By Ken Martin

Synchrophasors Point the Way

The emergence of a new technology.

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I WAS A TEST ENGINEER IN THE LABORATORY Division at the Bonneville Power Administration (BPA) in 1987. They needed someone to design, implement, and conduct a field test of a new computer-based device that measured the phasor equivalent of voltage and current sine waves. Knowing little about the technology and method, I went to a project meeting where Prof. Arun Phadke from Virginia Tech (VT), the principal investigator and primary creator of the concept, was leading the planning.

I realized that we were on to something very new that could have a significant impact if it worked. It seemed like a long shot, however. It first depended on microsecond-level timing over a wide area, using the new and not yet complete GPS, a satellite-based navigation system. I had worked with timing systems and knew that even maintaining reliable millisecond accuracy across a power system was rather challenging. The measurements required rather high-level microcomputing, which, for that time, was much more expensive than comparable analog electronic or magnetic-based measurements. Most field-based communications would not carry digital messages at the rate needed for measurement reporting. So, I was not confident that it would work but was certainly interested in seeing what it would do.

At the first project meeting, I was introduced to Prof. Phadke and the other team members. I was surprised that the method just basically took samples of the ac waveform and computed a Fourier transform to compute both the magnitude and phase angle. I didn't realize that you could get an accurate phase angle from just the conversion. The key is time synchronization, which was achieved by time synchronizing the sampling process. After the first meeting, I received some background articles and analyses so that I could come up to speed on the technology.

I was told they had done the initial development and testing, but it turned out that it was going to be several months before VT could produce devices that we could install. They would provide only the measurement unit and sampling interface, and we had to provide the GPS receiver. Most importantly, we had to decide where and how to install them. Since it was a field test, we needed them at a location where we could install the GPS timing receivers, have good communications back to our control center, and get some measurements with interesting events. We chose to install them on the Pacific NW–SW Intertie, which is important for power transfer between the Pacific Northwest and California metropolitan areas (Figure 1). This intertie is critical to power flow between the northwest and southwest, and there are a lot of remedial action schemes (RASs) devoted to assuring its stability. It also experiences significant dynamic swings when there are disturbances, so it was a good place to test an instrument like this.

Disclaimer

Many engineers, scientists, and others have contributed to the development of synchrophasor technology. I have had the privilege of working with a number of them, and I greatly value the experience as well as acknowledge their huge contributions. However, to keep this more focused and readably short, I have not included the work of others. This is a narrative of my experience with synchrophasor technology development. I hope others will also share their stories.

We decided to install one phasor measurement unit (PMU) at the John Day substation along the Columbia River and one at the Malin substation by the Oregon–California border. This observes about 280 mi of the intertie, which was a double circuit line at 500 kV. It also happened that BPA had high-speed analog voltage and power transducers installed at these stations that had direct telemetry back to the control center as well. This enabled setting up a parallel measurement so that we could compare the PMU measurement directly with the more traditional transducers.

The first challenge at that time was getting GPS receivers that could hold a reasonable synchronization through short outages. Complete GPS coverage (four plus satellites) occurred for only a few hours a day. We had to have GPS receivers that would hold their position once

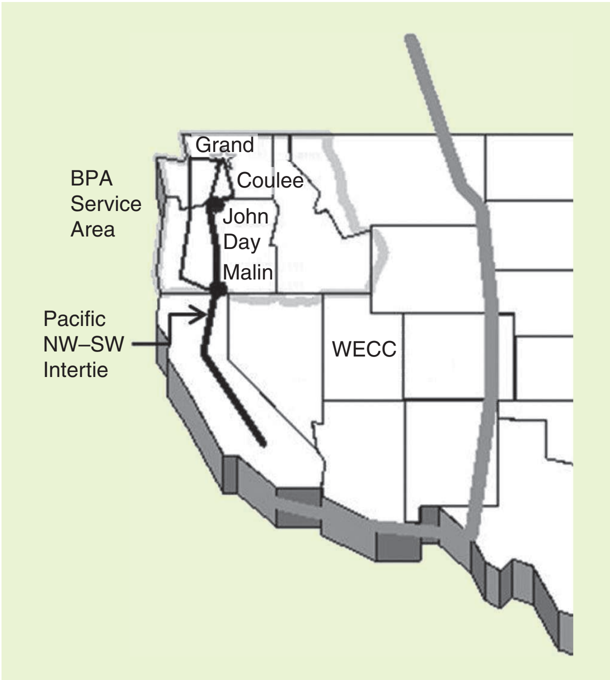

Figure 1. Western North America showing the BPA service area in the northwest United States and the area covered by the Western Electricity Coordinating Council (WECC) as the managing electric reliability organization. The Pacific NW–SW Intertie and test locations are indicated.

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acquired and then continue timing on one to three satellites and even hold a reasonable time when no satellites were in view. To get the best reception, we mounted the antennas at the top of the substation microwave tower and used low loss cable to minimize the signal loss.

On the other side of the PMU, we had to have modems that would keep up with the data stream. Communication was over analog microwave, and the fastest modems that would work reliably on our system were 4,800 b/s. At that rate, the fastest reporting rate that included the phasor and frequency data was 12 messages/s. That was considered very fast at that time; some engineers questioned the value of reporting at such a fast rate.

The first challenge at that time was getting GPS receivers that could hold a reasonable synchronization through short outages.

Figure 2 illustrates the test setup where the PMU data and the analog transducer data were brought into a computer system and recorded in parallel. The analog transducer data was digitized at 12 samples/s and time stamped for the same times as the phasor data. The phasor data were processed to discard errored samples, time aligned, and recorded. There was a small time skew between the phasor and analog data due to the difference in the location of time tagging, but it was not significant in this analysis.

The test ran for six months. A number of disturbances were selected and plotted. Comparisons indicated that the results were very comparable, but the phasor data had much lower noise, so the details were much easier to observe (Figure 3). Point by point comparisons over several days gave almost no outliers. The important thing was that the test demonstrated that the PMU measurement was stable, worked continuously, and was very clean with little noise.

The test pointed to the fact that the measurement quality was excellent, but it did not really tell us how accurate it was. So, the next step was setting up a test with a more precise signal source. We tested the steady-state magnitude accuracy with standard test equipment and found the accuracy was within 0.5%. The challenge was getting a signal with precise time synchronization since the phase angle is measured relative to time. The test signals were not time synchronized, so we used an oscilloscope to determine the actual signal phase angle. We triggered the scope with the precise 1 pulse/s from the GPS receiver and

