Diagnosing Equipment Health and Mis-operations with PMU Data

NASPI Technical Report

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NASPI North American SynchroPhasor Initiative

Preface

This report was written by Alison Silverstein, independent contractor and NASPI Project Manager, under contract to the Battelle Pacific Northwest National Laboratory (PNNL). The research and report was sponsored by the U. S. Department of Energy (DOE) and managed by Jeff Dagle of PNNL.

The North American Synchrophasor Initiative is a collaboration between the electric industry, manufacturers and vendors, academia, national laboratories, government experts, and standards bodies. The group works to accelerate the maturity, capabilities, and use of synchrophasor technology, to improve the reliability and efficiency of the bulk power system. NASPI receives financial support from the DOE and the Electric Power Research Institute and is managed through the Battelle PNNL.

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Executive summary

With widespread deployment of phasor measurement units (PMUs) and wider availability of synchrophasor data, many grid operators and transmission owners are discovering that they can use these data to gain unprecedented visibility into the status and health of equipment monitored by PMUs. Although most of the entities that have installed synchrophasor systems did so to enhance real-time monitoring and wide-area situational awareness, engineers working at several utilities and grid operators have been using PMU data to uncover and diagnose a variety of equipment health issues and mis-operations.

Examples of such uses span a variety of operational points across the power system, including incidents with hydro and fossil generators, oscillations caused by wind plants, a variety of problems with transmission equipment, and a number of proactive ways to use synchrophasor data and creative analytical techniques to detect and protect equipment before it fails. Some of these cases demonstrate how operations engineers are able to make diagnoses based on PMU data in near-real time, provide insight, and offer solutions to control room staff in minutes rather than hours. Other cases—particularly those involving generator settings and issues—can take days of investigation and analysis before the answer is revealed. But in every case, the availability of PMU data has expedited the identification and resolution of equipment problems and operational disturbances.

By using PMU data to diagnose and prevent problems, analysts are delivering significant unexpected benefits to the equipment owners and end use customers. The benefits include averting damaging equipment failures and costly repair or replacement efforts, faster identification and resolution of operational problems, safe integration and reliable operation of low-polluting renewable generation, avoidance of customer outages, and better overall grid reliability and security. These diagnostic efforts are supporting asset maintenance and protection, improving grid reliability, and delivering significant operational savings.

This report is intended to reveal the value of synchrophasor data and PMUs for investigating anomalous grid conditions and diagnosing potential problems in grid equipment. It shows the wide variety of events and equipment for which synchrophasor data have been used as a diagnostic tool and explains why each incident had actual or potential adverse reliability or cost impacts. In many of these cases, the asset owners or operators have shared details about the evidence and inquiry process that led to event diagnosis, thereby alerting industry colleagues about how to identify and resolve similar problems.

Acronyms and glossary

AC	alternating current
AGC	Automatic Generation Control
ATC	American Transmission Company
ARRA	American Recovery & Reinvestment Act of 2009, which funded the DOE SGIG and SGDP awards for synchrophasor and other electric technology investments
AVR	Automatic Voltage Regulator
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CCET	[Texas] Center for the Commercialization of Electric Technologies
COI	California-Oregon Intertie
CT	current transformer
CCVT	Capacitance-coupled voltage transformer, a transformer used to step down extra high voltage signals and provide a low voltage signal for measurement, or to operate a protective relay
DC	direct current
DCB	directional comparison blocking
DFR	digital fault recorder
DOE	U.S. Department of Energy
EHV	extra high voltage
EMS	energy management system
EPG	Electric Power Group
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible Alternating Current Transmission System device
FFT	Fast Fourier Transform
HVDC	High Voltage Direct Current transmission
Hz	hertz
IEEE	Institute of Electrical and Electronics Engineers
kV	kilovolt(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
MISO	Mid-continent Independent System Operator
MVAR	Megavolt Ampere Reactive
MW	megawatt(s)
MWh	megawatt-hour(s)
NASPI	North American SynchroPhasor Initiative
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OG&E	Oklahoma Gas & Electric

OMS	Oscillation Management System
PDCI	Pacific Direct Current Intertie
PDT	Pacific Daylight Time
PJM	PJM Interconnection
PMU	phasor measurement unit
PNNL	Pacific Northwest National Laboratory
PSS	Power System Stabilizer
PST	Pacific Standard Time
PT	potential transformer, designed for use on high voltage equipment to step down system voltage to a level that is safe for monitoring single-phase and three-phase power line voltages (potential)
RCF	Ratio Correction Factor
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SGDP	Smart Grid Demonstration Project
SGIG	Smart Grid Investment Grant
SONGS	San Onofre Nuclear Generating Station
SVC	static VAr compensator
TVA	Tennessee Valley Authority
VAR	volt ampere reactive
WSU	Washington State University

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1. Introduction

With widespread deployment of phasor measurement units (PMUs) and wider availability of synchrophasor data, many grid operators and transmission owners are discovering that they can use these data to gain unprecedented visibility into and understanding of the status and health of equipment monitored by PMUs. Although most of the entities that have installed synchrophasor systems did so to enhance real-time monitoring and wide-area situational awareness, engineers working at several utilities and grid operators also have been using PMU data to uncover and diagnose a variety of equipment health issues and mis-operations.

Examples of such uses span a variety of operational points across the power system, including incidents with hydro and fossil generators, oscillations caused by wind plants, a variety of problems with transmission equipment, and a number of proactive ways to use synchrophasor data and creative analytical techniques to detect and protect equipment before it fails. Some of these cases demonstrate how operations engineers are able to make diagnoses based on PMU data in near-real time, provide insight, and offer solutions to control room staff in minutes rather than hours. Other cases—particularly those involving generator settings and issues—can take days of investigation and analysis before the answer is revealed. But in every case, the availability of PMU data has expedited the identification and resolution of equipment problems and operational disturbances.

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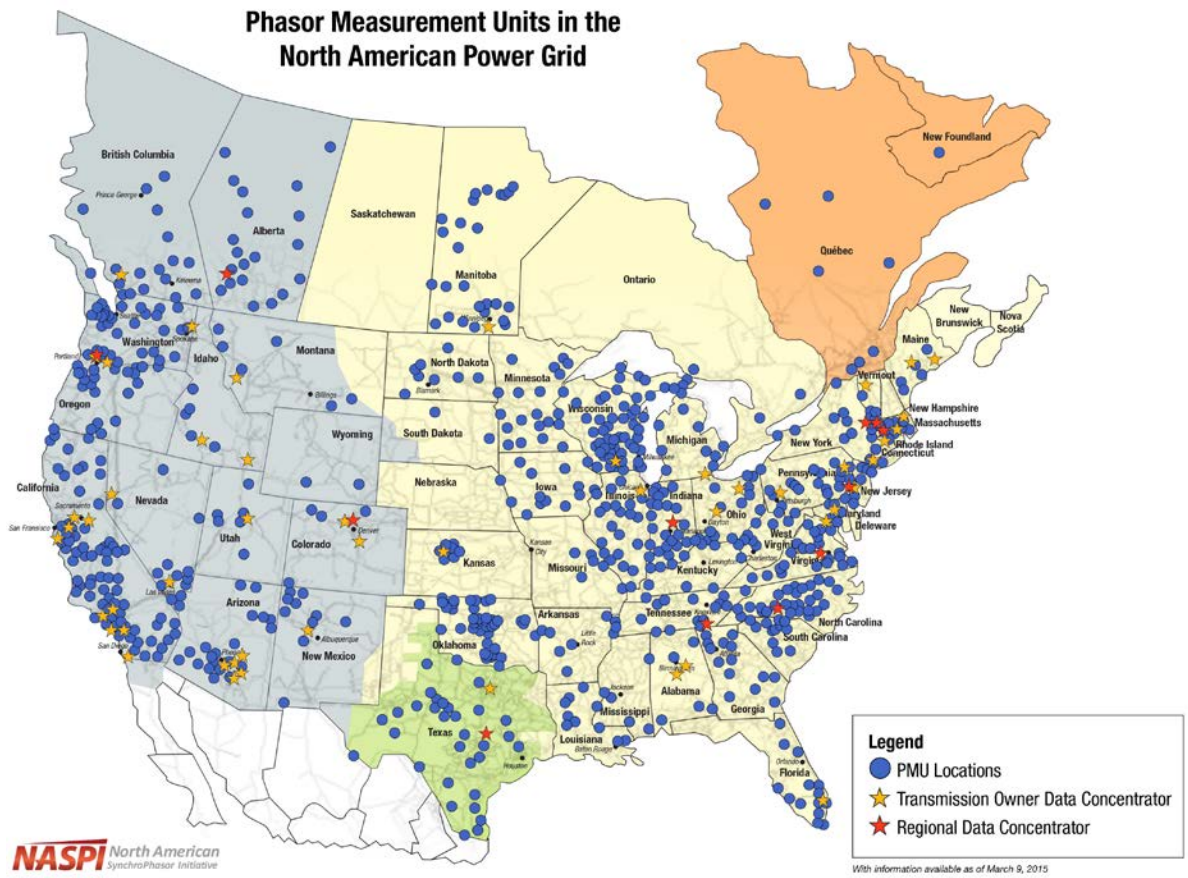
This report is intended to reveal the value of synchrophasor data and PMUs for investigating anomalous grid conditions and diagnosing potential problems in grid equipment. It shows the wide variety of events and equipment for which synchrophasor data have been used as a diagnostic tool and explains why each incident had actual or potential adverse reliability or cost impacts. In many of these cases, the asset owners or operators have shared details about the evidence and inquiry process that led to event diagnosis, thereby alerting industry colleagues about how to identify and resolve similar problems.

2. Background for use of synchrophasor data

While several utilities—particularly the Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), Southern California Edison (SCE), and Oklahoma Gas & Electric (OG&E)—installed phasor measurement systems in the 2000s, most of North America's adoption of synchrophasor technology and deployment of production-grade PMUs began in 2010, sparked by the award of over $350 million in grants from the U.S. Department of Energy's

(DOE's) Smart Grid Investment Grants (SGIG) and Smart Grid Demonstration Projects (SGDP)[1] for synchrophasor technology.[2] With the combined federal and private sector investments, more than1,700 production-grade PMUs were deployed across North America between 2010 and 2014, enabling increased visibility into and understanding of grid events.

Figure 1 shows a recent map of the PMUs installed across North America. Most of these PMUs were funded and installed using federal and private funds under the SGIG and SGDP grants.



(Source: NASPI)

Figure 1. Map of PMUs installed on the North American grid as of March 2015

Benefits of synchrophasor technology

Synchrophasor technology offers unprecedented visibility into what is happening on the grid as a whole, and into what is happening with individual power plants and pieces of grid equipment. But it may take some effort for engineering and operations staff to work from the initial observation that something odd is happening on the system, to review of the data from nearby

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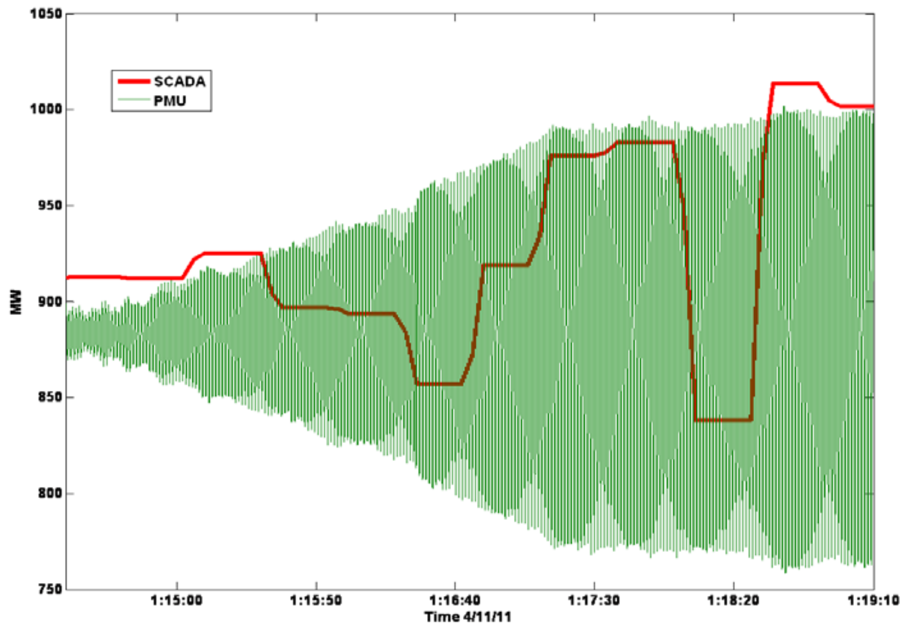
[1] The SGIG and SGDP grants were funded with monies authorized under the American Recovery and Reinvestment Act of 2009.

[2] A list of the DOE Smart Grid Investment Grant awards can be found at https://www.smartgrid.gov/recovery_act/project_information/?f[0]=im_field_project_type%3A5170.

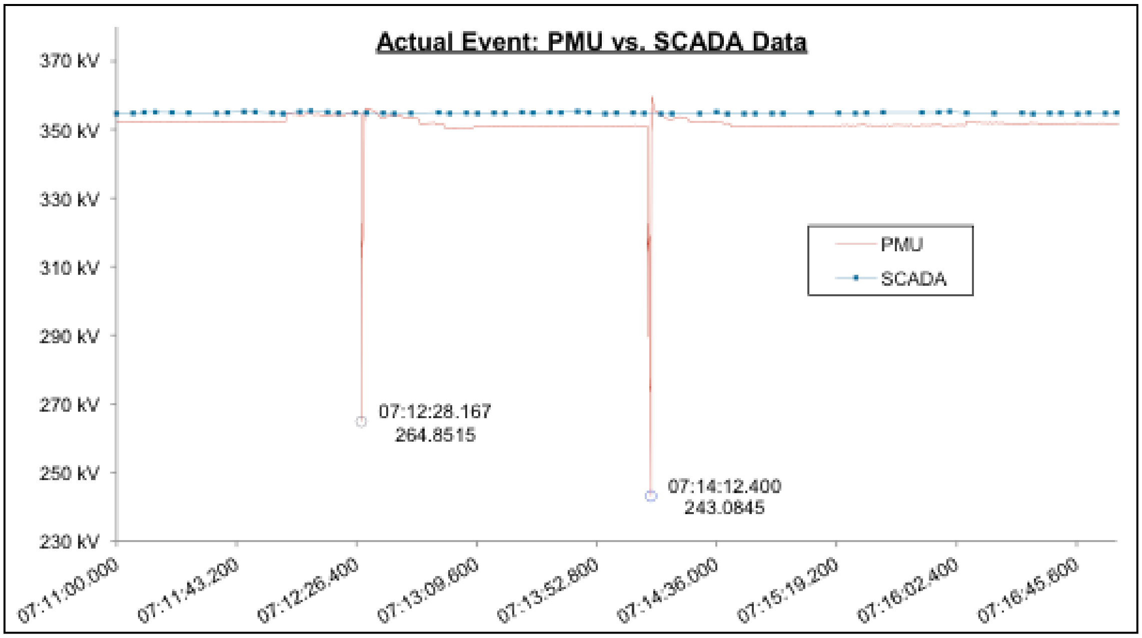
PMUs, and through a process of investigation and deduction to find a solution and fix the problem.

Synchrophasor systems enable better electric system observation and problem diagnosis because synchrophasor technology synchronously samples and records grid conditions with unprecedented speed and granularity. While Supervisory Control and Data Acquisition (SCADA) systems sample grid conditions every 2 to 15 seconds, PMUs measure frequency, voltage phasors, and current phasors at the rate of 30 to 120 samples per second, and calculate real and reactive power values from those phasor measurements. Thus, PMUs can capture dynamic and transient events that are not seen in SCADA monitoring, as illustrated in Figure 2 and Figure 3. The higher resolution of PMU measurements enables operators to see details that are obscured or completely missed in slower SCADA monitoring; an operator looking only at SCADA for the event shown in the figures below could miss the magnitude and duration of these power and voltage swings and have limited situational awareness of potentially significant real-time operating risks.



(Source: Dominion Virginia Power)

Figure 2. Comparison of SCADA versus PMU recordings of the same grid event – un-damped oscillations at a power plant



(Source: MISO)

Figure 3. MISO actual event comparison − PMUs spot what SCADA cannot

Every phasor measurement and calculated value is time-synchronized against Universal Time (within 1 microsecond, as determined using the Global Positioning System), producing accurate, time-aligned measurements that can be compared and tracked across wide geographic areas. This makes it easier to correctly identify and diagnose events occurring across a large region.

Oscillations help reveal grid problems

Many problems on the grid begin with or are manifested through oscillations, which can be observed in detail by PMUs. We can use PMUs to recognize and study an oscillation to understand both its causes and potential consequences. With this knowledge, the system analyst can work to mitigate or eliminate the problems causing the oscillation, and design measures to better manage the assets and protect the system from further adverse oscillations. Because many of the examples reviewed in this report were revealed through examination of an oscillatory event, it is worthwhile to understand oscillations in a power system.

Oscillations are manifested as cyclical changes in voltage or current. Here the term *oscillation* refers to any unintentional periodic exchange of energy across different components of a power grid. Oscillations can arise for a variety of reasons and are generally characterized by a set of frequency, damping, amplitude, and phase terms. Often, these terms cover a range that is particular to the oscillation's source.

In general, oscillations can be grouped into two types: natural and forced. Natural oscillations are analogous to the operation of a tuning fork. Just as striking a tuning fork produces an audible oscillation that is particular to the fork, disturbances to power systems produce natural oscillations that can be observed in synchrophasor measurements. Natural oscillations are always present in power systems; often multiple oscillations are occurring at the same time.[3] The characteristics of these oscillations are determined by the dynamic properties of the system. Persistent system disturbances due to random events, such as small load changes, continually excite the system's dynamics. Unstable oscillations can be local or system-wide, and can affect only specific equipment or the entire system.[4]

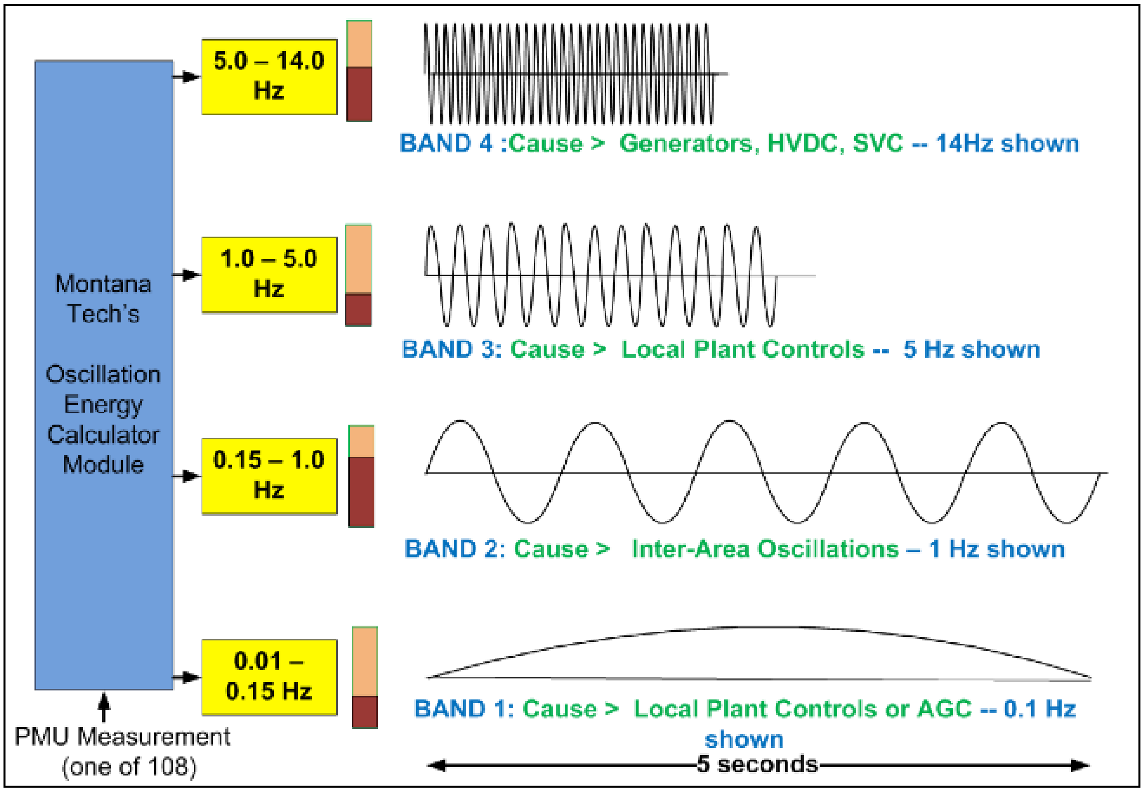
Natural oscillations can be further divided into groups based on the equipment participating in the energy exchange. Table 1 lists several oscillation varieties along with their typical frequency ranges. Oscillations arising because of the interaction of generating units between two areas are of particular interest due to their relation to the small-signal stability of the system. Figure 4 illustrates how some of these oscillation sources manifest in frequency terms.

Table 1. Typical oscillation causes and frequencies

Cause	Typical Frequency
Power plant speed governor, plant controller, AGC	0.01 to 0.15 Hz
Inter-area power oscillations, as from excessive real power transfers, ineffective damping controls or unfavorable load characteristics (voltage and frequency)	0.15 to 1.0 Hz
Local rotor angle oscillations	0.6 to 1.5 Hz
Generator excitation controls	1.0 to 15.0 Hz
Turbine shaft torsional subsynchronous oscillations	5.0 to 45.0 Hz

Adapted from Kosterev & Undrill, "Oscillations in Power Systems," June 3, 2011, and "Wind Farm Oscillation Detection and Mitigation," PowerPoint, April 22, 2014.

[3] D. Kosterev and J. Undrill, "Oscillations in Power Systems," June 3, 2011.
[4] Ibid.

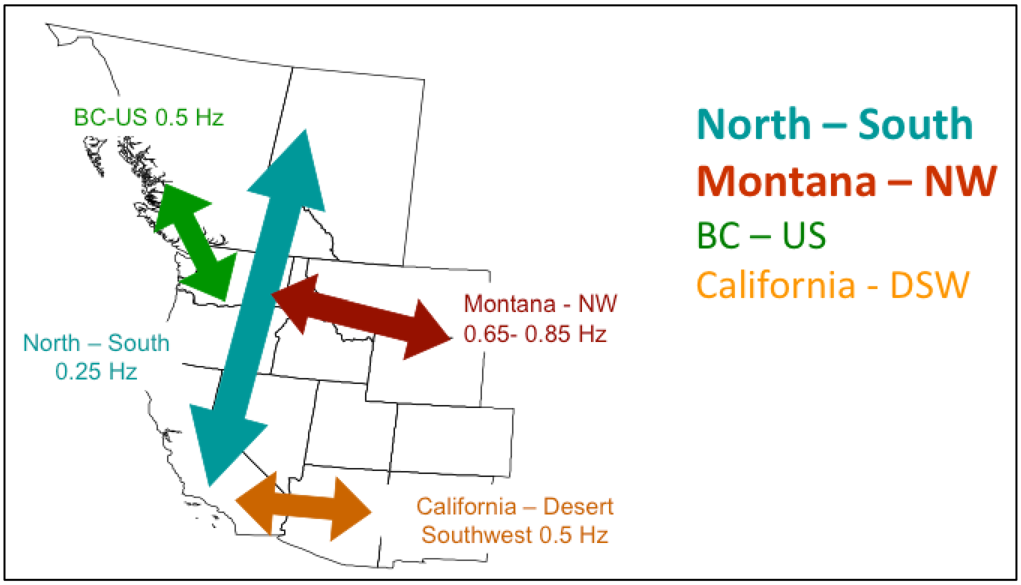


Example based on Montana Tech Oscillation Energy Calculator
Source: Nick Leitschuh, BPA, "Synchrophasor based oscillation detection at Bonneville Power Administration," NASPI, March 18, 2014

Figure 4. Oscillation modes. Local modes tend to be at higher frequencies while system-wide, inter-area oscillations are at lower frequencies[5]

Figure 5 shows the known inter-area oscillation paths in the western United States and Canada; these affect western grid operations and planning.

