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**Implementation and Operating Experience with Oscillation Detection
Application at Bonneville Power Administration**

**D. KOSTEREV, J. BURNS, N. LEITSCHUH, J. ANASIS, A. DONAHOO
Bonneville Power Administration
USA**

**D. TRUDNOWSKI, M. DONNELLY
Montana Tech University
USA**

**J. PIERRE
University of Wyoming
USA**

SUMMARY

Bonneville Power Administration (BPA) has developed and successfully deployed in its control center several real-time applications that use synchrophasor technology, including an Oscillation Detection application. This paper describes development and implementation of the Oscillation Detection application at BPA. The paper also presents several oscillation events that were detected since 2013, and actions taken by BPA to address these oscillation events.

KEYWORDS

Synchrophasor technology, oscillation detection, power system stability

I. OSCILLATIONS

Oscillations are always present in power systems. From a practitioner's point of view, we consider two different types of oscillatory responses in power systems: transient and forced. Transient oscillations are manifestation of the system's natural electromechanical modes and are typically initiated by ambient system noise or by a system disturbance (e.g., a fault). If one or more of these modes are un-damped, a sustained oscillation occurs within the system causing a near unstable condition. Un-damping (or very lightly damped) transients are extremely rare but represent a serious system stability threat [1]. Alternatively, a forced oscillation is the response of the system to a cyclic input often caused by malfunctioning control equipment, cyclic loads, bad operating conditions, etc. Examples include a malfunctioning valve at a power plant cycling on and off, a hydro generator operating in its rough zone, or control interactions in a generator. Forced oscillations are much more common than un-damped transient oscillations. They typically do not represent a major threat to the power system stability, but can often indicate a serious equipment problem. In some cases, a forced oscillation can result in resonant interactions and equipment damage [2]. Forced oscillations can take on many forms including sinusoids, limit cycles, pulse trains, saw-tooth waves, or just erratic signals. As such, it is difficult to classify them with a single frequency. Real-time monitoring of oscillations is critical to the reliable and safe operation of the power system. The goal of an oscillation detector is to quantitatively monitor the oscillation energy in a given frequency band for a given signal (such as the real power flowing on a given line). In an operations environment, if the energy exceeds a threshold for a specified amount of time, an alarm is provided to a system operator. An operator, then, can use time sequence and energy trends to diagnose the oscillation and to determine an appropriate course of actions.

II. BPA SYNCHROPHASOR PROJECT

Synchrophasors are precise time-synchronized measurements of power system quantities – voltages, currents, angles, frequency, active power and reactive power. BPA was among the first adopters of the synchrophasor technology in early 1990s. Initially, Phasor Measurement Units (PMUs) were installed as stand-alone disturbance recorders. After 1996 outages [1], BPA started to stream real-time PMU measurements to its laboratory at a rate of 30 times each second. In 2001, BPA started exchanging PMU data in real time with Southern California Edison. Meanwhile, BPA researched, developed and prototyped several applications that use wide-area synchronized measurements for power system analysis. However, the original synchrophasor infrastructure was research-grade and was not suitable for real-time control center applications.

In 2010, BPA started a capital project to build a production-grade synchrophasor infrastructure, including installations of redundant PMUs, high-capacity routers, networking and control center infrastructure. BPA installed PMUs at 43 substations, measuring more than 4,000 power system quantities. BPA also developed and implemented several control room applications that use the synchronized wide-area measurements. The application server is sourced with 60 samples per second PMU data pulled from the OSIsoft PI snapshot (real-time data buffer). The application engine processes over 18,000 measurements per second. BPA real-time analytics includes Oscillation Detection, Mode Meter, Frequency Event Detection, Islanding Detection and Phase Angle based transient response. Effective visualization displays are developed by BPA technical staff using PI Process Book to present analytical information to operators and engineering staff. BPA's synchrophasor investment project received Platt's Global Energy Award for Grid Optimization in 2013.

BPA is part of the Western Interconnection, and the interconnected operations require real-time data exchange among its operating entities. Western Interconnection Synchrophasor Program (WISP) was an unprecedented effort to develop an interconnection-wide infrastructure for real-time data exchange among operating entities in the West. Today, BPA exchanges data with 14 partners, enabling a wide-area visibility of the power system dynamic state.

III. BPA OSCILLATION DETECTION APPLICATION

A) Analytics

The Oscillation Detection (OD) algorithm is an “RMS Energy Filter” as derived and described in [3] and is shown in Figure 1 below. This extends a classic energy detector [5] to multiple frequency bands. A PMU-derived “Input” signal (e.g., active power or voltage magnitude) is formed and passed thru a band-pass (BP) filter that focuses on the desired bandwidth for oscillation detection. After BP filtering, the signal is then squared, passed thru an “Averaging Filter,” and then square-rooted. The goal of the “Averaging Filter” is to estimate the mean of the squared signal and is matched to the BP filter. The resulting output signal will be an estimate of the RMS of the input signal in the bandwidth of the BP filter. A similar approach was used at BPA in late 1990s for event detection [4].