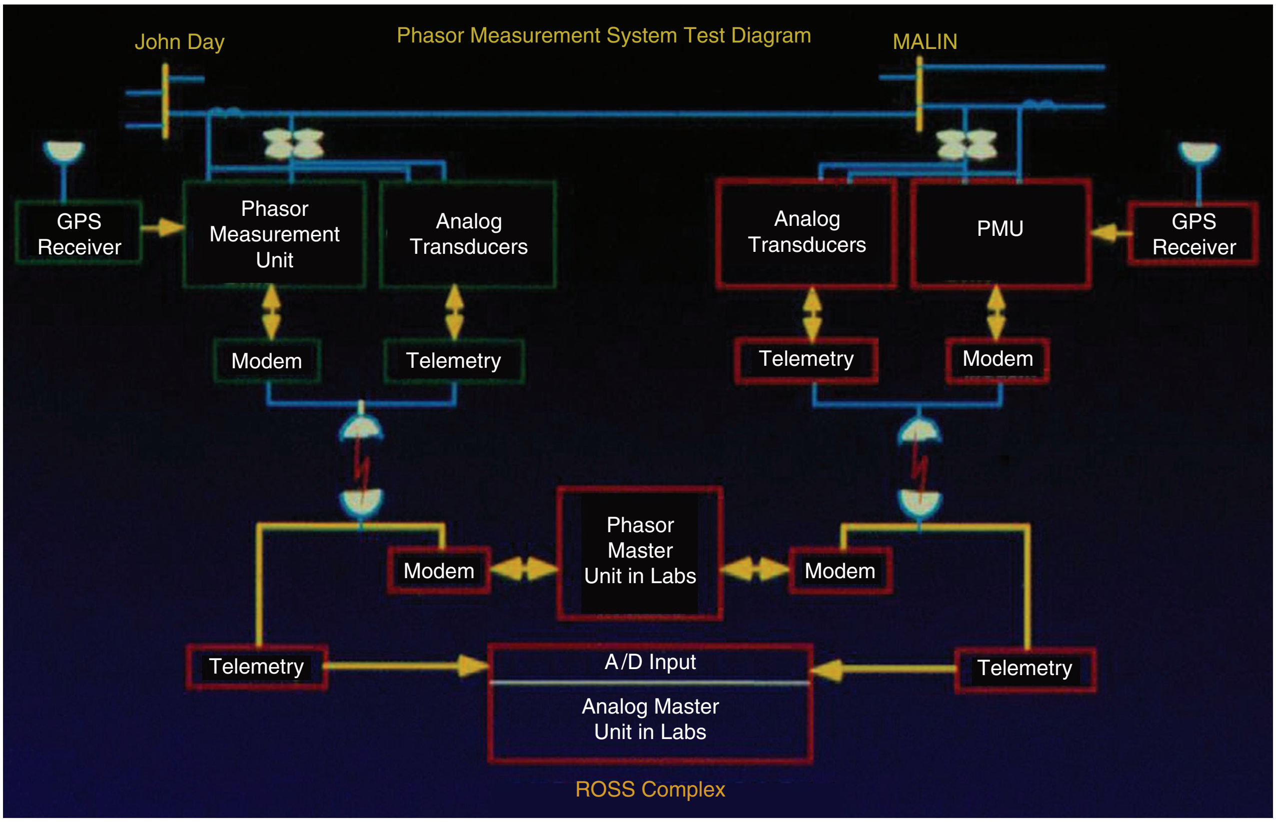

Figure 2. The original PMU test setup showing parallel analog and phasor data inputs.

measured the time to the signal zero crossing, from which we could calculate the actual phase angle of the output. Using this, we determined that the PMU phase angle measurement was consistently within 0.1°.

We also wanted to track the performance with dynamically changing signals. BPA had just finished building a digital simulator that would take mathematically generated signals and output them as voltage and current signals for testing relays. Using this, we generated test signals in which the magnitude was sinusoidally modulated or had a step change. The PMU made a nearly perfect measurement of both kinds of test signals (Figure 4).

This initial testing was evidence that the PMU was accurate, low noise, and stable. It tracked the system through dynamic swings and thereby provided a view of the system's dynamic performance we had never had before. The frequency measurements were more accurate than previous methods, particularly during dynamic changes. It could provide the ac phase angle, from which we could observe the system phase angle and compute the power flows. This is a measurement we never could do before. Most analysis uses phasor representation of the system parameters, so this measurement can be applied directly to system analyses. It was clear that this new measurement method offered significant benefits to power system engineering.

The first two PMUs were student built, and there were no options to get more units. We built two more PMUs that we could use for testing, development, or system tests. We used PMUs on two system tests: one at an aluminum smelter in a voltage collapse test and another at the Grand Coulee Dam while testing the transient excitation boost RAS control. In both tests, the portable PMUs set up easily, performed without a problem, and provided valuable information about the power system performance.

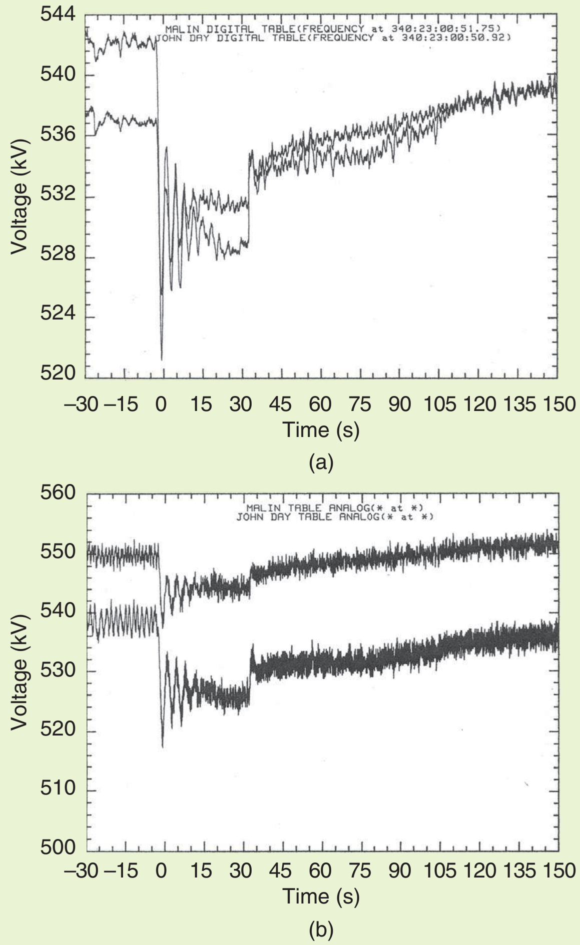

Figure 3. The generator drop/switching event with (a) PMU measurement and (b) the analog transducer illustrating lower noise and better definition from the PMU.

After the initial qualification tests and the ensuing uses of PMUs in system tests, the PMU development was set aside as new projects were being developed. The original two PMUs were left in service with a small application we developed that reported the phase angle between John Day and Malin to the main supervisory control and data acquisition (SCADA) system.

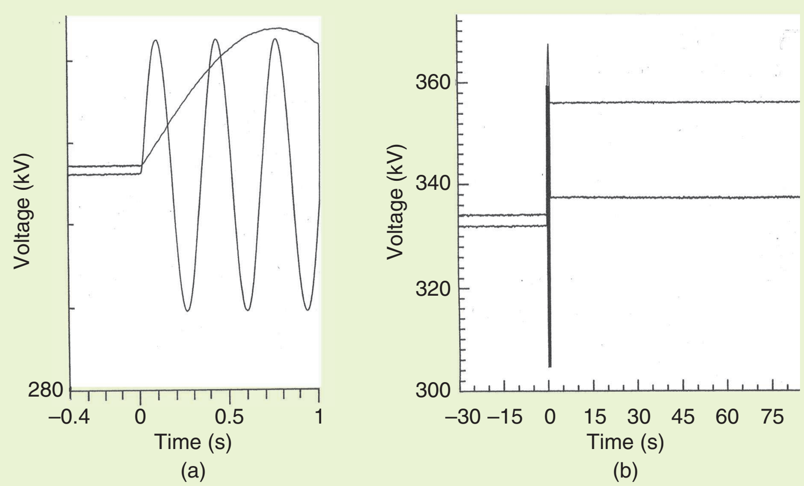

Figure 4. (a) The PMU measurement showing 1- and 3-Hz modulation and (b) a magnitude step response with 2 and 7% steps.

Timing Investigation—GPS Development

At this point, my main focus moved to the GPS timing aspect, which is critically important to phasor measurement. We needed to ensure that it would continue to be available and become more affordable.