[5] N. Leitschuh, "Synchrophasor based oscillation detection at Bonneville Power Administration," NASPI Work Group Meeting, March 18, 2014.



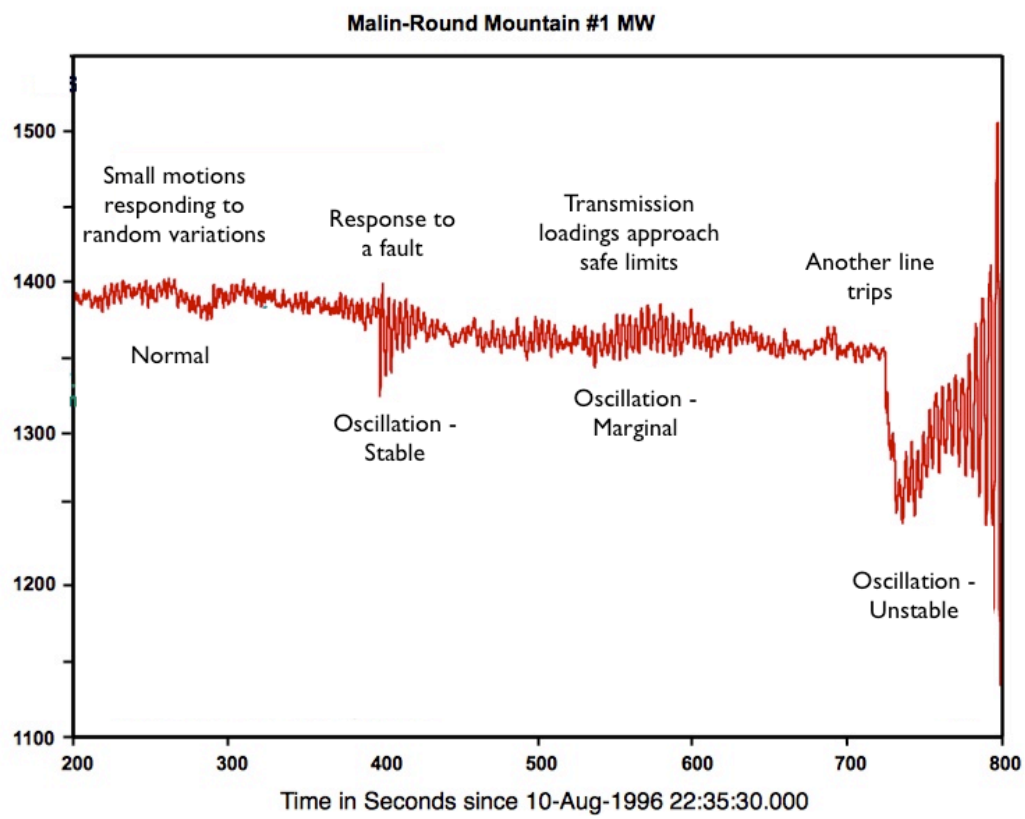
Source: BPA, Nick Leitschuh, "Synchrophasor based oscillation detection at Bonneville Power Administration," NASPI, March 18, 2014.

Figure 5. Known inter-area oscillation paths in the West

Often, the terms *electromechanical mode* or *oscillatory mode* are used to describe the dynamic properties of a power system that give rise to inter-area oscillations. When the electromechanical modes of a system are stable (i.e., the damping of the modes is positive), the system will also be small-signal stable and inter-area oscillations will diminish and die out over time. The oscillations shown in Figure 4 are stable and consistent in behavior and in most cases would not pose any problem for electric system reliability. However, if one or more electromechanical modes are unstable (i.e., with negative damping), the entire system will be small-signal unstable and inter-area oscillations will grow in magnitude until corrective actions are taken or a blackout occurs. The consequences of an electromechanical mode becoming unstable can be severe—un-damped oscillations have contributed to a number of major blackouts across North America.

Like natural oscillations, forced oscillations can constitute a significant problem in power systems. Rather than gaining their periodic nature from the system's dynamics like natural oscillations, forced oscillations reflect the periodicity of the unintentional system inputs that drive them. A wide variety of such inputs exist, including electronic transmission controls for direct current (DC) and Flexible Alternating Current Transmission System (FACTS) devices, malfunctioning equipment, equipment operated outside its intended range, and cyclic loads. Because of their wide variety of sources, forced oscillations do not have a particular frequency range. They generally exhibit near-constant amplitudes and thus are not characterized by a damping term. As a result, it is often difficult to distinguish between a forced oscillation and a marginally stable natural oscillation, but doing so is important because forced oscillations have contributed to several blackouts.

Figure 5 presents real power measurements from the August 10, 1996 event, which led to a significant blackout in the western United States. At the beginning of the plot, all electromechanical modes of the system are stable. The small deviations in power around the operating point are primarily the result of small random load changes. At approximately 400 seconds, the stable transient response of the system to a fault is clearly visible. This transient response, like most small-scale transient responses, was characterized primarily by the electromechanical modes of the system. During the time surrounding the 600 second mark, the damping of one of the electromechanical modes, and consequently its associated inter-area oscillation, becomes so low that the oscillation has a nearly constant magnitude. Finally, another line trip at approximately 700 seconds led to the damping of an electromechanical mode, and the associated inter-area oscillation with negative damping. The growing oscillation that resulted eventually led to a cascading blackout of much of the western U.S. power system. This particular event motivated western U.S. efforts to develop synchrophasor tools for monitoring electromechanical modes.



(Source: Kosterev & Undrill)

Figure 6. An undamped, unstable outage in the West (August 10, 1996)

Grid planners and operators need to understand which oscillations are present on the grid and be able to calculate the oscillation energy and identify excessive and/or persistent oscillations that could become a grid disturbance. PMU-based oscillation detection tools can identify such oscillations and alert operators, and synchrophasor data are being used to devise and test possible remediation and mitigation strategies for oscillation management.

For many of the operating events discussed below, oscillations in voltage or current provided the first clue of anomalous behavior reflecting some underlying operational problem that needed attention.

3. Generator settings and generator equipment failures

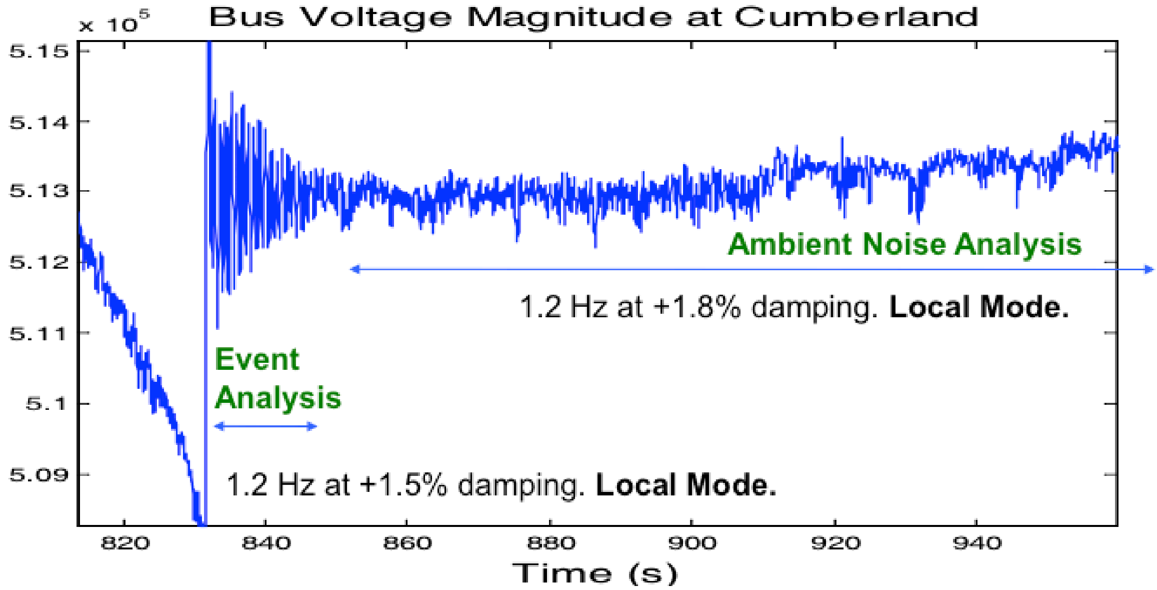
Generator owners, transmission owners, and reliability coordinators have been using synchrophasor data in two ways to identify failures in generator settings and operation. One method is through direct observation of the synchrophasor data coming from PMUs at or near the power plant, as in the cases described below for the Cumberland Power System Stabilizer (PSS) setting, Redbud oscillations, and examples in New York, Colstrip, Alberta, and Midcontinent Independent System Operator (MISO) service territories. The other identification method occurs when synchrophasor data are used to validate the model of the power plant and the analyst determines that the mismatch between actual plant performance and its model may be due to equipment malfunctions or an improper setting rather than inaccurate modeling. Such a case is described below for a hydro generator.

PMUs are also being used to protect power plants and enhance their operation. Dominion Virginia Power (Dominion) is using real-time PMU monitoring of transmission lines to protect generator rotors from unbalanced current overheating, and Manitoba Hydro is using PMUs to perform real-time commissioning of power system stabilizers.

Cumberland PSS setting – TVA

One of the earliest uses of PMU data to identify generator problems occurred in the TVA service territory. TVA set up an oscillation monitoring system (OMS) using research-grade PMUs in 2007 following a significant oscillation at TVA's Cumberland generator (a two-unit, 2,386 MW coal-fired plant) in 2006. TVA also installed a PSS at one unit of the plant. Subsequently, on November 29, 2007, with both units in service, TVA's OMS showed local plant mode damping at +1.7% (with an alarm); the PSS had been taken offline. On February 5, 2008, with both units in service, the monitoring system showed local mode damping at +3% (with an alarm), as shown in Figure 7. Further investigation revealed that the PSS was in service, but it was not performing effectively and appeared to need tuning; when the manufacturer checked the PSS card, it found that the card was faulty and had to be fixed.[6]

[6] M. Venkatasubramanian (WSU) & R. Carroll (TVA), "Oscillation Monitoring System at TVA," NASPI Work Group Meeting, June 2009, pp. 6-16.



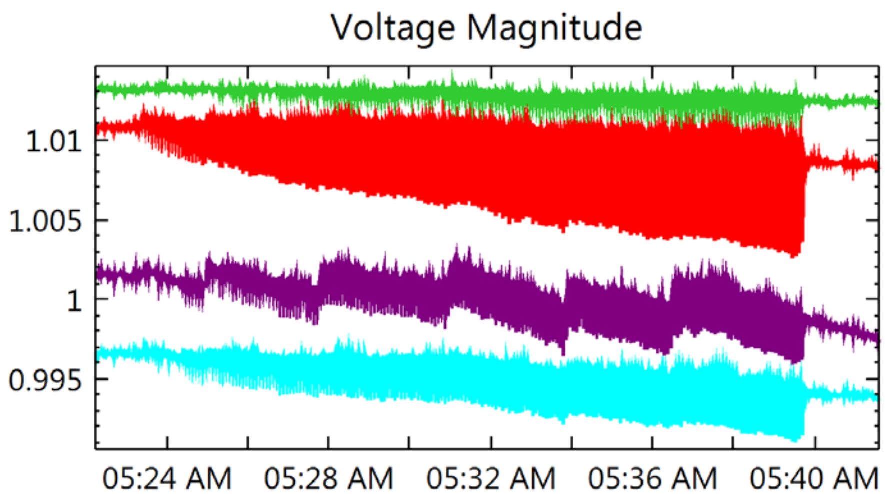
(Source: TVA, from Venkatasubramanian & Carroll)

Figure 7. Voltage oscillations at Cumberland plant in 2008

Redbud power plant oscillations – OG&E

OG&E staff observed voltage oscillations at 0.2 Hz in the PMUs monitoring several 345 kV lines across the system. Figure 8 shows PMU traces from four OG&E 345 kV lines; the red trace comes from the PMU closest to the power plant. OG&E engineers observed that the signal was most pronounced in the mega volt-ampere reactive (MVAR) plot and suspected the cause to be a generation problem (see Figure 9). Because the magnitude of the oscillations was greatest at the Arcadia PMU (the red trace in Figure 8), OG&E engineers suspected the problem to be at the adjacent Redbud power plant. They contacted the plant manager and provided a list of time-stamps for when the condition had occurred. This allowed the plant manager to determine that the oscillations corresponded with the startup of Redbud Unit 4, which was in volt-ampere(s) reactive (VAR) control mode, and lasted for 20 minutes. The oscillations disappeared (as evidenced in the graph when the oscillations stabilize suddenly near 05:40 am) when the operator switched the unit from VAR control to voltage control.[7] The plant was able to work with the *manufacturer to correct the problem*, which would not have been discovered without PMUs.

[7] A. D. White & S. E. Chisholm, OG&E, "Synchrophasor use at OG&E," NASPI Work Group Meeting, June 9, 2011.



(Source: OG&E, from White & Chisholm)

Figure 8. Voltage oscillations shown on three of four PMUs while plant in VAR control mode

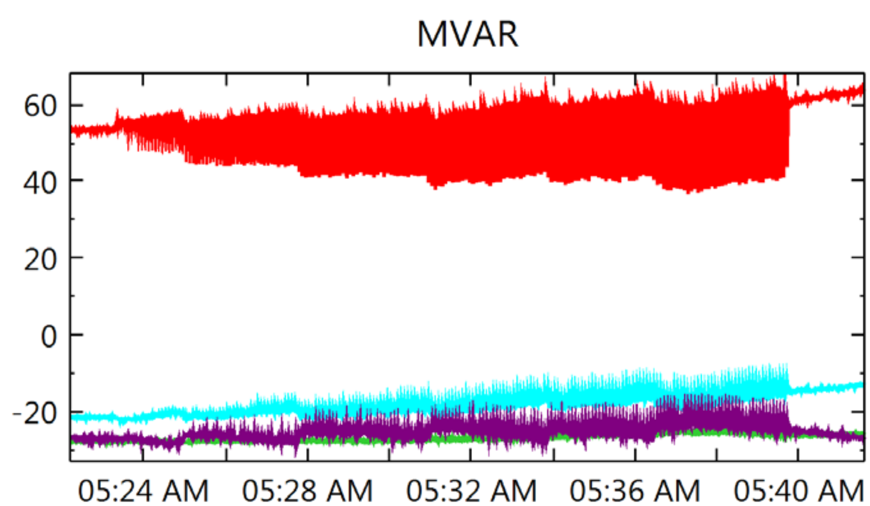
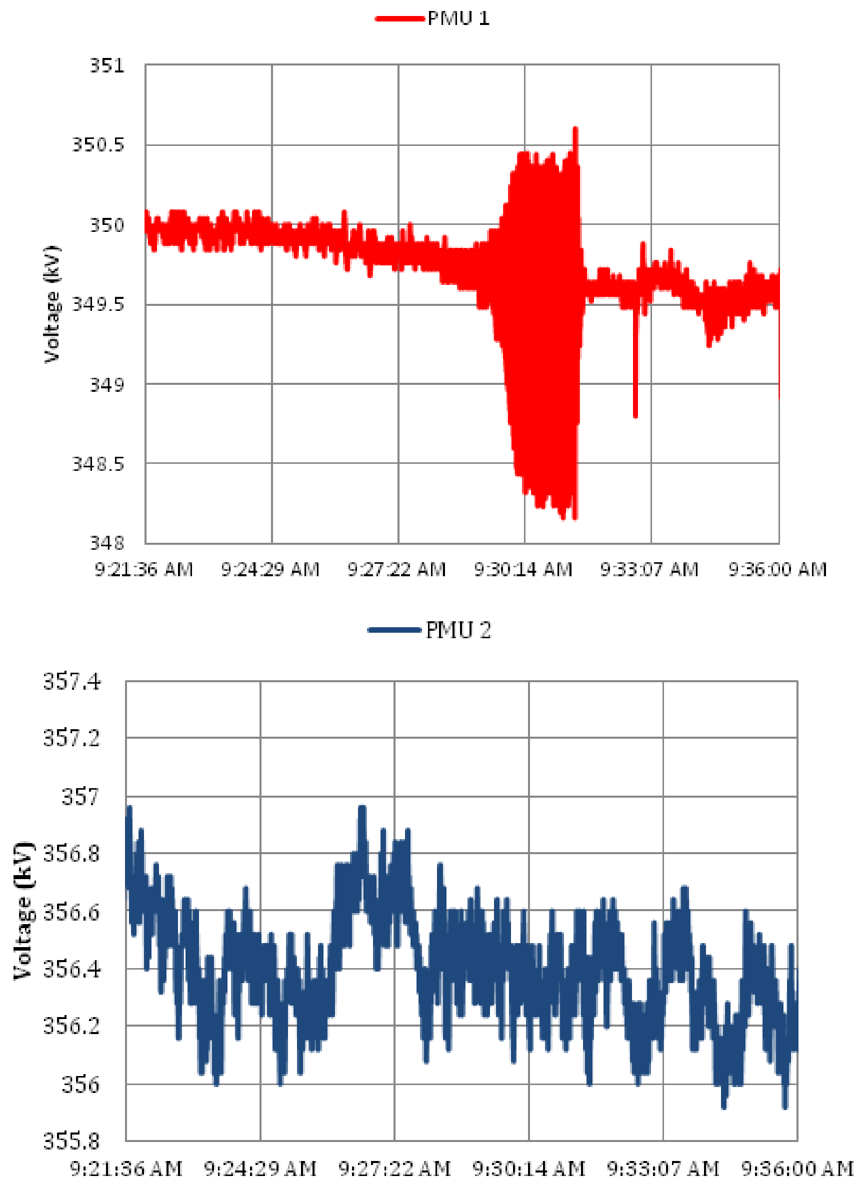


Figure 9. Reactive power (MVAR) oscillations on one unit of four generators

Malfunctioning generator AVR control system – NYISO

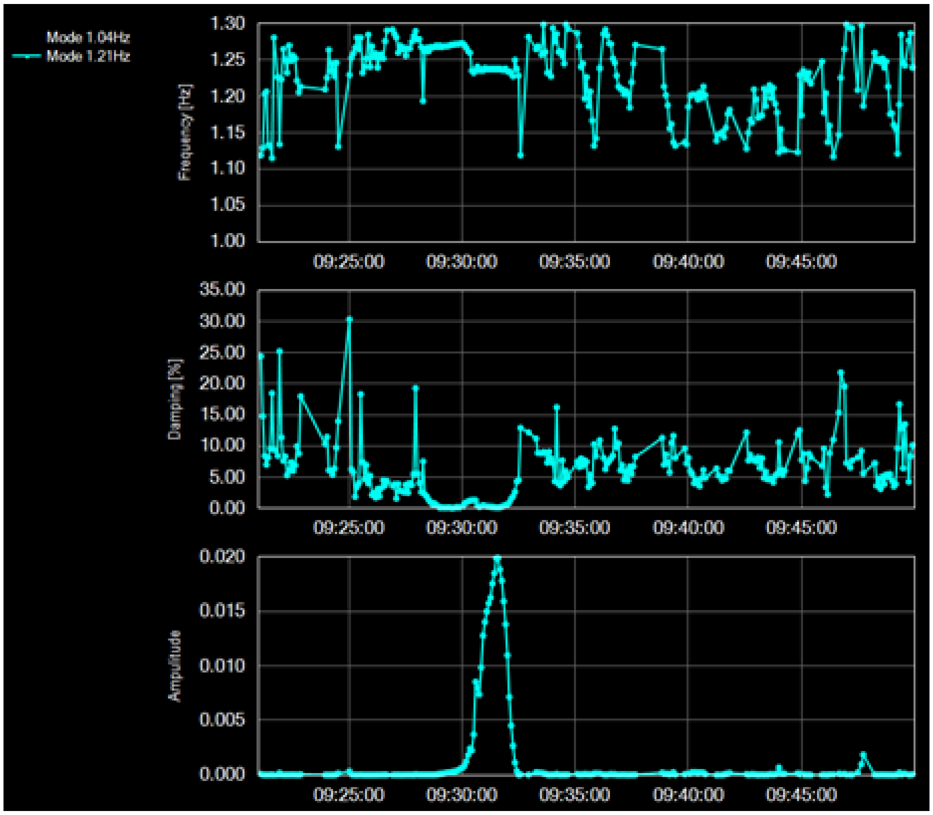
In May 2013, operators at the New York Independent System Operator (NYISO) observed transient voltage oscillations in SCADA data, and verified these from available PMU data. The oscillations lasted for 3 minutes and appeared on many of the western New York 345 kV buses (see Figure 10, top graph), but not on the eastern PMUs (bottom graph of Figure 10). Analysts used Phasor Grid Dynamics Analysis software for ringdown and modal analysis of the oscillation characteristics (see the power flow graphs in Figure 11), and found oscillations of +/-2 kV in the 1.25 Hz oscillatory mode. The PMU data revealed that while real power and voltage were fluctuating, frequency was not. This led operators to conclude that the voltage oscillation cause was local and generation-related. The grid operator identified the bus with the highest voltage oscillation levels and asked the operator of the generation complex closest to that bus to trouble-shoot the issue. The plant operator systematically turned off the excitation system for each of the generation units in the generator complex, and found one that had a malfunctioning generator Automatic Voltage Regulator (AVR) control system. Similar oscillations had occurred 3 years previously, but no one was able to identify the cause because no PMUs were installed on the New York system at that time.[8]



(Source: NYISO, from Cano)

Figure 10. Voltage oscillations on the western (top) and eastern (bottom) sides of New York system

[8] E.B. Cano, "NYISO Case Studies of System Events Analysis using PMU Data," NASPI Work Group Meeting, March 11, 2014, p. 5-6; and communication with Ed Cano, September 8, 2014.



