NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Eastern Interconnection Oscillation Disturbance

January 11, 2019 Forced Oscillation Event

December 2019

RELIABILITY | RESILIENCE | SECURITY




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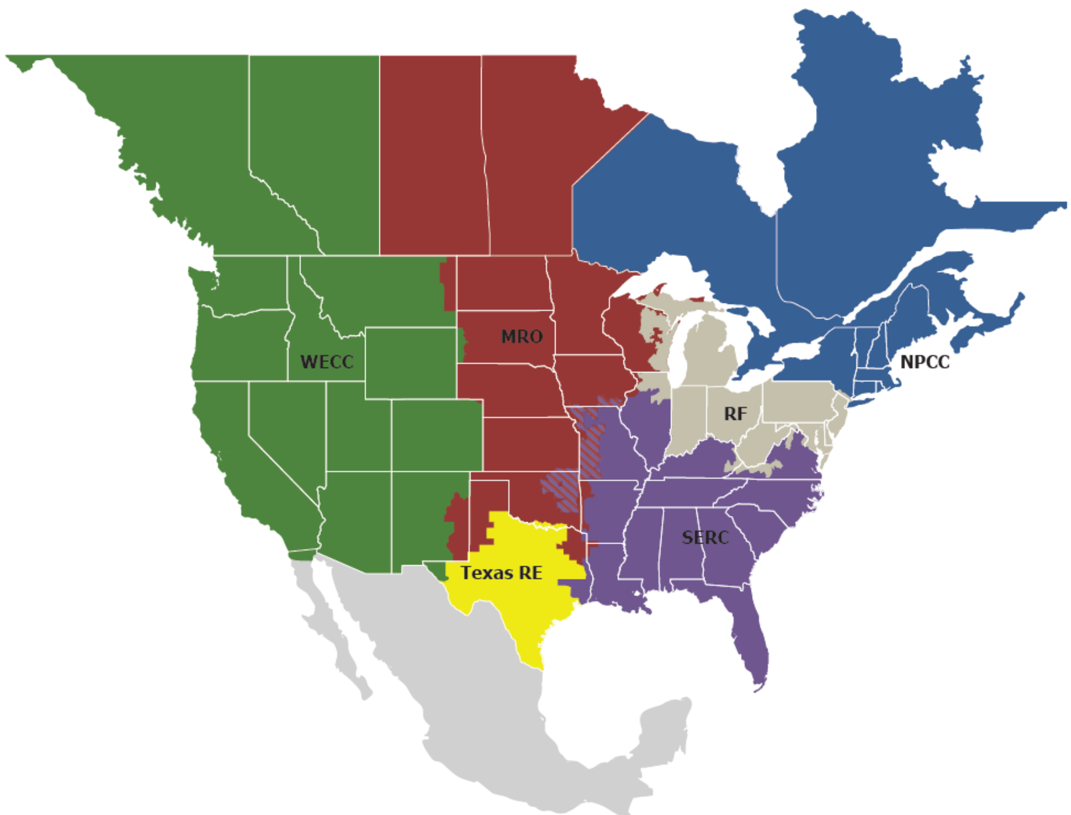
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (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

On January 11, 2019, a steam turbine at a combined cycle power plant in Florida experienced a faulty input to a control system that resulted in oscillations that persisted for around 18 minutes before the plant operator manually removed the unit from service. The oscillations were caused by a perceived power load imbalance (PLI) condition in the turbine controls that was initiated by a failed potential transformer (PT) connection and errored voltage measurement in the control system. The source of the oscillation was removed by the plant operator taking actions to shut down the plant following identification of inadvertent intercept valve operations due to the failure. The steam turbine experienced an oscillatory behavior that occurred near a 0.25 Hz frequency (about a four-second periodic behavior) that interacted[1] with the natural system modes of the Eastern Interconnection (EI). For this reason, the oscillation propagated through the entire EI, impacting entities across the EI. This was observed by phasor measurement units (PMUs) and other dynamic disturbance recording devices across all Reliability Coordinators (RCs) in the EI (see **Figure E.1**).

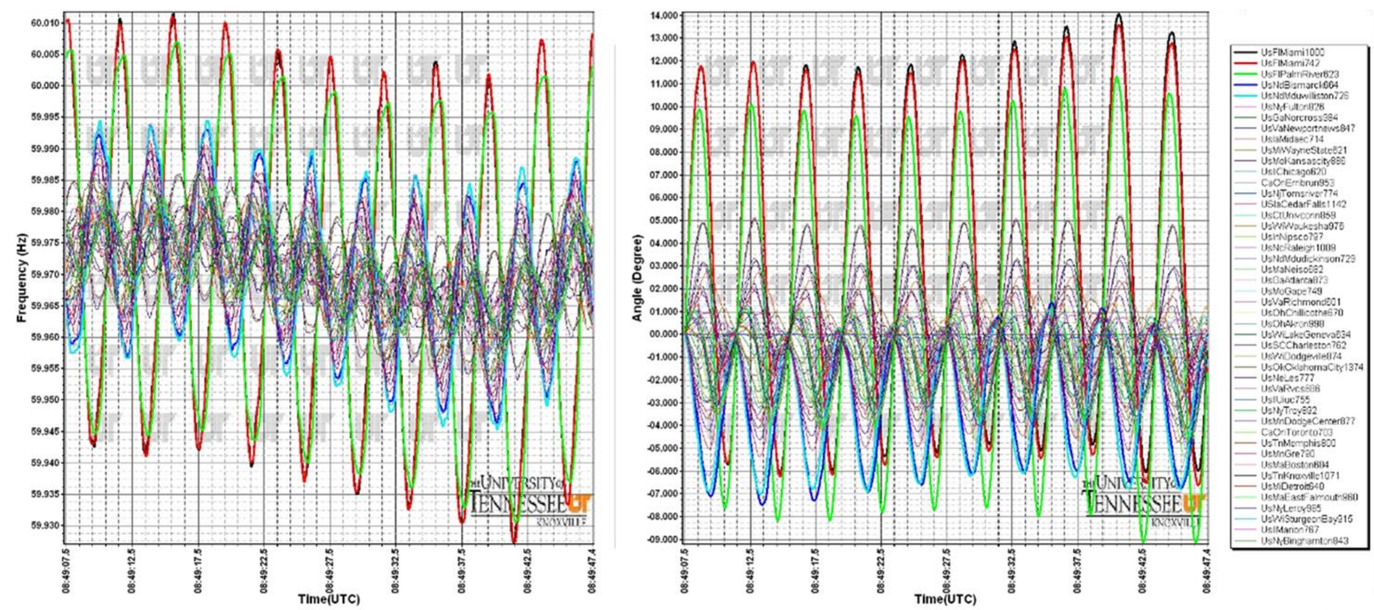


Figure E.1: Frequency and Phase Angle Measurements from across EI[2]
[Source: UTK/ORNL]

While the disturbance was not a categorized event per the NERC Event Analysis Process,[3] the interconnection-wide impacts of this oscillation warranted a more detailed analysis by the ERO and affected stakeholders. **Chapter 1** of this report describes the local plant disturbance that resulted in a forced oscillation and discusses multiple aspects of the oscillation disturbance. **Chapter 2** describes NERC oscillation analysis to characterize the forced oscillation and its resonance with natural system modes.

The goal of this report is to document the root causes of the oscillation, determine the reasons for propagation of the oscillation throughout the EI, and provide key findings and recommendations to the industry for proactive mitigation of potential future oscillation events.

[1] This interaction between the forced oscillation and natural system mode is often referred to as "resonance" or a "resonant forced oscillation."
[2] Captured from the FNET/GridEye system: https://powerit.utk.edu/fnet.html
[3] https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

Key Findings

Key findings identified during the analysis of the forced oscillation within the plant include the following:

- A failed PT connection and errored voltage measurement in the PLI turbine controls caused a steam turbine at a combined-cycle power plant to oscillate for around 18 minutes before local plant personnel removed the unit from service.
- While redundancy was built into the plant control and protection system inputs, the turbine controls relied on a single PT measurement. This measurement was different from the protection system input PT measurement. Hence, the protection system was unaffected by the failed PT measurement.
- PLI operation caused the intercept valves of the steam turbine to shut and reopen periodically with a cyclical period of about four seconds. This resulted in oscillatory power output with a frequency of around 0.25 Hz.
- Many different alarms that needed troubleshooting to identify their root causes challenged the plant operators. Prioritization of operator alarms is as much an issue for generator control centers as it is for transmission energy management systems.

Key findings identified during the analysis focused on the wide-area impacts of the oscillation disturbance include the following:

- The 0.25 Hz forced oscillation interacted with the natural system mode near that frequency, causing the entire EI to experience the forced oscillation. Two out of the three conditions required[4] for a forced oscillation to strongly resonate with a natural system mode were satisfied. The oscillation frequencies between the forced oscillation and the natural system mode matched, and the source location was in a high participation area of the natural system mode. However, the natural system mode was well-damped.
- The generating unit experienced oscillations of around 200 MW peak-to-peak; however, power swings were observed as far as the New England area of about 50 MW.
- RCs were aware of the oscillation event relatively quickly by using both SCADA data and advanced applications and PMU measurements. RCs sought coordination activities, including use of the RC hotline; however, the RC hotline was inoperable due to technical issues. RCs were forced to call neighboring RCs individually that led to misinformation and mischaracterization of the event initially. Wide-area operator action did not contribute to mitigating the oscillation event, and most tools were ineffective at identifying a source location for the oscillation.
- The forced oscillation appears to have grown in energy until the unit (forcing function) was disconnected from the BPS.
- From an interconnection-wide standpoint, the GridEye/FNET system provided one of the most effective means of quickly understanding the extent of the disturbance. Frequency disturbance recorders and SCADA measurements available to NERC helped quickly identify a potential source of the oscillation and the severity of the event.

