific portions of the Interconnections. This report aims to demonstrate the natural system oscillatory modes and to display the mode shapes for the dominant modes and their characteristics. These oscillatory modes, previously not well understood in some cases, should be closely monitored, studied, and simulated in order to conclude their characteristics. The intent of this report is to inform on mode shapes and behaviors and not to provide mitigation strategies for oscillatory events.

Key Findings

For all the chosen events for analysis for all Interconnections, only a handful of events exhibited forced oscillatory behavior and all resonance effects were deemed to be mild; this indicates that the conditions surrounding the event were not as severe as they could have been given the resonance conditions. Of these events, a total of six dominant modes were prominent. Each mode was given a name that describes the general shape of the mode where a previous name has not already been given. The frequency range and average damping ratio is provided for these modes in **Table E.1**. Throughout this report, references to modal damping ratio and frequency are provided but are not the focus of this report as system conditions will impact the frequency and damping ratio of the natural system mode. Whenever the damping ratio is "well damped" (or greater than 10%), the signal oscillation dampens down so quick that the numerical percentage is not as relevant; however, this does not indicate "poor damping" below 10%. Damping ratio performance criteria can be found in individual Reliability Coordinator (RC) system operating limit methodologies and discussion of such performance is out of this document's scope.

Table E.1: Dominant Mode Characteristics

Interconnection	Mode Name	Mode Frequency Range (Hz)	Mode Average Damping Ratio (%)
Eastern	NE–S	0.16–0.22	9.70
	NW–S	0.29–0.32	16.45
	NE–NW–S	0.23–0.24	12.80
Texas	N–SE	0.62–0.73	9.26
Western	NS Mode A	0.37–0.42	12.71
	NS Mode B	0.24–0.27	13.525

Recommendations

Based on the oscillation analyses performed and the key findings described above, the following recommendations are provided to enhance the understanding of interarea oscillations of the BPS:

- Each Planning Coordinator (PC) and RC should continue oscillatory studies for their respective Region. This includes using the mode shape plots[1] to further explore which set of generators participate in exciting these modes. Other sensitivities to consider are path flows and source-sink relationships. These studies should be pre-emptive in identifying mode shapes and performing verification on identified modes.
- The RCs and phasor measurement unit (PMU) industry should develop a standardized format for submitting PMU data for off-line oscillatory analysis as there were consistency issues in this data set. Standardization should include the types of measurements as well as the data format for those measurements.

[1] See *Detailed Event Analysis* Report here

- The Western Interconnection (WI) should improve the understanding of the east–west modes, specifically how Montana and Colorado participate in this mode.
- The Texas Interconnection (TI) should increase the PMU coverage from its northwestern region for greater observability of system oscillatory characteristics.
- The Eastern Interconnection (EI) should perform tests or studies to better understand the two modes near 0.25 Hz since these modes are observed across the entire Interconnection and demonstrate changing mode shapes.
- The EI should also track the 0.78 Hz forced oscillation source observed in many of the events and monitor the mode shapes of the interarea modes in the frequency range of 0.67 to 0.8 Hz. In particular, it would be useful to understand why these shapes do not extend into the New York/Canada regions in the north and do not extend into the Florida region in the south.
- Each RC should ensure adequate training and support for system operators and ensure coordination among neighboring RCs regarding how to handle wide-area oscillation events.
- The commercially available positive sequence RMS stability simulation tools should have the capability to model injection of forced oscillations at many source locations. This would improve the benchmarking between Interconnection-wide models and actual grid events.
- Transmission Owners (TOs), in coordination with their PC and RC, should consider visibility of interarea oscillations when identifying placement for future PMUs. PMU placement in areas of low visibility will improve the understanding of the natural modes and eliminate uncertainties in the analysis of these modes.

Introduction

Oscillations across all Interconnections in North America have been observed over the years with different phenomena as their causes. Some are localized to one or a group of power plants while others are experienced across a wide area. The WI, for example, has spent significant effort to understand the oscillatory behavior of that Interconnection due the small signal stability risks experienced in the 1996 blackout[2] and continued oscillatory risks during highly stressed operating conditions that are rare. Other Interconnections have not collectively analyzed the oscillatory modes of their system using wide-area, time-synchronized data. However, with the proliferation of PMUs and other types of disturbance monitoring equipment (DME), the industry is equipped with the measurements and capability to perform such analysis to better understand interarea system modes. The purpose and goals of this effort include the following:

- Use synchronized measurements across the Interconnection during grid disturbances or abnormalities to baseline the oscillatory performance of the Interconnection
- Provide the industry with a better understanding of interarea modes and forced oscillations on the BPS
- Recommend improvements to monitoring BPS behavior and identifying oscillatory conditions or sources, if and when they occur
- Use measured data during BPS disturbances to compare the modal characteristics of the planning models used in transient stability studies (compare model versus actual oscillations) as a component of system-wide model validation

This analysis involved coordinating with the REs and all RCs to collect wide-area PMU data. Data was also collected from the University of Tennessee–Knoxville (UTK) GridEye/FNET system. Lastly, NERC coordinated with the MOD-032 Designees[3] in order to perform benchmarking of planning cases against the actual oscillation events. These analyses are described in this report as a way to demonstrate oscillatory characteristics of each Interconnection. The intent of this report is to inform on mode shapes and behaviors and is not to provide mitigation strategies for oscillatory events.

This report begins with background information on the historic events found in some of the Interconnections and briefly overviews the dominant characteristics of each Interconnection. The measurements and data collection process for the study work contained in this report is also overviewed.

The later chapters detail each Interconnection's results pertaining to the top dominant modes over the chosen oscillatory events. Each mode was characterized by the parameters and named accordingly. In addition to the PMU recorded events, the analysis group benchmarked the Interconnection-wide planning cases that simulate the triggering event. The results of these benchmarked events was also tabulated and compared to the dominant modes found in the measured data. Other benchmarking work included the effects of frequency versus angle data sources, changing system-wide inertia, and an exploratory analysis of oscillatory characteristics on WI planning models. Based on the analysis, the analyzers were able to conclude that the planning cases were adequate for capturing the first dominant mode for a particular event and demonstrate the effects of many variables on the oscillatory mode characteristics. Between these benchmarking conclusions and the measured conclusions, this report projects a set of key findings and recommendations for future analysis and other studies.

The appendices of this report detail the fundamentals of oscillation analysis, the interaction of system natural modes and forced oscillations, previous oscillatory analyses, as well as the detailed analysis performed for each event in this

[2] https://www.nerc.com/pa/rrm/ea/System%20Disturbance%20Reports%20DL/1996SystemDisturbance.pdf.

[3] The current list of MOD-032 Designees can be found in this document

report. This report provides the high level results of each Interconnection while the appendices detail the event background and other particulars regarding the analysis.

Background on Historical Oscillation Events

A number of large-scale outages and near miss events have included oscillations as either a cause or effect of the event. This section provides examples of interarea oscillation events as well as events with interaction between system modes and forced oscillations.

WSCC August 10, 1996, Disturbance

On August 10, 1996, at 15:48 PDT, a sequence of events caused the WI to separate into four electrical islands. System conditions included high summer temperatures in much of the Interconnection, heavy exports from Canada across the Pacific Northwest into California, and 500 kV line outages in Oregon. The California–Oregon Intertie flow (about 4,350 MW) was within limits established as an outcome of the July 2–3 outages that had just recently occurred. Flow on the Pacific DC Intertie was 2,848 MW.

At 15:47:36 PDT, system protection removed the faulted Ross–Lexington 230 kV transmission line, also tripping the Swift generating units (207 MW). Reactive output of the McNary hydro units increased to 480 MVAr and then to 494 MVAr. The units held at this level for a short time until system protection began removing them from service. Between 15:47:40 and 15:49 PDT, all 13 units at McNary were removed from service as a result of erroneous operations of a phase unbalance relay in the generator exciters.

As the McNary units tripped due to high reactive power output, a poorly damped interarea oscillation began across the BPS (see Figure I.1). Generation in the Upper and Lower Columbia River hydro projects picked up much of the lost generation, further stressing transfers across the system. Eventually, the oscillation became negatively damped. Shunt capacitors switched in key locations on the BPA system; however, the oscillation continued, and the Pacific DC Intertie also began oscillating in response to the poor ac voltage. As the oscillations reached about 1,000 MW and 60 kV peak-to-peak at Malin 500 kV substation, voltage collapsed. This severed the ties between the Pacific Northwest and California and eventually caused the other ties between California and its neighbors to also open due to low voltage and out-of-step protection.

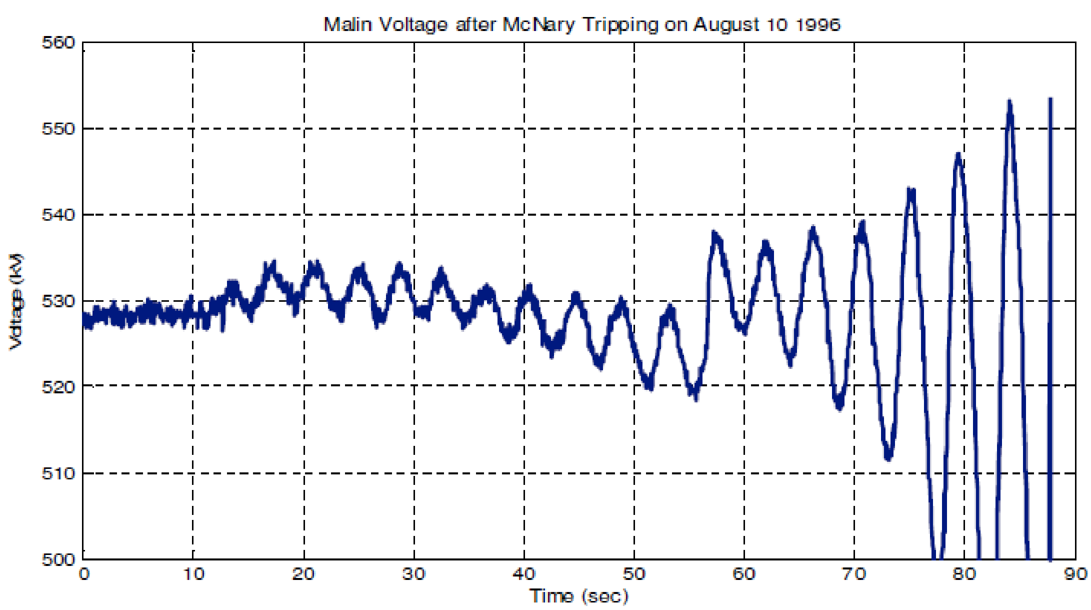


Figure I.1: August 10, 1996, Oscillation [Source: BPA]

WSCC August 4, 2000, Alberta Separation

On August 4, 2000, Alberta disconnected from the rest of the WSCC system, separating its one 500 kV and two 230 kV ties between Alberta and British Columbia systems. While this separation is studied and is planned for, this particular event resulted in marginally damped interarea oscillations that occurred after the separation (see **Figure I.2**). The oscillation continued for more than 60 seconds. While the separation did not cause any widespread instability or outage, it did identify a poorly damped interarea mode worth further investigation and study.

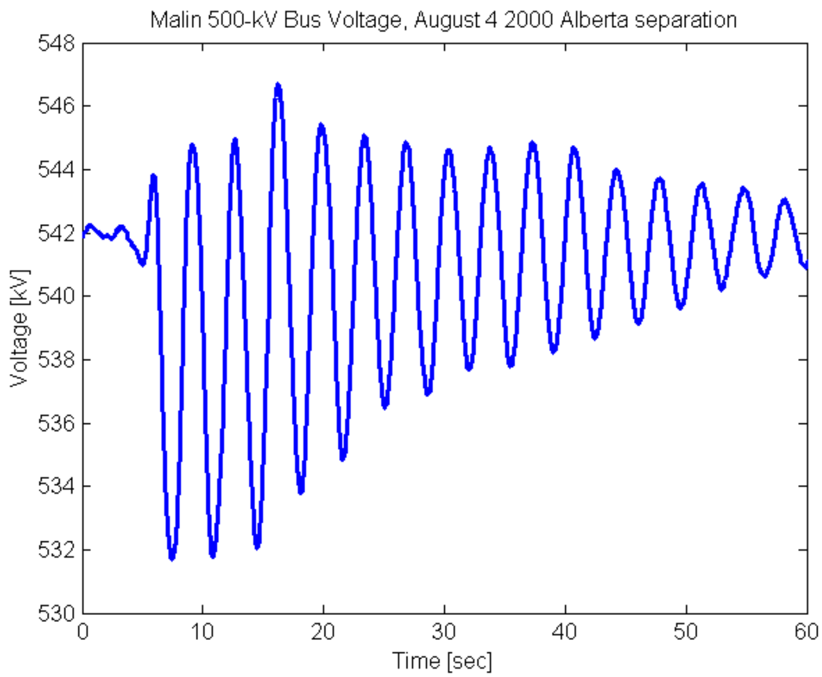


Figure I.2: Bus Voltage for Aug 4, 2000 Separation [Source: BPA]

WECC November 29, 2005, Oscillation Event

In November of 2005, a failed control valve at Nova Joffre cogeneration facility in Alberta, Canada caused a 20 MW peak-to-peak oscillation to occur at 0.27 Hz. The WI has a system mode at about that same frequency. The forced oscillation due to the failure at the plant excited the North-South system mode, resulting in 200 MW peak-to-peak oscillations on the California–Oregon Intertie (see **Figure I.3**). For about five minutes, the oscillation persisted until the steam supply diminished. This event is useful in illustrating the importance of identifying system modal characteristics to understand how unexpected forced oscillations can interact with the system modes.

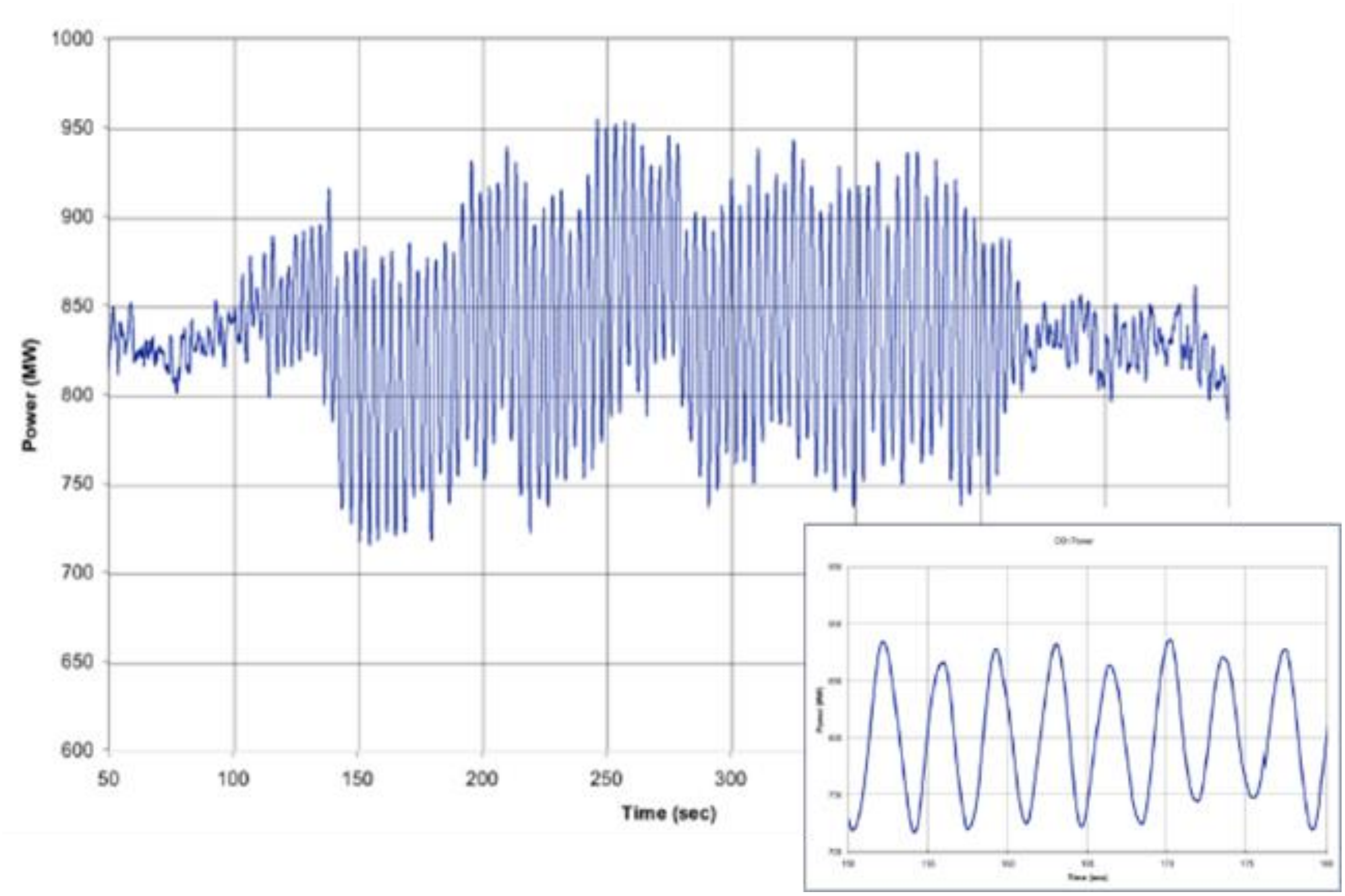


Figure I.3: California–Oregon Intertie Flow during November 2005 Oscillation [Source: BPA]

WECC September 5, 2015, Oscillation Event

On September 5, 2015, Peak Reliability's on-line modal analysis software indicated very low damping for the "North-South Mode B." At the time, there were no significant changes in transmission topology, generation, or loading to explain the sudden decrease in damping. After investigation, Peak determined that a forced oscillation from a relatively small 30 MVA machine in the Nevada area was the actual problem. Real power flow on a nearby line showed oscillations on the order of six MW peak-to-peak; however, the oscillation was experienced across the WI since the forced oscillation frequency (0.395 Hz) occurred near a system mode (0.403 Hz). Though the mode's damping was unchanged, the presence of the forced oscillation confused the modal analysis software. Since this event, algorithms and tools have been developed to prevent similar confusion in the future. Results from a post-event analysis showing both the mode and the forced oscillation are presented in **Figure I.4**.

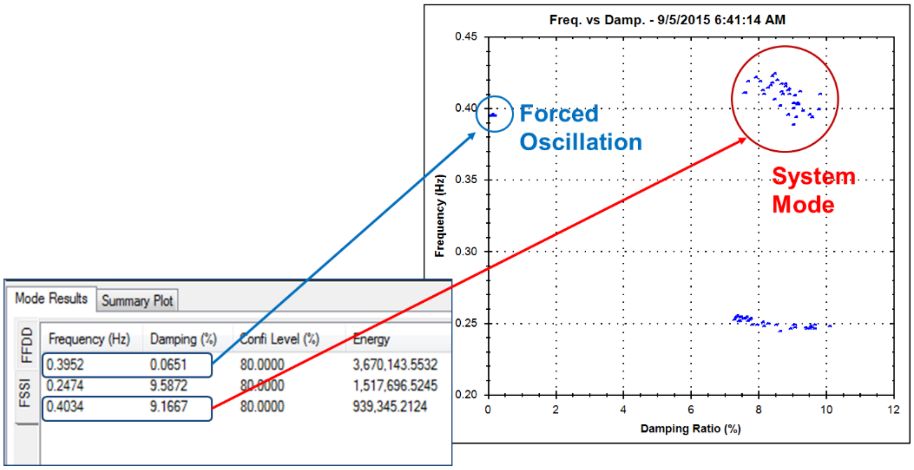


Figure I.4: Analysis of September 2015 Oscillation Event [Source: Washington State University]

Eastern Interconnection June 17, 2016, Oscillation Event

On June 17, 2016, a forced oscillation in the EI occurred at 0312 Eastern Daylight Time around 0.27 Hz. The EI has a system mode near that frequency that resulted in an interaction between the forced oscillation and system mode at that frequency. This caused the forced oscillation to show up across the system. The source was determined to be a control valve malfunction at Grand Gulf Nuclear Station (GGNS) in Entergy footprint; however, power oscillations were seen across the entire EI system. **Figure I.5** shows the two line flows (green and blue trends) capturing GGNS output. Because of the interaction with the eastern system mode, the 200 MW forced oscillation at Grand Gulf resulted in 40 MW tie line oscillations on one of the New York to New England lines about 1400 miles away (**Figure I.6**) from the source in Mississippi. This event is explained in more detail in **Appendix B**. An animation of the event has been prepared by the FNET GridEye monitoring system at University of Tennessee Knoxville.[4] The animation clearly shows interarea oscillations across the EI during this event.

