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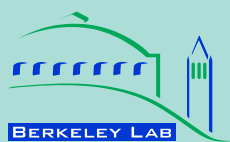
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Scoping Study on Research and Development Priorities for Distribution-System Phasor Measurement Units

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Abstract

This report addresses the potential use of phasor measurement units (PMUs) within electricity distribution systems, and was written to assess whether or not PMUs could provide significant benefit, at the national level. We analyze examples of present and emerging distribution-system issues related to reliability, integration of distributed energy resources, and the changing electrical characteristics of load. We find that PMUs offer important and irreplaceable advantages over present approaches. However, we also find that additional research and development for standards, testing and calibration, demonstration projects, and information sharing is needed to help industry capture these benefits.

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Acronyms and Abbreviations

AMI	advanced metering infrastructure
DER	distributed energy resources
DOE	United States Department of Energy
EPB	Electric Power Board (Chattanooga)
EV	electric vehicle
FIDVR	fault-induced delayed voltage recovery
GPS	global positioning system
Hz	Hertz
kb/s	kilobits per second
kV	kilovolts
MW	megawatt
MWh	megawatt-hour
NASPI	North American Synchrophasor Initiative
NIST	National Institute of Standards and Technology
PDC	phasor data concentrator
PMU	phasor measurement unit
PP&L	Pennsylvania Power and Light
PUD	public utilities district
PV	photovoltaic
R&D	research and development
rms	root mean square
SCADA	supervisory control and data acquisition
UPS	uninterruptible power supply
VHF	very high frequency

1. Introduction

Phasor measurement units (PMUs) provide precise, time-synchronized measurements of the electrical state of a power system. They are being deployed extensively within the high-voltage transmission and generation systems of the United States. Today, there are several thousand networked PMUs in operation across North America. The information provided by this new technology—particularly the wide-area view that phase angle observations provide—is revolutionizing the reliable operation of the nation’s high-voltage power systems.

PMUs can provide a wide-area view of the transmission system because the data they furnish is time-stamped with microsecond accuracy, and because the phase angle of the quantities being measured is included in the measurement. Phase angle allows an estimate to be made of the power flowing along a path without knowing exactly which circuits are carrying the power, and it can warn of overloads on a broader geographic scale than can be determined through traditional, more localized monitoring approaches.

PMUs are discovering unexpected behavior in some elements of the generation and transmission system—and confirming known but previously poorly observed behaviors. For example, generators have been observed with high-frequency oscillations that have not been seen previously, and wide-area oscillatory modes across transmission systems can now be measured with precision. These capabilities are the result of the high reporting rate for PMU data.

This report seeks to determine whether there are equally important roles for PMUs installed in the low-voltage distribution systems of the United States. Our viewpoint is from the national level, while recognizing that local factors will result in different local choices. Overall, we investigate the effect of such introduction on outages (which have financial costs both to customers and society much higher than the direct cost of unsold energy), on increased use of sustainable energy sources, and on the efficiency of energy delivery.

Within this framework, we approach the topic of adding PMUs to distribution systems by addressing the following sequence of questions:

1. How (and for what purposes) does monitoring presently take place in distribution systems?
2. Are present approaches to distribution system monitoring adequate?
3. If not, why not, and what role(s) might PMUs play in addressing present inadequacies?
4. Do PMUs represent a superior approach compared to other alternatives?

Today, there are no more than a small handful of PMUs installed in the distribution system to aid distribution operations. Therefore, a final question we address is:

5. What, if anything, should the U.S. Department of Energy (DOE) do to change the present state of affairs?

The remainder of this introduction focuses on addressing the first question: What are present practices for distribution system monitoring and how have they come about? We then provide a list of emerging challenges for today's practices. These challenges form a basis for assessing the value that installation of PMUs in distribution may have in the future. We close by providing background on the technical characteristics of PMU technologies. Section 2 examines a series of contemporary and emerging distribution system planning and operating topics that were suggested to us through our interviews and conversations with utilities. Thus, they are illustrative, not exhaustive of the range of topics PMUs in distribution might support. We explore these examples to address the second, third, and fourth questions: Why are PMUs needed? Section 3 provides additional information on deployment, communications, and information management topics common to the installation of PMUs in distribution systems. The final section of the report addresses the fifth question: What are the roles for DOE in supporting the deployment of PMU technology in the distribution system?

1.1. Present Distribution System Monitoring Practices

In comparison to the high-voltage generation and transmission system, there is little monitoring of distribution systems.¹ Understanding why this is so is fundamental to understanding why more advanced monitoring of distribution systems with PMUs might be warranted.

Distribution system monitoring practices reflect engineering judgments that balance the value provided by monitoring against the cost of monitoring. The differences in the purposes served by the transmission system, compared to the distribution system, clarify why these judgments have historically favored far more monitoring of transmission.

First, the topology of the transmission system is that of a network. Power can flow in either direction over a given transmission line. Monitoring is required to determine in which direction (and how much) power is flowing. Knowing the direction and magnitude of power flow is essential for managing the reliable and economic operation of the transmission system.

The topology of the distribution system is, for the most part, radial. Power flows in only one direction (i.e., from the transmission system to a customer). Monitoring is needed to know how much power is entering the distribution system. Less monitoring is needed for intermediate points within the distribution system because the flow of power is always in one direction. More monitoring is warranted for the portions of the distribution system that are networked, just as it is for transmission.

Second and more importantly, the amount—and hence the value of electricity transmitted over a unit (say, line-mile)—of transmission is vastly greater than that for electricity transmitted over a comparable unit of distribution. Higher value, with other things being equal, justifies higher expenditure (e.g., more monitoring), provided, of course, that monitoring is warranted.

The lower value associated with distribution assets (compared to transmission assets) has led to

¹ Some protection schemes capture fault events and voltage excursions.

mutually reinforcing design practices. For example, to reduce engineering costs, distribution system designs and implementation procedures are highly standardized. These practices introduce large design margins because obtaining more precise information (such as field measurements) that might lower them is costly. They are reinforced by economies of scale in equipment costs. This allows the designs to be replicated throughout a service territory with only minimal fine tuning. It also creates margin to accommodate load growth and pushes back the time when reinforcement may be required. Collectively, these practices greatly reduce the need for monitoring within the distribution system.

In another example, since power flows in only one direction radially, inexpensive protection systems such as fuses and non-directional overcurrent relays are routinely employed. Yet, as a result, a fault will typically interrupt service to all customers downstream of the fuse or circuit breaker. The speed with which power is restored depends on how rapidly the root cause and location of an interruption can be identified and remedied, or how quickly an alternate route can be found for the power. Because of the lack of significant distribution system monitoring, identifying the cause of a power interruption typically requires sending crews to inspect distribution lines in order to locate the problem. This means that some interruptions are lengthy. Here again, a trade-off against more distribution system monitoring has been made based on the cost of continuous monitoring compared to the cost of manual inspection, on an as-needed basis.

1.2. New Challenges Facing Distribution Systems

Distribution systems are facing new challenges that, among other factors, will encourage increased deployment of advanced technologies, including PMUs. They include:

1. *Customer requirements and expectations for electricity reliability are increasing.* It is well-understood that the economic value customers place on reliability far exceeds the cost of reliability (Sullivan, et al. 2015). Increasingly, utilities are taking these considerations into account formally in planning decisions. Improving the reliability of the distribution system, which is responsible for 90% of all customer power interruptions, will be a prime target for these efforts. Improved distribution system monitoring can detect and assess the extent of reliability events more accurately and rapidly than current methods, and can then be used to initiate and guide—and thereby accelerate—actions to restore service more quickly.
2. *More and more active power sources are being interconnected to distribution systems.* They include distributed generation (DG) or distributed energy resources (DER), such as combined heat and power (CHP), solar photovoltaics (PV), stationary energy storage systems (ESS), and, according to some, electric vehicles (EV). Although the impact of DER on the distribution system has been relatively minor to date, DER will be more important in the future and is already of growing importance and concern in Hawaii (Stewart 2012). Increased DER penetration affects distribution systems in at least three ways:
 - Power flows are no longer unidirectional; power might flow in either direction on the same line. This affects many aspects of planning and operations, in particular protection and voltage management practices.

- When large amounts of generation are being provided by DER, a sudden load disturbance can trigger protection schemes that cause the distributed generation to trip offline, making voltage and frequency control of the surrounding distribution and transmission systems more difficult.²
 - Distributed stationary (and mobile) energy storage adds unpredictability to the distribution system because of its charge and discharge profiles, which generally were not anticipated by the utility when the system was first planned.³
3. *The electrical behavior of loads is changing.* The leading example is fault-induced stalling by residential single-phase, induction motor-driven air conditioners. A more significant trend is increased adoption of power electronic–based conversion technologies in a wide variety of formerly direct-coupled motor-driven equipment (and other types of equipment). Power electronics make loads less dependent on system voltage and frequency, and introduce harmonics into the distribution system. The increase in harmonic content of load can affect the lifetime of distribution equipment such as transformers.

The use cases developed in Section 2 describe the ways that PMUs can help utilities address these challenges. However, before delving into them, we conclude this introduction with additional technical background on PMU technologies for readers not familiar with them.

1.3. Phasor Measurement Units: A New Generation of Grid Monitoring Technologies

The installation of PMUs on transmission systems was a major recommendation of the 2003 Northeastern U.S. blackout study (U.S.-Canada Power System Outage Task Force 2004). PMUs would have given system operators “big picture” information that could have helped them forestall that major cascading outage. Since 2003, new tools based on PMU data have been developed, enabling PMUs to have a major impact on system operations and reliability. Because PMUs can record more rapid changes in system parameters than was previously possible, they have identified previously undetected behaviors and enabled system operators to correct them. For example, small oscillations caused by control stability problems can be detected and fixed. Finally, PMU data can inform system planning and operations, improving modeling accuracy and thus system reliability.

The two key contributions of a PMU are speed and breadth. They measure much more rapidly than the

² An example of such a situation is in Germany where the high penetration of solar PV can, at times, provide more than 50% of generation (European Commission 2003). Despite smart inverters and communication deployment there is continued concern on the distribution system behavior. The revised IEEE 1547a seeks to address some of these challenges by developing ride through requirements for smart inverter technology. However, it will be some time before the IEEE standard is adopted and even more time before the voluntary practices it describes are fully embraced by industry.

