Synchrophasors for Distribution Applications

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Abstract—**The changing nature of the distribution grid leads to new concerns in system operation. New resources connected at the distribution level, changing load characteristics, and increased reliability requirements all point to the need for improved monitoring and control capabilities. Many existing synchrophasor applications have been installed to address distribution concerns. These applications include islanding detection, voltage collapse avoidance, and improved understanding of distributed generation dynamic response. This paper discusses both existing and future applications for synchrophasor technology in distribution systems. Monitoring, control, and protection applications are considered, including visualization, component monitoring, and high-speed applications. Details of installation and communications requirements are provided along with practical bandwidth and data storage requirements to meet proposed North American Electric Reliability Corporation (NERC) requirements. The time-synchronized and streaming characteristics of synchrophasors provide new capabilities to address distribution concerns. An understanding of the capabilities and limitations of synchrophasors in distribution systems will help engineers make maximum use of this advanced technology.**

I. INTRODUCTION

Following the North American Northeast blackout in 2003, synchronized phasor measurements, or synchrophasors, were identified as a measurement tool that could have provided information to avoid the cascading blackout. The phase angle between Cleveland and Western Michigan (shown in Fig. 1) clearly illustrated the growing problem that led to the collapse.
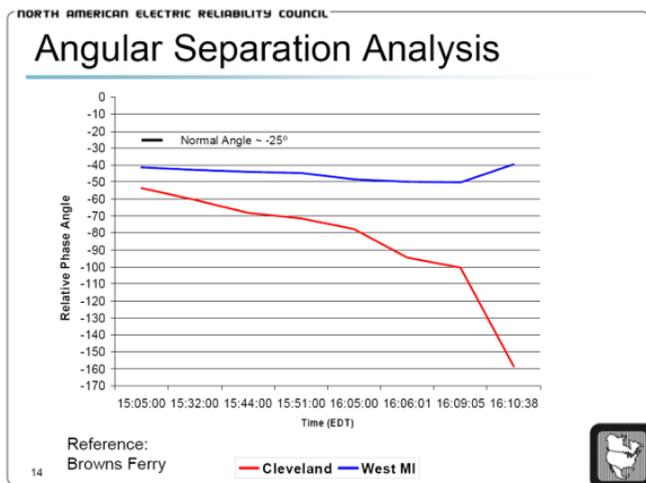
Fig. 1. System separation, August 2003 (figure courtesy of North American Electric Reliability Corporation [NERC]).

Because of this dramatic example of a synchrophasor application, many engineers in the power system field have assumed that transmission grid applications are the only use for this new technology. In order to understand the range of synchrophasor application possibilities, it is necessary to have some background information.

II. SYNCHROPHASOR BASICS

Synchrophasors provide the following three basic elements that traditional measurement methods do not:

- Data streams at rates from 1 to 60 messages per second.
- Synchronized measurements from all locations using high-accuracy timing.
- High-accuracy measurements of voltage, current, and digitals (status and alarms) [1].

The limits of synchrophasor applications are determined by how these characteristics can be used to solve power system problems. Because, by their nature, synchrophasors are focused on the fundamental frequency, they do not see harmonic problems. The frequency response of a typical phasor measurement unit (PMU) is shown in Fig. 2.
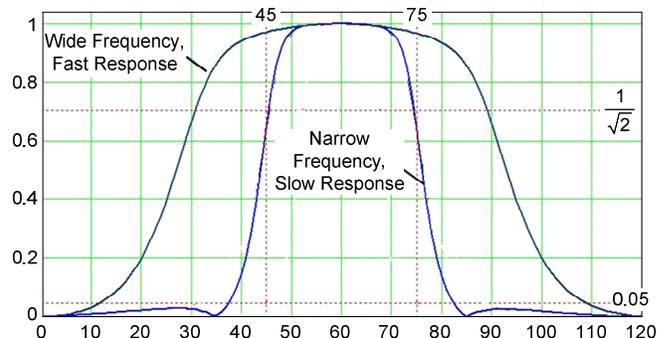
Fig. 2. Frequency response of PMU from dc to 10 Hz.