(Source: NYISO, from Cano)

Figure 11. Oscillation characteristics of power flow of the PMU closest to the oscillations

Malfunctioning generator PSS – NYISO

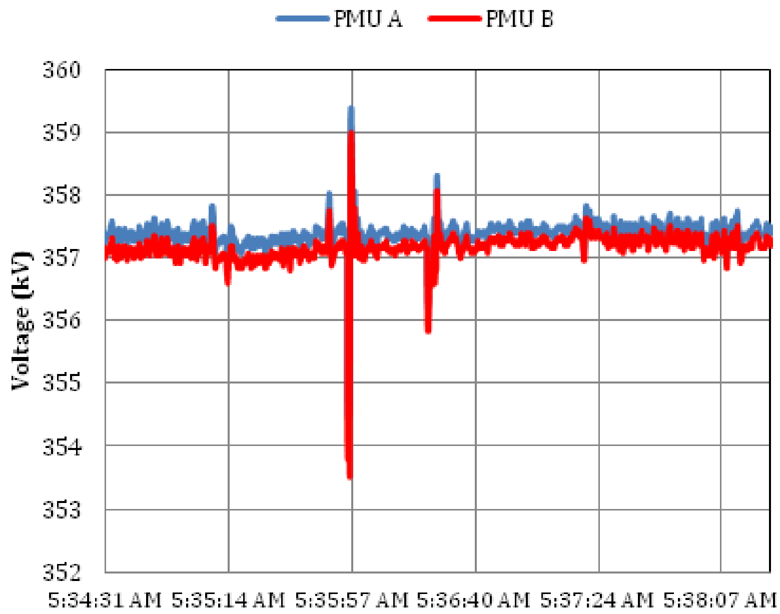
In August 2013, NYISO saw voltage oscillations on its 345 kV lines on SCADA and investigated them using data from its synchrophasor system. The NYISO staff found oscillations of 0.9 Hz that occurred close to a large, multi-unit generator complex in central New York, but were evident on PMUs across the New York system.[9] The 0.90 Hz mode indicates an inter-area oscillation, consistent with the widespread impact of this event. Staff at the generator investigated and found a malfunctioning PSS at one of the units; this was fixed by replacing the PSS control card.[10]

The engineers began their investigation of this event by using the PMU voltage data from the 345 kV system to determine where the problem was located; voltages on two PMUs in the central part of the New York system were very consistent, indicating that they were close to the source of the oscillation (Figure 12; in fact, these two PMUs are on buses on either side of the generation source of the oscillation). But voltages on PMUs in the western and south parts of the system (Figure 13) tracked less closely; the green trace in Figure 12 comes from a PMU closer to

[9] E.B. Cano, "NYISO Case Studies of System Events Analysis using PMU Data," NASPI Work Group Meeting, March 11, 2014, p. 11-12.

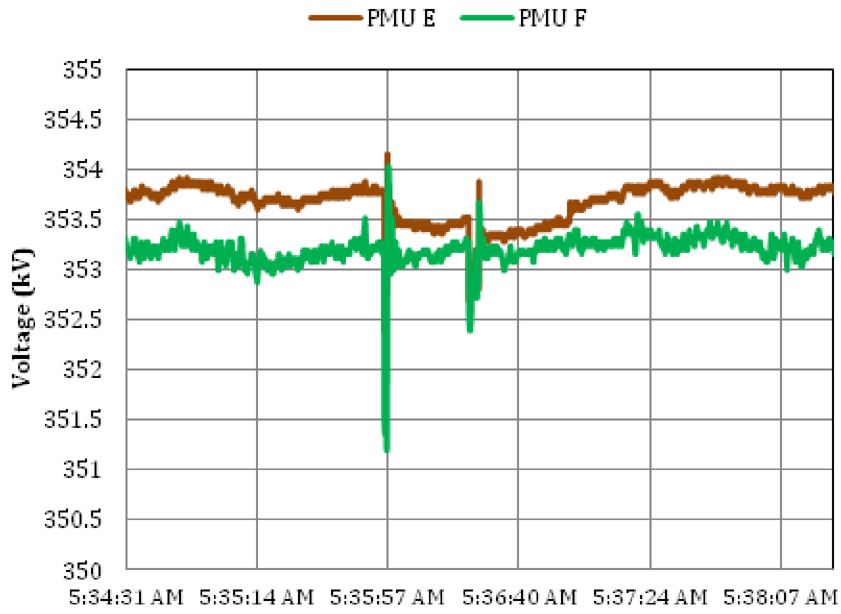
[10] Communication with Ed Cano, NYISO, September 8, 2014.

the oscillation source; and at the PMUs farthest from the generator (Figure 14), voltages in the far west and south central parts of the system varied most from those closest to the plant.



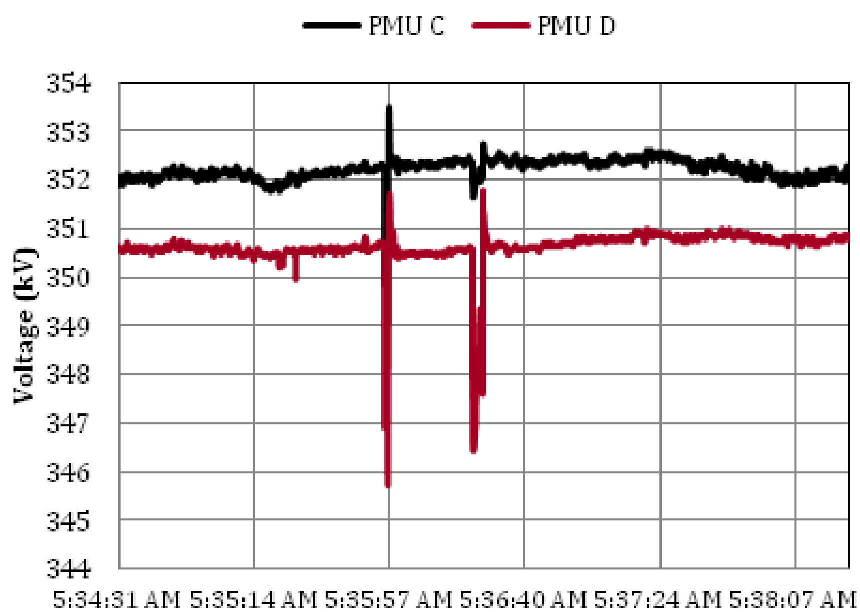
(Source: NYISO, from Cano)

Figure 12. Voltage (kV) traces on two PMUs in central New York system, closest to the source of oscillation



(Source: NYISO)

Figure 13. Voltage (kV) traces at PMUs on the western and south central parts of New York system



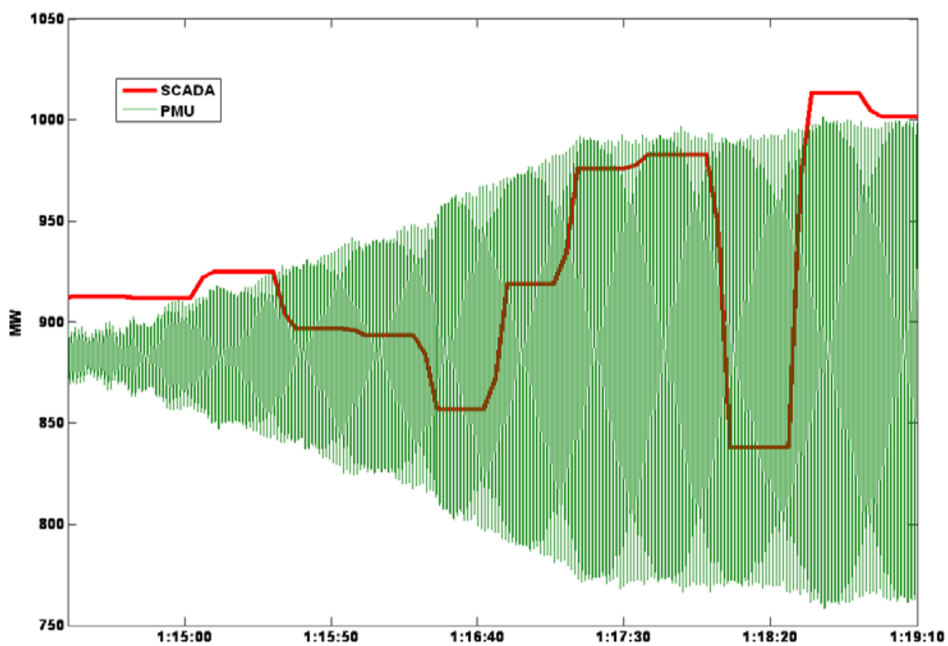
(Source: NYISO)

Figure 14. Voltage (kV) traces at PMUs on the eastern side of New York system, farthest from source of oscillation

Power oscillations at nuclear plant – Dominion

During light load system conditions (often experienced during spring and at night), operators must manage high voltages across the system caused by reductions in load and power transfers. One option is to reduce the scheduled voltage of power plants; the generator consumes more MVARs to bring the voltage down to its set-point. However, little reactive support from the grid coupled with under-excitation of the unit can result in very low synchronizing torque on the machine. These conditions can lead to a small signal instability problem, where small perturbations to the system can grow in magnitude because of lack of damping.

A nuclear generator experienced this problem in 2011, when it adjusted its terminal voltage schedule down by 3 kV. The voltage reduction caused the generator to go small-signal unstable, leading to severe oscillations with peak-to-peak amplitudes of more than 250 MW (Figure 15) and voltage oscillations in the range of approximately 230 kV to 235 kV. The oscillations continued for several minutes before Dominion operators spotted the event in SCADA data fluctuations. The oscillations lasted for a total of 12 minutes. The oscillations subsided when the plant's voltage schedule was returned back to its initial set-point.



(Source: Dominion Virginia Power)

Figure 15. Start of a twelve-minute oscillation at a nuclear plant

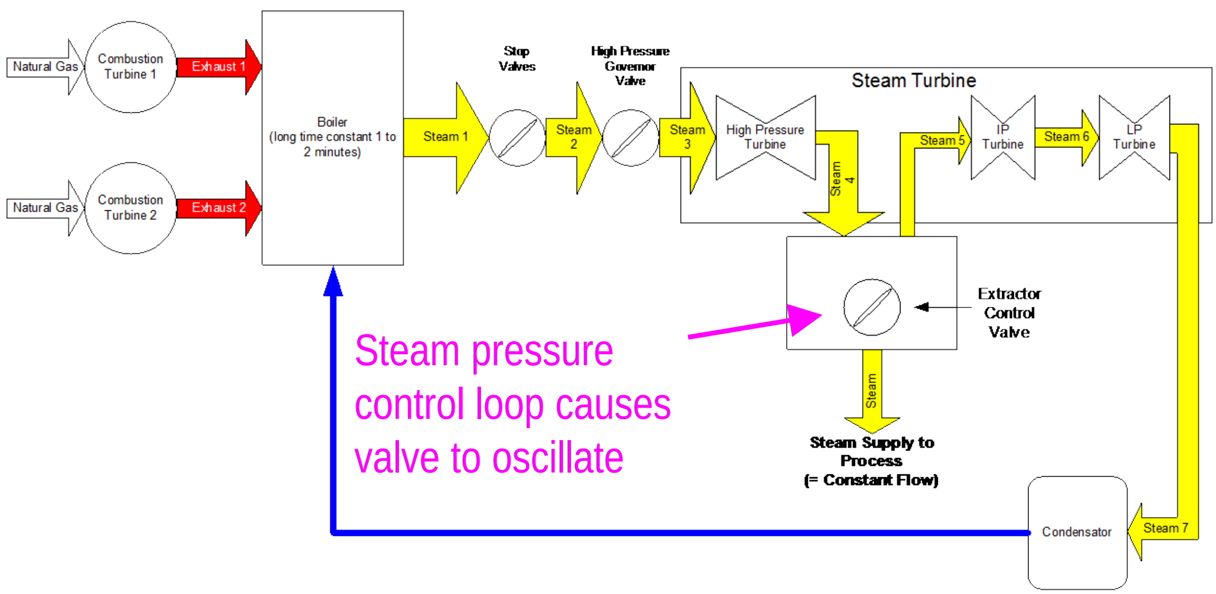
Large oscillations of a large generator entail significant dynamic movement in its shaft. This type of oscillation has the potential to cause serious damage to the generator's controllers, governors, and generator shaft. All of these pieces of equipment are expensive, time-consuming to replace, and requires an extensive generator outage. Had the oscillation continued for too long, it could have caused poles to slip and other generators to trip as well.

Following the event, Dominion and PJM Interconnection, LLC (PJM) staff performed event analysis and system validation studies to recreate the event. They used simulations with PMU data that captured the high-resolution dynamic measurements of the generating unit. Based on this event and analysis, Dominion subsequently installed PSSs on each of the units.

Governor control malfunction in Alberta caused large power oscillations on California-Oregon lines – BPA & CAISO

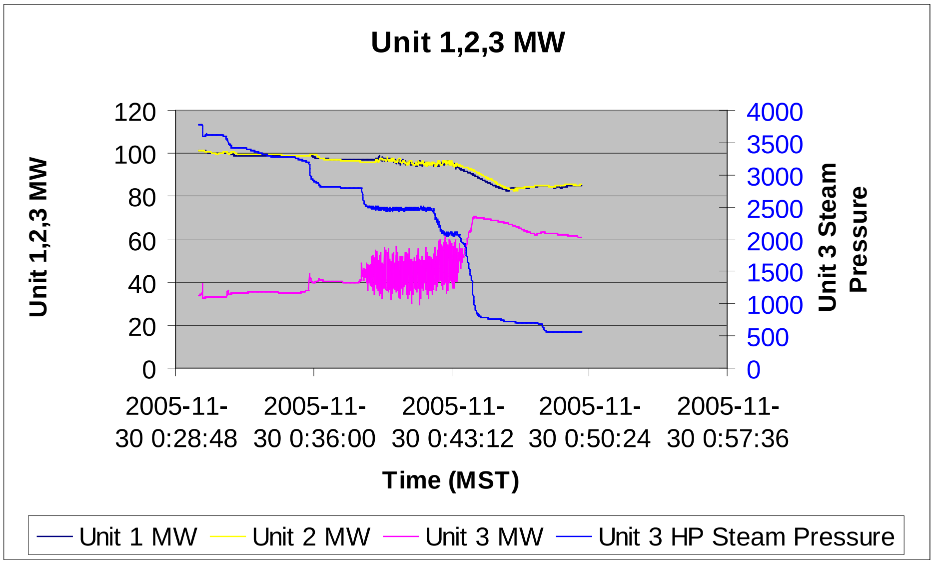
A sustained oscillation developed in the Western Interconnection at 23:37 PST on November 29, 2005. The oscillation was initiated by a malfunctioning steam extractor control valve at the Nova Joffre co-generating plant in Alberta, Canada (see Figure 16). The steam turbine generator developed a 20 MW peak-to-peak 0.28 Hz oscillation (Figure 17). The plant oscillation excited one of the North-South modes of inter-area oscillations in the Western Interconnection, causing a 200 MW peak-to-peak oscillation on the California-Oregon Intertie (Figure 18). The oscillation ended after 6 minutes when the steam supply to the industrial process was reduced.

In this case, the role of PMU data was to confirm and reveal the details of the forced oscillation and illustrate the link between the oscillation at the Alberta generator and the oscillation on the California-Oregon Intertie (COI).



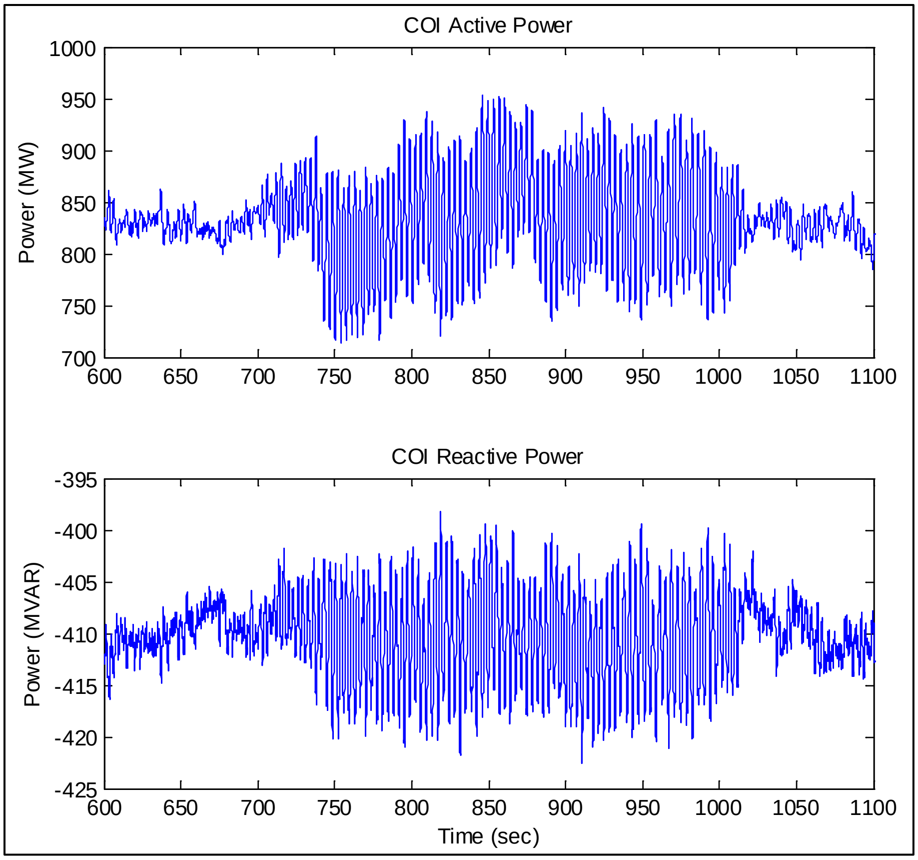
(Source: BPA, from Kosterev email)

Figure 16. Diagram of steam valve oscillation at Nova Joffre power plan



(Source: BPA, from Kosterev email)

Figure 17. Nova Joffre units real power output and steam pressure oscillation



(Source: BPA)

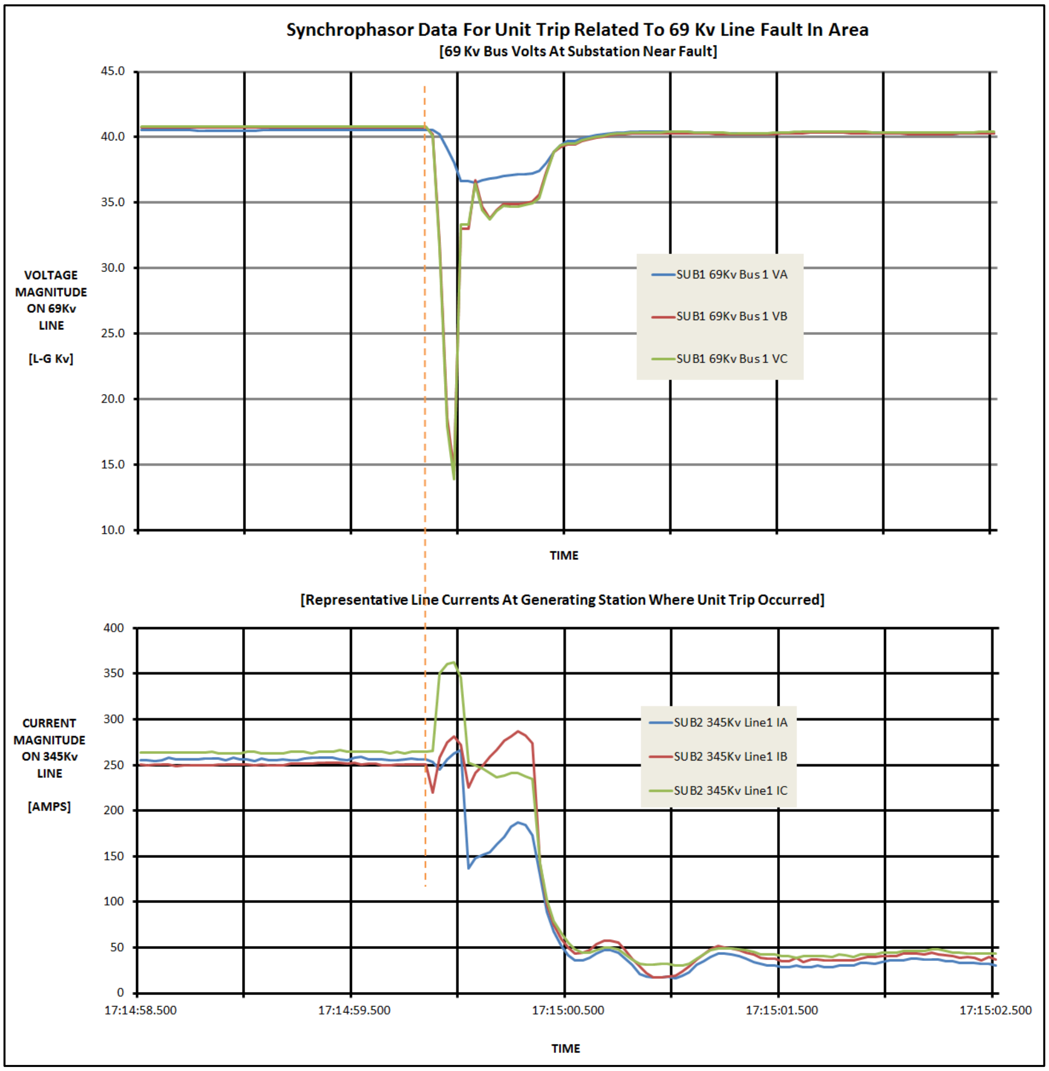
Figure 18. Power oscillations on the COI resulting from the Nova Joffre power plant valve mis-operation in Alberta, November 2005

Relay mis-operation causing generator trip – ATC

The American Transmission Company (ATC) has a network of 107 PMUs spread across the state of Wisconsin and the upper peninsula of Michigan, many of which were installed under its SGIG grant. ATC uses its synchrophasor data, "to fill in a visibility gap between four-second scan rate data [SCADA] and high speed fault recording equipment, because DFRs [digital fault recorders] don't always trigger when you need higher resolution data."[11] ATC's operations engineering staff use PMU data to review all transmission faults and its system's post-event response to each.

In an event that occurred in June 2014, ATC initially received a report that a generator tripped offline during a thunderstorm. ATC pulled up initial information on the event from its SCADA records, used a DFR at the plant to identify what happened, and used PMU data to find the precise timing of the trip (see Figure 19). ATC's first hypothesis suggested that the trip was related to a lightning strike, but there was no lightning strike immediately before the trip and staff were unable to correlate any lightning strikes directly to the event. Subsequent analysis of local PMU data showed that the unit trip occurred at the same time as a 69 kV storm-related line fault farther from the plant; PMU current and voltage data for the generator trip lined up within cycles of the fault.

[11] J. Kleitsch, "Using Synchrophasor Data to Diagnose Grid Events," NASPI Work Group Meeting, March 12, 2014.



(Source: ATC, from Kleitsch)

Figure 19. PMU data showing voltage and current before and after generator trip related to a 69 kV fault

ATC explains:

> The plant owner eventually identified an issue with a negative sequence relay setting in a transformer differential relay that made it [the negative sequence relay] overly sensitive to external faults. That issue has been addressed. They also identified what appears to be an issue with the quality of the current transformers (CT) used to provide the current inputs to the protective relay that tripped, and are working to test the equipment. The plant might have identified the issues without the PMU data but it did provide them with certainty that the

trip should not have occurred and would not have occurred but for the plant relay problem.[12]

Faulty generator control card – ERCOT

In February 2014, Electric Reliability Council of Texas (ERCOT) operations engineers noticed oscillations on their real-time dynamics monitoring system (RTDMS) displays of PMU data (see Figure 20). Examination revealed that the oscillations occurred only on Line 1 at the West 4 PMU location, as shown in Figure 21 and Figure 22.[13] ERCOT staff noticed that when the hydro unit closest to this PMU went offline, the oscillations died down, and when the second unit at the same plant was running no oscillations were observed. The same oscillatory pattern occurred again on February 27. Modal analysis of the oscillations indicated that the dominant mode was 1.8 Hz, indicating that the cause was a unit within the plant. After discussions between the ERCOT engineers and the power plant operator, they decided to change out some of the control cards for the problematic Unit 1, to test whether that would solve the problem. After the control cards were replaced, the plant was brought back online and the oscillations were significantly reduced.

