Lesson Learned

Interconnection Oscillation Disturbances

Primary Interest Groups
Reliability Coordinators (RCs)
Balancing Authorities (BAs)
Generator Owners (GOs)
Generator Operators (GOPs)

Problem Statement
On January 11, 2019, an Interconnection-wide oscillation of approximately 0.25 Hz frequency propagated through the entire Eastern Interconnection.

Details
A steam turbine at a combined-cycle power plant experienced a faulty input to a control system due to a failed potential transformer, resulting in oscillations that persisted until the plant operator manually removed the unit from service. The oscillation quickly evolved from a localized forced oscillation to an Interconnection-wide oscillation of approximately 0.25 Hz frequency that propagated through the entire Eastern Interconnection.

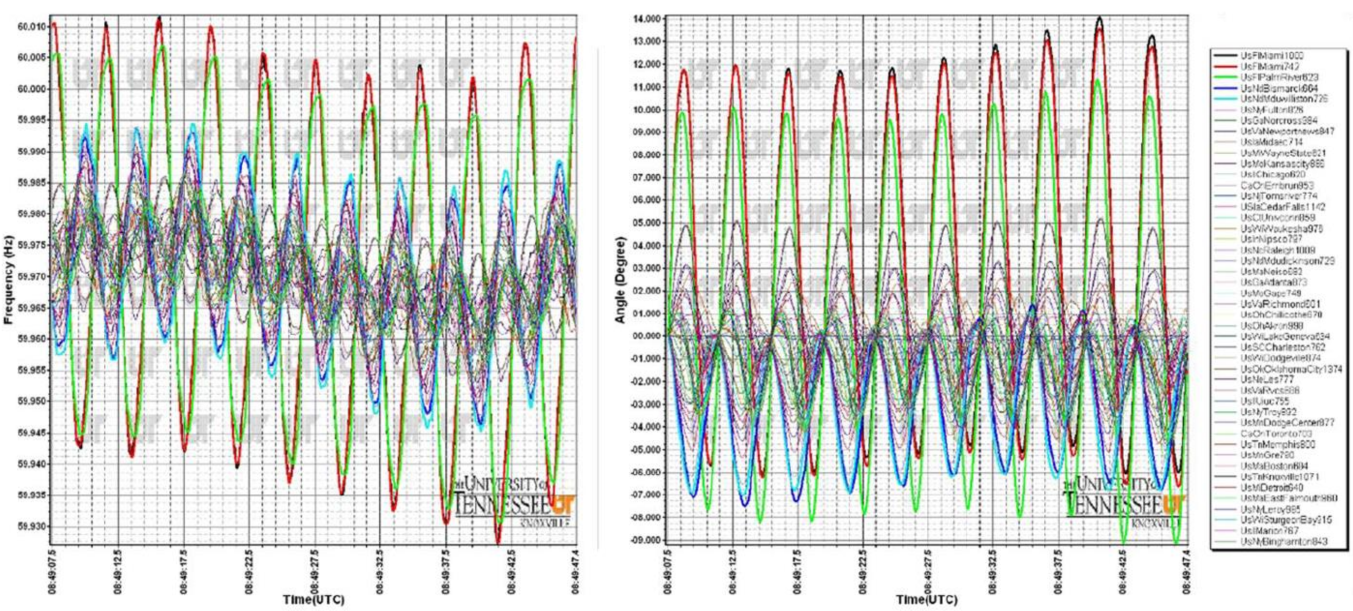

Figure 1: Frequency and Phase Angle Measurements from across the Eastern Interconnection [Source: UTK/ORNL]

A detailed analysis of this event is included in the January 11, 2019, *Eastern Interconnection Forced Oscillation Event Report* published on the NERC website during December 2019. The purpose of this lesson learned is to document the root causes of the oscillation and provide key findings and recommendations to the industry for proactive mitigation of potential future oscillation events.

Time Line of Disturbance

1. On January 11, 2019, around 08:44:16 coordinated universal time (UTC), an oscillation was observed in the Florida area.
2. Around 08:44:40 UTC, an oscillation began that persisted for approximately 18 minutes.
3. Around 09:02:26 UTC, the oscillation died down and the BPS returned to normal oscillatory behavior.

