UC Berkeley

Sustainable Infrastructures

Title

Phasor Measurements for DistributionSystem Applications

Permalink

<https://escholarship.org/uc/item/7bz2n6jp>

Authors

Stewart, Emma M
von Meier, Alexandra

Publication Date

2016-04-01

Peer reviewed

Phasor Measurements for Distribution System Applications

Emma M. Stewart¹ and Alexandra von Meier²

¹*Lawrence Berkeley National Laboratory, Grid Integration Group, Energy Technologies Area, Berkeley, CA, USA*

²*California Institute for Energy and Environment, Berkeley, CA, USA*

1 Introduction

The measurement and diagnostic capabilities of today's electric power-distribution systems are quite minimal. Measured sources include supervisory control and data acquisition (SCADA) data, distribution line sensors, smart metering and advanced metering infrastructure (AMI), and weather data, but these range widely in latency, frequency of measurement, and availability. Typically, direct voltage, current, and power measurements on primary (medium voltage) distribution circuits are available only from the feeder head at the substation, where SCADA systems acquire and communicate data at intervals ranging from seconds to minutes. Additional sensor data such as voltage measurements from automated line devices such as capacitor banks or reclosers may be available, but these measurements tend to be sporadic and difficult to align with each other in time. Deployment of weather and line current sensors is limited to small geographical pilots. Measurements from smart meters or AMI may be of limited use for operation and planning purposes owing to a lack of time resolution and communication bandwidth (e.g., 15-min intervals) and siloing in a data infrastructure designed for settlement rather than operations.

The scarcity of direct measurements limits distribution operators' and planners' situational awareness regarding the operating state of their system. This can in turn limit opportunities for grid modernization, including renewable energy integration and distribution automation. Situational awareness is increasingly important in order to plan and operate a distribution system efficiently and economically. With the emergence of distributed energy resources (DER), including distributed generation (DG) and demand response (DR) on the distribution grid, the need is growing for real-time monitoring, quasi-real-time analysis of grid behavior, and improved communication of measured data with distribution-planning and operations tools. For example, generation sources may introduce new time-varying behaviors relevant to

system stability and protection characteristics; they also increase the range of unknown conditions, such as load masked by generation behind a net meter, and make it more difficult to anticipate circuit loading and voltage levels during and after switching operations. In addition to hosting more variable resources, future distribution grids will increasingly rely on advanced operating strategies such as automated switching, reconfiguration, and voltage control, thus driving more complex control and visualization needs (Martinez *et al.*, 2011).

To make informed decisions for both the near and long term, distribution planners and operators need high-quality data delivered in a timely manner. Data requirements will depend on the application; for example, operations may need low volume but near real-time information, while planning may require high volume but longer term data. Better data will translate into better model accuracy and thus better results from distribution analysis tools. However, making effective use of available measured data means that it must be properly interpreted in the context of new and existing planning tools, which will require new forms of data management and education of tool users.

Data quality depends on the latency, accuracy, ease of use, time resolution, and, most important, availability. Efforts to improve the availability and integration of distribution system measurements include, for example, the increased deployment of line sensors or new approaches to leveraging AMI data. Among these various data sources, distribution synchrophasors or phasor measurement units (PMUs) have unique characteristics and capabilities that introduce significant new opportunities for operations and planning, assuming the information is harnessed and applied effectively.

2 Distribution PMU Technology

Distribution PMUs provide an unprecedented ability to compare synchronized measurements of voltage and current magnitudes and phase angles across an AC network. Synchrophasor technology was made possible in the 1980s by access to extremely precise GPS signals that permit the alignment of measurement time stamps at different locations within a small fraction of a cycle. Therefore, the zero crossing of the voltage waveform can be compared and the phase shift between locations identified. While the alternating voltage throughout an AC network is thought of as being *synchronous* at a high level, power flow is in fact driven by small differences in the voltage phase angle δ between any two points on a network. In transmission systems, when the line impedance is mainly inductive and resistance can be neglected, real power flow P_{12} between locations 1 and 2 on the network is approximated by the scalar Equation 1, where X is the line inductance, V_1 and V_2 are the respective voltage magnitudes, and δ_{12} is the difference in voltage phase angle.

$$P_{12} \approx \frac{V_2 V_1}{X} \sin \delta_{12}. \quad (1)$$

Voltage magnitude and phase angle at each node in an AC network are considered the *state variables* because they uniquely determine real and reactive power flows. In distribution systems, where the resistance of conductors tends to be of the same order of magnitude as inductance, the power-flow equations must be considered in a more complex form, sometimes even accounting for three-phase imbalance. Nevertheless, synchrophasor measurements in principle capture all information necessary to observe every aspect of AC power flow.

