Disturbance/Misoperation Analysis at OG&E

Oklahoma Gas & Electric utilizes many traditional methods and newer synchrophasor technology as a practical tool to locate disturbances and solve real world operating problems.

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Introduction

There have been many articles and technical papers written about the various tools and methods that can be used for disturbance event analysis. However, OG&E being a mid size utility serving parts of Oklahoma and Arkansas has been able to use traditional methods in conjunction with newer synchrophasor technology as well. Most publications on synchrophasor technology have been focused on solving regional or interconnection problems like wide area visualization and blackout prediction. The utility has implemented widespread synchrophasor technology as a practical tool to locate disturbances and solve real world operating problems, on a utility level. This paper will provide a brief overview of the technology and provide detailed examples of the real world applications, along with specific examples from several years of observations.

Overview of Analysis Tools

Just as the majority of utilities, OG&E makes extensive use of protective relay data, digital fault recorder data (DFR) and SCADA data to perform disturbance analysis. The addition of synchrophasor data has been very complementary to these traditional sources of data. Synchrophasor data literally serves as a system wide fault recorder, providing a top level overview of the system. It is used to quickly locate faults, determine the fault duration and area of impact. It is also easy to ascertain whether a fault was transient or permanent. With the increase of wind generation penetration in the utility's service territory, synchrophasor data is being used extensively to monitor system stability.

The majority of OG&E's detailed disturbance analysis comes from digital protective relays. Between the oscillographic event reports and sequence of events data, almost all the information is there to do a complete and thorough analysis. Digital protective relays cover approximately 60% of the utility's transmission lines today. Without the digital protective relays, engineers are mostly "blind" to disturbances on the system unless it is observed by a DFR. Most of the 27 substations with DFRs installed are located at EHV substations. The DFRs are great for electromechanical terminals and for faults that last longer than the protective relay event report duration. SCADA logs are also available if system state information is needed. However, it is difficult to use the SCADA information because the timestamps are much less accurate and don't match up very well with the other recordings.

Overview of Synchrophasors

As with most new technology projects, there is an evolutionary process which occurs as more is learned about the potential and practical applications of the technology. OG&E began with a single hardware phasor data concentrator (PDC) and eight multifunction phasor measurement units (PMUs) - line protection relays doubling as PMU's. The live synchrophasor data was streamed through the PDC to a PC software client for visualization. It was quickly realized that a need existed to further examine data from interesting events which had occurred in the past. Unfortunately, the software purchased at the time did not allow for viewing of historical data. So the utility developed a system to archive the data to a Microsoft SQL database along with a custom software application named PhasorView that could display the phasor data, both live and archived.

With the initial fleet of only eight PMU's on the 345kV and 500kV EHV system, OG&E made observations at a rate of thirty samples per second and established a baseline for what would be considered normal operating conditions. They also joined the North American Synchrophasor Initiative (NASPI) and began streaming data to the host site at the Tennessee Valley Authority (TVA). This allowed for the utility to contribute their portion of the grid to the system wide view of the U.S. Eastern Interconnection. For the first time, the utility was able to observe how events on the OG&E system affected the interconnection and vice versa.

The utility has expanded the PMU coverage of the transmission system by simply adding communications to existing substations with PMU capable devices already installed. High bandwidth communications were added to all EHV and other critical substations as part of a security initiative in 2005. PMUs have gradually been networked over the years, which now cover about 40% of the transmission system. This includes 100% of the EHV system, 100% of wind farms, 90% of the fossil generation fleet, and 34% of the HV system. In total there are now almost 200 transmission lines, autotransformers and generators monitored by PMUs.

OG&E has been using synchrophasors primarily for situational awareness and disturbance and misoperation analysis. The utility has purchased a tool for the SCADA/EMS software to bring synchrophasor data into the state estimator, which is currently being tested. The technology is used to assess the stability of the system and proactively find equipment problems. It is also used to monitor how the system responds to faults and assess the voltage recovery from these disturbances. Synchrophasors have also proved very useful for integrating renewable energy into the grid and monitor power quality.

Disturbance Analysis

One of the early observations was how widespread the impact of transmission faults can be seen on the system. Even faults at the 138kV and 69kV voltage level are observable on the EHV system and certainly by the distribution customers as well. To improve disturbance analysis capabilities, OG&E linked the archived synchrophasor database to the operations control center's database of transmission disturbances. This was done so that all disturbances could be quickly analyzed for impact to the system and to easily verify the protection system's performance. Figure 1 shows the voltage depression seen by the 345kV system for a 138kV line fault.

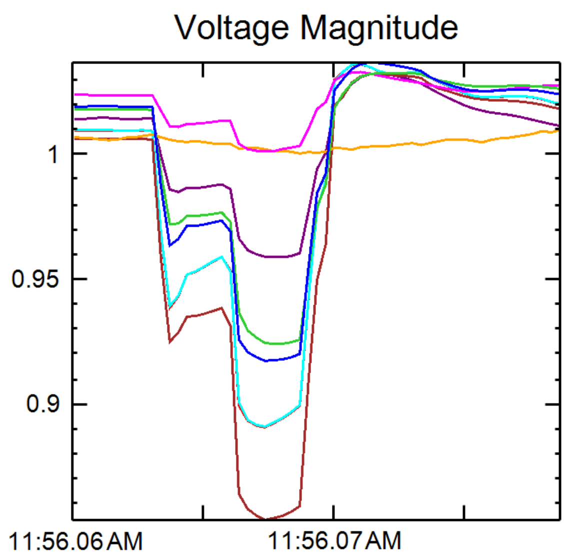


Figure 1 - Voltage Depression During a Fault

From the synchrophasor data it can also be determined if a disturbance is cleared by high speed or step distance (delayed) tripping. In the figure 1 example and many others as well, it was discovered that delayed tripping occurred in places where high speed tripping was expected. This finding prompted field investigations which resulted in corrective actions to repair and/or enable the high speed protection functionality.

The next evolutionary steps in the technology's application called for the utility to add many more PMU's and begin using an open source software package to concentrate the phasor data. A custom action adapter was written to archive the data to the SQL server database and continue use of the PhasorView software. Since the majority of the 500-600 annual transmission disturbance events involve weather related incidents, OG&E incorporated a geospatial overlay of the transmission system and substations along with lightning and weather radar data. It could instantly be discerned if a transmission disturbance was storm or lightning related and determine the area of impact. The synchrophasor system could now be utilized as a utility wide fault recorder, becoming the top level overview for analyzing transmission disturbances. Engineers could quickly locate the source of the disturbance using the wide area synchrophasor data and continue down to the substation level digital fault recorder and digital relay data to investigate further.