There was also a wider interest at BPA in timing as it was used for a number of systems. We had a central time system (CTS) that sent time via inter-range instrumentation group timecode B (IRIG-B), an electronic timing code used by utilities, over the BPA microwave to all substations, where it was used to time tag events and fault recording. The CTS also provided time to all control center systems. However, the CTS was synchronized from WWVB, a 60-kHz timing signal broadcast by the U.S. Bureau of Standards (now called the National Institute of Standards and Technology). It provided only about 1 ms accuracy and was subject to interference. As the CTS was due for replacement, we considered using GPS.

There was real concern about whether we could get a continuous, accurate timing signal from a satellite with a signal that was buried in noise (spread spectrum).

We also had a unique fault locating system (called FLAR) that located faults by triangulation using the traveling wave generated by the fault. The wave travels along the power lines at nearly the speed of light. By time tagging the arrival of the wave at the nearest busses, the location of the fault can be calculated. With microsecond timing accuracy, the location can be assessed within 1,000 ft, which generally will locate the tower or other object where the fault occurred. A special wideband microwave channel was used to synchronize clocks since standard communication channels would not do that. That limited the system to the BPA 6-GHz analog microwave, which left out some desired fault detection locations. As BPA and neighboring utilities were migrating to fiber and digital microwave systems, there was a strong need to find another synchronization method. There were also some problems with the IRIG-B time transmission. Thus, there was a clear need for a better timing system—one that would serve all needs and allow for future expansion.

GPS seemed like a good prospect for both, but there was serious uncertainty in adopting that approach. Receivers were very expensive. The U.S. military had primary control, so there was concern about whether they would continue to supply civilian access. The full constellation was not yet deployed, so there were gaps in coverage. There was real concern about whether we could get a continuous, accurate timing signal from a satellite with a signal that was buried in noise (spread spectrum). So, our challenge was convincing ourselves that GPS could deliver, convincing vendors to produce the kind of receivers we needed, and proving to potential users that it could deliver. Surprisingly, there was little concern about jamming, spoofing, meaconing, and any other degradation. This was probably because the system was so new that few people other than specialists had even imagined these things.

Working with various colleagues, we attacked this on all fronts. We attended technical meetings where timing issues were discussed, such as the Precise Time and Time Interval group, the Institute of Navigation, and IEEE meetings. We presented the need for GPS timing applications in the power industry to the Civil GPS Service Interface Committee. We determined that the receiver technology was improving steadily and would probably reach the point where receivers would be competitive with any other timing alternative. We purchased more GPS receivers with high-precision crystal and rubidium oscillators for better stability and strengthened our testing program. When we found that receivers did not meet our needs, we pressed vendors to improve performance and provided feedback on the problems we discovered.

Over the course of a couple of years, technology improved, and we were able to get the receivers we needed. Because we demonstrated performance that could meet our needs, we got approval to try new applications of GPS. We proposed a new CTS based on GPS to serve all timing needs, including the FLAR system. I designed a system with triple-redundant GPS timing input and extensive self-monitoring to meet the many user needs. A vendor built the system for BPA, and it was installed in 1994. The system was able to perform at a 1-μs accuracy level over its 10-year life, validating the capability of GPS-derived timing.

With the new CTS controlling the FLAR master, we started a program to switch the FLAR field timing to GPS rather than the sync channel. We ordered specialty GPS receivers that had time tag capability and expanded the protocol used to report time tags to the master at the control center. The time tag included an extra input channel with which we could time the microwave sync channel. Using these sync channel time tags, we demonstrated that the GPS receivers were keeping accurate and reliable time at the remote substations.

As we continued to use GPS, user confidence and acceptance grew. The price of receivers came down. We started a class for field staff on GPS technology and the testing and maintenance of these devices. We purchased and stocked spares. In other words, we went through the normal process of adopting a new technology.

The Blackouts

In 1990, the first commercial PMU, the Macrodyne 1690, was introduced and offered a path to further deployment. A few system tests were done in the first few years after that, but there were few, if any, installations for regular operation. In 1993, the Electric Power Research Institute (EPRI) initiated a large-scale demonstration project in the western system (WECC) that used PMUs to provide the measurements to control swings across the Pacific NW–SW Intertie. There had been a few major incidents that had caused a separation or near separation. If the swing could be detected quickly enough, it could be damped and outages prevented. Under this test, participating utilities got between two and four PMUs and one data concentrator for collecting and forwarding data. BPA planned installation at the two sites already used, John Day and Malin, and also designated Grand Coulee and Colstrip as sites. This would give a good broad picture across the BPA system. These PMUs were installed around June 1996 but were still awaiting communication connection in August of that year.

It was a wet year in 1996 with a big snowpack in the Pacific Northwest. That created a big runoff and lots of hydrogenerated power to sell. The summer was also hot on the west coast, so there was a high power demand in California. In early July, there were two blackouts caused by interrupted power through Wyoming and Idaho into the intertie. These caused small blackouts in the Idaho area but did not spread further. Actions were taken to mitigate those issues. On 10 August 1996, faulted lines in western Oregon and Washington led to a cascading failure of generators that provided voltage support to the intertie. This led to instability across the intertie that caused intertie failure and a blackout through much of California and a breakup of the western system into four islands. It resulted in the loss of 25,570 MW of generation and 30,500 MW of load during the 5–20 h of the blackout. This precipitated a major investigation of the system planning and operation as well as a flurry of interest in systems that could provide better information about the state of the system.

We had three PMUs in service at that time that captured key information about the blackout. They captured short duration snapshots of the events in local memory only since the communication systems weren't in operation yet. These records showed key facts. For example, although the intertie power flow remained about the same throughout the day, the phase angle across the system increased as lines within the area tripped out (Figure 5). The records also indicated that the system became unstable with a growing oscillation that resulted in intertie separation at Malin when the swing exceeded the protection limits (Figure 6). We expect to see the phase angle increase when there are

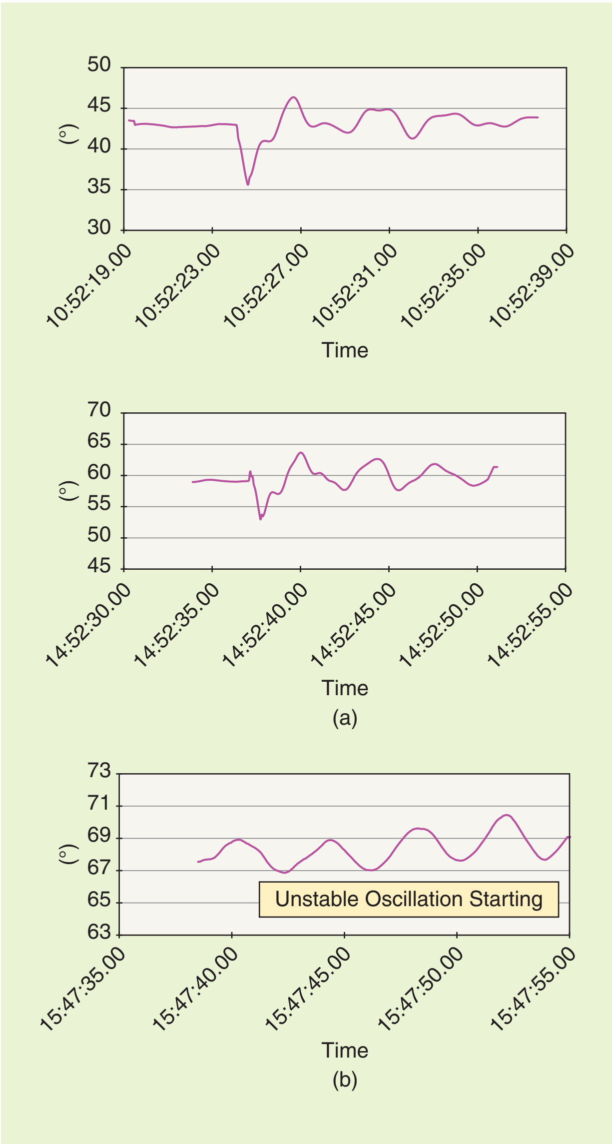

Figure 5. The system phase angle from Grand Coulee to Malin grows from 43 to 68° as lines supporting transmission are lost. (a) A 60° angle for Grand Coulee–Malin and (b) a 68° angle.