If the network impedance is known, a voltage phasor measurement can serve as a proxy for current measurement; conversely, if both voltage and current are measured, the impedance can be computed. A fundamental advantage of measuring voltage phasors is that the phasor is associated with a *node* in the network,

whereas current and power flow are associated with a *branch*. Thus, a single nodal μ PMU measurement at the service drop or substation bus remains a valid reference point for neighboring resources or circuit branches.

Synchrophasors have seen rapidly growing deployment on transmission systems in recent years, with hundreds of PMUs presently in use in the United States (NASPI). Their vital diagnostic capabilities were recognized in particular after a widespread blackout in 1996, caused by power oscillations in the Western US grid (Taylor, 1999). This dynamic behavior, resulting from the interaction of generators and long transmission lines, was neither predicted by models nor detected with conventional instrumentation. PMU data is now increasingly considered essential by transmission system operators for monitoring grid stability in real time.

By contrast, distribution synchrophasors – that is, measurements comparing not only different substations but also different points on the same distribution circuit – are quite new. Radial distribution systems with mainly passive components have never previously necessitated this type of measurement, and clearly a different business case must be made at the distribution scale. Furthermore, phase-angle differences across distribution networks are much smaller than on transmission systems, requiring more refined measurements: while transmission analysis can use a 1° angular accuracy (where 1° at 60 Hz equals $46\ \mu\text{s}$), distribution PMUs must discern small fractions of a degree. At the same time, electrical measurements on distribution systems are noisier, adding to the challenge of data analysis.

As low-cost devices such as micro-PMUs receive inputs ranging from fractions of a volt to hundreds of volts (Power Standards Laboratory (PSL), 2015), they require transducers – specifically, potential transformers (PTs) and current transformers (CTs) – to make measurements on the primary distribution system. The accuracy and cost of PTs and CTs are therefore significant limiting factors for the performance and economics of distribution PMUs. Alternatively, PMU measurements can be made at the secondary distribution level (Grady and Costello, 2011), although magnitude and phase shifts through loaded transformers may need to be considered for high-precision distribution system applications.

It may be advantageous to consider magnitude and angle measurements of the fundamental waveform, reported once or twice per cycle, alongside power-quality measurements at higher sampling rates of up to tens of kilohertz. In some situations, such as event analysis, the value of the ultra-precise time stamping by PMUs may lie simply in aligning and correlating magnitude measurements from different locations, rather than computing the phase-angle difference.

While hardware designed for these tasks has already been demonstrated, as shown in Figure 1 (Power Standards Laboratory (PSL), 2015), ongoing research and development will expand the capabilities for managing, integrating, and applying distribution PMU data in practice.

Figure 1 A micro-PMU. *Source:* (a, b) Reproduced by permission of Power Standards Lab, <http://PQube3.com>

3 Measurement Timescales

For context, consider the timescales of various data sources. Each type of measurement, such as different aspects of power systems themselves, has inherently different timescales of importance. For example, economic price signaling to DR could be on an hourly basis, but could also inform customer behavior and therefore load in shorter time steps once DR is activated. Weather data for forecasting of short-term variability may be on the timescale of minutes. Grid and component models require scales from subcycle to seconds to hours (Figure 2). Future distribution-grid planning and management decisions will require knowledge of evolving grid conditions that is collected at many different timescales. Therefore, planning and operational software applications will need to be prepared to take in data in different formats and fidelity.

These timescales relate to the type of analysis being completed. In the realm of hours and days, concerns include the power system's steady-state operation, generation dispatch, reliability, and economics. On the scale of micro- and milliseconds, power systems exhibit diverse nonlinear electromechanical and electromagnetic responses related, for example, to switching, power quality, and protection.

Each application for advanced data within a modernized distribution grid will require a different level of data fidelity, quality, and communication. Time-synchronized phase-angle and magnitude measurements can be used on multiple timescales. These range from steady-state circuit behavior, where applications may include topology detection or validation of network impedance as measured at the point of interconnection, to quasi-steady-state conditions, such as power-flow direction, to dynamic circuit behavior and control, such as the diagnosis and mitigation of voltage variability at high penetrations of DER.