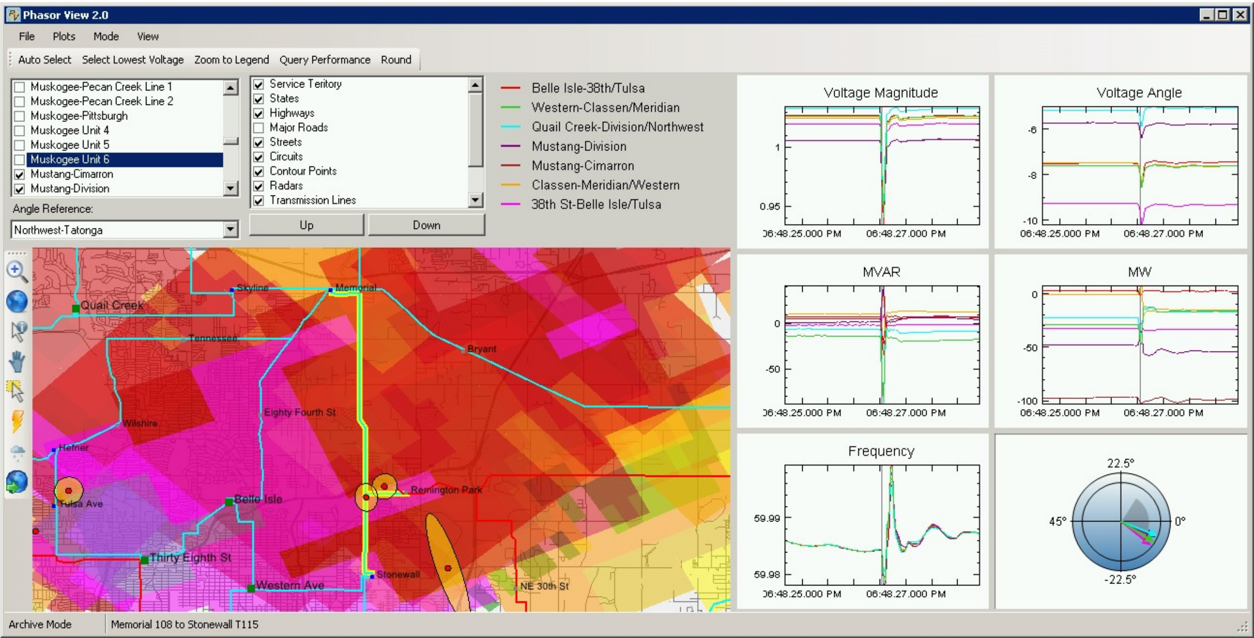


Figure 2 – PhasorView software for visualization

Figure 2 shows a screenshot of the PhasorView software used for visualization. This example includes a disturbance caused by a lightning strike, which is shown with the red dot and its surrounding yellow probability ellipse. As one can see the strike is directly over a transmission line and corresponds in time with the voltage magnitude pull down observed with the synchrophasor data.

One unique feature of OG&E's PhasorView software is that any and all data collected is instantly accessible without specifying a new file or database as the data source. The user can look at any specified increment of live data or instantly zoom out to the last day, week, month or year. Any PMU or combination of PMU's can be selected either by checkbox or from the GIS portion of the program. Under the default PMU selection mode, the program automatically selects 8 PMU's that are spread across the entire EHV system to provide a broad view. Once a disturbance is detected by voltage pulldown, the user can zoom into the disturbance and select 8 new PMU's with the most severe voltage pulldown with one click of the mouse. This enables the user to quickly locate the source of the disturbance and proceed with their investigation.

One unique tool used to locate disturbances on the system is to plot the MVAR flow direction on the map as shown in figure 3. Since VARs always flow toward the fault, the change in MVAR flow from prefault to fault conditions is calculated. Arrows are then drawn on the map for each line monitored with a PMU and point to the fault location.

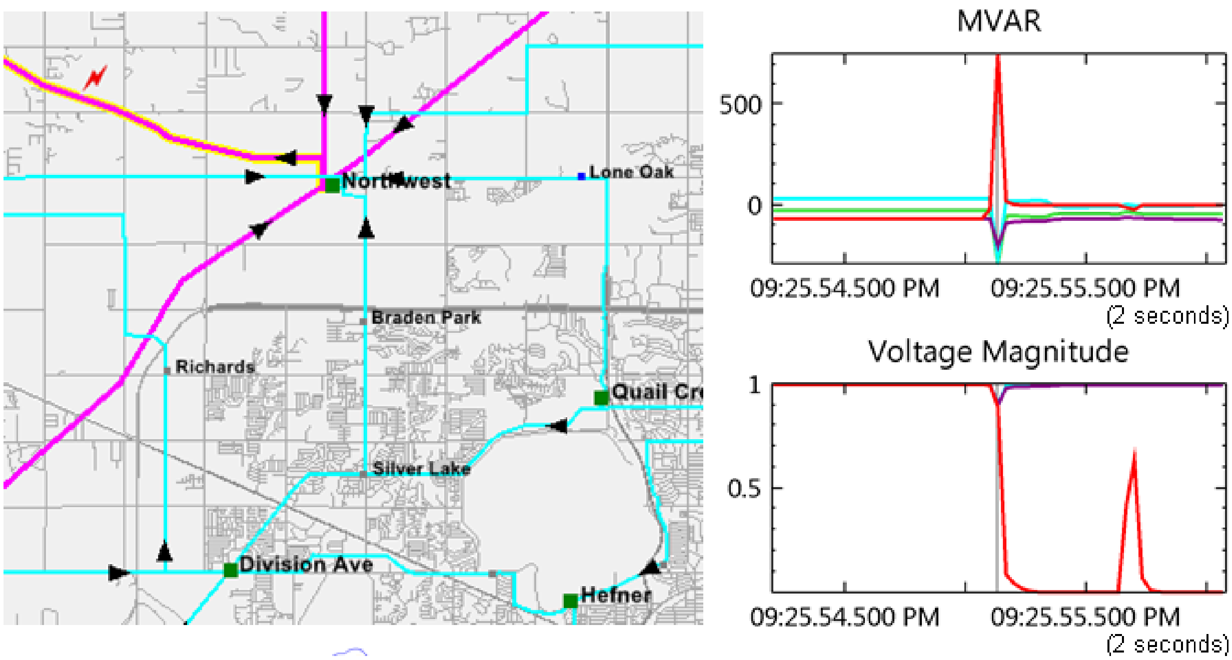
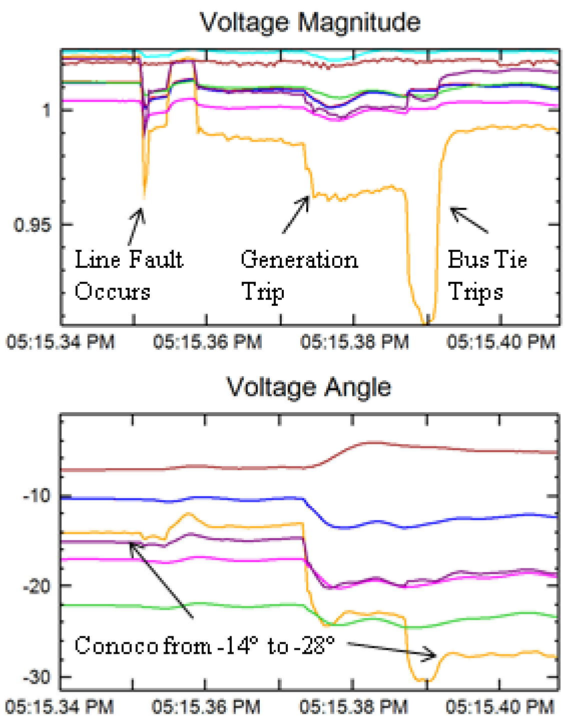


Figure 3 – Fault Location Using VAR Flows

For some specific examples of using the technology for disturbance analysis, two events of unusually long duration are presented. The extended duration of such events make it difficult to assess the situation with protective relay and DFR records due to their limited duration, segmenting the event into multiple records.



On August 10th, 2009 a fault occurred on the 138kV Sooner – Cow Creek/Stillwater line. The Sooner end of the line failed to trip because of a wiring problem in the relay potential circuit due to multiple grounds. Protection on the Sooner Unit 1 generator detected the fault and tripped the unit. The 400MVA bus tie autotransformer also saw the fault and tripped. Being close to Sooner on the 138kV system, notice how the Conoco North voltage responds to this event in figure 4. Its voltage angle relative to Muskogee was -14 degrees before the event and dropped to -28 degrees after, which indicates stress to the system.

Figure 4 – Five Second Fault Event Shows System Stress

In March of 2011, a track hoe contacted one of OG&E's 138kV lines out of Horseshoe Lake substation, resulting in a line to ground fault. The line operated once, reclosed and then failed to operate. This is one of the utility's largest stations, so it took 19 breakers behind Horseshoe Lake to clear the fault remotely. The fault was finally cleared when it went phase to phase and could be detected by the distance relays. The electromechanical ground relays could not detect the fault because the current polarizing circuit was compromised by a bad underground control cable. The result, shown in Figure 5, affected 32,000 customers and took 2 hours and 17 minutes to restore power, which equates to 4.38 million customer minutes interrupted (CMI).