(Source: ERCOT)

Figure 20. Frequency oscillations on RTDMS system

[12] J. Kleitsch, communication with the author, July 3, 2014.
[13] ERCOT, "PMU Event Analysis Report for February 18, 2014," March 20, 2014.

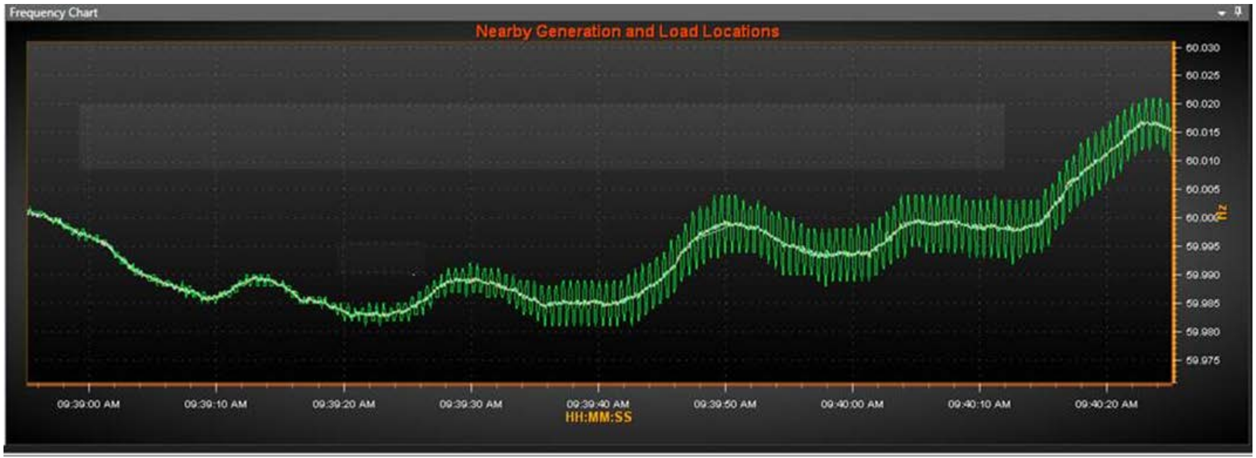


Figure 21. Frequency oscillation on West 4 PM

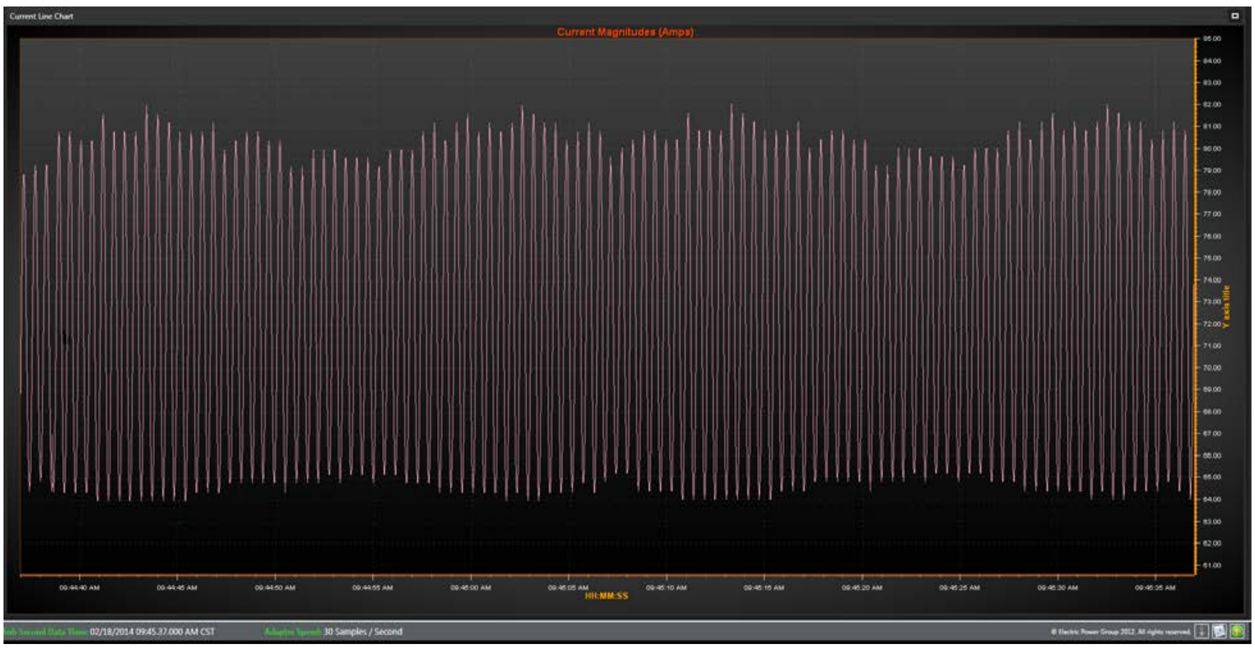
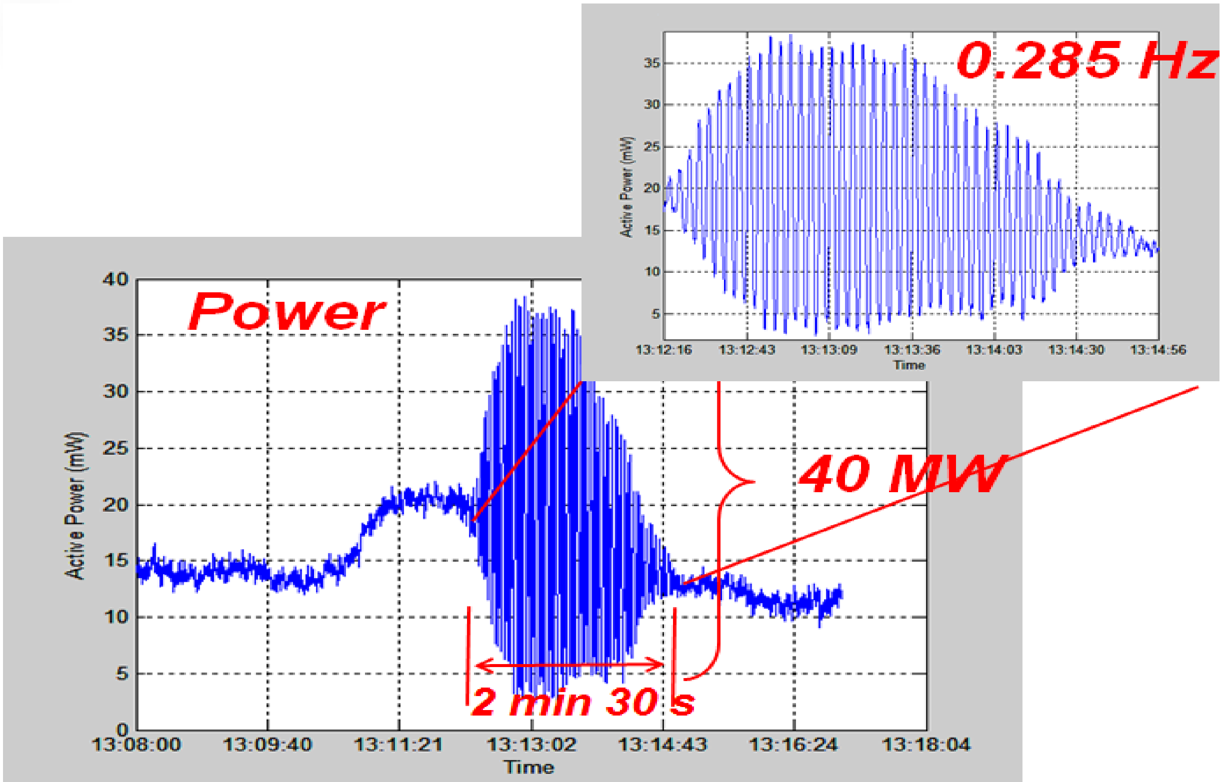


Figure 22. Current oscillations on West 4 PM

Governor control issue – MISO

MISO currently monitors approximately 420 PMUs within its footprint and uses the data for operations and situational awareness. In 2012, MISO performed baselining analysis to set inter-area oscillation monitoring thresholds for the oscillation monitoring application. Although focusing on inter-area oscillations, the baselining analysis identified two instances of short-term local forced oscillations in the western part of the MISO footprint; one of these instances is shown in Figure 23. Additional analysis indicated the likely source was a large coal-fired generating plant. MISO staff contacted staff at the generating plant about the analysis results.

Investigation by plant personnel confirmed that the unit was the source of the oscillations, and identified the cause to be a control system malfunction that caused continuing turbine fast valve actions after routine turbine valve testing; it is likely the issue was related to a recent control system upgrade on the unit. The control system malfunction was quickly resolved.[14]



(Source: Midcontinent ISO)

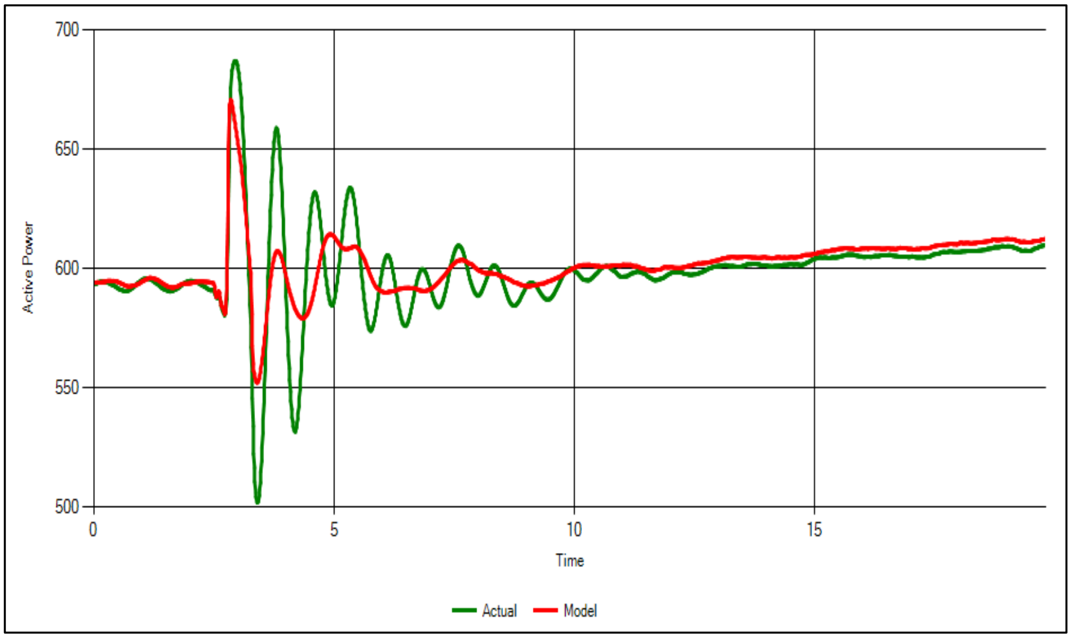
Figure 23. Forced governor oscillation in MIS

Figuring out governor settings – BPA

BPA analysts looking at PMU data for the performance of a large hydro plant during a grid disturbance found significant differences between the expected and observed responses of the plant to the disturbance (Figure 24). The plant had been modeled with its PSS (part of the plant's generator excitation controls) turned off because plant personnel indicated that the plant was operating in that fashion (because the light on the control panel was lit). But when the BPA analyst tried to run the generator model using the same event data with the PSS turned on, he found an exact match between the predicted and actual performance (Figure 25). However, the difference between expected and observed plant behavior persisted for several events. Eventually, technical staff performed PSS testing during a plant visit and found an internal contactor failure: while the PSS status was ON, the signal was not sent to the voltage regulator (i.e., the PSS status indicator was not operating correctly).

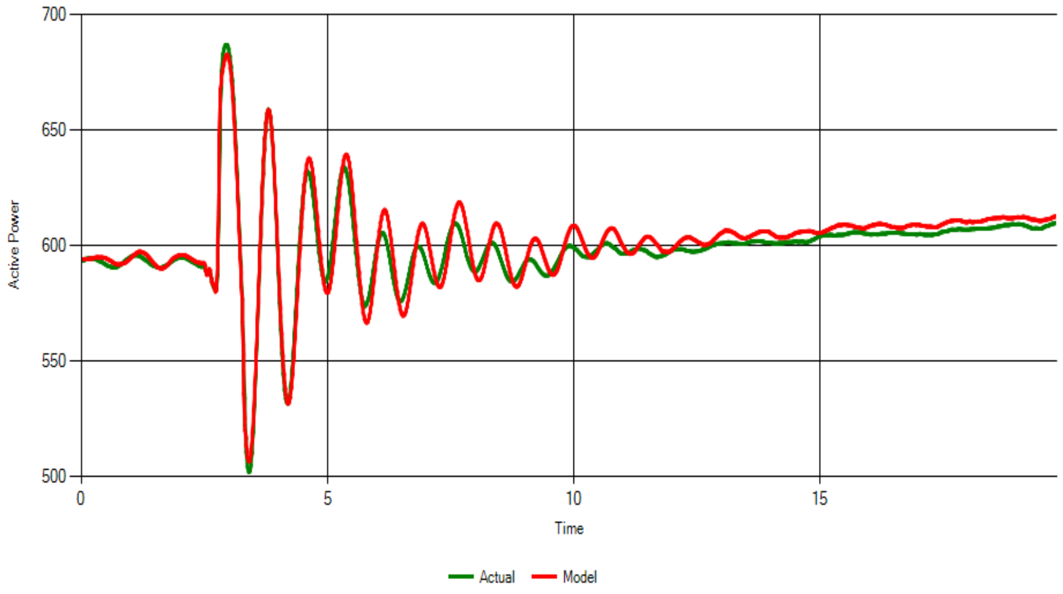
BPA analysts found several other generators where the PSS was either not performing or ineffective. All have since been fixed.

[14] Information provided by Kevin Frankeny in communication with the author, September 26, 2014.



(Source: BPA, from Yang email)

Figure 24. Real power comparison for Grand Coulee Unit − Actual (green) versus Model (red line) with PSS modeled as turned on



(Source: BPA, from Yang email)

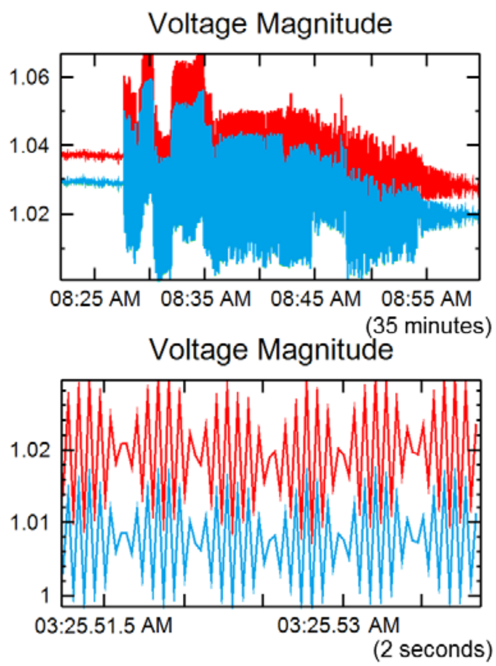
Figure 25. Real power comparison for Grand Coulee Unit, PSS modeled as turned off

Wind plants and oscillations

With wind generation increasing rapidly in many regions of North America, there is an urgent need for improved monitoring and modeling of this generation to gain a better understanding of how changes in wind plant output affect local voltage and system frequency. Grid operators and transmission owners in Oklahoma, Texas, and Oregon have been particularly active in using PMUs to track and analyze the causes and effects of wind plant oscillations.

Wind plant oscillations – OG&E

More than 3,100 MW of wind generation units are installed in the state of Oklahoma, most of it on the western side of the state. OG&E staff observed in 2011 that during periods of high wind (and only during these periods), the PMUs located at the wind farms in its service territory showed oscillations of 13−14 Hz (determined using Fast Fourier Transform [FFT] analysis), with fluctuations as high as 5% (see Figure 26). The OG&E staff wondered whether the oscillations were originating from a single plant, or caused by a type of turbine or turbine control, or originating from the interaction between multiple wind farms. They performed switching to electrically isolate the wind plants from each other, and determined that the oscillations were a problem only at the wind farms using a specific turbine model. With the cause of the oscillations identified, they then determined that the only solution available to limit the oscillations was to curtail output from those plants under high wind conditions.[15]



(Source: OG&E and NREL)

Figure 26. Voltage fluctuations observed at OG&E-served wind plants

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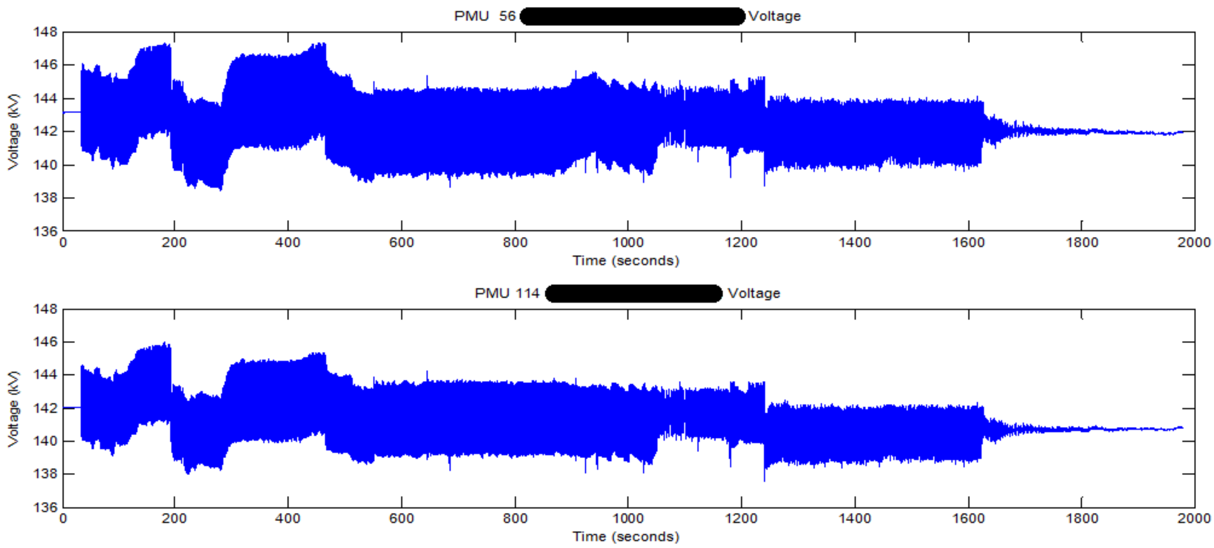
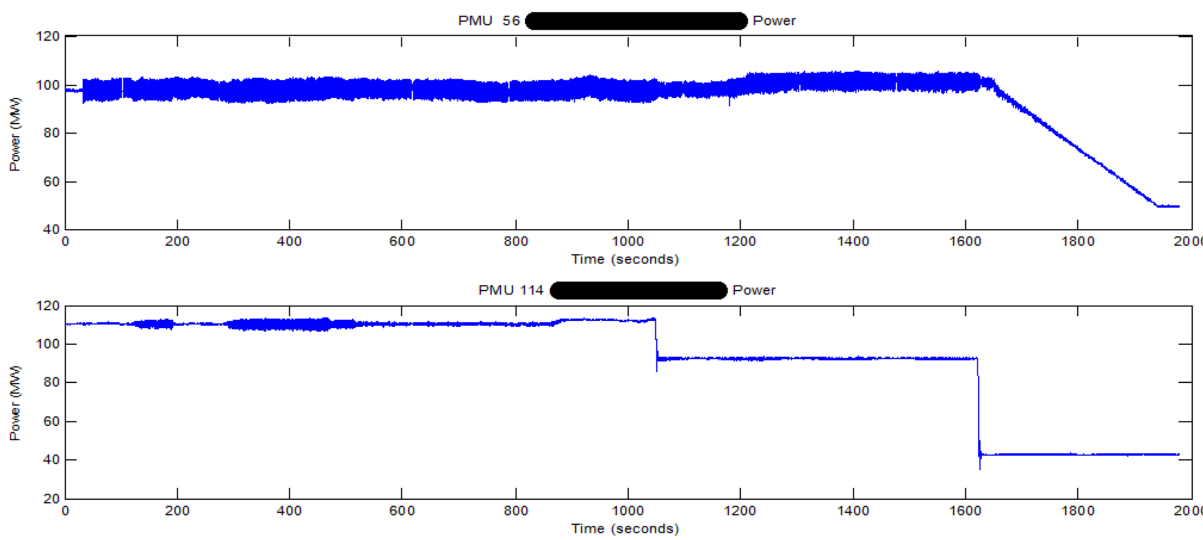
[15] A. D. White & S. E. Chisholm, OG&E, "Synchrophasor use at OG&E," NASPI Work Group Meeting, June 9, 2011.

PMU data can detect sub-synchronous oscillations that are too fast for SCADA to capture. One example is illustrated in Figure 27, which shows the voltage from two wind plants over 33 minutes on April 5, 2011. The voltage oscillations "followed almost identical paths and lasted more than 25 minutes unabated," with a peak-to-peak amplitude of 5.1 kV (3.7% of nominal voltage of 138 kV), as shown in Figure 27. Plant power also oscillated (Figure 28). System operators tried to reduce plant output gradually (see sequential power drops), but the oscillations did not stop until both plants significantly reduced their output. OG&E customers near the wind plants have experienced flicker when a voltage oscillation occurs.



(Source: NREL)

Figure 27. Voltage oscillations



(Source: NREL)

Figure 28. Real power oscillations

Based on extensive analysis of OG&E data, National Renewable Energy Laboratory (NREL) and OG&E researchers have concluded that several sub-synchronous frequencies are inherent to two types wind turbines installed within OG&E: the Type 4 wind generators with variable-speed generators and full AC-DC-AC conversion and the Type 3 wind generators with doubly fed induction generators and power converters.[16] NREL researchers conclude that the oscillations are more frequent for wind plants connected to the grid at 138 kV, and that there is a lower likelihood of oscillations for plants connected at 345 kV.[17] OG&E researchers observe that most of their wind oscillation problems occur under weakened system conditions, and seem to be sensitive to changes in the Thevenin impedance of the system.[18] However, grid disturbances may excite one or a group of these sub-synchronous frequencies to begin to oscillate during high wind periods.[19]

NREL reports that small voltage oscillations of different frequencies appear to be occurring constantly at wind plants.[20] NREL's analysis of the PMU data for Oklahoma wind plants concludes that wind plants routinely ride through grid disturbances as designed, and that common system events such as lightning strikes, line outages, and loss of generation cause wind plant voltage to sag and swing in the same ways that fossil generators respond to such events.[21]

A similar event has happened at another wind plant during contingency conditions. This plant connects on OG&E's 69 kV system and oscillates at 3.0 Hz. In this case, one of the two lines serving the wind plant tripped offline. About 5 minutes later, the wind started to pick up (as seen in the increase in MW output in Figure 29) and the plant began to oscillate at 3.0 Hz. This oscillation peaked at about 15% voltage fluctuation and dampened out on its own (Figure 30 and Figure 31) following a slight decrease in wind levels.