³ Yet, local energy storage, including EVs, can also be a grid resource when the power system is stressed. EVs are a special case in part because they are mobile, so their availability varies much more than that of traditional, stationary storage.

previous generation of instruments and, in addition to measuring voltage or current (which can also be measured by simpler devices), a PMU also measures *voltage phase angle*, *frequency*, and *rate of change of frequency*. The speed and breadth of measurement improves model validation, and the two additional measurements offer important operational advantages.

Phase-angle information, which is not available without a PMU, makes it possible to close a switch reliably by determining whether the phase angles on either side of the switch are close enough to one another.⁴ Using this information, a local control scheme given a remote command to close a switch could override that command if the phase angles were determined to be too far apart. By only permitting the switch to reclose when phase angles are acceptably close to one another, the PMU increases the likelihood that the switch will remain reclosed.

Frequency information allows local generation to continue to operate as an electrical island even if its connection to the larger grid is broken. Information about system frequency is required for matching generation and load during islanded operation, and for reconnecting to the main grid.

Another feature of PMUs is time synchronization of measurements. Time synchronization enables aggregation and comparison of measurements from multiple sources and locations. It therefore allows for a wider-area view of the system, with simultaneous analysis of separated events that would not otherwise be relatable. It also allows coordination of overall grid operation. Without time synchronization, communication and equipment delays create uncertainty about measurements, making such coordination difficult.

In the following section of this report, we will describe how these unique features of PMUs can be used to address contemporary and emerging distribution system planning and operating topics.

⁴ Technically speaking, phase angle represents the shift in time associated with the starting point of a sinusoidal signal. A 90-degree phase angle implies the waveform starts a quarter cycle later than the reference sinusoid (e.g., a sine versus a cosine wave). In power systems, the phase-angle information between two points (phase-angle difference) provides information on potential current flow between those points. A small or zero phase angle indicates low or nonexistent current flow, which is ideal for closing switching devices reliably.

2. Potential Uses of PMUs on the Distribution System

This section presents a series of distribution system use cases. The use cases illustrate how PMUs can address the present and emerging distribution system challenges outlined in the introduction, and they seek to show how PMUs can address these challenges in better than available alternatives.

The five use cases described in this section are illustrative. They do not comprise an exhaustive list of all possible use cases, nor do they necessarily represent what we may eventually determine are the highest value applications for PMUs in distribution systems. Instead, they represent promising and unique applications of PMUs that have been suggested to us through our discussions with utilities. As such, they are an appropriate starting point for this study because they represent expressed areas of interest, at least for these utilities, rather than ones we might hypothesize. They are also appropriate because they are examples of use cases that can only be addressed fully with PMUs.

The first use case focuses on distribution system challenges that primarily affect the reliability of electricity delivery: system reconfiguration (Section 2.1). The next three focus on the increasing presence of DER within distribution systems: DER modeling and simulation for, among other things, interconnection planning (Section 2.2), voltage fluctuations and ride-through (Section 2.3), and islanded operation (Section 2.4). The final use case focuses on the changing electrical behavior of load: fault-induced delayed voltage recovery (Section 2.5).

Finally, Section 2.6 lists other use cases that may be appropriate for further discussion and development along with an indication as to whether, on a provisional basis, we believe they can be only addressed with PMUs.

2.1. Use Case #1: System Reconfiguration to Manage Power Restoration

The distribution system is often reconfigured to manage power restoration after a fault on the system.⁵ PMUs are needed to support these processes when the phase angles across reconfigured portions of the power system are so great that they must be taken into account.

To illustrate how reconfiguration works, we use a simplified example of a distribution network, shown in Figure 1. We show the primary feeders, at an assumed level of 13 kV, a representative value. At that voltage level, the primary feeders (connected to the substation busbars by circuit breakers), and laterals (connected to the primary feeders by fuses), follow the routes of the neighborhood streets. These circuits are radial (although in a typical suburban situation, the details of the circuit are often very complicated). Figure 1 is a simplified diagram of a suburban overhead network fed by one feeder from a substation. This network has roughly 100 customers. The black dots represent pole-top transformers, and the squares represent switching devices. The diagram does not distinguish among ordinary breakers, reclosers, and sectionalizing switches.

⁵ Reconfiguration is also used during normal operations, for example, to balance load through transfers of customers served from one feeder to another, managing voltage, or improving the efficiency of power delivery.

System reconfiguration could be used for restoration management following a fault on the distribution circuit. For example, in Figure 1, if a fault arises at the corner of Main and Banana Streets on a feeder from the Main Street substation, the protection scheme would normally trip the breaker at the substation. This action would disconnect all the customers on this feeder. This protection scheme, although it makes the system safe, is the reason that the distribution system is responsible for the majority of power interruptions to customers: a fault removes the entire feeder and all customers from service, not just those in the directly affected portion.⁶

However, an automation system could reconfigure power flow in this situation, reducing both the number of customers without power and the time during which many customers are disconnected. Opening the switch on Apple Street just south of Main Street would restore much of the system by closing the connection to Station Street. The sectionalizing switch on Main Street between Egg and Banana would have to be opened, and the fuse on Banana Street would likely blow, or, if that fuse failed to blow, the fuse on the interconnection between Chestnut and Banana would blow, disconnecting the customers on the Apple and Banana Street laterals. Although customers on some streets would be without power, some customers served by the Main Street substation would not experience a long outage.

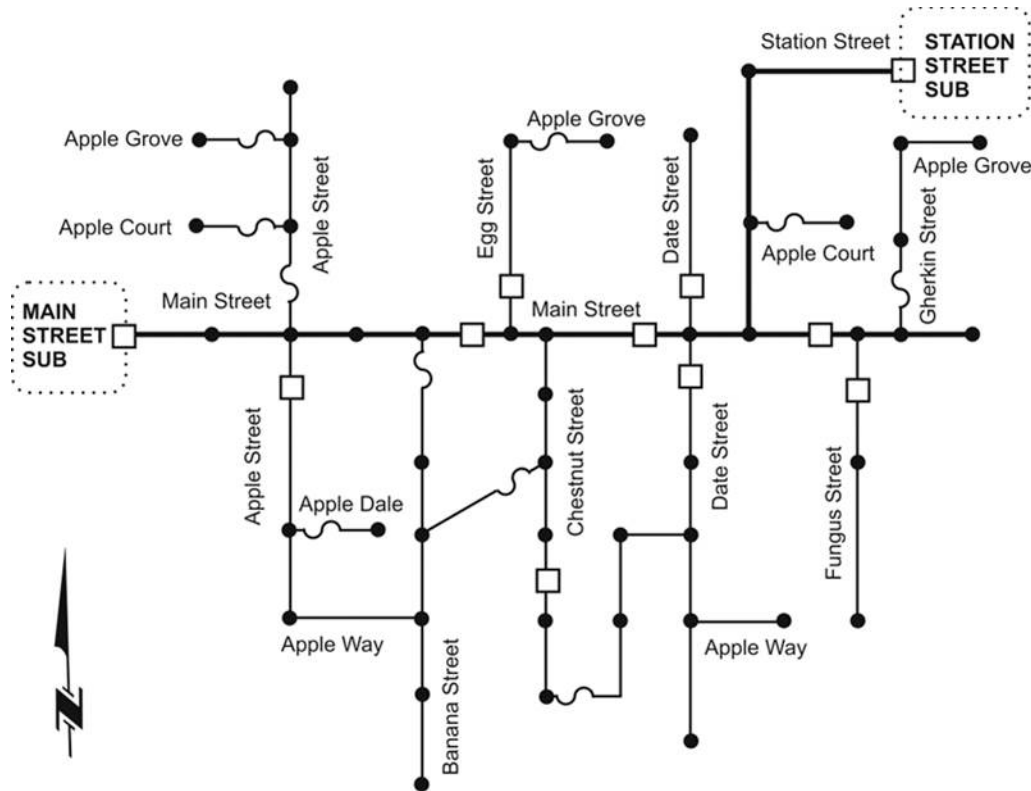


Figure 1. Example of an overhead distribution circuit, 13 kV

⁶ This aspect of distribution protection has driven the development of alternative schemes for protection. In these schemes, sectionalizing switches are used to reduce the amount of load disconnected.

With accurate, rapid reporting of the state of the system followed by rapid reconfiguration, the outage time for the fault could be reduced to minutes instead of hours. Engineers at Snohomish Public Utilities District (PUD) recently told the authors of this study that even partial automation was beneficial. Instead of completely automated switching, they used remote commanding by the system operator. Customer outage time was down to just five minutes for most common distribution faults. Traditional, manual restoration would require a crew to go out and do the switching, which would typically take at least an hour. This considerable improvement in the reliability of power delivery for most customers provides economic benefit to both the customer and the utility.

A similar situation was reported by the president and chief executive officer of the Chattanooga Electric Power Board (EPB), Harold DePriest, at the February 2015 Innovative Smart Grid Technology conference in Washington D.C. Following a heavy snowfall in 2014, effective restoration management reduced the number of customers without power from what would previously have been an estimated 76,000 to less than half that number. For some of these customers, outage time was reduced from eight days to three. The savings from this kind of application are sufficient to justify the reconfiguration infrastructure that EPB has installed.⁷ (Alabama Power and Snohomish PUD have also invested in system reconfiguration infrastructure based on the costs of un-served load.)⁸

Reconfiguration also can be used in less extreme events. For example, suppose one of two transformers in the Main Street substation fails and must be unloaded. The other transformer could pick up the load by switching in the substation, but it may be necessary to reduce total load on the substation to stay within the emergency rating of the good transformer. The utility has another option: closing the breaker on Station Street (at the top right of Figure 1) to create a parallel between the two substations.

The usual sequence would be to pick up the load at Main Street substation and measure to see whether the remaining transformer was overloaded. (Transformers are rated for short-term overloads.) If the transformer was overloaded, a decision would have to be made about paralleling substations or reducing load. Demand response (resetting thermostats, for example) could reduce load by a small amount but is not likely to help an overload situation. More likely, the choice would be between disconnecting a lateral or transferring load to Station Street. Because a transformer failure caused the problem and transformer replacement is a slow process, the solution must be long term. Therefore, disconnecting a lateral is not an attractive choice. System reconfiguration that transfers load to another substation is the only acceptable option. The transformer-failure scenario would conclude after the parallel had been accomplished. A sectionalizing switch on Main Street would be opened to complete the transfer of load over to the Station Street sub. The parallel operation is only temporary.