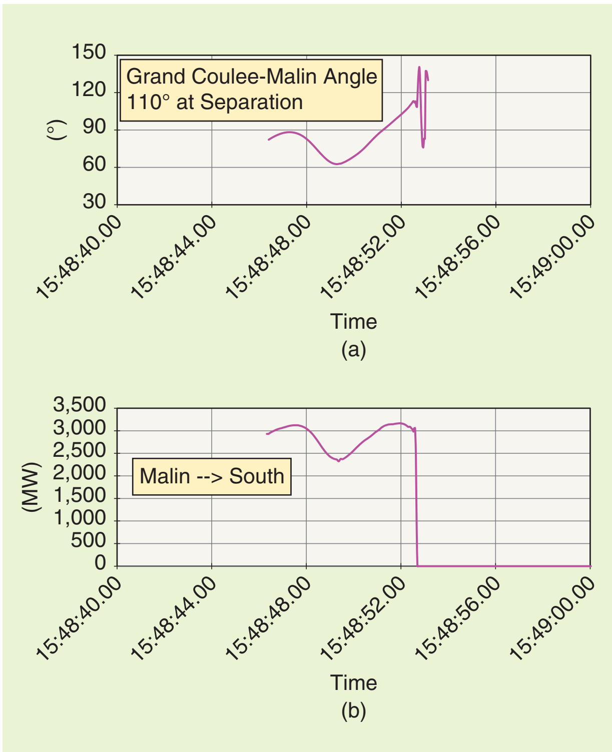

Figure 6. Growing oscillations up to the point of system separation, as seen in the (a) voltage phase angle and (b) MW power transfer.

fewer transmission lines carrying the load, but this was the first measurement showing the change. Hence, this demonstrated that phasors offered another way that we could monitor system reliability. Phasors also displayed the oscillatory responses much more clearly than SCADA measurements. As a result of observing these benefits, BPA decided to build out the phasor measurement system beyond the original scope of the EPRI test.

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Planning the BPA Phasor Measurement System

Given the mandate and backing, we had the freedom to create a measurement system that could support multiple applications. The clear and obvious use was the analysis of system dynamics. We had already used PMUs for special tests and found that they provided accurate measurement with excellent dynamic response. BPA ran system tests on a regular basis, so phasor measurements could provide good support for this work. This work requires measurement at key points across the system as well as good data collection and storage.

We also saw the benefit of using phasors for operation and control applications. These both require real-time data gathering and communication. Allowable delay in receiving data for operations is in the 1–2 s time frame and not difficult to achieve. Automatic controls, like RASs, may require delays of fewer than 0.1 s, so the design and implementation of measurement systems can be very exacting. Reliability is paramount for critical controls; such systems require careful design and self-monitoring capability. Consequently, the system design required the capability of very low latency operation and incorporating redundancy features.

With the existing EPRI project, we had a broad coverage of BPA but with little detail. Power system dynamics are largely controlled by the generator responses, so the best coverage will include the main generator sites, key transmission connections, and sites of other significant power flow controls, such as static var compensator (SVC) or thyristor-controlled series capacitor (TCSC) locations. The system planners designated sites that would give the best coverage. We also considered the accessibility of potential transformer/current transformer signals and communication back to the control center.

BPA had a microwave system that covered all of the main grid substations. The modems then in use would not handle data transmission at the rate we wanted to use with the new PMUs. The PMUs could report at 30 measurements/s, and we wanted to establish this rate for the new system. We had to buy and test a number of modems to find one that would work with the binary data format and BPA communication at this rate. As with most utilities, the communication system was a star architecture, with the substations connecting directly back to the control center. We used that same architecture, sending phasor measurements directly to a concentrator at the control center. The concentrator had to collect the data and then send them on the applications that would use the data. The field connections were all serial, but by the time they were collected from a number of PMUs, the data rate would be too high for serial communication. Hence, we decided that the concentrator output would be Ethernet, using the highest speed commonly available at the time, 10 Mb/s. Ethernet would also allow for easy data distribution as local area networks (LANs) were becoming common within the company.

For operation and control applications, real-time data delivery to applications on the LAN would work fine. The analysis needed a system for data storage and retrieval. With that plan, we could write an application for a PC that would store the data from the stream in files that could then be accessed by other computers for analysis. The important thing was making the data readily accessible to the users.

An important aspect of any operational system is troubleshooting and maintenance. Since a phasor measurement system is spread out over the grid, has components in substations, goes over communication systems, and uses applications in the control center, it can be difficult to locate or resolve problems. To deal with this, we planned a monitor application that would display visually in real time the status of each PMU and its data as well as keep a record of the performance. With this, we could observe at any time if there was a problem—and the likely cause. We could also look at the ongoing performance to see if there were intermittent problems and how severe they might be. The historical record aids in tracking down the source of each problem.

Implementing the System

The first requirement was a better method of collecting the data. The data concentrator we had was not very reliable, did not align the data by time stamp, and did not keep a full record. A PMU measures phase angle using a Coordinated Universal Time (UTC) time reference, so angles between phasors can be calculated only when they represent the same measurement time. Consequently, the data from PMUs need to be aligned by time tag before they are sent to applications and storage. Time tag alignment requires some complicated processing algorithms to handle data delays, transmission errors, and dropouts. We also decided to incorporate the monitoring and some data storage functions into the concentrator. To differentiate this from previous concentrators, we called it a phasor data concentrator (PDC) so it could be readily associated with this technology.

Based on these criteria, I designed the PDC as an expandable, multiple CPU system using high-performance hardware (VME with 6820 CPUs) and a real-time operating system (OS9). The PDC could check event trigger indications that were set in the data by the PMU and save a file of data, including pretrigger data. Pre and posttrigger data are valuable for assessing conditions that cause a disturbance as well as the reaction. The PDC also did all of the data quality checking and basic statistics and sent it to a PC-based monitor using the Ethernet connection.

Since we wanted to transmit and store data from multiple PMUs as a synchronized record, we had to create a new format.

The next requirements were data management formats, including communication and data storage. The format from the PMU was established by Macrodyne, the PMU vendor. They already had two formats for their two models, and the PDC was designed for multiformat input. The IEEE PMU standard 1344 was not used at that time and was not designed for multiple PMUs. Since we wanted to transmit and store data from multiple PMUs as a synchronized record, we had to create a new format. We were working with a couple of other WECC utilities at the time, so together, we took elements from the Macrodyne and 1344 formats and created the PDCstream format. We created a companion file format that was very similar, using elements of the IEEE common format for transient data exchange (COMTRADE). Since the data files could get very large, we used a very compact binary format. Even then, we could fill a 100 MB disk (large at that time) in a few days.

With that, we had a complete plan for measurement, data concentration, storage, and distribution (Figure 7). Next, we needed applications to see and use the data. Through a research project sponsored by Edison Technology Solutions, we developed the application StreamReader (Figure 8). This application would connect to the data stream from the PDC and display the user-selected frequency, phase angle, and power flow quantities. It was adjustable for time period and scaling. Simultaneously, the application would store the data continuously on the PC hard drive for a length of time selected by the user. The automatic time limit prevented filling the disk with a subsequent application crash. The application was very handy for seeing what was happening on the system; we even used it to monitor system tests.