OG&E received quick notification of this event, and others, from its FFT Oscillation Detection program. OG&E developed this software to perform an FFT on a sliding window of 256 PMU samples; the program sends an email or text message when the oscillations reach an "objectionable level"[22] (see Figure 29). OG&E has used this notification system on numerous occasions to make system operators aware of changes in grid conditions, and to initiate curtailment orders to the generator if necessary to manage the oscillation.

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16 Y.H. Wan, "Synchronized Phasor Data for Analyzing Wind Power Plant Dynamic Behavior and Model Validation," National Renewable Energy Laboratory, Technical report NREL/TP-5500-57342, January 2013, p. 23.

17 Y.H. Wan, op. cit., p. 26.

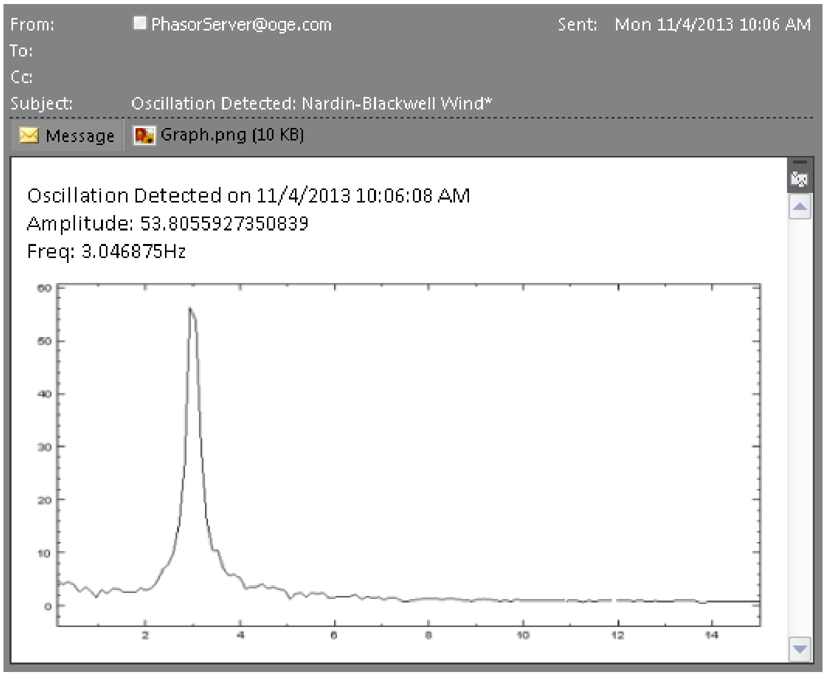
18 Communication from Austin White, OG&E, August 25, 2014.

19 Y.H. Wan, op.cit., p. 30.

20 Ibid.

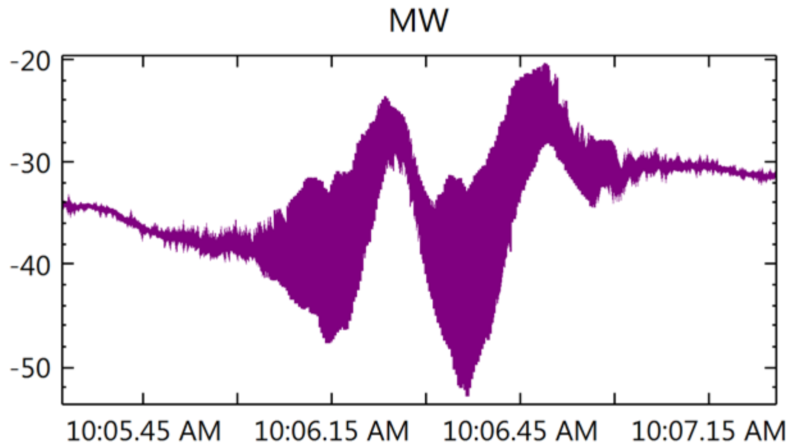
21 Ibid., p. 31.

22 "White, Austin (OG&E), Steve Chisholm (OG&E), Hamed Khalilinia (WSU), Zaid Tashman (WSU), Mani Venkatasubramanian (WSU), "Analysis of Subsynchronous Oscillations at OG&E", March 2012.



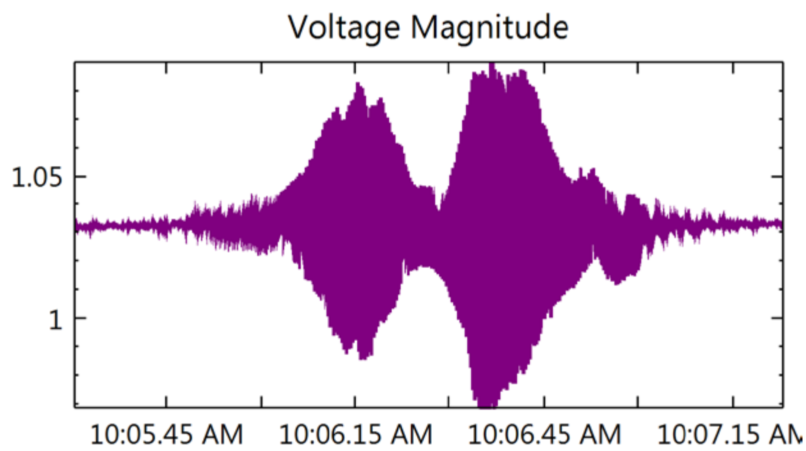
(Source: OG&E)

Figure 29. Wind plant oscillation as detected on OG&E Oscillation Detection Tool



(Source: OG&E)

Figure 30. Wind plant oscillation – voltage trace



(Source: OG&E)

Figure 31. Wind plant oscillation − real power

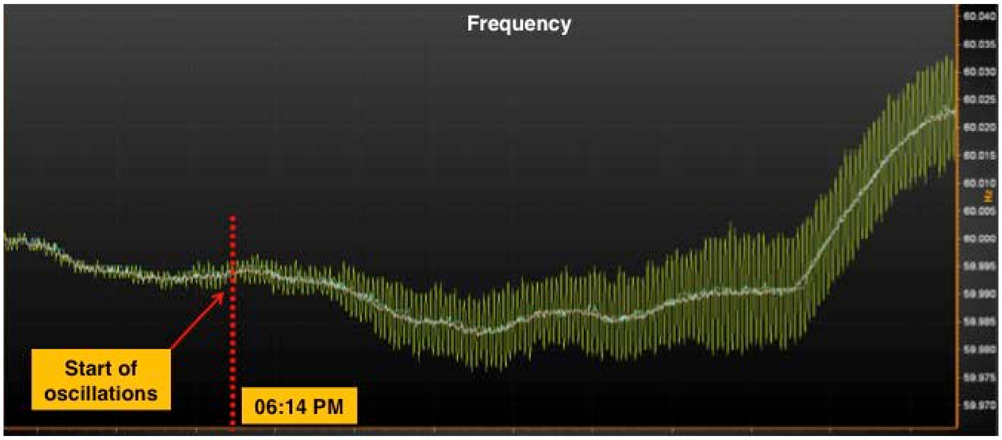
Wind controller software update flawed – ERCOT

Wind generators use electronic controllers to regulate power output; some of the controls are placed on individual wind turbines, and others are placed at the point of interconnection between the group of wind turbines that collectively make up the wind plant and the bulk power system that delivers its power to customers.

In early 2014, ERCOT operators observed oscillations in data from a PMU located at a wind plant, but did not find those oscillations associated with any other PMUs. The oscillation frequency was 3.3 Hz with damping less than 1%; oscillations in the 3.3 Hz oscillation mode corresponded to local controls, leading the operators to conclude that the cause was the wind farm controller settings. The oscillations persisted for almost 17 hours[23] (see Figure 32 and Figure 33). The oscillations displayed a constant frequency and low damping coefficient (Figure 34). To address the issue, operators first directed the plant owner to disable the wind farm's AVR, which had no impact; thus, they concluded that the AVR was not the cause of the problem. Next they reduced the wind plant's output from 56 to 45 MW, causing the oscillations to decrease but not damp out completely. When they dropped the wind plant output to 40 MW, the oscillations damped out completely (Figure 35).

While researching the problem, ERCOT operators contacted the wind plant's turbine manufacturer, who acknowledged that the controller settings had been changed on Day 1 (to increase performance) at the time when the oscillations began. After the manufacturer restored the original controller settings, the plant's power output was increased back to pre-event levels without causing any further oscillations.

[23] See EPG, "Wind Farm Oscillation Detection and Mitigation White Paper," April 2014, and "Wind Farm Oscillation Detection and Mitigation," PowerPoint presentation, April 22, 2014.



(Source: CCET and EPG)

Figure 32. Start of wind-triggered oscillations on Day 1

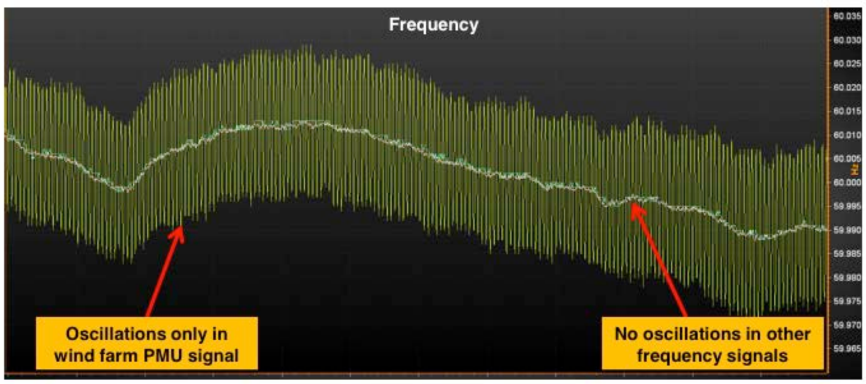


Figure 33. Continuing oscillations on Day 2 for a total of 17 hours

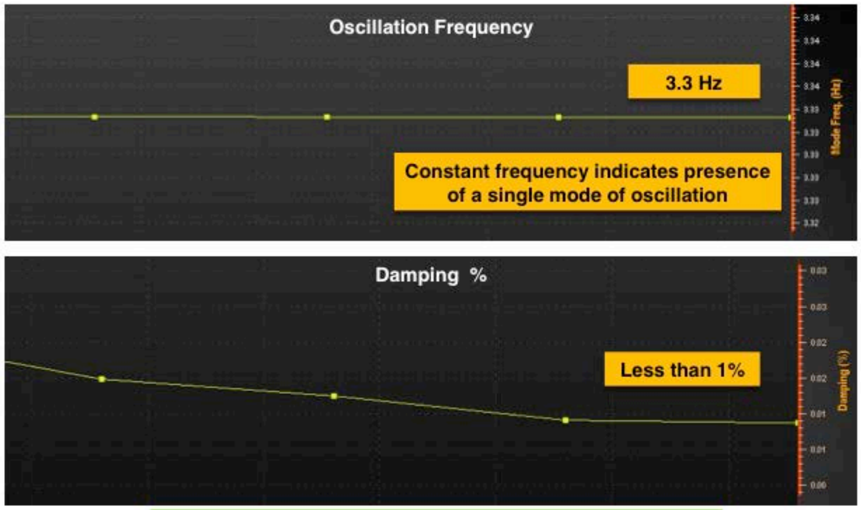


Figure 34. Constant oscillation frequency and low damping coefficient for the duration of the oscillations

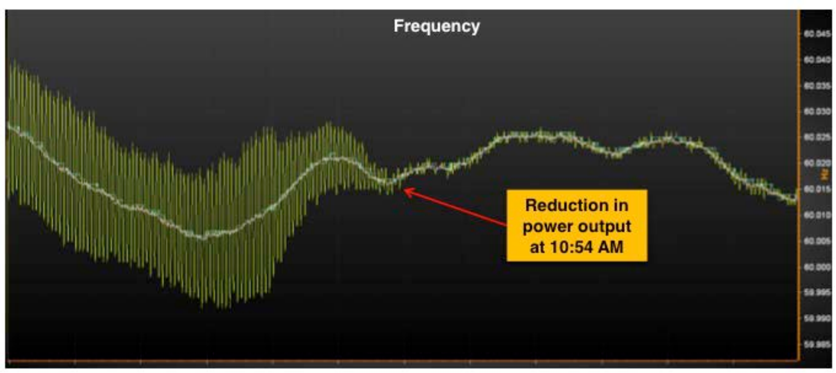


Figure 35. Oscillations stopped after wind plant power output dropped from 45 to 40 MW

Wind events and turbine controllers – ERCOT[24]

As of 2014, ERCOT had over 11,500 MW of wind capacity installed, with another 8,000 MW of capacity in development and more than 26,700 MW under study. Wind power composed 9.9 percent of total energy used in the ERCOT region in 2013, and at peak served a record 38.4% of total system demand on March 27, 2014.[25] Even before this growth in wind capacity and generation, ERCOT experienced several oscillatory events and issues relating to wind generation. ERCOT and four of its transmission owners partnered with the Consortium for Commercialization of Electric Technology in a DOE-funded SGDP designed (in part) to increase synchrophasor technology deployment and analytics. Today there are 69 PMUs deployed across

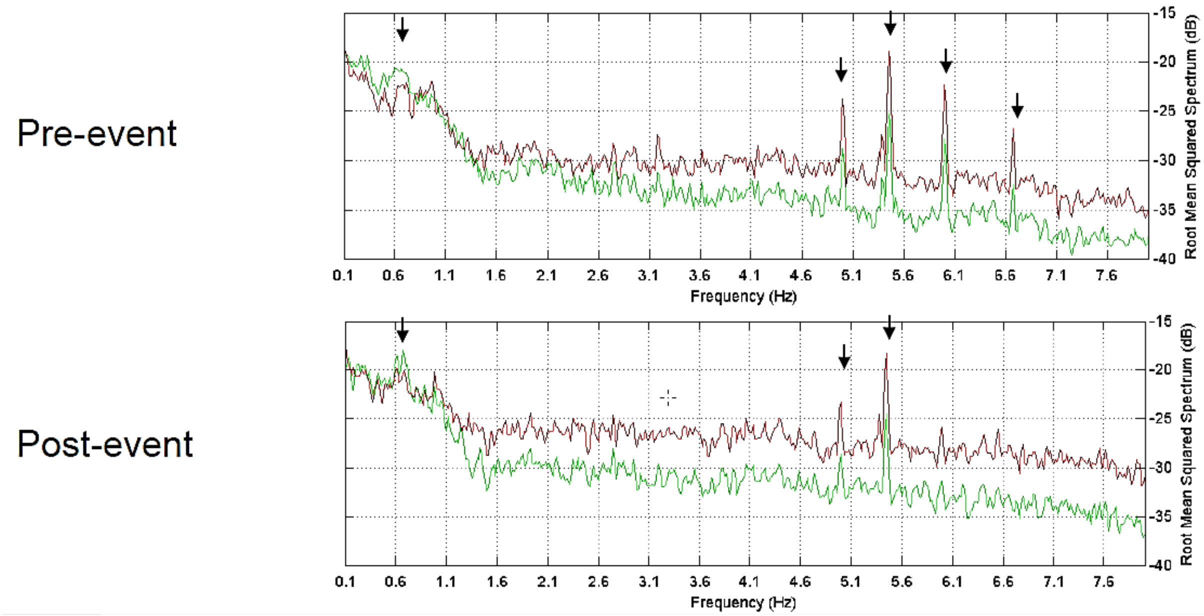
[24] J. Adams & P. Shrestha (ERCOT) and J. Ballance & P. Palayam (EPG), "Event Analysis Using Phasor Data," NASPI Work Group Meeting, June 5, 2012.
[25] ERCOT press release, "Wind generation output in ERCOT tops 10,000 MW, breaks record," March 28, 2014.

ERCOT, and ERCOT has become a leader in using its PMUs and analytical tools to enhance wind integration.

ERCOT and its consultants conducted post-disturbance spectral analysis of the PMU data for voltage magnitude and angle oscillations following several significant wind events, and found several patterns:

- There are natural ERCOT oscillatory frequencies at and around 0.28 Hz, 0.67 Hz, and 0.7 Hz.
- There are oscillations around 3.2 Hz, 5.0 Hz, 5.4 Hz, and 5.5 Hz that are only apparent in wind generation areas.[26]

Figure 36 shows an example of these analyses for a set of oscillations that occurred on November 3, 2010, triggered by a generation loss of 1,353 MW under high wind conditions.

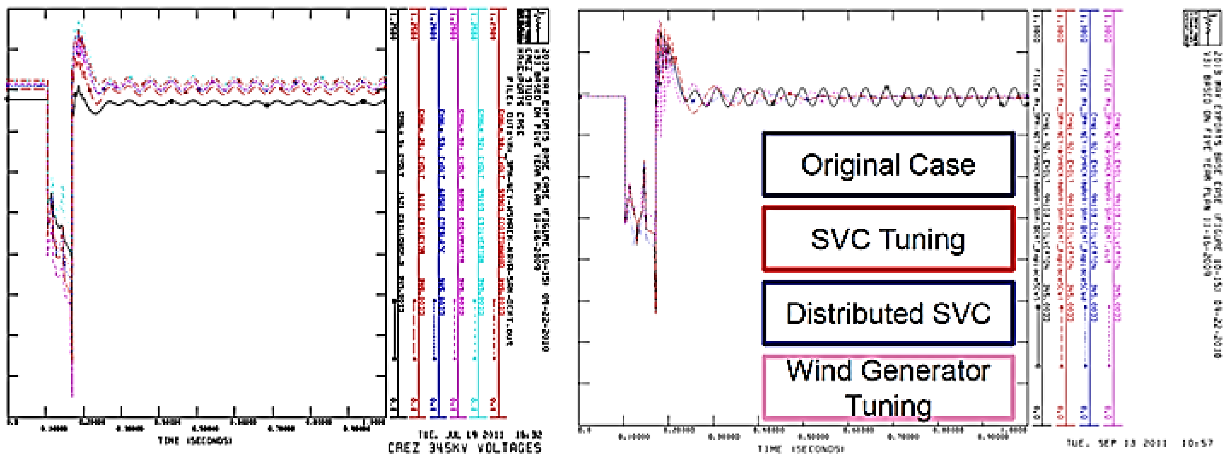


(Source: ERCOT)

Figure 36. Oscillation frequencies in voltage magnitude and angle signals near wind generation in ERCOT; 0.7 Hz is natural ERCOT grid oscillation

ERCOT has also observed several examples of oscillations driven by wind plant controllers under high wind output conditions, with poor damping and negative damping (see Figure 37). ERCOT hypothesized that the causes were the combination of a weak grid[27] in combination with high wind output and fast voltage control.

[26] J. Adams et al., op. cit.
[27] These events occurred before the full ERCOT Competitive Renewable Energy Zone build-out was completed.

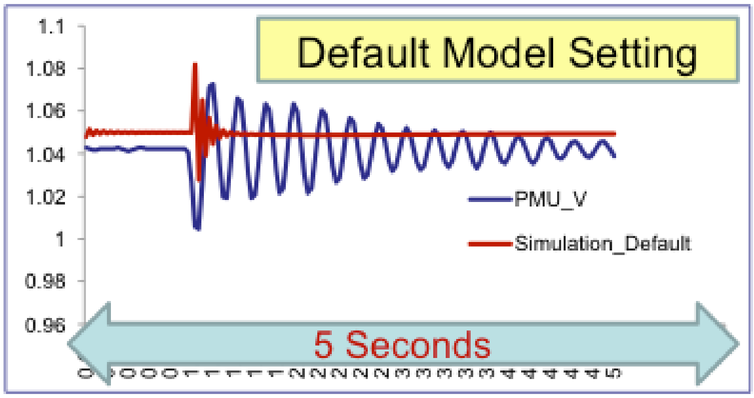


(Source: ERCOT)

Figure 37. Texas Competitive Renewable Energy Zones high frequency oscillations under high wind output

ERCOT staff then conducted a dynamic study using conditions identical to the September 2011 voltage event, trying to first recreate the poorly damped high frequency oscillations in the simulations, then recreate the negative damped high frequency oscillations by increasing wind output in the simulations. To accomplish the first two steps, and then find potential solutions, they first had to recalibrate the initial default model (Figure 38) using PMU data to reproduce the oscillations effectively (Figure 39). They then used the simulation to test various solution options to mitigate the oscillations, including putting lines back into service, performing static VAr compensator (SVC) tuning, tuning the wind generator, and curtailing wind output.

ERCOT concluded from this and similar dynamic modeling exercises (enabled by the availability of PMU data) that wind generation does oscillate against the grid, with poor and negative damping, under the conditions of a strong wind plus weak grid. Modeling has indicated that a stronger grid and better tuning of wind controllers, with occasional wind curtailments as needed, are necessary to mitigate the oscillations.