⁷ It should be pointed out that EPB also makes use of the sectionalizing switch technology mentioned earlier. The protective relays used have synchrophasor technology built in. EPB has been working with partners and Oak Ridge National Laboratory (ORNL) to use these measurements for monitoring and emerging applications in operations and control.

⁸ System reconfiguration infrastructure includes motorized switchgear and breakers which allow for manual or automatic sectionalizing of the distribution system. Automatic system reconfiguration is a function of distribution automation.

Another application of reconfiguration is to improve power delivery efficiency—a notion at least 30 years old. In 1984 and 1985, Pennsylvania Power and Light (PP&L) collected time-of-day load data at 15-minute intervals on six feeders in their Lehigh Division. Together with Westinghouse, they studied reconfiguration and found that losses could be reduced by 14%, mostly through the reduction of current through the distribution lines by moving loads to less heavily loaded portions of the feeder. When applied across the 26 feeders in the entire division, this could amount to an annual reduction of 2,500 megawatt-hours (MWh). Using these methods, PP&L was able to increase efficiency from 0.2%, to 98.95% (Lee and Brooks 1988).

This work suggests that, on a national scale, a significant amount of energy could be saved by system reconfiguration as part of normal operations. In the PP&L study, the improved efficiency was a result of daily reconfiguration, which requires automation (unlike seasonal reconfiguration, which could be done manually). The distribution system is designed to cope with peak loads, which occur during the day because of commercial and industrial usage. When the load is not at peak, the system can be reconfigured to be more efficient.

2.1.1. Existing state of the art and why automated system reconfiguration is rarely done

Automated system reconfiguration requires a data acquisition system that can deliver the required information to a control scheme. That system, in turn, must be able to send appropriate instructions back to remotely commanded switches. It must therefore include: a system of sensors; an “inbound” communication channel; a command system; an “outbound” communication system; and remotely operable switching devices. This combination is not currently widely in routine use.

In the hypothetical example above, and in the case of EPB, customer outage time was considerably reduced by automated reconfiguration. However, it is much more common for utilities to send crews to perform the necessary switching in an outage. Automated configuration is not typically done because of several factors: (1) the lack of monitoring (and thus information) about the state of equipment located between the substation and the customer, as discussed in the introduction to this report; (2) the specific lack of information about phase angle to enable transfer of load; and (3) delays in communication that prevent automatic control from operating.

The problem posed by lack of information about phase angle can be illustrated using one of the examples of reconfiguration above, in which restoration involved making a parallel between two substations. Before the substations could be paralleled, it would be necessary to know the phase angle across the open switching device. If the angle is too large (compared to an index established through planning studies), the closing of the switch would result in a large, damaging circulating current. If the substations are fed from the same high-voltage source, they are likely to be close in phase angle, but if they are fed from different sources, the phase angle could be large enough to be problematic.

In some (perhaps most) cases, the reliability of the incoming supply would be increased by arranging for an automatic transfer of load if one source is disconnected. Because a disconnection can happen at any time, a “parallel on the low side” would be checked in advance by measuring the voltage across the

breaker—which is not an easy thing to do. If permanent equipment is installed to make the measurement, it needs to perform the specialized function of measuring the voltage across (not on either side of) the breaker. Knowing the magnitude of the voltages on each side of the breaker does not solve the problem of phase angle. The root mean square (rms) voltage values could be identical, but there could still be an unacceptable difference in phase angles.

The problem of delays in communication preventing proper operation of distribution automation is illustrated in an example provided by the Snohomish PUD. Various environmental and other impacts cause significant bandwidth issues and latencies up to 30 seconds on this system. Snohomish PUD has attempted to alleviate latency issues by using adaptive technologies and polling-interval scenarios, but delays still occur. If a large latency occurred during a situation requiring rapid response (such as an automated load-shed or feeder-disconnect event), the reconfiguration could fail to take place in time—which could cause an even larger outage. As distribution automation increases, the physical limitations of the communications setup will have increasing impact.

2.1.2. How PMU technology can address the system reconfiguration problem

By giving a value for the voltages and measuring the phase angle of each relative to an internal reference, PMUs solve the problem of not knowing the phase angle. The difference between the two phase angles gives the value of the angle across the breaker. With a PMU making the voltage measurements, the automated system can decide quite accurately whether the circuits can be connected safely.

The problem of delay in moving information from the PMU to an application is outside the scope of the PMU *per se*. PMU data is timestamped, so applications that are not time-critical can always time-align the data. But time-critical applications such as reconfiguration would remain dependent on good communications, PMUs or not.

2.1.3. Alternatives to the PMU solution to system reconfiguration

Reconfiguration is possible without PMUs. That is, the distribution system can be reconfigured without phase angle information as long as system operators know that the primary-side phase angles were not changed when reclosing was needed, and that the reclosing angles are therefore acceptable. However, this manual action cannot be carried out with the speed and efficiency of an automated reconfiguration. Manual reconfiguration does not offer the same potential as automated reconfiguration to minimize the number of customers who lose power in a fault situation or to rapidly restore power.

In general, there are few circuit breakers in place to allow automatic reconfiguration in the distribution system. Most switching of this type is manual on the distribution system. To allow automation, breakers could be installed along with synch-check relays that would ensure the phase angle across each breaker was within acceptable limits before the breaker was closed. Modern numerical protective relays that perform synch-check (also identified as ANSI/IEEE protection device number 25), typically include

synchrophasor measurements as part of the numerical relay package. These protective relays, when necessary, are typically connected through communications to the substation through real-time automation controllers or communication SCADA hubs, which allow the measurements to be time synchronized through either a local or remote substation satellite clock.

2.1.4. Comparison of PMUs and alternate solutions to system reconfiguration

PMUs are the only technology that can provide the phase-angle measurement required for safe, automated system reconfiguration. Because the phase-angle calculation function would be one of several functions PMUs would perform, the implementation cost is likely to be less than the total cost of multiple, stand-alone measurement systems.

Just as with other measurement systems, PMUs depend on a reliable communications infrastructure to report its measurements. This communications cost and reliability level is one of the major issues with using PMUs outside of substations. See Section 3.2 for more information about communications infrastructure.

2.2. Use Case #2: Planning and Modeling Requirements Associated with High DER Penetration

The safe, reliable, and economic operation of distribution systems relies on planning studies. As noted in Section 1, historically, planning has been straightforward due to the one-way flow of power and the absence of active sources within distribution systems. Customer and utility adoption of DER within distribution systems renders these simplifications inappropriate. As a result, more detailed modeling and simulation must augment traditional planning practices. PMUs are an irreplaceable source of measured information that is needed to improve the calibration and validation of distribution planning models.

The amount of power provided by DER has been increasing since the Public Utilities Regulatory Policy Act of 1978 mandated that utilities accept power from qualifying facilities. As a result, DER's impact on the distribution grid has national relevance. DER is installed in sizes ranging from a few kilowatts (e.g., a rooftop PV array) to tens of megawatts (MW).

On the distribution system, the insertion of even just a few MW into a feeder by a DER installation may cause power flow to reverse direction locally. Wide-area feeder controls may be necessary to prevent overloading some feeders past their rating. In addition, the inverters at DER installations use proprietary controls that can behave quite differently than the models assumed in utility planning scenarios. Measured synchronized data on DER behavior on the distribution system could improve the accuracy of modeling.

In addition to DER interconnection, the distribution system is expected to cope with increasing levels of distribution automation, and more complex loads, such as combined heat and power. As these aspects of the system become more common, the degree of error introduced by inaccuracies in planning data is

likely to increase. Improving the accuracy of planning models would help enable effective and cost-effective distribution system management and reliability.

Improving the accuracy of models requires accurate measurement and characterization of several fundamental system features: impedance, load magnitude, and type and topology of distribution feeders. Two key areas in which modeling errors are especially prevalent are load estimation (both steady state and time series) and impedance of conductors on feeders. Further, these features are sensitive to time and seasonal temperature changes, so the models must be continually updated. Phase-angle measurements uniquely enable accurate characterization of the real and reactive portions of a load, line impedance, and overall power-flow behavior. This information could be used to construct and calibrate distribution-system models.

In summary, inaccuracy in distribution modeling results from:

1. The absence of appropriate observability into the system. Distribution grid response is therefore not observed as the number of DER increases, and loads change; and
2. The lack of measured data to calibrate or validate models' performance.

This lack of accurate information actually limits DER's deployment (Davis et al 2007). That is, limits on how much DER is interconnected are based on assumptions about how much DER can safely be hosted on a feeder. Those assumptions are conservative because of insufficient data and analysis of the actual behavior of DER on the grid. Without the explicit DER characteristics or how the grid responds during different levels of energy production, the planners must use "worst-case numbers" that may represent a much larger impact to the system than really occurs, which helps ensure any uncertainty is still within tolerable operating limits. The conservative approach avoids compromising distribution-grid safety and power quality and the potential for voltage violations and disruption of utility protection schemes.

2.2.1. Existing state of the art and why the necessary data collection is not currently done

The present state of the art in distribution planning is rudimentary compared to that for transmission. The process lacks the monitoring infrastructure, which is a given for transmission. In addition, the lack of standardized data formats means that even the data that are available are often difficult to use in planning studies (McMorran et al. 2012).

Distribution-planning models must be able to access both measured data and data from other simulation models. Measured data could be used to validate assumed load size and characteristics, which could then be used to improve the results of planning models. In practice, using measured data to improve planning model studies requires placing the data into standardized formats that are compatible with planning tools. To date, measured data sources available on the existing distribution grid include:

- Supervisory control and data acquisition (SCADA) data
- Distribution-line sensor data

- Smart metering and advanced metering infrastructure (AMI) data
- Weather data

Validation processes for distribution planning models have changed little for several decades. Engineers check the status of the distribution feeders in a particular area, utilizing either manual confirmation from field crews or, if available, local reporting measurement devices. Loads are verified against aggregate customer information and possibly historical measured data at the substation level. The validation process will generally be based on last best-known status, and this can be out of date or inaccurate. This basic process has been sufficient until now because the distribution system has been treated like a simple load rather than an actively managed resource on the grid.

Some utilities have conducted pilot studies to validate models with measured data. For example, Southern California Edison (SCE) collected data in order to validate load magnitude, performance, and conductor types/topology. SCE has also used measured data from substation meters, advanced metering infrastructure (smart meters), and distribution automation devices for model calibration. See SCE 2012 and SCE 2015.

