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Synchronized Measurements and their Applications in Distribution Systems: An Update

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Introduction

The mission of the NASPI Distribution Task Team is to foster the use and capabilities of networked PMUs at the medium-voltage distribution level, beyond the substation. This group will share information in support of effective research, development and deployment of distribution PMUs. We aim to create a community to solve technical and other challenges specific to distribution PMU technology and applications.

This report provides a discussion of uses for time-synchronized measurements in electric grid operation, spanning both power transmission and distribution. As an update to the 2018 DisTT Report, it is intended to inform decisions to deploy available measurement technologies in a manner that addresses urgent needs of real-world practitioners.

We consider not only synchrophasor data, but also other sources of time synchronized and high-frequency measurements. Our goal is to assess what measurement capabilities would be necessary to support the highest priority use cases expressed. The measurements under consideration include:

- Synchrophasor data (i.e., 30-120 Hz frames reporting rms magnitudes and phase angles at various accuracies)
- Time-synchronized data (e.g., rms magnitudes time stamped to within a fraction of a second, at various reporting rates)
- Point-on-wave data (e.g. time domain waveform with kHz sampling, time stamped, streaming or archival)

In the first section of this report, we summarize findings from our 2019 online survey about the needs and priorities of grid operators that may be supported by time-synchronized measurements. We then discuss selected applications, with an aim to clarify capabilities introduced by various levels of data availability. Ample references provide further details on the various applications, methods and case studies presented. Based on these examples, we comment on requirements for further development of sensor technologies and information infrastructure, in alignment with practitioner needs. This is not intended to be an exhaustive analysis, but a continuing work in progress—which, we hope, provides some useful insights.

1 Survey Findings

In 2019, the Distribution Task Team offered a detailed technical survey of users of grid data, distributed to the NASPI mailing list. The survey aimed to assess the needs and priorities of electric grid operators for using time-synchronized measurement data, particularly in distribution systems. Its purpose was to identify applications that Phasor Measurement Units (PMU) and related measurements should support, and to maximize the relevance of technical information that NASPI provides to the industry. There were nine respondents from four countries, seven utilities and two academic institutions. Four of the respondents presently use PMUs.

Measurement Types

Measurement usage varies among respondents, with four currently using PMUs. Nearly all respondents use SCADA accompanied by one or more additional measurements: either AMI, PMUs or both. It is noteworthy that many respondents already have access to a diversity of measurement data that differ in time resolution, synchronization, location in the feeder, number of devices deployed, and quantities measured. However, work on tools that leverage multiple types of measurement streams is limited. Based on these answers, it appears important that time-synchronized measurement applications consider a diverse set of input measurements.

Monitoring Priorities

Monitoring priorities vary significantly across utilities. Respondents tend to agree that fault detection is a very high priority, while asset health monitoring, voltage management, and topology monitoring are high priorities. Of respondents, only one had an asset monitoring application already in place, consisting of monitoring the loading of transformers and other equipment with AMI measurements. One respondent was especially concerned about topology monitoring as their network is switched so frequently it no longer has a standard, non-switched configuration. On the other hand, another respondent considers topology monitoring irrelevant, probably because their network operates under a fixed topology. Monitoring solar PV generation is a medium priority. Cybersecurity and state estimation are generally lower priorities.

The ranking of monitoring applications from highest to lowest priority based on aggregated responses was:

1. Fault detection
2. Asset health monitoring / Topology monitoring
3. Voltage management / State estimation
4. Cybersecurity / Solar PV generation monitoring

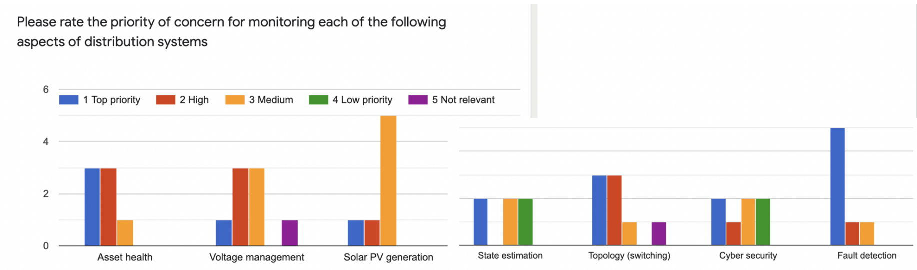


Figure 1: Survey responses to monitoring priorities

This ranking likely reflects the most immediate issues facing distribution utilities.

Wildfire Risk Management

Undergrounding lines and public safety power shutoffs are the most frequently used approach to wildfire mitigation, with 6/7 respondents adopting these strategies. More targeted approaches include falling/broken conductor detection (5/7), high impedance arc fault detection (4/7), optical recognition of point source fires (2/7), and sensitive ground fault protection (4/7). Two respondents who do not have PMUs in their system report using falling/broken conductor detection and high impedance arc fault detection. It is unclear what measurements they use for these applications, which generally require high resolution, time-synchronized data.

Of the respondents who do have PMUs deployed, one implements public safety shutoffs and undergrounding only to handle wildfire risk. Indeed there is no clear difference in the wildfire risk management approaches taken by utilities with PMU measurements versus those without. As PMUs promise to enable more targeted approaches, this suggests that even utilities with PMUs may be underutilizing their data or have too limited deployment to deliver actionable insights.

Respondents also reported the wildfire mitigation strategies they consider most promising in the future. The following ranks strategies from highest to lowest future promise based on the aggregated survey responses.

1. Falling/broken conductor protection
2. High impedance arc fault detection / Sensitive ground fault protection
3. Optical recognition of point source fires
4. Public safety power shutoffs

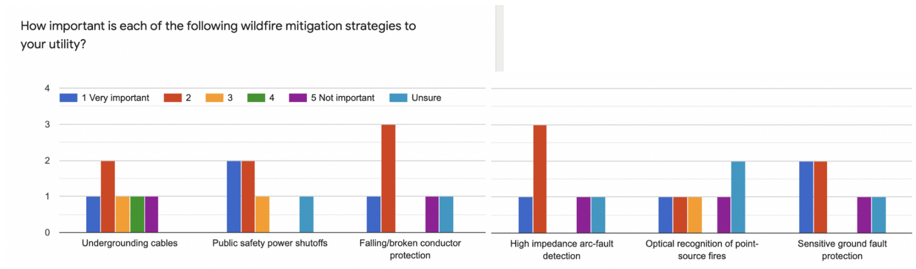


Figure 2: Survey responses to wildfire risk management

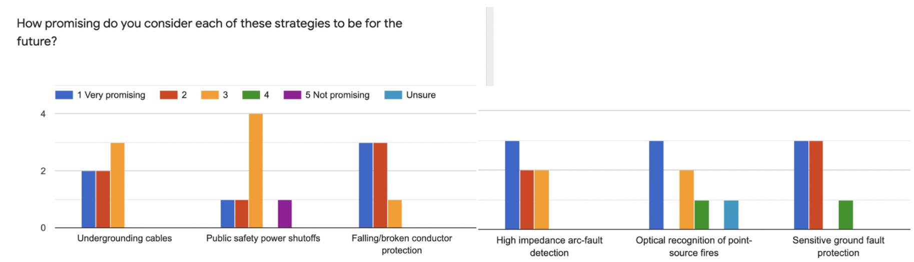


Figure 3: Survey responses to future wildfire risk management strategies

Respondents generally agree that targeted approaches such as falling conductor and high impedance fault detection are cost effective compared to undergrounding. Respondents suggested that machine learning on high resolution, time synchronized measurements to identify signatures and root causes of grid events can be useful for wildfire mitigation, as can collation of PMU measurements with geospatial data.