[4] S. A. N. Sarmadi, V. Venkatasubramanian, "Inter-Area Resonance in Power Systems From Forced Oscillations," *IEEE Transactions on Power Systems*, vol. 31, no. 1, pp. 378-386, Jan. 2016.

Recommendations

Recommendations based on the key findings identified for the forced oscillation within the plant include the following:

- Generator turbine controls, including PLI and other types of controls that could result in a cyclic behavior from the generator, should avoid using a reset timer that has a period close to the reciprocal of the natural system modes (i.e., T = 1/f). Generally, this is in the range of 0.1–0.8 Hz; this relates to cyclical timers in the range of 1.25 seconds to 10 seconds. In particular, the frequency of the following dominant interconnection-wide modes should be avoided:5
  - Eastern Interconnection: 0.16–0.33 Hz (3.3–6.5 seconds)
  - Texas Interconnection: 0.6–0.75 Hz (1.33–1.66 seconds)
  - Western Interconnection: 0.24–0.42 Hz (2.38–4.17 seconds)
- Turbine controls should not have a single point of failure, including PT and current transformer input measurements that could fail and cause abnormal or unexpected turbine actions.
- The PLI circuit design in the turbine and generator control systems should consider tripping the unit after a short time for these types of persistent alarms to ensure integrity and safety of plant equipment and personnel.
- Training for Generator Operators (GOPs), RCs, Balancing Authorities (BAs), and Transmission Operators (TOPs) outlining root cause analysis and specific actions to take or not to take during oscillation events should be developed and reviewed periodically.

Recommendations based on the key findings focused on the wide-area impacts of the oscillation disturbance include the following:

- RCs should have real-time oscillation detection tools in place to identify when oscillations are occurring, determine if it is limited locally within their footprint or across a wider area, and distinguish between forced oscillations and poorly damped natural system modes.
- RCs should improve communication with neighboring RCs in the event of widespread oscillation disturbances on the BPS. Operating procedures could be an effective means of ensuring this coordination upon identification of an oscillation.
- RCs should consider jointly developing interconnection-wide oscillation detection and source location applications using interconnection-wide PMU and SCADA data.
- The industry should develop open-source, publicly available robust tools for performing oscillation analysis that can be used by various entities:
  - The industry should seek improvements to standardized data formats for offline engineering analysis using large volumes of PMU data.
  - The NERC Synchronized Measurement Subcommittee (SMS) should develop guidance on oscillation analysis methods to encourage consistency in monitored quantities and thresholds.
- Based on a survey of RCs, NERC SMS should develop a white paper identifying any potential gaps or areas for improvement in the NERC Reliability Standards pertaining to RC-to-RC coordination and the use of PMU data.
- Commercially available simulation software should develop or improve the capability of simulating forced oscillations such that grid planners can analyze the effects of these oscillations across the BPS.

[5] Refer to the NERC Oscillation Analysis Report for more details: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf.

Chapter 1: Disturbance Analysis

This section provides a time line of the disturbance, details the results of an SMS survey to RCs in the EI regarding awareness and reactions to the oscillation, and describes the issues experienced within the generating facility that caused the forced oscillation.

Time Line of Disturbance

On January 11, 2019, around 08:44:16 coordinated universal time (UTC), an oscillation was observed in the Florida area as shown in **Figure 1.1**. Subsequently, around 08:44:40 UTC, an oscillation began that persisted for approximately 18 minutes. At around 09:02:26 UTC, the oscillation died down and the BPS returned to normal oscillatory behavior (see **Figure 1.2**). During the oscillation, the dominant oscillation frequency observed across the EI was around 0.25 Hz with a near-zero damping ratio (see **Table 1.1**).[6]

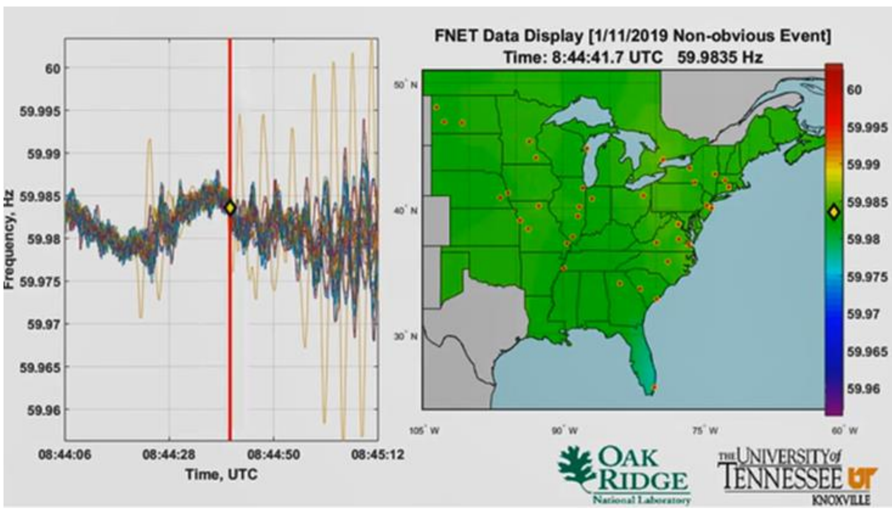


Figure 1.1: Beginning of Oscillation Disturbance [Source: UTK/ORNL]

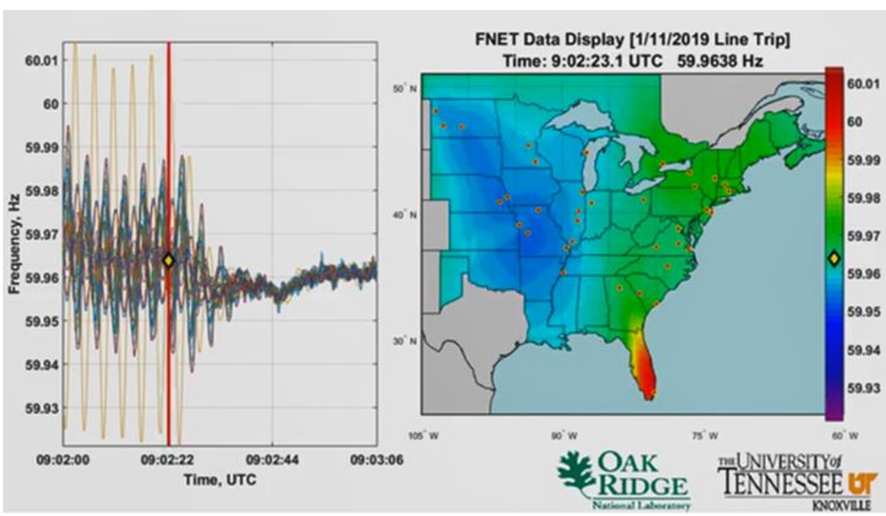


Figure 1.2: End of Oscillation Disturbance [Source: UTK/ORNL]

[6] Forced oscillations are expected to have a low damping ratio since a persistent forcing function exists. This is not necessarily indicative of instability unless the underlying natural system modes are also poorly damped.

Table 1.1: FNET Oscillation Mode Detected [Source: UTK/ORNL]				
Unit Name	**Frequency [Hz]**	**Damping Ratio (%)**	**Phase [deg]**	**Amplitude [deg]**
Mode #1 – Frequency: 0.25 Hz, Damping Ratio: 0.16%, Amplitude: 2.38°				
UsNyFulton826	0.25	0.92	0.64	2.18
UsGaNorcross984	0.25	0.39	-72.11	3.44
UsVaNewportnews847	0.25	0.75	-57.24	1.81
UsFlMiami742	0.25	0.33	-64.35	9.26

Identification of Oscillation Source and RC Actions

As the oscillation quickly evolved from a localized forced oscillation to an interconnection-wide oscillation, several RCs and TOPs began noticing the oscillation on their system through different means. Some observed the oscillation through advanced oscillation tools that utilize PMU data while others noticed the oscillation through SCADA indication due to the severity and prolonged duration of the event. Some TOPs and RCs were made aware of the event by calls from generating plants who had units oscillating in response to their terminal frequency and voltage oscillating. As a result, several units were removed from automatic generation control (AGC) in an attempt to try to fix the perceived oscillation or to try to prevent damage to the units there was little to no information about what was occurring. As the event started to subside, several BAs were considering bringing larger units off-line for safety reasons.

The RC hotline[7] network was unavailable as a result of complications from a previous call. Without the RC hotline available, RCs were forced to directly call neighboring RCs one at a time to share and receive information. This complicated the transfer of information, leading to a slower response as well as inaccurate information being shared. Without a means for sharing information with all RCs and a lack of tools for the entire EI, the source of the oscillation was not confirmed until several hours after the oscillation stopped.

Cause of the Forced Oscillation: Steam Turbine Controls Failure

The forced oscillation occurred on the steam turbine[8] generator at a 4x1 combined-cycle facility that oscillated by approximately 200 MW peak-to-peak until the unit was manually tripped by the plant operator. The oscillation was caused by a perceived mismatch between electrical output power and steam flow (input power), a function of the PLI control. The PLI control interfaces with the fast closing actions on the intercept valves. Refer to **Figure 1.3** for a simplified control diagram, a marked error signal, and the location of the forced oscillation caused by the controls. The perceived mismatch was driven by the failure of a PT connection feeding the calculation of generator electrical power output. When an unbalance is identified by the control system, the control system attempts to remedy the unbalance by controlling the valve position. The controls were programmed to only take action after a 20% imbalance. When the PLI threshold is reached, the controls engage the reheat intercept valves.[9] The valves go through an open/close cycle with a predefined time period.