At the Sacramento Municipal Utility District and Hawaiian Electric Company, aggregate performance of distributed PV is monitored at the substation level. The results are linked to irradiance data, but not at the level of individual interconnected PV sites. As a result, verification of PV performance, especially at the level of individual PV arrays, is incomplete. The information is of limited help in understanding the implications of larger deployments of distributed generation deployment (Ellis 2011, Bank 2013).

To validate impedance for the interconnection of larger distributed generation (>1 MW), utility planning engineers perform a number of steady-state, quasi-steady-state, fault-current, dynamic, and transient studies. Modeling errors can occur in each of these studies, and the impact of these errors can be significant. For example, an incorrect-impedance line model can erroneously predict voltage impacts such as voltage rise, load tap changer concerns, or power-quality issues. As a result of these predicted impacts, the interconnecting party may be requested to install mitigation solutions that are not actually needed and can be very expensive—such as energy storage or static reactive power compensation. Although these will arguably result in a more robust grid, they are costly to the DER operator and may be unnecessary. On the utility side, these modeling errors may lead to the changing of conductor types, which would also strengthen the network, but would create inefficiencies and increase capital costs to the utility.

Because of the distribution network's radial structure and historically unidirectional power flow, network behavior has been fairly predictable. Thus, relatively rudimentary model-validation procedures have been sufficient (Nguyen and Turitsyn 2015).

However, in the near future, the level of DER penetration (primarily PV) exceeds or is expected to exceed daytime minimum and eventually peak load. That is already the case in Hawaii and in some locales in California (Nakafuji et al. 2013). Depending on feeder type/topology, the tipping point for out-

of-acceptable-range behavior in a feeder has been estimated to be at 20–30% PV penetration (Stewart et al. 2013).

Previous model validation methods will not accurately capture this change in feeder behavior. Shortcomings that prevent contemporary model validation methods from accurately addressing the changing nature of the distribution grid include:

- The interactions of various proprietary DER with existing infrastructure are not well understood
- Circuit models contain inaccurate representations of physical infrastructure (e.g., impedances, three-phase imbalances)
- Load models are based on data that cover only long time-scales
- There is a lack of commercial software that integrates different functionalities for steady-state, dynamic, and transient analysis
- Information from different sources and tools often exists in incompatible formats

Lack of standardized models and measured data formats is a barrier to the integration of measured data in modeling. Work is currently being done to standardize customer, utility, and vendor data. However, these formats are not interoperable because each aims to meet a specific need for a specific category of stakeholder. An example of a standard format for distribution model data is the common information model or CIM (King 2008) which, although effective, has not been implemented by many distribution modeling tools (McMorran et al. 2012).

2.2.2. How PMU technology can contribute to a solution for DER interconnection planning and operations modeling

Research is already being conducted on the benefits of deploying PMUs at the distribution level (von Meier 2014). The ability to make high-speed measurements at the distribution level will improve power system planning and operational models, and will help address the challenges of planning for high penetration of DER.

PMU measurements enable the use of actual (rather than calculated) impedance, which will allow for more accurate DER interconnection studies. For example, knowledge of load variability over time is of critical importance for PV integration (Broderick et al. 2013). PMUs' time-synchronization of data allows for better understanding of impacts and correction of models for load behavior before and after interconnection.

Deployment of PMUs on the existing distribution grid could also facilitate a new level of communication and control, which would enable better utilization of distributed resources. There may also be an efficiency payoff: phase-angle measurements may provide a sort of backup feature for sensors installed to collect other data. It may be possible, as a side-effect, to detect conditions not yet measurable at the distribution level, such as transient and dynamic impacts of large volumes of PV and other complex loads.

2.2.3. Alternatives to the PMU solution for DER planning and operations modeling

Alternative solutions include better utilization of smart metering data, and measurements from individual inverters, line current sensors, etc. However, these solutions typically lack phase-angle information, are not accurately time-synchronized, and have low measurement reporting rates. These system attributes are needed to improve the accuracy of models and planning for DER interconnection and future distribution feeders.

2.2.4. Comparison of PMU and alternate solutions for DER planning and operations modeling

There are some inherent limitations and barriers to using smart metering and line sensors for validation of distribution planning. The data volume required for this application may exceed the communications capabilities provided, for example. The phase-angle measurement provided by PMUs provides a level of high-speed detail that traditional distribution-level measurement devices do not provide. PMUs could conceivably enable the use of fewer sensors. The PMU's phase-angle estimates across the distribution system are essential for complex impedance calculation and verification. Tracking this complex impedance, as well as the other quantities that PMUs measure, will provide a new level of detail.

Model validation using PMU measurements can enable more accurate estimation of voltage profiles and reverse power flows. The phase-angle information provided by PMUs also gives information on the direction in which power is flowing—valuable knowledge with increasing levels of interconnected DER. Specifically, high-precision PMU measurements can be used to validate assumptions regarding:

- The physical network
- Relationships among generation, loads, and voltage profiles on the feeder
- The time-varying behavior of DER in both steady state and non-steady state.

In addition, PMU measurements can provide monitoring as conditions evolve and deviate from planning assumptions. This monitoring capability gives planners the ability to fine-tune their models. The unprecedented visibility provided by PMUs—with temporal resolution much greater than was ever possible with SCADA—will provide valuable insight, especially as load becomes more complex and DER reach higher levels of penetration. PMU time synchronization has no equal for time-series estimation of performance and load behavior, as well as for the detection of topological changes and power-flow directions.

2.3. Use Case #3: Voltage Fluctuations and Low- and High-Voltage Ride-Through Associated with DER

Voltage fluctuations are sudden, noticeable changes in rms voltage level that can be caused by changing system loads—for example, voltage sag resulting from the starting of a large motor. DER (such as solar PV, wind, geothermal, and energy storage) connected to distribution-level feeders can lead to unpredictable variations in feeder node voltages, especially in weak residential and rural networks. These fluctuations can cause voltage instability and often require reactive compensation or energy-storage support (such as inverters in volt/Var control mode) to maintain a stable voltage profile. PMUs

are needed to monitor the actual performance of the distribution system, especially when DER penetration is high.

2.3.1. Existing state of the art in voltage fluctuation and ride-through management

Voltage stability is studied for a distribution feeder of concern on a per-interconnection basis. The studies identify any need for reactive compensation and coordination, inverter control algorithm adjustments and coordination, or energy storage. Voltage fluctuations are often addressed in off-line planning calculations.

Once DERs are interconnected to the distribution system, there is typically no follow-up monitoring; it is simply assumed that the planning and engineering study adequately addressed any future issues. If any post-interconnection monitoring is done, it is usually a post-mortem analysis following an unexpected event on the feeder. This post-mortem analysis is performed using available event snapshots captured by protective relays, digital fault recorders, and power-quality meters.

The requirements for fault ride-through for renewable energy sources have evolved during the past ten years. Today there is an emerging consensus that these sources should continue operating during system events to contribute to overall voltage stability. This capability helps maintain protection coordination and operation, and provides power within the mandatory voltage limits.

For low- and high-voltage ride-through, utilities can benefit from implementing inverter ride-through controls that can be managed remotely. Such a scheme could disable the ride-through or change specific protection set points when there is a significant transmission level event or when there is a protection communications failure. Discriminatory control can also disable ride-through functions for anticipated unbalanced or ground-type faults during major storm events. These faults could appear simply as a ramping load to DER power inverters. If the inverters perceive these conditions as ramping load, the result would be large, unbalanced current contributions to the power system.

2.3.2. How PMU technology can address voltage fluctuation and ride-through issues

Strategically placed PMUs can assess the actual operational conditions of interconnected DER. The monitoring data from these PMUs can be used to evaluate and validate assumptions made in the pre-interconnection engineering. The PMU data stream includes valuable information, such as:

- How distributed generation affects voltage levels:
 - at the main substation
 - on the feeder
 - at the end of the distribution line
- How fault current from the DER inverter affects:
 - the energy into a local fault
 - the phase and ground protection coordination across the feeder and at the substation

- How the substation voltage reacts to sudden switching on the distribution line:
 - during fault events,
 - during reconfiguration
 - during control operations on the feeder

PMU monitoring can identify ways to improve the interconnection process and pre-planning analyses, and it can prevent costly system issues related to voltage fluctuations from DER. PMUs can also ensure that the standards for high and low voltage limits are used to benefit the system, going beyond simply making sure the system stays within the guidelines.

As noted in Section 2.3, from the utility perspective little is known about inverters at PV and other DER plants, which operate using proprietary controls. Wide- and local-area PMU measurements can provide information on the aggregate characteristics of these devices when they ride-through faults. PMUs installed on the distribution grid could capture how grid operations change over time as more DER are added. This characterization can feed into future DER interconnection planning. (See Section 2.3 on DER planning.)

In addition, measurements from distribution PMUs can provide feedback information to improve smart inverter effectiveness in providing voltage support and power quality functions for the distribution grid. Examples of smart inverter functions that could benefit from PMU measurements include Volt/VAR control (Kempener et al. 2013), power factor correction (Liu and Overbye 2014, Peng et al. 2013), and real & reactive power support to local loads (Carnieletto et al. 2011).

In summary, PMU technology, when installed and configured appropriately, can monitor system conditions and use the results to assess the system state and predict future issues related to distributed generation. This approach can prevent problems before they happen and therefore, are an improvement over the present post-mortem and follow-up mitigation approach.

2.3.3. Alternatives to the PMU solution for voltage fluctuation and ride-through

The lengthy process of testing the behavior of DER under normal and faulted operations and inputting test results to utility planning and operations models is the only alternative to the rapid measured data that PMUs can provide.

2.3.4. Comparison of PMU and alternative solutions for voltage fluctuation and ride-through

PMUs can be used at all stages of the DER interconnection process: in the planning phase to get background data, during interconnection tests when inverter performance is validated, and in real-time operations across all seasons. PMU data is higher resolution than typical analog SCADA measurement, so it provides greater visibility of system conditions. PMUs can provide real-time data on both normal and abnormal operation conditions so that, over time, new engineering rules can be developed based on actual measured behavior of DER. In short, information collected by PMUs can create a knowledge base on which utilities can develop design and planning philosophies for interconnecting DER.