Distributed Energy Resources (DER)

Respondents vary in their assessment of the challenges associated with DER integration. Protection misoperation, exposure to sudden loss of generation, and voltage deviations are overall the highest concerns. Of lesser concern are degradation of tap changing transformers and reaching distribution system capacity limits. Unintentional islanding and power quality were also mentioned as concerns. Respondents recognized that time synchronized measurements can help with islanding detection, and more broadly topology monitoring. Two respondents mentioned the usefulness of PMU measurements for frequency response. This application would require PMU measurements to be coupled with the control of actuators (batteries / loads) either on the utility or customer side.

All respondents agreed that high-precision measurement data would be useful for validating distribution feeder models. The majority (5/7) prioritized studying feeders with high DER penetration while one respondent prioritized

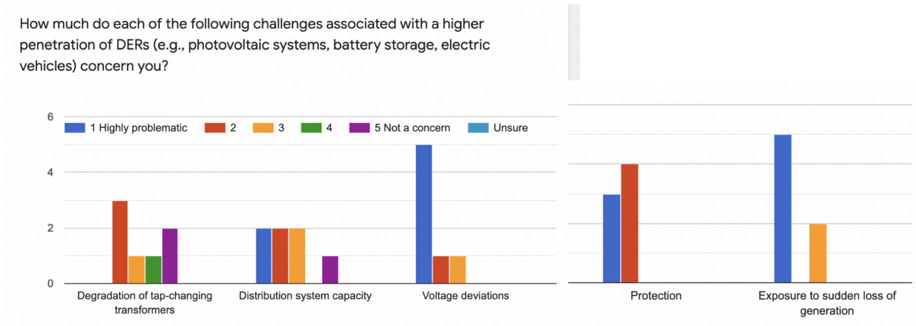


Figure 4: Survey responses to DER challenges.

feeders with several industrial loads.

Distribution State Estimation

3/7 respondents did not conduct state estimation in their distribution feeders. One utility did conduct capacity analysis to determine DER integration limits and integration points on every circuit. Only two respondents implemented anything approaching real-time state estimation. Of these, one used low-resolution AMI data for state estimation, although they doubted the efficacy of the results given uncertainty about the true network topology. The other uses PMU measurements for real time state estimation. Therefore, of those respondents with PMU deployments, only one is currently using the phasor measurements for distribution state estimation. This again hints at a possible underutilization of PMU data.

Microgrids

While all respondents were interested in using synchrophasors for microgrid monitoring, as of now 4/7 respondents have operational or planned microgrid projects within their networks. All these microgrid projects are or will be equipped with PMUs, suggesting that synchrophasors are becoming the established technology for microgrid monitoring and integration.

PMU Concerns

Several respondents mentioned the robustness of PMUs, particularly dependence on time synchronization via GPS signal, as a concern. The cost of distribution PMUs was another concern.

It is worth commenting that both of these issues are being addressed, through efforts to provide alternative or redundant timekeeping services, and efforts (such as OpenPMU) to produce lower cost PMUs.

2 Applications

2.1 Event Detection

Electrical faults cause undesired abrupt changes in voltage and current waveforms depending on the fault location, type, and grid conditions. These faults, in some cases, lead to tremendous technical, economic, and societal damages to stakeholders and citizens. Distribution level Phasor Measurement Units (PMU) introduce more opportunities for detecting and locating fault events using various data analysis methods.

Event Recognition

An important challenge in leveraging measurement data for situational awareness is to recognize valuable portions out of large data sets from raw time-series streams such as 120-Hz micro-PMU streams. To this end, the authors of [1, 2] developed two novel *data-driven event detection* techniques. Subsequently, a *data-driven event classifier* was developed to effectively classify events, and a multi-class support vector machine (multi-SVM) classifier over 15 days of real-world data from two micro-PMUs on a distribution feeder in Riverside, CA. The effectiveness of the developed event classifier is compared with prevalent multi-class classification methods, including the k-nearest neighbor method as well as a decision-tree method.

Machine Learning Approaches

With recent advancements in machine learning and data analysis, data-driven fault detection methods are gaining more attention. In the literature, Neural Networks (NN) [3], Support Vector Machines (SVM) [4], Statistical Change Detection [5, 6] along with fuzzy algorithms [7] are among the most frequently used methods for fault detection in power systems. However, accurate fault detection may require a significant amount of data for training and testing that may be scant and expensive. In other words, most machine learning algorithms for power system fault detection are categorized under supervised methods. There is space for developing more semi-supervised and unsupervised techniques for fault detection. For example, the [8] is a semi-supervised fault detection method that minimizes the need for labeled data for training the learning algorithm. It bridges the gap between supervised learning, semi-supervised learning, and learning by using hidden structures in data sets.

To improve the machine learning methods performance in complex problems such fault diagnostics, various feature extraction techniques have been proposed. For example, the shape of the voltage or current measurements during a fault event can be a key to better diagnose the type of the fault. In [9, 10], a shape-based distance with a square-root velocity function (SRVF) is used for clustering fault data with high accuracy that has better performance compared to statistical features. A group of studies such as [11, 12] has been focused on temporal

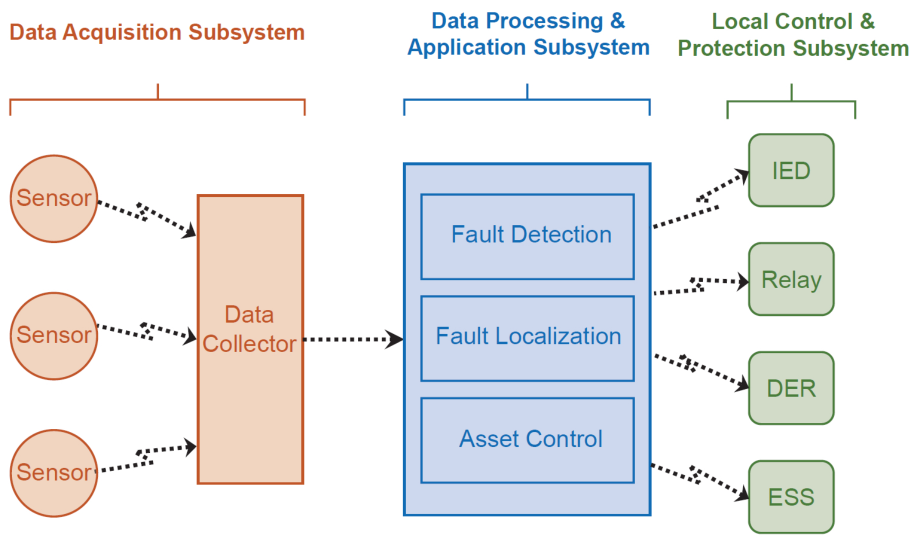


Figure 5: Functional diagram of synchrophasor-based networked protection [13]. The dotted arrows indicate communication links.

and spatial dependencies among measurement devices within a network. Such time synchronized dependencies, which are also the proximity of the network topology, lead to a better understanding of the impact of different types of fault in different locations of a distribution network.

2.2 Event Localization

PMUs can enhance localization of low- and high impedance faults in distribution networks and microgrids. Depending on the synchrophasor reporting rate, the localization may be carried out with some higher delays when compared with the local overcurrent relays [13]. Fault localization can be performed based on one single PMU [14] or several PMUs distributed across the distribution feeder [15, 16, 17]. It is possible for Artificial Intelligence (AI) and learning methods to play the role of virtual PMUs, which eventually lower the number of required PMUs for protection application [14, 17]. Fig. 5 shows the general configuration and main components of networked protection based on synchrophasor data, where each "sensor" represents a micro-PMU.

Fault location methods naturally depend on the density of PMU placement and availability of measurement data from specific locations, such as transformers or relay points. Further the accuracy of the localization algorithm can be improved by making the PMU placement logic cognizant of the fault localization algorithm [17].