Upon the closing of the reheat intercept valves, the electrical power output drops quickly, and the imbalance between input and output power is eliminated since both approach zero. Once the threshold is met, a timer is started and

[7] The RC hotline is a secure tool that can be utilized by RCs to communicate with all other RCs throughout the EI for large events like this oscillation event.
[8] The combustion turbine generators were not involved in the oscillation.
[9] The PLI controller is protecting the turbine for overspeed conditions. The intercept valves typically remain wide open during normal operation. When the PLI perceives a mismatch, it is concerned with overspeed and tries to shut the intercept valves to slow down the turbine.

once exceeded when the valves are released. The PLI controls then reopen the values and the unit can again quickly ramp up power output. However, since the PT measurement still failed, the PLI controls again perceive a mismatch and the process is repeated on a continual basis. The periodicity of this closing and reopening of the intercept values was approximately four seconds.

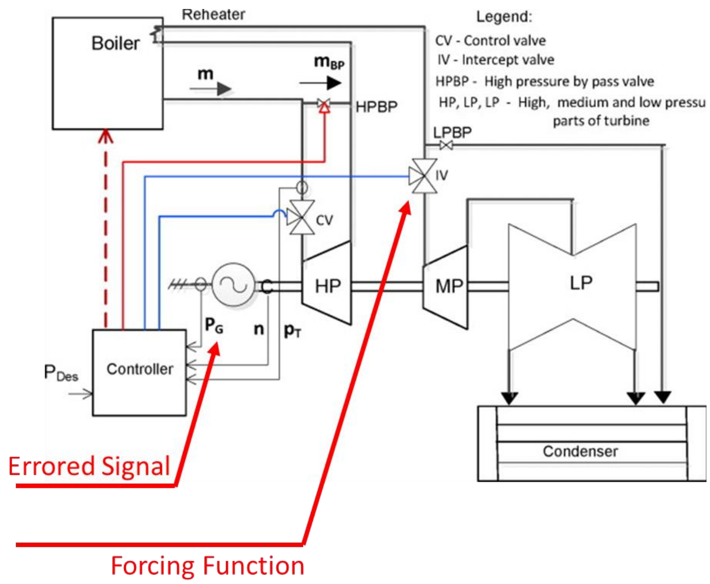


Figure 1.3: Basic Illustration of PLI Failure Mode

The plant digital control system (DCS) alarms went off during the event, particularly the "PLI active" alarm. However, the plant operators were unable to see this alarm during the event. The relays and control systems use different PTs, so the relays never detected any issues on their voltage measurements. The metering PTs feeding the turbine control system use three sets of transducers that provide three independent MW output signals to the plant DCS. The DCS uses a voting scheme that requires two out of the three measurements to match. However, all three transducers are using the same PT input signal, so when one voltage PT measurement failure occurs, all three transducers experience that same failure. The PTs on this controller had a cabinet-type drawer where the secondary side B-phase cabinet had a bad connection that eventually completely opened mechanically. As the connection in the cabinet failed,[10] the calculated MW value reported by the plant DCS was significantly less than the actual MW output.

The local plant operator took actions to remove the plant from the BPS, addressing the primary source of the oscillation. Wide-area RC coordinated actions to identify the source of the oscillation did not contribute to its mitigation. The plant operators received alarms of high thrust position and loss of PT sensing. When the alarms were brought to the attention of the operator, they immediately began to see the intercept valves begin to open and close. However, there were no other alarms to communicate to the operator about the PLI event being triggered. Therefore, the operator began to troubleshoot the reasons for the loss of PT sensing and why the intercept valves were operating. While troubleshooting these issues, the BA was in communication with the plant control room multiple times to ask if there were any issues and to discuss the BPS conditions being observed. When the operators could not determine a reason for the valves operating and were unable to regain control of the unit, the superintendent of plant operations decided to trip the steam turbine. The iterative troubleshooting and assessment took time, and by the time that the superintendent of plant operations made the decision to trip the unit, 18 minutes had transpired.

The plant started seeing spikes in power output and anomalous behavior back in August 2018, five days after an unexpected steam turbine trip. However, the spikes in output were so infrequent that one would not attribute this to a serious issue (e.g., it could be deemed just a periodic loss of signal). It was reported that these spikes occurred every few weeks, but no more than that. Until January 11, it was likely that the connection failures did not cause a sufficient drop in PT measurement for the power calculation to trigger the PLI continuously.

NERC SMS Survey of Reliability Coordinator Awareness and Actions

The NERC SMS issued an informal survey to its member RCs to better understand the level of awareness of the oscillation event and any mitigating actions taken, the level of communication between RCs and any tools used to monitor the interconnection for oscillations, and the desire for a review of potential improvements to NERC Reliability

[10] Vibration over time could have caused the door to move slightly, developing a weak connection for the PT measurement. This was likely a leading candidate for the signal being dropped.

Standards in this area. The survey consisted of seven questions and a general comments section. Eleven utilities participated in the survey, some of which not designated as RCs. **Figure 1.4** shows the questions asked and the results from the survey.

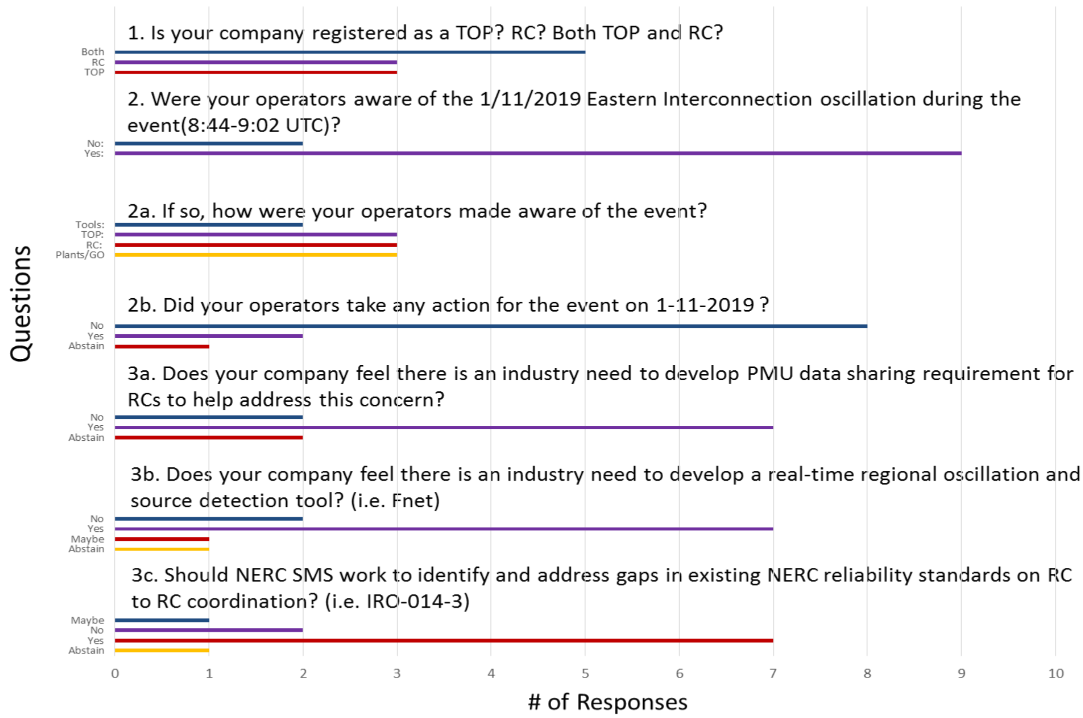


Figure 1.4: NERC SMS Survey Results

Based on NERC SMS review of the survey results as well as follow up discussions with the RCs, the following observations were made:

- Most RCs and TOPs queried were aware of the oscillation event while it was occurring to some extent. While the RCs were aware of the oscillation, the level of situational awareness was relatively low.
- Few RCs took actions during the event to mitigate the oscillation. One entity removed generating units from AGC during the event but failed to mitigate the oscillation in any way.
- RCs need to improve the guidance and operating plans that are provided to system operators on what actions should be taken when oscillation events occur.
- The industry agreed that some form of PMU data sharing requirements for RCs to better identify issues and address interconnection-wide disturbances, such as oscillation events, is warranted. More visibility and effective data sharing and communication are needed for these types of events.
- Existing NERC Reliability Standards should be reviewed closely to determine if the requirements need to be more descriptive to address these types of events. While RCs may have some degree of situational awareness, these types of oscillation events require close RC-to-RC communication to identify the source location and take appropriate mitigating action in a timely manner.

NERC SMS should investigate tools that can provide interconnection-wide oscillation detection and source location. Further, NERC SMS and the NERC Operating Reliability Subcommittee should continue developing training and education materials on oscillation events, particularly focused on appropriate operator actions.

Chapter 2: Interconnection-Wide Oscillation Analysis

The forced oscillation that occurred on a steam turbine at a combined-cycle generating facility in the Florida area was observed across the entire EI. The forced oscillation frequency occurred very close to a natural system mode frequency, resulting in a resonance effect between the two oscillations. RCs, Transmission Owners (TOs), and Generator Owners (GOs) across the EI reported oscillatory behavior at their facilities. **Appendix A** provides observations of the oscillations from across the EI.