A critical driver for the utilization of PMU data will likely be the modeling of DG. Within the next decade, distribution grids could contain a complex mix of generation, storage, load, DR, and automated resources all operating on different timescales, creating a growing need for real-time monitoring and quasi-real-time planning analysis of the distribution grid. Of these diverse distributed resources, solar DG has seen the highest penetration levels to date; it also presents unique modeling challenges such as dynamic behaviors and change of power-flow direction. For these reasons, there may be significant benefit in the flexibility to obtain high-resolution, low-latency measurement data from multiple points in the distribution network.

Figure 2 The range of common data requirements and timescales at utilities. *Source:* Reproduced from Stewart E.M., S. Kiliccote, C. McParland (2014) US Government

4 Communications and Data Integration

The strength of PMU data fundamentally derives from the comparison of different points. Unlike measurements with strictly local application (for example, controlling the action of a voltage regulator), PMU data thus inherently suggest cross-referencing. Different choices exist for data aggregation and physical communication layers, such as Ethernet or 4G wireless (von Meier *et al.*, 2014). A PMU measuring both voltage and current magnitude and angle on three phases will produce 12 data streams, at a rate up to 120 Hz. Although the bandwidth and storage requirements for streaming and recording such high-resolution time-series PMU data are considerable, they are not prohibitive, as advanced computing techniques have been successfully applied in this context to support rapid querying and near real-time analysis (Andersen *et al.*, 2015).

To make full use of this information, however, it needs to be integrated with other sensor technology; it must also be input to distribution-planning and operations tools to support real-time, near real-time, and longer term planning activities. Distribution-planning and operations tools will thus need to process large volumes of measurements and potentially run both steady-state and dynamic analyses accounting for rapidly varying grid conditions owing to automation, volatile DER, and DR. Resilience and stability in the modernized grid will depend on the measurement and communications of these types of high-fidelity data and the rapid analysis of these data by advanced tools.

Existing operations tools presently accept SCADA data (4-s to 15-min time steps), weather measurement devices (15-min to hourly time steps), and AMI data (15-min to hourly time steps) for outage location and management. In contrast to the SCADA and AMI time steps, PMU data time steps will be in the range of milliseconds to minutes. The reporting frequency by PMUs can of course be reduced, for example, through report by exception rules, but at the expense of leveraging some of their unique capabilities (Figure 3).

The ability of distribution-grid operations and planning tools to accept dynamic and transient data collected in small short steps is not well documented. However, in future grid scenarios, the real-time input of these data may form the backbone of early detection of and response to faults and other operational conditions.

Figure 3 Timescales of variability and control

5 Applications

Circuit conditions that can be either directly measured or inferred from raw PMU measurements include steady-state power flow, dynamic and transient voltages and currents, and impedances between points. Observation of these basic conditions extends to model validation, state estimation, topology detection (i.e., connectivity or switching status), event and anomaly detection, and the monitoring and dynamic characterization of active devices such as distributed generators and varying loads.

Measurements of steady-state operating conditions are necessary to create a basic picture of the underlying condition of the circuit, meaning knowledge of the network connectivity and the rms values (i.e., averaged over multiple cycles) of voltages and currents. Input information (e.g., PMU measurements, SCADA, and AMI data) will likely vary in fidelity and will not include all nodes of the circuit. The steady-state picture of the circuit provides the background for time-varying behaviors that may be superimposed.

Dynamic system behavior and analysis will include short-time disturbances (subcycle) in system states. Dynamic system behavior monitoring is the basis for applications such as oscillation detection, inverter performance monitoring, and the detection of complex load interactions such as fault-induced delayed voltage recovery (FIDVR). Inverter performance monitoring is also considered a quasi-dynamic or short time-step series analysis.

PMU data could enhance event detection and location using recorded measurements of voltage magnitude and angle before and during the event and interpreting these in the context of a circuit model or other available data. This approach will rely on development of customized applications, integration and manipulation of measured data within a commercial grid modeling tool, and determination of the accuracy of the location itself.

The current basic operations outage and event location methods essentially consist of mapping phone calls of customers who are experiencing outages or power-quality issues to determine where to send crews to start visually looking for damaged lines, a tripped pole mounted switch, or other indicative features. Locating underground faults is a difficult task for example, but overhead faults are much more common (S.E. Laboratories, 2013). The precision of these systems is limited by the density of protection devices, which indicate location within an accuracy of about 1000 feet. This traditional approach has been extended by the development of low-cost line sensors that provide visual indicators and/or wireless communication of the sensing of fault currents. These devices can be deployed at cost-effective densities to help pinpoint events, but many devices are required to get a precise location.