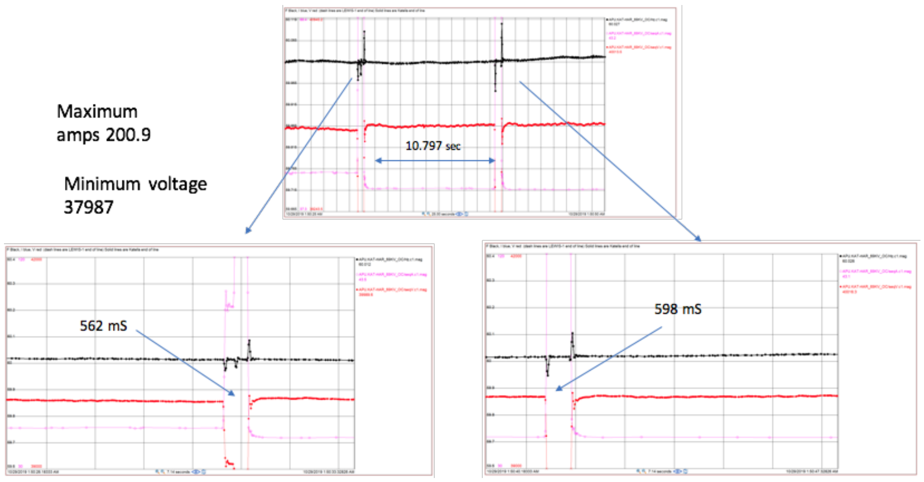
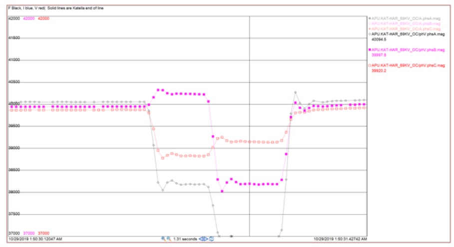


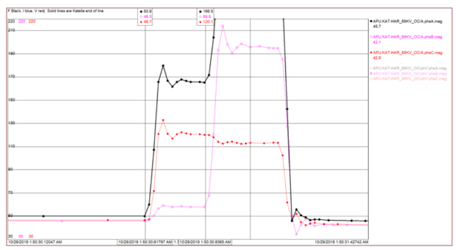
Figure 6: Figure showing voltage and current events with different durations within a 11 s interval.

One type of method is based on “time of arrival” of fault events to different measurement points, since the disturbance propagates through the grid with a certain delay. This depends on both time synchronization and fast sampling of synchrophasor data. The measurement points that record the event first are considered to be the closest ones to it. New tools that map different transformers of the distribution circuit to these measurement points and then locate the event based on time of arrival are currently being developed [18, 19]. Even if no exact location is determined, the purpose of these tools is to help operators and field personnel estimate at least an approximate location of the fault before narrowing it down with further analysis. The observation of the same event with different arrival times is illustrated in Fig 6.

Second, fast sampling of PMU measurements is used to estimate dynamics of the grid using a grid topology model. In this method, a characteristic function is estimated using measurements, and this multiple-input, multiple-output (MIMO) function provides dynamic transient information such as oscillation frequency of the grid (e.g. 0.33 Hz for the WECC system), resonance modes, damping factor and participation factor of different events. Using these parametric features, operators can locate events depending on how well they are damped at each measurement point. This information along with current phasor information gives a complete picture of the fault location for any event in the distribution system. Within each phase, negative sequence voltage and current elements provide insight into the type of the fault. The two figures below show current and voltage phasor data for each phase in case of a phase-to-phase fault (A-B). This data is used to extract dynamical information of the grid from this



(a) Voltage



(b) Current

Figure 7: Figures show voltage and current phasor data for each phase in case of a phase-to-phase fault (A-B).

measurement point.

In [20], a novel method is proposed to locate the source of events in power distribution systems, using micro-PMUs. Here, an event is defined rather broadly to include any major change in any component across the distribution feeder. The proposed method is built upon the *compensation theorem* in circuit theory to generate an equivalent circuit to represent the event by using voltage and current phasors. This method makes critical use of not only magnitude but also synchronized phase angle measurements, thus, it justifies the need to use micro-PMUs, as opposed to ordinary RMS-based voltage and current sensors. The proposed method can work with data from as few as only two micro-PMUs.

Online post-fault analysis

An advantage of using synchrophasor data for protection applications is related to new functionalities that were not feasible in traditional power systems. In fact, synchrophasor data can provide accurate information about the grid behavior at different nodes. Current phasors can be processed to mimic the role of overcurrent relays [14], and frequency or ROCOF data can be processed to play the role of islanding relays in microgrids.

Online post-fault analysis is one of the new functionalities that can be realized based on synchrophasor data. Post-fault analysis can reveal voltage or frequency disturbances that may emerge from high-penetration of DERs that are

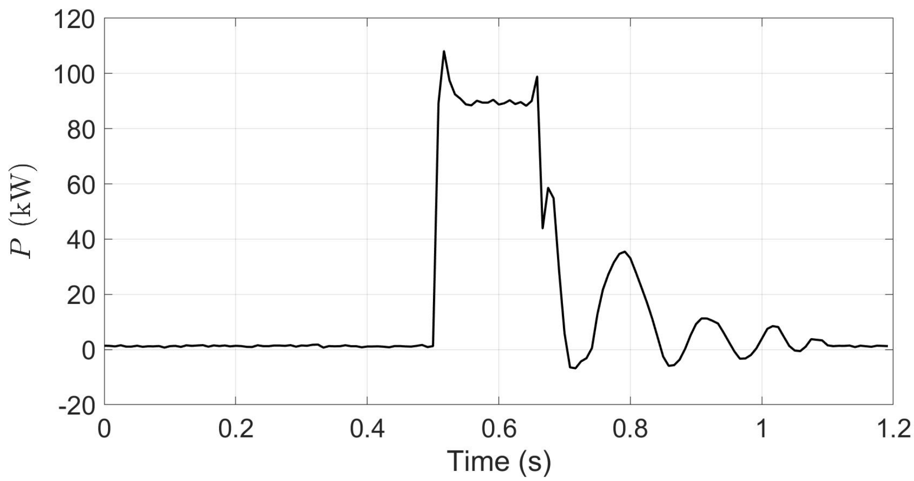


Figure 8: Real power flowing into a residential feeder with a high-capacity PV system under normal ($t < 0.5s$), faulty ($0.5s < t < 0.65s$), and post-fault ($t > 0.65s$) conditions [14].

subjected to line faults. Moreover, it is shown that a late fault isolation can lead to significant power fluctuations or instability in the presence of high-capacity DERs [14]. Fig. 8 shows the fluctuations of real power that flows from the main grid into a low-voltage residential feeder with 90% penetration level of solar PV.

The post-fault analysis enables the backup protection systems to determine the maximum fault tolerance time, and enhance asset management after the fault occurrence.

2.3 Monitoring the Operation of Protective Systems

A high PMU reporting rate allows the substation controller (or microgrid central controller) to monitor the operation of the local relays and switches, e.g., opening and reclosing of circuit breakers in response to temporary line faults [14]. One method is based on the analysis of pre-fault and post-fault synchrophasor time-series data and check if the topology of the feeder has a significant change [14]. The basic premise of this methodology is that the fault isolation due to the operation of the circuit breakers often divides the distribution network into two grid-connected and islanded subnetworks [16], which implies that the topologies of the network before and after the fault isolation are not identical.