Per IEEE C37.118 [2], PMUs have an accuracy of better than 1 percent total vector error at 5 Hz from nominal. The narrow frequency, slow response characteristic shown in Fig. 2 complies with standard requirements for out-of-band rejection. As can also be seen from Fig. 2, the response is fairly flat out to 15 Hz from nominal, if the wide frequency, fast response filter is selected for the PMU. This characteristic will not have the same out-of-band rejection as the narrow response, but for many applications, it is quite suitable. The bandwidth around nominal defines the oscillation frequency that can be detected by the PMU. The wide response filter can see system oscillations of up to about 15 Hz, while the narrow response filter sees oscillations of up to about 10 Hz. The data reporting rate also impacts the oscillations that can be observed. For the applications in this paper, the Nyquist criterion is not critical. If we are sending data at 1 sample rate

per second, any oscillations above 0.5 Hz from nominal frequency may cause aliasing and therefore corrupt oscillation signals below 0.5 Hz from nominal frequency. However, for the distribution applications in this paper, such aliasing is not a problem because these applications are not based on finding small oscillations around nominal frequency.

III. DISTRIBUTION APPLICATIONS

From the previous discussion of the nature of synchrophasors, it can be seen that there is nothing inherent about them that restricts them from distribution systems. It has been stated that synchrophasors are a solution waiting for a problem. The truth is that synchrophasors are a tool that may or may not be appropriate to apply to many different problems that exist on power systems. In this section, we look at a few difficult problems faced by distribution systems that may be addressed by synchrophasor-based solutions.

A. Islanding Detection

The expansion of generation into the distribution system has had a specific impact on the ability to detect why a portion of the system is islanded. If a section of the distribution system is supported by a single feeder with a single circuit breaker, it is a very simple process to detect when the breaker is opened and then signal the generator to disconnect from the system. Consider a small distribution network that was configured to provide reliable service to critical loads, as shown in Fig. 3 [3].
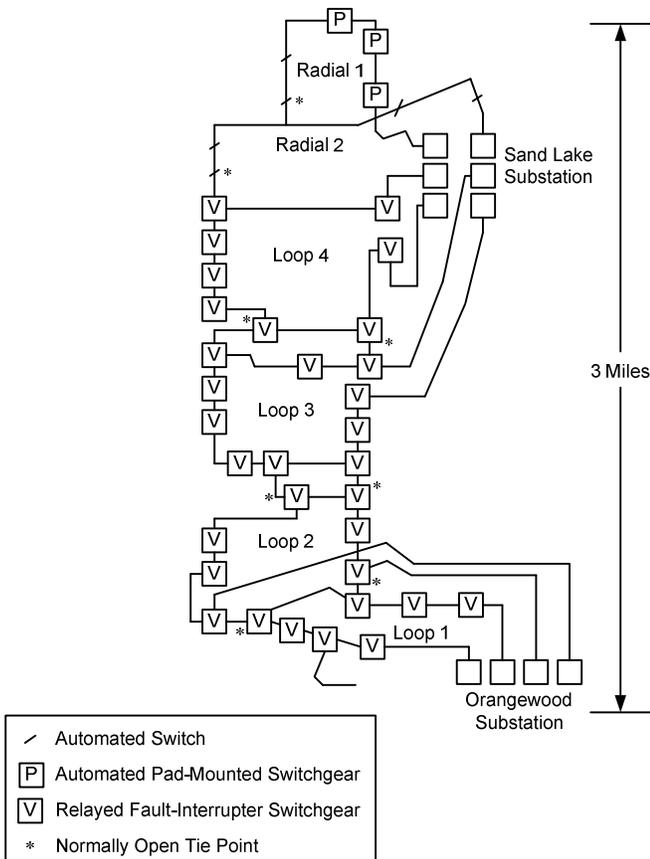
Fig. 3.   International Drive feeder diagram [3].

In a case such as this, it would be difficult to determine which combination of open breakers and switchgear would cause a generator out on the distribution system to be islanded with nearby connected loads. Wide-area communications, combined with PMU capability in relays, make it possible to provide islanding detection at any location with distributed generation at virtually no extra cost. In the example shown in Fig. 3, there is communication to all points and microprocessor-based relays. While the relays did not include PMU capabilities at the time of installation, they do now, in many relays at no extra cost.