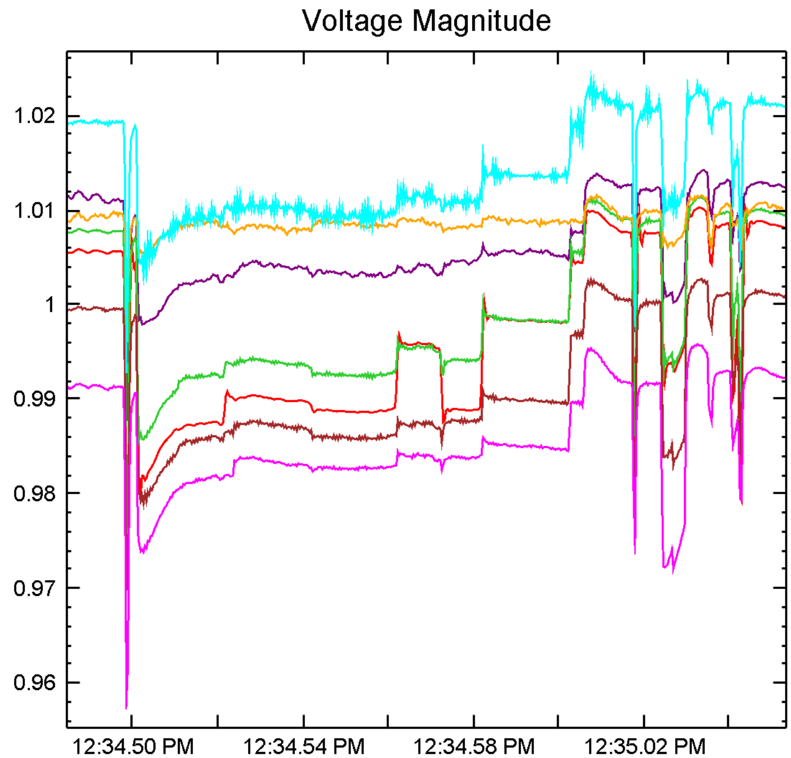


Figure 5 – Ten Second Fault Event Shows System Stress

<u>Voltage Recovery Assessment</u>

Another benefit of synchrophasors has been the assessment of system voltage recovery. Delayed voltage recovery is currently a hot topic of study for NERC as SCADA lacks the resolution to detect these events. The potential impact for such an event is to take down large amounts of metro load and potentially cascade to large scale blackouts, especially during peak conditions. On June 11th 2009, the utility observed a disturbance followed by an extended period of low voltage in southern Oklahoma, as shown in figure 6. It appeared to be a generator trip, so it was determined from confirmation with the control center that it wasn't any of OG&E's units. Engineers then contacted interconnecting utilities to find that it wasn't any of their units either, but they also noticed the low voltage in southern Oklahoma. It turned out to be a unit at the Tolk power plant in the Texas panhandle over 300 miles away. This type of event is not detectable with current planning standards because it involves multiple contingencies across many transmission owners' systems.

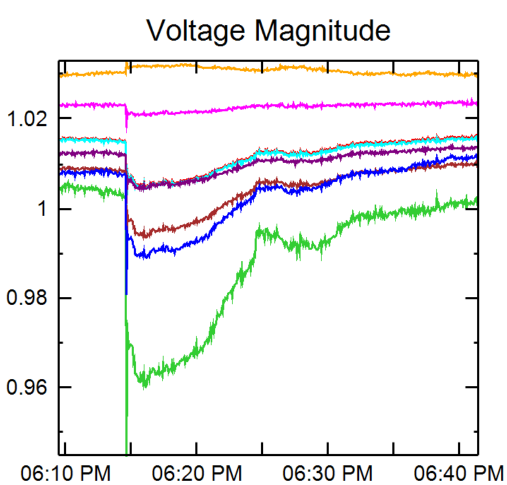


Figure 6 – Voltage Recovery Assessment

Proactive Discovery of Equipment Failure

Another valuable use of synchrophasor data is the detection of equipment failure, most of which is not detectable by SCADA monitoring systems. Many instances have been observed where the positive sequence voltage magnitude spikes randomly or drops to 66% of nominal. These were determined to be caused by loose connections at the safety switch or terminal cabinets, loose caps on renewable fuses, animal damage to wiring, and blown potential transformer fuses. In some cases there was a protection misoperation associated with the failure. Even modern digital relays do not always detect these conditions, confusing the directional element logic or not properly declaring the loss of potential. If a particular substation has multiple bus or line PT's that are monitored, loose primary connections or failing CCVT's can also be detected since the intermittent signal problem will manifest itself on every PT at the station. The best defense against these conditions is to have field personnel dispatched as soon as the problem is identified to correct the problem and prevent protective relay misoperations. The green trace in Figure 7 shows an example of a loose PT connection at the secondary fuses.

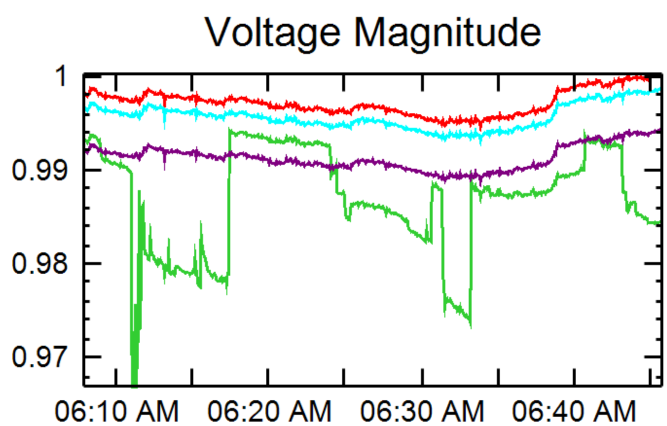


Figure 7 – Loose PT connection discovered

The tool that is used to detect these instances of failing equipment is the PT problem report. It performs a dV/dT on all voltage magnitude data and sends a daily report via email. Any abnormal voltage fluctuations are detected and the report provides a counter along with the timestamp of the fluctuation. The example in figure 8 shows a failing analog input on a PMU. The PT problem report showed over 181,000 dV/dT instances that exceeded the threshold that day. This algorithm is also good at detecting disturbances on the system, which can be very useful for event detection.

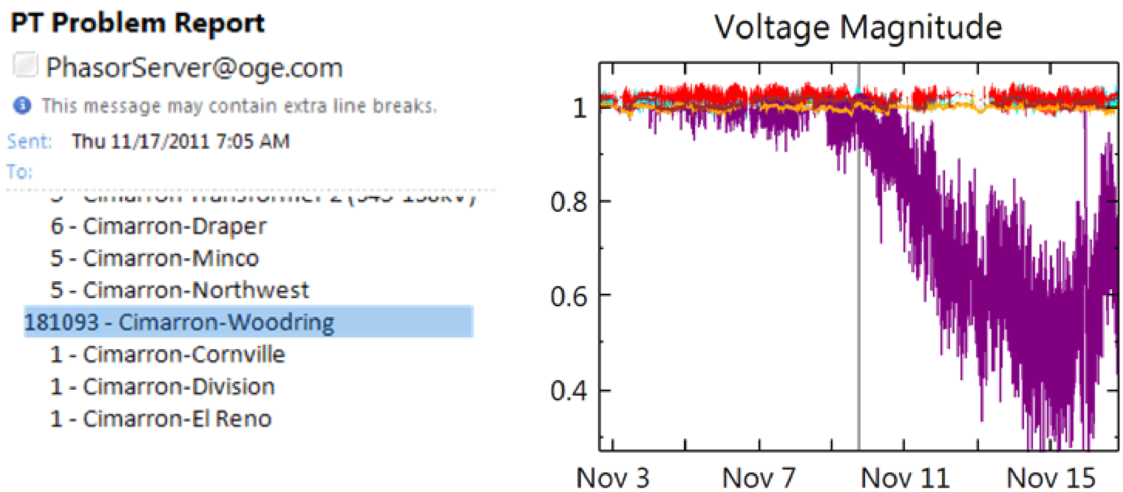


Figure 8 – PT Problem report shows a failing analog input

In June of 2012 engineers observed an unusual reclosing event following a fault on a 345kV line as shown in Figure 9. It was clear that multiple reclosing attempts had been made when only one reclose was expected. Construction work had changed the substation configuration and it was found that relay settings had not been updated as intended. The relay settings were then updated, restoring the reclosing to proper functionality. Having widespread PMU visibility allows for quick analysis of all fault events and allows for identification of potential problems.