In [21], a data-driven experimental analysis is conducted on a single-phase-to-neutral fault at a distribution grid in Riverside, CA, using data from five micro-PMUs. Of particular interest is to extract the time-line during the fault. With the high resolution, precision, and time synchronization of the data from micro-PMUs, the hypothesis about optimal operation of protection devices during each period of the fault time-line is examined, followed by exploring the success of coordination between lateral fuse and main feeder recloser. In addition, the response of inverter based resources to fault, specifically to islanding, is observed and the miscoordination between anti-islanding protection of PV inverters and the feeder recloser is deduced.

2.4 Asset Health Monitoring

With increasing availability of PMU data at the substation level, it becomes more feasible to use the information contained in the measurement to estimate and predict asset health and use this information for predictive maintenance programs. A number of long term studies such as [22] have shown that the signal-to-noise ratio of synchrophasor data can be used as a reliable indicator of transformer failure. Once a transformer approaches a failure mode, the noise in the surrounding voltage magnitude signals increases significantly and further steps can be taken before the time of failure.

Similarly PMU data can be used to identify deteriorating transmission lines [23]. By using PMU data to estimate impedance parameters [24, 25] and tracking the results over longer time frames, it is possible to identify transmission lines that are most likely in need of maintenance and prioritize line inspections accordingly.

A number of other studies, such as [26], have shown that PMU data can be used to detect abnormalities in breaker mis-operation and identify breakers in need of manual inspection. While higher sampling frequency is needed to satisfy NERC requirements for predictive maintenance on protection equipment, this information can be used to prioritize inspections to avoid extensive and costly maintenance outages.

In [27], a data-driven experimental analysis is conducted on capacitor bank switching events that are captured in [1, 2]. Of particular interest was to monitor the health of the capacitor bank remotely, and thus eliminating the need to install a separate asset sensor. The capacitor bank in this study is rated 900 kVAR, and is switched by a vacuum circuit breaker (VCB). The VCB is controlled by a Volt-VAR controller. Typically, for a wye-floating capacitor bank, the strategy for switching-off is to open contacts in two steps: first, opening one phase at zero-crossing of its current; second, opening the two other phases at quarter of a cycle later, at 90° relative to the zero-crossing of the first phase. For the capacitor bank in this study, we can confidently conclude that the capacitor bank switching is ideal during the first step, but there are always about 20% overshoot and undershoot transients in current magnitude lasting for 100-200 ms during its second step. The unbalanced or underrating operation of the capacitor bank was also investigated. This is likely due to internal fuse blowing, which is a common and important practical concern with capacitor banks.

2.5 Topology Identification

The proliferation of phasor measurement units (PMUs) to measure three-phase voltage and currents have improved signal-to-noise and real-time monitoring capabilities of the power network [phadke2002]. Novel approaches to detect faults in a network using synchrophasor data and state estimation [28] rely on network topology in the form of a network admittance matrix, commonly seen in network modeling (Newman, 2010) and the estimation of topology of networks [29, 30] and physical networks [31, 32]. As the entries of the network admittance matrix are the admittance or impedance connection between pairs of buses, measurement of three-phase voltage and current signals can be used to characterize the significant components [33] of the three phase power flow. Such a data driven approach will facilitate event detection [34] but also detailed information on three phase impedance changes in the network.

The available literature on topology detection in power systems using distribution-level PMUs or D-PMU data can be classified into two major categories: model-based and model-less approaches. Two examples of model-less approaches are [35, 36]. They used pattern recognition methods to classify synchrophasor voltage measurements. Their main idea is that each switching activity creates a unique signature in the vector and current phasor measurements based on the network topology. The model-based topology detection methods mainly rely on the power flow results that run in parallel. For example, the authors of [37] developed a voting-based scheme that searches for the minimal difference between measured and calculated voltage angle or voltage magnitude to detect the topology. Similarly statistics of voltage can be used to define probabilistic graphical models, that can then be mined to determine the underlying topology, estimate line impedances and changes therein [38, 39, 40, 41, 42, 43].

Synchrophasor measurements are used in [44] to present a data-driven approach to recursively estimate the three phase admittance connections in a power network. Unlike the contribution in [31], the approach presented here in [44] assumes the topology of the network to be known due to the physical location of transmission or distribution lines. The contribution of this paper in [44] is the development and testing of a recursive estimation over short time intervals to be able to detect abrupt changes in the three phase line admittance. The singular value decomposition approach as proposed by [34] is used to address the identifiability of three-phase impedance over short time intervals. The approach is illustrated on actual three-phase synchrophasor measurements obtained from a distribution circuit.

A likely path is to extend techniques from transmission topology identification. Comparing PMU voltage angles is a natural method for identifying subsecond transmission topology. The prerequisite is that a PMU is installed at each relevant transmission line terminal, including substations and any switch/tap structures. For the distribution case, the following challenges arise: Can we economically achieve the necessary density of placement of PMUs on distribution circuits? If the objective is to be able to identify the connectivity of any point on the system (i.e., every meter), this would require PMU data at every node or switching location (e.g. jumper, switch, cutout, vault, or transformer). Few of these equipment types have provisions today for connecting to existing potential or current transformers (PTs/CTs). If PMU/Point on Wave saturation is achievable, does the data contain everything needed to identify distribution topology per the defined metrics above? If the answers to 1 and 2 are yes - Can software successfully compute distribution system state 30 times per second (or greater)? Is that a reasonable request? Sub-second topology identification with a confidence interval ¿ X% (99+%) would allow implementing protection and control measures within protection/reliability standards.

Subsecond grid topology identification spanning both transmission and distribution systems is a pressing issue that will support various related use cases. One example is autonomous load shaping, where loads are controlled in coordination with instantaneous generation and local infrastructure constraints. To enable the most intelligent recruitment of loads relative to capacity or voltage constraints, knowing their exact instantaneous location within a potentially reconfigured network is essential.

2.6 Fire Risk Mitigation

One proven approach to fire risk mitigation is Falling Conductor Protection (FCP). The purpose is to detect an energized conductor as it breaks and de-energize it before it strikes the ground, reducing the risk of an ignition source for wildfire. The system utilizes a substation based Real-Time Automation Controller (RTAC), Phasor Data Concentrator (PDC), and associated networking devices, substation circuit breaker, line-side reclosers, and line monitors to provide the monitoring, protection, and isolation. The circuit breaker, reclosers, and line monitors are all equipped with protective relays that provide GPS time-synchronized Synchrophasor measurements of system voltages. The voltage signals from all participating devices are transmitted back over radio or fiber optic cable to the substation network to ultimately provide data to the RTAC.

The RTAC performs calculations to determine if the voltages are healthy and thus and status of the conductor and if it should be de-energized. Methods employed are:

• rate-of-change of voltage (dv/dt) • zero and negative sequence voltage magnitude (V0 and V2 magnitude) • zero and negative sequence voltage angle (V0 and V2 angle)

When the set-points are exceeded for any of the above parameters, the RTAC will issue a trip to the zone of protection where the deviation is detected, which is likely a falling conductor. The protective devices that encompass the boundary of that protective zone will trip and isolate the part of the circuit where the potential falling conductor was detected. Indications will be provided to the station annunciator that an FCP event has been detected and a trip issued.