2.4. Use Case #4: Operation of Islanded Distribution Systems

Islanded operation refers to operation of a group of generation and load that is disconnected from the power grid. Islanding can be intentional or unintentional. A *microgrid* is a group of generation and load that is designed to operate as an island, and which can disconnect from the grid either intentionally or unintentionally.⁹ PMUs can play an irreplaceable role in helping microgrids manage frequency during islanded conditions. They can also support re-synchronization of islanded microgrids to the main grid in a manner similar to that discussed earlier under system reconfiguration (see Section 2.1).

Microgrids are sometimes built around self-contained distribution networks. For example, a facility requiring highly reliable power might operate uninterruptible power supplies (UPSs) and generators, which are synchronized and connected to the grid. If utility power were lost, those generators could pick up the uninterruptible load. The specific loads to be powered would be pre-planned, and all necessary communications and control equipment for this function would be installed in advance.

Our focus in this section is not on pre-planned microgrids, but on the potential for ad-hoc islanding. Some groups of load that are not pre-designed to operate as microgrids can be kept powered. The goal is to continue to operate these ad hoc islands to maintain power to as many customers as possible during the prolonged outage.

Although it is not possible to plan for all of the events that might create an electrical island, some preparation may be possible and can prevent power outages to subsets of customers. For example, in 2008, Hurricane Gustav caused several billions of dollars in losses because of damage and an estimated \$8-10 billion in lost oil production (Amadeo 2008). More than 4,000 transformers and 2,500 miles of power lines in Louisiana were damaged. Precautionary measures taken before the hurricane's landfall included placing some generators on "hot standby"—running, but not feeding the grid. As the storm moved inland and power lines tripped, alert operators saw the opportunity to maintain power to the New Orleans area as an island not connected to the rest of the grid. That island was sustained for 33 hours and eventually reconnected to the grid through the use of PMUs installed on the transmission system (Galvan et al. 2009).

Islanding is also possible on the distribution network (Osborn and Flerchinger 2011). The network shown in Figure 1, for example, could include candidates for islanded operation in case of a grid interruption. If that region has abundant renewable DER, such as multiple PV sources or small hydro generators, and the network disconnected on the high side of the substation, the DER might provide enough power to supply some (or all) of the local load. In that case, this network could become a functioning electrical island. Just as system reconfiguration is valuable because of the economics of unserved load (as described in Section 2.1), islanded operation is similarly valuable during a fault.

⁹ Other portions of the interconnected grid can be islanded but only unintentionally, usually, as a result of a grid fault or some other problem; these islands are ad-hoc assemblages of equipment that arise as a result of an unplanned sequence of events.

2.4.1. Existing state of the art and why islanding is not done

If a blackout occurs without warning, as most do, the control system can only create a functioning island if it knows how much load could be supported and if it has the information to balance load over time.

Information about how much load can be supported can be obtained in several ways. For example, in our hypothetical scenario using Figure 1 above, if the power is flowing *into* the substation along the Main Street feeder just before the blackout, it is fair to assume that there is enough power for the whole network. If not, the flow at various locations can be measured and a sustainable island created by operating the various controllable switching devices. Although the hardware and software to accomplish this are not installed in any distribution systems today, there is research on this practice.

At the distribution feeder-level, power quality requirements and the safety of utility repair personnel are both important. Most distributed generation, especially renewable generation, adheres to IEEE 1547 interconnection standards. In order to prevent a DG from powering up a line (and possibly electrocuting a repair crew), IEEE 1547 imposes strict disconnect requirements for all distributed generation devices. IEEE 1547 also specifies power quality requirements, but only for single devices. Coordination of multiple devices may be needed to properly mitigate power quality issues. Without observability into the distribution island, most distributed generation falls back to the conservative safe state of “disconnected,” to prevent any danger or possible liability to the operating utility. Islanding is thereby ruled out.

The value of having PMUs provide needed information is evident in the scenario that unfolded during Hurricane Gustav. No one could have predicted which transformers would fail and which lines would trip during Gustav, and the same applies on a smaller scale in distribution; it is not possible to say whether and where a tree might fall on a lateral. The information necessary to balance load over time was available to the operators of the New Orleans electrical island during Gustav, in part, because their transmission system had PMUs installed. As a result, those operators were able to rely on PMU data to manage the balancing act of load and generation for 33 hours until the city could be reconnected. If PMUs were installed in the distribution system, the same benefits would be available to distribution operators.

2.4.2. How PMU technology can address the islanding problem

The description in the previous section of the formation and maintenance of the New Orleans electrical island makes clear the role of PMU technology in enabling ad-hoc islanding on the distribution system. Once an island has been created, it is like a small version of the grid whose power must be controlled; voltage must be maintained at the proper values for the customers, and the frequency should be kept close to nominal. Hydro generators (even small ones) have inertia and therefore tend to respond slowly to changes in load. PV generation has no inertia and can respond rapidly. In either case, the frequency must be controlled. If both are present on the system and are the only sources of power, their outputs must be coordinated.

The PMU is one of very few devices that can measure frequency accurately and rapidly enough to perform control actions in the system. With PMUs installed to monitor and control the system state, it is possible to control enough generation and load to maintain a balance—if the appropriate communication and control infrastructure are present. On the transmission network, load changes tend to smooth out, and generation can be controlled relatively slowly. This is how large systems have balanced load and generation in the past. Without the smoothing effect of large numbers, a distribution system island would require rapid control—which PMUs enable.¹⁰

When power is restored on the main grid, the island controller would be responsible for reconnecting the island to the grid. That operation requires synchronizing—controlling the island frequency to bring the phase across an open switch to zero before closing the switch. As explained in more detail in Section 1.3, only a PMU can provide the phase-angle information required to reclose the switch reliably.

2.4.3. Alternatives to the PMU solution to the islanding problem

The manner in which PMUs measure frequency meets the requirement for rapid reporting defined in the standards. The PMU is in a class of instruments designed specifically for application in power systems; there are no alternatives with the same high-rate capability. Although, as mentioned above, a large island could be managed without benefit of PMUs, the distribution system does not have the inertia of a large system and therefore requires the high-speed measurements that PMUs can provide.

2.4.4. Comparison of PMU and alternate solutions to the islanding problem

The PMU is the only option for this application in the distribution system for the reasons explained in Section 2.2.3.

2.5. Use Case #5: Detection and Measurement of Fault-Induced Delayed Voltage Recovery (FIDVR)

Single-phase induction motors (such as those used in residential central air conditioning units) are now so numerous that they can delay voltage recovery after a fault. The sequence of events looks like this: a fault on the grid causes voltage to drop, which causes induction motors (primarily in air conditioners) to stall. When the fault is cleared, the stalled motors pull so much current from the power system that the distribution system voltage does not recover very quickly. Finally, the motors trip out because they are overheating, after which the voltage recovers. This sequence is known as fault-induced delayed voltage recovery (FIDVR) (NERC 2009, <http://fidvr.lbl.gov>). PMUs can play an irreplaceable role in providing monitored information rapidly to help diagnose and assess the risks posed by FIDVR.

It is not obvious whether the solution to FIDVR is a utility problem or a customer problem. On the customer’s side, the stalled motor eventually disconnects, but not before it has spent considerable time

¹⁰ In the Gustav island discussed earlier, “hunting” was observed from time to time, which is a kind of oscillation between independent control systems on the generator governors. There was no high-speed coordination between generators because no one had planned to operate the system islanded. PMUs allowed Entergy system operators to avoid hunting by using direct measurement of phase-angle differences to guide actions to re-interconnect to adjacent power systems.

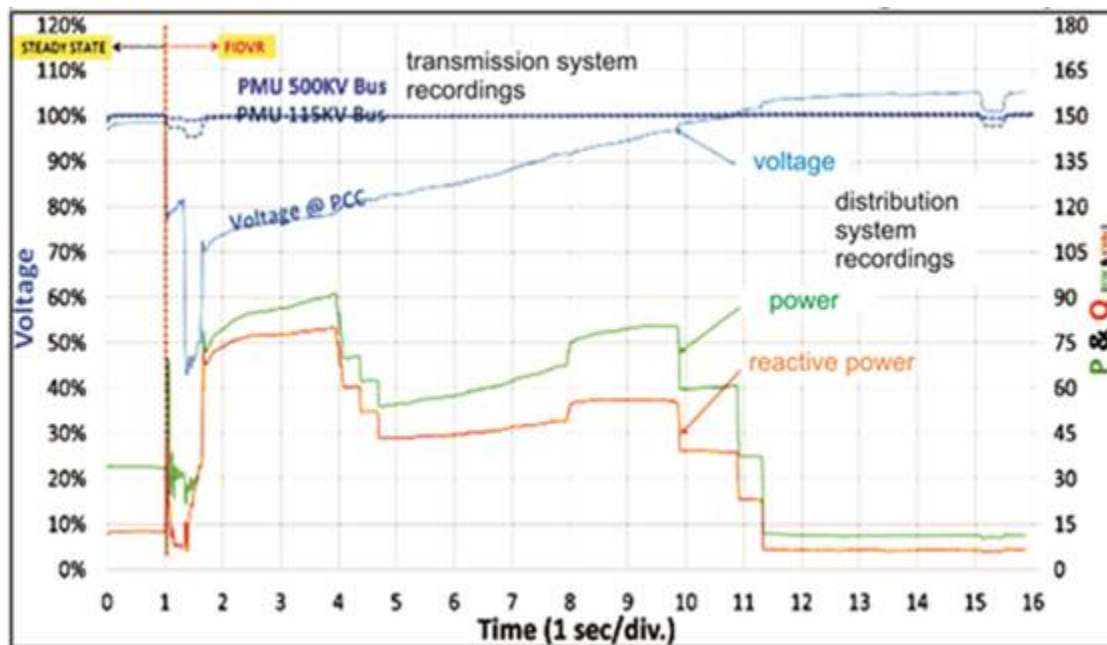
in an abnormal condition. Although the current flows and temperature effects of this abnormal operation could shorten motor life, there are date no reports of this to date.

On the utility side, FIDVR depresses the voltage for tens of seconds and, once the induction motors trip, often causes over-voltages on the system because FIDVR tends to be associated with periods of high load when voltage support capacitors are used. If the load is suddenly removed, the capacitors may create too much voltage support (NERC 2009, CERTS no date). Because these effects cause loss of supply or overvoltage to all customers, whether or not they have an air conditioner operating, the utility must take this problem seriously. Whether viewed as restoration management or overvoltage prevention, FIDVR is a problem worth solving.