[4] FNET videos: https://www.youtube.com/watch?v=1vuxZJitEJg&feature=youtu.be and https://www.youtube.com/watch?v=2YKb2yj1P_M&feature=youtu.be.

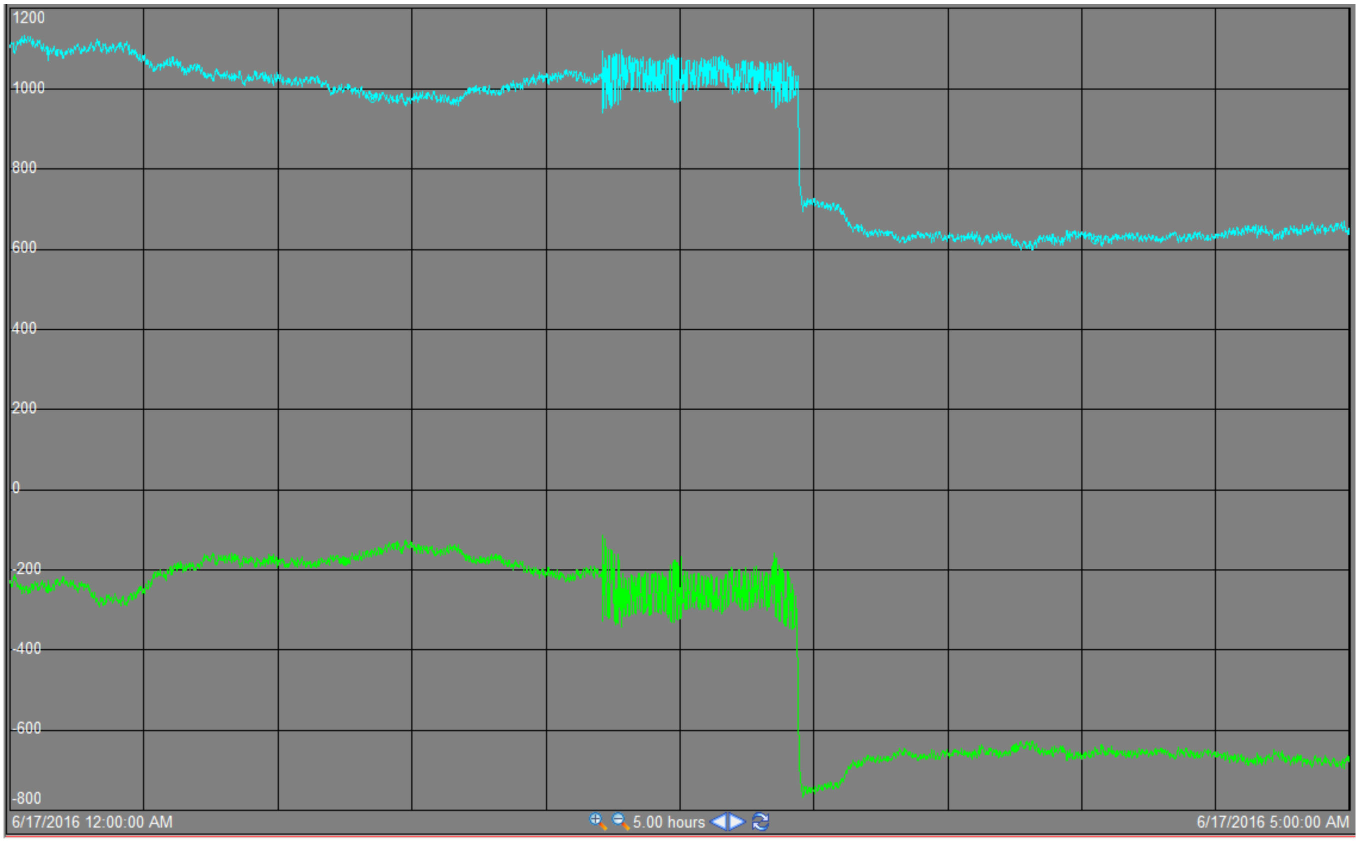


Figure I.5: Approximately 200 MW Forced Oscillation at GGNS [Source: Entergy]

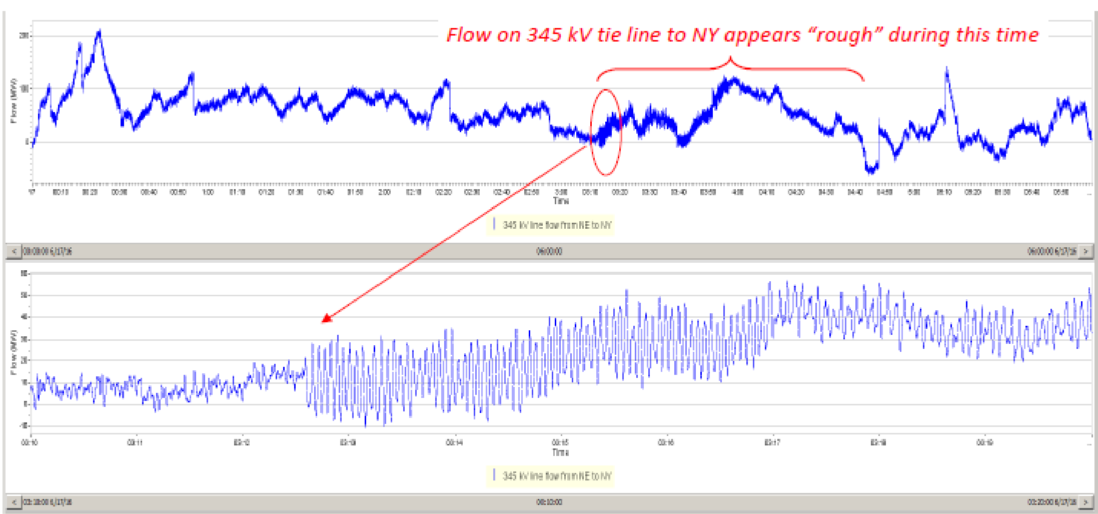


Figure I.6: Approximately 40 MW Oscillations Seen in New England Region [Source: ISO-NE]

Characteristics of Each Interconnection

The three major Interconnections in the North American power system, namely the Eastern, Western, and ERCOT Interconnections, have different oscillatory characteristics because of differences in generation-load patterns and the structure of transmission lines. The WI historically has been characterized by long transmission lines that carry power from generation rich regions, hydro plants in Northwest America and Western Canada, coal plants and wind energy farms in Montana and Wyoming, down to load centers in California. The WI has experienced major events associated with interarea mode oscillations where the generators in the North were swinging against the generators in the South across the long distance transmission lines. The EI, on the other hand, has a mesh-like transmission line structure where the oscillatory properties are more complex and can change depending on the nature of power exchanges across different regions in the EI. This characteristic is true for most sections of the EI except for the upper Midwest region, which is transmission sparse in comparison to the coastal regions. The TI, like the WI, has clear distinct oscillatory modes because of the north-to-south power exchanges. Moreover, the smaller size of the TI compared to EI and WI makes it more sensitive to changes in system inertia and transmission support. The fast growth in wind energy sources in the western portion of Texas has introduced more variability in the transmission line flows in the TI system. In general, the increasing penetration of renewable energy sources in all Interconnections points to a continuously evolving nature of oscillatory modes in the Interconnections and emphasizes the need for regular monitoring of the system modes for understanding their significance and implications.

Measurement Infrastructure

A PMU is a device that measures the electrical quantities on the grid using a synchronized time source. Time synchronization is usually provided by the global positioning system, providing a high accuracy, common-time reference for measurements taken across the grid. The PMU then converts the sinusoidal time series measurement of voltage and current into a phasor representation. A phasor is a complex number that represents both the magnitude and phase angle of the voltage and current sinusoidal waveforms (60 Hz) at a specific point in time (see Figure I.7). The resulting measurement is known as a synchrophasor, and these measurements are typically reported at rates of 30-60 samples per second. Compared with conventional measurement technologies, such as the supervisory control and data acquisition (SCADA) systems that provide system measurements once every two to four seconds, the higher resolution and time synchronization of PMU technology enables significant improvements in monitoring, control, and BPS performance analysis.

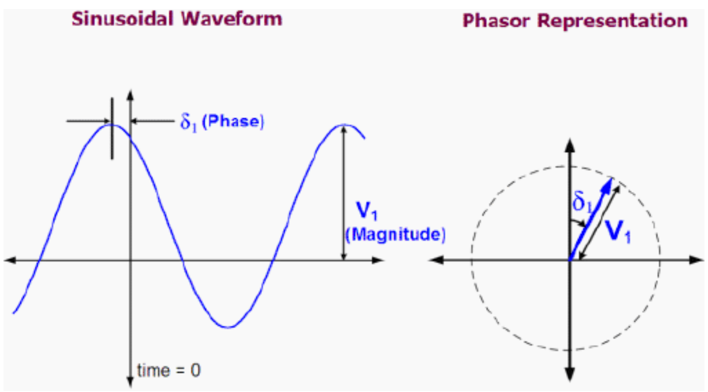


Figure I.7: Sinusoidal Waveform and Phasor Representation [Source: CERTS]

Synchrophasor systems consist of PMUs installed throughout the grid that send measurements over a reporting protocol, IEEE Std. C37.118.[5] The streams of C37.118 measurement frames are aggregated and time aligned at a device called a phasor data concentrator (PDC). Once the synchronized measurements have been collated, checked

[5] For history of the C37.118 standards development, see relevant IEEE standards:

- 1344-1995 IEEE Standard for Synchrophasors for Power Systems
- C37.118-2005 IEEE Standard for Synchrophasors for Power Systems
- C37.118.1-2011 IEEE Standard for Synchrophasor Measurements for Power Systems
- C37.118.1a-2014 IEEE Standard for Synchrophasor Measurements for Power Systems–Amendment 1: Modification of Selected Performance Requirements
- C37.118.2-2011 IEEE Standard for Synchrophasor Data Transfer for Power Systems

for data quality, etc., they are provided to historians and advanced applications (either off-line or real-time) for further processing and use. The PMUs are generally owned by the equipment owners, such as TOs and Generator Owners (GOs). PMU data is often sent to a central PDC (or sometimes first to a substation PDC) that is either owned by the TO or may be owned by the RC. If not streamed directly, data is passed from the TO to the RC for a wide-area view of the system. In some cases, not all synchrophasor data is sent from the TO to the RC; rather, a reduced set of key measurements are selected for RC observability and use.

With the help of the Recovery Act Smart Grid Investment Grant projects and DOE-sponsored efforts related to synchrophasor technology, the North American power grid has seen a vast deployment of PMUs over the last decade. Thousands of PMUs have been deployed across all Interconnections, unlocking visibility into grid dynamics and improved monitoring capability. **Figure I.8** shows the map of PMU installations as of 2015, created by the North American Synchrophasor Initiative (NASPI).[6]

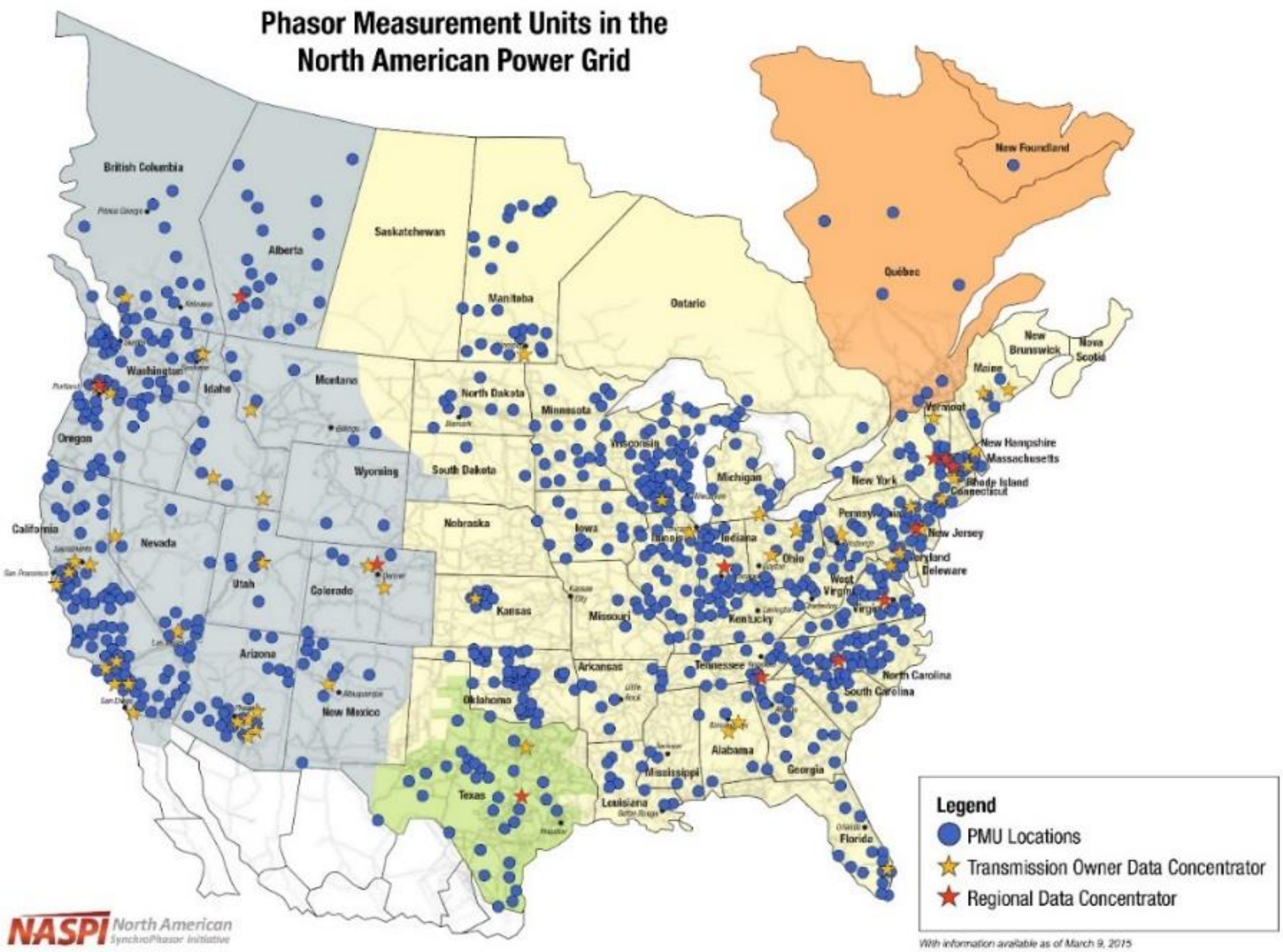


Figure I.8: Synchrophasor Deployment Map–2015 [Source: NASPI]

Data Collection Process

In June 2016, the NERC Synchronized Measurement Subcommittee (SMS) scoped out a data collection process in coordination with the RCs and REs to collect wide-area, time-synchronized PMU data for disturbance events for the

[6] https://www.naspi.org/.

purposes of analyzing the oscillatory behavior of those events. The data collection process also served to test the ability to gather Interconnection-wide data in large quantities for future event analysis if needed. Each data request was coordinated with the NERC SMS as well as the RCs to ensure a reasonable yet thorough collection of data across a wide ranges of events. RCs have the wide-area view and stream real-time PMU data from the respective equipment owners. Generally, the RC only receives select measurements that are determined valuable for the wide-area perspective. These measurement locations are ideal for oscillation analysis studies and provide wide-area coverage of key BPS locations. The data reporting duration, measurement requirements, formatting requirements, and submission process can be found in the *Oscillation Analysis Scope Document*.[7]

[7] https://www.nerc.com/comm/PC/Synchronized%20Measurement%20Subcommittee/SMS%20-%20Interconnection-Wide%20Oscillation%20Baselining%20and%20Data%20Collection%20Scope%20Document%20-%2012-14-2015.pdf.

Chapter 1: Oscillation Analysis Results

NERC used a set of oscillation ringdown analysis as described in **Appendix A** in an attempt to identify the modal properties of each Interconnection based on the wide-area PMU data collected. The results of such analysis techniques are averaged across similar-looking mode shapes and provide the initial study efforts into understanding the modal characteristics of each Interconnection. The analysis window was chosen using engineering judgment to avoid any nonlinearities or discontinuities in the signals analyzed, and to capture a high signal-to-noise ratio (SNR) in the event data.

To describe the high-level oscillatory behavior across the Interconnections, the U.S. Census Regions[8] were used (where possible). Where the U.S. Census Regions were too general or nonexistent (i.e., Canadian Providences), a more detailed geographic region was used. This was chosen as an effective way to describe wide-area modes, and is used throughout this report and in the detailed analysis document.[9] Multiple sections in this chapter utilize the data found in this companion document and should be read alongside the findings discussed here. Results for each Interconnection are summarized in the following subsections with the major mode shapes and characteristics defined.

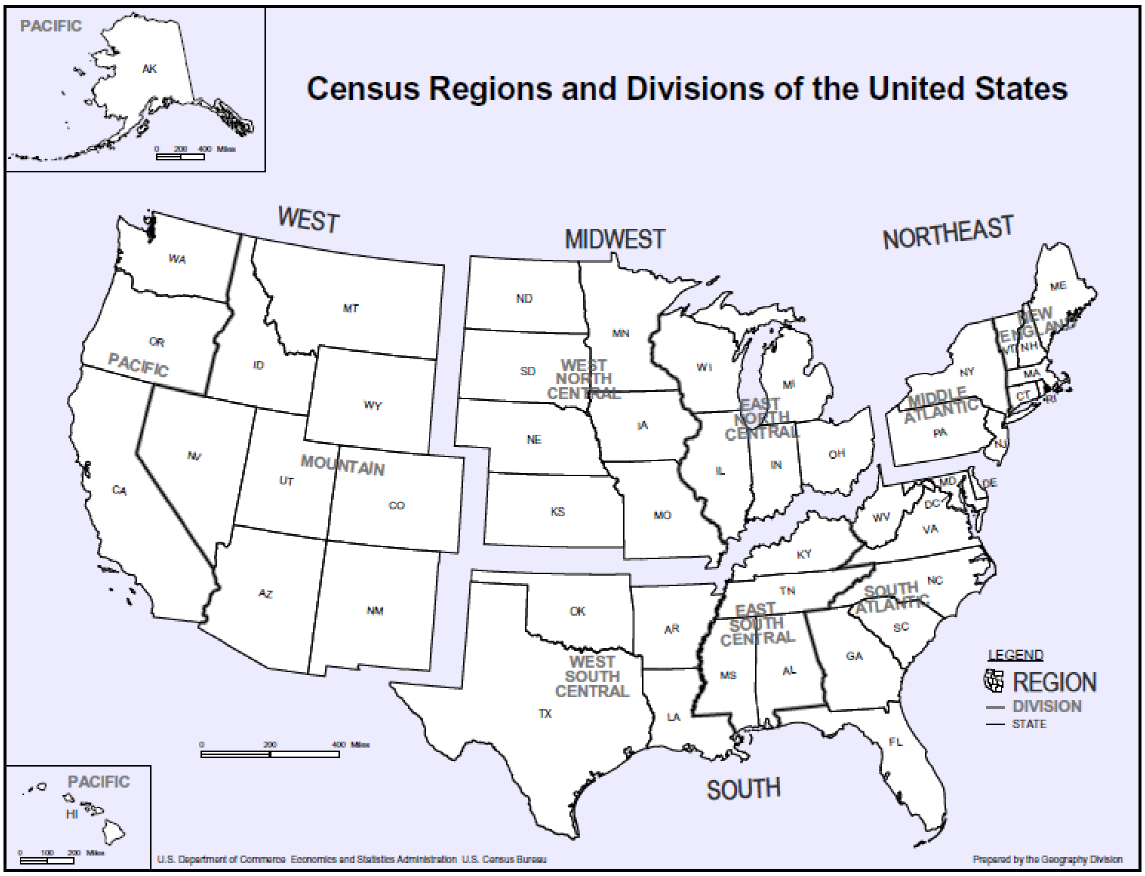


Figure 1.1: U.S. Census Regions used to Describe Oscillation Mode Shapes [Source: U.S. Census Bureau]

[8] https://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf.
[9] See *Detailed Event Analysis* Report here

Eastern Interconnection

A number of system modes were observed in the EI in each event analyzed; however, two modes appear to be regularly excited. The EI modes have been observed to be well damped in the events chosen. Coupling these well damped modes with the knowledge that the PMU coverage in the EI is sparse compared to the number of substations, the ringdown analysis proved challenging to get realistic results.