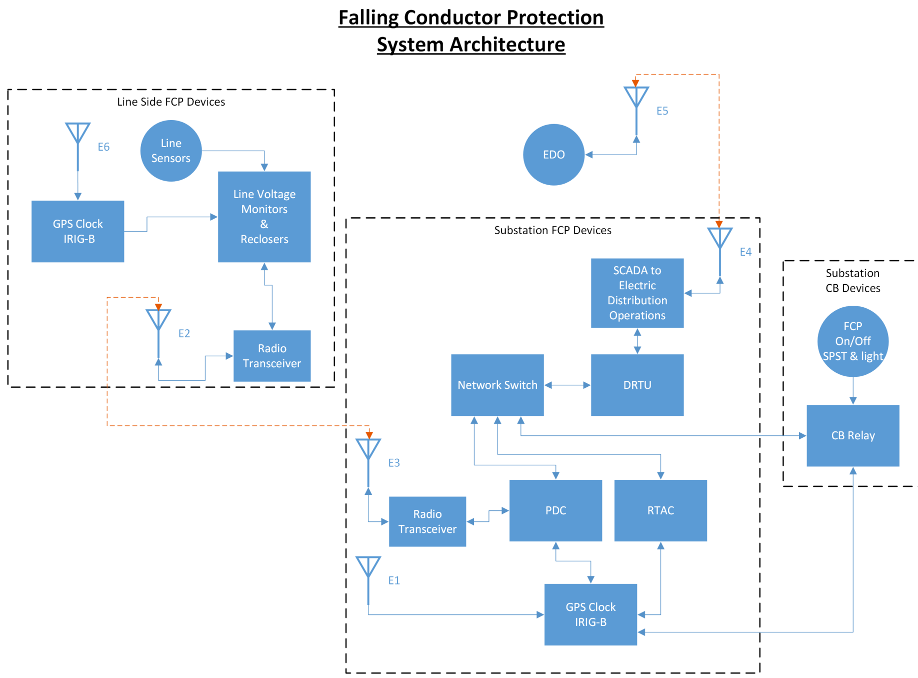


Figure 9: Falling Conductor Protection scheme.

The SCADA system at Electric Distribution Operations will be alarmed to alert an operator that the FCP protection has detected and isolated a potential falling conductor, in order to prompt an immediate response.

For an analysis of FCP related events, records from corresponding devices will be downloaded to determine that the operation is correct.

The design process for FCP follows a simple narrative: protect as much of the distribution line, specifically the main feeder from the substation, as possible. Site selection of reclosers is subjective to logically segment the circuit into zones where protection will force the least customers out while weighing the high cost of installation per device. Line monitors are deployed to cover the ends of lines, mid-points along lines or bordering fuses which create discontinuities that look like broken conductors when operated. High speed radio networks are necessary for the communication to the substation for all data of the line-side devices. In the selection and placement of reclosers, line monitors, and radio repeaters the pole locations must be carefully selected so that they are truck and crew accessible (no helicopter-only access) as well as complying with environmentally sensitive area issues. The closer the pole is to a roadway, typically the better the chance of a successful placement the designer will have.

2.7 DER Integration

While the main focus in managing Distributed Energy Resources (DER) is generally on mitigating adverse impact from solar PV generation, similar impacts may also apply to high load volatility with growing adoption of electric vehicles.

Network design studies and operational issues experienced in the field indicate that the installation of high levels of unmanaged solar PV generation can introduce the following technical problems for distribution infrastructure:

1. Tripping of a generating unit(s) upon reverse power flow into the power station (due to low load and excess solar generation)

2. System instability upon large step loads exceeding the step capability of the conventional generating units or exceeding the station spinning reserve (due to cloud events influencing the intermittency of solar PV production)

3. Periodic power quality issues including poor power factor and voltage rise at the customer node and on sections of LV circuits, resulting in temporary disconnection of customer DER systems

To date, without the visibility and orchestrated control of DER systems, or the market's ability to offer customers a cost effective grid edge control or generation management solution, the industry manages these problems by imposing limits on the installed solar PV capacity in a microgrid. These limits are defined as the Hosting Capacity and are determined on a per system basis, accounting for power station spinning reserve, generator unit capability, system voltage profiles, system frequency variation and an estimate of the diversified performance factor of solar PV generation.

In addition, with even higher levels of unmanaged and basic controllable solar PV, network studies indicate the near future requirements to

1. provision sufficient reactive power support;

2. implement primary and secondary layer voltage and frequency control with greater contribution from inverter based systems

3. implement tertiary layer real and reactive power dispatch of DER systems; review protection design due to reduced fault levels

4. to provision weather forecasting services to: influence DER control schemes, indicate optimal times to transition to temporary grid modes such as islanding sections of network and/or facilitating 100% inverter based generation modes.

2.8 Microgrid Control

Smart microgrids can effectively harness DERs and synchrophasor technology to improve performance in terms of power quality, service reliability, and situational awareness. Hierarchical control structures that often require communication systems are deemed to be effective models for control of microgrids and consist of three different levels, namely, primary (local), secondary and tertiary levels. The use of PMU data at the primary level of control structure is not recommended as the primary controllers are implemented inside the DERs and form current and voltage control loops to fix the injected power, or stabilize voltage and frequency at the DER's point of connection. This requires very fine sampling of voltage and current signals and very small measurement delay which are definitely far beyond the capability of modern PMUs.

The PMU data can be fed to the secondary and tertiary controllers to facilitate decision making and improve the controller performance. For instance, in the secondary level of hierarchical control structure a central controller is usually responsible for reliable and optimal operation of the microgrid by supervising the DERs. The synchrophasor data can play important roles in improving the performance of the microgrid central controller through different applications such as power sharing, connection or disconnection of units, frequency and voltage monitoring, fault monitoring, etc.

A microgrid control system aims to satisfy requested performance criteria under a variety of different test cases. This section presents an overview of control objectives and controller architecture that can be supported by PMU data. The control objectives comprise satisfying the reference power flow at the point of interconnection (POI) of the microgrid subject to the operational limits of the Distributed Energy Resources (DERs) and within tolerable voltage and frequency bounds. The microgrid control function must meet these objectives by dispatch of the available DERs (i.e., PV, diesel generators, energy storage, and controllable loads). This function is typically divided into two separate subsystems of power control and DER power distribution. At the first stage, the total dispatch required by all DERs to meet the reference POI power is computed. In the next stage, this computed set point is distributed between the DERs, while considering the operational limits of each DER.

The following is a typical set of rules to illustrate decision-making for microgrid control:

- PV power should be prioritized for supplying the load demand and meeting the POI power set point.
- In mitigating disturbances or meeting abrupt set point changes, the high ramp rate of inverter-based DERs should be used to mitigate POI power deviations from the set point.
- Under grid-connected operation, diesel generators are dispatched only to provide additional power to meet the POI power.

PMU data can enhance the performance of such a control system by providing high-resolution streaming measurements that inform very quick action, such as curtailment of PV, or trading off real (kW) for reactive (kVAR) output, to mitigate issues such as high voltage volatility, reverse power flow and frequency instabilities developing in real-time. Because inverters can actuate on extremely short time scales, i.e. on the order of a few cycles (typically 5-10), fast sampling becomes critical to fully leverage the inherent control capabilities [45].

For the above purposes, measurement of voltage and current magnitude quantities is typically sufficient, and the ability to compute a relative phase angle is not needed. However, it can be helpful to measure angle differences across the POI in order to ascertain whether the microgrid is islanded, and to assist in synchronizing it back to the main grid [46].

Furthermore, new phasor-based control strategies under early-stage research development take into account both voltage magnitude and angle relative to a reference point in order to control DER. The idea is to locally regulate real and reactive power output or demand by DER so as to track a voltage phasor difference computed by a supervisory controller [47].