This chapter describes the oscillation analysis performed by NERC to characterize the interconnection-wide oscillation and builds off of the recently completed oscillation analysis activities performed by NERC.[11] The goal is to provide industry with useful information related to interconnection-wide oscillatory behavior that can be applicable to all interconnections.

After identifying the extent of this oscillation event, NERC issued[12] a data request to each RC in the EI that sought all PMU data collected during and around the time period of the oscillation.[13] Oscillation analysis was performed by NERC using two analysis tools: Event Analysis Offline and Damping Monitoring Offline.[14] The Damping Monitoring Offline tool was primarily used in this analysis due to the sustained nature of the forced oscillation; however, the Event Analysis Offline tool was also used for benchmarking results. These engines derive the modal characteristics of the electrical signals captured from the PMUs across the EI. In particular, the oscillation frequencies, relative energies, and mode shapes were of most interest to better understand the interaction of the forced oscillation with the system natural modes. Refer to the NERC Interconnection Oscillation Analysis Report for more details.[15]

Oscillation Analysis Results

Oscillation analysis was separated into three distinct timeframes: prior to, during, and after the forced oscillation event. The Damping Monitoring Offline tool[16] was used to determine the oscillation characteristics during each of these timeframes. Electrical quantities from PMUs across many areas of the EI were included in the analysis. **Table 2.1** shows the dominant oscillation frequencies, their relative damping ratio, and their relative energy. The relative damping ratios and energies are ranked on a classification scale of high, medium, and low for illustrative purposes. Results in **Table 2.1** clearly show that the forced oscillation changes the relative damping ratios and energies during the oscillation period. The forced oscillation dominates the oscillatory behavior with a low relative damping ratio and a high relative energy. Prior to and after the forced oscillation, all damping ratios are high and relative energies are medium to low.[17]

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[11] https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf

[12] The data request was issued at 9:05 PM EDT on January 11.

[13] NERC SMS previously established a data request process for gathering interconnection-wide PMU data for oscillation analysis. This process was used for collecting PMU data for this event: http://www.nerc.com/comm/PC/Synchronized Measurement Subcommittee/SMS - Interconnection-Wide Oscillation Baselining and Data Collection Scope Document - 12-14-2015.pdf

[14] https://www.energy.gov/sites/prod/files/2015/07/f24/3.%20Mani%20Oscillation%20Monitoring.pdf

[15] https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf

[16] The results shown use the Fast Fourier Domain Decomposition (FFDD) method and are confirmed by the Fast Stochastic Subspace Identification (FSSI) method. FFDD performs a Fast Fourier Transform (FFT) of all signals in the sliding window and utilizes the frequency domain to determine the power spectral density of the signals. Oscillatory parameters are determined through singular value decomposition. FSSI assumes that the measurements are of a linear system excited by independent white noise inputs. The Eigen properties of the estimations determine system modes and oscillatory parameters. FFDD is a frequency domain analysis; FSSI is a time domain analysis.

[17] The combination of these factors indicates natural system modes that are well-damped.

Table 2.1: Oscillation Modal Characteristics			
Oscillation Frequency	**Prior To Oscillation**	**During Oscillation**	**After Oscillation**
Relative Damping Ratio			
0.2 Hz Mode	High	High	High
0.24–0.25 Hz Mode	High	High	High
0.25 Hz Forced Oscillation	–	**Undamped**	–
0.29–0.33 Hz Mode	High	Medium	High
Relative Energy			
0.2 Hz Mode	Medium	Low	Medium
0.24–0.25 Hz Mode	Low	**High**	Medium
0.29–0.33 Hz Mode	Low	Low	Low

The results in **Table 2.1** and benchmarking between two oscillation analysis algorithms[18] confirm the resonance of the forced oscillation and the natural system modes that are spectrally close in frequency. The risk that this resonance poses to BPS reliability can be based on three factors:[19]

- The forced oscillation frequency is close to system mode frequency.
- The system mode is poorly damped.
- The forced oscillation location is near a strong participation location of the system mode (i.e., a sensitive location for that system mode).

The natural system mode shapes are shown in **Figures 2.1**–**2.3** and match closely to the modes previously identified in the NERC oscillation analyses.[20] The forced oscillation mode shape is shown in **Figure 2.4**. Refer back to **Figure** , which shows a snapshot in time during the forced oscillation period. The different parts of the EI oscillating clearly map to the mode shape plot in **Figure 2.4**.

[18] These algorithms include FFDD and FSSI. Refer to the NERC Interconnection Oscillation Analysis Reliability Assessment, published July 19: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf.
[19] S. A. N. Sarmadi, V. Venkatasubramanian, "Inter-Area Resonance in Power Systems From Forced Oscillations," *IEEE Transactions on Power Systems*, vol. 31, no. 1, pp. 378–386, Jan. 2016.
[20] https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf

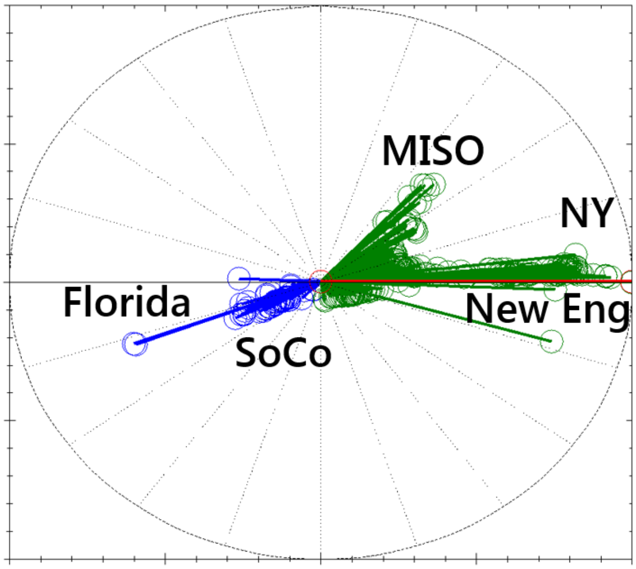

Figure 2.1: 0.2 Hz
System Mode Shape

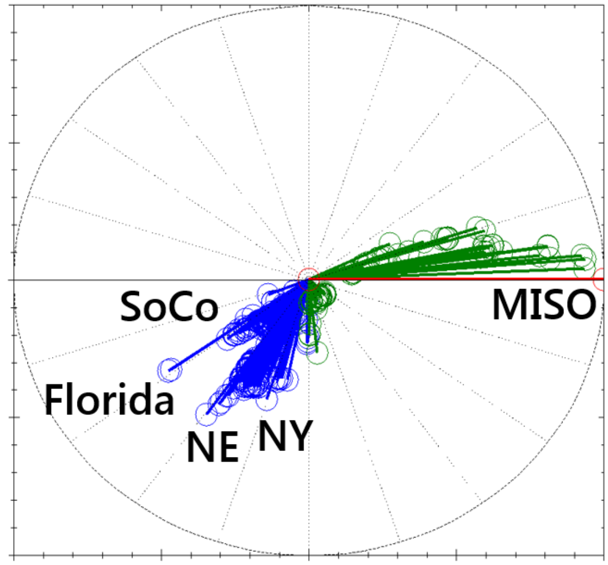

Figure 2.2: 0.24–0.25 Hz
System Mode Shape

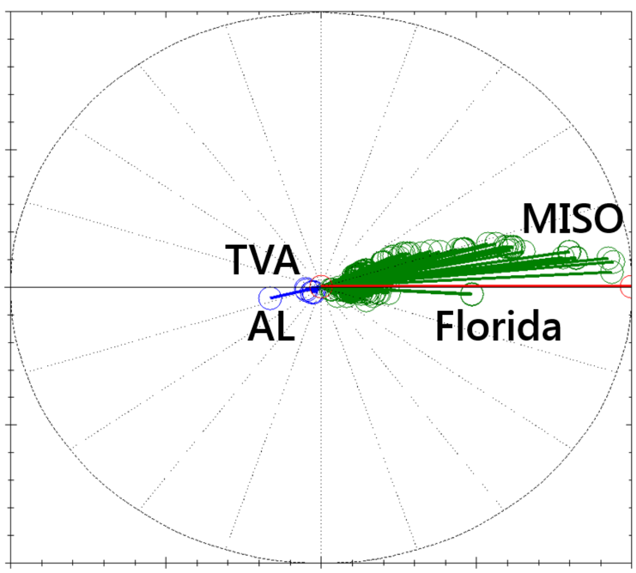

Figure 2.3: 0.29–0.33 Hz
Natural System Mode Shape

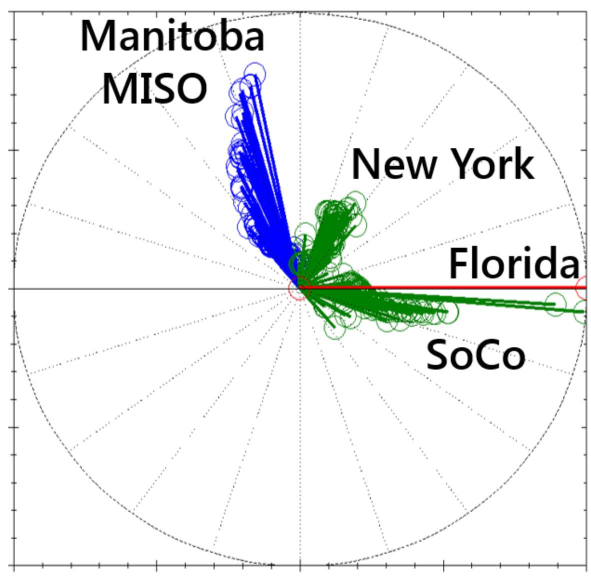

Figure 2.4: 0.25 Hz
Forced Oscillation Mode Shape

Table 2.2 summarizes the resonance effects of the forced oscillations with the system modes. As the table shows, the 0.24–0.25 Hz mode had the greatest risk, particularly since the forced oscillation frequency matched closely with the system mode frequency and occurred in an area of the BPS with strong participation in that system mode. However, the system mode was well-damped, preventing further risk due to strong resonance. The 0.29–0.33 Hz system mode frequency did not match closely with the frequency of the forced oscillation but did have the similar sensitive location with regard to strong participation.