6 Model Validation

We focus here specifically on model validation as a vital and early application for distribution PMU data. Many of the applications potentially supported by distribution PMU measurements rely on the ability to accurately validate a distribution-planning or operations model. Empirical PMU measurements could be used to improve the accuracy of modeling and planning, in particular related to reducing potential adverse impacts of variable DER and helping ensure system reliability. In addition to DER interconnection, the distribution system is acquiring other features, such as increasing distribution automation and complex loads. As these features become more numerous, the degree of error in planning models is likely to increase, affecting system reliability. Reliability will also become more expensive to maintain as the unknowns increase, and this increase in costs for the electricity provider will in turn lead to higher costs for the consumer. Improving the accuracy of planning models would help prevent these outcomes by enabling cost-effective distribution system management and reliability.

Two key areas where modeling errors are especially prevalent are load estimation (both steady state and time series) and impedance calculations of conductors on feeders. Inaccuracy in distribution modeling can result from different sources, including (i) the lack of appropriate tools to account for distribution-grid behavior at different timescales as the number of active and variable network components increases and (ii) the lack of measured data to calibrate or validate models' performance. It has been noted that the present state of the art in distribution planning is limited by a lack of monitoring infrastructure to provide measured data, including data on the behavior of interconnected DER and lack of standardized data formats to allow effective use in models of even the data that are available (McMorran *et al.*, 2012).

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. In particular, phase-angle measurements would allow accurate characterization of the real and reactive portions of a load, line impedance, and overall power-flow behavior.

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, yielding more accurate predictions by planning models. Present validation processes for distribution-planning models are quite basic. 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, which are uncommon. 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, which can be out of date or inaccurate; even the phase connectivity (A, B, C) may not be known.

7 DG Integration

Because of the distribution network's radial structure and historically unidirectional power flow, network behavior has been fairly predictable in the past, so the rudimentary model validation procedures above have been sufficient. With the need to actively manage resource on the distribution grid, however, the tolerance for estimation errors in planning will decrease. In the near future – indeed, already today in Hawaii and some parts of California – the level of local DG, primarily solar PV, exceeds or is expected to exceed daytime minimum load and eventually peak load (Nakafuji, Stewart, and Aukai, 2013). Depending on feeder type and topology, the tipping point for out-of-acceptable-range behavior in a feeder has been estimated to be at 20–30% PV penetration (Stewart, Kiliccote, and McParland, 2014). Previous model validation methods will not accurately capture this fundamental and potentially damaging change in feeder behavior.

To determine impacts of larger (>1 MW) DG interconnections on a distribution feeder, consultants or utility planning engineers perform a number of steady-state, quasi-steady-state, fault-current, dynamic, and potentially transient studies. These studies determine actions to ensure stability and protection of the distribution system during operation of the DG site, such as changes in protection settings or voltage regulation. Modeling errors in each of these studies can have significant consequences. For example, an incorrect impedance line model will predict incorrect voltage impacts such as voltage rise, inappropriate load tap changer operation, or power-quality impacts on other customers. As a result, the interconnecting party may be requested to install mitigation solutions that are not actually needed but that can be very expensive, such as energy storage or static reactive power compensation. Although these mitigation measures will arguably result in a more robust grid, they are costly to the DG operator and may unnecessarily deter the utilization of renewable resources. On the utility side, such modeling errors may lead to the changing of conductor types, which would also strengthen the network but create unnecessary capital expenses. Conversely, modeling errors may result in the failure to recognize and mitigate adverse impacts of DG interconnection, which can then create costly surprises or even safety issues.

Distribution PMU measurements can improve this process in several important ways. First, phasor measurements will enable the use of empirically validated rather than estimated line impedances, which will allow for more accurate power-flow simulation and thus more accurate interconnection studies overall. Second, it has been noted that load variability over time is of critical importance for PV integration (Broderick *et al.*, 2013). Time-synchronized data will provide better visibility and understanding of load behaviors, both before and after interconnection, to correct the load models used within interconnection studies and to observe the actual combined effects of DER. Moreover, data that also captures the direction of power flow, by virtue of measuring angles, will help disaggregate information about loads and DG (e.g., behind net meters) and will be essential especially in high-penetration scenarios, where reverse power flows on the feeder are increasingly likely. Finally, the precise time stamping of distribution PMU data to within half a cycle allows the correlation of events to help diagnose the causes and effects of variations and disturbances.