In general, generation tripping near the areas of strong participation excite a North to South mode from the New England to South Atlantic regions; however, some events indicate an interaction with the Midwest region as well. **Table 1.1** holds the most common mode frequencies and their damping ratios with respect to each event. For these events in **Table 1.1**, the mode shapes primarily have two distinct areas swinging against the other with a few other intermediary areas between these areas. For the 0.16–0.22 Hz mode the two major regions are the North and South portions of the EI, primarily in the South Atlantic regions against the North East regions. The 0.29–0.32 Hz mode is largely defined by the same North to South regions with some interactions between the Eastern and Western portions of the EI. In comparison, the 0.23–0.24 Hz mode has a clearly defined interaction between three regions between the Midwest, South Atlantic, and New England regions. Further investigation on the 0.23–0.24 Hz mode shape is warranted to understand the interaction with the two identified possible representations of the mode shape. Current data demonstrates a possibility that two modes exist near the same frequency of 0.24 Hz with the South Atlantic being one tail end of the mode, but the interactions between the other regions are still unclear. As Events 3 and 4 were forced oscillation events, a ringdown analysis was not applied and thus are not included in **Table 1.1.**

Table 1.1: Damping Ratio Mode Comparison for Non-Forced Oscillation Events

Mode Frequency (Hz)	Event 1 Damping Ratio (%)	Event 2 Damping Ratio (%)	Event 5 Damping Ratio (%)	Event 6 Damping Ratio (%)	Event 7 Damping Ratio (%)
0.16–0.22	NO	13	8.3	7.8	NO
0.29–0.32	NO	20	NO	12.9	NO
0.23–0.24	13.4	NO	NO	NO	12.2

Note: NO–Not Observed or Well Damped

The forced oscillations presented in **Table 1.2** are representative of the modes found in Events 3 and 4 in the Interconnection analysis. While the forced oscillation was present, it excited the indicated natural system mode shapes. The participation factor for the forced oscillation source in the nature system modes was small in Events 3 and 4. As a result, spectral proximity to the natural system model frequency is the primary cause for the small resonance effects. Should the system mode shapes become less damped, the results of **Table 1.2** would indicate the higher resonance effects.[10]

[10] S.A.N. Sarmadi, and V. Venkatasubramanian, ``Interarea Resonance in Power Systems from Forced Oscillations," IEEE Trans. Power Systems, January 2016, Vol. 31, No. 1, pp. 378–386.

Table 1.2: Interaction of Forced Oscillation and Interarea Modes			
FO Frequency (Hz)	0.3 Hz System Mode	0.67 Hz System Mode	0.76 Hz System Mode
0.28[11]	S	NO	NO
0.75[12]	NO	S	S
0.70[13]	NO	S	S

Note: S–Mild Resonance Effects; M–Medium Resonance Effects; H–High Resonance Effects; NO–Not Observed

The two forced oscillation events in the EI found that the resonance effect between the forced oscillation frequencies and the natural system modes were mild across all of the modal frequencies. Both events had a 0.75 Hz forced oscillation on the system that excited mode shapes near the system mode frequency. Events 3 and 4 forced oscillation resonating with the natural system modes confirmed the natural system mode shapes found in the ringdown analysis performed on the other chosen events. **Figure 1.2** shows this interaction and the natural system modes the forced oscillation resonated with follow the ringdown shapes seen in other events. Where the spectral density (dB/Hz) was high, it demonstrates the signal contained those components. Thus, when there are peaks in the lower regions, the analyzers were able to conclude these system modes resonated during the forced oscillation. Event 4 primarily followed this interaction, but since the excitation source of the forced oscillation was different, it was not as prevalent across the system. The unique aspect in Event 3, however, was the addition of a 0.28 Hz forced oscillation that excited the complex mode shape in a manner that was slightly larger than the 0.75 Hz forced oscillation. The analysis team found the Mississippi location to have a strong participation in exciting the system mode. For details on the analysis and the accompanying mode shapes, see the companion document.

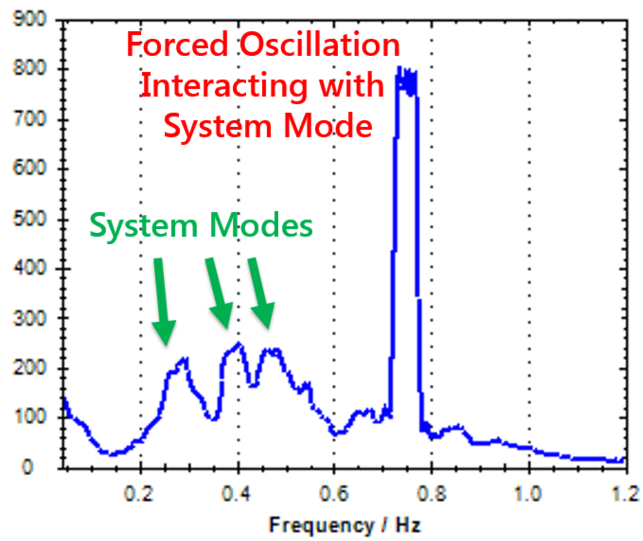


Figure 1.2 Event 3 0.75 Hz Forced Oscillation Interactions with System Modes

Some examples of the mode shapes discovered are in **Figure 1.3** to **Figure 1.5**. These mode shapes can change shape slightly based upon system conditions. The detailed event report contains each mode shape result on a per-event basis. As the current data allows for two distinct mode shapes for the 0.23-0.24 Hz mode, both are reported in **Figure 1.5**.

[11] The June 17, 2016, event (Event 3) discusses this.
[12] Several events discuss this FO; it is mainly persistent in Event 3 and 4.
[13] The November 27, 2016, event (Event 4) discusses this.

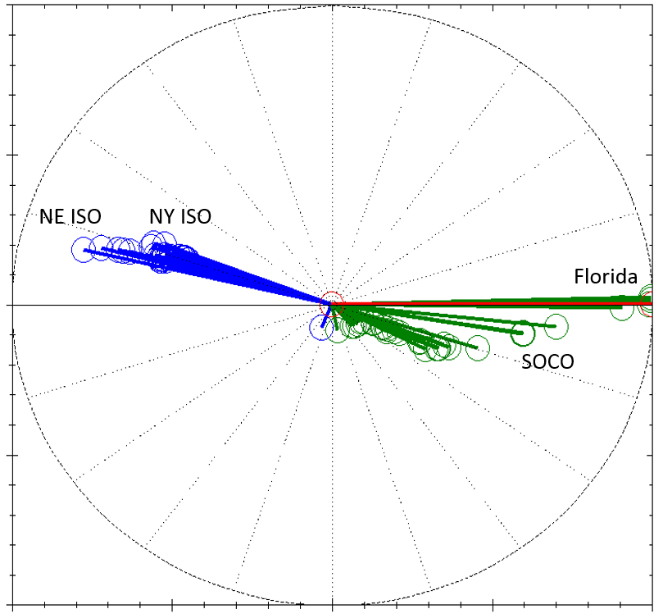


Figure 1.3 Mode Shape Plot for 0.16-0.22 Hz Mode

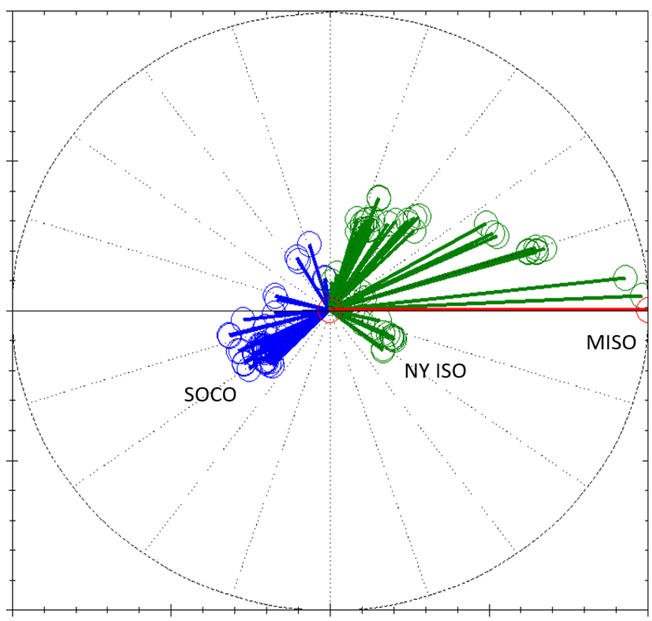


Figure 1.4 Mode Shape Plot for 0.29-0.32 Hz Mode

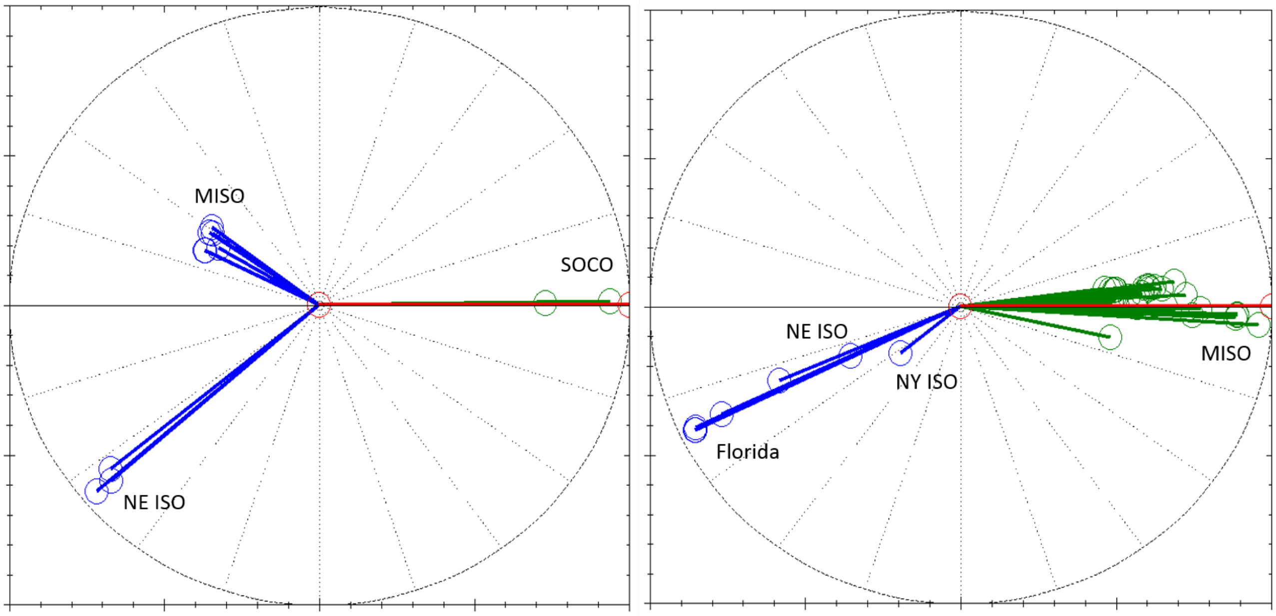


Figure 1.5 Mode Shape Plot for 0.23-0.24 Hz Modes (Left: Event 2, Right: Event 5)

It is possible to investigate how the mode shapes change with different operating conditions as the data demonstrates that these might influence oscillatory response. Events 2 and 5 had a very similar excitation location and the mode shapes between Events 2 and 5 demonstrate that they are the same mode; however, the frequency estimate of the mode in Event 2 is 0.17 Hz and Event 5 is 0.22 Hz. Further investigation is recommended.

For the two forced oscillations events studied, the resonance effects were deemed to be mild. The forced oscillation had a similar frequency to a system mode; however, the system mode was well damped and the forced oscillation did not occur in a location with strong participation with the observed system mode. In Event 3 (June 17, 2016), the 0.3 Hz mode shape (**Figure 1.6**) demonstrates a high participation of the 0.28 Hz forced oscillation source in the 0.3 Hz mode shape; however, that geographic location did not have a high participation factor in the natural system mode. The proximity of the forced oscillation's frequency to this natural system mode's frequency is the leading cause of why such a large oscillatory response was seen.

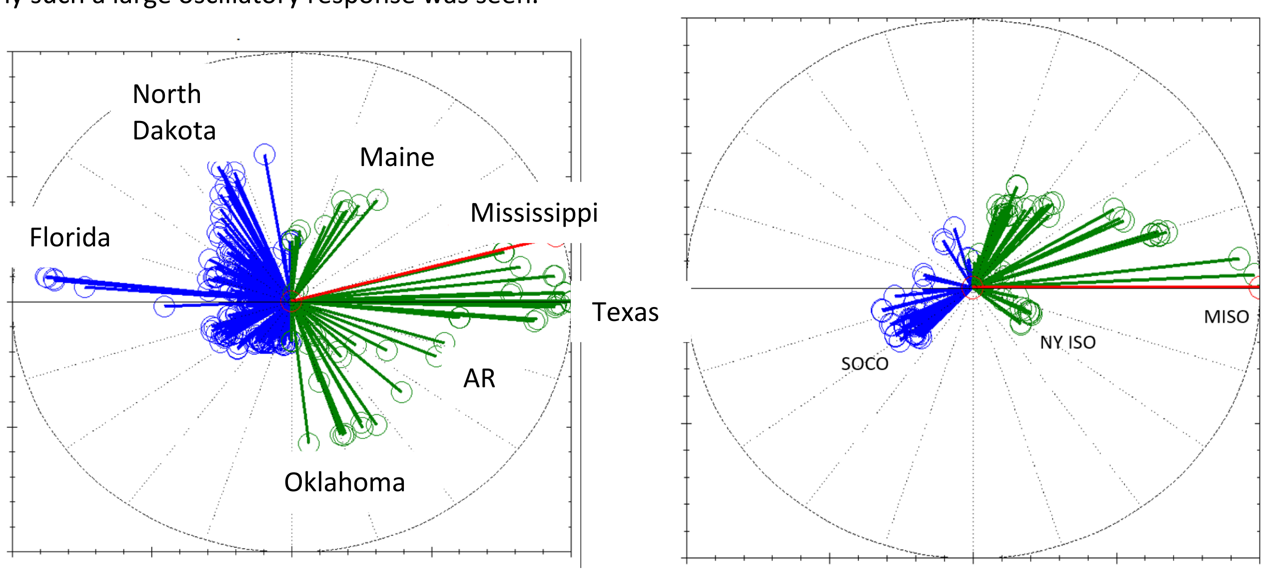


Figure 1.6 Event 3 0.28 Hz Forced Oscillation (left) Compared to Closest Natural System Mode (right)

Key Takeaways:

- The EI contains more complex mode shapes than other Interconnections. Each of the modes have at least three major regions that interact during ringdown events and the forced oscillation events resonated with these complex natural system modes. To complicate the situation, natural system modes in the EI demonstrate high damping ratios, meaning that the Signal to Noise Ratio for the interarea modes is low.
- The North East, Southern Atlantic, and Midwest regions contain high participation factors in the identified natural system modes.
- All oscillatory behavior had high (>10% on average) damping ratios for nonforced oscillation events. FOs resonated with well-damped (>4%) natural system modes for the events selected.

Texas Interconnection

In all the events analyzed, an oscillation mode with frequency of around 0.6–0.7 Hz was observed. **Table 1.3** shows how the damping ratio changed in each event analyzed. The mode is considered well damped across all the events.

Unlike the EI and the WI, the TI has lower damping ratios for the identified major mode with ranges on average below 10%. Based on the topology of the Interconnection, the regions are separated into generation rich and load rich areas, making this Interconnection similar to the WI but on a smaller scale. With this smaller scale, the oscillation risk due to specific contingencies may be higher. Transmission Planners (TPs) should continue to conduct studies that address the damping ratio of interarea modes. In addition, repeat analysis of these events would be better improved by more PMU coverage and would allow TPs to more accurately benchmark their model to real world events. **Figure 1.7** demonstrates the shape of the observed mode.

Table 1.3: Damping Ratio Mode Comparison

Mode Frequency (Hz)	Event 1 Damping Ratio (%)	Event 2 Damping Ratio (%)	Event 3 Damping Ratio (%)	Event 4 Damping Ratio (%)	Event 5 Damping Ratio (%)
0.62–0.73	7	9.9	10.2	8.2	11

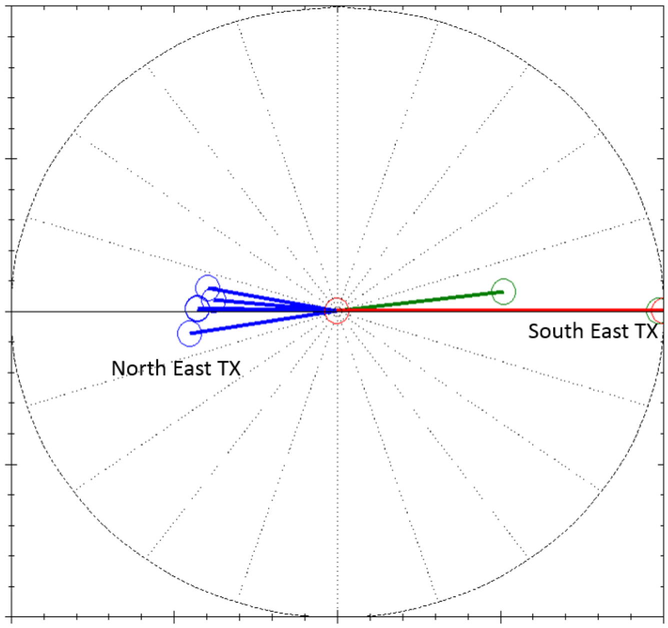


Figure 1.7 Mode Shape Plot for 0.62-0.73 Hz mode

Analyzing the TI PMU data proved to be challenging due to the lack of PMU signals provided by the RC. For all events, only a handful of PMU signals were provided, meaning that an error in any one of the signals could have a stronger impact on the overall results of the mode shape and oscillation characteristics. This lack of data was likely a contributing factor to only being able to identify a North Texas to South Texas mode shape (since it was challenging to identify any other cardinal directionality to the modes). More PMU signals are needed to further define the more localized regions that strongly participate in these modes and to rule out any other regional modes that might be at a lower energy than this dominant mode.