For analysis, we developed a program called PhasorFile (Figure 9). This program could automatically retrieve selected data files using FTP. It would open and scale the data and provide multiple plots with many options for analyzing the data. There was also another application available, developed by Pacific Northwest National Labs, that would do a more in-depth analysis, including frequency spectrum and Prony decomposition.

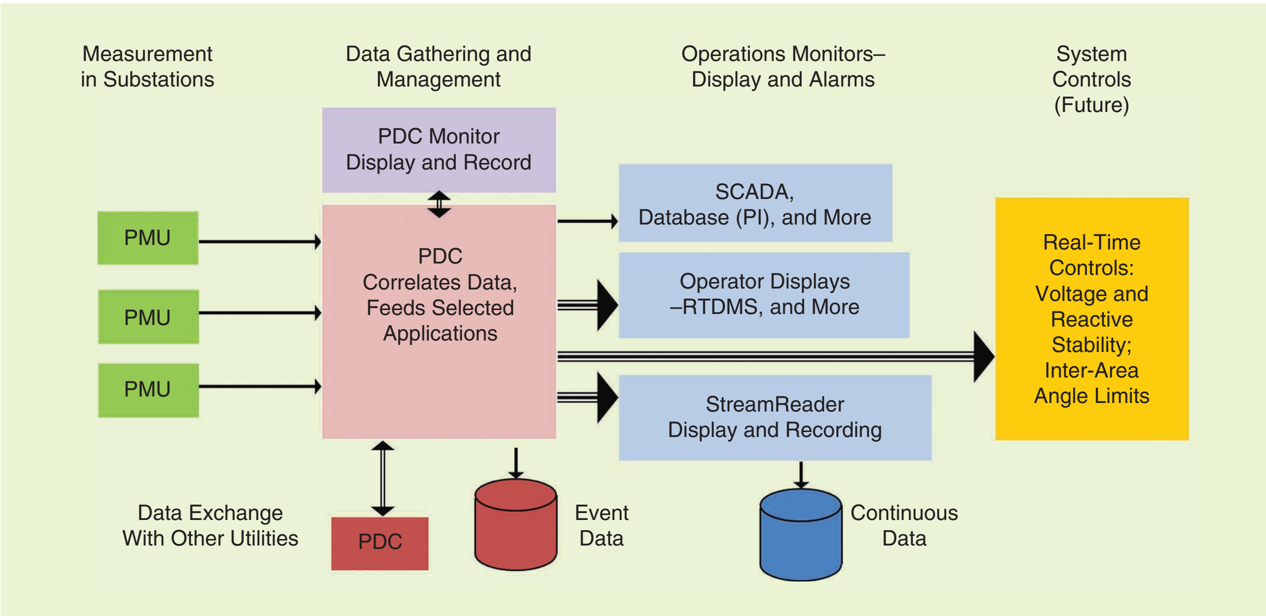

Figure 7. A phasor measurement system block diagram showing data flowthrough from measurement to applications. RTDMS: real-time dynamic monitor system.

The phasor system was implemented over the next year and was fully functional by the end of 1997, with the original four PMUs plus one in Los Angeles. We provided a PDC to Southern California Edison (SCE) in 1998 and added a direct link between PDCs so that we had a direct wide-area view. With that, we were able to observe the electromechanical traveling wave across the system that occurs when an event in one area (such as a generator drop) causes the realignment of power flows across the system (Figure 10).

Continued Development in WECC

Following the lead at BPA, other WECC utilities developed phasor measurement systems. WECC developed guidelines that required longer term, high-speed disturbance recordings like those provided by phasor systems. In 2004, both the California and Denver area PDCs were linked in with BPA for more comprehensive coverage. All of these new systems used the BPA PDC and the same data display, storage, and analysis tools. A new analysis tool was developed at SCE, adding more features. Data from these systems were shared among utilities for system event analysis. By 2006, this data was the primary information source for system-wide event analysis.

Though readily accepted for analysis, phasor displays were not used in control centers. Operators had been provided with displays showing data graphs, phase angle and voltage profiles, real-time spectral plots, waterfall plots, alarms, and so on, such as the RTDMS by the Electric Power Group. While interesting and informative, the problem was that these were not providing them with the information they needed for basic operation. In some cases, there was not enough coverage to see the detail they needed. In other cases, phasor applications were providing alarms for impending blackouts, but that happens so rarely that the application is set aside before anything happens. Until phasors could provide operators with something they needed that they didn't already have, there was not much reason for them to add this to their already-busy monitors.

There were some other application developments going on at that time. For example, at BPA, Carson Taylor designed a wide area stability control system (WACS) using phasor measurements. It could detect a system swing that could result in an intertie outage and cause a blackout. It could identify the swing on the intertie and take remedial action before the swing completed in less than 300 ms. Through tests, we determined the PMU measurement speed (33 ms) and communications to the controller (<66 ms) to confirm that the action could be made. The system operated

Figure 8. StreamReader with voltage, phase angles, and frequency on the left and currents with resulting power flows on the right. The application included continuous data recording.