Model validation using distribution PMU thus has the potential to be far more accurate than previously possible in predicting voltage profiles, reverse power flows, and dynamic impacts. 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; and the time-varying behavior of DER in both steady state and nonsteady state.

Data from other types of monitoring devices, such as line sensors and smart meters, are typically insufficient or too imprecise to be used for these purposes. For example, while smart metering may provide information on load magnitude, the geographical and electrical location of that meter may not be clearly specified. Furthermore, smart meter measurements often represent an average or median value over the reporting interval (often 15 min or more), which may exclude relevant, faster information needed to validate the system models. Similarly, conventional line sensor data typically lacks one or more of the attributes that distribution PMUs offer, including directionality of power flow, time- and location-synchronized data, high-speed data rates, and high accuracy.

Beyond initial model validation, distribution PMU measurements can provide ongoing monitoring in operations as conditions evolve and deviate from planning assumptions. This monitoring capability gives operators and planners the ability to fine-tune their models based on empirical data collected. The unprecedented visibility provided by PMUs on sliding timescales and with temporal resolution down to the subcycle level will become especially important as load behaviors are more complex and DER reaches higher levels of penetration. In addition to confirming the properties and behaviors of interconnected devices, PMU measurements can provide visibility of the real-time status of the network itself by detecting the topology, for example, confirming the open/closed status of connection points such as circuit breakers, sectionalizers, or tie switches.

Ultimately, PMU data could also facilitate a new level of control at the distribution level, enabling better utilization of distributed resources. By offering the possibility of curtailment in response to real-time conditions and constraints, active control of DER may represent an alternative to conservative limits on feeder hosting capacities. Phase-angle measurements may require fewer sensors than would be required by other data sources and could detect conditions not yet realized at the distribution level, such as transient and dynamic impacts of large volumes of PV and other complex loads.

Barriers to the integration of empirical high-precision data in modeling begin with accessibility and availability of data sources. A key problem is the lack of standardized model and measured data formats. Although work is underway to standardize customer, utility, and vendor data, these formats are not interoperable today 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 (CIM) which, although effective, has not yet been implemented by many distribution modeling tools (McMorran *et al.*, 2012). Finally, there is

little knowledge to date about how accurate the models must really be in order to satisfactorily answer the questions at hand.

8 Accuracy

Data sources can have multiple objectives: for example, they may be used to control distributed resources such as inverters in a grid, they may serve visualization and control at a central point, or they may be utilized in the planning environment to plan for the future (Hamilton, 2012). There are varying accuracy concerns and data needs for all of these settings. In a grid control scenario, for instance, the impact of the error in control would significantly depend on the penetration of renewables deployed. Thus, while there is no one correct answer for what accuracy is needed in distribution system measurements, some general observations are useful.

In a standard distribution measurement system, there are multiple voltage and current measurement error ranges to be considered. These include the accuracy of the instrument transformer for voltage and current that physically connects to the system, and secondly the measurement device or sensor itself. The combined accuracy of these can be calculated using a Gaussian distribution (Irwin, 2011). Performance classes for instruments and metering include the ANSI C12.1 (ANSI, 2008) and the standard that covers demand meters and instrument transformers and C12.20 (ANSI, 2003) that covers metering. These standards relate to a maximum range of error that would be seen in the data at output.

Specifically, an instrument transformer may have a relative error range of 0.2–0.5% (0.2–0.5 class devices). If both the current and voltage measurements are included (e.g., to compute power), the total error is calculated using Equation 2. The error for the whole system including measurement device is then calculated using Equation 3. The maximum error visualized at the output of the measurement device in this case is approximately 1.0% (Irwin, 2011). A further metric to consider is the error of the modeling tool, referenced in Equation 4.

$$\epsilon_{IT} = \sqrt{\epsilon_{VT}^2 + \epsilon_{CT}^2} \quad (2)$$

$$\epsilon_{TS} = \sqrt{\epsilon_M^2 + \epsilon_{IT}^2} \quad (3)$$

$$\epsilon_{MV} = \sqrt{\epsilon_{TS}^2 + \epsilon_S^2} \quad (4)$$

where:

ϵ_{IT} = error of instrument transformer

ϵ_{VT} = error of voltage transformer

ϵ_{CT} = error of current transformer

ϵ_{TS} = error of measurement system

ϵ_M = error meter

ϵ_{MV} = expected error of model validation

ϵ_S = error of simulation tool

Assuming a maximum error for modeling of 0.5%, and assuming the common ranges of measurement devices available commercially at present, the outer band for model validation potential from measured data is therefore 1.1%. A final impact of the error that must be considered is the impact of the simulation tool error on control actuation (Stewart *et al.*, 2015).