Table 2.2: Forced Oscillation Resonance Summary

Oscillation Frequency [Hz]	Spectral Proximity	System Mode Poorly Damped	Sensitive Location
0.2 Hz	No	No	No
0.24–0.25 Hz	Yes	No	Yes
0.29–0.33 Hz	No	No	Yes

Figure 2.5 shows a time domain representation of the oscillation analysis, illustrating oscillation frequency, damping ratio, energy, and the confidence level estimate. At the time of the forced oscillation, the frequency remains right around 0.23–0.24 Hz. The estimated damping ratio during this time drops to near zero due to the sustained forced oscillation. The oscillation energy continues to grow during the forced oscillation, and confidence level of the estimate is high during this time. Note that the growing oscillation energy across the EI is not well understood at this time. Electrical waveforms from the source of the oscillation show a constant peak-to-peak active power oscillation.

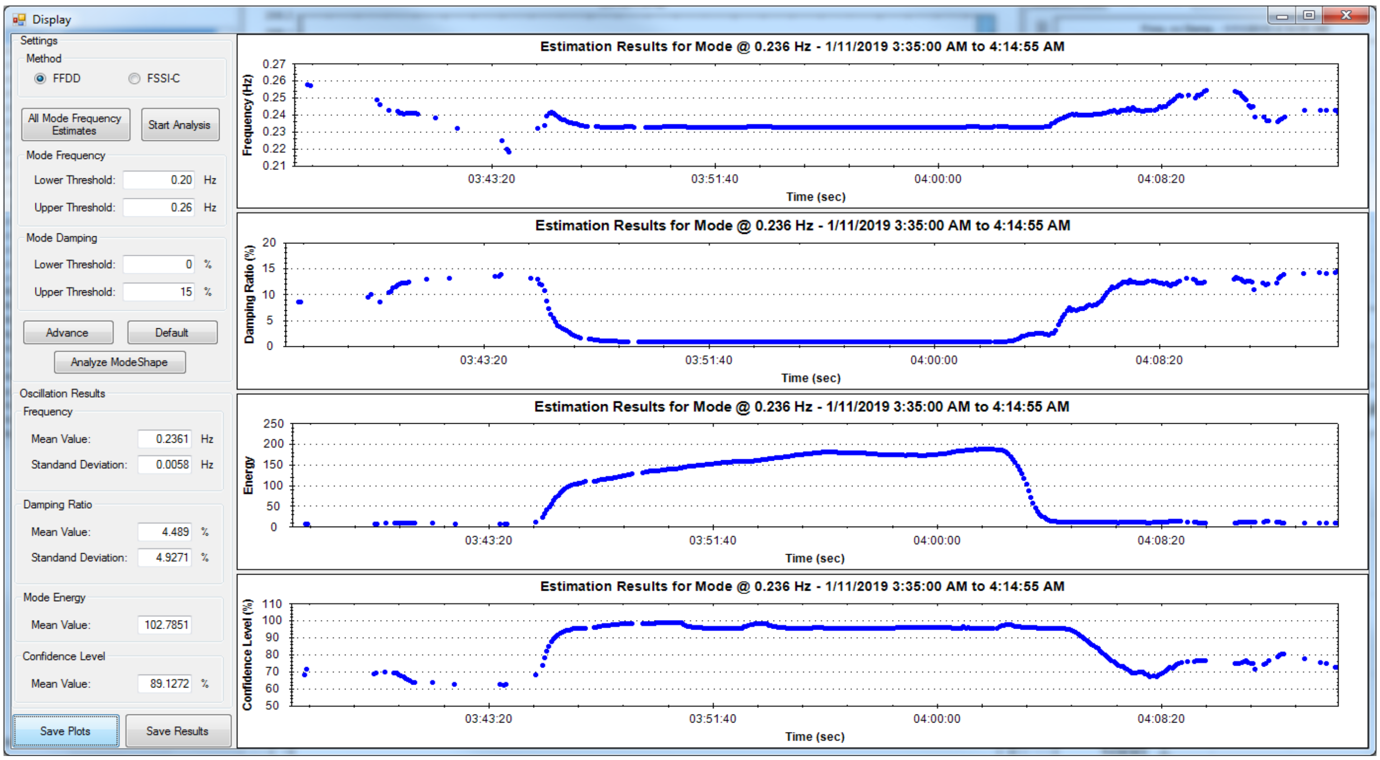

Figure 2.5: Time Series Results of Oscillation Analysis

Figure 2.6 shows a 230 kV bus magnitude during the time of the oscillation, starting with around 4 kV and ending around 8 kV peak-peak swings. The reasons for the growing oscillation energy should continue to be explored by the industry in further studies.

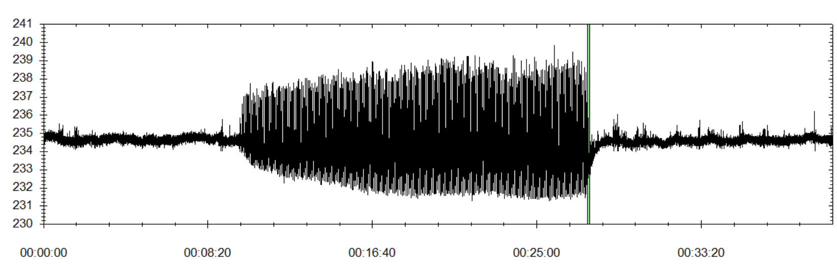

Figure 2.6: Growing Magnitude of Oscillation Observed in Bus Voltage Magnitude

Ringdown analysis at the end of the forced oscillation period was also used to evaluate the damping level of the natural system modes following the removal of the forced oscillation. Upon unit disconnection, the EI exhibited a classical ringdown of frequencies and voltage angles as the system returned to steady-state. **Table 2.3** shows the results from ringdown analysis. The 0.24 Hz mode dominated the relative energy, and its mode shape is shown in **Figure 2.7**.

Table 2.3: Modal Characteristics		
Frequency [%]	**Damping Ratio [%]**	**Relative Energy[%]**
0.24–0.25	12.9	100

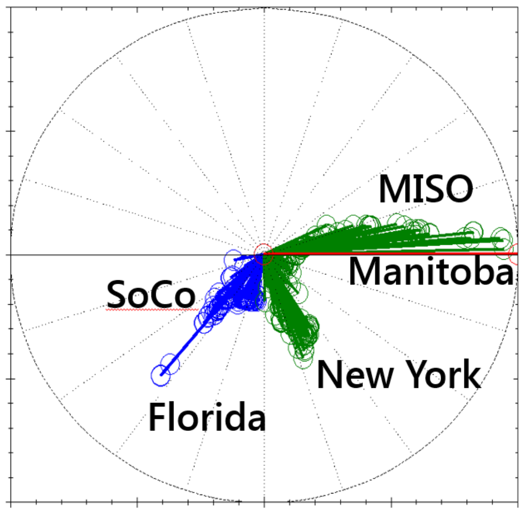

Figure 2.7: Mode Shape for the Identified 0.24-0.25 Hz Mode

Initial estimates of this mode were challenging due to a nonlinear contribution from some PMU measurements. **Figure 2.8** illustrates how a separate forcing function caused the ringdown analysis to identify different modal properties for the 0.24–0.25 Hz mode based on local oscillatory signals. The top plot in **Figure 2.8** from a PMU near the oscillation source shows that the forced oscillation was removed from the system around time 27:25 (relative plot time). The bottom figure in **Figure 2.8** shows that the forced oscillation was present at a different generator electrically far from the oscillation source until around 27:35 (relative plot time).[21] This initially caused incorrect estimation of the damping ratio for the system mode. After changing the time window to be after 27:35 (in **Figure 2.8**), the damping ratio returned to the specified value in **Table 2.3**. Entities using PMU measurement data sets[22] should ensure that any signals containing spurious or nonlinear measurements are omitted from the analysis dataset. Verifying the oscillation analysis results by using results from multiple signal groups and different time windows also helps verify the validity of the results.

[21] The persisting oscillatory behavior was attributed to voltage regulator controls tuning issues at that generating facility. The owner of this data was notified of this issue.

[22] This concept would also apply to tools using other time synchronized data sources and SCADA data.