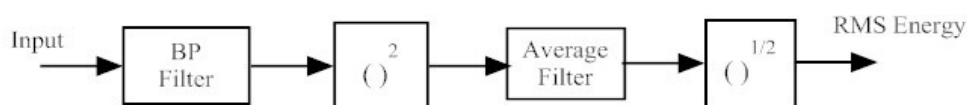


Figure 1: RMS energy filter in Oscillation Detection application

The RMS energy filter approach has several distinct advantages as an oscillation detection algorithm [3]. First, the BP filter can be designed to focus on a specific desired frequency range. Secondly, it provides useful engineering units for the output; that is, the total RMS content in the signal. Though it is often convenient to use units of peak-to-peak value of the oscillation energy when visually examining time-domain waveforms during an oscillation event, the RMS value is a more accurate and consistent measure. Lastly, it is not dependent on the oscillation having a single frequency; many oscillations have multiple frequencies (e.g., harmonics).

Four different RMS energy filters are implemented for the operation control application. The response time is the max time the RMS energy filter takes to respond to an oscillation.

- Band 1, with a pass-band of 0.01-Hz to 0.15 Hz, monitors very slow oscillations that typically involve speed-governor controllers. The response time is 200 sec. or less.
- Band 2, with a pass-band of 0.15-Hz to 1.0-Hz, is tuned to oscillations typically observed in the electromechanical oscillation range. The response time is 12 sec. or less.
- Band 3, with a pass-band of 1.0-Hz to 5.0-Hz, is typically associated with local electromechanical modes and generator controls. The response time is 6 sec. or less.
- Band 4, with a pass-band of 5.0-Hz to Nyquist, may be associated with torsional dynamics of a generator, for example, or may be related to voltage or other relatively high-speed controllers.

Early versions of the Band 1 filter showed false alarms for ramp conditions on the Pacific HVDC Intertie (PDCI). A new version of the Band 1 filter has been designed to reject ramps to avoid the false alarms.

The current alarm system used in the BPA control center is a definite-time alarm strategy. If the RMS energy for a given band exceeds a trigger level for a fixed amount of time, an alarm is set. Future versions being considered use a combination of inverse-time and definite-time alarm as shown in Figure 2. The black curve is the alarm curve. The A_i are alarm levels set by the user.

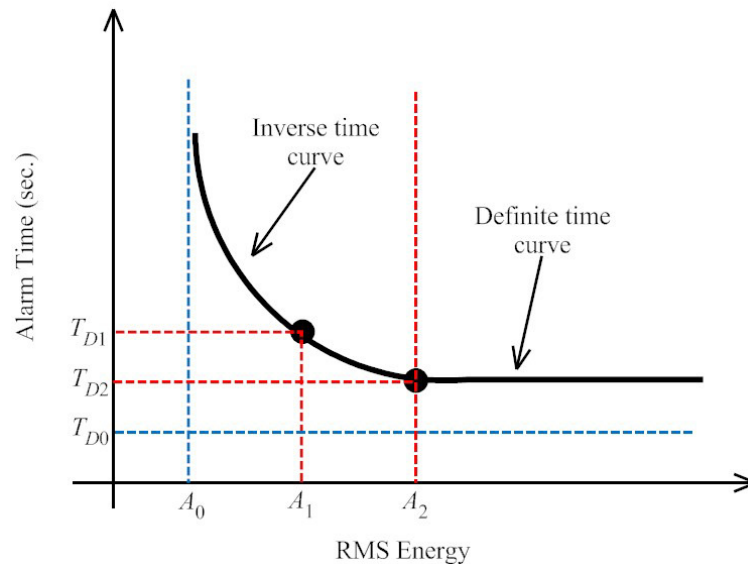


Figure 2: Combined inverse-time and definite-time alarm curve

B) Implementation at BPA

Bonneville Power Administration implemented and deployed the Oscillation Detection application in its control room in October 2013. The Oscillation Detection application scans multiple signals (power, frequency, voltages) across the grid for indication of growing or sustained high energy oscillations. The application monitors power plants, the Pacific HVDC Intertie, Satic VAR Compensators (SVCs), and the 500kV grid internal to the Pacific Northwest. The application's primary purpose is to detect unanticipated oscillations that result from control system failures, local power plant instability, forced oscillations, excitation of inter-area modes, or a generating unit in an unstable operating region.

Figures 3, 5, 7, 10 and 13 are examples of the overview display for the Oscillation Detection application. PMUs at locations where oscillations are monitored are placed on a Northwest map. The specific location names have been removed from the map for data confidentiality reasons. Each PMU has four frequency bands as described above. Should an oscillation alarm occur, a corresponding frequency band at a corresponding PMU will turn "red". The display provides very effective visual indication on whether the oscillation is local or wide-area. For local oscillation, only one or a few PMUs in the vicinity of oscillation source will go into an alarm state. For wide-area oscillations, multiple PMUs will go into an alarm state over a large geographic area. The display also provides initial indication of the type of oscillation based on the frequency band alarmed. The oscillation must persist for pre-determined time period for the application to issue an alarm.