PMUs for Islanding

The microgrid is connected to the main grid feeder via a static switch (SS) or a circuit breaker (CB). The status of the switch determines the operating state of the microgrid, i.e. when open the microgrid is isolated from the utility grid or islanded, and when closed, the microgrid is grid-connected. In islanded mode, due to the difference between local supply and demand, the voltage and frequency fluctuate and are not synchronous with that of the main grid. At any given time t_k, the voltage across the interconnection switch (dropping time index) is given by:

$$|V_{AB}| = \sqrt{V_A^2 + V_B^2 - 2V_A V_B \cos(\theta_{V_A} - \theta_{V_B})}$$

where V_A, V_B and θ_{V_A}, θ_{V_B} are voltage magnitudes and phase angles of the phasors of the main grid and microgrid feeder respectively. For a smooth transition at the time of reconnection, the magnitude of V_{AB} should be close to) meaning voltages on both sides of the switch should have the same magnitude, phase angle, and frequency to avoid huge inrush current. For non-zero V_{AB}, the resulting real and reactive power flow due to voltage difference at the time of reconnection is:

$$P_{PCC} = \frac{V_A V_B \sin(\theta_{V_A} - \theta_{V_B})}{X}$$

where V_A and V_B are voltage magnitudes at the two sides before reconnection, and X is the connection impedance. As seen in these equations, phase angle difference across the breaker can lead to large real power surges while voltage magnitude difference can lead to reactive power surges. Typically, voltage magnitudes at nodes A and B are regulated at close to 1 p.u. by the main

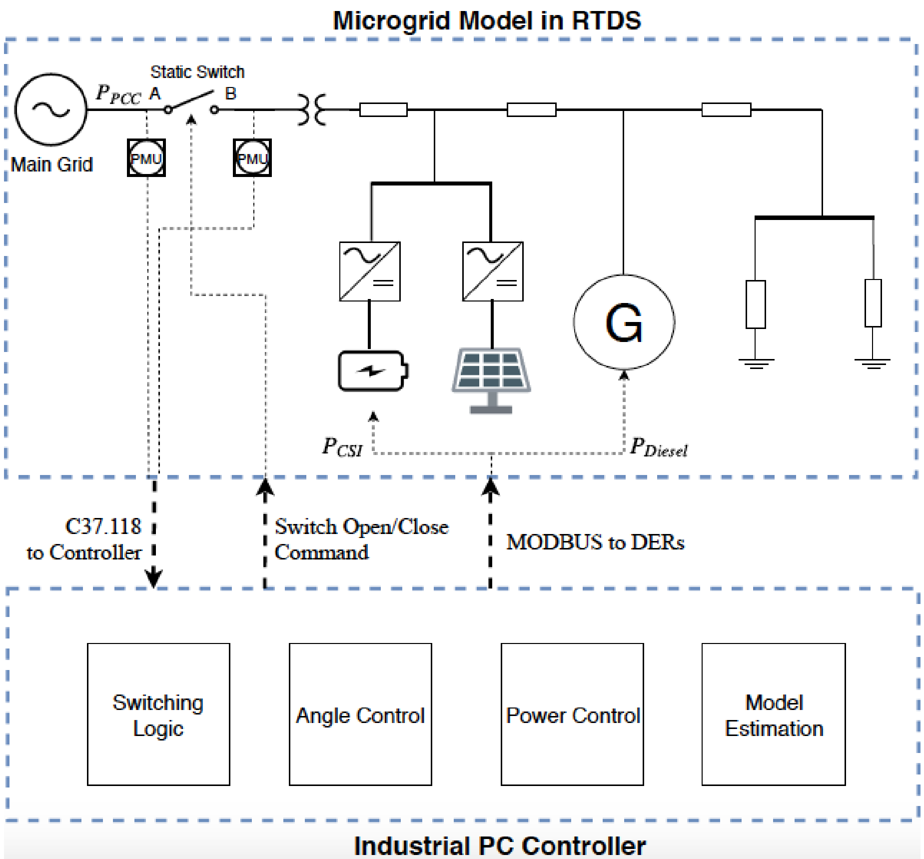


Figure 10: Schematic for a microgrid with multiple DERs and loads.

grid and by the DER primary controls. Therefore, voltage magnitude difference will have negligible effect on reactive power flow and is not discussed here for a smooth transition. Hence, our focus at the time of reconnection is to minimize the difference between voltage angles of nodes A and B [46] The acceptable angle difference (10 degrees) for reconnection is specified in IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power System.

Case Study: Anza Borrego Microgrid

The Anza Borrego Microgrid project focused on the design, installation, and operation of a community scale "proof-of- concept" microgrid [45]. The microgrid was an existing utility circuit with a peak load of 4.6 MW serving 615 customers in Borrego Springs, California, a remote area of the San Diego Gas & Electric service territory. The key aspects of the project were integrating and operating the following types of equipment and systems:

- Distributed Generation
- Advanced Energy Storage
- Price Driven Load Management
- Fault Location, Isolation, Switching and Restoration
- Integration with utility control systems and Microgrid Controls.

This project was funded through a US Department of Energy and California Energy Commission grant, and cost share provided by San Diego Gas & Electric and other project team members. The Energy Commission portion of the project focused on the integration of resources on the customer-side of the meter and evaluated their contribution to microgrid operations, primarily on the Price Driven Load Management aspects of the Microgrid. This project is important in this context because it heavily leverages PMUs to meet the use-cases. The description below illustrates how synchrophasors are the heart of this project.

Fig. 11 shows the location of the seven phasor measurement unit (PMU) devices that send information to the microgrid control function implementation through C37.118 protocol. PMU 1 and PMU 2 send positive-sequence voltage and current phasors on both sides (utility side and microgrid side) of the breaker, frequency measured on both sides, phase angle difference, and, finally, the breaker status. PMU 3 and PMU 4 send positive-sequence voltage and current phasors at the terminals of the Battery Energy Storage System (BESS) connection, along with the state of charge and real and reactive power measurements. PMU 5 is used at the terminals of the PV inverter and sends positive-sequence voltage and current phasors, real, reactive power injection, and the solar irradiance at the inverter location. PMU 6 and PMU 7 send positive-sequence voltage and current phasors at the terminals of the diesel generators along with the real, reactive power injection and the measured power

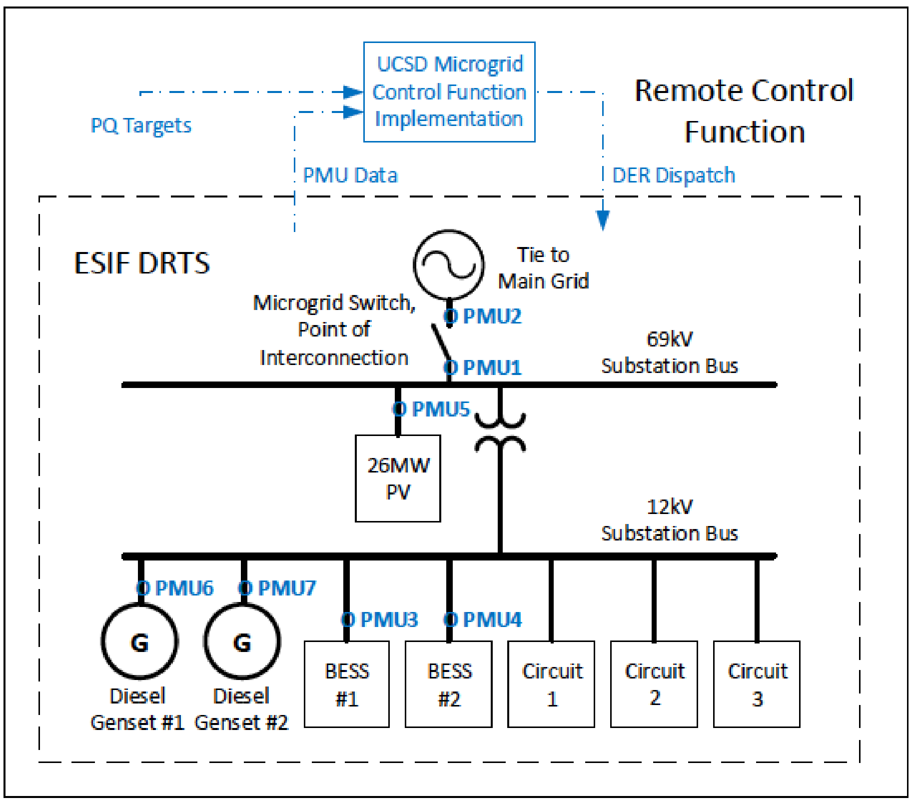


Figure 11: Anza Borrego Microgrid Control Schematic

factor. All the PMU signals are sent at 60 samples per second. Use of the already existing protocols helps eliminate the need to develop new protocols to communicate the information needed by the microgrid controller. Since the information communicated by the 7 PMUs is not redundant, the loss of communication with any PMUs could potentially lead to the controller failing to meet the objectives. However, if there is a need to reduce the amount of high update rate communication with the PMUs due to bandwidth considerations, the PMUs associated with diesel generators (PMUs 6 and 7) could be programmed at a lower data communication rate. This can be made possible due to the slower dynamics of diesel generator assets that a lower update rate control loop could provide equally good performance for those assets [48].