IEEE 1547 requires distributed generation to disconnect for an islanding condition in 2 seconds or less, regardless of the load generation balance. Traditional local islanding detection schemes, usually based at the generator, include voltage or frequency measurements. More advanced, but still local, schemes depend on sudden phase shifts to detect the loss of remote connections. A modern system based on PMU measurements at both the generator and a remote station has been shown to not only be sensitive but fast enough to meet the requirements of IEEE 1547 [4]. Test results from this system are shown in Fig. 4.
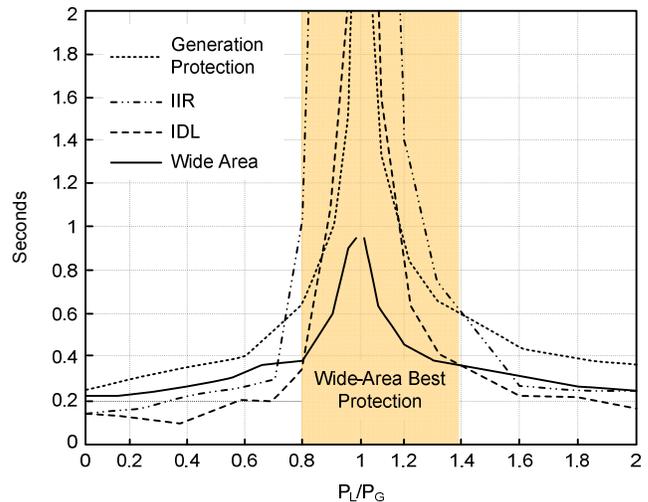
Fig. 4.   Islanding detection schemes, operate time versus load-to-generation ratio.

Note how generator protection, infinite impulse response (IIR, or phase shift), and local islanding detection logic (IDL) schemes all go to very long, or infinite, operate times as the load-to-generation ratio approaches 1. The wide-area scheme in this case used a combination of phase angle slip and acceleration between the generator location and the remote station location.

As was discussed in [4], an even better application than islanding detection would be to control conditions within the island to provide continuous power if the generator can serve the load. Synchrophasors can help here by improving generator control and then providing input to ongoing control of the island. For example, one process-sensitive installation with on-site generation is located in an area that experiences numerous power outages. In order to maintain the on-site

generation when the local area is islanded, the generator control must switch from power regulating to frequency regulating. This control switch must occur before the machine goes unstable, which requires high-speed control. A scheme similar to that described in [4] has been in service successfully for several years as part of a high-speed energy management system.

B. Phase Identification

As service quality becomes a more important issue to engineers and public service commissions, the simple matter of phase identification becomes more important than it was decades ago. With even a relatively simple distribution junction that looks like Fig. 5, it is clear that phase identification is not a trivial matter.

Fig. 5.   Dual feed and underground transition on distribution feeder.

Having improper phase identification causes problems with load balance, fault location and targeting, metering, and other reliability issues. As computerized fault location becomes more practical and with increased inputs from distributed intelligent electronic devices (IEDs), it becomes both more important and perhaps easier to provide phase identification.

With the increased availability of microprocessor-based smart controls and communications reaching down the entire length of distribution feeders, more single-phase control and monitoring are being utilized. Adaptive multiphase or single-phase tripping is now available from recloser controls. Proper phase commissioning is essential for correct operation of these reclosers. Additionally, information and control from microprocessor-based regulator and capacitor bank controls may be used in distribution management systems. Correct phase identification is of the utmost importance in these systems as well to ensure that the volt/VAR optimization scheme is operating with correct data. Finally, automated restoration schemes are being implemented where normally radial lines are momentarily tied together during throw-over operations. Tying systems together out of phase is damaging to the system, and while these schemes would be thoroughly commissioned up front, phase identification through a PMU system allows for easier initial commissioning and ongoing monitoring over time to detect potential problems following inadvertent changes to phasing on one of the feeders.

Along with distributed IEDs comes the opportunity to apply distributed synchrophasors for phase identification. Using a synchrophasor meter function, it is simple to either manually or automatically identify phases. Consider the synchrophasor meter response of two different locations, as shown in Fig. 6.

```
Synchrophasors
                 Phase Voltages
            VA           VB           VC
MAG (kV)    67.278       67.261       67.186
ANG (DEG)  −61.437      178.563       58.550

                 IW Phase Currents
            IA           IB           IC
MAG (A)   1978.296     2008.109     1991.966
ANG (DEG)  −63.508      176.186       56.690
```

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Synchrophasors
                 Phase Voltages
            VA           VB           VC
MAG (kV)    66.975       66.986       66.979
ANG (DEG)  −55.678       64.719     −175.508