Key Takeaways:

- More measurement locations are required to fully visualize the interarea natural system mode.
- TI should continue to address damping ratios of interarea modes in their TP studies.
- TI can experience larger oscillatory behavior due to its small size, lower damping ratios (<10 percent), and topology.
- Participation factors are likely in areas between the generation rich and load rich areas.

Western Interconnection

System modal behavior has been well understood in the WI for many years from previous studies. The results presented here confirm some of the modes defined in those studies. In particular, the commonly referred to modes of N-S Mode A and N-S Mode B were observed in all events. These modes and their damping ratio for each event are listed in **Table 2.4**.

Table 1.4: Damping Ratio Mode Comparison							
Mode Frequency (Hz)	Event 1 Damping Ratio (%)	Event 2 Damping Ratio (%)	Event 3 Damping Ratio (%)	Event 4 Damping Ratio (%)	Event 5 Damping Ratio (%)	Event 6 Damping Ratio (%)	Event 7 Damping Ratio (%)
0.37–0.42	12	9.9	10.2	10.8	13.8	14	18.3
0.24–0.27	NO	8.6	18.2	9.8	NO	NO	17.5

The mode shapes for the defined modes can be found in **Figure 1.8** to **Figure 1.9**, which confirm the modes defined in the previous oscillations studies by other entities. For Event 4, the analysis proved to be more difficult due to the uniqueness of the event as it contained a very slow drop in frequency that seemed to have no oscillations in its data when viewing the relative bus frequencies. However, once the first derivative of the relative voltage angles was utilized, a realistic and reasonable damping ratio of the natural system mode, verified by ambient methods, was determined.

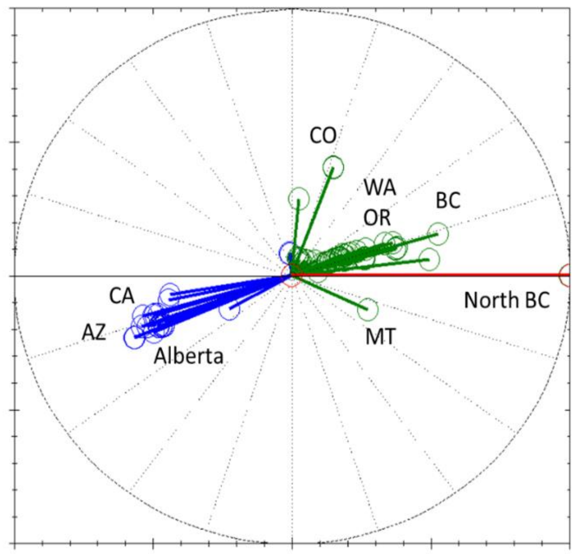


Figure 1.8 Mode Shape Plot for 0.37–0.42 Hz mode

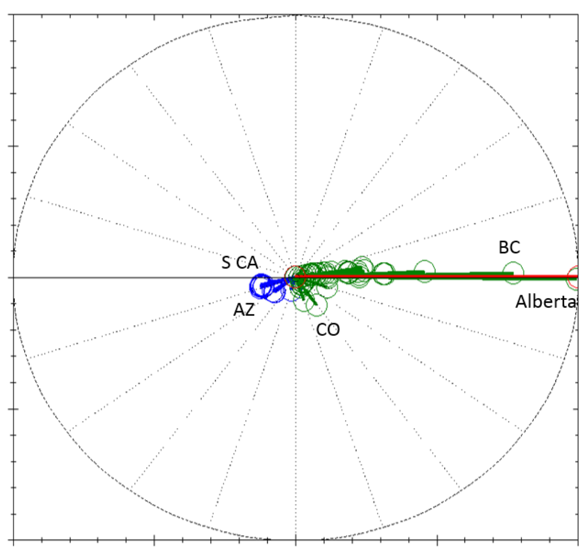


Figure 1.9 Mode Shape Plot for 0.24–0.27 Hz mode

The presence of a near 1.2 Hz local mode in the Montana region was found that did not fully match the interarea Montana mode identified in previous WI oscillations studies. This local 1.2 Hz oscillation (see **Figure 1.10**) mainly involved a few generators close to each other. The strong response of this 1.2 Hz mode, however, could not be duplicated in model simulations of the event that requires further study to understand the strong response of this local mode during the event.

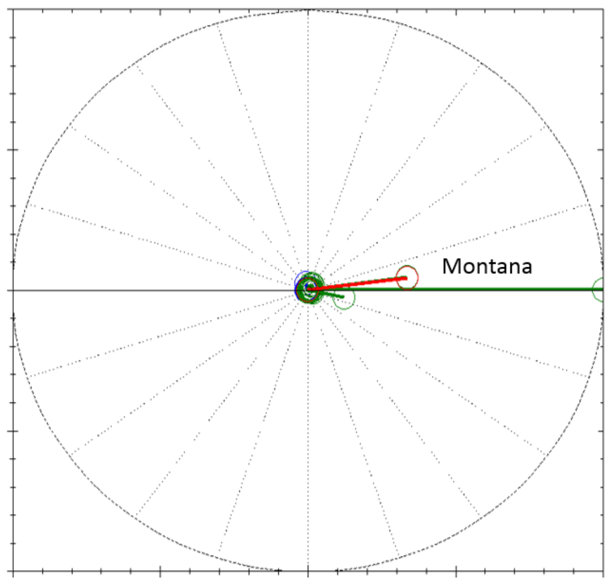


Figure 1.10 Mode Shape Plot of localized Montana Mode

Key Takeaways

- The two most commonly distinguished system modes in the WI (N-S Mode A and N-S Mode B) were also identified in this analysis.
- WI should continue to address damping ratios of their identified interarea system modes
- The Northern and Southern ends of the WI have strong participation factors.

Chapter 2: Benchmarking and Sensitivity Analyses

Analysis of wide-area oscillations by using time-synchronized PMU data allows for the opportunity to roughly compare the Interconnection-wide planning cases' ability to capture the same modal characteristics as the actual system. This helps NERC prioritize its efforts under the Modeling Improvements Initiative as NERC works with industry to improve the models used for planning and operating the BPS. The importance of such an endeavor lies in the ability to predict any oscillatory behavior for future system studies. NERC performed a series of benchmarking studies to determine if the existing dynamic models can recreate the oscillatory behavior captured using PMU data if the model is subjected to the same disturbance to some degree. This chapter details the results and key findings for each Interconnection.

Benchmarking Interconnection-wide Models

NERC used PSLF and PSSE simulation software platforms to compare simulated disturbances with actual disturbance data captured from the wide-area PMUs.[14] The cause of each disturbance is known, using information from the NERC Situation Awareness department. The disturbance was simulated in an "off-the-shelf" planning base case provided by the MOD-032 Designee for each Interconnection. A case was selected that somewhat matches the conditions in which the disturbance occurred (e.g., "light spring" or "peak summer"). The only modifications to the case were to ensure the units that tripped were operating at the correct predisturbance output level. Care was also taken to ensure no severe thermal or voltage violations were present in the powerflow solution of the new dispatch and that dispatch was utilized to simulate the disturbance for each event. **Table 2.1** shows which base case was selected for the analysis.

Table 2.1: Benchmarking Case Selection	
Interconnection	**Case Title**
Eastern	MMWG_2017SUM_2016Series_Final_ds
Western	17HS2a
Texas	NT2018_HWLL_Final

By doing so, NERC staff was able to find the general oscillatory characteristics of the Interconnection-wide planning models and to assess their capability to model these oscillations. A value for the oscillation mode frequency within 10% of the physical data was considered to be adequate, and a band of +/- 5% for both the damping ratio and relative energy was considered adequate. Many different variables (e.g., transmission line flows, local temperatures, other operating conditions) can impact the results of a simulation versus reality; however, none of these factors were considered to recreate the specific event. The purpose of the benchmarking was to address whether the current state of a base case can reasonably match the observed mode shapes. Results were then analyzed utilizing the ringdown analysis methods discussed in **Appendix A**.

Eastern Interconnection

The April 15, 2016, generation trip event was chosen for model benchmarking. The resource loss totaled 1200 MW from estimations on the FNET report. While the PMU data set contains many signals, most of them are concentrated in dense areas, providing an overall sparse view of the EI. In the simulated case, a total of 206 signals (e.g., frequencies, voltage magnitudes, and voltage angles) were recorded across the Interconnection. After simulating the disturbance and running the oscillation analysis on the simulation data, the mode shapes and modal characteristics differed between the simulation and the PMU data set. See the results for Event 2 in Appendix D[15] for more information on the PMU data. **Figure 2.1** shows the simulated generator trip occurring at t = 5 seconds with the

[14] GE PSLF: https://www.geenergyconsulting.com/practice-area/software-products/pslf
Siemens PTI PSSE: https://www.siemens.com/global/en/home/products/energy/services/transmission-distribution-smart-grid/consulting-and-planning/pss-software/pss-e.html

[15] See *Detailed Event Analysis* Report here

analysis window from t = 9–15 seconds. Results from each oscillation solution engine are shown in **Table 2.2**. A comparison of modes shapes are presented in **Figures 2.2** to **2.4**.

The dominant mode is captured quite well in both the PMU data and simulated data. The other dominant modes differ between simulation and actual data. The differences between the oscillation mode between simulated and PMU data are likely due sparsity of PMU coverage compared with the model representation as the more signals available increase the observability of the mode. The different operating conditions between simulated and actual data also likely have an impact. In addition, the simulation demonstrates some nonlinearities in the early portion of the second swing, introducing some inherent errors during the time when the oscillation was highly excited.

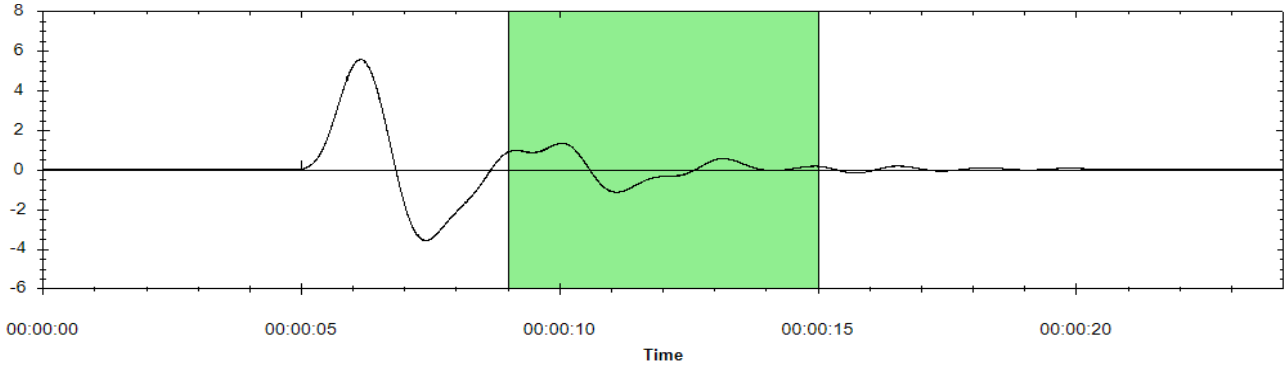


Figure 2.1 Analysis Window

Table 2.2 Dominant Mode Comparison

	Dominant Mode 1 Simulated	Dominant Mode 2 Simulated	Dominant Mode 3 Simulated		Dominant Mode 1 Actual	Dominant Mode 2 Actual
Frequency (Hz)	0.32	0.71	0.53		0.32	0.17
Damping Ratio (%)	17.8	6.4	6.7		20	13
Relative Energy (%)	44	37	12		79	16

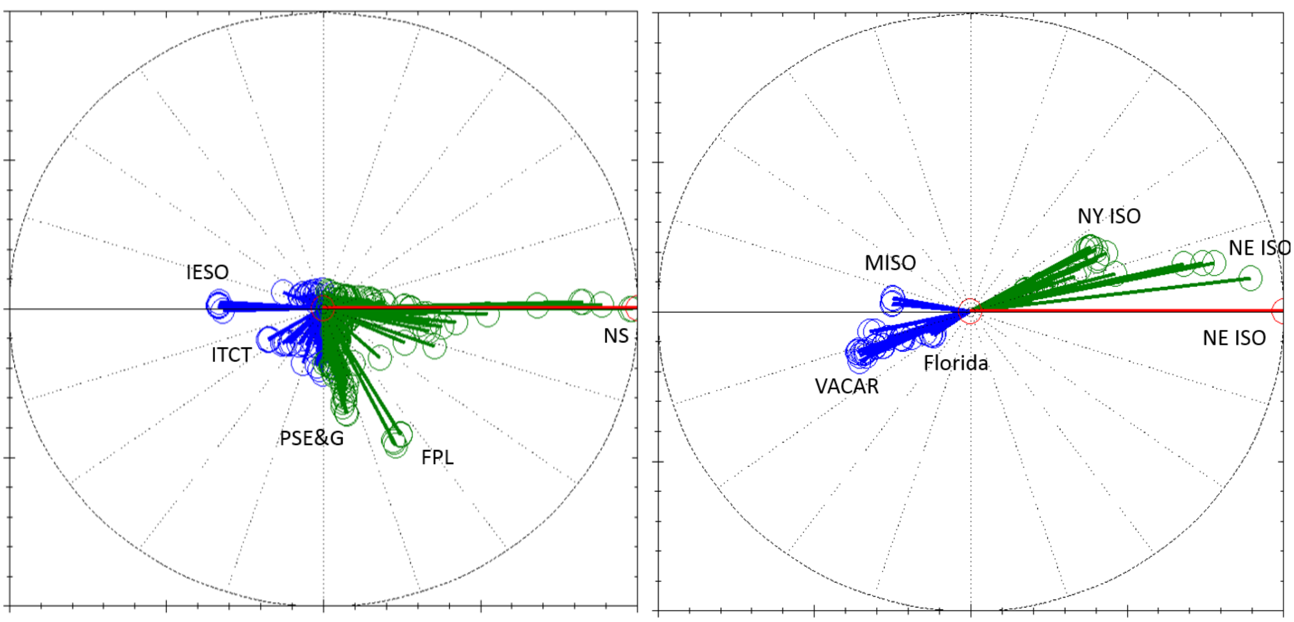


Figure 2.2 Simulated (left) versus Physical (right) Dominant Mode Shape 1

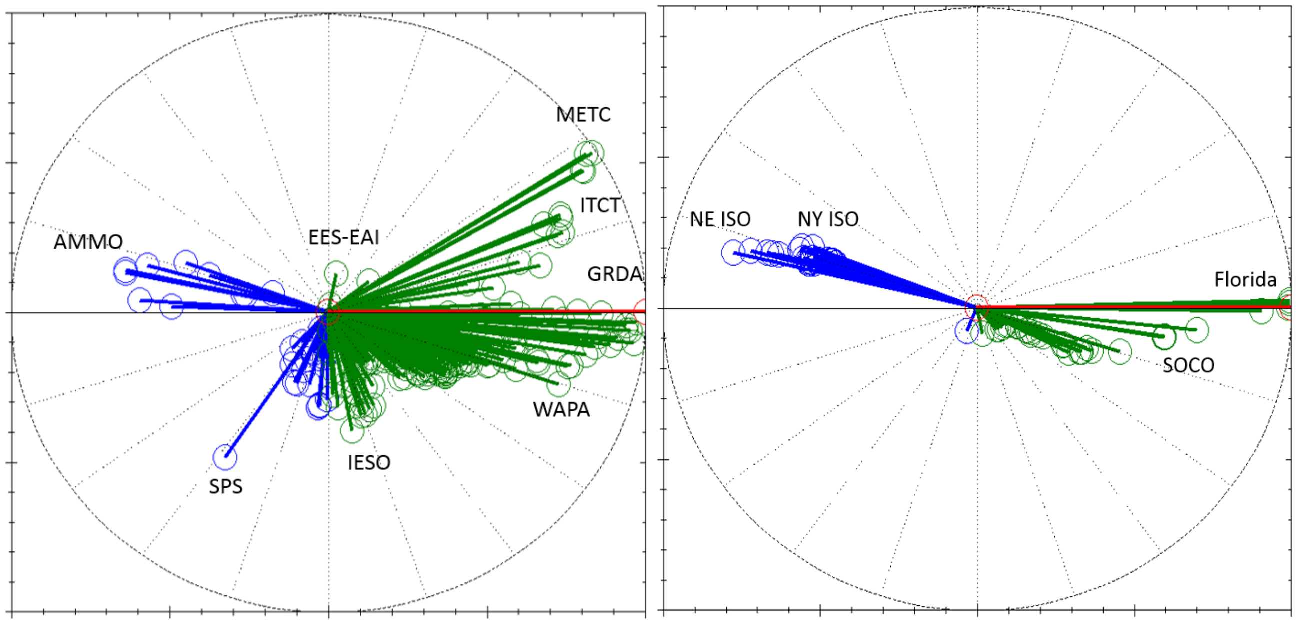


Figure 2.3 Simulated (left) versus Physical (right) Dominant Mode Shape 2

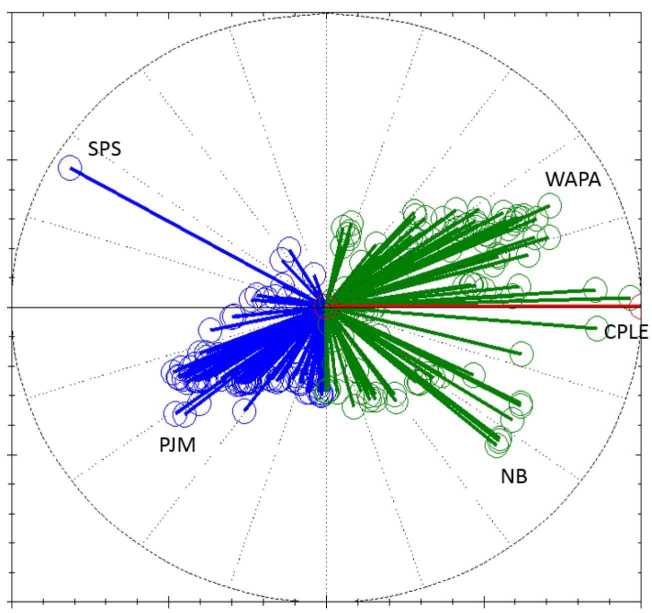


Figure 2.4 Simulated Dominant Mode Shape 3

Texas Interconnection

The March 10, 2017, event was chosen for model benchmarking. The resource loss totaled 823 MW from a single generator tripping off-line. Relatively few signals were provided in the PMU data set received, and therefore the simulation results contained more signals. This created a scenario where NERC could determine if the simulated responses could accurately depict a result gained from only a handful of signal samples. After running the analysis, it was determined that the simulated results and the actual results (Event 5 in Appendix E[16]) are consistent with each other.

The simulated disturbance occurred at t = 1 second with the analysis from t = 2–7 seconds (**Figure 2.5**). Results from each oscillation solution engine are shown in **Table 2.3**. The mode shape comparison is also presented in **Figure 2.6**.

[16] See *Detailed Event Analysis* Report here

Results show a relatively close resemblance between simulated and actual data. As the number of signals in the actual PMU data were low, it is hard to characterize the mode shape truly; however, the simulated results (the left portion of **Figure 2.6**) depicted this much better.