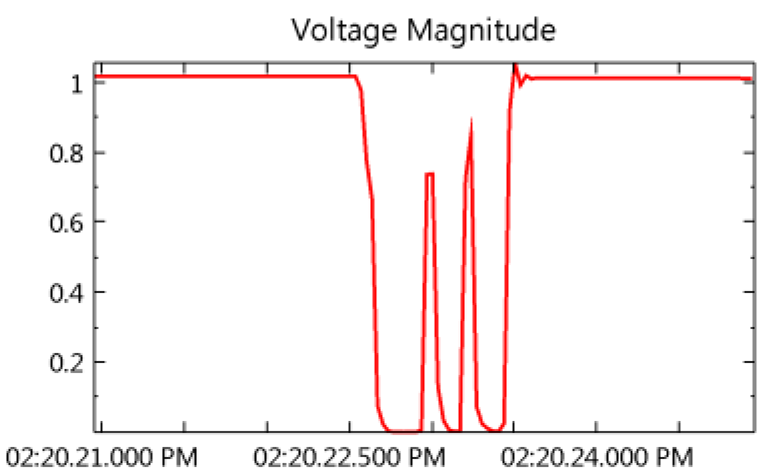


Figure 9 – Failed reclosing attempt due to incorrect settings

Identification of failing equipment doesn't necessarily need to be limited to the power system assets. There have been many observations of problems with the GPS clocks that serve as the precise time reference to substation IEDs. GPS problems are usually pretty easy to spot in the PMU voltage angle data. It has been noted that a 3G data radio antenna mounted adjacent to the GPS antenna will very effectively jam the GPS signal. Fortunately, the STAT frame in the PMU stream shows when the PMU is in sync. It is advised to use the STAT frame data in any event detection algorithms to avoid using bad data.

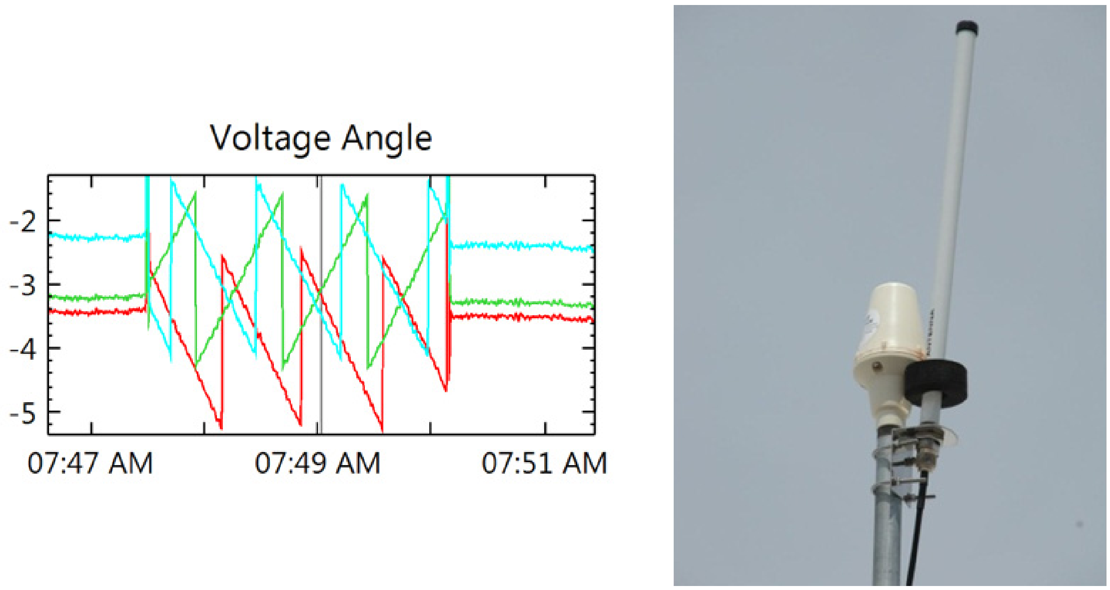


Figure 10 – Interference from a close RF source can jam GPS reception

Stability Assessment

Traditional tools for stability assessment involve offline simulation of various system conditions within a dynamic stability model. While useful, these models do not always capture the intricacies of an interconnected system. After observing many instances of voltage oscillations, the utility implemented a FFT detection program to detect these oscillations and send email and text notifications when it requires corrective action. The example shown in Figure 11 shows the frequency spectrum of a voltage waveform with many undesirable components, the most prominent at 14.0 Hz. Stability assessment with PMU data is a must because SCADA lacks the resolution to detect sub harmonic frequencies.

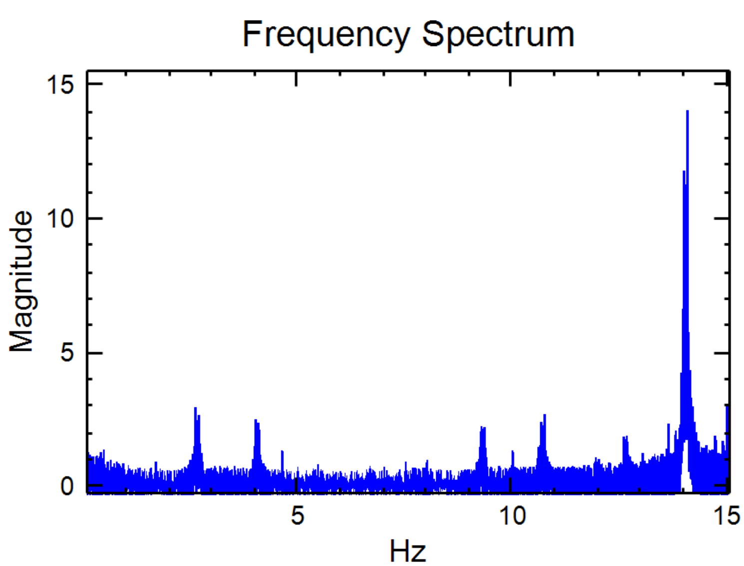


Figure 11– FFT Detection shows undesirable oscillations at 14Hz.

Beginning shortly after bringing the first PMU's online, OG&E discovered strange voltage oscillations on the EHV system at a frequency of 0.2 Hz as shown in Figure 12. The oscillations were most pronounced at one of the PMU's near a combined cycle natural gas generation facility. The observed signal was strongest on the MVAR plot, so it was suspected to be a generation control problem. Using the snapshots of the event and the specific dates and times that it occurred, the utility contacted the power plant manager, asking if it corresponded with any of the daily plant operations. The plant manager indicated that there was indeed a correlation and found that it was being caused by a problem within a particular unit's VAR control scheme. This particular generation unit's start up procedure placed it in a VAR control mode which was subsequently switched by an operator into voltage control mode once the unit was synchronized. This switch in control mode was the trigger which stopped the oscillations. As a result the plant was able to resolve the control issues with this particular unit and prevent further stability problems. Without the sensitive synchrophasor measurements, this anomaly would have gone undetected and could have potentially escalated into a more widespread event.

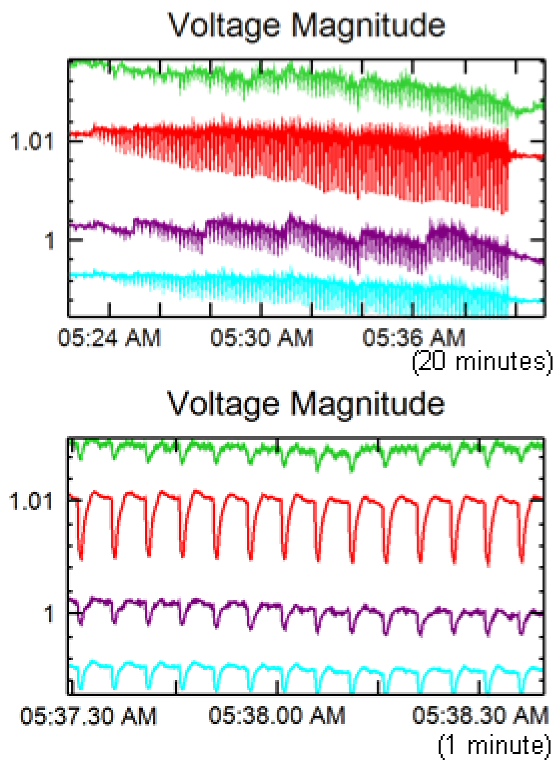


Figure 12– Generation Unit Oscillations

Wind Farm Integration/Monitoring

OG&E, along with many other utilities in the Great Plains region, has a large wind generation resource potential. Many large scale wind farm facilities varying in size from 100MW to 300MW have been brought online, with many more under development. Currently the Southwest Power Pool's generation interconnection queue is approaching 30GW of wind resources, making it one of the nation's most prominent sources of renewable energy. Determining how these vast resources will be integrated into the regional power grid proves to be a challenge and synchrophasor technology is able to provide the tools necessary to do so in a reliable manner.