                 IW Phase Currents
            IA           IB           IC
MAG (A)   2004.431     1997.885     1993.773
ANG (DEG)  117.671     −121.951       −1.792
```

Fig. 6.   Synchrophasor metering response from two different locations from the same time.

Note that the Phase A voltage angle differs between the two locations by about 6 degrees, a reasonable difference due to load flow. Phase B and Phase C, however, are different by about 114 and 126 degrees, respectively. This is a clear indication that what are labeled as Phase B and Phase C are reversed between the two locations. Of course, this could be an error in secondary wiring or in the primary circuit. A physical inspection can determine this. While this display is three phases, the same principle can be used for single-phase IEDs, such as a voltage regulator control. Distributed three-phase devices include recloser controls and capacitor bank controls. The low cost of satellite-synchronized clocks has made it reasonable to have synchrophasors at many distributed locations.

C. Load Characterization

The potential impact of electric vehicles on the power grid has been recognized by popular publications [5]. This

highlights the importance of gaining an increased understanding of distribution loads and how they are impacted by changing grid conditions. Not surprisingly, distributed PMU-capable IEDs provide the capability to better understand both the load and how local and system-wide conditions change that load.

PowerSouth Energy Cooperative initiated a project to collect synchronized data from voltage regulator controls. These controls provide timed events with power, voltage, current, frequency, and changes in power and reactive power on voltage steps. This has led to a massive amount of data in even the early stages of the study. Fig. 7 shows a graph of 18,000 data points of power versus feeder voltage.
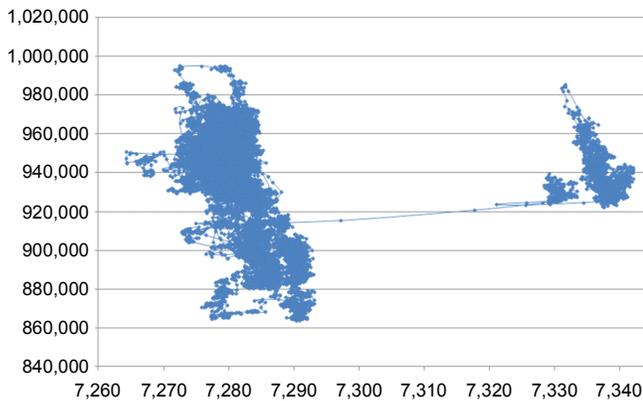
Fig. 7.   Power versus feeder voltage.

While 18,000 data points may seem like a lot, at 60 points per second, this is only 5 minutes of time. The utility went on

to use these types of data from individual feeder circuits to identify good candidates for conservation voltage reduction (CVR). Depending on the load characteristic, a change in voltage can result in a corresponding change in power demand. For CVR where peak management is desired, a CVR factor (ratio of demand reduction to voltage reduction) is calculated, with 1 being considered ideal. In this case, the steady stream of high-resolution data from the PMU function of the regulator control allowed for precision in calculating the power change occurring coincident with the tap changes. This is only one example of how these data can be used. Given that the data are synchronized, information from different feeders and aggregate values from the substation or region as a whole can be compared with confidence that they were taken at the same moment in time. Additional available data help improve the characterization of system load in order to assess the impact of CVR. As we look at the impact of changing loads, this becomes more important to determining what is needed to maintain distribution reliability.

D. System Monitoring

It has been demonstrated that PMUs placed at locations in the secondary system can detect both system conditions (such as low frequency oscillations) and local voltage transients (such as those caused by the cycling of process loads) [6]. While distribution-connected PMUs detect system phase shifts, frequency, and oscillations, transmission-connected PMUs do not detect localized disturbances. This can be illustrated by Fig. 8, which was an early synchrophasor PMU connected at an industrial location.

Fig. 8.   Industrial view of frequency event plus local pulsed load.

In the center of the display, we see a frequency drop caused by a loss of generation in the Pacific Northwest. The spikes on the trace were initially thought to be an aliasing error in the PMU. Further investigation determined that the spikes were caused by the regular pulsing of an industrial oven controlled by a thermocouple. In this case, the voltage variation caused by the pulsing load was not enough to cause power quality problems in either the industrial plant or its neighbors, but the clear visibility given by a PMU connected closer to the load than a transmission substation provides distribution engineers with an improved understanding of the dynamics of the connected loads.

IV. DATA STORAGE AND BANDWIDTH

The idea of improved visibility of system conditions is attractive, but the practical side of transmitting and storing the data needs to be considered. The IEEE C37.118 data format is efficient, but at rates of up to 60 messages per second (including voltage, current, frequency, phase angles, df/dt, analogs, digitals, and time stamps), this adds up to a lot of numbers. For example, a single PMU transmitting eight phasors, two analog values, and two digitals, all in floating-point numbers at 60 messages per second, requires 61.2 kbps on a serial port, 84.375 kbps in Transmission Control Protocol (TCP), and 78.75 kbps in User Datagram Protocol (UDP). This raises an immediate concern in that a typical PMU serial port is limited to 57.6 kbps, so an Ethernet port must be used. Changing to integer format from floating-point format brings us down to 37.2 kbps on a serial port, 65.625 kbps in TCP, and 60 kbps in UDP. Floating-point numbers are certainly easier to manipulate but may not be worth the bandwidth.