(Source: ERCOT)

Figure 38. ERCOT's initial default dynamic model of wind plant

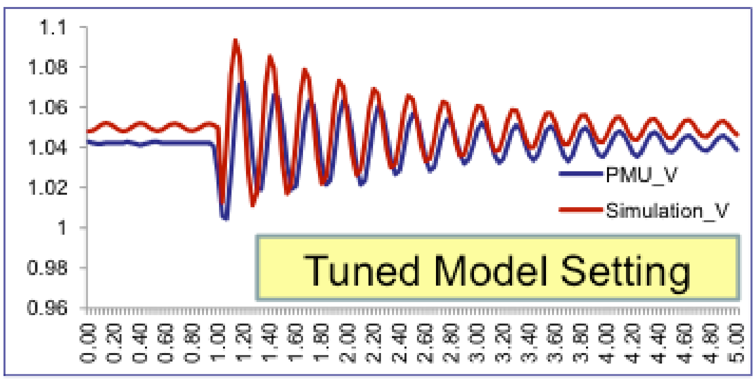
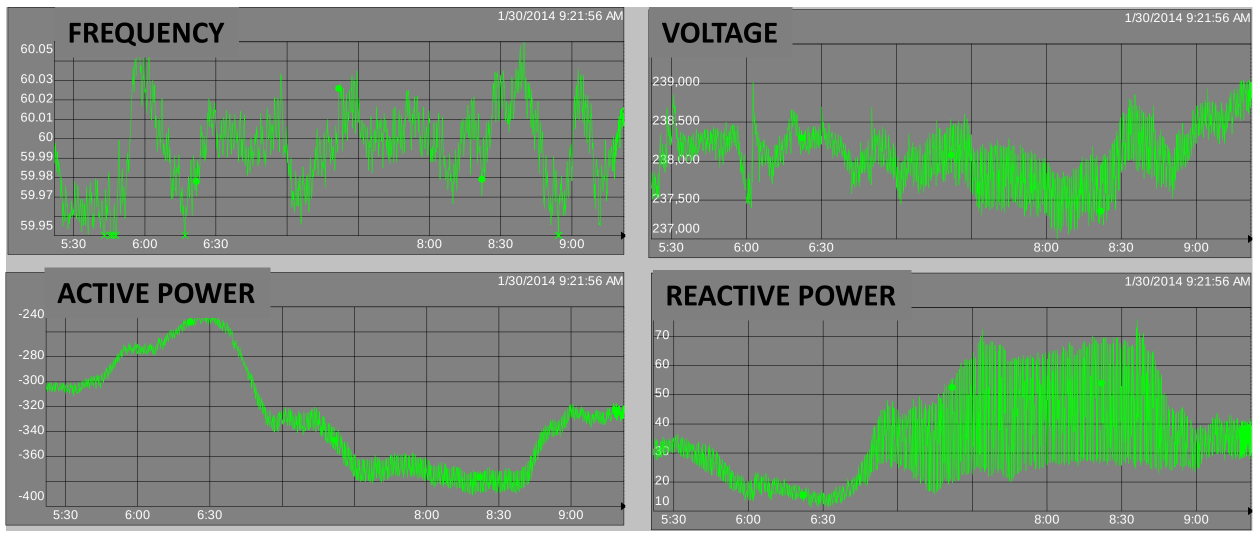


Figure 39. ERCOT's PMU-tuned dynamic wind plant model

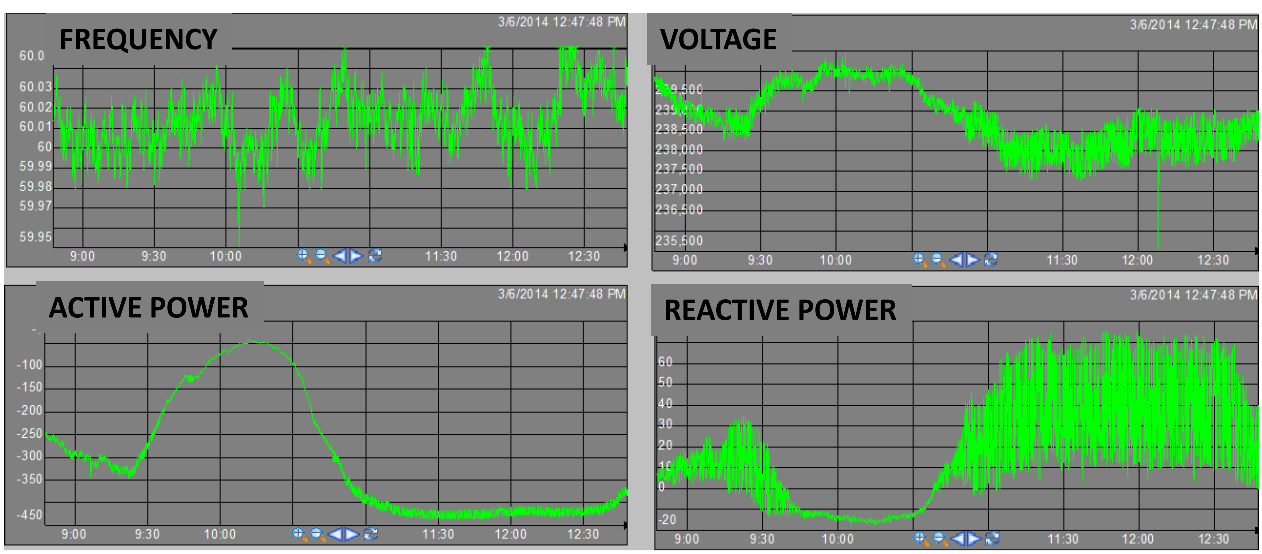
Wind power plant high-frequency oscillation in Pacific Northwest – BPA

As early as May 2011, BPA observed high-frequency oscillations during high wind generation. However, the coverage of older research-grade PMUs was not adequate to locate the source of these oscillations. Deployment of new PMUs at wind power plants allowed BPA engineers to identify the plant driving an oscillation. BPA's Oscillation Detection Application consistently alarmed when that specific wind power plant operated at high power output. After the plant was identified, BPA staff became concerned about the oscillation frequency of 14 Hz, which is close to the modulated resonance frequency of a series-compensated 500 kV line adjacent to the plant. BPA was concerned about the low-probability risk of sub-synchronous control interactions in case the wind plant becomes isolated on the series-compensated line (similar to the event on the ERCOT system). At the request of the plant operator, the wind generator manufacturer upgraded the plant's controls. No oscillations have been observed since April 2014.

Figure 40 shows three examples of wind generator-initiated oscillations in the Pacific Northwest, all initiated by the same power plant at high output. In each case, the active and reactive power measurements are taken at the BPA substation closest to the wind plant. As the wind power plant ramps to about 400 MW, reactive power oscillation develops with 80 MVAR peak-to-peak. The bottom set of plots shows an oscillation that occurred after the wind plant's control upgrade; the magnitude of oscillations after the upgrade is significantly lower than the pre-upgrade events.



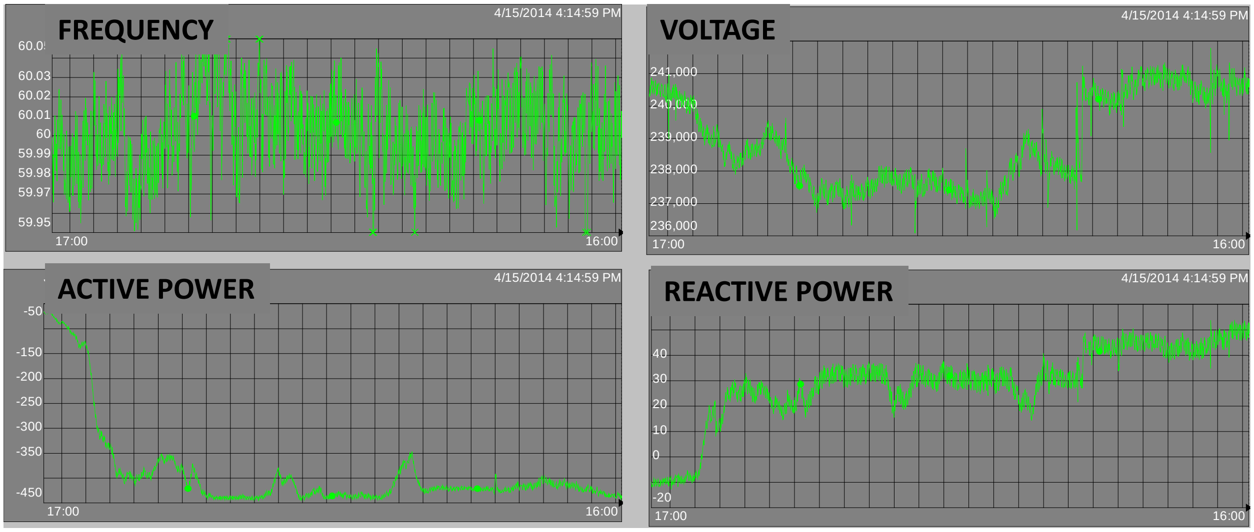
Example 1 − Wind generation ramp with high oscillations before control upgrade



Example 2 − Another wind plant ramp causing oscillations

(Source: BPA)

Figure 40. Three sets of wind plant-initiated oscillation incidents in the Pacific Northwest



Example 3 − Wind generation ramp after control upgrade, with lower magnitude of oscillations

Figure 40. (contd)

4. Transmission equipment

PMUs can monitor a variety of transmission equipment and detect many different problems across the grid. Companies like OG&E, ATC, and Dominion, with many PMUs deployed, have significant experience using PMU data to identify and diagnose failing equipment and equipment mis-operations. Each of these utilities uses operations engineers to regularly review PMU data to support control room operations with diagnoses of local disturbances and events. ATC, OG&E, Dominion, and others have used PMU data to identify problems with instrument transformers, capacitor banks, loose connections, faulty controls on a DC line, and a 69 kV arrester failure, as explained below. In a more dramatic example, PMU data were used after the fact to diagnose an oscillation on the 1000 kV Pacific high-voltage direct current (HVDC) Intertie that caused operational problems in both southern California and the Pacific Northwest.

Controller oscillation at Pacific HVDC Intertie – BPA, SCE, & CAISO

At 14:09 PDT on January 26 2008, an oscillation event occurred on the Pacific HVDC Intertie. The oscillation lasted 55 minutes. At the time of the event, the PDCI was operating in the south to north direction, with the Pacific Northwest (Celilo) importing about 1,700 MW from Southern California (Sylmar). An outage of two 500/230-kV transformers near the Celilo converter station caused weak system conditions at the inverter. This affected the PDCI controls, causing a high-frequency oscillation. The active power oscillation reached 150 MW, reactive power oscillation was at 200 MVAR peak-to-peak, and 230 kV bus voltage oscillation reached 7 kV peak-to-peak. The oscillation frequency was 4 Hz, corresponding to a control-related oscillation.

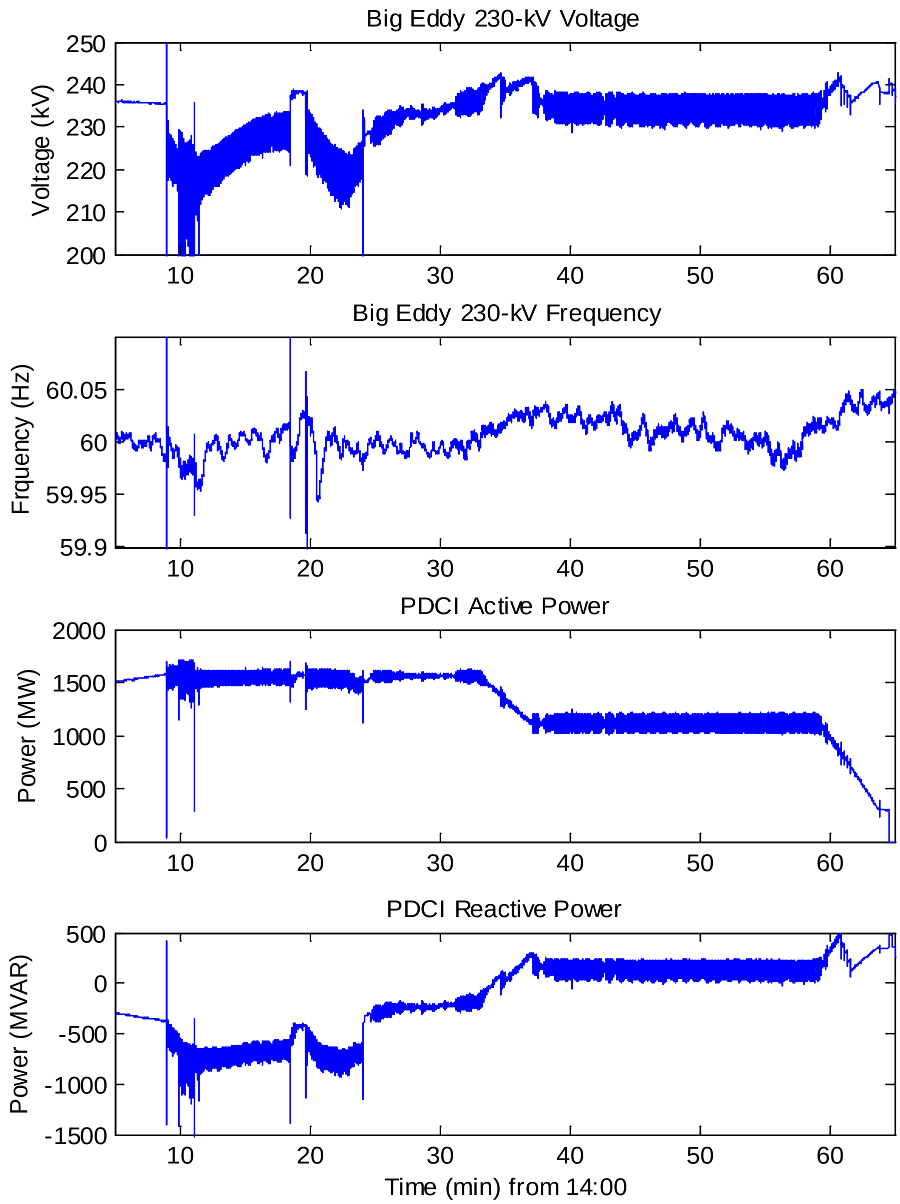
In this case, grid operators and the Intertie asset owners (BPA and SCE) were able to identify the actual details of the event and their impacts on the system by looking—after the fact—at the PMU recordings (Figure 41), as taken in Southern California (top two graphs) and the Pacific

Northwest (bottom two graphs). These PMU traces show the impact of some of the events occurring during the oscillation:

- At 14:11, PDCI Pole 3 was temporarily blocked, followed within seconds by a trip of a nearby combined cycle plant with 250 MW of generation.
- At 14:13, SCE noted very erratic frequency, active and reactive power swings at all its major interties. The Los Angeles Department of Water & Power did not see the oscillations in its SCADA system nor believe the oscillations were coming from the Sylmar PDCI Converter station.
- At 14:15, SCE received a call from San Onofre Nuclear Generating Station (SONGS) inquiring about system conditions causing erratic reading on SONGS Units 2 and 3.
- At 14:18:31, one of the transformers returned to service, and the oscillations stopped momentarily. BPA attempted to reclose the second transformer a minute later, both transformers tripped again, and the oscillation reappeared.

PDCI power was ramped down by 500 MW from 14:33 to 14:38 to alleviate overloads on the BPA system. In spite of reduced power transfers, the oscillations persisted at the reduced power transfer, and grid operators decided to remove the PDCI from service. The PDCI was ramped down to zero from 14:59 to 15:01, and the oscillations stopped.[28]

[28] Details provided by Dmitry Kosterev (BPA) in communication with the author.



(Source: BPA, from Kosterev)

Figure 41. January 6, 2008 PDCI oscillation event – oscillations seen in PMU recordings in Southern California at the Big Eddy substation (top two graphs) and on the Pacific DC Intertie (bottom two graphs)

Failing potential transformer – ATC

ATC has used PMU data to identify a failing potential transformer (PT). ATC reports that while they were reviewing fault operations they:

> … stumbled across an odd voltage signature from a PMU monitoring one of our 69 kV substations …. [See Figure 42] [There was] slow voltage decay on one phase that eventually jumped back to "normal." We confirmed the same issue

> present on both secondary windings for the PT. We determined it was an issue with the primary winding. All connections verified good so [we] determined this was an internal primary winding issue on the PT. [The] decision was made to replace the defective PT before it failed. The substation could not be back-fed from the distribution system so we were able to schedule a mobile transformer and serve the load while we replaced the unit before we had a failure. We believe we avoided an extended outage by catching this before it failed and saved money as we were able to replace it during normal work hours.[29]

In Figure 42 (top graph), the point that triggered ATC staff's interest was that the green voltage trace is diverging from the other phase voltages on the bus. This was a 500−600 V drift away from the other phase voltages over a 1−2-minute period, then a jump back to what would be considered normal. This pattern is similar to a failing PT fuse that ATC saw in an earlier event. ATC System Protection personnel looked at data from multiple relays served from different secondary PT windings at the same substation, and saw that the behavior was showing up on both PT secondary windings. This meant that the problem was neither on the wires nor the secondary PT fuses; therefore, ATC staff concluded that the problem was with the primary PT winding.[30] In Figure 42, PMU data in the bottom graph (from Alstom's PhasorPoint software) show a significant increase in zero sequence voltage. If there is an observed imbalance on the system like this, "the discrete jumps could have alerted us to this problem had we set relay limits to alarm on zero sequence."[31]

If a PT connection is bad or the PT itself is failing, it may provide inaccurate voltages to the attached relays. In the event of a significant voltage drop (as was observed in this case), one or more of the connected relays could have mis-interpreted the drop and mis-operated. This could have caused system problems depending on the extent of affected equipment.

This failing winding in the PT could have culminated in the catastrophic failure and breakup of the PT, which could have blown up and damaged other equipment in the substation. In this case, because ATC was able to identify the bad PT before it failed, the utility was able to take the bus out of service, pull in a mobile transformer to serve customers served from the affected bus, and replace the entire unit with deliberate transmission coordination and crew scheduling without having to put any customers out of service.[32]

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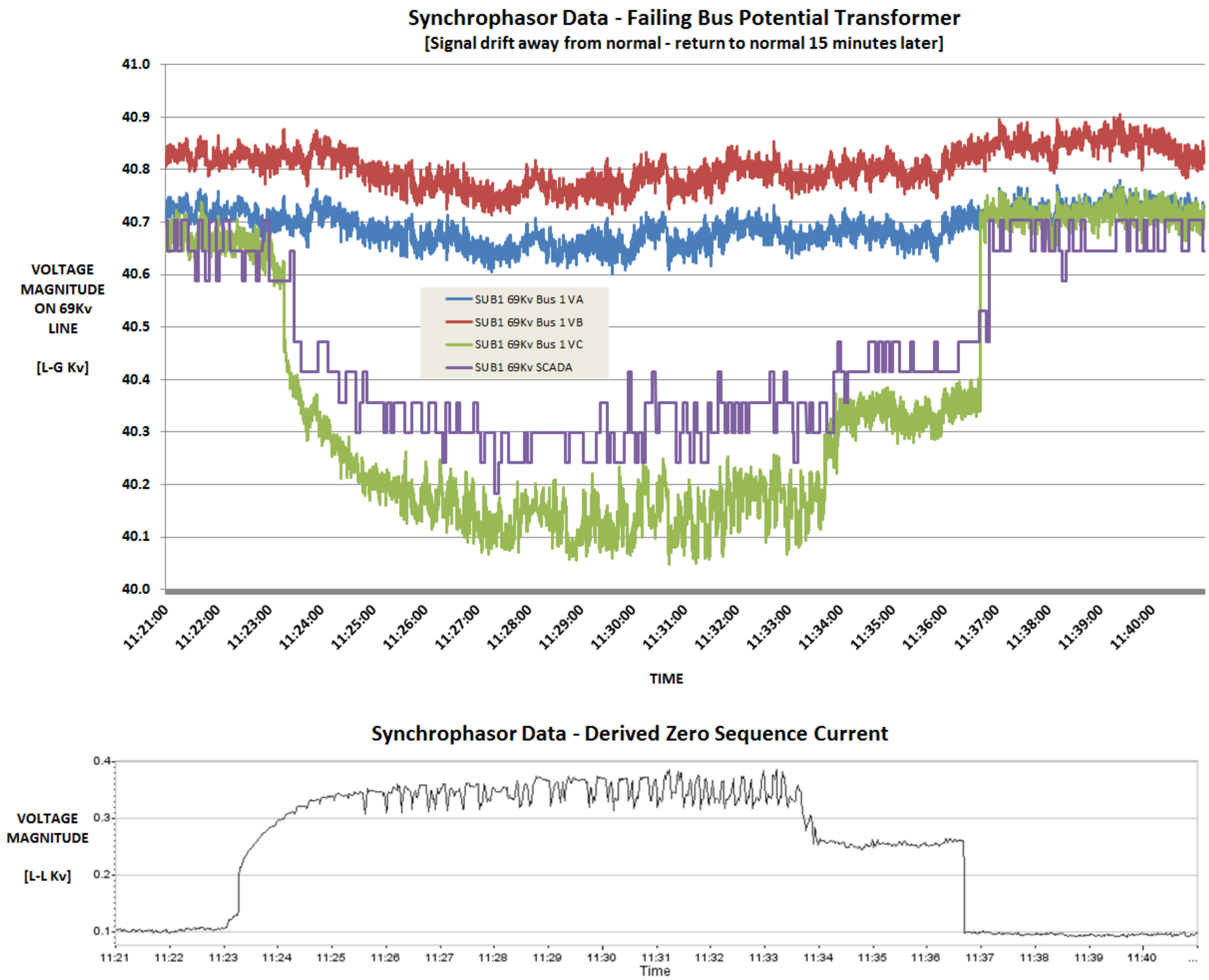
[29] J. Kleitsch, "Using Synchrophasor Data to Diagnose Grid Events," NASPI Work Group Meeting, March 11, 2014.

[30] Had both PT secondaries seen the same problem, ATC would have concluded this was a problem with the primary winding.

[31] Communication with Jim Kleitsch (ATC), August 12, 2014.

[32] Communication with Jim Kleitsch (ATC), August 12, 2014.



(Source: ATC, from Kleitsch)

Figure 42. PMU data indicating failing potential transformer

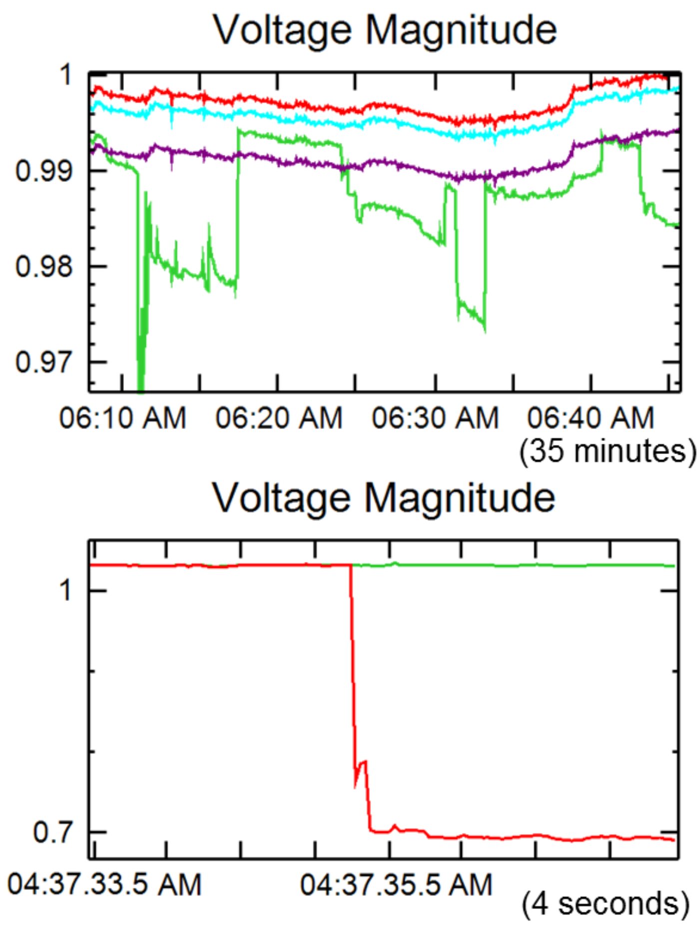
Finding loose connections in potential circuits at fuses and terminal blocks – OG&E

OG&E has found several loose connections in the potential circuits at fuses and terminal blocks through observation of PMU data. Loose connections have caused relay mis-operations in the past at OG&E, so by finding and fixing them, OG&E can proactively avoid future outages and mis-operations.[33]

In Figure 43, the top graph shows four voltage traces from the same substation bus. These should all be moving closely together, but the green trace is fluctuating wildly, indicating a loose connection. An OG&E technician dispatched to the substation found that the fuse connections were loose in the Coupling Capacitor Voltage Transformer (CCVT) safety switch. PMU data

[33] A. D. White & S. E. Chisholm, OG&E, "Synchrophasor use at OG&E," NASPI Work Group Meeting, June 9, 2011.

have revealed similar events resulting from faulty or loose terminations, animal damage to conductors, corrosion on the safety switch contacts, and loose fuses. The bottom plot in Figure 43 shows two voltage traces from the same bus; in this case, one of the traces dropped to two-thirds of nominal. This indicates a blown fuse on one phase. Because the PMU is sending the positive sequence voltage, the voltage magnitude dropped by one-third.