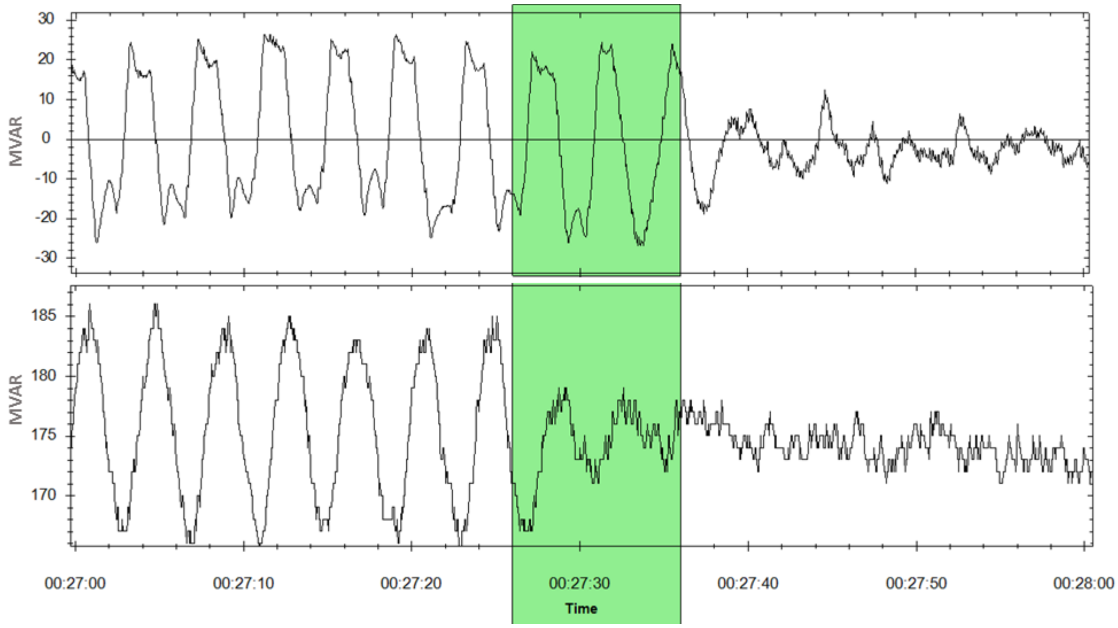

Figure 2.8: Window Demonstrating Forced Oscillation Overlap

Figure 2.9 shows the estimates of oscillation frequency and damping ratio during the forced oscillation event. Each red box shows an estimate cluster associated with one mode or oscillation. The results show the simultaneous presence of the 0.25 Hz forced oscillation (cluster with zero damping) and a well-damped natural system mode at around 0.24–0.25 Hz (the other cluster around that frequency). There are also noticeable system modes that are well-damped around 0.2 Hz and 0.33 Hz. Mode shapes for the system modes during the event match those from pre-event and post-event time periods.

The oscillation analysis demonstrates that the increasing visibility of electrical quantities within a natural system mode shape helps improve a detailed analysis of the mode shape and allows for a higher fidelity of results. An interesting feature of this forced oscillation event was the growing energy of the oscillation in some portions of the BPS during the event, which was only mitigated by the manual tripping of the forcing function. Oscillation analysis confirmed that two of the three factors required for resonance between the natural system modes and the forced oscillation were satisfied. A possible local control tuning issue was identified and reported accordingly.

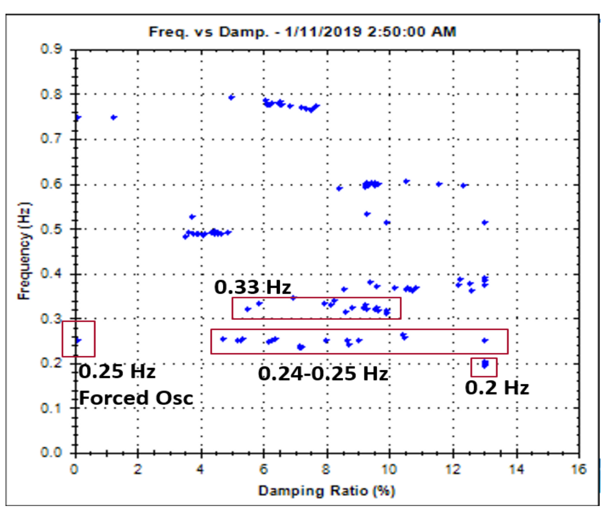

Figure 2.9: Estimate of Modes during Oscillation Event

Appendix A: Observations of Forced Oscillation Event

RCs from across the EI provided the following plots of observed oscillations in electrical quantities that occurred during the disturbance. These plots are provided here to illustrate the extent to which the oscillation was observed across the EI. Refer to the figure captions for details on the locations of each plot.

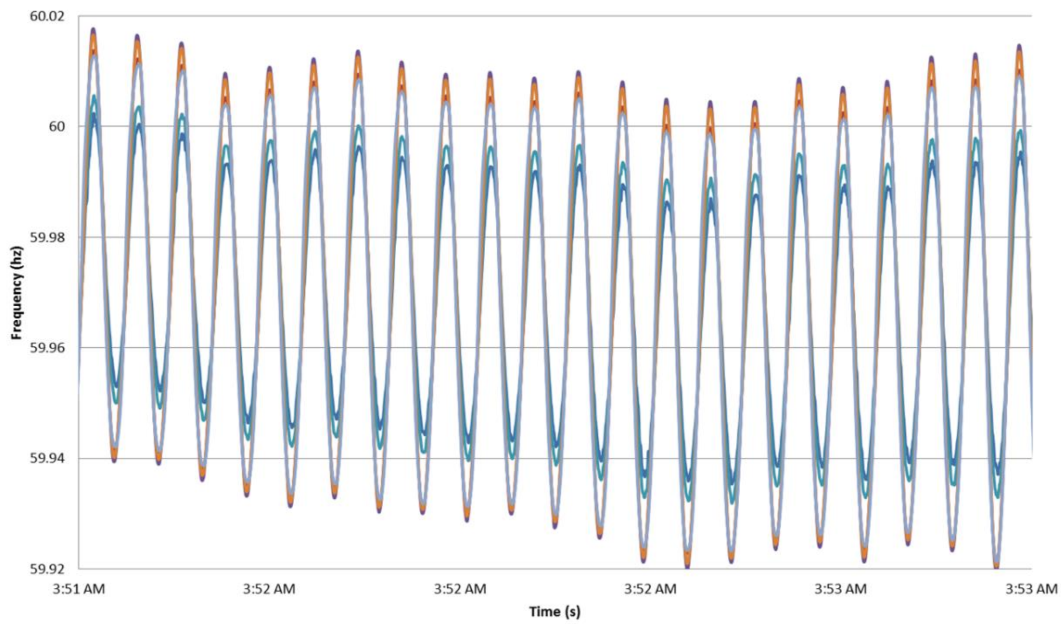

Figure A.1: Frequencies in FPL Footprint
[Source: FPL]

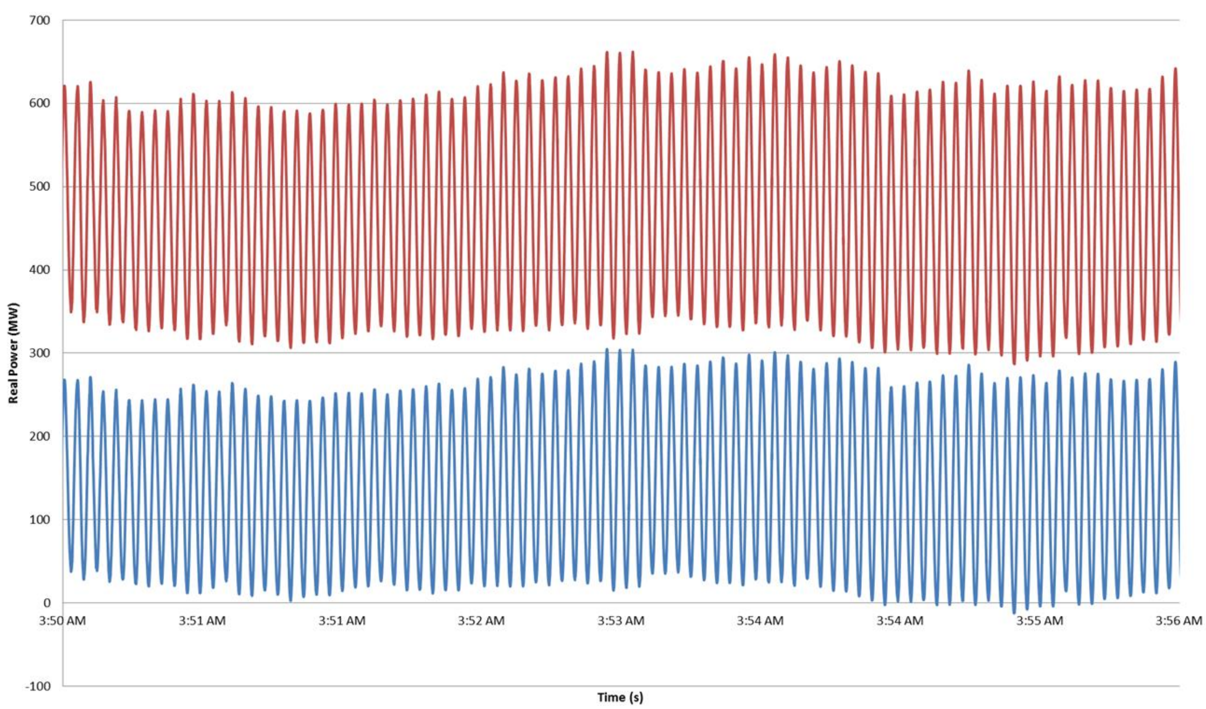

Figure A.2: 500 kV Line Active Power Flows in FPL Footprint
[Source: FPL]