Now, let us consider ten PMUs (for ease of comparison) at the substation, with the same characteristics as listed in the integer case. If each of the ten PMUs has its own data stream, we will be looking at 650 kbps in TCP and 600 kbps in UDP. If we combine the PMUs in a local phasor data concentrator (PDC), we will have 260 kbps in TCP and 254 kbps in UDP. The local PDC eliminates duplicate time stamps and Ethernet overhead from each individual message. Additional savings can be realized by eliminating duplicate frequency and df/dt data points from devices that are always on the same bus.

Once the data arrive, the question becomes one of storage. The ten-PMU floating-point example requires about 177 MB per hour, 4.3 GB per day, 124 GB per month, and 1.5 TB per year. Again, we can save significant storage space by going to integer format, with storage requirements now at 94 MB per hour, 2.3 GB per day, 67 GB per month, and 810 GB per year. As in the PDC bandwidth requirements, we can save significant storage space by eliminating duplicate information of frequency, df/dt, and other data that would be presumed to be identical from different PMUs.

The real key is to look at how the data will be used, which determines the type of data (floating point or integer), amount of data (phasors, frequency, and so on), and data rate. If the application only needs 20 messages per second in integer format, we can reduce the bandwidth and data storage requirements by a factor of six compared with floating-point numbers at 60 messages per second. Because distribution applications open up the potential for data overflow, care should be taken in data definition and requirements.

V. CONCLUSION

As synchrophasors have been installed in transmission systems, applications have been found that benefit from the streaming, coherent data that become available. Similarly, in distribution systems, as synchrophasor-equipped devices become available in the substation, on the feeder, at voltage regulators, and at capacitor controls, applications become more obvious. Things to consider in the application of synchrophasor technology to distribution systems include the following:

- Advancements in IEDs increase the available locations of PMU technology. Locations out on the feeder (such as recloser controls, regulator controls, and capacitor controls) have PMU capabilities.
- Data rates of synchrophasor technology are an order of magnitude higher than traditional supervisory control and data acquisition (SCADA), providing improved visibility of more transient conditions.
- Applications should be matched to data rate and type in order to optimize communication.
- Existing and new applications for distribution synchrophasors will only grow with new IED capabilities.

An understanding of synchrophasor capabilities helps engineers apply this tool to existing problems. The present focus on smart grid technologies highlights the need to use the latest advancements to drive real improvements. Demonstrated capabilities in islanding detection, transient visualization, and load characterization will serve as a basis for growth into new applications and improvements in system reliability and efficiency.

VI. REFERENCES

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VII. BIOGRAPHIES

Greg Hataway received his B.S. in electrical engineering from the University of Alabama in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, Mr. Hataway served nearly 12 years at Alabama Electric Cooperative, where he worked in distribution, transmission, and substation protection before assuming the role of superintendent of technical services. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2002 as a field application engineer in the southeast region of the United States. After 8 years at SEL, Mr. Hataway rejoined PowerSouth Energy Cooperative in 2010 as a division engineer in power delivery. He has authored numerous technical papers and guides and is a member of the IEEE Power and Energy Society.

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Roy Moxley received his B.S. in electrical engineering from the University of Colorado. He worked for Schweitzer Engineering Laboratories, Inc. (SEL) from 2000 to 2012 as a marketing manager. He has authored and presented numerous papers at protective relay and utility conferences. Prior to joining SEL, he was with General Electric Company as a relay application engineer, transmission and distribution (T&D) field application engineer, and T&D account manager. He is a registered professional engineer in the state of Pennsylvania and a member of IEEE and CIGRE.