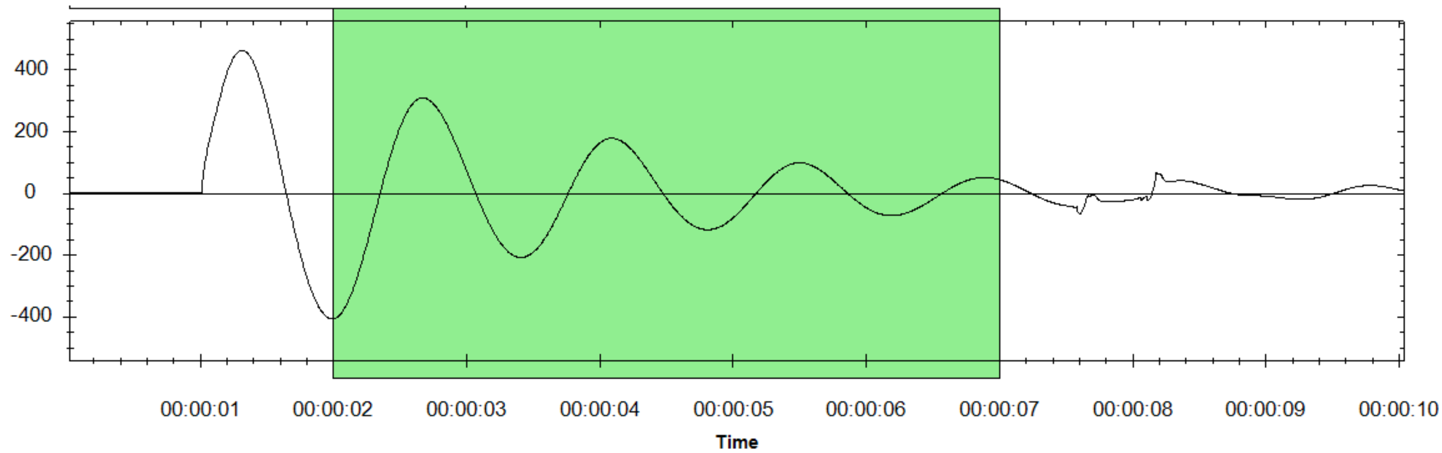


Figure 2.5: Analysis Window

Table 2.3: Dominant Mode Comparison		
	Dominant Mode 1 Simulated	**Dominant Mode 1**
Frequency (Hz)	0.71	0.67
Damping Ratio (%)	9	11
Relative Energy (%)	98	95

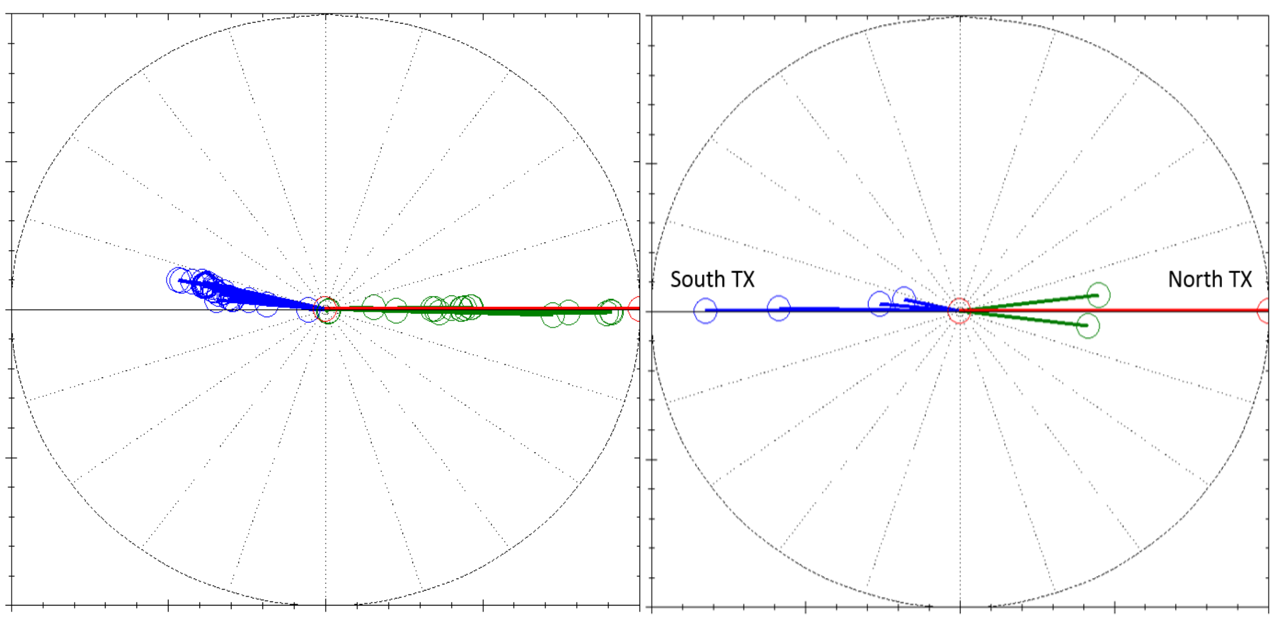


Figure 2.6 Simulated (left) versus Physical (right) for the Dominant Mode Shape

Western Interconnection

The January 21, 2016, event was chosen for model benchmarking. In this case, the number of signals from the simulation were much lower than PMU data set received from Peak RC. While there were a few discrepancies between the simulated and PMU data results (see Appendix F[17]), the results were consistent and the models were accurate in depicting the primary interarea mode.

The simulated generator trip occurred at t = 1 second, and the analysis window was from t = 10–18 seconds (**Figure 2.7**). Results from each oscillation solution engine can be found in **Table 2.4**. The mode shape comparisons are presented in **Figures 2.8** and **2.9**. Results demonstrate a reasonably close resemblance for the dominant mode, but the simulation appears to have picked up an interarea mode while the actual data picked up a local mode. More work should be done to identify secondary modes between the model and actual data and to reflect that work into the Interconnection-wide models.

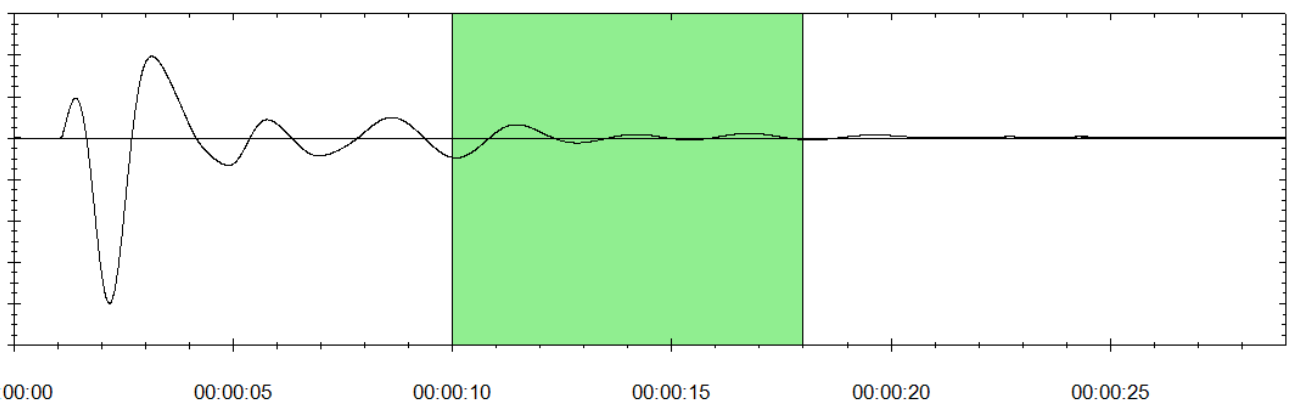


Figure 2.7 Analysis Window

Table 2.4: Dominant Mode Comparison

	Dominant Mode 1 Simulated	Dominant Mode 2 Simulated		Dominant Mode 1 Actual	Dominant Mode 2 Actual
Frequency (Hz)	0.37	0.25		0.42	1.29
Damping Ratio (%)	8	16		12	8
Relative Energy (%)	72	27		51	31

[17] See *Detailed Event Analysis* Report here

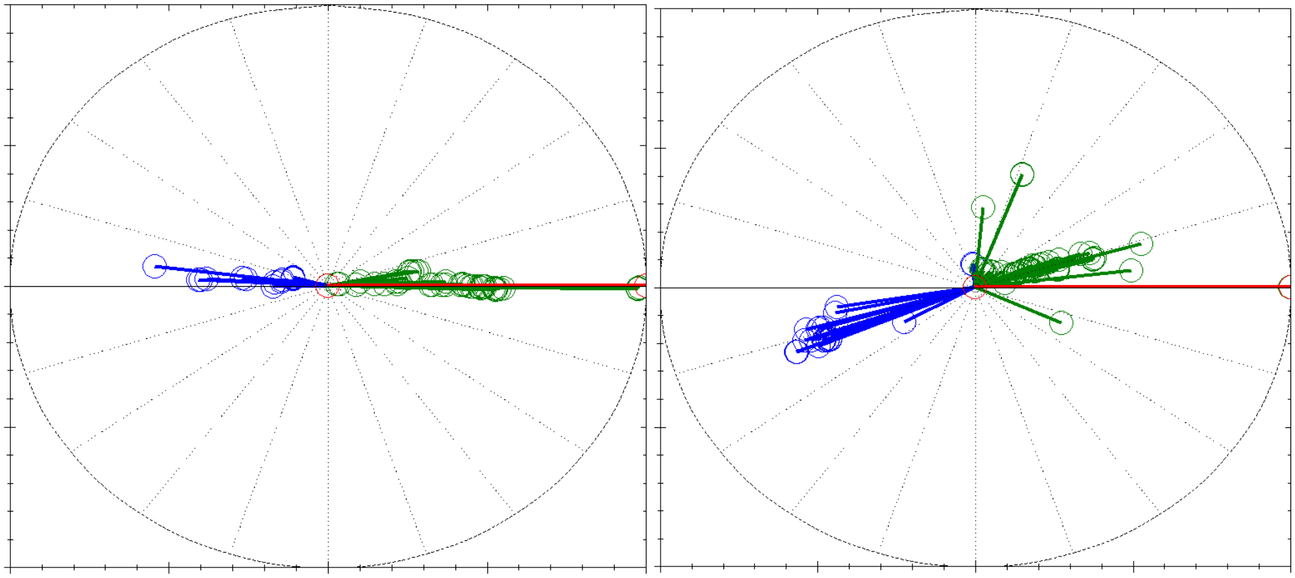


Figure 2.8 Simulated (left) versus Physical (right) Dominant Mode Shape 1

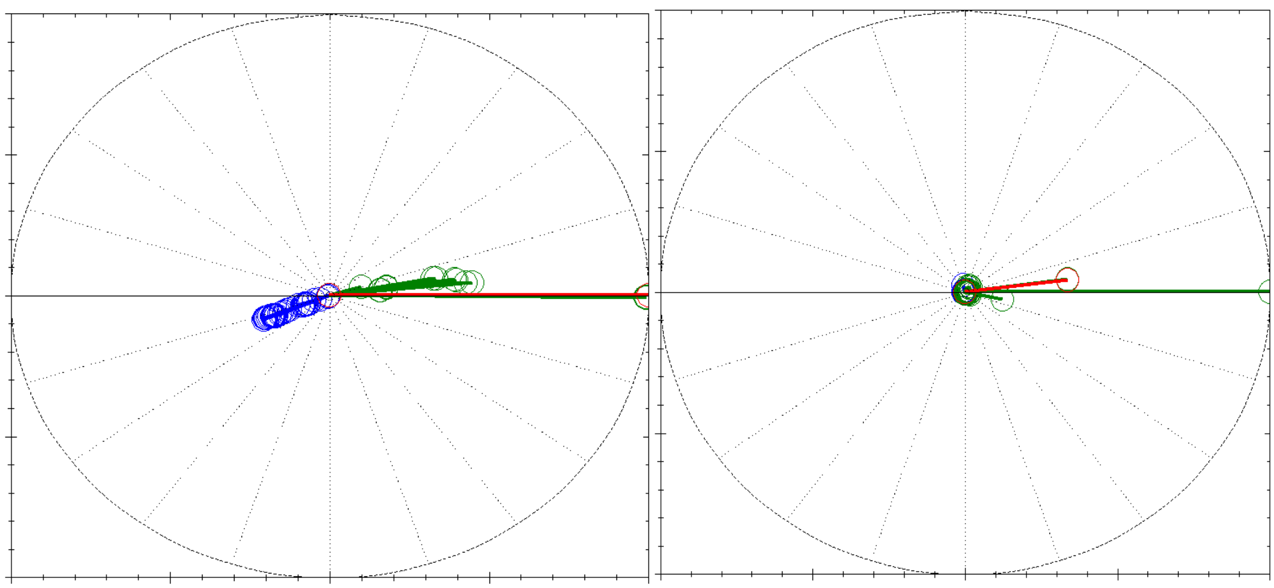


Figure 2.9 Simulated (left) versus Physical (right) Dominant Mode Shape 2

Conclusions

Overall, benchmarking results demonstrated that the models were able to recreate the dominant mode in each Interconnection. The value for the oscillation model frequencies were within 10% of the PMU data, and the damping ratio and relative energy were within +/- 5% for the primary dominant mode. Further investigation into the differences for the second dominant modes yielded valuable results for each Interconnection's ability to model their system modes correctly. In short, each interarea oscillation is observable in the planning cases for each Interconnection. The models appear to be relatively sufficient to capture interarea oscillatory behavior. However, each Interconnection (i.e., the MOD-032 Designees) should continue to monitor grid events and perform benchmarking of oscillatory behavior between simulated response and actual PMU data. This is particularly valuable as PMU density increases across each Interconnection. As the density of PMUs increases, the performance of the planning model should match observed results under the same system conditions. It is demonstrated above that the EI benchmarking identifies the three major modal shapes in Chapter 2 of this report; however the mode shapes are very sensitive to generation dispatch and flows throughout the system, so the mode shapes may differ from those demonstrated in this and other sections. The WI and TI modes are well captured in the benchmarking section except for the local phenomena found in the events.

Key Takeaways

- EI and WI should address system models to more accurately reflect the observed data results. The current models are deemed sufficient to capture the dominant mode shapes.
- Each Interconnection should continue to benchmark their planning models with performance events. The rising PMU density helps to observe the natural system mode shape and should assist in this benchmarking.

Using Frequency versus Voltage Angle Data

Ringdown methods are largely dependent on the accuracy of the data used. Different sources of data can results in different answers obtained after performing the oscillation analysis. When analyzing the PMU data, one may use either measured (calculated) PMU frequencies or PMU voltage angles. Efforts were made to compare oscillation analysis results between using PMU frequencies and PMU voltage angles. Entities have stated that using frequencies or voltage angles may result in different results since IEEE Std. C37.118 is prescriptive on calculating the phasor quantities but less so on calculated frequency. This hypothesis was tested using one of the WI events from January 20, 2017.

Figure 2.10 and **Figure 2.11** show the FFT match for both PMU frequency and voltage angle data (using the angle derivatives option) with similar FFT shapes and reconstructed signals.[18] The red lines indicate the reconstructed signal from the analysis while the black lines indicate the original data from the source of the signal. The spectral density of the FFT for the frequency data contains more low frequency results than the voltage angle data (reflected in the results in presenting higher modal frequencies). A comparison of the three dominant modes is provided in **Table 2.5**. Notice that the skew towards higher frequency results in the voltage angle versus the frequency data. This provided results that contained much more energy in the higher modes as well as a slight increase in the mode frequency of the low frequency mode. By understanding that the angle data will skew towards higher frequencies, the user can simply adjust the relative energy threshold when utilizing voltage angle data sources to accommodate for this shift. This makes the results similar to using the frequency data. If the user is concerned with a possible low frequency mode (~0.15-0.3 Hz), the frequency data will provide a more conservative damping ratio than the voltage angle data as the skew impacts the damping ratio of the low frequency modes in the voltage angle data.

[18] In the first iteration, the raw angle data was found have a poor visualization of the oscillation during the event period, and thus, the derivative of the angle measurements (or a pseudo-frequency) was used to obtain the results. These calculations utilize a linear scale between points, so the calculations are affected by how many consecutive data points are missing or the PMU data was not available for a few samples.

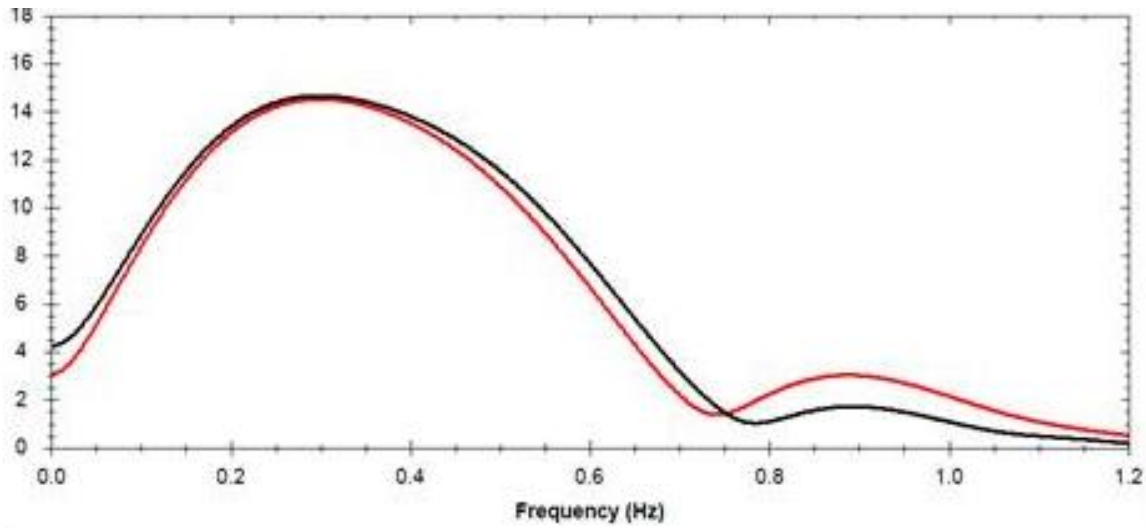


Figure 2.10: Frequency Data Source FFT plots

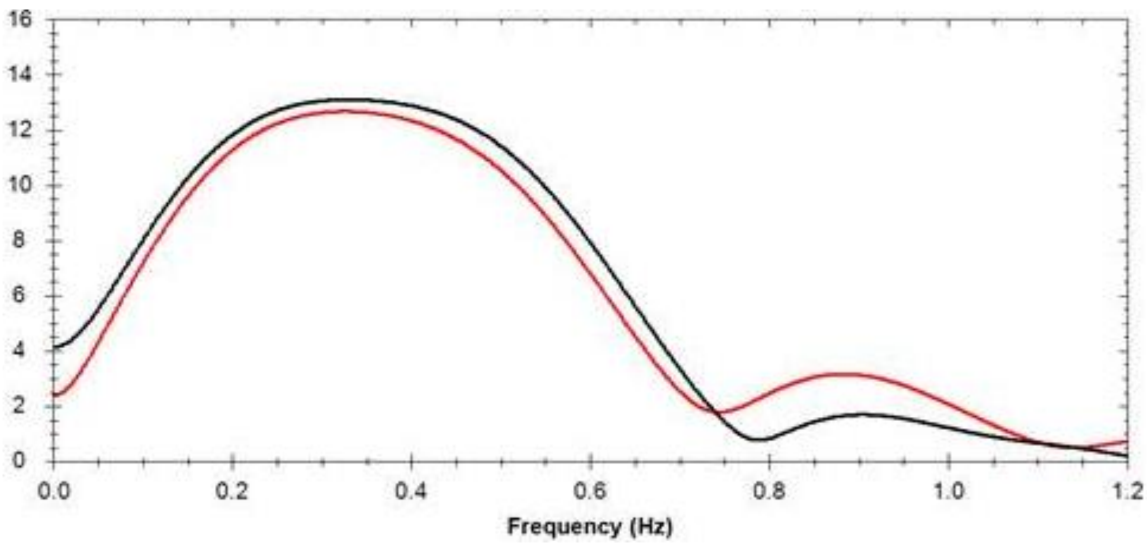


Figure 2.11: Voltage Angle Data Source FFT Plots

Table 2.5: Dominant Mode Comparison

	Frequency Data Source			Voltage Angle Data Source		
	Frequency (Hz)	Damping Ratio (%)	Relative Energy (%)	Frequency (Hz)	Damping Ratio (%)	Relative Energy (%)
Mode 1	0.44	13.89	56.74	0.44	14.44	42.94
Mode 2	0.23	12.37	23.60	0.24	17.99	29.90
Mode 3	0.83	18.71	19.67	0.83	17.45	27.16

Effects of Changing Inertia on Oscillation Frequencies

In addition to the model benchmarking described above for the TI, the impacts of decreasing inertia on system modal characteristics were also explored. A slightly modified base case with the same disturbance event was used as described above. That case was then compared against a case with the same load level but less on-line generation and lower available headroom, resulting in decreased inertia. These results were then compared to the simulated case to identify any relationship between inertia and the primary components of the system modes (i.e., frequency, damping ratio, and relative energy). Table 2.6 shows the comparison of system inertia and the primary oscillation mode frequency, damping ratio, and energy.