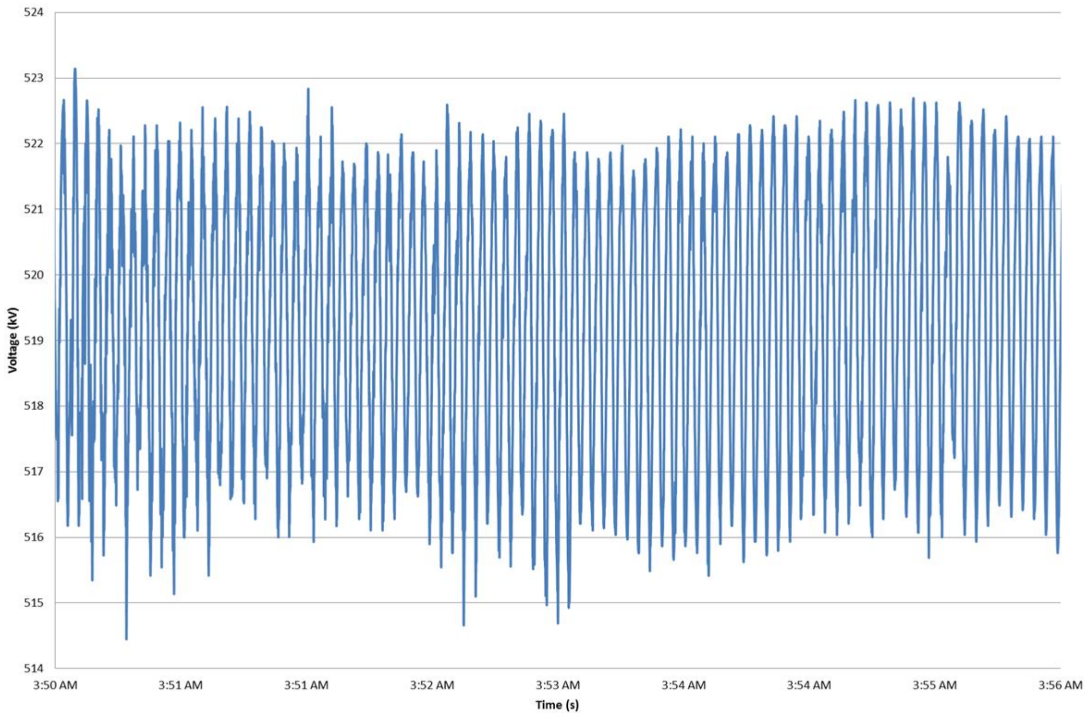

Figure A.3: 500 kV Bus Voltage in FPL Footprint
[Source: FPL]

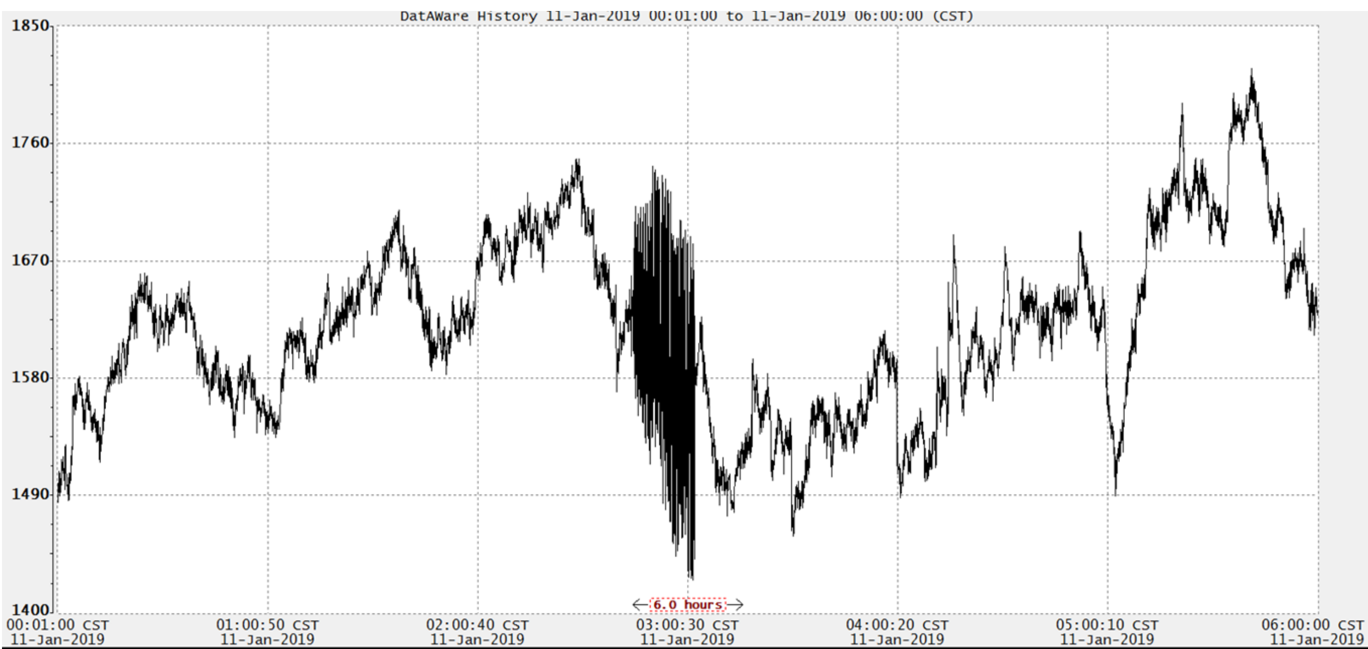

Figure A.4: Line Active Power Flow in TVA Footprint
[Source: TVA]

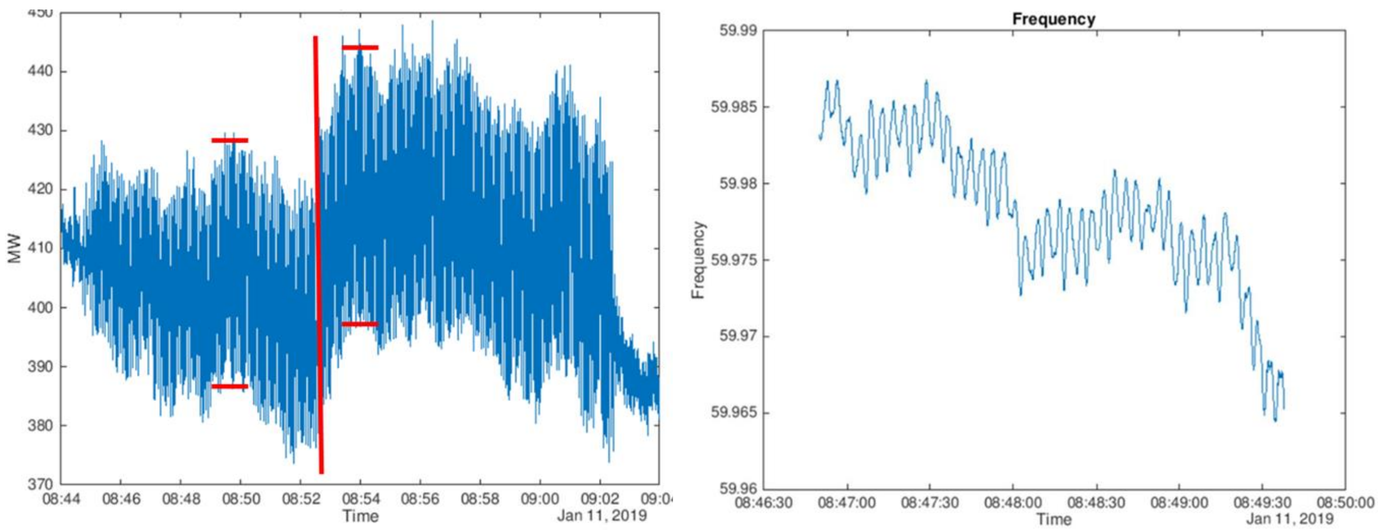

Figure A.5: Line Active Power Flow and Bus Frequency in Dominion Footprint [Source: Dominion]

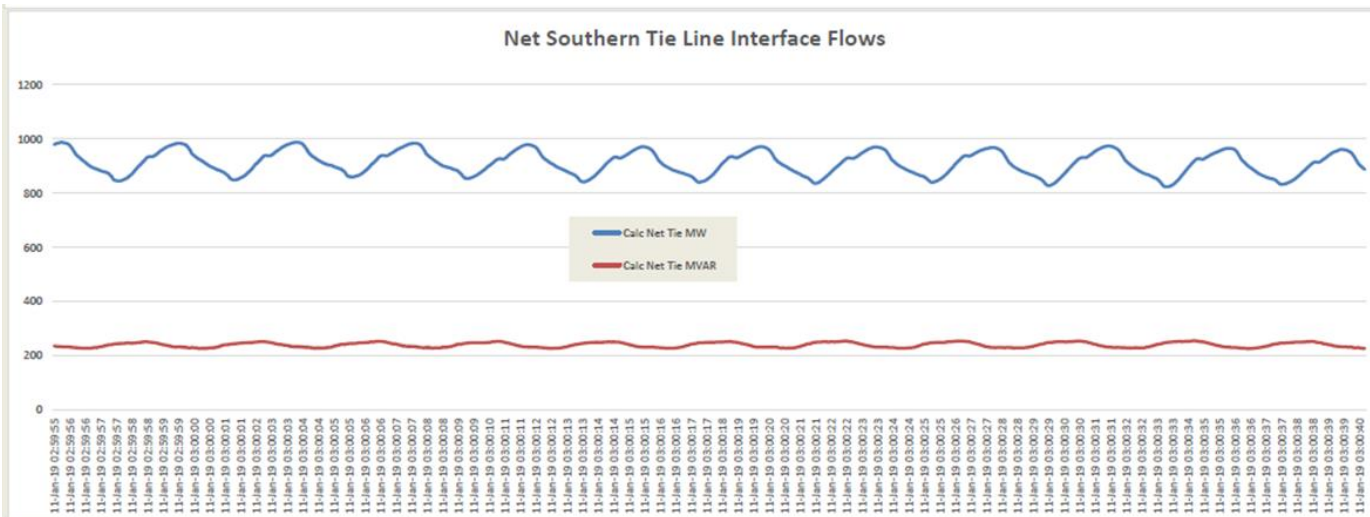

Figure A.6: Intertie Active Power Flow in ATC Footprint [Source: ATC]