9 Conclusions

Power-distribution planning and operation activities are undergoing profound changes. Drivers include aging legacy equipment, a need for greater efficiency, less redundancy, and higher reliability, and most importantly the integration of renewables, new types of loads, and other distributed resources at the customer and distribution levels. These developments pose new challenges in particular to the process of distribution system modeling and model validation. Existing processes were sufficient in the past, when there was a larger bandwidth for error owing to multiple redundancies and manual processes for evaluating system status. However, as the distribution system develops new functionalities as an active infrastructure, model inaccuracies will become a barrier to modernization.

Distribution system management applications, starting with model validation, will have a growing need for high-precision, synchronized measurement data. As discussed in this chapter, distribution synchrophasors or PMUs are a technology that provides unique capabilities to support the needs of the future power-distribution infrastructure in its mission to deliver clean, reliable, and economical electric power.

References

- ANSI (2003) American National Standard for Electricity Meters – 0.2 and 0.5 Accuracy Classes, ANSI Standard C12.20-2002, Jan. 2003.
- ANSI (2008) American National Standard for Electric Meters Code for Electricity Metering, 2008 ANSI Standard C12.1-2008, June.
- Andersen, M.P., Kumar, S., Brooks, C., *et al.* (2015) DISTIL: Design and Implementation of a Scalable Synchrophasor Data Processing System. IEEE SmartGridComm Conference, Miami, FL, November.
- Broderick, R., Lindl, T., Fox, K., *et al.* (2013) *Integrated Distribution Planning Concept*, Interstate Renewable Energy Council, <http://www.irecusa.org/wp-content/uploads/2013/05/Integrated-Distribution-Planning-May-2013> (accessed 01 October 2015).
- Grady, W.M. and Costello, D. (2011) Implementation and application of an Independent Texas Synchrophasor Network. *SEL Journal of Reliable Power*, **2** (2), 1–12.
- Hamilton, S. (2012) Smart Grid: A Model Centric Approach, white paper, Brookhaven National Laboratory, December.
- Irwin, L.A. (2011) A high accuracy standard for electricity meters, Schneider Electric White Paper.
- Martinez, J.A., Dinavahi, V., Nehrir, M.H., *et al.* (2011) Tools for analysis and design of distributed resources – part IV: future trends. *IEEE Transactions on Power Delivery*, **26** (3), 1671–1680.
- McMorran, A., Stewart, E., Shand, C., *et al.* (2012) Addressing the Challenge of Data Interoperability for Off-Line Analysis of Distribution Networks in the Smart Grid, IEEE PES Transmission and Distribution Conference and Exposition, Orlando, FL, May.
- von Meier, A., Culler, D., McEachern, A., *et al.* (2014) Micro-synchrophasors for Distribution Systems. ISGT Conference Transactions, Washington DC, February.
- Nakafuji D., Stewart, E.M., and Aukai, T. (2013) HiP-PV Lessons Learned from Improved Observability on Hawaiian Electric Utility Feeders. Distributech Conference, San Diego, CA, January.
- Power Standards Laboratory (PSL) (2015) Alameda CA, www.powerstandards.com (accessed 01 October 2015).
- Stewart E.M., Kiliccote, S., and McParland, C. (2014) Software-Based Challenges to Developing the Future Distribution Grid, Lawrence Berkeley National Laboratory Publication. LBNL Report Number 6708E.
- Stewart, E.M., Kiliccote, S., Arnold, D., *et al.* (2015) Accuracy and Validation of Measured and Modeled Data for Distributed PV Interconnection and Control, IEEE PES General Meeting, 27–30 July, Denver, CO.
- S.E. Laboratories (2013) *Overhead Fault Indicators*, <https://www.selinc.com/FCI/Overhead> (accessed October 2013).
- Taylor, C.W. (1999) Improving grid behavior. *IEEE Spectrum Magazine*, **36** (6), 40–45.