Table 2.6: Dominant Mode Comparison

	Base Case Simulation (204.8 GVA*s)			Lower Inertia Simulation (191.5 GVA*s)		
	Frequency (Hz)	Damping Ratio (%)	Relative Energy (%)	Frequency (Hz)	Damping Ratio (%)	Relative Energy (%)
Mode 1	0.72	9.21	100	0.79	7.15	100

The damping ratio decreased from the higher to lower inertial cases that correlated with a rise in the frequency of the mode shape. This confirms the expectations of a higher modal frequency usually resulting in a lower damping ratio for a particular mode shape; however, this may be the related by generation dispatch, transmission tie line flows, or aggregate inertial values. Most likely, each of these reasons play a factor in determining the damping ratio. The mode shape comparison for these two inertia levels is demonstrated by comparison in Figure 2.12.

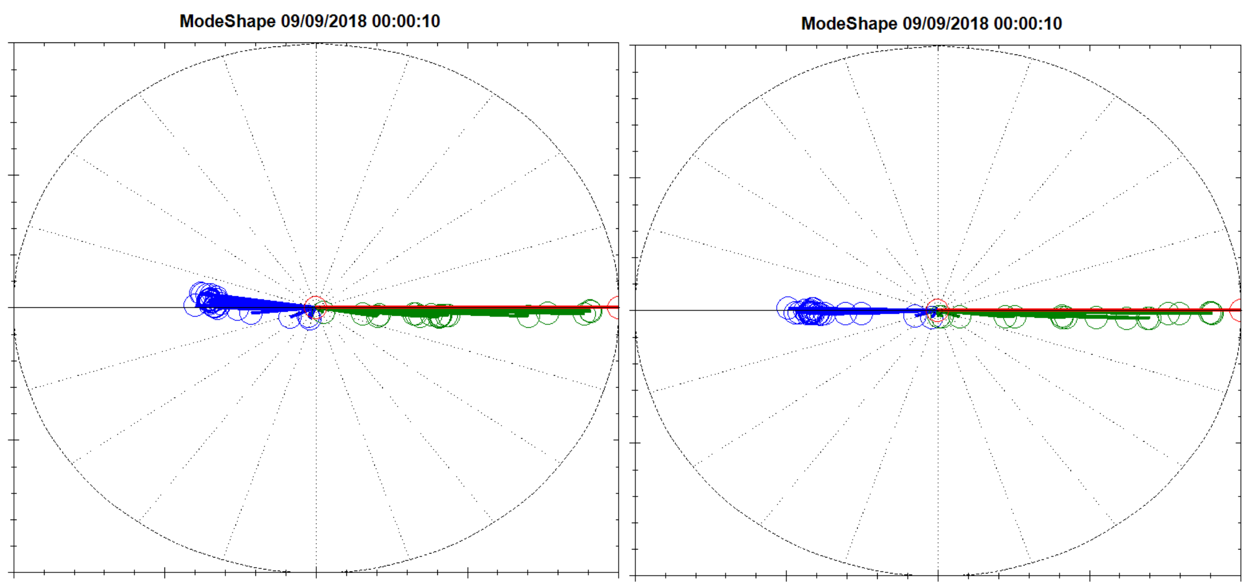


Figure 2.12 Higher Inertia (Left) versus Lower Inertia (Right) Natural System Mode Shape

An Exploratory Analysis on the Western Interconnection

The study group also wanted to determine if the planning models were adequate in capturing the system mode shape and its changes by exciting different portions of the Interconnection. They excited six different areas of the Interconnection to see the impacts on the mode frequency, damping ratio, and relative energy for the identified modes in Chapter 2 of this report. For many of the events, the mode shape performed similarly to the measured responses to the Interconnection with minor errors due to transmission path flow differences and some generator dispatches, which is to be expected. In addition, the method of excitation for these events included generator tripping, which will amplify the contributions of signals near the generator trip; however, the other aspects of the mode shape we can compare and provide validation between the planning model and the measured events. This analysis show which are the strong controllable regions for the two main interarea modes of the WI. For instance, Alberta mainly excites the 0.25 Hz NS Mode A while NW and MT excite the 0.37 Hz NS Mode B. Figure 2.13 demonstrates the differences between the expected and identified results. This evidence suggests there is a possibility that mode shapes can differ depending on the excitation location. Table 2.7 and 2.8 and also compares the changing damping ratios and relative energies of the two major modes. The relative energy mode comparisons are telling with higher relative energies of the interarea modes that indicate which common interarea mode has more impact for generation resource loss in that area. These types of studies are encouraged to continue with different seasonal cases and for different operating conditions to fully understand the impact a generation loss has in a regional area with respect to the dominant interarea mode characteristics.

Table 2.7: Damping Ratio Mode Comparison

Mode Frequency (Hz)	2DC Damping Ratio (%)	2PV Damping Ratio (%)	Alberta Damping Ratio (%)	BC Damping Ratio (%)	Colstrip Damping Ratio (%)	Coulee Damping Ratio (%)
0.24–0.26	15.1	14.1	18.0	14.3	19.2	12.7
0.35–0.37	12.0	9.0	NO	8.8	7.3	8.6

Note: NO–Not Observed or Well Damped

Table 2.8: Relative Energy Mode Comparison

Mode Frequency (Hz)	2DC Damping Ratio (%)	2PV Damping Ratio (%)	Alberta Damping Ratio (%)	BC Damping Ratio (%)	Colstrip Damping Ratio (%)	Coulee Damping Ratio (%)
0.24–0.26	69.9	69.2	93.2	54.8	68.7	26.6
0.35–0.37	24.3	23.5	NO	41.8	31.3	73.4

Note: NO–Not Observed or Well Damped

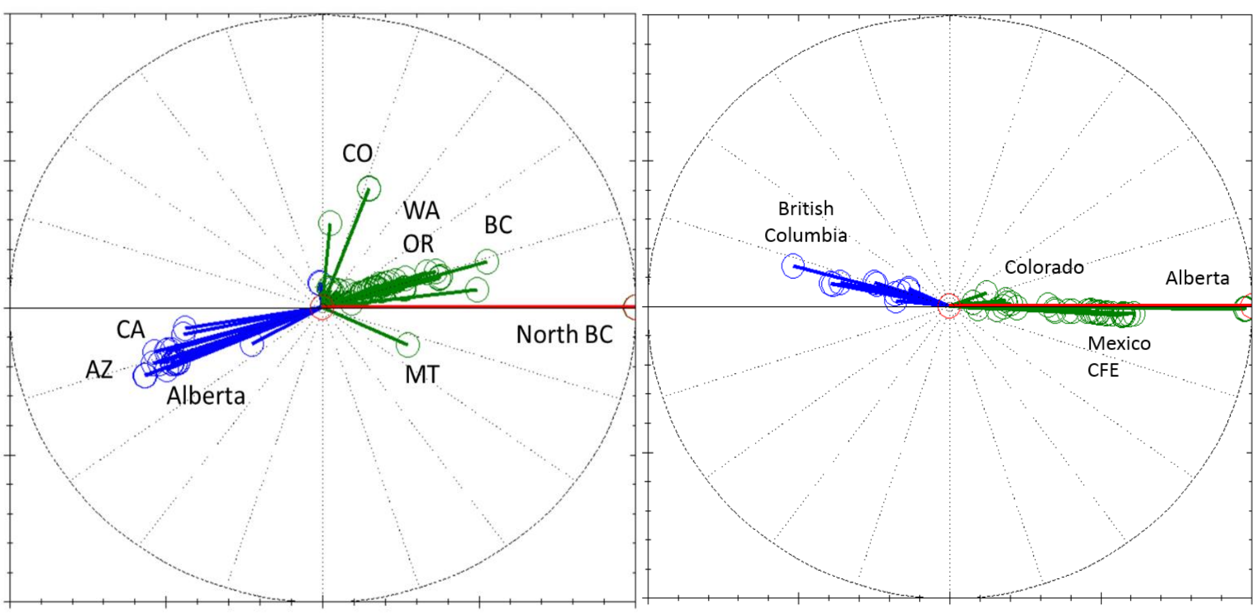


Figure 2.13 Mode shape of expected (left) versus identified in Exploratory Analysis (right)

As demonstrated in the differing mode shapes, the excitation location for the event demonstrates how the participation factors between the ends of the region behave with respect to that region. In addition, **Figure 2.14** depicts an identified low relative energy 0.52 Hz mode in the simulations. This mode is described as having ends in the North California to North British Columbia regions and has large participation factors for the Eastern portion of the WI as well, which indicates the presence of a reasonably complex mode shape.

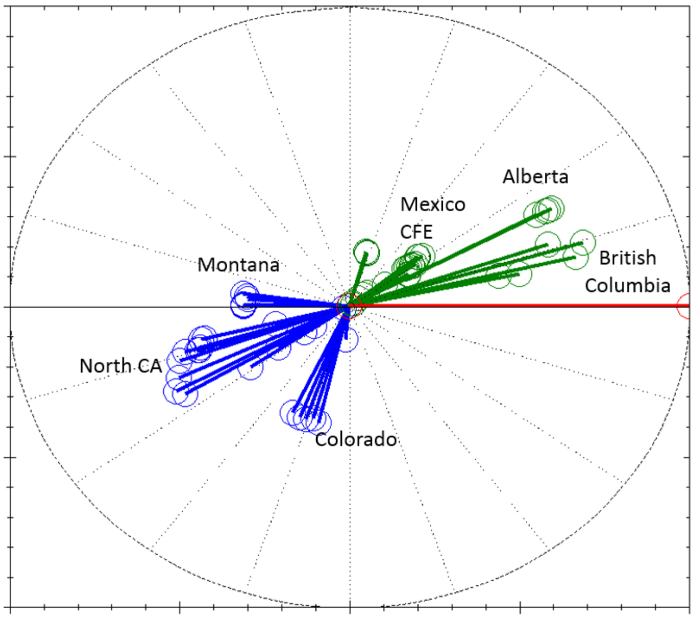


Figure 2.14: 0.52 Hz mode shape identified in some of the Exploratory Analysis cases

The 0.52 Hz mode shape in the WI was not well identified in previous studies, and **Figure 2.14** demonstrates its relative participation factors defined by the regions. The blue and green regions correlate to the mode shape plot in **Figure 2.13**. As seen in the figure, the mode shape is complex in nature and has three distinct regions for each half of the mode shape. This mode shape may have been seen in Event 6 in the WI Analysis, but is sensitive to the placement of the reference signal in the mode shape analysis.

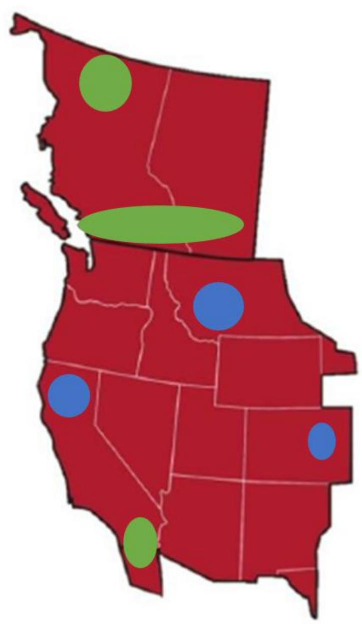


Figure 2.14 0.52 Hz mode Shape Regionally Defined

Chapter 3: Conclusions and Observations

In this chapter, the overall mode shapes and higher level observations and suggestions are discussed and recommendations for future efforts in identifying the interarea oscillations are mentioned. As the PMU coverage is expected to increase, new modes and more accurate details of previous modes are expected to be discovered. The conclusions and recommendations here are presented as the initial effort in monitoring, studying, and simulating the interarea modes of oscillation found in each Interconnection.

Conclusions

For all the chosen events for analysis for all Interconnections, only a handful exhibited forced oscillatory behavior and all resonance effects were deemed to be mild, indicating that the conditions surrounding the event were not as severe as they could have been given the resonance conditions. In the events, a total of six dominant modes were seen. Each mode was given a name that describes the general shape of the mode where a previous name has not already been given. The frequency range, average damping ratio, and average relative energy is provided for these modes in **Table 3.1**.

Table 3.1: Damping Ratio Mode Comparison

Interconnection	Mode Name	Mode Frequency Range (Hz)	Mode Average Damping Ratio (%)
Eastern	NE–S	0.16–0.22	9.70
	NW–S	0.29–0.32	16.45
	NE–NW–S	0.23–0.24	12.80
Texas	N–SE	0.62–0.73	9.26
Western	NS Mode A	0.37–0.42	12.71
	NS Mode B	0.24–0.27	13.53

Plots of the dominant modes are found in **Figures 3.1** to **3.3** and are listed in order of average relative energy in the Interconnection. These modes shapes are based on the events chosen and the order presented here may change with future analysis and additional visibility of the respective Interconnection. In the figures, each different color represents a leg of the mode shape per Interconnection. Colors were chosen based on contrasting coloration from the background color. Inscribed circles identify that two regional possibilities exist for that mode shape, only seen in the EI for the NE–NW–S mode. The different colors coordinate to different phase legs of the mode shape and thus oscillate against each other. For the more complex mode shapes with three distinct phase legs, three colors were chosen. This is to contrast two distinct phase legs with the remaining system “filling in” the remaining mode shape that is identified with only two colors.

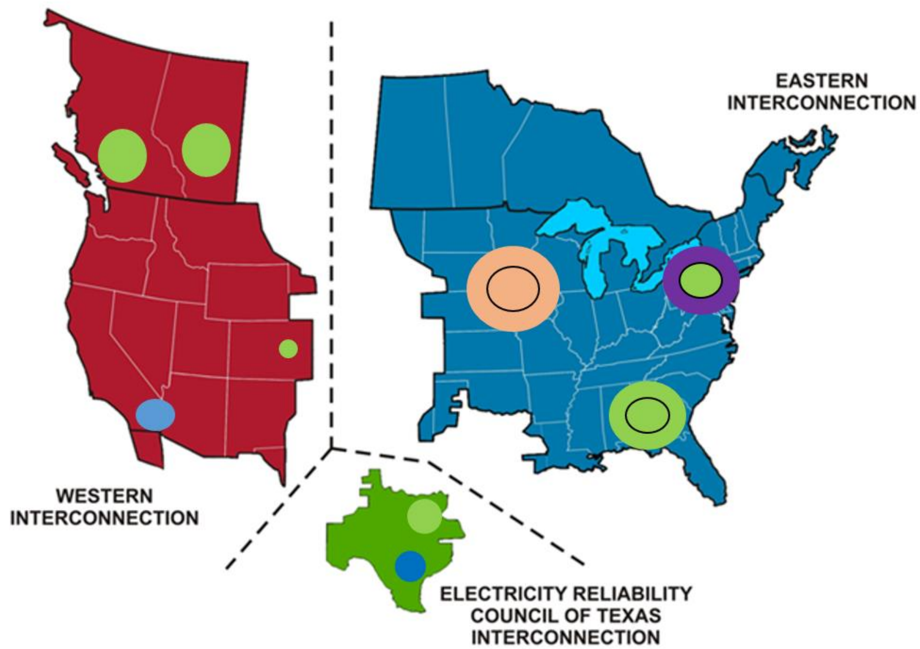


Figure 3.1 Dominant Mode 1 Geographic Representation

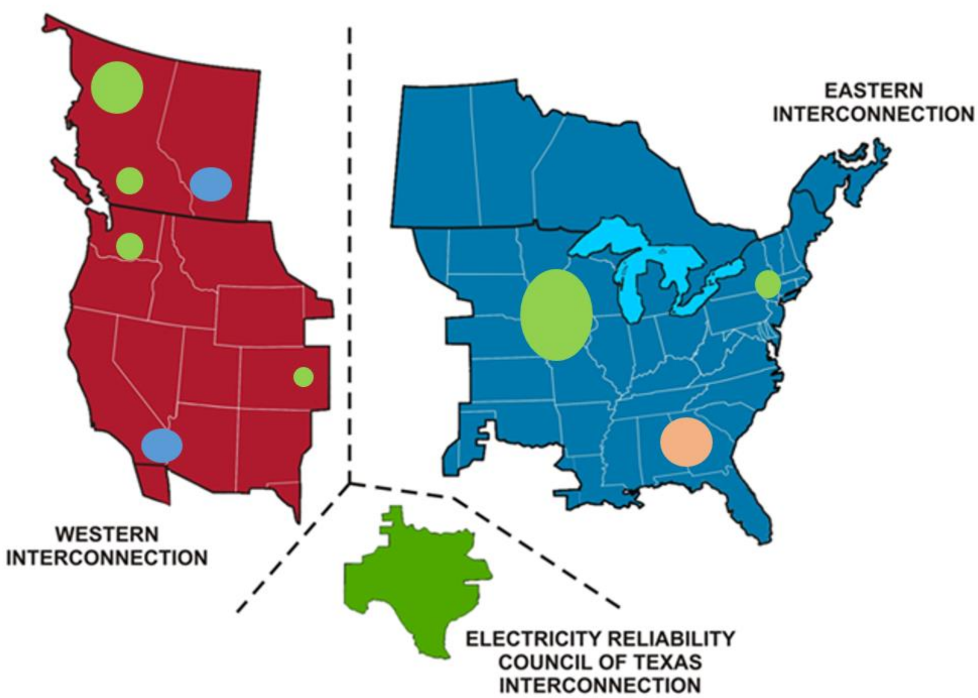


Figure 3.2 Dominant Mode 2 Geographic Representation

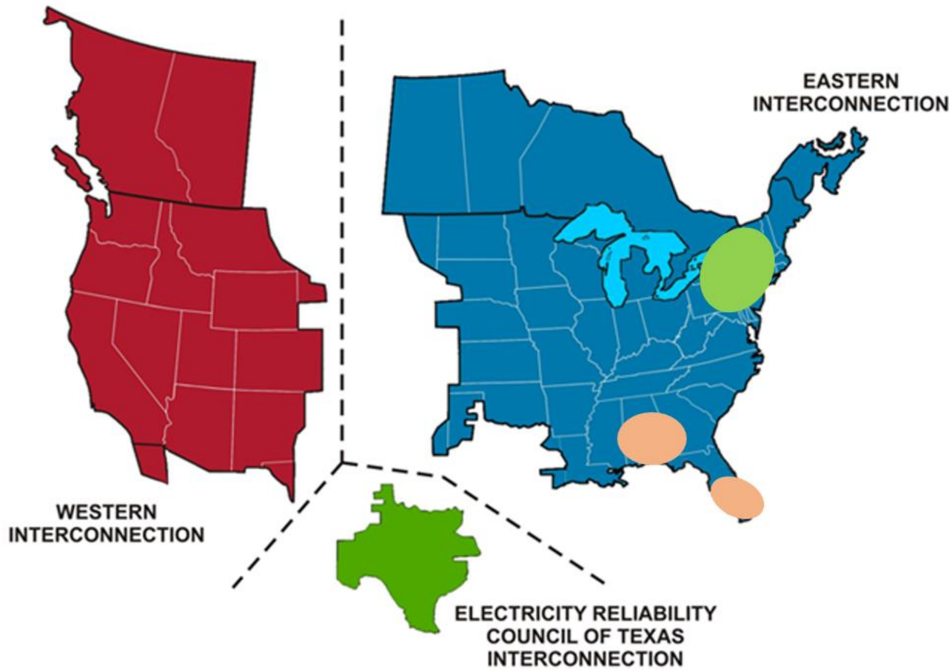


Figure 3.3 Dominant Mode 3 Geographic Representation

Key Takeaways

- Continued analysis of oscillatory behavior is needed to understand newly identified interarea system modes.
- No forced oscillation event had more than mild resonance effects to natural system modes in the events studied.
- Most Dominant modes have a complex geographic representation but a simple mode shape.
- Most Dominant modes have, on average, high damping ratios; however, system configurations impose a significant variance to this average.