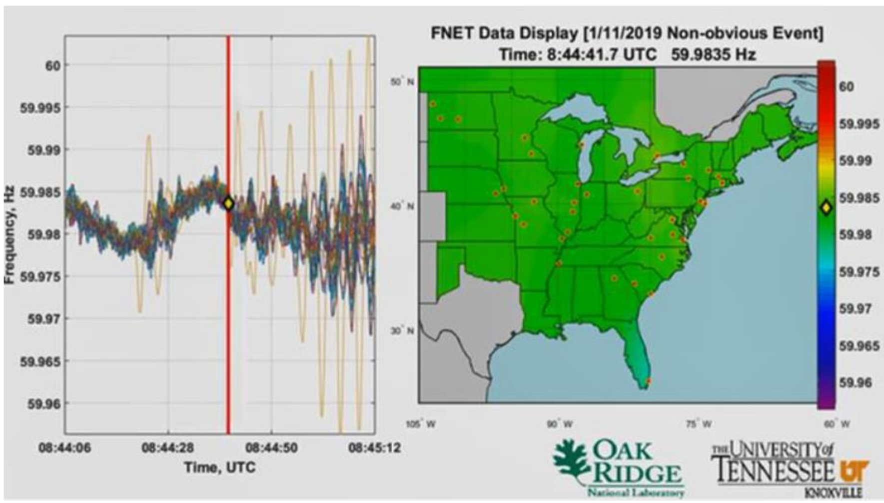

Figure 2: Beginning of the Oscillation Disturbance

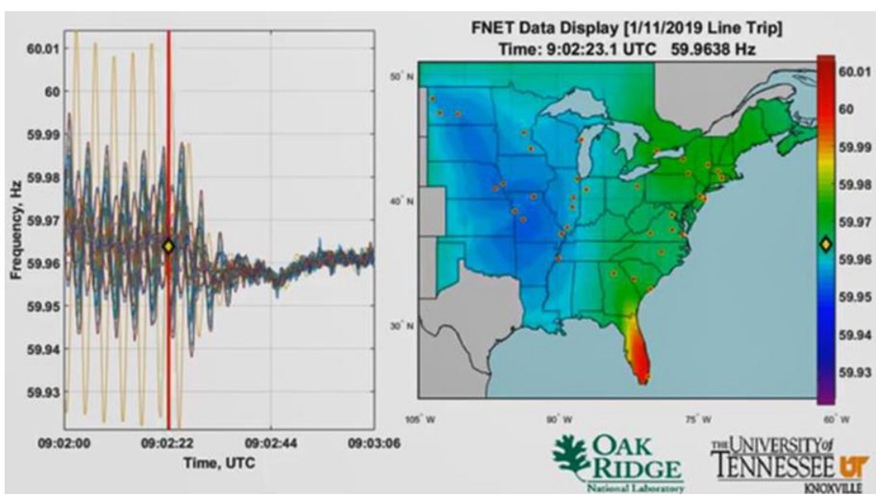

Figure 3: Near the End of the Oscillation Disturbance

Summary of Key Findings: Plant Level

- A failed potential transformer (PT) connection and erroneous voltage measurement in the Power Load Imbalance (PLI) condition in the 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 and 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 presents issues for generator control centers and for transmission energy management systems.

Summary of Key Findings: Wide-Area Impacts

- 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 three conditions required 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.
- The generating unit experienced oscillations of around 200 MW peak-to-peak.
- Power swings of about 50 MW were observed in the New England area.
- RCs became aware of the oscillation event relatively quickly using SCADA data, 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, leading to misinformation and mischaracterization of the event during its initial stage.
- 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 an effective means of quickly understanding the extent of the disturbance.[1] Frequency disturbance recorders and SCADA measurements available to NERC helped quickly identify a potential source of the oscillation and the severity of the event.

Lessons Learned

Below is a summary of recommendations from the January 11, 2019, *Eastern Interconnection Forced Oscillation Event Report*. They include a summary of recommendations based on key findings within the

[1] Here is an animated example from a 2008 event: https://www.youtube.com/watch?v=bdBB4byrZ6U

plant where the oscillations began and recommendations based on the wide area impacts of the oscillation disturbance.

Summary of Recommendations: Plant Level

- 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 1.25–10 seconds. In particular, the frequency of the following dominant interconnection-wide modes should be avoided:
  - 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)
- When turbine controls have single points of failure - including PT and current transformer input measurements - the design should result in fail-to-safe conditions if failure occurs.
- The PLI circuit design in the turbine and generator control systems should consider tripping the unit after a short time for persistent alarms to ensure integrity and safety of plant equipment and personnel.
- Training for GOPs, RCs, BAs, and TOPs outlining root cause analysis and specific actions to take or avoid during oscillation events should be developed and reviewed periodically.
- The GOP and BA should communicate as soon as one notices significant unit output oscillations and determine if the generator's equipment is endangered; if it is, the unit should be taken off-line. If a frequency disturbance is being created, the unit should be taken off-line.

Summary of Recommendations: Wide-Area Impacts

- 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.
- System operators discovering an oscillation are responsible to communicate with others who may be impacted:
  - BAs, upon discovery of an oscillation, should contact the apparent source (if known) and notify their RC.
  - RCs, upon noticing an oscillation, should contact the BA for the apparent oscillation source.
  - RCs should communicate with neighboring RCs in the event of widespread oscillation disturbances on the BPS. Enhanced 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 off-line engineering analysis that uses large volumes of PMU data.
  - The NERC Synchronized Measurement Subcommittee (SMS) should develop guidance on real-time oscillation analysis methods to encourage consistency in monitored quantities and thresholds.
- Based on a survey of RCs, the NERC SMS should develop a white paper that identifies any potential gaps or areas for improvement in the NERC Reliability Standards that pertain 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.

Additional reference information:

- NERC Reliability Assessment "Interconnection Oscillation Analysis" July 2019
- NERC Informational Webinar "Oscillation Analysis" September 13, 2019
  - Webinar Presentation Slides (PDF)
  - Webinar Streaming Recording

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC is asking entities who have taken action on this lesson learned to respond to the short survey provided in the link below.

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