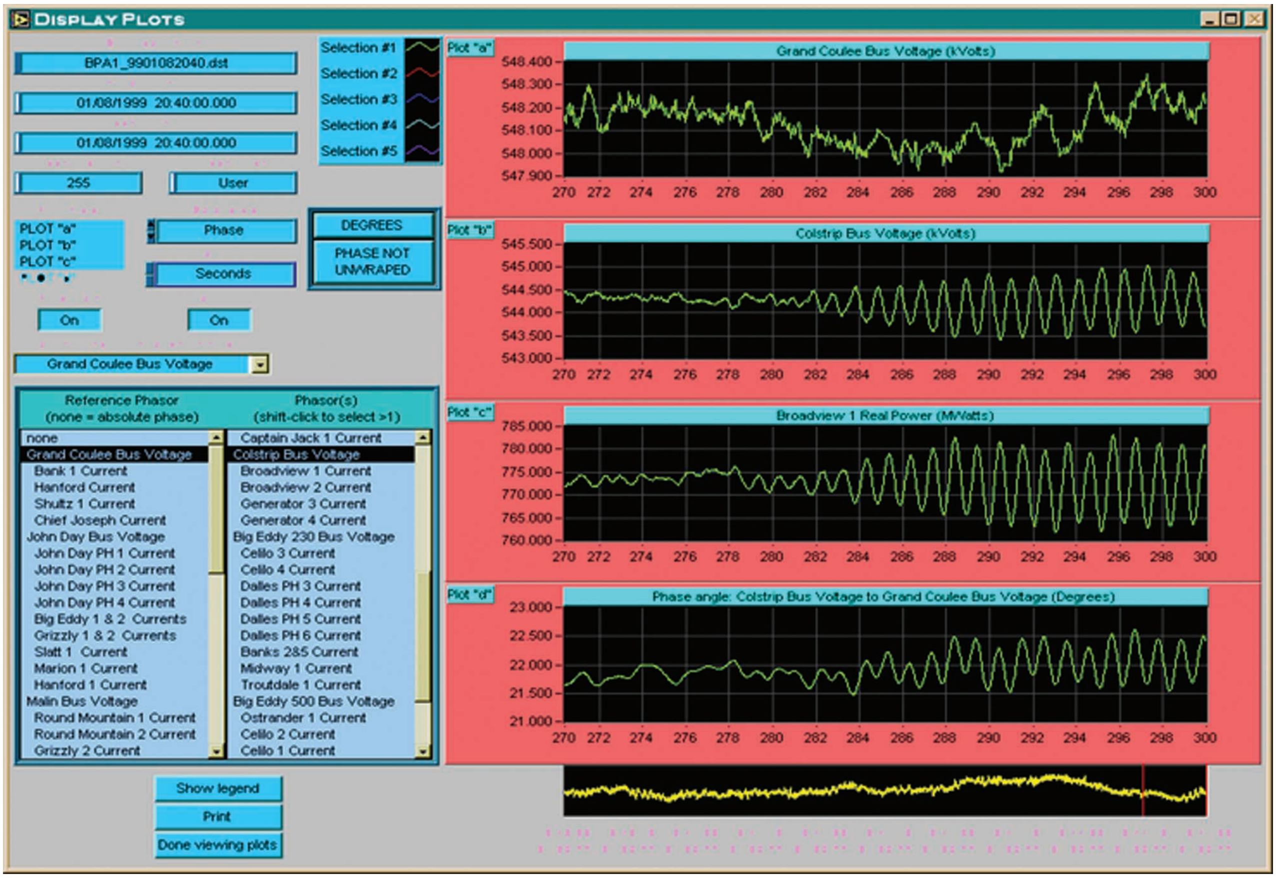

Figure 9. The PhasorFile analysis showing multiple synchronized plots of voltage, power, and phase angle for close comparison.

correctly in test mode during one major disturbance but was not put in service due to the additional development work required for regulatory approval.

Phasor Measurement Systems Across North America

A few phasor measurement systems had been installed at utilities in the Eastern Interconnect (EI) before 2003, notably the New York Power Authority and Ameren in Missouri. In August 2003, a large blackout occurred in the Ohio–New York area, putting 50 million people in the dark for seven-plus hours. When the event was analyzed, it was noted that operators had limited visibility of the system for situational awareness, and the analysis was exceedingly long and difficult because they lacked synchronized long-term recording, such as what phasor systems could provide. A project called the Eastern Interconnect Phasor Project (EIPP) was sponsored by the U.S. Department of Energy to introduce and acquaint EI utilities with phasor measurement and encourage them to develop their own systems.

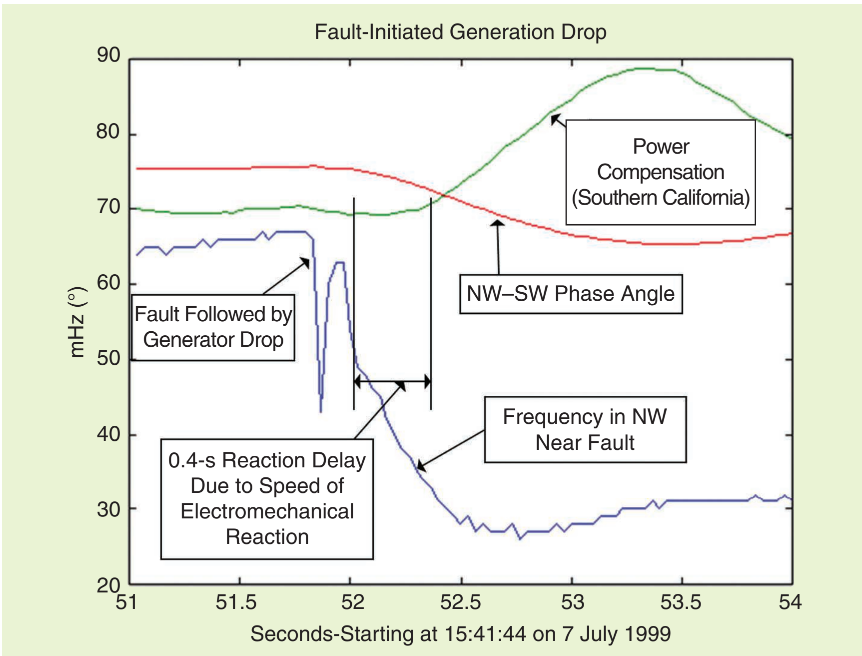

Figure 10. Synchrophasors capture the delay in system responses over a large area due to electromechanical wave propagation.

This helped educate and encourage this development, although actual deployments were slow. For most utilities, projects have to go through a cycle of perhaps three years to get anything going. Consequently, there was limited new deployment before the 2008 recession occurred. This event slowed many projects across the country.

However, in response to the recession, the U.S. government initiated programs to boost the economy. One of these, the American Reinvestment and Recovery Act (ARRA), made millions of dollars available for power system infrastructure development. A small part of the program included funding for the installation of PMUs, communications, and applications for data management and system monitoring. This resulted in a large boost of measurements and system coverage as well as the development and deployment of applications for using the data. It also supported more data exchange, such as a secure, redundant communication system built for data exchange among all utilities in the WECC. The EIPP transitioned into the North American SynchroPhasor Initiative (NASPI), which carried on the phasor system information sharing. NASPI tracked its development, including maps demonstrating system development in North America (Figure 11).

At this time, the drivers for phasor measurement systems became the system operators [e.g., the independent system operator (ISO), regional transmission organization, and so on] as they were the ones who had to deal with real-time situational awareness and also system planning. Since the transmission owners (TOs) actually installed and maintained equipment, the ISO had to arrange the PMU and communication installation through them. The first level of data gathering and system management was the TO. The data they gathered was then forwarded to the ISO, where it was combined with data from other TOs. This multilevel system required the development of advanced monitoring tools and better troubleshooting techniques to maintain reliable operation. There have been big improvements, and the data systems are working successfully, though data quality problems are still an issue today.