Observations

As demonstrated in **Chapter 2** of this report, most of the observed modes were very well damped in the seconds after the studied events. Some things to note across the analysis are that the larger the set of PMU data was, the greater visibility into which geographic regions contribute to that particular system mode. Whenever the system modes were not well damped, the system eventually recovered; however, the recovery time was quite long. For the mode shapes defined on the modes that can go towards the undamped regions, a damping control system that acts to increase the damping ratios for the defined modes can help prevent high energy oscillations and resonance from causing a catastrophic event. Such projects are currently under research and testing in the DOE CERTS[19] program. It is important to note that there was no sensitivity done to take out the modeled PSS on generation units. Tuning these systems to dampen system modes will impact the results in this report.

In addition to cases of lower damping, another high-level observation about these events was that the higher meshed systems seemed to provide better damping ratios in their system. That is, the electrical system parameters between

[19] https://certs.lbl.gov/

sinks and sources had a denser population of the Ybus matrix than the sparsity seen with loosely connected lines. The Interconnections and areas that had these denser matrices provided greater oscillations damping in the interarea mode shapes. For those Interconnections and areas that were not as heavily interconnected, the oscillatory behavior usually had a much lower damping ratio when excited with a high energy oscillation near the system mode.

In general, the size of generation loss in the event played an insignificant role in determining the damping ratio of the most dominant interarea oscillation excited by that event. That is, an event with twice the MW impact in the Interconnection can result in either a higher or lower damping ratio of the dominant interarea oscillation. This implies that the impact of these generator trips is determined by the transition from the state before the trip and the state after the generator trip. Size will, however, impact which mode shapes dominate the oscillation as the events demonstrate a variance in their relative energy with respect to the excitation location. This important to note for future analysis as the signals close to the generator trip will have greater values of excitation compared to the rest of the system.

Interaction between Natural and Forced Oscillations

From the results found in Chapter 2 and in the companion document that contains the detailed results for each Event, the system natural modes that are excited by the forced oscillations demonstrate small resonance. The major consideration for all events then is how strong of a resonance effect each event (in the case of a forced oscillation) has to the natural modes of the system and the damping ratio of the natural system modes. In the chosen events, the primary factor that dictated the resonance effect was the spectral proximity to the natural system modes rather than occurring in an area of high participation to or at a time of low damping ratio for the natural mode. In the chosen events, the primary factor that dictated the resonance effect was the proximity of the forced oscillation’s frequency to the frequency of natural system modes, rather than the location of the forced input or the damping ratio of the modes.

Recommendations

Based on the oscillation analyses performed and the key findings described above, the following recommendations are provided to enhance the understanding of interarea oscillations of the BPS:

- Each PC and RC should continue oscillatory studies for their respective region. This includes using the mode shape plots[20] to further explore which set of generators participate in exciting these modes. Other sensitivities to consider are path flows and source-sink relationships. These studies should be pre-emptive in identifying mode shapes and performing verification on identified modes.
- The RCs and PMU industry should develop a standardized format for submitting PMU data for offline oscillatory analysis as there were consistency issues in this data set. Standardization should include the types of measurements as well as the data format for those measurements.
- The WI should improve the understanding of the east–west modes, specifically how Montana and Colorado participate in this mode.
- The TI should increase the PMU coverage from its Northwestern region for greater observability of system oscillatory characteristics.
- The EI should perform tests or studies to better understand the two modes near 0.25 Hz since these modes are observed across the entire Interconnection and demonstrate changing mode shapes.
- The EI should also track the 0.78 Hz forced oscillation source observed in many of the events and monitor the mode shapes of the interarea modes in the frequency range of 0.67 to 0.8 Hz. In particular, it would be useful to understand why these shapes do not extend into the New York/Canada regions in the North and do not extend into the Florida region in the South.

[20] See *Detailed Event Analysis* Report here

- Each RC should ensure adequate training and support for system operators and also ensure coordination among neighboring RCs regarding how to handle wide-area oscillation events.
- The commercially available positive sequence RMS stability simulation tools should have the capability to model injection of forced oscillations at many source locations. This would improve the benchmarking between Interconnection-wide models and actual grid events.
- TOs, in coordination with their PC and RC, should consider visibility of interarea oscillations when identifying placement for future PMUs. PMU placement in areas of low visibility will improve the understanding of the natural modes and eliminate uncertainties in the analysis of these modes.

Appendix A: Power System Oscillations and Analysis Techniques

This appendix briefly describes some fundamental aspects of BPS oscillations and various analysis techniques. It also provides information regarding the analysis techniques used in this oscillation assessment.

Fundamentals of Power System Oscillations

Oscillations are always present in the BPS due to the electromechanical[21] nature of the electric grid. Under no significant external system influence, the grid still oscillates at its natural frequencies for small disturbances, such as constant changes in load. These oscillations are usually well-damped and contained; however, growing or high-energy oscillations can present system instability, potential equipment damage, safety concerns, and power quality issues. In addition to these natural oscillations, forced or "rogue" inputs to the system can also cause oscillations and should be detected and mitigated to the most possible extent. To explain these concepts of oscillations on the BPS, it is important to clearly differentiate between the types of electromechanical oscillations that are present. From a practical standpoint, power system oscillations can be categorized as System or Forced:

- **System (Natural):** low-frequency rotor angle oscillations caused by instantaneous power imbalances. These are often differentiated further as follows:
  - **Local:** oscillations where one power plant or generating unit oscillates with the rest of the system, generally caused by heavy loading and generator excitation and turbine-governor controls
  - **Intraplant:** oscillations where generating units within a power plant oscillate with each other at the same location,[22] generally caused by poor tuning of plant controls, unit control interactions, and unit operating modes
  - **Interarea:** oscillations characterized by several coherent units or parts of the system oscillating against other groups of machines, often predominant in power systems with relatively weaker interarea connections
  - **Torsional:** high frequency (below 60 Hz) oscillations caused by resonance conditions between highly compensated transmission lines and the mechanical modes of a steam-turbine generator (typically referred to as subsynchronous resonance[23])
- **Forced:** sustained oscillations driven by external inputs to the power system, such as unexpected equipment failures, control interactions, or abnormal operating conditions that can occur at any frequency

Chapter 1 of the *Reliability Guideline: Forced Oscillation Monitoring and Mitigation*[24] provides a useful high-level reference regarding the fundamentals of power system oscillations that are briefly summarized in **Table A.1**.

[21] Electromagnetic oscillations can also occur in power systems. These types of oscillations are outside the scope of this guideline.

[22] These types of oscillations are normally manifested within the plant site and often difficult to observe external to the power plant itself.

[23] Past subsynchronous resonance (SSR) and subsynchronous control interaction (SSCI) oscillation events have resulted in equipment damage. See reference: J. Adams, C Carter, S.-H. Huang, "ERCOT Experience with Sub-Synchronous Control Interaction and Proposed Remediation," IEEE PES Transmission and Distribution Conference and Exposition, May 2012.

[24] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf.

Table A.1: Characteristics of Oscillations		
Characteristic	**System**	**Forced**
Source	Natural property of electro-mechanical system; characterized by frequency, damping ratio, and shape	Due to external forcing function acting on system
Shape	Explains how parts of system interact with one another, related to eigenvectors of the linearized system	Measure of the amplitude and relative phasing of the oscillation at different locations in the system
Frequency	Frequency at which oscillation is occurring; explains type of phenomena occurring in the BPS depending on range	Can occur at any frequency; often includes harmonic content of the fundamental forced oscillation frequency
Damping Ratio	Expresses how quickly an oscillation decays; tied to system stability	Appear as sustained oscillations due to the persistence of their source and do not reflect the system's damping

Interactions between System and Forced Oscillations

The interaction and relationship between natural modes of the system and forced oscillations are documented in the *Reliability Guideline: Forced Oscillation Monitoring and Mitigation*,[25] which can be referred to for more information. This report includes analysis of both types of oscillations captured by PMU data, so it is important for the reader to familiarize themselves with these oscillations. There have been documented instances that are described throughout this guideline when generating plants across North America that experienced a forced oscillation have induced larger system-wide oscillations. This drives the need to understand the system modes in each of the Interconnections to be prepared for these types of situations when the oscillations could interact with one another. Understanding the potential interactions is critical when trying to identify the source of oscillations, particularly when they are observed throughout the BPS.

For interactions between system modes and forced oscillations to occur (i.e., "resonance effect"), the following conditions must be met:

- The forced oscillation frequency must be near a system mode frequency.
- The system mode must be relatively poorly damped.
- The forced oscillation must have strong participation in the system mode.

A strong resonance effect occurs when all three conditions are met, a moderate resonance effect when two conditions are met, and a mild resonance effect when one conditions is met.[26]

An example of a forced oscillation is in **Figure A.1**. The forced oscillation has a frequency of 0.27 Hz (largest peak value of the frequency domain power spectrum density estimate). The forced oscillation also includes second and third harmonics (corresponding to peaks at 0.54 Hz and 0.81 Hz, respectively, in **Figure A.1**). The other peak at 0.75 Hz is caused by a different forced oscillation at a different location in the system.

[25] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf.

[26] S.A.N. Sarmadi, and V. Venkatasubramanian, ``Interarea Resonance in Power Systems From Forced Oscillations'', IEEE Trans. Power Systems, January 2016, Vol. 31, No. 1, pp. 378–386.

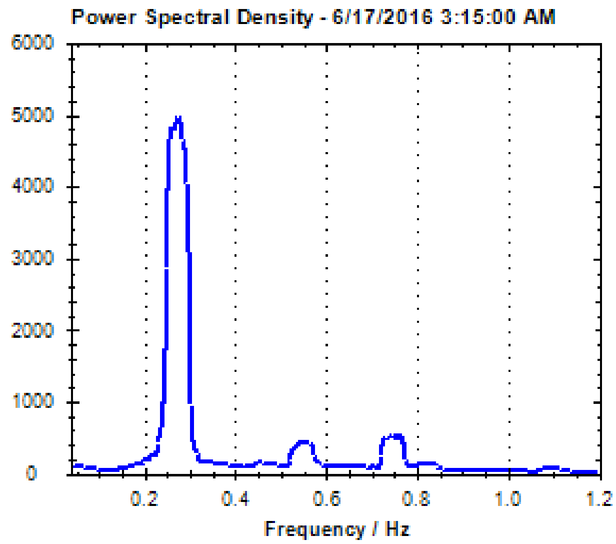


Figure A.1: Power Spectral Density Example

Types of Oscillation Analysis Techniques

There are numerous algorithms and techniques to analyze power system oscillations either in real-time tools or offline analysis. IEEE Power and Energy Society (PES) developed a comprehensive technical report, *Identification of Electromechanical Modes in Power Systems,*[27] on power system oscillations and modal identification methods used to study electromechanical modes. It also describes experience and performance of these methods in actual tools. Consider referring to that document for a much more detailed description of some of the techniques described here.

Ringdown Methods

Ringdown methods are used to analyze natural oscillations that result from large disturbances on the BPS (e.g., faults, switching action, loss of generation or load, etc.). These methods include, but are not limited to, the following:

- **Prony Methods:** Prony's original method proposed in 1795 estimates damped sinusoidal components in a linear system response by expressing the system outputs as linear combinations of fundamental sinusoidal modal components. Prony methods have evolved a lot over the years and the modern versions include singular value decompositions (SVDs) for handling the measurement noise and for reducing the computational burden. This method can estimate the dominant mode frequencies, their damping levels, their mode shapes, and relative energy levels from multiple measurements.

- **Eigensystem Realization Algorithm:** The Eigensystem Realization Algorithm is a system identification method well suited for the identification of lightly damped oscillations. Its application in a variety of fields is well documented. In this method, the number of significant modal components in a given signal (or signals) is obtained from the singular value decomposition of a matrix whose entries are samples of the system impulse response (Hankel matrix). Typically, this is a relatively small number. Using this information, a reduced linear system realization is computed (i.e., the system state matrices). The significant modal damping ratios and frequencies in the given signals can be readily computed from the reduced system.

- **Matrix Pencil:** The Matrix Pencil method formulates the ringdown analysis problem as a generalized eigenvalue problem of an associated matrix pencil. This involves computation of a pseudo-inverse of a matrix that is done using an SVD technique. This also includes a built-in filter for leaving out noise-related phenomena in the SVD formulation.

[27] 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*)*

- **Variable Projection (VARPRO):** The Variable Projection method is a general nonlinear least-squares optimization technique for fitting a waveform to a basis of fundamental curves. In the context of modal analysis, the input waveform is the measured ringdown response expressed in terms of a combination of exponentially damped oscillatory waveforms. The basis of curves used in the method include exponentially damped oscillatory waveforms, simple exponentials, and detrending waveforms. The results of the variable projection curve-fitting process are the frequency, damping, amplitude, and phase of each oscillatory component in the response; the amplitude and decay of each exponential component; and the coefficients of the detrending waveforms. This method is distinguished from other common techniques for modal analysis in that it is a direct curve-fitting technique.[28]

- **Hankel Total Least Squares (HTLS):** HTLS first formulates a Hankel matrix from the observed PMU measurements of the event and then uses a Total Least Squares approach for evaluating the eigenvalues again using a SVD computation. By modeling the noise explicitly in the formulation, the HTLS approach is somewhat better in handling noisy data compared to the other methods.

- **Frequency Domain Methods:** In frequency domain ringdown analysis methods, such as Multi-dimensional Fourier Ringdown Algorithm (MFRA),[29] the method identifies the system modes by finding the local peaks in the Fast Fourier Transform (FFT) response of the outputs first. Then the damping of the modes is estimated by tracking how the energy of the mode in the frequency domain changes over time. Frequency domain methods for oscillation detection use the fact that the energy in PMU measurements remains relatively constant over time under ambient conditions. When a sustained oscillation begins, it adds significant energy to the collected measurements. Frequency-domain methods for sustained oscillation detection operate by monitoring the signal energy of measurements for significant changes. Detectors operate in the frequency domain because the energy in sustained oscillations is not evenly distributed over the frequency ranges captured by PMU measurements. A significant increase in a frequency range's energy indicates that a sustained oscillation is present in that frequency range.[30]

Ambient Methods

Ambient methods are used to analyze signals during normal steady-state conditions where the primary excitation to the system is random load changes. These methods include, but are not limited to, the following:

- **Yule-Walker:** The Yule-Walker algorithm is a block-processing method of estimating the frequency and damping ratio of electromechanical modes from ambient synchrophasor measurements. The 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.[31]

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

[29] Z. Tashman and V. Venkatasubramanian, "Multi-dimensional Fourier Ringdown Analyzer for Power Systems using Synchrophasors," Power Systems, IEEE Transactions on , vol.29, no.2, pp. 731–741, Mar. 2014.

[30] In (Donnelly, Trudnowski, Colwell, Pierre, & Dosiek, 2015) and (Kosterev, et al., 2016), this approach is used with four frequency bands while in (Follum & Pierre, 2016) individual frequency bins are examined:

Donnelly, M., Trudnowski, D., Colwell, J., Pierre, J., & Dosiek, L. (2015). RMS-Energy Filter Design for Real-Time Oscillation Detection. *2015 IEEE Power & Energy Society General Meeting*, (pp. 1–5). Denver, CO.

Kosterev, D., Burns, J., Leitschuh, N., Anasis, J., Donahoo, A., Trudnowski, D., Donnelly, M., Pierre, J. (2016). Implementation and Operating Experience with Oscillation Detection Application at Bonneville Power Administration. *Proceedings of CIGRE 2016 Grid of the Future*. Philadelphia.

Follum, J., & Pierre, J. W. (2016, May). Detection of Periodic Forced Oscillations in Power Systems. *Power Systems, IEEE Transactions on*, 31(3), 2423–2433.

[31] The method was first proposed in (Pierre et al., 1997). An extension called Overdetermined Modified Yule-Walker that models system zeros was employed in (Wies et al., 2003). Pierre, J. W., Trudnowski, D. J., and Donnelly, M. K. (1997). Initial results in electromechanical

- **Least Squares:** The Least-Squares algorithm is a method of estimating the frequency and damping ratio of electromechanical modes from ambient synchrophasor measurements. The method fits a model that describes the current measurement in terms of past measurements and the current random input. This model is 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. The Least-Squares algorithm can be implemented as a block-processing method, but it can also be implemented recursively to more effectively track changes in the power system.[32]
- **Frequency Domain Decomposition:** Frequency domain decomposition is a multi-dimensional ambient modal analysis algorithm for estimating the frequency, damping ratio, energy level, and mode shape of the dominant modes and oscillations from ambient synchrophasor measurements. In this method, power spectrum density functions of the ambient measurements are first estimated in the frequency domain. SVD is then used to combine and extract the principal singular values of the multiple power spectrum density estimates. Local peaks among the singular values can be shown to correspond to frequencies of system modes and oscillations that are observed in the data. Modal properties can then be estimated by analyzing these principal singular values near the peak frequencies. Fast frequency domain decomposition is a recent accelerated version of the algorithm that is effective in simultaneous processing of hundreds of synchrophasor measurements.
- **Stochastic subspace Identification:** Subspace methods were developed in linear system theory for system identification. Stochastic subspace identification formulations in power system oscillation analysis formulate the PMU measurements as outputs of a linear system that is being excited by unknown random load fluctuations that are modeled as independent white noise inputs. The essential features of the linear system model describing the power system can then be estimated and the Eigen properties provide insight on the dominant system modes and oscillations that are observed in the PMU measurements. Being time-domain methods, stochastic subspace identification algorithms involve solving large-dimensional matrix problems and are generally well-known for estimation accuracy though they are computationally intensive. One of these methods has been improved to be called Fast Stochastic Subspace Identification,[33] which is detailed in the reference material.

Oscillation Detection Methods

Methods have also been developed to detect when sustained oscillations appear. Depending on the algorithm, the targeted oscillations can be forced, poorly damped natural, or either. In the following, descriptions are provided for some of the earliest methods that reflect general detection strategies.

- **Root-Mean-Squared Energy:[34]** This approach operates by detecting sudden increases in energy associated with sustained oscillations. Input synchrophasor measurements are first filtered to focus on frequency bands

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mode identification from ambient data. *Power Systems, IEEE Transactions on*, 12(3): 1245–1251. Wies, R. W., Pierre, J. W., and Trudnowski, D. J. (2003). Use of ARMA block processing for estimating stationary low-frequency electromechanical modes of power systems. *Power Systems, IEEE Transactions on*, 18(1): 167–173.