2.5.1. Existing state of the art in FIDVR detection and remediation

The explanation of FIDVR above has been confirmed by measurements. Investigations using a distributed high-speed time-synchronized data-acquisition system confirmed the accuracy of the theory (Bravo et al. 2013). On a scale of seconds, the effect can be seen as a slow voltage recovery, as shown in Figure 2.

The measurements seen in Figure 2 are much faster than could have been obtained via a SCADA system, which is the traditional mainstay technology for data acquisition in utilities. SCADA systems typically gather data by polling every few seconds; because so much information is missed during the intervening seconds, no SCADA system had been able to confirm the explanation of FIDVR. The rapid measurement capability of PMUs is needed to obtain the data.



Source: Bravo et al. 2013

Figure 2. FIDVR event, rms results, scale of seconds

2.5.2. How PMU technology can address the problem of identifying and remediating FIDVR

The results shown in Figure 2 for the transmission system were obtained from PMU readings. However, because there are no PMUs on the distribution system, the results shown in Figure 2 for the distribution system were from another device called a PQube,¹¹ which was capable of recording sampled input signals (not just measurement results) rapidly and accurately with time stamps (though not as accurate as the GPS-based time stamps provided by PMUs).

The model for FIDVR was not confirmed for several years because, as discussed above, the distribution system contains little or no monitoring equipment. FIDVR was the subject of a special investigation before it was tracked down.

The PMU offers the rapid measurement and time sampling needed to identify FIDVR on the transmission system and could do the same on the distribution system. The role of PMUs (both in transmission and distribution) is to help validate the planning models that are used to study the consequences of and approaches for mitigation of FIDVR.

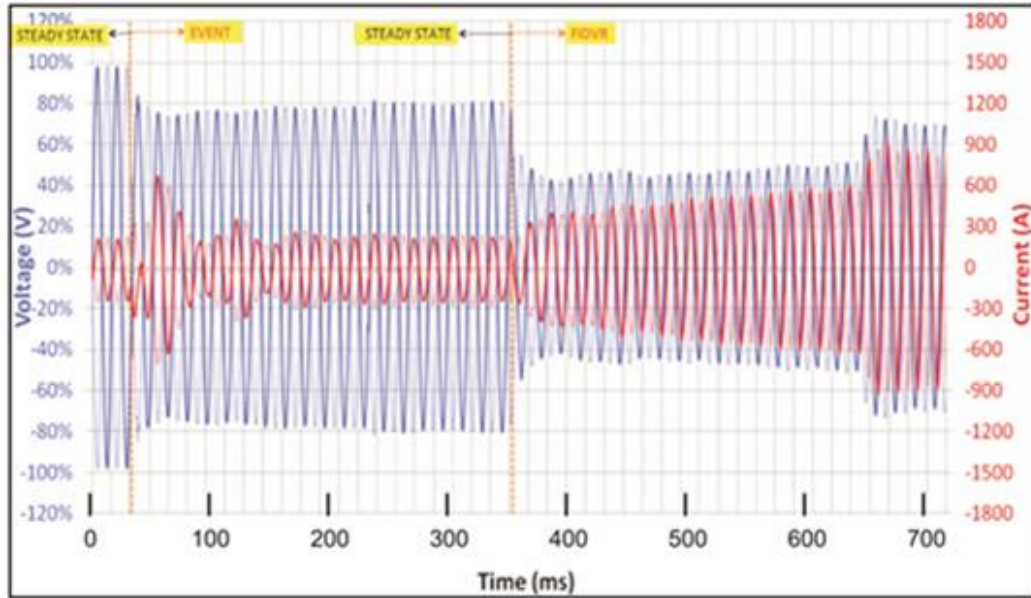
2.5.3. Alternatives to the PMU solution to identifying and remediating FIDVR

The PQube equipment used to obtain the distribution system data shown in Figure 2 could also be used to identify FIDVR on the distribution system; the results shown in Figure 3 were produced by a PQube. These data could be expanded¹² and the distortion of the waveforms seen more clearly.

The evidence that confirmed the FIDVR explanation came from a combination of high-speed sampling and measurement in both transmission and distribution. The PQube technology used to expose FIDVR on the distribution system is similar to PMU technology in that it can make rapid measurements. Distribution PMUs could arguably have done the job because measurements are time stamped. While a PMU would not have the bandwidth to recreate the detail of Figure 3, it would have enough speed to allow a signature of FIDVR to be recognized.

¹¹ PQubes are stand-alone monitoring devices that were deployed in the first-ever field measurements of FIDVR in distribution circuits. Unlike distribution PMUs, PQubes require that data be retrieved manually through periodic visits to each device. Moreover, PQubes do not communicate with GPS to ensure that time-stamps are synchronized with one another.

¹² Figure 2 was produced from the sequence of A/D sampled values stored in the device's memory. These 'point-on-wave' data allow the input waveform to be reconstructed.



Source: Bravo et al. 2013

Figure 3. FIDVR results, scale of milliseconds

2.5.4. Comparison of PMU and alternate solutions to identifying and remediating FIDVR

The PMU and the PQube are similar. Both have rapid time-synchronized measurements, and both could identify where the air conditioner motors are stalling. However, the PMU is the only one of the two that is designed to be connected to a communication system that maintains a data stream which is continuous, rather than event-triggered. Further, the PQubes used in the FIDVR work could not time synchronize their measurements, and therefore did not provide an opportunity for time-synchronization, which is possible with PMUs.

From the cost point of view, if a PMU is being installed, it would make sense to include an application that would enable operators to discover a FIDVR problem using the PMU data. Although FIDVR alone might not be a compelling reason to install PMUs on the distribution system, PMUs could detect and assist in the remediation schemes for FIDVR. The incremental cost of adding a small number of PMUs would be lower than the cost of installing separate systems just for monitoring FIDVR, and the added benefit would be a consistent data collection system across the power system.

2.6. Toward the development of future distribution PMU use cases

We envision a future involving highly automated distribution systems with PMUs installed. Such operation would be faster and lower cost than manned operation. Intelligent controls could significantly improve reliability and performance. PMUs at distribution substations, therefore, would support many aspects of distribution automation.

The use cases presented in this section were ones suggested to us by utilities with an active interest in installing PMUs in their distribution systems to address these issues. They are leading examples of

where we might expect PMUs to enter into applications in support of distribution system planning and operations. By the same token, there are many other use cases.

It is beyond the scope of this report to develop use cases for all potential applications of PMUs within distribution systems. Instead, for completeness, we simply list here the full range of use cases related to distribution that we believe warrant consideration. Notably, some of these use cases are ones that are not uniquely dependent on deployment of distribution PMUs; they may be supportable with other distribution monitoring technologies. The importance and priorities among these will differ among utilities. Viewed from the national level, the implementation of the collection of functions listed below would have significant benefit, either on a stand-alone basis or as complements to other deployed functions.

System Operation (normal)

1. Active management of distributed energy resources
2. Monitoring of the performance of the power system itself
3. Control of voltage in the power system
4. State estimation/power flow
5. Reconfiguration of the system for loss reduction or system management
6. Thermal and health monitoring of devices

System Operation (faulted)

7. Coordination with relaying (especially reverse power flow)
8. Detection of outages and location of faults (including high impedance)
9. Reconfiguration of the system following a fault
10. Islanding (microgrid) detection and operation
11. FIDVR detection and remediation
12. Oscillation (forced or resonant) detection

Diagnostics and Modeling, (non-real-time functions)

13. Power quality monitoring
14. Model parameter validation
15. Forensic analysis of events or abnormal system conditions

Planning (also off-line, but has a specific and narrow purpose)

16. balancing of loads for optimal system operation
17. collecting load data for system planning
18. analysis of dynamics (including state estimation)

3. Perspectives on PMU Installations and Communications Infrastructure

The subsections below offer our perspectives on a handful of infrastructure topics relevant to potential PMU installations on the distribution grid: the number of PMUs needed, the communications data rates required for PMUs to be effective, PMU communications architectures, and PMU data management. They are not intended to be definitive or prescriptive. Instead, they summarize observations and our current perspectives on cross-cutting issues that emerged through development of the use cases.

3.1. How many PMUs?

PMUs can be installed anywhere that a voltage or current measurement is needed. As illustrated in the use cases in Section 2, PMUs are of benefit in at least two locations: distribution substations and DER interconnections. How many PMUs are needed in those locations to enable the functions described in this study?

At a distribution substation, there are usually multiple transformers stepping the high voltage of the sub-transmission or transmission system down to the lower levels used in distribution. The possibility of system reconfiguration on the low side requires that the phase angle be known on both sides of any breaker that can close across two systems. Each side could use the capability of a PMU to act as a synchro-check. In combination with basic model information, a single PMU could estimate phase angle change across the network. Therefore, it is likely not necessary to put a PMU at every breaker that might be involved in reconfiguring the system. A substation PMU might not be able to accomplish all that is required throughout the network, however. Some power quality issues, for example, could be undetected at the substation.

Other locations where a PMU is essential for the applications we have described are large DER installations. DER larger than a specified size (which could be defined in relation to the local system) would be equipped with a PMU for all of the reasons discussed in Section 2.3. This would be similar to deployment of PMUs for cogeneration in the transmission system. A PMU on a DER installation could improve the chances for a successful ad-hoc island in case of a grid fault. Changes in interconnection regulations are anticipated to relax the requirement for a hair-trigger trip on DER, so there is an increasing likelihood that an ad-hoc island would be allowed. The example of Hurricane Gustav in Section 2.4 shows the value of having PMUs during ad-hoc island conditions. Further, as noted in Section 2.3.2, PMUs have the potential to enhance the functionality of smart inverters in providing power quality and voltage support services to the distribution grid.

The incremental hardware cost of the PMU is thus likely to be low (especially compared to the cost of a standalone PMU). For large DER, a requirement for PMU monitoring is easily justified. Some distribution utilities have very capable communication systems using advanced technology. Some have engaged in partnerships with DOE-sponsored smart-grid demonstration projects, and have built communication networks for automation and reliability. These utilities could easily support wide area PMU

deployment. The requirements of a PMU may nevertheless exceed the communications capability in many locations. It is therefore worthwhile to look at where improvement in the communication capability can be justified by the benefits of a PMU. We discuss PMU communications data rate requirements next in Section 3.2. Section 3.3 looks at Communication Architectures, and Section 3.4 deals with data management. The effort devoted to these infrastructure considerations may be crucial to the success of a PMU project.