Each new wind farm facility brought online in OG&E's service territory is accompanied by PMU measurements at the point of interconnection. In December 2010, the utility began observing sub-synchronous oscillations on the transmission system in a concentrated portion of the grid in northwestern Oklahoma as shown in Figure 13.

These oscillations were found to be occurring during periods of high wind generation, above 80% of the nameplate capacity. The voltage oscillations observed were as high as 5% fluctuation at an oscillatory frequency of around 14Hz as shown in Figure 14. This level of voltage fluctuation exceeded the IEEE 141-1993 standards for objectionable flicker, and it was confirmed that the impact was observable to the area distribution customers. The problem has been localized to specific wind farms and the utility is undergoing efforts with the turbine manufactures to resolve the problem. This phenomenon could not be observed with traditional SCADA monitoring and without synchrophasor technology, the problem would have taken much longer to identify and resolve. The benefit of having PMU measurements at the point of wind farm interconnection is to ensure that customers receive clean power while maintaining the level of system stability necessary for reliable power system operation.

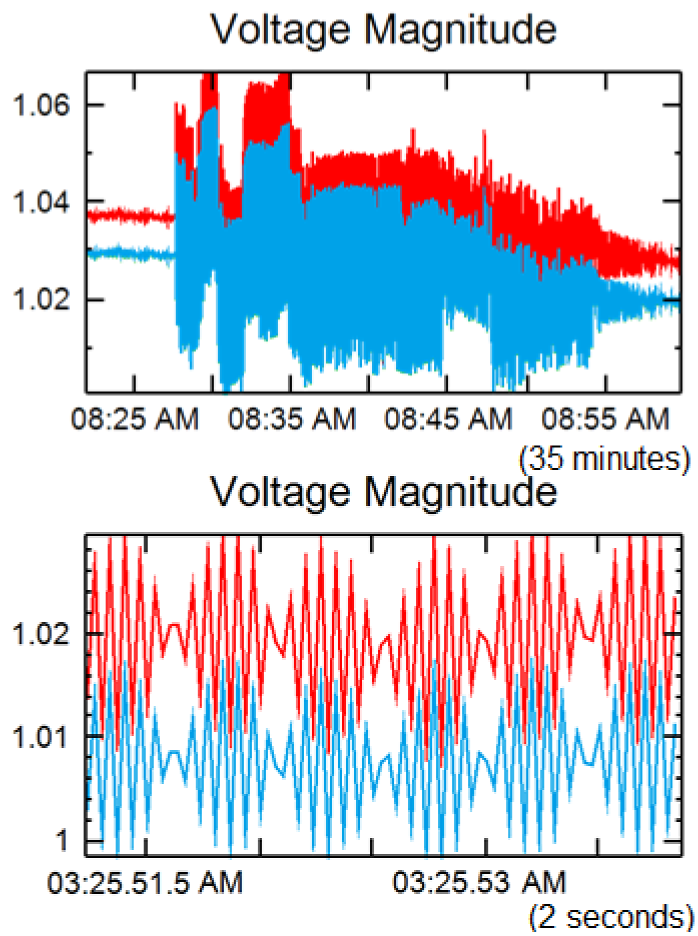


Figure 13 – Windfarm Oscillations

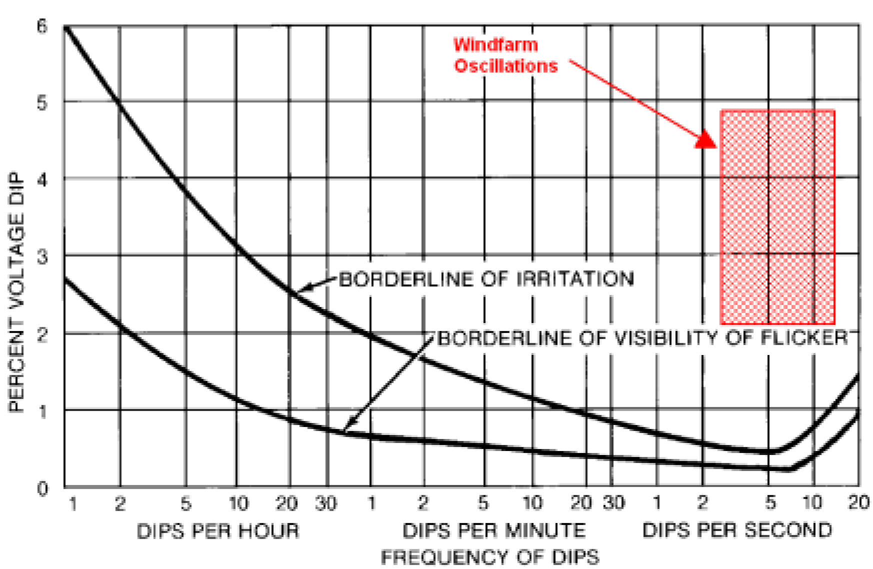


Figure 14 – Flicker region of Windfarm Oscillations

It is worthwhile to compare the resolution of the PMU data with SCADA measurements. For the oscillation event, engineers requested the SCADA data for the same time frame. Figure 15 shows the PMU data in red, with the black trace showing the SCADA data. The voltage oscillations were obviously not detectable with SCADA.

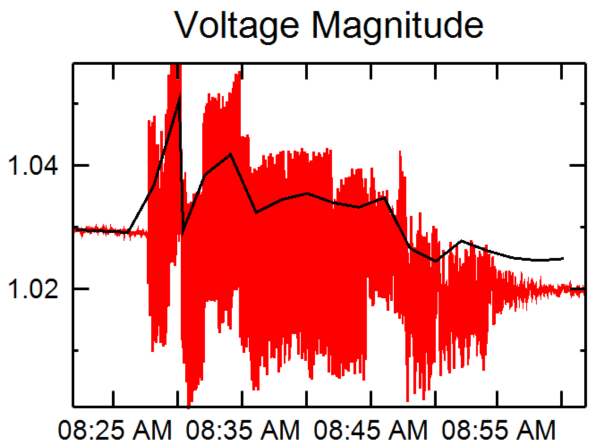


Figure 15 – Comparison of PMU and SCADA data

The utility experienced another oscillation event at a new wind farm that was recently placed into service. In December of 2012 a line outage caused a major oscillation at a new 60MW wind farm interconnected at 69kV. The voltage variations were as high as 18% at a frequency of 3Hz as shown in Figure 16. It took about a half an hour to curtail the plant and restore the system to normal operation. The event adversely affected the operations at a nearby large industrial customer. The utility collaborated with the manufacturer to devise a solution that is currently undergoing testing.

There appears to be a strong correlation between the stability of a wind plant and changes in the system Thevenin impedance. Another example occurred on December 14 2011, when a transmission line was out of service for maintenance and a permanent fault occurred on another line in the area.