[32] RLS techniques are described in the following references:

Zhou, N., Pierre, J. W., Trudnowski, D. J., and Guttromson, R. T. (2007). Robust RLS methods for online estimation of power system electromechanical modes. *Power Systems, IEEE Transactions on*, 22(3): 1240–1249.

Zhou, N., Trudnowski, D. J., Pierre, J. W., and Mittelstadt, W. A. (2008). Electromechanical mode online estimation using regularized robust RLS methods. *Power Systems, IEEE Transactions on*, 23(4): 1670–1680.

Follum, J., Pierre, J. W., and Martin, R. (2016), "Simultaneous estimation of electromechanical modes and forced oscillations," in *Power Systems, IEEE Transactions on*, available online.

[33] Fast Stochastic Subspace Identification: T. Wu, V. Venkatasubramanian, and A. Pothen, ``Fast Parallel Stochastic Subspace Algorithms for Large-Scale Ambient Oscillation
Monitoring'', IEEE Trans. Smart Grid, Vol. 8, No. 3, May 2017, pp. 1494–1503.

[34] Donnelly, M., Trudnowski, D., Colwell, J., Pierre, J., & Dosiek, L. (2015). RMS-Energy Filter Design for Real-Time Oscillation Detection. 2015

associated with different types of oscillations. Next, the root mean squared (RMS) energy of each resulting signal is calculated over a sliding window. Baselining is required to determine the normal range for the signal's energy. Once this range is established, a corresponding threshold is set to detect when the signal's energy increases due to a sustained oscillation. Ideally, signals from several locations in the grid are monitored simultaneously. The locations and frequency bands of signals that trigger an alarm can be used to guide the initial response to the alarm.

- **Periodogram:**[35] The periodogram method is also based on signal energy, but it is specific to forced oscillations and operates in the frequency domain. To begin, the periodogram of the input signal is calculated. The periodogram captures how a signal's power is distributed over frequency. At the frequency of a forced oscillation, the periodogram tends to become very large. The threshold for detection is based on the signal's power under ambient conditions that can be extracted from the signal under analysis. As a result, baselining is not required. The method can detect small oscillations and accurately estimate the frequency of the forced oscillation, characteristics that are useful in some applications.
- **Coherence:**[36] Coherence methods also operate in the frequency domain, but instead of examining a signal's energy, they focus on the relationships between signals. Coherence is a measure of how correlated signals are as a function of frequency. When a sustained oscillation is visible throughout a system, the coherence between signals that are normally unrelated tends to increase at the oscillation's frequency. Alternatively, the coherence between a signal and a delayed version of itself can be examined. A sustained oscillation, present in the signal before and after the delay, increases the coherence and leads to detection. The limited range of the coherence between zero and one simplifies baselining.
- **Oscillation Monitor:** An oscillation monitor operates by detecting any oscillation with near-zero damping. A variety of algorithms can be used to accomplish this task, including ambient methods initially designed to monitor the electromechanical modes that give rise to natural oscillations. Thus, it is important to recognize that an oscillation monitor is primarily concerned with an oscillation's damping, rather than the damping of system dynamics. Once a sustained oscillation is detected based on near-zero damping, it can be categorized as natural or forced and addressed properly.
- **Time Domain Analysis:** Another approach is to detect oscillations in a two stage process:[37] first, detect system events by looking for anomalies in streaming PMU data across multiple signals and second, analyze the ringdown PMU data to check the modal properties of the ringdown response. This approach has the advantage that it can detect poorly damped, undamped, and negatively damped oscillations. Also, the time window of analysis typically much shorter than the other methods and the method tends to be responsive to sudden changes in system operating conditions.

IEEE Power & Energy Society General Meeting, (pp. 1–5). Denver, CO.

Kosterev, D., Burns, J., Leitschuh, N., Anasis, J., Donahoo, A., Trudnowski, D., . . . Pierre, J. (2016). Implementation and Operating Experience with Oscillation Detection Application at Bonneville Power Administration. Proceedings of CIGRE 2016 Grid of the Future. Philadelphia.

[35] Follum, J., & Pierre, J. W. (2016, May). Detection of Periodic Forced Oscillations in Power Systems. IEEE Transactions on Power Systems, 31(3), 2423–2433.

And

J. Follum, F. Tuffner and U. Agrawal, "Applications of a new nonparametric estimator of ambient power system spectra for measurements containing forced oscillations," *2017 IEEE Power & Energy Society General Meeting*, Chicago, IL, 2017, pp. 1–5.

[36] Zhou, N. (2013, July). A coherence method for detecting and analyzing oscillations. Power and Energy Society General Meeting (PES), 2013 IEEE, (pp. 1–5).

Zhou, N., & Dagle, J. (2015, Jan). Initial Results in Using a Self-Coherence Method for Detecting Sustained Oscillations. Power Systems, IEEE Transactions on, 30(1), 522–530.

[37] Oscillation Event Analysis: G. Liu, J. Quintero, and V. Venkatasubramanian, "Oscillation monitoring system based on wide area synchrophasors in power systems," Proc. IREP Symposium on Bulk Power System Phenomena-VII, Revitalizing Operational Reliability, Charleston SC, August 2007.

Source Location Methods

There are different methods used for identifying the source location of an oscillation:

- **Mode Shape of the Oscillation Analysis:** When the forced oscillation does not significantly interact with system modes, the mode shape of the oscillation (i.e., its amplitude and relative phasing as seen by analyzing the MW or MVAR outputs of power plants) can directly point to the source of forced oscillations. When resonance is present between the forced oscillation and a system mode, the mode shape may be misleading.[38] However, when the resonance effect is weak, the mode shape analysis of available PMU signals can indicate the source of a forced oscillation. For oscillations related to reactive power issues, voltage magnitude signals or MVAR plant outputs can be used. For oscillations related to active power issues (e.g., speed governor malfunctioning), voltage phase angles or MW plant outputs can be used in mode shape analysis. Recently, techniques based on SCADA MW and MVAR plants have been proposed as well.

- **SCADA Based Approaches:** While SCADA measurements are not collected at a high enough sampling rate to fully analyze power system oscillations, they can often help identify the oscillation's source. After an oscillation is detected using synchrophasor measurements, SCADA data from before the oscillation occurred is compared to measurements collected during the oscillation.[39] Units with significant increases in the level or variation of power output are automatically identified as likely sources of the oscillation.

- **Energy Function Analysis (Dissipating Energy Flow method by ISO-NE):** This energy-based method calculates the flow of the Dissipating Energy (DE) component of transient energy in the network during the oscillatory process. Dissipating Energy flows from the source(s) to sink(s) of oscillations. Tracing the DE flow in the network allows identification of the source(s) of oscillations. This methodology is described by Lei Chen in her 2016 paper.[40] DE can be calculated for any transmission element (e.g., line, transformer, and generator) by using frequency, voltage, and current PMU measurements. The dissipation energy flow method is a version of energy-based method for robust, practical implementation with actual PMU data by using PMU data preprocessing. The method allows for the identification of a specific generator/power plant as the source of oscillations at sufficient observability of the network by PMU; the identification of a specific area as the source of oscillations by using PMU measurements on tie-line between areas and significant localization of the suspect zone-source of oscillations at limited observability of network by PMU.[41]

Other Classifications of Analysis Methods

The various types of oscillation analysis methods can also be classified in different ways. These include the following:

- **Time Domain vs. Frequency Domain:** Given the linear system formulation of the small-signal analysis assumed in this report, the system dynamics can be analyzed either in time-domain or in the frequency domain. Accordingly, many algorithms for oscillation ringdown modal analysis as well as ambient modal analysis have been developed in both time-domain and in-frequency domain. In general, time-domain methods are considered more accurate given ideal conditions even though they tend to be sensitive to measurement noise and assumptions (e.g., the choice of model order) and also tend to be computationally intensive from the handling of large-size matrices. Large model orders may be needed for effective handling of noise, but this introduces spurious modes into the analysis results that require careful filtering to interpret estimation results. In contrast, frequency domain methods can inherently handle noise issues better by focusing on the modal frequency content of interest and are also generally computationally faster by

[38] S.A.N. Sarmadi, and V. Venkatasubramanian, ``Interarea Resonance in Power Systems From Forced Oscillations,'' IEEE Trans. Power Systems, January 2016, Vol. 31, No. 1, pp. 378–386.

[39] J. O'Brien, T.Wu, V. Venkatasubramanian, and H. Zhang, ``Source location of forced oscillations using synchrophasor and SCADA data,'' Proc. Hawaii International Conference on System Sciences, 2017.

[40] Chen Lei, Min Yong, Hu Wei. An energy-based method for location of power system oscillation source. IEEE Transactions on Power Systems, 2013, 28(2): 828836.

[41] Slava Maslennikov, Bin Wang, Eugene Litvinov "Dissipating Energy Flow Method for Locating the Source of Sustained Oscillations," International Journal of Electrical Power and Energy Systems, Issue 88, 2017, pp.55–62

decomposing the analysis into parallel handling of different modes. However, simplifying assumptions made in the frequency domain formulations tend to make the results more approximate compared to the time-domain methods.

- **Recursive vs. Block Processing:** In PMU data based oscillation analysis, there are two classes of algorithms, namely, recursive and block processing methods. In recursive methods, the system model is adjusted continuously a little at a time by using the latest observed measurements. In this sense, the system is assumed to evolve continuously over time that the model continuously tries to keep track of. In contrast, the block processing methods formulate the system model for each estimation instant by using a block of recent observations without using recent estimates. Recursive methods are faster in implementation since they handle smaller data blocks and since the model is adjusted incrementally at each estimation instant. Block processing methods require larger data analysis windows to estimate the system models and are computationally more intensive. For sudden changes in system conditions such as in the case of switching actions, the analysis length of block processing methods can be shortened to improve tracking at the expense of estimate variance. Recursive methods can be designed to make a similar trade-off using a parameter that can be adjusted following system events. Data quality is also an important factor in the accuracy of the recursive methods, since any estimation error introduced tends to linger longer owing to the memory effect inherent in recursive methods.

Parameters Utilized for Analysis

For ringdown analysis, Prony, Matrix Pencil, HTLS, and the Eigenvalue Realization Algorithm are used. For ambient modal analysis, Fast Frequency Domain Decomposition and Fast Stochastic Subspace Identification are used. The tools were run on a specialized platform to run offline oscillation analysis. The tools used rank dominant modes on relative energy rather than absolute energy. In the analysis, whenever a trend was identified in the data, a bandpass filter with corners at 0.1 Hz and 10 Hz could be applied to the data; however, the analysis for these events utilized no filtering of the posted data by default. Both direct voltage angle differences and frequency differences were utilized for the majority of events; however, the first derivative of voltage angle differences was utilized where the study group found the estimates to have a poor fit in the voltage angle differences or frequency differences. The data was not downsampled; however, signals that had significant consecutive time or percentage of missing data were discarded from the analysis.

Appendix B: Past Oscillation Analyses

This section details past studies of interarea oscillations performed by utilities across North America. These studies are intended to inform.

2005–ISO-NE Study

ISO-NE, in collaboration with Powertech Labs, performed a small signal stability study for the ISO-NE region exploring the impacts of critical contingencies and power transfers on local and interarea modes. The study also examined the role and performance of PSSs in mitigating such oscillations. Seven base cases and all N-1 345 kV circuit outages were considered. The study identified some poorly damped local modes as well as interarea modes at 0.26 Hz, 0.47 Hz, 0.66 Hz, and 1.0 Hz. For each oscillation considered in detail, the participation factors of each generator in the ISO-NE region were identified and PSS tuning studies were performed

In particular, the analysis identified two key interarea oscillation modes that were shown to have low damping:

- Peak load conditions: 0.7 Hz and 0.8 Hz modes close to 4% damping ratio
- Light load conditions: 0.66 Hz mode close to 3% damping ratio

Figure B.1 shows the mode shape for the 0.66 Hz mode under light load conditions.

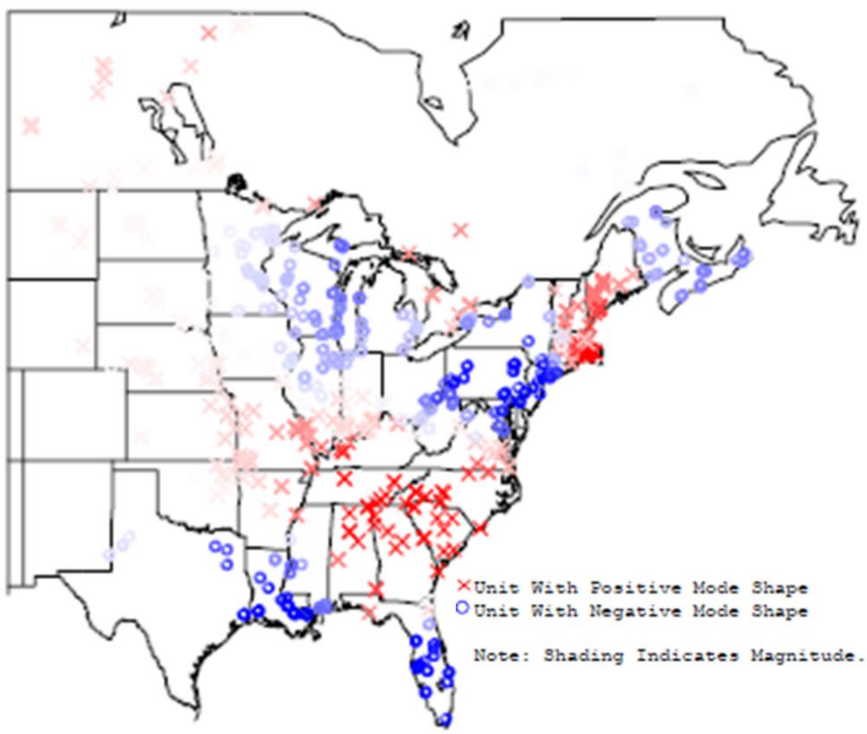

Figure B.1: Mode Shape of 0.66 Hz Mode for Light Load Base Case Conditions [Source: ISO-NE]

The observable modes in the ISO-NE system were the primary focus of the study. However, to determine the modes in which generators in the ISO-NE system were participating in, the full set of oscillation modes were explored. **Table B.1** shows the oscillation modes with less than 5% damping for one of the light load cases explored. Of those, the 0.66 Hz and 0.73 Hz modes were observable in the ISO-NE system.

Table B.1: Low Damping Modes for a Light Load Case	
Frequency (Hz)	**Damping (%)**
0.80	3.00
0.66	3.52
0.96	3.81
0.73	4.39
0.0	4.69
0.99	4.84
0.85	4.91

2010–MISO and MRO Study

MISO, in collaboration with Powertech Labs, performed a small signal stability study for the MRO region in 2010. This analysis, among other things, analyzed the local and interarea low frequency oscillation modes observable in the MRO footprint. **Table B.2** shows the system modes for the study cases considered.

Table B.2: Interarea Oscillation Results from MRO Study in 2010 [Source: MISO]										
Mode	**2015 LL**		**2015WP**		**2015SH**		**2015SH1**		**2015SH2**	
	Freq. (Hz)	**Damping (%)**	**Freq. (Hz)**	**Damping (%)**	**Freq. (Hz)**	**Damping (%)**	**Freq. (Hz)**	**Damping (%)**	**Freq. (Hz)**	**Damping (%)**
1	0.35	9.49	0.35	9.37	0.35	8.89	0.34	8.72	0.34	7.94
2	0.42	5.07	0.41	5.4	0.41	3.98	0.41	3.93	0.41	3.92
3	0.45	6.13	0.44	6.14	0.44	6.02	0.43	5.19	0.43	4.84
4	0.47	5.87	0.47	6.80	0.47	5.75	0.47	5.98	0.47	5.98
5	0.54	4.03	0.54	4.61	0.53	3.21	0.52	2.84	0.51	2.69
6	0.58	8.39	0.57	8.17	0.57	7.94	0.58	7.97	0.58	7.98
7	0.69	7320	0.57	7.33	0.66	8.56	0.65	5.71	0.65	5.32
8	0.70	5.27	0.68	8.97	0.67	6.19	0.72	7.07	0.72	6.96
9	N/A	N/A	0.79	5.31	0.72	7.16	0.37	7.52	0.37	7.56

2013–WECC

In 2013, the WECC in their JSIS subcommittee presented a report whose intent was to characterize the modes of oscillations in an Interconnection, so that they can model them appropriately in power system studies, and to develop operating procedures and mitigation measures. Simulations were performed to benchmark oscillation performance[42]

[42] See full report at https://www.wecc.biz/Reliability/WECC%20JSIS%20Modes%20of%20Interarea%20Oscillations-2013-12-REV1.1.pdf

This paper summarizes the modal properties of the dominant interarea modes in the wNAPS. The primary focus has been on the most wide-spread and troublesome NS Mode A and the NS Mode B. Initial work on EW Mode A has also been presented. The properties are estimated based upon several years of actual-system data analyses and to a lesser extent, model-based analysis. NS modal properties include the following:

- NS Mode A is typically near 0.25 Hz. Its damping is typically larger than NS Mode B with typical damping near 10–15%.
- NS Mode B is typically in the 0.35 Hz to 0.4 Hz range with a damping of 5% to over 10%.
- The shape for NS Mode A has the northern half of the wNAPS swinging against the southern half. By far, the most dominant observability point is the Alberta Canada area of the system. The node or dividing line is very close to Malin on the COI.
- The shape for NS Mode B has the Alberta area swinging against BC and the northern US, which in turn swings against the southern part of the US. The northern node or dividing line is just south of Langdon on the BC/Alberta intertie. The other node is typically south of Tesla and north if Diablo Canyon. The observability is much more widespread than NS Mode A in that no one location is dominant.
- The controllability of NS Mode A is dominated by Alberta while the controllability of NS Mode B is very wide spread. Therefore, contingencies outside Alberta primarily excite NS Mode B.
- The Alberta-BC intertie has the largest impact on the two modes. When Alberta disconnects, the two modes "melt" into one mode typically near 0.32 Hz. This mode typically is more lightly damped. The shape for this mode is very similar to NS Mode B excluding the Alberta area PMUs.

EW Mode A is very near in frequency to NS Mode B. Based upon one day of measurement, the mode seems to have the eastern portion of the system centralized in Colorado oscillating against the system. The mode can also be observed in smaller amplitude in southern California. This paper also demonstrates the need for continued monitoring of these modes and to get a better understanding of lesser visible modes and future modal shapes.

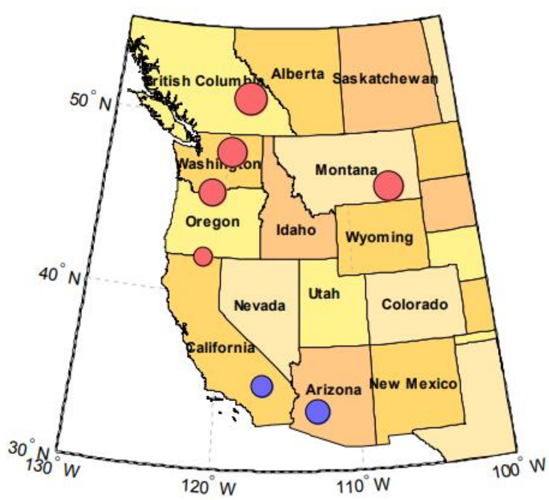

Figure B.3: Map of the NS Mode B Shape [Source: WECC]

Appendix C: Contributors

NERC would like to thank all members of the NERC SMS for their guidance in developing this report. NERC would also like to thank the RCs for their willingness and support in sharing wide-area, time-synchronized PMU data for this analysis. Each of REs also played a key role in ensuring this data was submitted effectively. Lastly, NERC would like to thank Dr. Mani Venkatasubramanian for his expertise in analyzing the grid events. In addition, NERC would also like to thank the DOE CERTS program for funding in this endeavor.

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