BPA dispatcher and operations technical staff can drill down further into the oscillation by clicking on the PMU and bringing a trend display with monitored signals. The signals that triggered the alarm will be identified on the display, as will be illustrated in the following section describing actual oscillation events.

IV. OSCILLATION EVENTS

BPA Oscillation Detection application detected a large number of oscillation events since it was implemented in 2013. Most of the events were local forced oscillations due to equipment issues or bad operating point. There were several wide-area events due to oscillatory instability of generators.

A) Wind Power Plant Oscillation

Starting May 2013, BPA detected multiple occurrences of sustained power oscillations at one of its wind generation hubs, as seen in Figure 3. The oscillation was local, confined to a 450 MW wind power generation plant. The oscillation frequency was above 5 Hz, suggesting voltage control problems. Many of the oscillation events lasted for several hours. Further analysis indicated that the oscillations developed every time the wind plant was generating above about 85% of its rated output. Reactive power oscillations were reaching 50 MVAR peak to peak, as seen in Figure 4. The oscillation frequency was 14 Hz, similarly to the oscillation frequency observed during sub-synchronous control interaction event in Texas in 2009 [2]. BPA also has series-compensated lines in the area, and was concerned about risk of a similar interaction should the wind power plant become isolated on a series-compensated line. BPA engineering staff notified the plant owner about the oscillations and associated risks, and the plant owner requested the wind generator manufacturer to upgrade its voltage controls. There were no occurrences of power oscillations after the wind generation control upgrades made in April 2014.

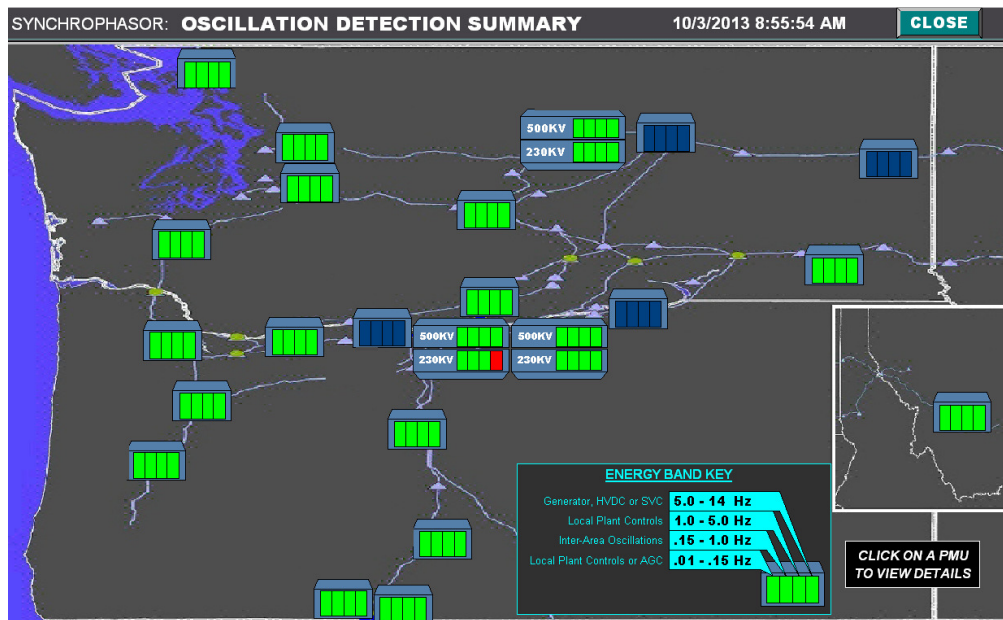


Figure 3: Oscillation Detection overview display, wind power plant oscillation in October 2013