2.9 Proactive Control for Resilience

Decision support for distribution grid operators have been more challenging given the recent increase in the number of weather events and adverse impact on the grid. Some of these extreme events (e.g. hurricanes) are predicted and monitored closely in advance, allowing operators to take pre-event proactive control actions to minimize the impact and enhance resilience. Distribution PMUs provide new opportunities in supporting such proactive actions. Related work is presented in [49]. The concept is to use distribution PMUs to monitor flow on the distribution line, which is expected to go out due to extreme events (e.g. on the hurricane path). Load in the distribution system can be shifted and shed with the series of proactive control to make the flow on this line closer to zero just ahead of expected event. An outage of the distribution line after the event hits will then impact the system operation minimally, as pre-event power flow is almost zero. The data quality requirement is high in this case, given the direct use for control. This work [49] also provides data mining approaches for anomaly detection in distribution PMUs.

2.10 State Estimation

State Estimation (SE) is the methodology that processes online measurements from various points in the system to calculate an as close to real-time as possible power flow solution of that system [50], based on the network topology (admittance matrix of the lines, transformers, etc) which is presumed to be known. Although discussed for over 20 years [51, 52, 53], SE of distribution systems specifically has only recently become critical. A major factor in this growing interest is the proliferation of renewable and distributed energy resources [54, 55] which has vastly increased the uncertainty in distribution system planning and operation.

Specifically, despite their generally positive impact, solar PV and wind resources are characterized by volatility [56], which can cause excessive activation and thus wear of infrastructure owned by the network operator (regulators and on-load tap changers of transformers) [57] as well as power quality issues [58]. The implications of high penetration levels of DER for investments in system upgrades are not obvious [59]. High densities of DER deployment can lead to unacceptable voltage rise, requiring compensation [57], [60], or reverse power flows that require bi-directional switching equipment [61]. Despite the presence of DER, distribution systems may still become congested, particularly with reactive power delivered from the bulk grid [62] or suffer poor voltage profiles [63]. Because state estimation reduces uncertainty, standards such as feeder hosting capacities that limit the penetration of DER may be applied in a softer manner if SE is available. For example, voltage deviations averaged over specific time intervals [64] may be contained through the online control of the distributed generation units that cause them. Similar concerns apply to the increased adoption of electric vehicles (EVs), which can cause congestion (e.g. transformer capacity) particularly if they are clustered on a circuit, and uncertainty regarding residential and commercial customers' behavior in the context of demand response programs.

A related motivation for distribution state estimation is to increase system reliability. The expectation is that SE will improve handling of faults by locating them [50], [52], and responding to them more efficiently [15]. System reconfiguration can also be facilitated by SE [65, 66, 67, 68, 69, 70]. The idea is for SE to support the distribution operator in monitoring conditions that would dictate the need to reconfigure the system, and assess the effects of every reconfiguration option on the operating profile.

Distribution state estimation can thus be considered a current problem of utmost importance, in order to monitor and mitigate impacts of DER while further promoting them, to log the behavior of distribution systems with regard to long-term planning decisions, and to enhance end-customer load service and power quality.

To practically perform state estimation of a power system, a set of online measurements – preferably voltage magnitude, voltage angle, active and reactive power – has to be gathered from at least some points across that system [Abur, Roytelman, Baran], which may include Phasor Measurement Units (PMUs) [67, 71, 72], SCADA, and energy meters. Installing metering equipment and managing state estimation across a control area has traditionally been among the main duties of the transmission system operator (TSO), primarily relying on SCADA systems. In light of the above motivation, distribution system operators (DSO) have been keenly exploring the equipment and software options available to them for deploying SE at the distribution level [53, 68, 72, 73, 74, 75].

Although the premises of the application are straightforward, there are a few major challenges to be considered. Most of the recent SE research has sought for the optimal placement of measurement devices, i.e., defining the least amount of equipment to be used and its optimal point in the system to be controlled

[65, 67, 68, 71, 76, 77]. These approaches, based on optimization techniques or "rules of thumb," reduce the capital expenses for a DSO in order to realize a SE project to meet specific criteria. Nevertheless, if (as suggested from test results) half the network nodes (e.g. transformers, branch points or switching points) of a given feeder have to be equipped with metering devices [71], the cost quickly becomes prohibitive. Absolute minimum criteria for SE of acceptable quality have been estimated at 10% of distribution network nodes to be monitored with measurement modules [67, 71]. Even at this level of instrumentation, broad deployment would entail high costs. Due to cost concerns, a key challenge for distribution state estimation is to rely only on a very scarce measurement infrastructure of arbitrary placement.

Realistically, industrial units, commercial complexes, DG units and energy-intensive facilities tend to install at their points of common coupling (PCC) to the grid (usually, behind their utility meter) their own private smart meters with increased measurement and processing capabilities. In this scope, a DSO may perform SE thanks to privately owned measurement infrastructure, if allowed access to it, thus partly tackling the investment challenge.

At the distribution level, a SCADA approach as in transmission is impractical, because each DSO is usually responsible for numerous feeders, of diverse operating characteristics, mostly independent of one another and dispersed over a particularly large area [51, 72]. Hence, the central elaboration of measurement data for DS SE might be particularly challenging, while even a localized implementation based on control centers with proximity to the monitored systems poses challenges of reliability and maintenance [52]. Alternatively, and as an answer to the aforementioned issues, SE that may be realized in a distributed manner [78] should be preferred for DS feeders.

The importance of employing distribution SE as described above has fairly little to do with control over secondary or low-voltage (LV) end-points; most of the relevant equipment and control actions that can practically affect the operating profile are found and employed at the primary or medium voltage level [56, 57, 62]. The cost and disruption caused by installing metering devices directly at the MV level, not to mention maintenance, are considerably higher [79]. Using LV-side measurements to perform SE for the MV network, on the other hand, has to account for propagating errors across distribution transformers.

Due to the general scarcity of measurements at the distribution level, the corresponding SE has to rely heavily on pseudo-measurements, i.e. on assumptions about the value of variables required to calculate the system state. Usually, such assumptions are made on the active and reactive power of loads, generation and branch flows. Load forecasting [51, 52] constrained optimization approaches [66, 70, 80] and machine learning tools [74, 81, 82] are used to ensure that those pseudo-measurements are as realistic as possible and/or will affect the least the

SE outcomes. In a similar sense, classic SE has been proposed to be replaced by heuristic methods [69]. Some approaches also take advantage of the radial topology of distribution circuits [83].

Although many of these ideas have shown remarkable performance, the most complicated of the pseudo-measurement assessment techniques require considerable overhead in know-how for the DSOs that have hardly been standardized. Additionally, recent advances in deep-learning imply that new tools will keep emerging in the field.