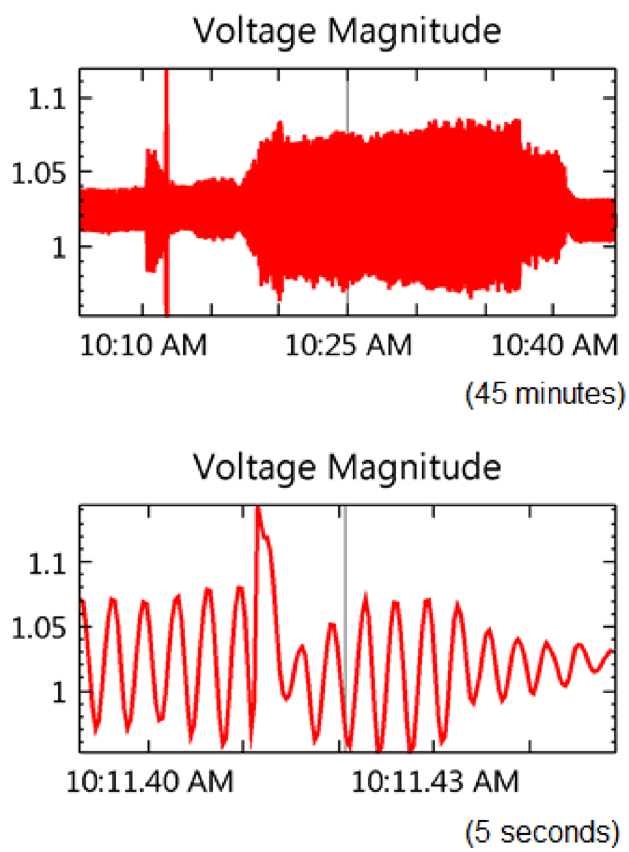


Figure 16 – New 3Hz Wind Farm Oscillation Event

The loss of the second line caused the wind farms to begin oscillating and it persisted for about a half an hour until the plant's output was curtailed. During this fault event, the voltage pull down was about 80% for 5 cycles, which is typical for a 138kV line with communications.

However, one of the area wind plants lost about 57MW when the fault occurred as shown in Figure 17. The turbine's low voltage ride through capability should have been able to handle this grid disturbance. However there have been several other instances of ride through failure at other wind facilities as well. This remains something to watch out for as the wind penetration increases throughout the service territory.

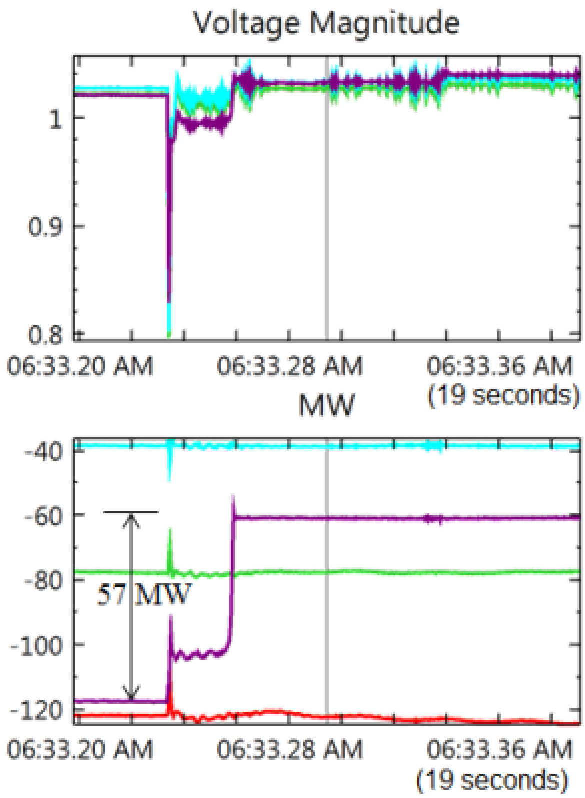


Figure 17 – Monitor Wind Farm Low Voltage Ride Through

<u>Operations Support</u>

Another application that was somewhat unexpected is the usefulness of phasor data to many different groups within a utility. The information provides situational awareness to the control center operations, disturbance/misoperation analysis for protection engineers, and troubleshooting information for field personnel. As the lines between these different groups begin to cross, members can achieve a common goal together. One example is when an unusually high voltage angle was observed between two buses, indicating system stress. This prompted further investigation by the protection engineers and it was found that a major EHV transmission autotransformer was taken out of service for maintenance. As a result it was observed that another key autotransformer was being overloaded. The engineers notified the control center and subsequently, transmission loading relief was instigated by the RTO to bring the loading down to safe levels and protect the autotransformer from damage.

Another example involved the energization of a new 100MW wind generation facility. The collector substation had been energized with PMU measurements at the 138kV high voltage bus. The PMU measurements however indicated nearly zero positive sequence voltage at the bus. This prompted protection engineers to examine the protective relay data further, which exposed the presence of negative sequence voltage instead of the expected positive sequence voltage. Figure 18 shows the result of the SEL "meter pm" command and improper phase rotation used to discover the root of the problem.

```
=>meter pm

SEL-421-3 S/N 2009061190                    Date: 09/24/2009  Time: 17:36:13.000
138kV OU Windspirit - Woodward District (PCB 111)     Serial Number: 2009061190

Time Quality   Maximum time synchronization error:    0.000 (ms)  TSOK = 1

Synchrophasors
                     Phase Voltages                Pos. Sequence Voltage
                  VA          VB          VC              V1
MAG (kV)          83.239      83.511      83.254            0.189
ANG (DEG)        -37.951      82.198    -157.712         -154.789
```

Voltage on all three phases

Positive Sequence Voltage near zero, but it should match the phase voltages in magnitude

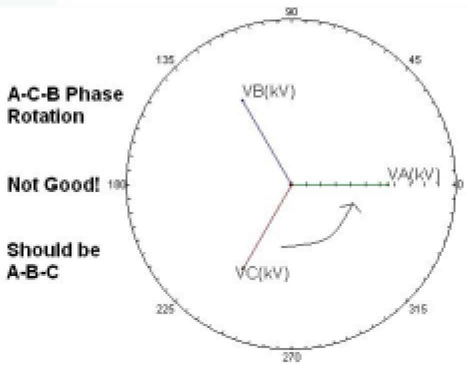


Figure 18 – Phasing error discovered during commissioning

The engineers suspected a phasing problem during commissioning and field personnel determined that the A and C phases were swapped on the secondary potential circuit. The benefit of having synchrophasor data during commissioning is to proactively find problems like this before they can evolve into bigger problems.

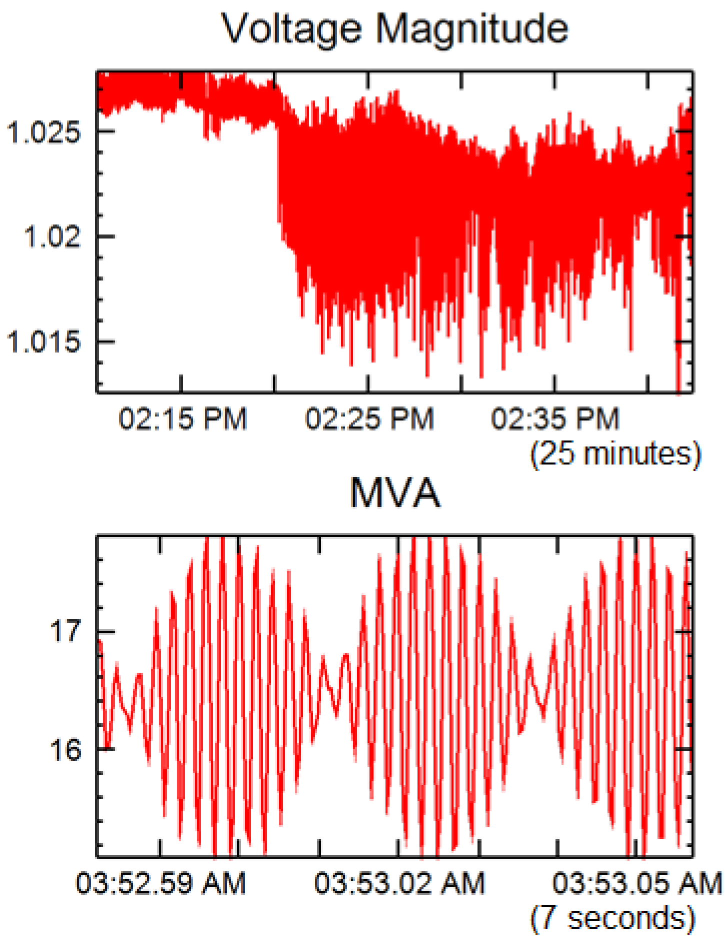


Figure 19 – Monitoring Power Quality

Monitoring Power Quality

Besides the known customer impact due to voltage oscillations, the synchrophasor data can also be used for monitoring power quality. It has been observed that large industrial loads can inject noise onto the transmission system that is visible on the voltage, current, and frequency waveforms. The first waveform in Figure 19 shows the beginning of an arc furnace burn as seen by the 161kV bus at an adjacent substation. The second waveform shows the load characteristic of a refinery injecting sub-harmonics at 4.62 and 5.0 Hz. Synchrophasors allow for real time power quality monitoring that cannot be observed by SCADA or DFRs.