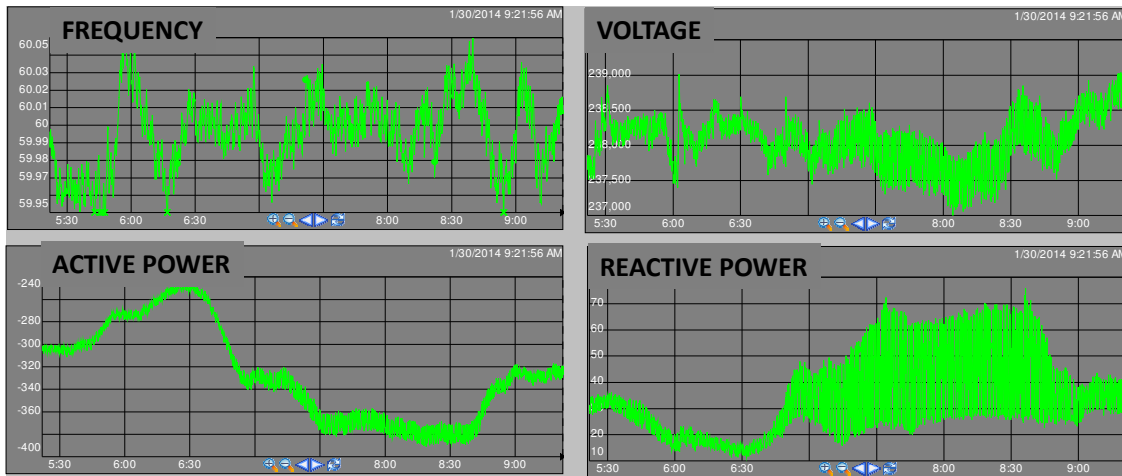


Figure 4: Wind Power Plant oscillation - details

B) Hydro Power Plant Rough Zone Oscillation

Hydro-turbines are designed for most efficient operation at nominal head and flow. Hydrodynamic instability (rough zone operation) occurs at partial load, typically 25 -60% of rated generator power. The generators go through the rough zone every time during its loading and un-loading, however, the transition only lasts about 30 to 60 seconds. Continuous operation in a rough zone is very undesirable because mechanical forces can cause premature wear of equipment or even catastrophic damage. The BPA Oscillation Detection application issued an alarm of a sustained oscillation at one of its hydro-power plants in October 2014, seen in Figure 5. The oscillation alarm was local and in the second frequency band, the sustained oscillation frequency was 0.38 Hz, seen in both active and reactive power, Figure 6. Advised by BPA technical staff, the BPA dispatcher notified the plant operator about the oscillation. Plant operators were not aware of the problem, they increased the generator power output above the rough zone, and the oscillation went away. There were several other occasions of similar sustained oscillations detected at other hydro-power plants in BPA territory.