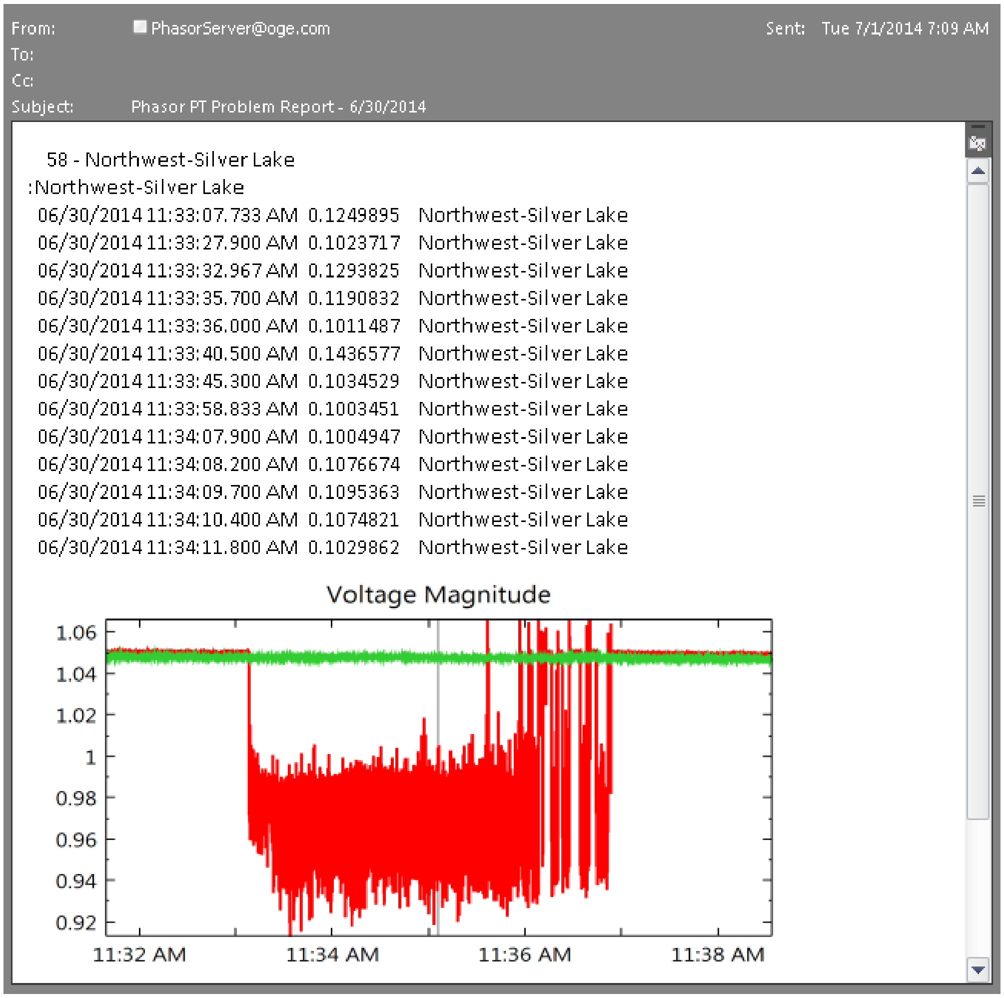


(Source: OG&E, from White & Chisholm)

Figure 43. Voltage traces from an OG&E substation bus, indicating a loose fuse connection

OG&E has created a PT Problem Report tool, which performs a dV/dT on all voltage magnitude data to detect any abnormal voltage fluctuations in each day's PMU data. The PT Problem Report tool provides a counter of each voltage fluctuation along with the time-stamp of the fluctuation (for instance, on the day above [Figure 43], the PT Problem Report showed 58 dV/dT instances that exceeded OG&E's threshold) and sends a daily report via email to OG&E's operations support team. Figure 44 shows one such report; the particular example graphed is for a loose connection at the safety switch for the PT feeding the PMU.[34]

[34] Communication from Austin White (OG&E), August 26, 2014.



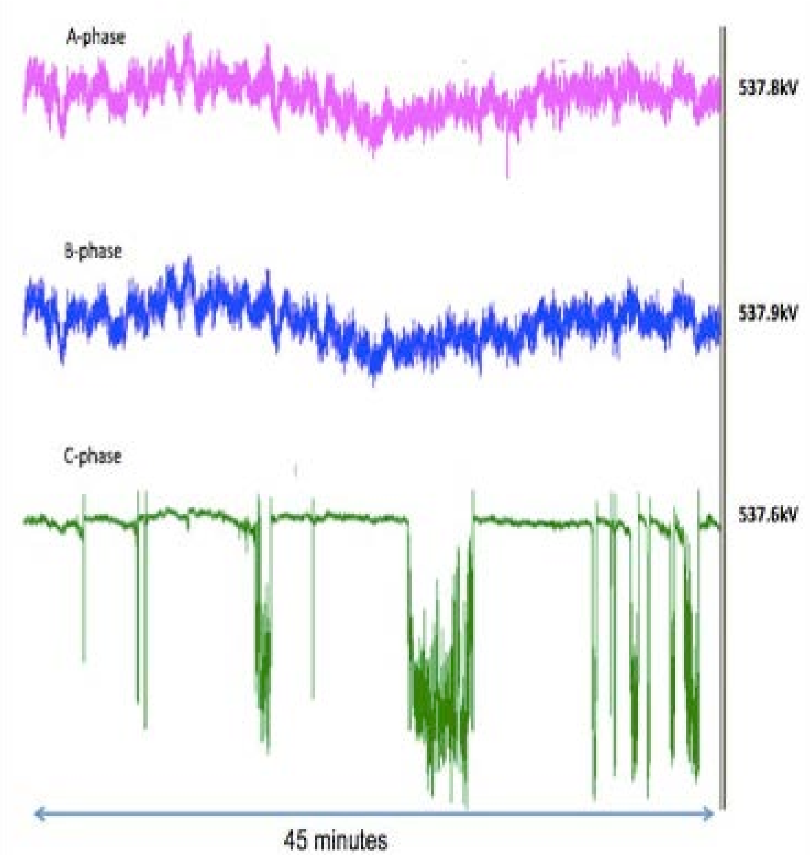
(Source: OG&E, from White)

Figure 44. Sample OG&E Phasor PT Problem Report

Voltage transformer failing – Dominion

Dominion engineers spotted fluctuations in the PMU recordings from the C-phase of a three-phase voltage transformer on a 500 kV line terminal (see Figure 45) which was not tracking well with the A and B phases, that caused them to suspect there was a problem with the equipment.[35] These sporadic voltage dips of 5 kV are not typical of a system event but do signal an equipment problem. These CCVT voltage fluctuations are a sign of a capacitor at the end of its life, and the dips in one capacitor are placing a greater burden on the other capacitors in the unit.

[35] J. Thorp & R. M. Gardner, "Dominion's Synchrophasor Deployment and Applications," NASPI Work Group Meeting, October 22, 2013, and communication with Kyle Thomas, August 14, 2014.



(Source: Dominion Virginia Power, from Gardner)

Figure 45. Dominion PMU recording for a 500 kV voltage transformer, indicating a problem on the C-phase

CCVTs are used on many extra-high voltage (EHV) installations—EHV buses, lines, transformers and generators—instead of wound voltage transformers for protection elements, equipment monitoring, automatic control devices, and power quality measurement. A CCVT contains capacitors as well as an inductive element and a transformer to step down the voltage. If a capacitor fails in the CCVT, it can explode and send shrapnel yards away, damaging other substation equipment and creating safety concerns for personnel. Therefore, the CCVT owner wants to remove and replace a failing CCVT quickly, to avoid a catastrophic failure that could cause personnel injury or an extended customer outage and avoid unscheduled, emergency crew deployment, and replacement equipment acquisition.

In the case above, after the failure alarm on the line relays was triggered, field inspection of the voltage transformer indicated that it was on the verge of failure. Dominion replaced the failing equipment. Dominion notes that the PMU data displayed evidence of the imminent failure four days before the CCVT failure alarm was triggered in its SCADA system.[36] Dominion staff noted that the SCADA monitoring for CCVTs is lower resolution and based on zero sequence

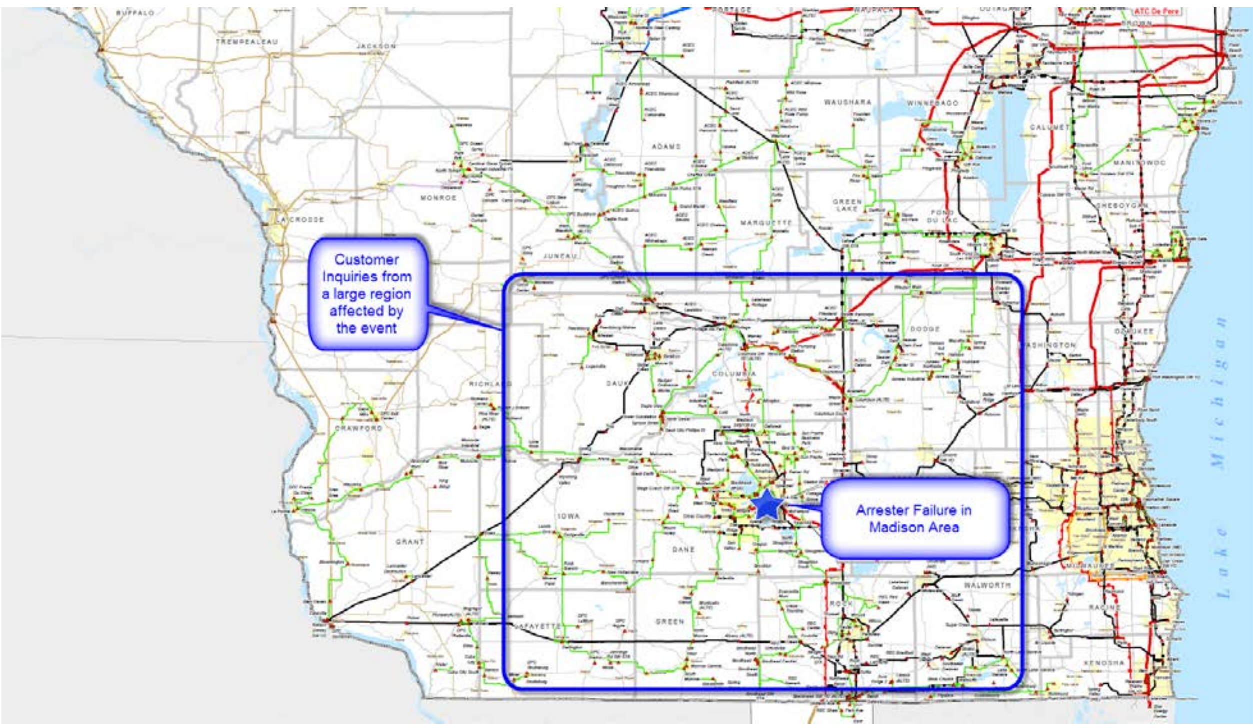
[36] J. Thorp & R. M. Gardner, "Dominion's Synchrophasor Deployment and Applications," NASPI Work Group Meeting, October 22, 2013.

components, so they could never have spotted this early failure indicator using only SCADA data.[37]

Identifying 69 kV arrester failure affecting customers – ATC

ATC experienced an arrester failure on its 69 kV system on a clear day, causing depressed voltage for a short, 10-cycle period across a wide portion of its system[38] (see Figure 46). ATC control room operators saw no fault on SCADA (purple line in Figure 47), but received a number of customer calls about the problem. The control room called engineers to review the PMU data (blue, red, and green lines in Figure 47); within 2 minutes the analysts were able to tell customer service personnel about the cause and duration of the event and its wide impact on the local system.[39]

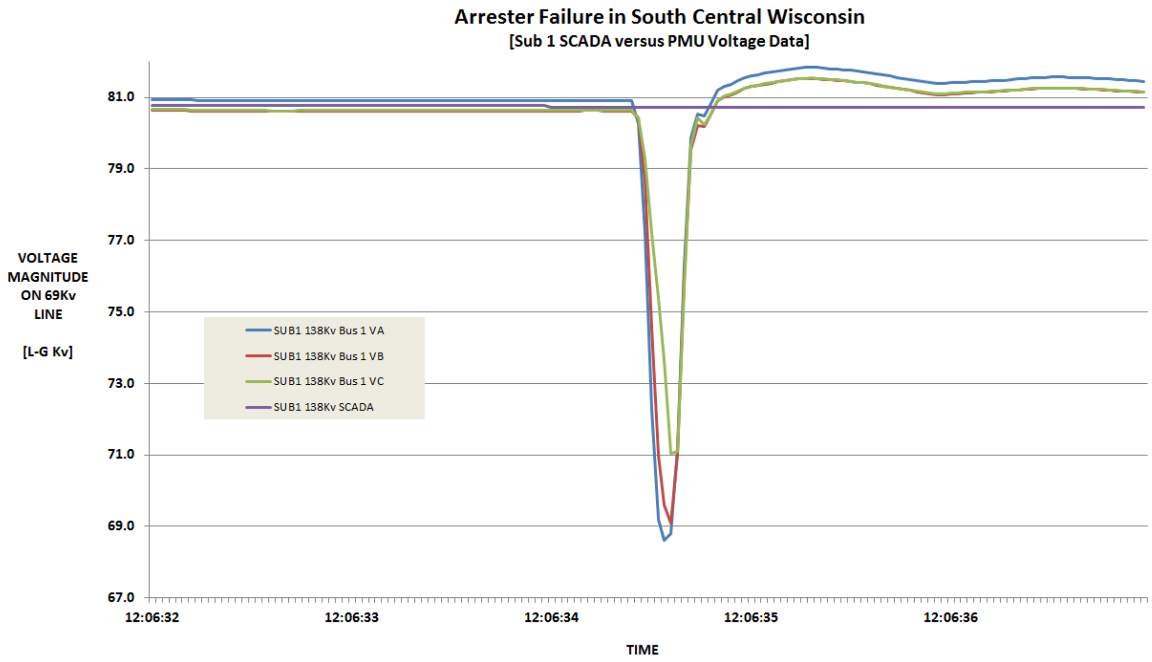
ATC intends to integrate its synchrophasor data, through Alstom PhasorPoint, into its energy management system (EMS) with integrated alarms informed by SCADA, EMS, and PMU data.



(Source: ATC)

Figure 46. ATC area affected by 69 kV arrester failure

[37] Communication with Kyle Thomas (Dominion Virginia Power), August 14, 2014.
[38] Ibid.
[39] Communication with Jim Kleitsch (ATC), August 12, 2014.



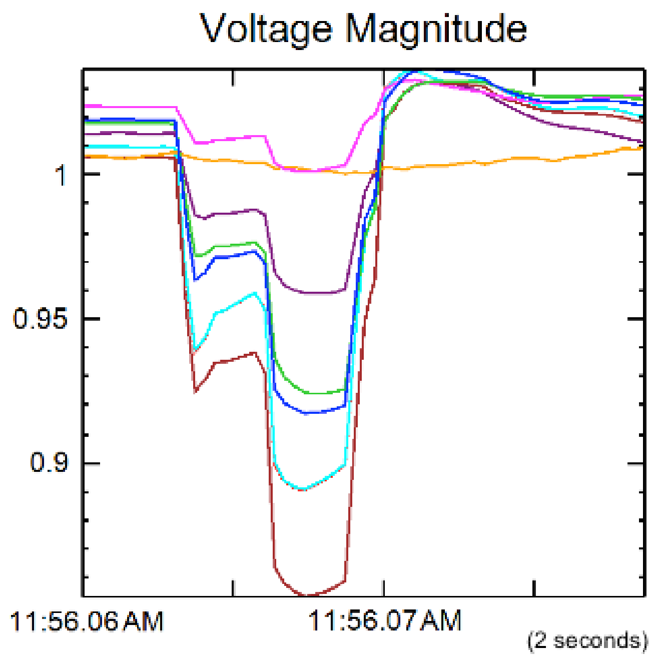
(Source: ATC)

Figure 47. PMU data for arrester failure

Voltage sags linked to line communications carrier – OG&E

OG&E experienced a fault in Oklahoma City in January 2009 that was seen across its entire EHV system. OG&E staff observed that the voltage sags were much worse when their line communications carrier was turned off.[40] Figure 48 shows the voltage depression across the entire OG&E EHV system (covering the entire state of Oklahoma) resulting from a long-duration fault on a 138 kV line in Oklahoma City.

[40] A. D. White & S. E. Chisholm, OG&E, "Synchrophasor use at OG&E," NASPI Work Group Meeting, June 9, 2011.



(Source: OG&E, from White)

Figure 48. Voltage sags on PMUs across statewide EHV system for a fault on a 138 kV line in Oklahoma City

OG&E explains that before they had a synchrophasor monitoring system, the utility was having:

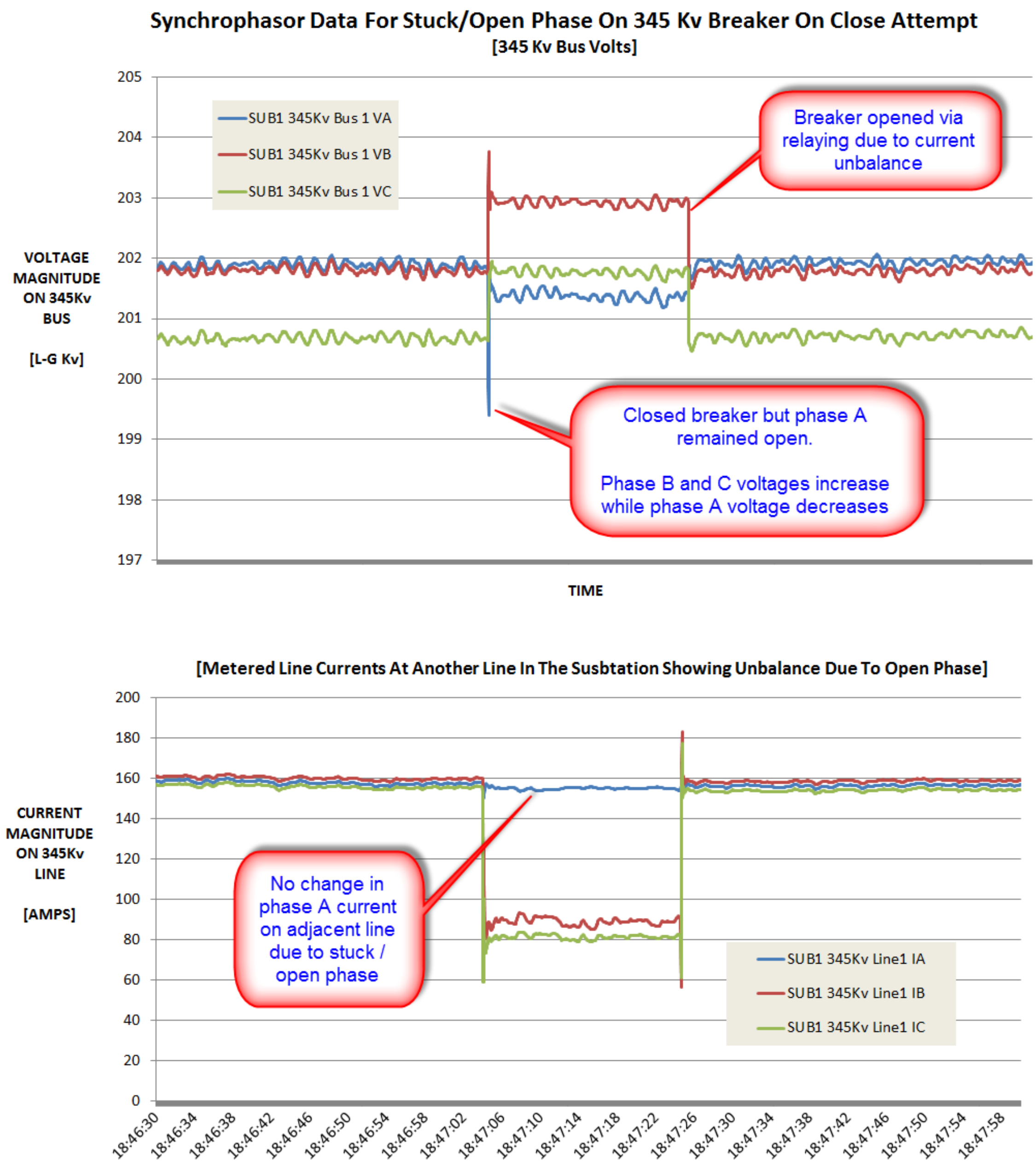
> … many protective mis-operations with directional comparison blocking relaying (DCB high speed carrier tripping). With a DCB scheme failure, the blocking signal does not make it through and the relay over-trips for a fault on an adjacent line…. [To address this, they] decided that once a mis-operation of such type occurred, we would turn off the DCB carrier scheme to prevent further mis-operations until the problem could be fixed…. When we began using synchrophasors (which are very useful as a system-wide fault recorder), we found that the voltage depressions during a fault are seen across the entire transmission and distribution system -- not just near the fault location. We had no idea the impact of a fault could be seen so widely across such a large area. To make the problem worse, the duration of the fault is much longer when the DCB carrier is turned off [as seen in Figure 48]. Normally with high-speed tripping, a fault is cleared in 3 to 5 cycles, but in this example the step distance relays extended the fault duration to about 36 cycles (0.6 seconds)…. Customer equipment cannot ride through voltage pull-downs that are this long in duration. After observing the widespread impact of long duration faults and recognizing the impact this had on our customers, we immediately decided to reverse our policy of turning off the malfunctioning carrier communications. So leaving the malfunctioning carrier

turned on and accepting the over-tripping mis-operation in this case is much better because it has a lesser impact on our customers.[41]

Finding open phases and unbalanced phase currents on breakers – ATC

ATC crews were working on a breaker feeding one of two 345 kV lines at a 345/138 kV substation. When the line was re-energized and picking up load, the breaker closed and tripped open within 20 seconds; two of the three phases closed and opened (blue and yellow lines in Figure 49) but the third remained open (green line flat at 160 amps in Figure 49) and the load redirected accordingly. The line monitored by an ATC PMU saw unbalanced phase currents while the other breaker was closed (see Figure 49 bottom graph), but no DFRs triggered for this and there were no event files available to explain what happened.[42] ATC engineers eventually determined that the breaker opening here was due to a problem in relay logic.

[41] Communication from Austin White, OG&E, August 25, 2014.
[42] J. Kleitsch, "Using PMU Data to Diagnose Grid Events," March 12, 2014, NASPI Work Group meeting, pp. 17-18.