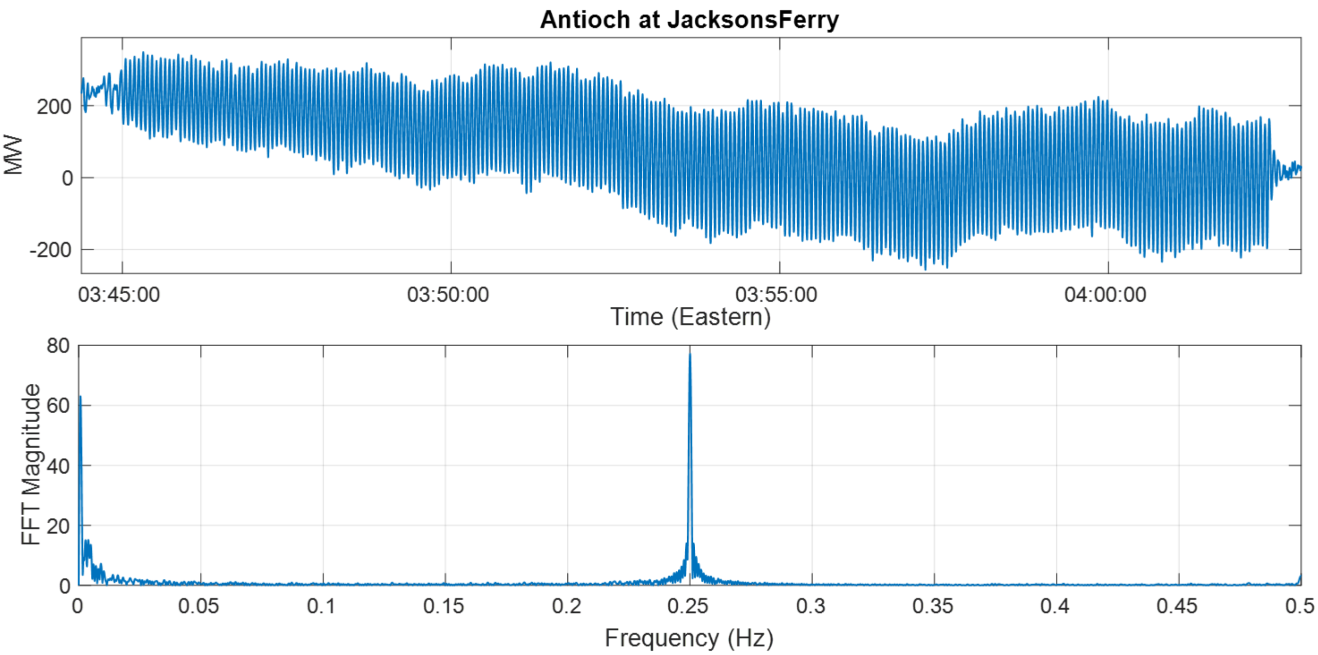

Figure A.7: Line Active Power Flow in AEP Footprint
[Source: ISO-NE]

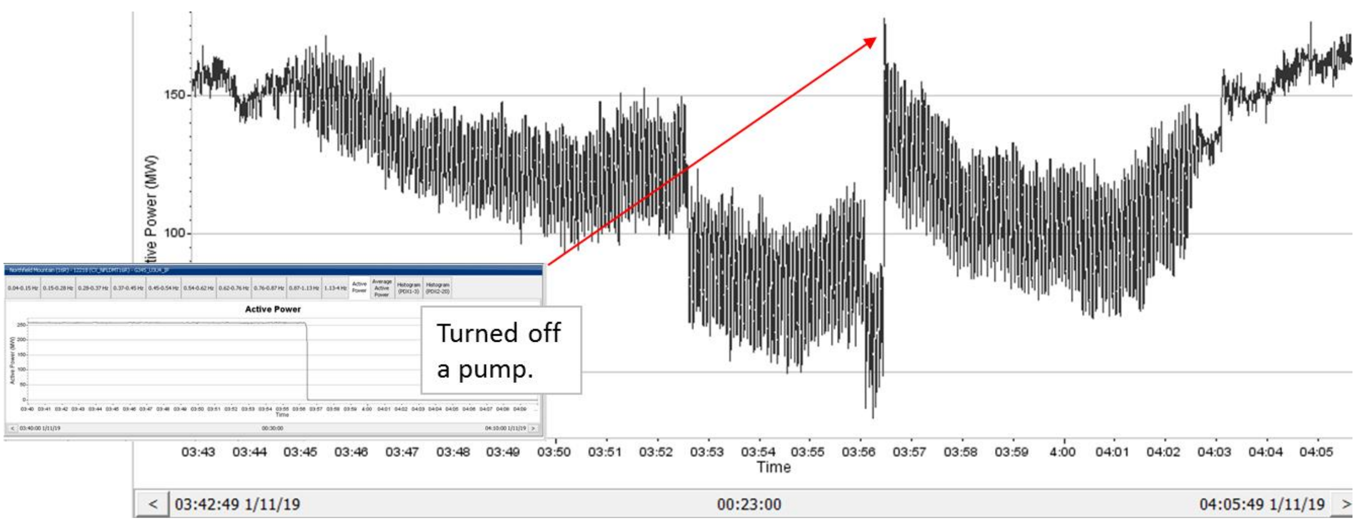

Figure A.8: Line Active Power Flow in ISO-NE Footprint
[Source: ISO-NE]

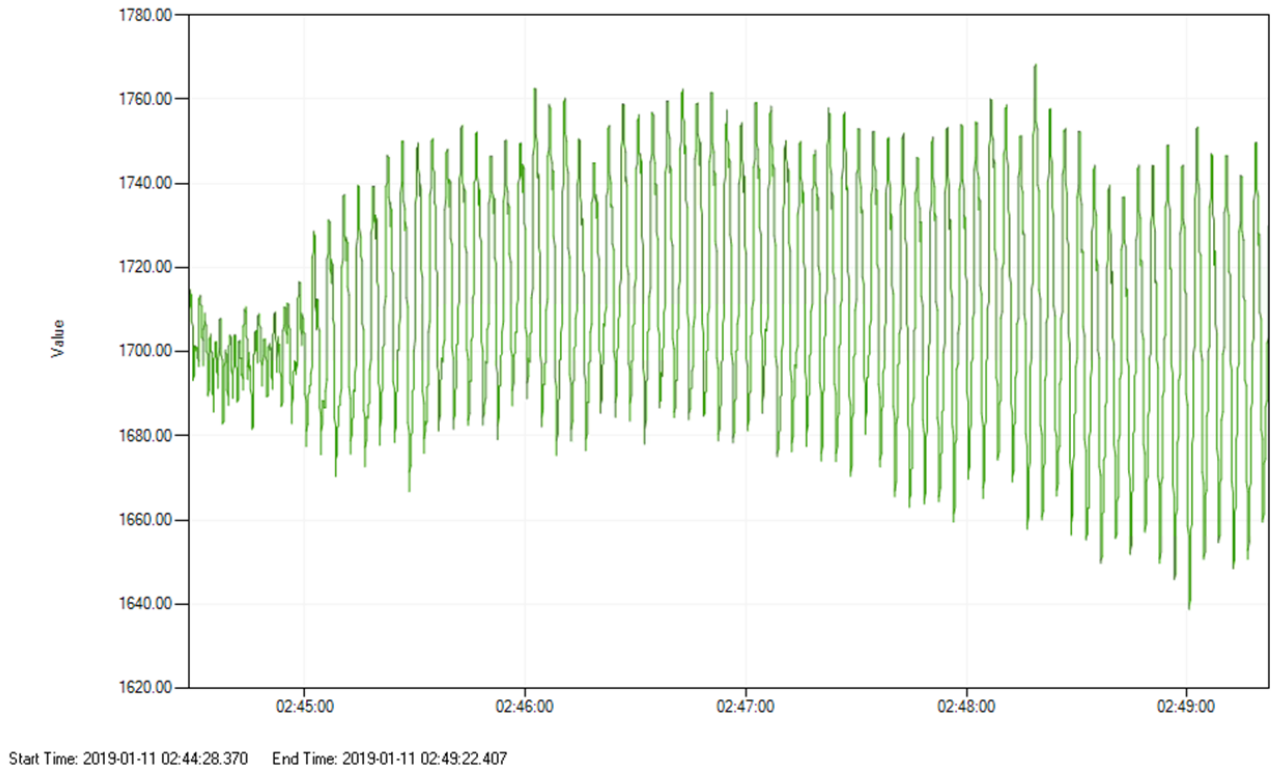

Figure A.9: Line Current in ComEd Footprint
[Source: ComEd]

Contributors

NERC gratefully acknowledges the contributions and assistance of the following individuals in the preparation of this report. NERC also would like to acknowledge the technical discussions and contributions of the NERC SMS.

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