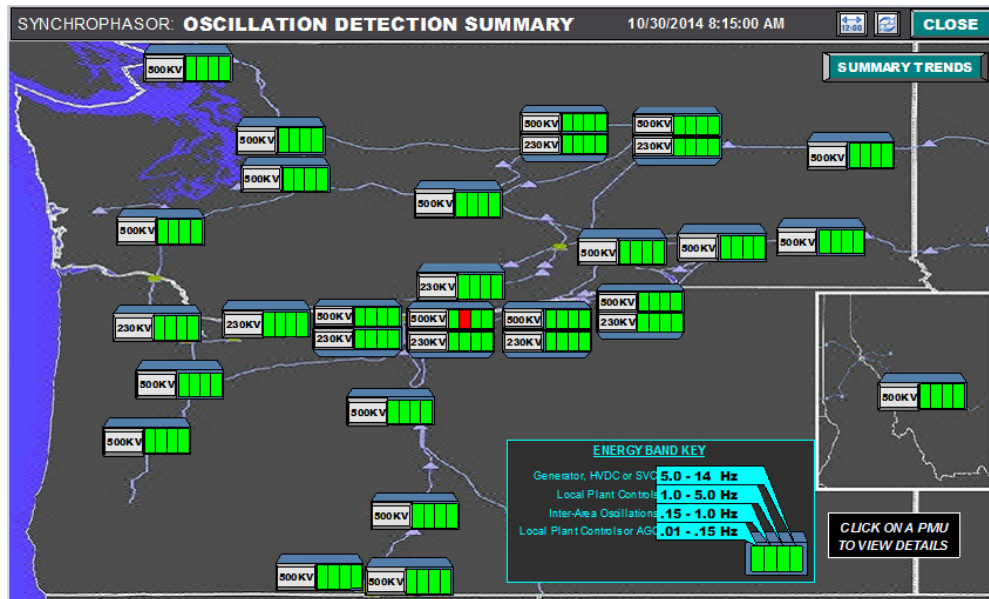


Figure 5: Oscillation Detection overview for hydro event on October 2014

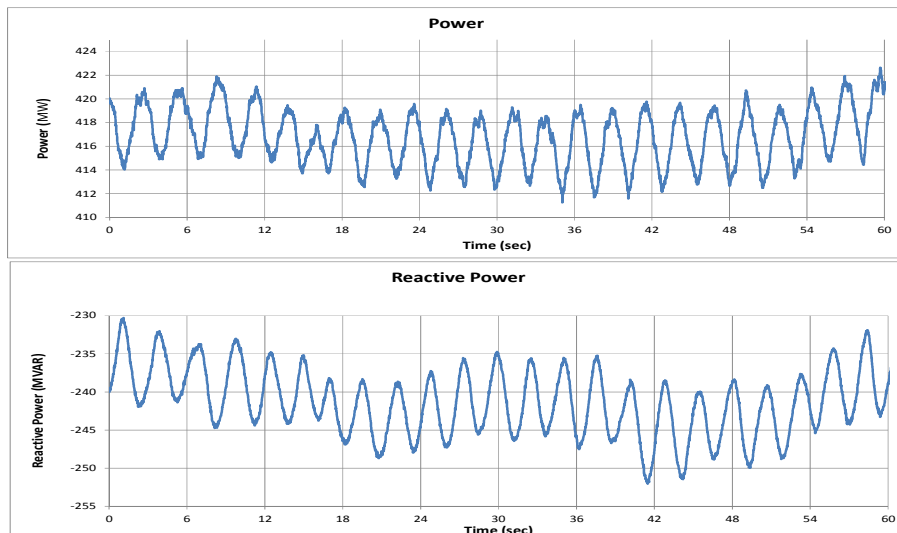


Figure 6: Hydro power plant oscillation due to surging water vortex

C) UEL and PSS Interaction at a Hydro Power Plant

BPA Oscillation Detection application detected several occurrences of sustained oscillations at one of its hydro-power plants in fall 2015. The oscillation triggered local alarms in frequency bands 3 and 4 seen in Figure 7. The oscillation waveform had a unique beat characteristic, Figure 8. Further analysis indicated that the oscillation was due to interactions between Power System Stabilizers (PSSs) and Under-Excitation Limiters (UELs). 2015 was a low hydro generation year in the Pacific Northwest, as a result, transmission voltages were high due to lighter transmission loading, and fewer generators were available to absorb the increased reactive power. BPA technical staff notified plant operators about the problem. The plant technical staff re-tuned the UEL gains in January 2016, and the problem was resolved successfully.

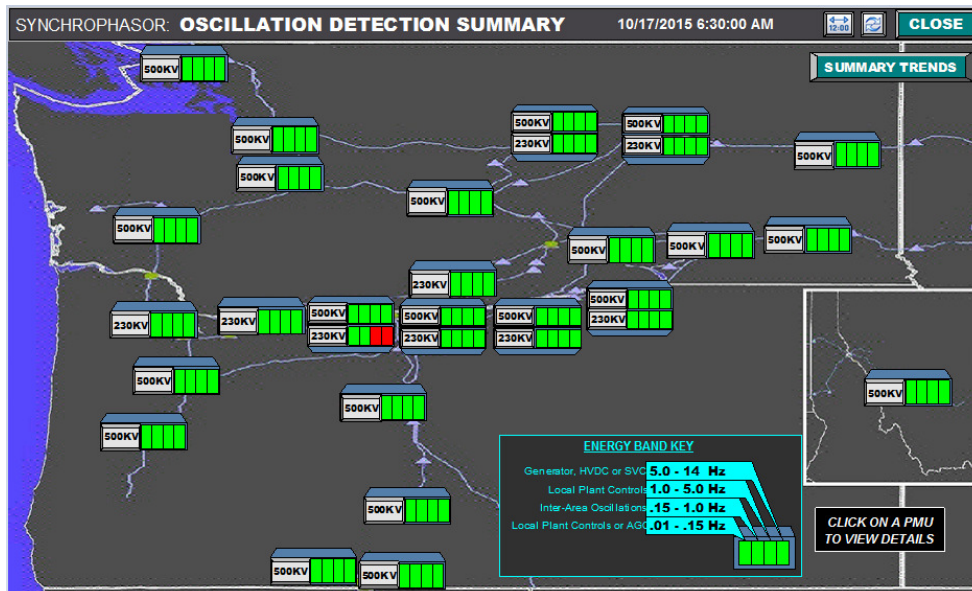


Figure 7: Oscillation Detection overview for UEL and PSS Interaction at a hydro power plant

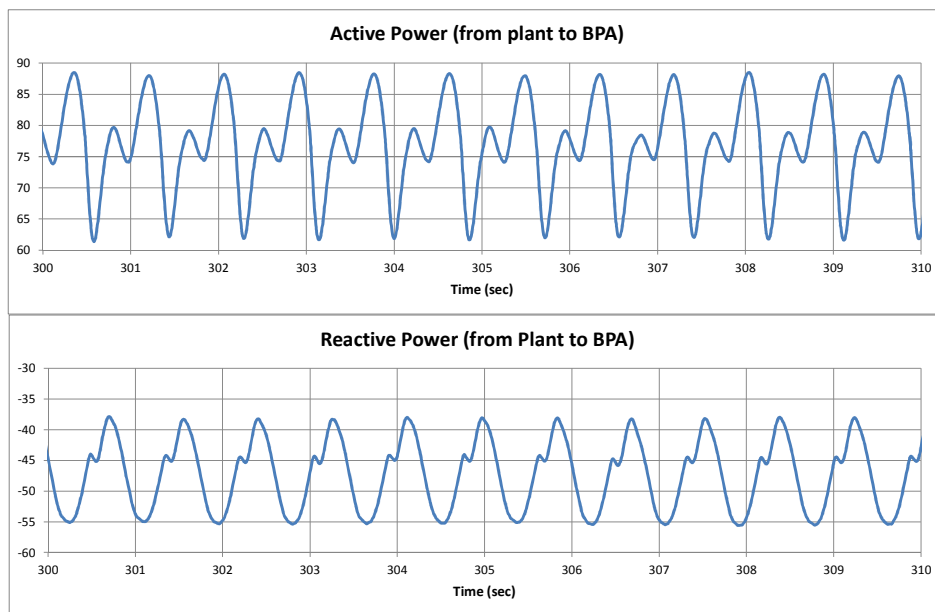


Figure 8: Hydro power plant oscillation due to PSS and UEL interactions

D) Power Plant Active Power Controller Erratic Behavior

BPA Oscillation Detection application detected erratic power controller behavior at a power plant in May 2016, as seen in Figure 9. The oscillation triggered an alarm in band 1. The oscillation lasted for more than one hour. While it was not a periodic oscillation, active power steps were large enough to trigger an alarm. The problem was due to issues with an interface between a plant controller and a generating unit's governor.