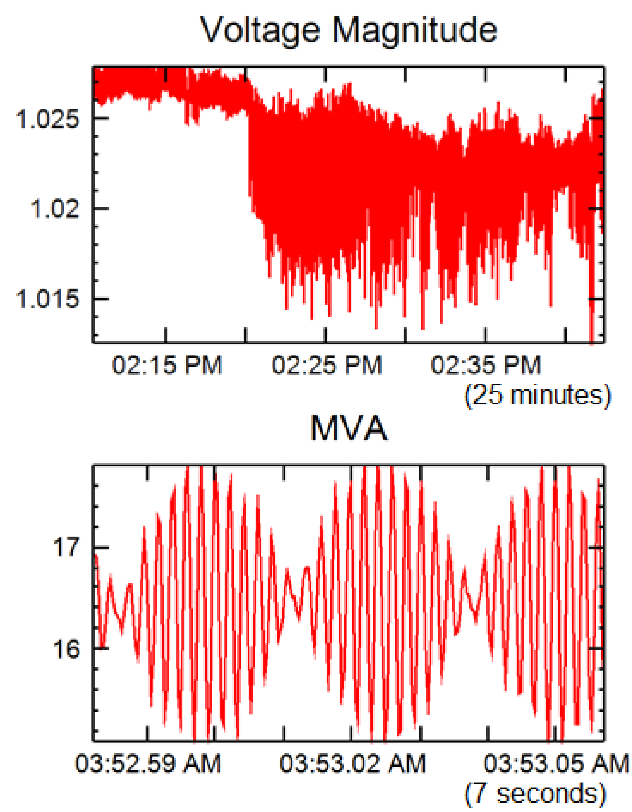
(Source: ATC, from Kleitsch)

Figure 49. Open phases on 345 kV breakers

Power quality monitoring – OG&E

OG&E uses synchrophasor data to monitor power quality, because the PMUs pick up grid conditions that cannot be observed by SCADA or DFRs. Large industrial loads have been observed to inject noise onto the transmission system that is visible in the current, voltage, and frequency waveforms. In Figure 50, the top graph shows the beginning of an arc furnace burn, as measured by a PMU at the 161 kV bus at an adjacent substation. OG&E can use the synchrophasor data to measure the flicker observed by nearby customers and determine whether the industrial source meets the flicker limits of irritation and observability outlined in the IEEE 519 standard.

In the lower graph of Figure 50, the waveform shows the load characteristic of a refinery injecting sub-harmonics at 4.62 and 5.0 Hz. These load-induced oscillations may appear as observable flicker (as outlined in IEEE 519), and could require mitigation. OG&E has also observed that these load-induced voltage and power variations can cause nearby wind generation to react, in some cases amplifying the signal under certain system conditions.[43]



(Source: OG&E, from Chisholm & White)

Figure 50. Monitoring power quality with synchrophasor data. Top graph shows arc furnace burn impact on voltage; lower graph shows a refinery injecting sub-harmonics

Monitoring harmonics and noise related to new equipment – ATC

ATC put new equipment into service on its transmission system, and found that it was injecting noise and harmonics back into the local transmission system. Some of the noise was lower frequency (20 Hz) and was captured with ATC's synchrophasor df/dt data. ATC engineers have been able to use these data during equipment commissioning to identify operational issues and determine whether the system is operating properly with the new equipment in service.[44] In

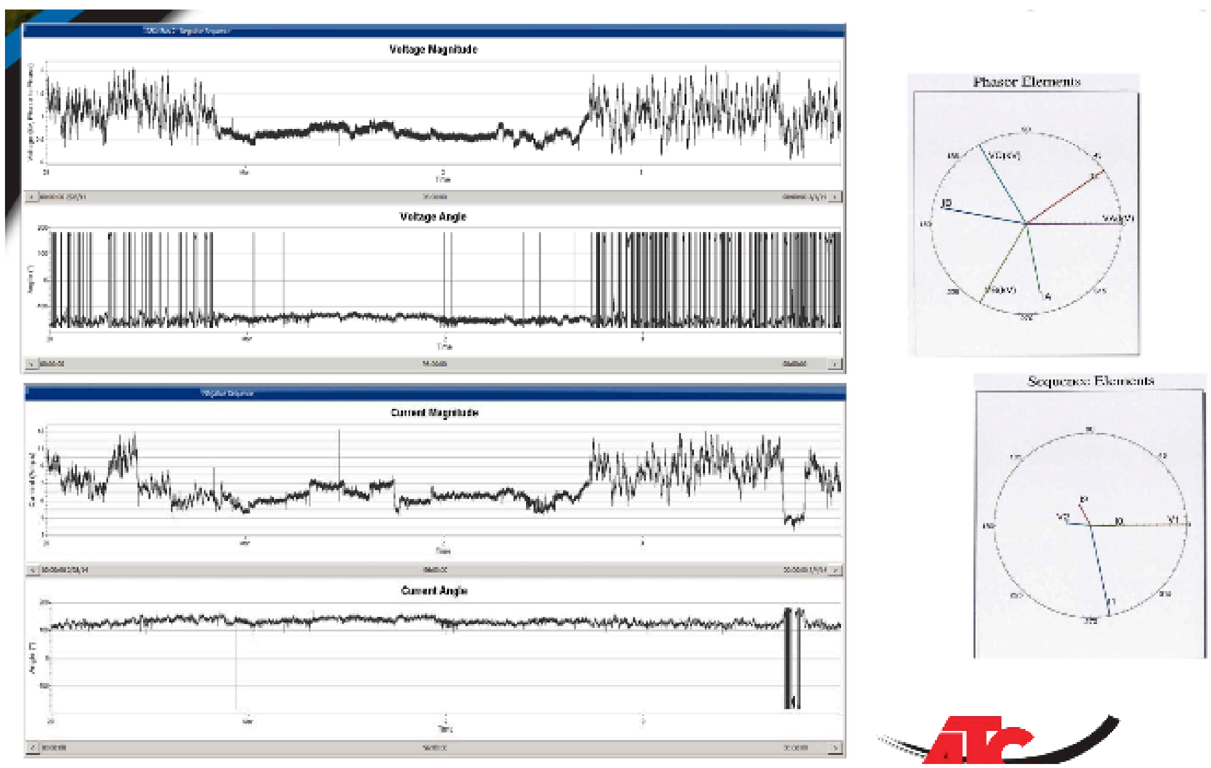
[43] Communication from Austin White (OG&E), August 25, 2014.

[44] The PMUs cannot directly record some of the problems that are occurring because they are in the kilohertz frequency range.

addition, the availability of these data and insights is encouraging additional company users to ask for synchrophasor data and interpretive assistance.[45]

Negative sequence alarms – ATC

A generator in the ATC service area was experiencing negative sequence alarms. The system protection engineer was able to trigger an event record showing the phase unbalance. ATC engineers used the PhasorPoint application and PMU data from the generator's point of interconnection to the grid to derive the negative sequence data and plot (Figure 51) to show the generator what was happening. ATC now hypothesizes that the negative sequence was initiated by a single-phase arc furnace load operating nearby.[46]



(Source: ATC, from Kleitsch)

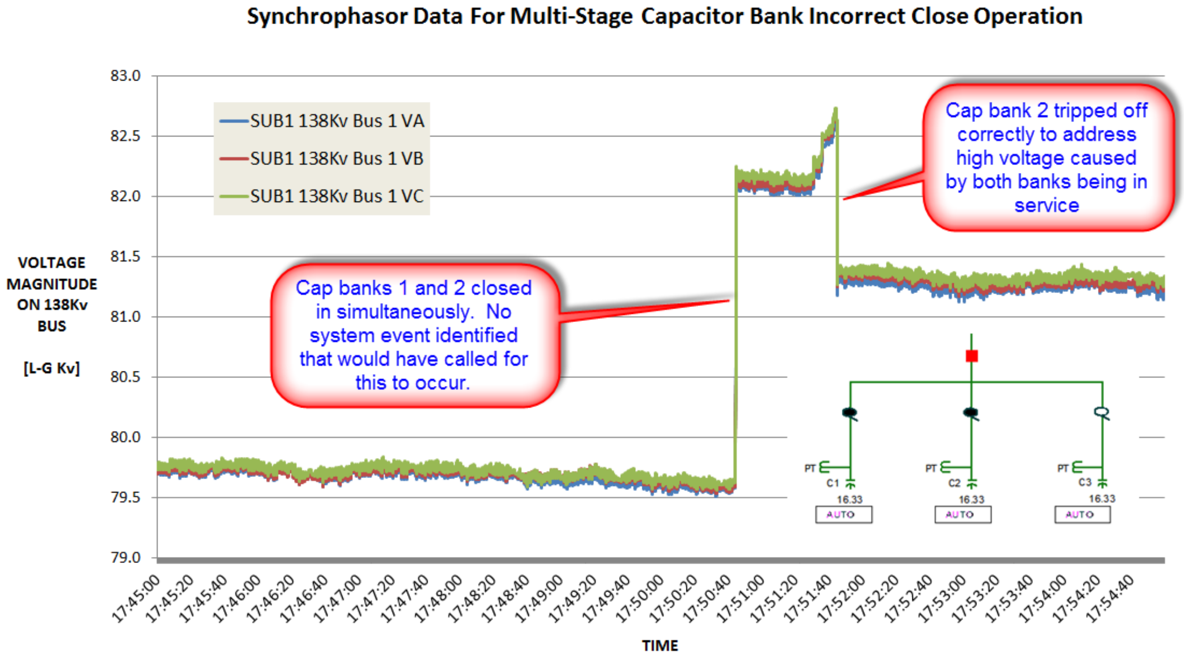
Figure 51. Negative sequence and phase unbalance evidence

Capacitor bank switching problem – ATC

At one of its 138 kV substations, ATC has three 16 MVAR capacitor banks that are supposed to switch in sequence, -but PMU data indicated that two of them switched in at the same time, and the second tripped off immediately. System protection personnel asked operations engineering

[45] Communication from Jim Kleitsch (ATC), July 3, 2014.
[46] J. Kleitsch, "Using Synchrophasor Data to Diagnose Grid Events," NASPI Work Group meeting, March 12, 2014, pp. 19-20.

staff whether there had been voltage dips in the area before the closes, but neither relays nor SCADA recorded enough pre-event data to answer this question. Review of the PMU system condition data (Figure 52) revealed no triggering event in voltage that should have caused the second bank to operate. This allowed engineers to conclude that the cause was a switching error rather than an event-driven operation.[47]



(Source: ATC)

Figure 52. Capacitor bank switching problem at ATC

Proper capacitor bank closing should be staged with delays between the closes. Unnecessary operations of a capacitor bank increase wear on the equipment and shorten its operational life. In this case, ATC staff fixed the problem by resetting the voltage control scheme for these capacitor banks.

Transmission-level fault analysis – NYISO

With more than 40 PMUs deployed across the New York grid, the NYISO is actively using its synchrophasor system for fault analysis. NYISO staff report that this has significantly reduced the time required for system event reporting and data collection and improved their understanding of system and equipment responses to system events.[48] NYISO's operations engineering staff use Phasor Grid Dynamics Analyzer software to conduct offline voltage and oscillation analyses, transient voltage recovery, and system stress (voltage phase angle) analyses

[47] J. Kleitsch, "Using Synchrophasor Data to Diagnose Grid Events," NASPI Work Group meeting, March 12, 2014.

[48] Cano, E. B., "NYISO Case Studies of System Events Analysis using PMU Data," NASPI Work Group Meeting, March 11, 2014.

of these events. Some of the events NYISO staff have studied include an instance of multiple elements tripping (two 765 kV lines and a FACTS device), three-phase faults within New York City, and a double-line to ground fault that tripped several transmission elements and customer load.

5. Proactive uses of PMUs for equipment installation and protection

Commissioning power system stabilizers – Manitoba Hydro

Manitoba Hydro has been using synchrophasor data to commission PSSs more efficiently. This reduces costs relative to onsite testing, because the tester can see the PSS modes in real time at the moment of tuning by looking at the PMU data (sampling at 30 samples/second).[49] This allows for instant feedback from the real power system for small variations from the original design parameters (because the original design was based on offline models only) compared to the actual final commissioned ("as-left") values. By using synchrophasor data for PSS commissioning at the installation phase, later PSS testing and model verification become more accurate and efficient.[50]

Using PMUs to install equipment – ATC

In the same way that PMUs can be used to identify failing and mis-performing equipment, they can be used to support equipment installations, by using a local PMU to verify that new equipment has been installed and is working correctly.

ATC has been using PMU data to verify that it has established the correct phasing when building new transmission facilities and interconnecting them to the transmission system. It does this by temporarily enabling the PMU functionality at multiple locations near the facility, then capturing and comparing the PMU phase data. ATC utilizes existing PMUs if available, but also has two mobile set-ups (relay, test switches, and antenna) that can be used in cases where the station does not contain a relay with PMU functionality. As an example, during construction of a new 69kV greenfield substation being built to replace an existing station, ATC was able to validate and label phasing on all lines tied to the old substation before construction started. This allowed them to identify and address any phasing discrepancies before construction began, and assure a seamless transition to the new substation. ATC reports that the up-front work on site phasing identification can save as much as $10,000 in avoided costs that would be required to correct an incorrect phasing installation.[51]

[49] Tony Weekes, Manitoba Hydro, "MHEB Smart Grid Investment Grant Update", NASPI Work Group Meeting, October 22, 2013, p. 7.
[50] Communication from Tony Weekes, Manitoba Hydro, to author, September 16, 2014.
[51] Communication from Jim Kleitsch (ATC), July 3, 2014 and April 30, 2015.

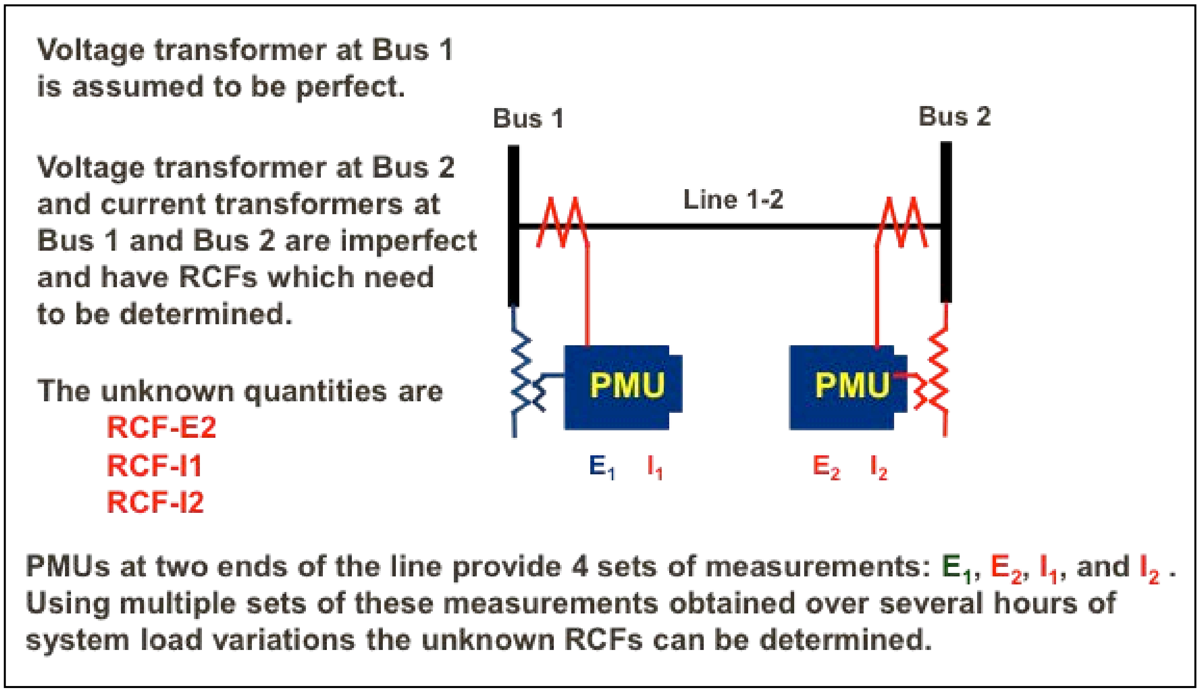
Checking system protection device operation – ATC

ATC is using its PMUs to quickly check the operation of its system protection devices. ATC routinely uses PMU data to verify that faults cleared in a reasonable amount of time and that all three phases opened at the same time.[52]

Using PMUs to calibrate instrument transformers – Dominion

Dominion is using PMU data to calibrate instrument transformers (CTs, CCVTs, and PTs), as illustrated in Figure 53. In an ideal PT or CT, the ratio of primary and secondary voltages of the transformer would be equal to the turns ratio in the winding, and the two terminal voltages would be in precise phase opposite each other. But in an actual instrument transformer, there would be some error in both the voltage ratio and the phase angle between the primary and secondary voltages. A utility needs to know the magnitude of this error because it affects the measurement accuracy of the relays, PMUs, and meters attached to each CT or PT; as the error increases, it can cause inaccurate voltage and current readings that would allow the operator to assume the grid is in a secure condition when the true conditions are otherwise. These instrument transformer measurement errors “drift” and increase over time; because the impact of measurement errors on multiple pieces of equipment is exponential rather than additive, it is important to understand the measurement error on each transformer to understand and quantify their cumulative impact on grid condition estimates.[53] Thus, the utility uses a Ratio Correction Factor (RCF) to adjust the measurements taken by devices attached to each instrument transformer (including synchrophasor data) before passing those measurements on for use in state estimators or protection and control applications.

[52] J. Kleitsch, “ATC Smart Grid Investment Grant Update,” NASPI Work Group meeting, October 23, 2013, p. 11.
[53] Communication with Kyle Thomas (Dominion Virginia Power), August 14, 2014.



(Source: Dominion Virginia Power)

Figure 53. Dominion Virginia Power instrument calibration method

Dominion explains that:

> The calibration technique is based on using measurements made from a high-accuracy voltage transformer in conjunction with measurements made with imprecise current and voltage transformers. Using a sufficient number of measurement sets over a period of several hours as the system load changes, the … technique is able to obtain RCFs of all imprecise instrument transformers with very high accuracy. The technique was perfected through simulations of the [Dominion Virginia Power] system over its daily load variations, and is now working with real-time data being obtained from PMUs.[54]

PMU data have enough time and measurement granularity and precision to be usable for PT and CT ratio error calculation. Dominion begins the RCF estimation process with a single "near-perfect" voltage measurement from a device with a low fixed error (i.e., an error rate of 0.01%) that is monitored by a PMU; the staff use that PMU and device as the basis against which other PMU-monitored transformers are calibrated. Typical instrument transformer errors fall in the 1% to 5% range.

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[54] J. Thorp & R. M. Gardner, "Dominion's Synchrophasor Deployment and Applications," NASPI Work Group Meeting, October 22, 2013.

The alternatives to the PMU-based RCF calibration technique are to do raw estimation, or to conduct field testing of the instrument transformers. Field testing entails sending out utility or contract crews to each substation; taking the substation equipment out of service; plugging test equipment into each CT, CCVT, or PT; and testing each instrument individually. It takes at least a day to test all of the equipment in one substation, and more time back in the office to analyze the test results and calculate the new RCFs. A typical substation has many voltage transformers (PTs) and CTs in each substation—a small substation may have 50 or more of each type—so field testing would be costly and time-consuming across all substations owned by a utility. Because of these costs, most utilities do not perform field testing to estimate RCFs, but only estimate them (and build in an extra level of conservatism into asset utilization and alarm settings).[55]

By using PMUs for RCF calculations, Dominion is able to operate its grid with more accurate asset utilization and operational security, without incurring significant field testing costs. Dominion is now working to automate the RCF assessment and calculation process, commenting that, "With PMUs in place, we can track and correct ratio errors for free."[56]

Monitoring system current unbalance to protect large power generator rotors – Dominion Virginia Power

Dominion engineering staff are using PMUs to monitor current unbalance across their system to help protect their large generators from equipment damage.[57] Specifically, they observe that:

> Voltages and currents on a three-phase network are rarely balanced − the magnitudes of quantities in the three phases are not equal and the phase angles of quantities in the three phases are not 120˚ apart. These unbalances are due to network unbalances existing within the networks of interconnected systems as well as unequal loads in the three phases. [Such] unbalanced currents are particularly harmful to the rotors of large power generators, as they may be overheated if the unbalance exceeds a threshold.[58]

To monitor this, Dominion uses PMUs to measure three phase currents on all their transmission lines and calculate the symmetrical components to identify the negative sequence current (which is most harmful to generators) at each location. Negative sequence current can flow into a generator stator, which could cause its rotor to over-heat. Over-heated rotors can break or warp, causing a complete generator failure that can take weeks or months to repair.

Dominion now has PMUs monitoring almost every point of interconnection between a generator and the bulk power system. Dominion uses these to continuously monitor negative sequence current levels on its lines and sums up all the negative sequence currents in lines connected to each generator; its system alarms when the amount of actual negative sequence current entering a

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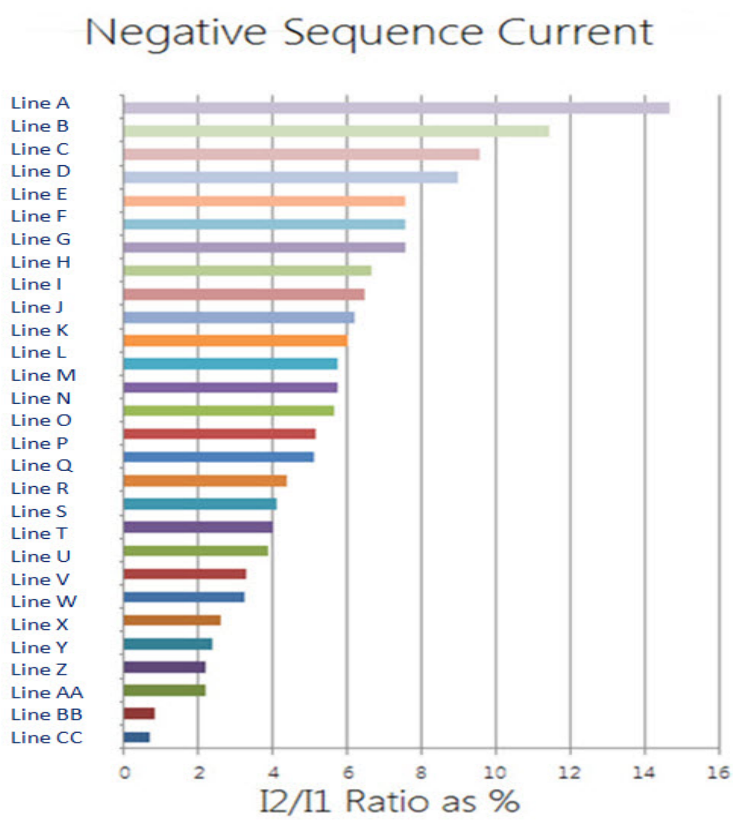
[55] Communication with Kyle Thomas (Dominion Virginia Power), August 14, 2014.
[56] Ibid.
[57] J. Thorp & R. M. Gardner, "Dominion's Synchrophasor Deployment and Applications," NASPI Work Group Meeting, October 22, 2013.
[58] Communication with Kyle Thomas (Dominion Virginia Power), August 14, 2014.

specific generator exceeds the limit set by that generator's manufacturer. Figure 54 shows the negative sequence current calculated for Dominion's major transmission lines at a single point in time; the lines with higher percentage ratios have more negative sequence current (I2) compared to positive sequence current (I1), and thus pose a higher risk to adjacent generator stators.[59]



(Source: Dominion Virginia Power)

Figure 54. Example of negative sequence current on Dominion Virginia Power lines

[59] Communication with Kyle Thomas (Dominion Virginia Power), August 12 and September 8, 2014.