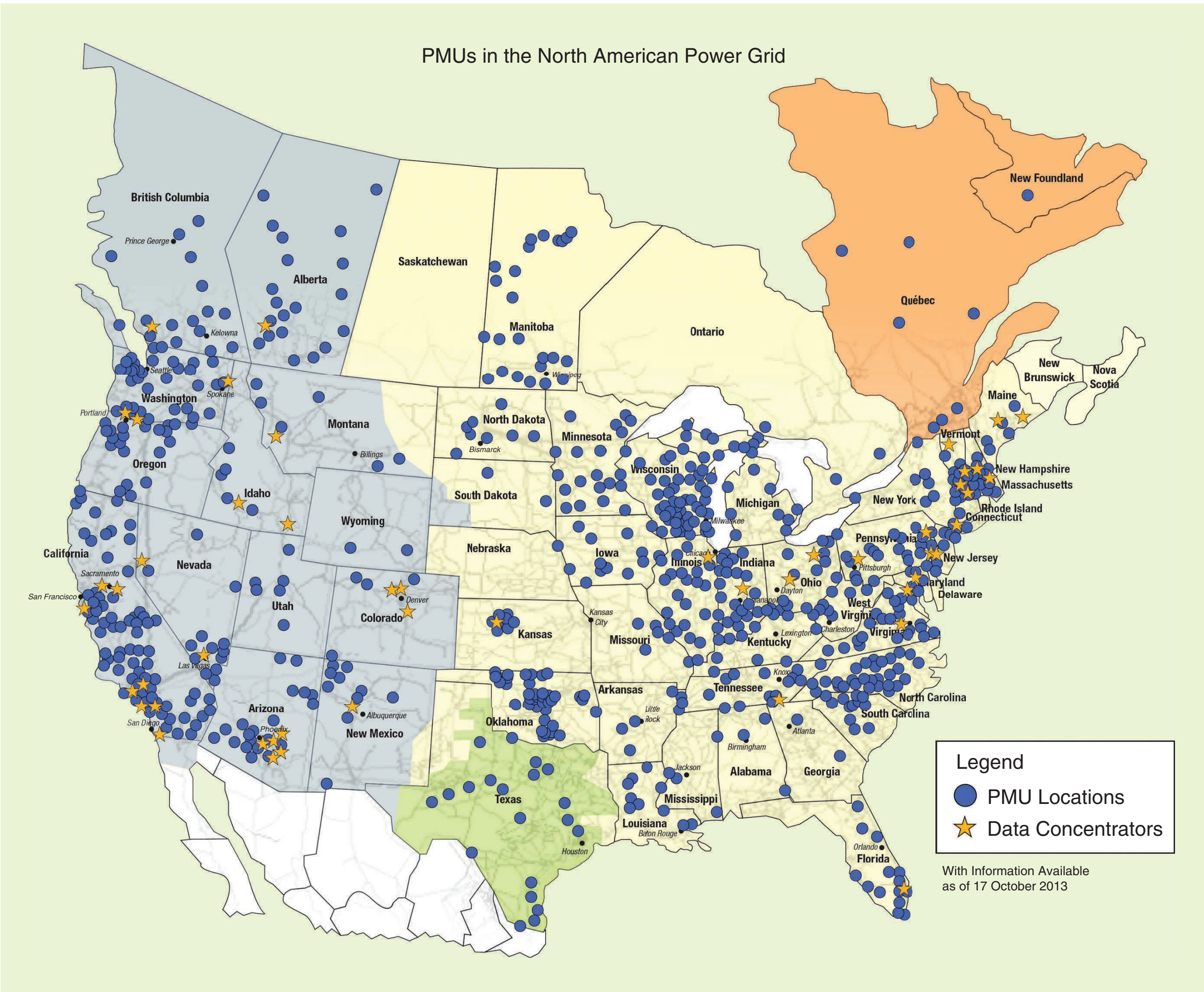

Figure 11. A map of the North American synchrophasor system deployments in 2013 after four years of ARRA support.

Synchrophasor Standards

The original phasor measurement was based on time-synchronized sampling and a recursive discrete Fourier transform estimation. It provided a phasor estimate synchronized to the nominal frequency reference (60 Hz in North America). The first IEEE standard, 1344, was based on this development and focused on the sampling rather than the estimated phasor. New hardware and estimation techniques did not consistently produce the same results, and there was a lot of vendor uncertainty about how to make the estimate. This, and the development of more comprehensive communication protocols in WECC, spurred the development of the second synchrophasor standard, IEEE C37.118-2005.

C37.118 presented formulas that defined the synchrophasor value. It set the reference time at the UTC second rollover. These specifications provided a common basis for all implementations. The standard also introduced the total vector error (TVE) method to evaluate the measurement. This method compares the PMU measurement with a theoretical value from the reference signal, both expressed in rectangular coordinates. The standard specified tests covering a range of amplitudes, phase angles, frequencies, and steady-state values. It also specified tests that assure the PMU can make a good measurement in the presence of interfering signals, including both harmonic and nonharmonic signals. This approach paved the way to assure that all PMUs would make comparable measurements under normal operating conditions. The reference (i.e., theoretical) synchrophasor value is calculated as

$$\mathbf{X} = \frac{X_m}{\sqrt{2}} e^{j\phi} = X_r + jX_i, \tag{1}$$

and the PMU measured value as

$$\mathbf{X}(t_0) = X_r(t_0) + jX_i(t_0), \tag{2}$$

where the TVE is calculated using

$$\mathrm{TVE} = \sqrt{\frac{(X_r(t_0) - X_r)^2 + (X_i(t_0) - X_i)^2}{X_r^2 + X_i^2}}. \tag{3}$$

On the communication side, the original 1344 protocol was rewritten using the elements developed in the WECC protocol, PDCstream. The new protocol specified messages and message content so that it could be used with any basic system, including RS232 serial, raw Ethernet, or Internet Protocol. The protocol allowed for the combining of data streams from several PMUs and sending them on to another location or application. Its simplicity and effectiveness have contributed to its use in synchrophasor systems worldwide.

These specifications provided a common basis for all implementations.

The main problems with the C37.118 standard were that it did not qualify PMU measurements under dynamic operating conditions, and it did not have any qualifications for the frequency and rate of change of frequency (ROCOF) measurements. Most users were concerned with using PMUs to capture dynamics. PMUs had proven to follow dynamics very well, but there were some differences among PMUs. And without a test, there was no real proof as to how accurately the dynamics are measured. While frequency measurement is not exactly a phasor value, it had been included with phasor systems since the start and was widely used. It had been shown that it did not always agree with the phasor values, so there was a strong reason to provide a definition and performance requirements to assure that it was an accurate and consistent measurement.

Concurrently, there was an interest in creating compatibility with International Electrotechnical Commission (IEC) standards as synchrophasors were increasing in worldwide deployment. To facilitate this, the C37.118 standard was split into a measurement standard, C37.118.1, and a communication standard, C37.118.2. This allowed for the independent development of these two aspects as well as compatibility with the IEC, which separates measurements and communications. The IEC developed a protocol upgrade (TR90-5) for the communication standard 61850 to handle the special aspects of synchrophasor data. The C37.118.2 standard had minor upgrades from the original to enable it to handle larger data sets yet maintain compatibility with the previous version.

The measurements underwent a major upgrade to account for dynamic signal changes. Complete definitions for phasor, frequency, and ROCOF values were created to define reference signals for testing. Three dynamic measurement tests were defined, and limits were specified. Limits for frequency and ROCOF were established for all of the phasor performance tests. This standard was completed in 2011 and then amended in 2014 to account for some measurement limitations.

In 2014, I convened a working group to establish a joint IEEE and IEC standard based on the just-completed C37.118.1 standard. This standard, IEC/IEEE 60255-118-1, was completed in 2018 and is the current standard covering synchrophasor measurements. It is essentially the same as C37.118.1, with some clarifications and extensions.

The Present Synchrophasor Outlook

Currently, there are synchrophasor measurement systems in every developed country worldwide. Some of these, such as the systems in India, China, Norway, Oman, and Brazil, are integrated nationwide and cover the whole country. Others are regional systems, such as the Electric Reliability Council of Texas; PJM; and the California ISO, which cover the entity area. Each of these systems covers a key area of a grid that enables visibility of the grid for operation and analysis. All of these systems include real-time data reporting to an operation center to support monitoring and control as well as system analysis. The benefits of phasor measurement systems like these include:

- operation analysis
- model validation
- situational awareness for operators
- alerts for problems
- regulatory standards compliance
- RAS and other advanced controls
- tools to support phasor measurement systems.

Currently, there are synchrophasor measurement systems in every developed country worldwide.

The most common and important uses are operation analysis and model validation. Since phasors capture system dynamic response so well, they provide essential details of the system events and system characterization. They provide detailed measurements of the system response to a wide range of phenomena. This has become increasingly important as power systems incorporate power electronics. Unlike more traditional rotor and iron core transformer-dominated electrical phenomena, newer system generation resources and controls use electronic controls. Grids are incorporating increasing numbers of renewables. Most renewables either produce dc power or convert their output to dc for inversion onto the ac power system. System ac is generated by an inverter with electronic controls.

Other system controllers, such as SVCs and TCSCs, use electronic controls. If the control is not properly matched to the system, it can become unstable and oscillate, potentially exciting an existing natural mode. These controls can create very high frequency reactions that are hard to detect with traditional measurements (Figure 12). They can also create very unusual interactions that are hard to resolve without comprehensive, long-term recordings taken over a wide area of the grid. Phasor measurement systems can provide that wide-area observability and detail with accurate time stamps to resolve system interactions.