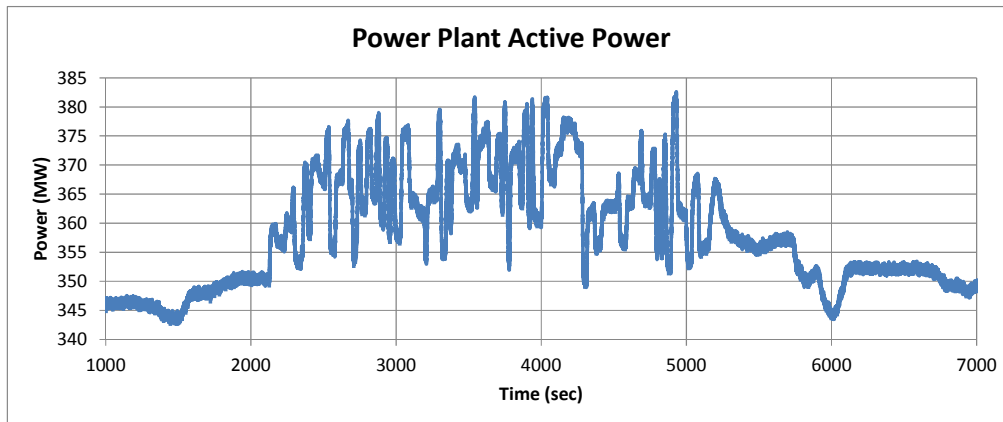


Figure 9: Active power erratic behavior due to plant control issues

E) Central Oregon Plant Oscillation

In February 2014, BPA observed a 140 MW peak-to-peak 1.2 Hz sustained oscillation in power flow measurements at its 500-kV substation in Central Oregon. The oscillation was significant enough to be detected by seven PMUs, Figures 10, 11, and 12. BPA did not have a PMU located directly at the plant, but PMUs in the plant vicinity were able to see the oscillation. The oscillation was a result of the plant control system being supplied an erroneous measurement from its local meter. The wires terminating at the meter had been poorly crimped and generated enough heat to start a fire. The plant operator powered down the unit in response to the fire, and the sustained oscillation stopped after 5 minutes. During the event, the operator was unaware that the generator was oscillating, but the owner of the unit was grateful that BPA had captured the event and sent them the data.