Analysis of a Major Winter Storm Event

A severe winter storm moved into northwest Oklahoma on February 25, 2013 dumping as much as 22 inches of heavy wet snow as shown in Figure 20. Numerous line outages occurred during the storm, which progressed throughout the day. With synchrophasor data, the utility was able to see the system weaken as lines locked out. The following figures show the progression of the event with voltage angles in northwest Oklahoma referenced to Oklahoma City.

Figure 20 – Major Winter Storm Event

Northwestern Oklahoma is tied to the rest of the transmission system by a 345kV line, 4 138kV lines, and a few 69kV lines. Over the course of several hours the storm gradually severs all ties to NW Oklahoma as shown in Figure 21. The area load equals about 200MW, but there is a high concentration of wind farms in this part of the state totalling 944MW. The following voltage angle plots are referenced to Northwest substation in Oklahoma City, with data from Centennial which is a 120MW wind farm.

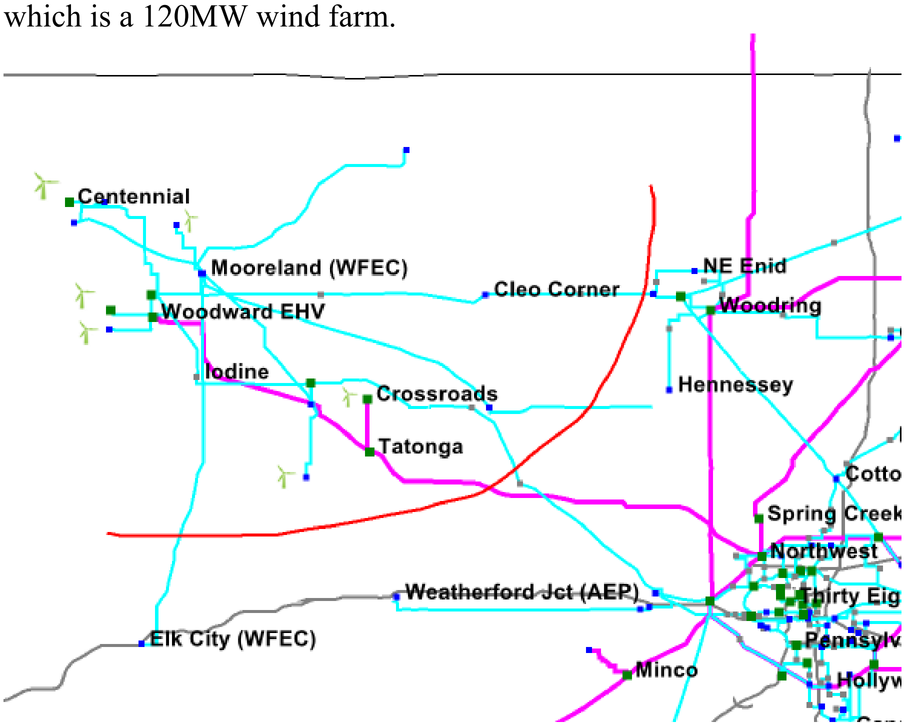


Figure 21 – Transmission Map of Northwest Oklahoma

At 1:57PM the 345kV Northwest-Tatonga line trips out, which is the major tie line to northwest Oklahoma. The voltage angle at Centennial prior to the fault is 18 degrees leading, and it increases to 28 degrees after the line locks out as shown in Figure 22. The increase in angle suggests that there is excess generation in northwest Oklahoma that is being exported to the larger load pockets in the south and east. The Centennial wind farm displayed partial failure of the low voltage ride through as 49MW was lost for several minutes and then restored.

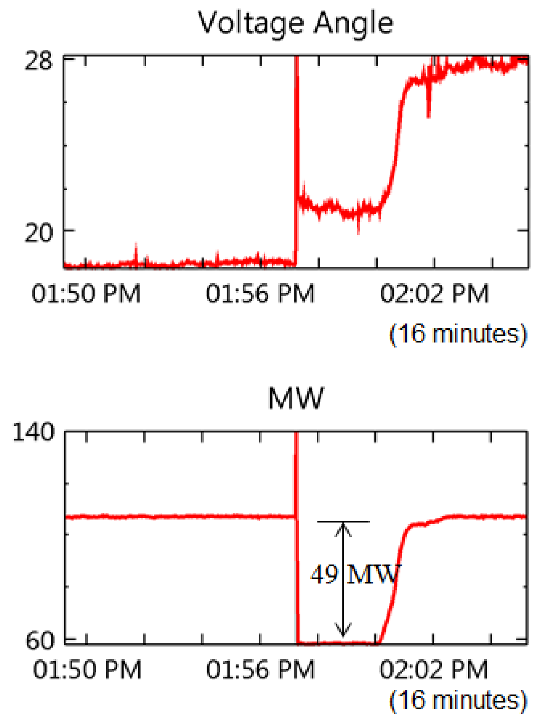


Figure 22 – 345kV Northwest-Tatonga Line Trips

At 6:09PM the 138kV Dewey – Woodward line operates and the voltage angle increases from 28 to 33 degrees as shown in figure 23. The line successfully reclosed and the angle returns to 28 degrees. The ring down observed on the angle and frequency plots is much more pronounced with the 345kV line out of service (6 seconds).

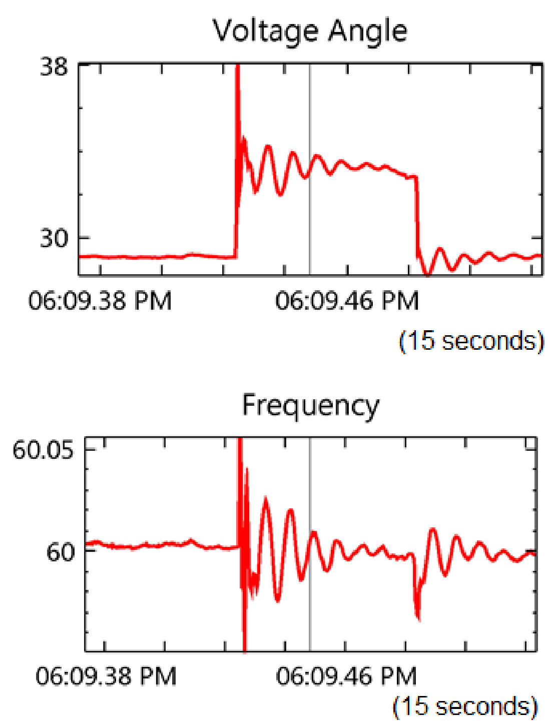


Figure 23 – 138kV Dewey-Woodward Line Trips

At 6:25PM the 138kV Dewey – El Reno line trips and the voltage angle moves from 28 to 46 degrees as shown in Figure 24. The line automatically reclosed from El Reno on the Oklahoma City side but the angle is beyond the sync check of 30º for hot line in phase reclosing at Dewey. The ring down period is extended to about 10 seconds, showing the system becoming weaker with the line outage.