System model accuracy has been a long-standing problem. After the 1965 blackout in New York, utilities began using models extensively to plan systems operation. The models were somewhat incomplete but provided a better tool to assure reliability than simple scheduling. As grids have grown and power transfers have become more regional, reliance on models has increased. However, limitations with accurate and detailed measurements to validate the model created some spectacular failures, such as the 1996 blackout in the WECC. Since then, increasing effort has been put into model validation. Phasor measurements have proven to be essential for this task. Models are built with the same frequency domain representation that phasors provide. Techniques have evolved where we can take operational phasor data and compare them to the model data for the same event and demonstrate that the model is correct or not. Using several events, we can apply techniques to update and correct the model (Figure 13).

Figure 12. Oscillation at about 4.3 Hz caused by unstable inverter control. The frequency is too high to be detected or analyzed by SCADA.

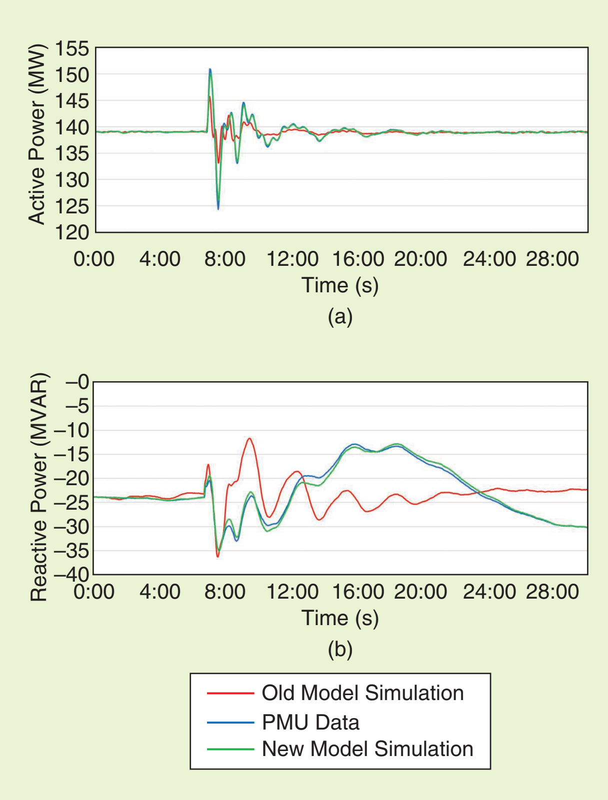

Figure 13. The model calibration showing generator (a) real and (b) reactive power reacting to an event. First, the recorded PMU data (blue) is compared with the simulation using the original model (red) and then compared with the updated model (green) after calibration. (Courtesy of Electric Power Group.)

Situational awareness became an important consideration after the 2003 blackout in the northeastern United States. In that incident, the utilities involved did not have the visibility to evaluate the overall situation that was evolving. It involved several utilities spread over a large area; customary procedures focused the operators' attention on the area that they control with little visibility outside of that area. Situational awareness should present information about the entire grid in which they operate to prevent surprises from outside of their control area. Phasor systems have evolved as wide-area systems since they look at the key grid parameters of voltage magnitude, angle, and frequency. Both utilities and commercial companies have developed displays and alarms for operators. These products started off with more traditional observations like voltage profiles and system phase angles and have evolved to include oscillation detection with source location, one line diagrams, and voltage stability sensitivity. Most use various color schemes and alarm limits to alert operators to potentially unstable situations (Figure 14).

Features have been added to take advantage of phasor capability. Phasors have proven the best way to detect oscillations. New techniques can locate the source of oscillations in real time and provide notification to operators so that they can resolve the problem. Phasors can provide input to real-time contingency analysis that can be used as validation or backup for a similar application supported by the energy management system (EMS). Phasors can also supply system phase angles that can be used to check that the angle across an area is within the allowable limits. This can provide a backup to the traditional monitoring of individual line power flows. These new applications complement the traditional EMS operation, give a wider area view, and provide independent backup.

Traditional power systems up to the 1980s were mostly vertically integrated with each utility, supplying their own generation and transmission to serve their own load. With deregulation and the growth of renewables, systems have become more diverse, interconnected over large areas, and dependent on a variety of resources for energy, some quite intermittent. Governmental regulation [under the North American Electric Reliability Corporation (NERC) in North America] has increased to manage this growth and tried to assure the reliability of supply. NERC regulations are focused on planning, operation, design, maintenance, and so on without citing a particular technology in most cases. However, there are 23 standards or regulations that can be addressed using phasor data since it has proven to be so accurate and comprehensive. In addition, another seven regulations call for measurements that phasor measurements can and do supply. In this way, NERC has recognized the important contribution that these measurements bring to the industry.

One of the earliest targets for phasor measurement systems was control systems, both medium speed, such as voltage control, and high speed, like RAS systems. So far, phasors have been used only in a few controls, and those have been operated intermittently. One of the first, though intended only as a demonstration project, was the EPRI-sponsored wide-area control for WECC in 1993. This project produced some valuable PMU deployments but no definitive control results. The North American blackouts in 1996

Figure 14. An operator display using phasor measurements showing phase angles on a geographic map, an alarm dashboard with a trend chart, and the system frequency, with both a current value and a historical chart. (Courtesy of Electric Power Group)

and 2003 also spurred deployments but no control applications. A few control applications have appeared that use phasors for control situations:

- The aforementioned 2004 WACS project at BPA used phasor measurements to detect swings on NW–SW intertie.
- An application in Mexico uses phase angle measurements to automatically adjust relay settings to account for the number of lines in service.
- An application in southern China uses phasor data to analyze oscillations caused by interactions between ac and dc links. It then uses the result to retune the controller to damp the oscillations.
- A team from Sandia National Labs, Montana Tech, and BPA completed a control that uses phasor measurements to modulate the dc intertie to damp out swings or oscillations. This direct feedback system has been tested and proven but is not likely to be placed in regular service until authorities believe it has the level of reliability expected for such a key system.

The main barrier to more control system deployment and use of phasor measurements has been data reliability. Phasor measurements depend on precise time, which is usually from a satellite system. Keeping these sources accurate and in service has been challenging. Phasors are used in wide-area applications and require reliable communication. These have also been difficult to maintain, particularly given the high data rates, large volume of data, and required wide-area security. These two problem areas have been the major sources of data unreliability. There have been additional problems with the measurement devices, data handling and storage systems, and other system elements, but no worse than with any other system.

To address these problems, tools for bad data detection and remediation are being developed and deployed. The simplest detection is an examination of the quality flags that the PMU generates, which include internal PMU errors and poor time quality. Another simple quality check looks for outliers in some signals, like a voltage that is three times normal or a frequency deviation of 10 Hz. More detailed checks get much more complicated. To combat missing data or inaccurate calibration, linear state estimation (LSE) is used. This applies the measured values to the system model and resolves the solution with a least squares estimate. This is like traditional state estimation except that it is linear (because phasors include angle), fast, and always solves. The LSE can improve on the measured values and extend the coverage. Unlike other techniques, it can provide improved or missing values based on the other values. More techniques are steadily being developed to detect data quality problems and deal with them once discovered. Creating and assuring good data quality is one of the most important issues for the future growth and application of phasor measurements.

Conclusion

Phasor measurements have contributed to the development and operation of power systems. They have improved our understanding of the system and helped engineers develop better models. As power systems evolve into larger grids with more elements and uncertainty, we need a better vision of the whole system and the dynamic interactions within the system. We require better visibility in real time to deal with emerging problems. Our society is increasingly dependent on the reliable energy that power systems provide, so our utilities need to keep developing the means to keep these systems operating reliably. Phasor measurements are one of the elements we need in the grids of the future to help ensure reliable operation.

For Further Reading

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Biography

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