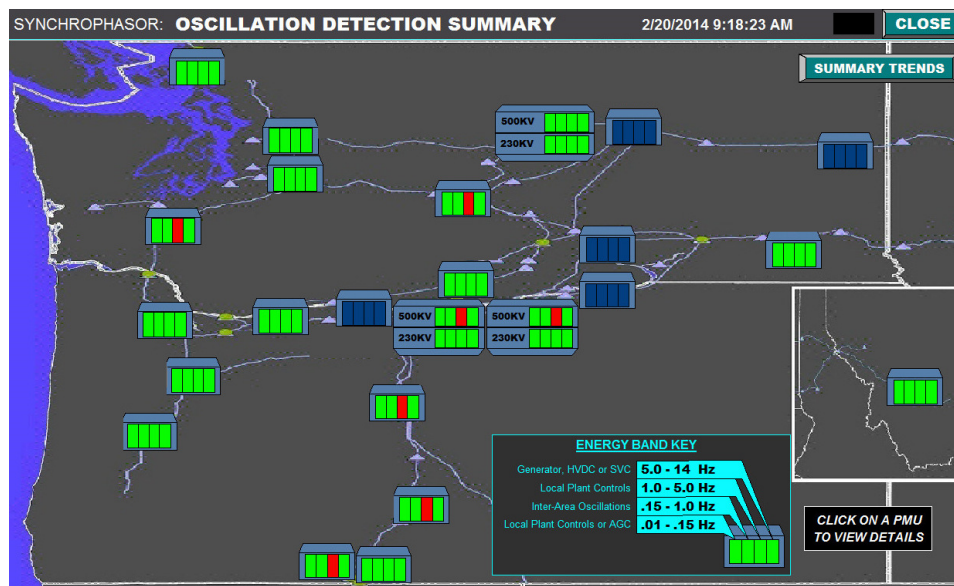


Figure 10: Forced oscillations at a power plant in Central Oregon - overview

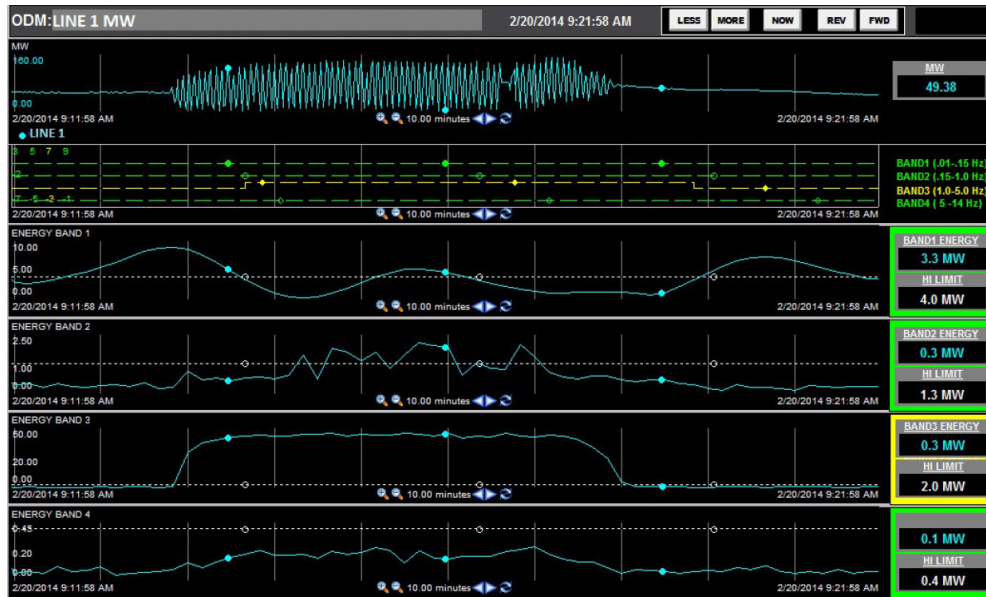


Figure 11: Forced oscillations at a power plant in Central Oregon - trends

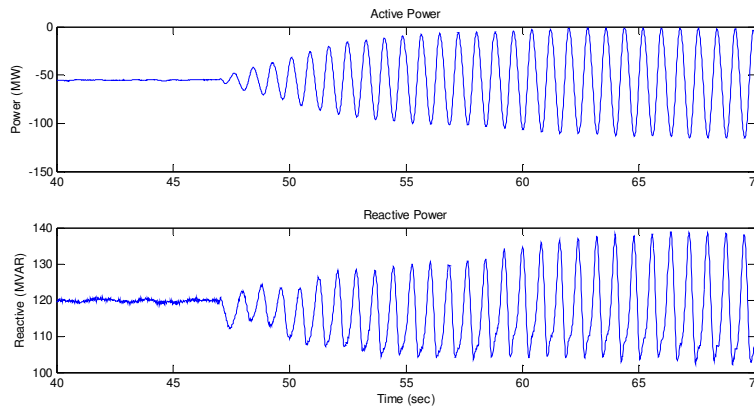


Figure 12: Analysis oscillation at a power plant in Central Oregon - oscillation build-up

F) Generator oscillations because of transmission outages

BPA Oscillation Detection application detected two events of generator oscillations due to transmission outage configurations. Both events were seen as “wide-area” because the oscillation energy was significant to trigger alarms on multiple PMUs; however, they were driven by a local generator. In both cases, BPA did not have a measurement directly at the power plant. BPA technical staff used bus frequency oscillation energy to locate the area from which an oscillation originated, and then correlated line switching information to narrow down the oscillation source. Such oscillation events usually clear in 5 to 10 minutes, mainly by taking oscillating generators off-line.

G) PDCI oscillation

In April 2016, a high energy oscillation originated at the PDCI and propagated across the Pacific Northwest system. The oscillation triggered multiple alarms, mainly in oscillation bands 3 and 4, see Figure 13. Further drill-down shows that both pole 3 and 4 were involved in the oscillation, Figure 14. The oscillation was due to equipment failure at one of converter stations.