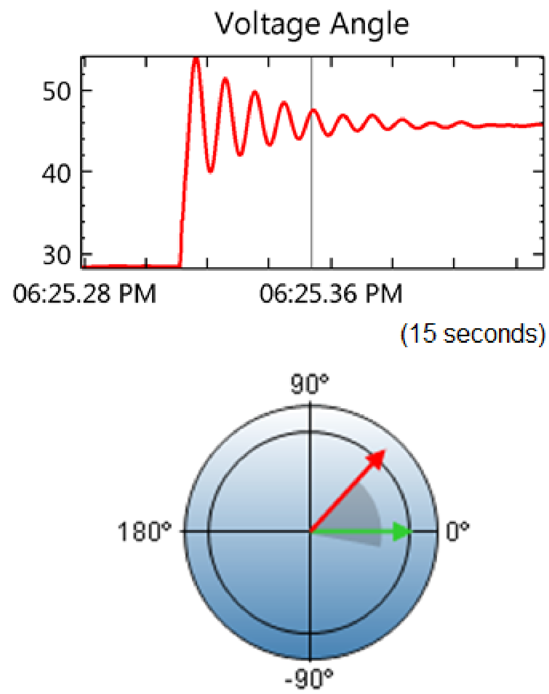
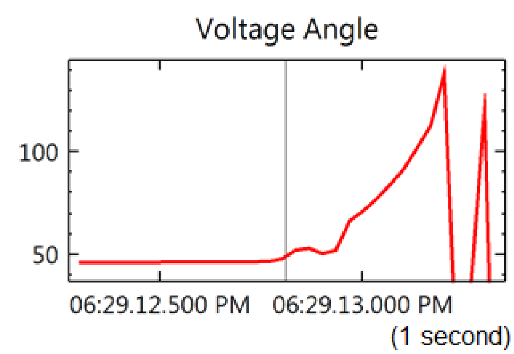
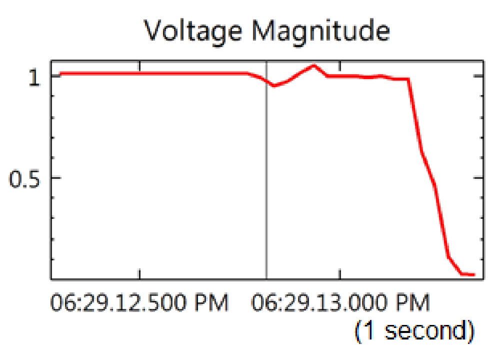


Figure 24 – 138kV Dewey-El Reno Line Trips

At 6:29PM the 138kV South 4th Street – Imo line trips. The system is unable to cope with the excess generation and the frequency immediately begins to ramp up. The voltage angle increases from 46 to 136 degrees as the voltage collapses. It only took 0.6 seconds from the time the last fault occurred until the load pocket was in the dark. Interestingly enough since the 138kV Dewey – El Reno line was hot from the Oklahoma City side, the automatic hot line-dead bus reclosing was able to restore the island within 20 seconds. With the wind farms then offline, the northwest Oklahoma area load was able to be picked up from the lines that reclosed.





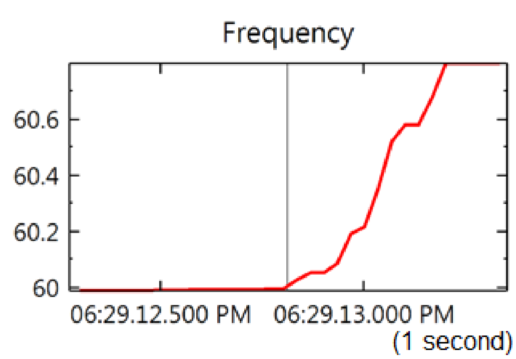


Figure 25 – 138kV South 4th St – Imo Line Trips

Automatic Event Processing

With widespread deployment of digital protective relays and DFRs, retrieval and management of the vast stores of data can become overwhelming. To assist in this daunting task, OG&E has deployed a software application that uses existing engineering access to automatically collect substation IED data on a preset schedule. It retrieves event reports and sequence of event data from protective relays and DFRs and stores it in a central location. It also tracks changes to the relay firmware and settings. All the data is presented in a web interface and includes mapping capabilities for distance to fault data. The driver behind the use of this application was the loss of data experienced to the limited local storage in substation IEDs. Many times it was necessary to retrieve event records for a specific event, but the records had been overwritten by newer data. With literally thousands of substation IEDs, it is not possible to retrieve these records manually, so this software system ensures all the data is available for analysis.

OG&E is currently in the process of expanding the capabilities of this software to use the real time synchrophasor data for event detection. The digital data in the PMU stream contains information like relay trip bits, breaker position, dead line status, etc. An algorithm will associate this digital data with specific events like a line trip. A disturbance log is created with the timestamp and the line that operated. This process is currently performed manually by the system operator using breaker position data from SCADA. After logging the disturbance, the software will retrieve the associated relay/DFR records and SER.

There are four cases that the software will use to determine the location of faults on the system as shown in Figure 26. The first case is when PMU data is available from both ends of a transmission line. The software algorithm will look for a relay trip signal in the digital PMU data. When a relay trip is present from both ends of a line, a fault is declared on the line. The second case is when PMU data is only available on one end of a transmission line. In this case the algorithm is able to use the relay trip signal from one end of the line, followed by a dead line status and a specified number of dV/dt calculations that exceed a given threshold. The dV/dt calculation ensures that there was a voltage deviation caused by a fault condition and that the relay trip was not due to relay testing. A similar approach is used in case three to flag potential misoperations due to overtripping. The relay trip signal from one end of a transmission line is used in conjunction with a specified number of dV/dt calculations that exceed a given threshold and the absence of a dead line signal. The fourth case is used to flag a disturbance on the system that was not directly observable by any PMU terminals. In this case the dV/dt calculations are used to

PMU Fault Analysis ?

Live update of PMU faults and the Partial Faults from devices

Top PMU Faults

Area	Station	Device	Fault Type	Occurred
Ardmore	Park Lane	pmu_9	PMU-3PT-dvdt-deadLine	04/08/2013 11:02:58.073
Metro	Mustang	pmu_5	PMU-3PT-bothEnds	04/07/2013 00:01:05.693
Metro	Mustang	pmu_5	PMU-3PT-bothEnds	04/06/2013 23:58:11.760
Enid	Woodring	pmu_3	PMU-3PT-bothEnds	04/06/2013 23:54:01.300
Metro	Mustang	pmu_5	PMU-3PT-bothEnds	04/06/2013 23:51:42.923
Metro	Mustang	pmu_5	PMU-3PT-bothEnds	04/06/2013 23:49:59.353
Enid	Woodring	pmu_3	PMU-3PT-bothEnds	04/06/2013 23:47:55.807
Metro	Pennsylvania	pmu_6	PMU-multi-dvdt	04/06/2013 23:46:36.243
Enid	Woodring	pmu_3	PMU-multi-dvdt	04/06/2013 23:46:31.120
Enid	Woodring	pmu_8	PMU-multi-dvdt	04/06/2013 23:46:29.380

Figure 26 - Automatic PMU Fault Event Processing

determine the closest PMU terminal to the fault. The dV/dt calculations that show the greatest magnitude are nearest to the fault location. This data can also be further enhanced with the technique of plotting the change in MVAR flow on a map to visualize the direction of the fault current flow as discussed earlier in figure 3.

Future Plans

With the benefits clear, OG&E intends to continue to connect PMU's anywhere the communications infrastructure will allow. It is believed that synchrophasor technology will continue to complement traditional SCADA measurement of the power grid, providing added system observation capabilities and thus improving reliability for customers. Some believe that PMU measurement capability will eventually expand to the entire power grid, and OG&E believes that anticipated changes in grid operations will make it necessary to do so. With the amount of available data from PMU's, it will also be necessary to implement automated routines that can detect system anomalies and correct them before it impacts customers and the bulk electric power grid. Algorithms are currently in use and more are under development to analyze the data to detect failing equipment and oscillations that can affect system reliability and stability. Synchrophasors provide the means to make the transmission grid smarter and improve reliability. OG&E is prepared to utilize the technology to the fullest extent and encourages others to do the same.

Author Bios

Austin D. White is a Lead Engineer at Oklahoma Gas and Electric Company in Oklahoma City, OK. He is currently responsible for transmission/substation protective system settings and coordination, disturbance event/misoperation analysis, and system modeling/simulation. Recently, Austin has been leading the efforts to deploy a synchronized phasor measurement system for OG&E. He received his B.S. in Electrical Engineering from Oklahoma Christian University in 2001, followed by a M.S. in Engineering and Technology Management from Oklahoma State University in 2008. He is also a licensed Professional Engineer (PE) in the state of Oklahoma.

Shawn W. Jacobs is a Lead Engineer at Oklahoma Gas and Electric Company in Oklahoma City, OK. He is currently responsible for transmission/substation protective system settings and coordination, disturbance event/misoperation analysis and NERC CIP and PRC compliance. He received his B.S. in Electrical Engineering from the University of Oklahoma in 2002. He is also a licensed Professional Engineer (PE) in the state of Oklahoma.