In summary, a preliminary answer to the question of how many PMUs might be needed is that PMUs at each distribution substation, and at each interconnection of a sizable DER, would provide information of value.

3.2. PMU Communications Data Rates

A crucial element of the infrastructure to enable PMUs to perform the functions described in the use cases in Section 2 is a communications network. A PMU requires communications both to transmit its measurements and receive commands. As noted earlier, the volume of data produced by PMUs is on the order of 60 measurements per second of multiple parameters. The relevant standard (IEEE 2011) indicates a maximum bandwidth of less than 32 kilobits per second (kb/s) for a PMU delivering data for 12 phasors at 30 reports a second. If a utility that operated 50 substations, each with six PMUs operating at this rate (32 kb/s), decided to put all the data on one channel, the bandwidth would be just under 10 megabits (Mb/s).

In practice, bandwidth requirements depend on location. Power distribution lines are connected in topologies that look like the branches and twigs of a tree. A PMU installed at a tee-connection on a suburban feeder would require even less than the estimated 32 kb/s bandwidth. A substation with a dozen major feeders would require less than 1/3 of Mb/s. By today's bandwidth standards, all of these numbers are tiny. A home with a cable connection would typically have this amount of bandwidth to spare.

The above numbers are for inbound data (i.e., data collected by and transmitted from the PMU to the operations center). Outbound data (i.e., operational commands), would rarely be sent. The outbound channel would thus require thousands of times less bandwidth than the inbound. Avoiding delays in transmission would likely be a more important requirement than bandwidth. Independent inbound and outbound communications systems could be considered because of the different requirements of the two types of communications.

Currently, even these modest communications requirements are rarely met on the distribution system. Most utilities that have automatic metering infrastructure use very high frequency (VHF) radio to reach the meters. The bandwidth of the systems selected meets the requirements of the metering system, but is inadequate to support a PMU system. Cell phone technology could meet the need, but might be considered too costly, and a standard quality of service may not be reliable enough—especially for applications that are aimed at improving power system availability. Existing Ethernet communications

to the substation may also be used, but few utilities have this capability. As demonstrated by the Chattanooga EBP and Snohomish PUD systems mentioned in Section 2.1, fiber optics can meet PMU bandwidth requirements. In Snohomish, a fiber system connects the substation to the control room. In Chattanooga, the connection extends all the way to the customer. Chattanooga also uses the fiber to provide internet services. However, utility fiber optic applications such as these are not currently common, likely because of their cost.

Past implementations would affect the timing of PMU introduction. At Snohomish PUD, for example, the control system was expanded from the center outward, so Snohomish substations have communications capability adequate to handle the data flow from PMUs. The same is true in the EPB territory. However, other utilities are expanding their smart grid capability from the outside in (for example, using an AMI system) and do not have the system for communication to substations that would be required for PMUs.

Large DER might not have adequate communications initially but might be close to a suitable system onto which it can piggyback. In locations where direct transfer trip is specified for protection, fiber optic communication is also normally specified to ensure communication with the utility. Many homes have excellent internet connectivity, for example. For such locations, adding a connection to a PMU might be possible.¹³

Early distribution automation schemes attempted to use multiple communications technologies, usually a separate one for every application. These included customer telephones, whose bandwidth was low. In addition, the customer had priority for use of the line, which was not always convenient for the utility. Power line carrier was also used, which had the advantage of being utility controlled, and went everywhere the power system went. But it suffered poor signal-to-noise ratio, which resulted in a maximum data rate of just a few bits per second—even worse than what was possible using telephones. In addition, the signal was often attenuated at transformers and splices. (Blair and Rhyne 1982, Russell 1980, Weers and Shamsedin 1987).

In contrast to these earlier schemes, some of which are still in use today, contemporary technology can build the communications necessary for PMUs.

Ideally, a traffic study would be conducted to evaluate communications requirements; such a study collects the volume and path of data, the acceptable delay, the error rate, and various other characteristics. For example, the system protocols would need to know whether the data is “bursty,” whether the volume of data between two points exhibits symmetry, and the nature of the channel noise. From this collected information, an appropriate communication scheme can be selected (or, rarely, designed). Such studies are rarely done on the distribution system because of cost. However, the benefits of PMU use could justify the cost of improving the communications infrastructure.

¹³ The reliability of the communications channel would also have to be taken into account. If the data were important in emergency conditions, or in applications that need high reliability data for control (such as microgrid control) some augmentation of service must be considered.

3.3. PMU Communication Architectures

The communication system whose design process was outlined above was somewhat idealized, but the notion of “design to requirements” should be taken seriously. For example, many existing transmission systems access PMU data by sending it from the PMU device to aggregation points called phasor data concentrators (PDCs). It should not be taken as a given that this is appropriate for the distribution system.

There have been discussions on the challenges with the setup on the transmission system in many professional working group meetings (e.g., the North American Synchrophasor Initiative (NASPI) and the Western Electricity Coordinating Council’s Joint Synchronized Information Subcommittee (WECC JSIS)). This uncertainty in the transmission implementation suggest that the distribution PMU communication system design should be considered early in the development process, especially since it will have different requirements than in transmission. That justifies the idealized process outlined above.

What differences might exist between transmission and distribution solutions? We speculate that the challenges of distribution system operations may not fit the existing transmission system architecture well. The “bottom-up aggregation” of the transmission PMU-PDC model works for centralized control (and hence data collection) schemes, whereas distribution PMUs may be used in more dispersed control and monitoring methods. What blend of methods/approaches would be most appropriate would come out of the traffic study mentioned above. For example, *ad-hoc* islanding seems somewhat incompatible with central control, and peer-to-peer communications by PMUs located at distribution substations seems to be a more robust approach. It is also highly likely that system reconfiguration in general would be more efficiently served by peer-to-peer links than centralized.

During system design, thought must be given to overall data structure and handling. An open-source platform is an approach that might help ensure that different application requirements are all served. The overall solution must ensure interoperability between different distribution PMUs and their data sets. Individual elements can be implemented in an open source manner, similar to the Grid Protection Alliance’s openPDC concepts on the transmission level. Insufficient detail exists at the moment for us to promote any particular solution in this report. However, it is a topic for investigation as distribution PMUs are considered further.

3.4. PMU Data Management Handling

This report has so far investigated use cases for distribution PMUs that mostly address local situations, and which are largely concerned with system operation. But uses such as system planning require access to the data generated by the PMUs, albeit not necessarily in real-time.

Data from the distribution system should be regarded as a resource for the utility’s future. We have already noted that planners and analysts in the utility can use the collected information to update models; they may go on to mine it in ways not presently anticipated. In this section, we will discuss how

this might come about, to give the reader a more complete picture. It is not that we are trying to present a one-size-fits-all solution—rather that we discuss aspects of the situation that should be included.

It seems obvious that the data will be most useful if it is widely available in the utility. Very likely, the data will have to be kept from public access, however, because of privacy issues. A system allowing local control and central data collection could be planned to permit the various participants to access the data as needed.

Figure 4 shows a scheme that would allow data to be archived for use by planners and modelers at the utility, and allow tests (such as for model validation) to be done in a coordinated fashion. Involvement in the PMU-monitored distribution system by investigators other than the utility that owned the system would also be allowed.

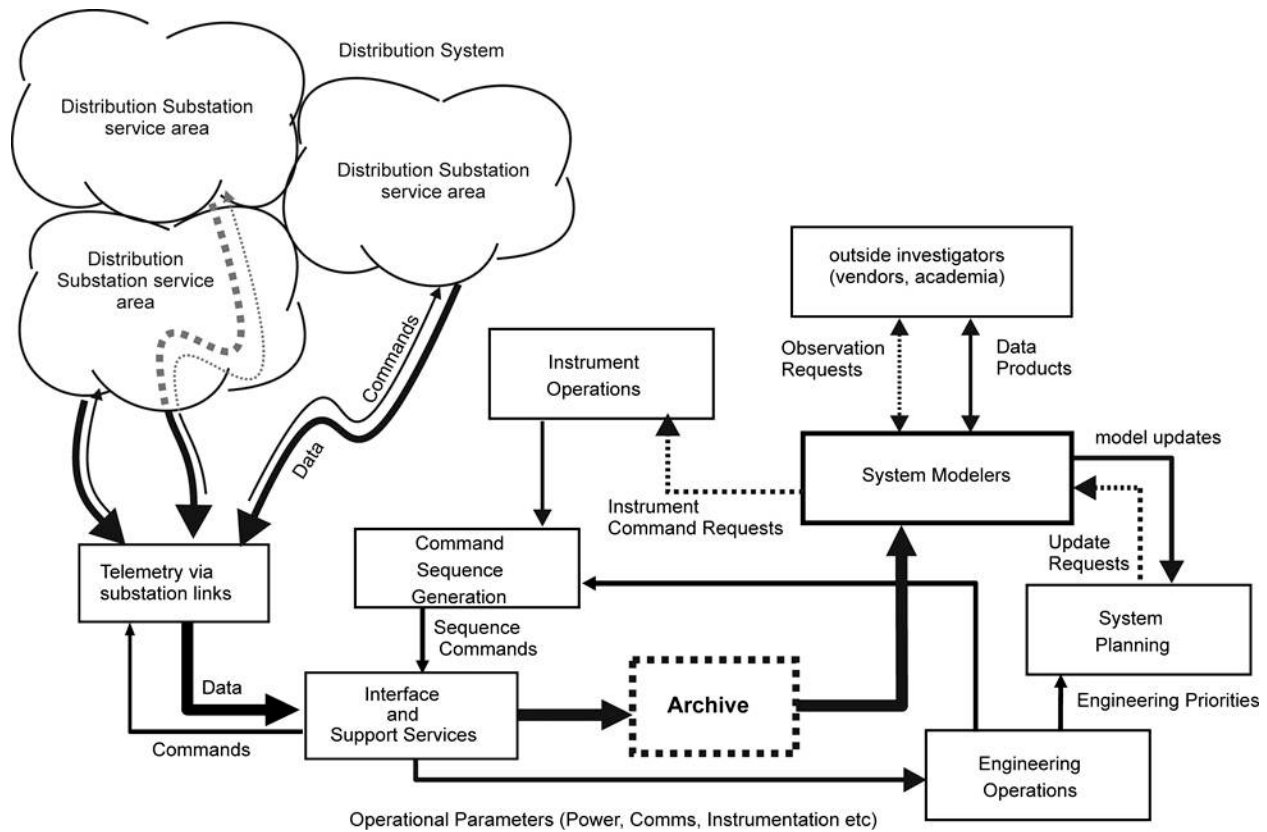


Figure 4. PMU Data Acquisition scheme for multiple investigators

The archived data is shown as primarily available to the system modelers, but there are many others involved. Indeed, the apparent complexity of the method of Figure 4 stems from the need to accommodate multiple users, and is not unusual in terms of how data is handled at an archive. Since the needs of the various investigators may not be aligned (and could even be in conflict—for example, a command to turn a device off must not interfere with some other user who needs it on), some method

of resolution is needed. This resolution is done in the block called Command Sequence Generation. To make best use of the capability, Engineering Operations and the System Planning groups are involved, and outsiders are allowed some access.