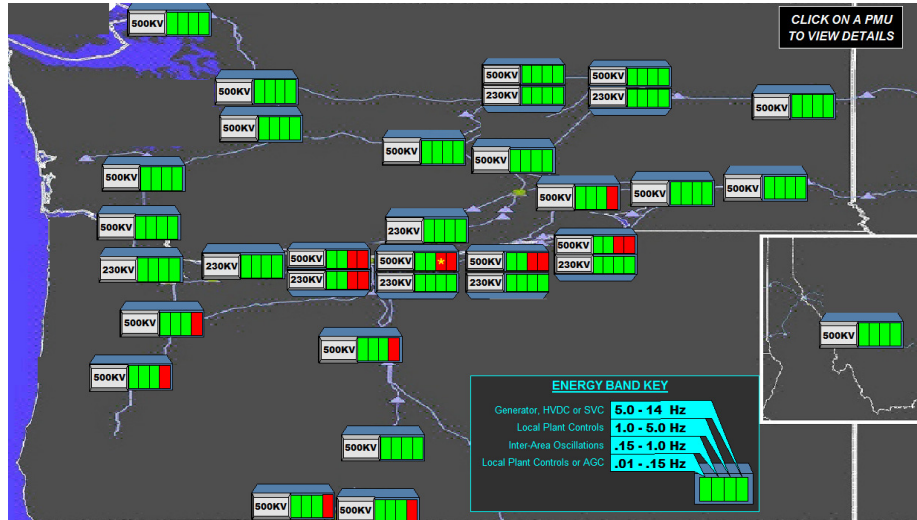


Figure 13: Overview display for PDCI event in April 2016

V. OPERATING PROCEDURES AND TRAINING

Currently, there are operating procedures in place for system operators to respond when an alarm is received from the BPA Oscillation Detection application. These went into effect June 1st, 2016, after BPA technical staff performed several dispatcher training sessions on the application. BPA training included oscillation basics, modes of oscillations in the Western Interconnection, local versus wide-area oscillation, application description and demonstration, philosophy behind alarm thresholds, overview of displays, actions to be taken, and analysis of historic oscillation events.

If a single PMU alarms, the basic process is for the system operator to contact the local operator/field staff at the specific location where the alarm is coming from. The local operator then investigates the event, since it is most likely a local equipment issue and may require reduction of power at that location.

If multiple PMUs detect an oscillation, it is considered a wide area oscillation, and a conference with the Reliability Coordinator may be required to diagnose the cause, locate the source and develop a course of actions. BPA system operators will take more proactive steps in addressing the alarms. This can include inserting series capacitors, insert transmission lines that are out of service for voltage control, move generation to help increase system inertia, and curtail schedules depending on the location and severity of the oscillation event.

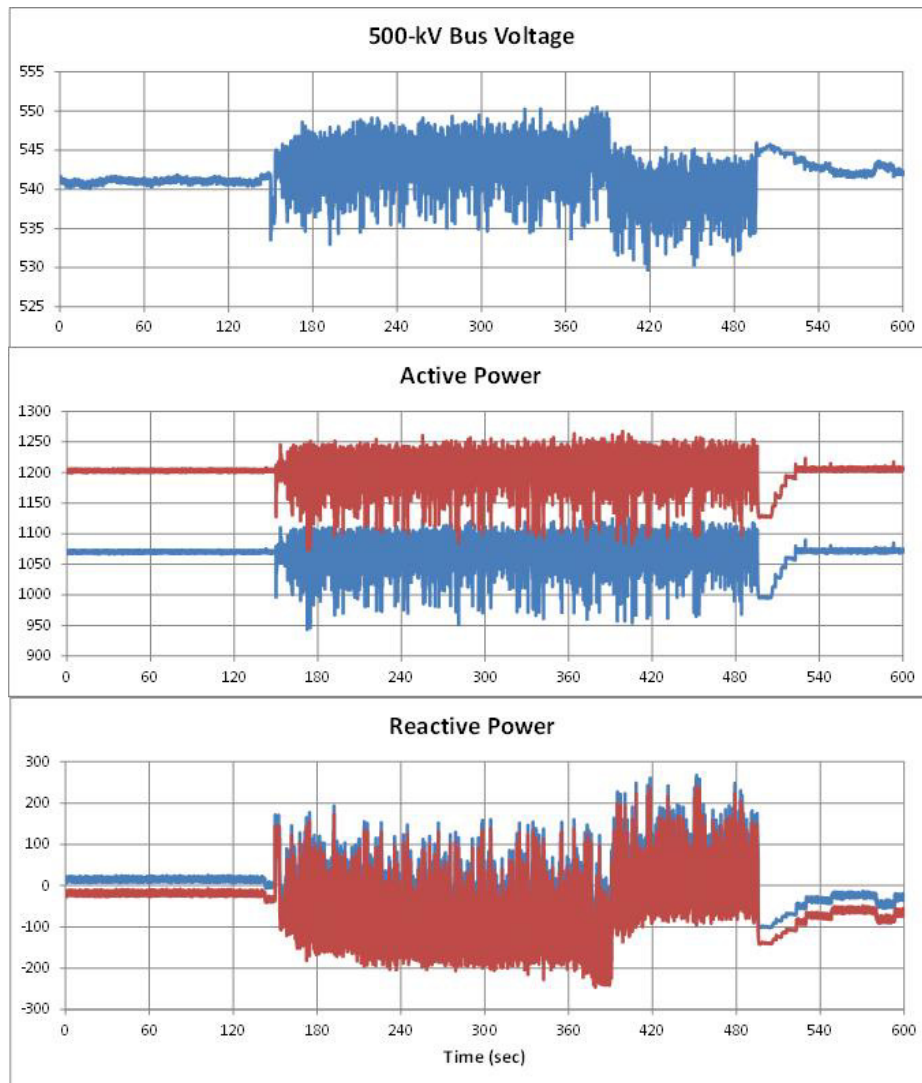


Figure 14: Analysis of PDCI event in April 2016

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