The data returned by the PMUs and other instruments is shown in Figure 4 as going to an archive. It is important to acknowledge that the archive is not simply a big bucket of information, and that the process of data acquisition is not simply a matter of pouring bits into the bucket. Some possibilities for the archive are shown in Figure 5. It shows an expanded version of the process of getting information from the real world into an archive.

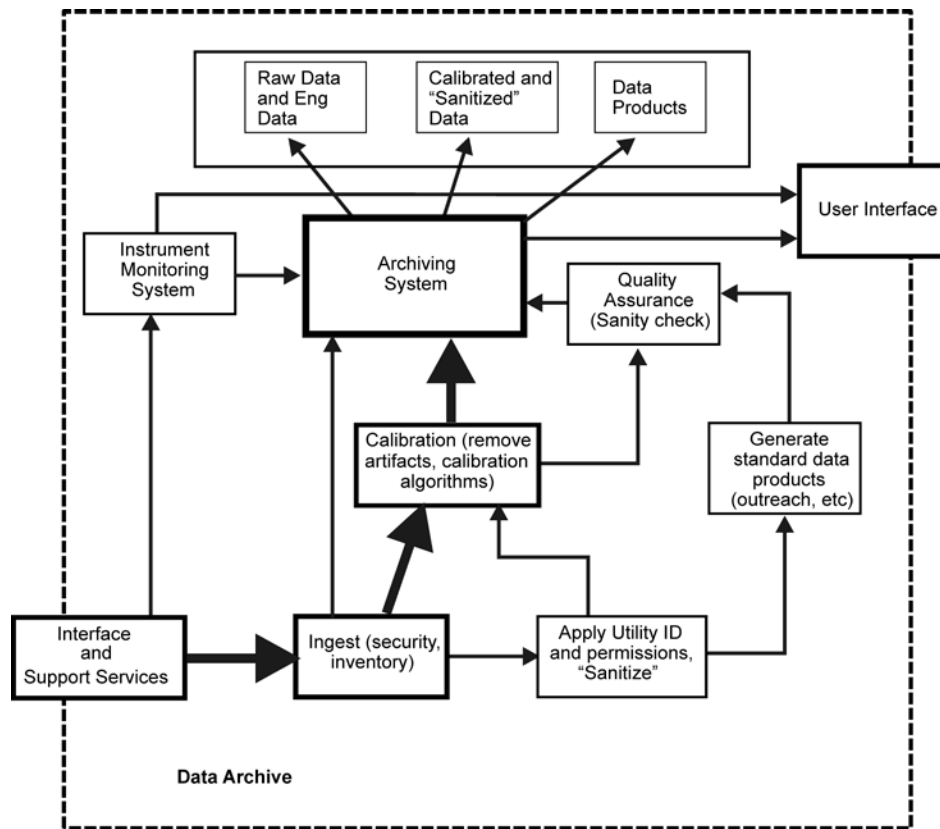


Figure 5. Data archiving

The data are assumed to be returned from the utility power system via the distribution substations, and data are then sent to the archive system shown. On arrival, the first thing¹⁴ that happens is a process called “ingestion.” Here, the incoming data is checked for security, checked to see whether it is new (some communication protocols allow multiple copies of packets), and checked for completeness.

Most of the data (perhaps all) then goes to the calibration module, where calibration metadata is used

¹⁴ Well, almost. Some of the data may be siphoned off and sent to an instrument monitoring system designed to check on the PMU system itself. It may be that this function could help reveal unreliable hardware, for example, before an investigator found a problem in the archived data.

to “clean up” the information. From there, the archiving system stores the results in the actual archive. Other processes are used to sanitize data (typically, this will be important to protect the privacy of customers) and to apply permission information. The generation of certain standard data products may be automated, say, for outreach purposes.

User access to the information is also shown in Figure 5. The user may ultimately be a National Laboratory, a vendor, or a university investigator, but access is managed by the utility (or its agent). The level of access that is allowed to non-utility users is controlled by the archiving system, and may change over time.

The work required to implement an archiving system in addition to a local control and monitoring system is not to be underestimated. For many utilities, this effort represents new territory. However, it should be remembered that schemes of this kind are not uncommon, and that a body of expertise exists that can be drawn on. Utilities that are working with distribution automation schemes are already involved in many of the activities shown—and some are realizing the need to assign full-time staff to the data side of the projects.

As the number of utilities considering distribution PMUs grows (assuming it does), the expertise of NASPI should be made available. The performance and standards Work Group in NASPI has already agreed to consider distribution uses. It may be that a distribution PMU users group should be formed to spread expertise and disseminate lessons learned.

4. Why and How DOE should be Involved

This section focuses on the national interests served by deployment of distribution PMUs and the appropriate roles for federal research and development (R&D) managed by DOE.

4.1. National interests served by deployment of distribution PMUs

The federal government, utilities, and consumers all have an interest in increasing distribution grid reliability. From the national point of view, we can take note of three factors: the financial losses associated with outages, the increased use of sustainable energy sources, and the efficiency of energy delivery.

It has been shown that the economic losses from power outages greatly exceed the value of the undelivered energy (LBNL 2005). As noted earlier, the distribution system is recognized as the source of 90% of all power interruptions. This means that the distribution system is the logical place to look for improvement. As this study has shown, distribution-system PMUs can support rapid automated actions that result in shorter outages (see Section 2.1).

Both federal and state governments have established a number of policies, regulations, and programs that favor energy sustainability. These policies will increase the amount of distributed generation and storage, particularly in the distribution grids. Such sources and loads must be studied and characterized for proper planning, and operation of the power system. This study has described how PMUs can support these activities (Sections 2.2, 2.3, and 2.4).

Finally, distribution system losses are important in terms of federal policies directed toward energy efficiency.¹⁵ Although the power flow (and thus the losses) in a given line or transformer cannot easily be changed in real time, the information provided by a PMU can help in the optimization of some aspects of system performance.

4.2. Appropriate roles for DOE R&D on distribution PMUs

A vitally important role of DOE is to support basic and applied R&D in support of national interests. In this final subsection of the study, we outline several considerations that we believe are appropriate for guiding DOE's activities.

First, we should make it clear that we think the measurement technologies required to produce commercial-grade PMUs for the distribution system do not require R&D support from DOE. These technologies derive from mature products that are already commercially available.

¹⁵ Distribution system losses are estimated to be greater than transmission system losses. A study of losses on the New York Independent System Operator transmission system states that distribution losses are normally about 8% and transmission losses are about 6% (ABB 2009).

There are, however, some areas related to measurement where DOE R&D support is definitely warranted. For transmission PMUs, DOE has played a significant role in standards and calibration. Standards have the effect of encouraging competition by leveling the playing field. They must be unbiased and consensus-driven, and they must allow for advances in technology. That work will be required for distribution PMUs, too.

In collaboration with the National Institute of Standards and Technology (NIST), DOE has supported the development of testing and calibration facilities for transmission PMUs. Such testing is inextricably linked to performance standards. The early implementation of transmission PMUs was hampered by a lack of an adequate standard and information was sometimes inconsistent.¹⁶ The lessons from that experience can be applied to distribution PMU deployment. DOE involvement is appropriate to harmonize and accelerate these efforts.

We believe that an important role for DOE R&D in advancing deployment of PMUs in distribution systems lies in supporting demonstrations conducted in partnership with utilities. Such demonstrations evaluate promising technology. The utility industry is rightly viewed as a conservative one when it comes to deployment of advanced technologies. This conservatism historically came from risk-avoidance, and now is a response to the need for reliable and safe service. Most utilities would argue that they are not in the business of advancing technology readiness.

Pilot-scale demonstration projects—especially ones carried out in conjunction with utility personnel on their own systems—carry special weight in paving the way to wider deployment. The demonstration requires that safety and security be established first, and functional performance is then shown in a real-world environment. That achievement is late in the sequence of technology development, but is an important milestone in many ways. The next logical step would, after all, be a large-scale demonstration, and then full deployment (Kirkham & Marinovici 2013).

Another near-term role for DOE R&D support is facilitation for unbiased, neutral information sharing. A leading and directly relevant example of this role is DOE's investment in the formation of the North American Synchrophasor Initiative or NASPI (www.naspi.org). NASPI provided significant, timely, and irreplaceable leverage for the rapid deployment of PMUs on transmission systems sponsored by the American Recovery and Reinvestment Act of 2009. NASPI has already begun to feature panel discussions on deployment of PMUs in distribution systems. Continued exploration of these synergies is a welcome area for DOE's continued support.

Following on another example pursued by NASPI, it may also be appropriate, in the not too distant future, for DOE to consider development of a business-case for distribution PMUs, similar to the one developed for transmission (Novosel et al. 2006). We caution, however, against pursuing development of such a business case in the very near-term. The applications for PMUs in distribution are only just

¹⁶ While activities of this kind benefit the industry as a whole, individual firms tend to under-invest in them. While the technology will develop without these standards, it will do so inconsistently and slowly.

beginning to emerge. A business case at this time would under-recognize and hence under-value the full range of applications that would be appropriate to consider in a complete business case. Instead, we believe a higher priority in the near-term is on support for and the broad dissemination of results from utility demonstrations of promising new applications.

In summary, there are several significant roles for DOE to support a growing role for PMUs in distribution. They build directly upon past demonstrated DOE successes in supporting PMUs in transmission.

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