In [84], a novel method is proposed for state estimation in distribution systems to update the system states following an event, e.g., a sudden load change. The event occurs in between the 5 to 15 minutes intervals of a typical distribution system state estimation cycle, without the need to rerun the whole state estimation. This method is of particular interest for real-time monitoring and control applications. The proposed method uses measurements from as few as two micro-PMUs, which are installed at the substation and at the end of the main feeder or laterals. The method is developed based on the *compensation theorem* in circuit theory to generate an equivalent circuit according to the pre-event and post-event feeder data in order to update the state estimation results.

2.11 Load Modeling

Static Load Modeling

There currently exists a mature literature on modeling the *aggregate* load of a distribution feeder by making use of measurements at its feeder-head at substation. The primary application of such feeder-aggregated load models is in sub-transmission or transmission system analysis. However, there is a growing need in practice also to model each *individual* load across the feeder. If available, such individual load models have applications in power distribution system analysis; e.g., to better integrate distributed energy resources or to improve power quality and reliability. Motivated by this observation, a new method for individual load modeling in power distribution systems is proposed in [85]. It works by using the detected *load switching events* in [1, 2] from only one micro-PMU at the feeder head. By tracking the downstream load switching events, the proposed method can make a robust estimation of the ZIP load model parameters for all individual loads.

Transient Load Modeling

There is a growing interest among power system operators to encourage load resources to offer frequency regulation. In prior studies, the potential adverse impact of wide scale load resource participation on distribution system performance, in the *transient* time frame, is often overlooked. In [86, 87], the load transient profile is modeled in the form of a three-phase surge current profile, that could be induced on a distribution feeder once a group of loads responds to a *regulation down* event. Subsequently, distribution grid reliability is analyzed by taking into account the characteristics of the main feeder's protection system as well as lateral's protection system. Case studies suggest that it is possible to jeopardize distribution grid reliability if several regulation down load resources are on the same feeder. Achieving a suitable trade-off between distribution grid reliability and regulation market efficiency will benefit from improved load models as well as real-time monitoring.

3 Sensor Infrastructure Requirements

3.1 Measurement Error

The 2018 DisTT Report discussed accuracy requirements for PMU measurements—e.g., in terms of Total Vector Error (TVE)—relative to different distribution-related applications. These requirements vary widely. It is important to remember that not only PMUs themselves, but instrument transformers through which the sensors are connected to primary distribution system, contribute to the error budget; the latter often dominate. When evaluating algorithms in simulation, it is important to consider how they will handle systematic measurement errors and noise in realistic field settings.

One question raised in the 2018 DisTT Report was whether measurement errors in the field should be modeled as a Gaussian (normal) distribution. Subsequent work, drawing on field data from FNET and micro-PMU deployments, identified that non-Gaussian error modeling is indicated [88], [89].

3.2 Data and Algorithms

The various applications and use cases described above impose different requirements on synchronized measurement data to support them. Topology identification is an instructive reference case because it has both a spatial and temporal dimension, and different levels of performance that can be envisioned. Topology identification can be useful at the most basic level as an off-line application, e.g. for phase (ABC) identification, but is also considered here as an online application running in (near) real-time, whose value increases with speed and accuracy.

In order to define an expectation regarding topology identification, it is helpful to consider three criteria: definition, granularity and confidence interval. That is, what information do we need to know (definition), how often do we need to know it (granularity), and with what degree of certainty (confidence interval). As a starting point, we propose:

- Definition: Identifying the source
- Granularity: 30 data frames per second
- Confidence: 99%

Identifying the source here means identifying the specific distribution circuit, including ABC phase, that feeds a given measurement point from the substation in a radial system. Topology identification should also recognize if and when the circuit configuration is not radial at any given time, in which case there would be more than one source feeding the measurement point. If the density at which sensors are deployed throughout the network is commensurate with the number of circuit branches and sectionalizing or switching points, identifying the source for each sensor should allow identifying the on/off status of every operable switch, or a discontinuity on any branch, and thus provide a complete situational picture of connectivity.

The rationale for a granularity of 30 samples per second is that this is fast enough for some control actions or protection actuation decisions, but readily attainable and meaningful within the phasor domain. Clearly, there is a trade-off between data resolution on the one hand, and the economy of continuous streaming on the other. Streaming grid data at the 30-Hz level is now a very well-established technology, with ample experience from transmission-level synchrophasors. In some cases, going to a 60 or 120-Hz reporting rate may add value (or 25, 50 and 100-Hz, respectively). A half-cycle is the shortest interval for which it makes sense to report quantities defined in terms of the sinusoidal representation, i.e., root-mean-square magnitude values and phase angle of the fundamental. Beyond this granularity, we are talking about point-on-wave (POW) data. POW measurements are obviously essential for local protection applications, including anything that operates within less than a cycle, as well as any applications for which waveform plays a role [**?**]. The emphasis here, however, is on supplemental non-local information that takes advantage of the fact that measurements are synchronized with those from different locations. In the case of topology identification, the key question is about network connectivity, which is readily inferred from phasor domain reports (specifically, phase angle separation) and not specifically associated with waveform. Phasor information at 30 Hz that implies real-time topology changes can be actionable for protection operations, as exemplified by the "Falling Conductor" use case.

Information and actuation speeds on the order of several cycles are the norm for many legacy devices on distribution systems. Others, particularly DER inverters, have much faster internal switching steps, but deal with external controls on time steps slower than a cycle. We should anticipate that capturing full benefits from granular, real-time topology identification algorithms in the future would entail making control decisions, including protection settings and operating settings for DER. Providing topology updates on a time step of several cycles would leave ample time budget for DER control to be computed and actuated. For example, recognition of a new topology might prompt curtailment of PV inverters or EV chargers in order to avoid excess power flow (positive or negative) or voltage violations. Making such adjustments on the order of seconds in response to moderate violations should be fast enough to prevent physical harm to any utility or customer owned equipment.

Likely more important than speed is the confidence with which an actionable topology change is identified. This is a somewhat subjective criterion, and the needs will vary depending on how impactful an action is to be taken on the basis of the topology information. We suggest 99% as a reference benchmark. It seems reasonable to expect that a 1% chance of topology misidentification could be tolerated for control actions which, if taken in error, do not endanger anyone's life, or would not directly result in a loss of load or physical equipment damage. A 10% chance of erroneous operation, on the other hand, suggests non-negligible costs accruing as a result (e.g., due to sub-optimal economic operation, or the trouble of double-checking and correcting previous actions.)

3.3 Communication Requirements

Delay-sensitive control and protection applications require synchrophasor networks that meet the following needs [15]:

1. High data reliability and integrity
2. Low data latency

The synchrophasor datasets at the output of the Phasor Data Concentrator (PDC) are fed to the applications which make decisions by processing the datasets in real-time or near real-time. Link failures and link access delays adversely intervene in the data collection mechanism at the PDC which may lead to not-a-number (NaN) indicators and incomplete synchrophasor datasets.

High data reliability and integrity implies that the communication links should be designed in such a way that the number of NaN indicators becomes minimal. Low data latency means that the end-to-end data latency (which is a function of the communication delay) should stay very low while the data reliability remains at the highest level.

The following items directly affect the end-to-end data latency:

1. PDC data pushing logic (absolute or relative) and the related parameters
2. Type and capacity of the communication links
3. Access to the communication links (public or private network)
4. Network congestion and background traffic conditions in shared communication networks

Synchrophasor-based protection and control applications in distribution networks and microgrids are normally implemented in a hierarchical framework, such as secondary control and backup protection [16]. The communication links can be classified as:

1. links between PMUs and the PDC
2. links between the PDC and the application
3. links between the applications and the local protective or control devices

If the synchrophasor network feeds a protection application, the links between the PMUs and the PDC will be critical since the packet rate in these links is higher than that of the links between the protection application and the local systems. The link between the PDC and the application is not a concern as it can be based on fiber or Ethernet, and the local PDC is often located inside the distribution substation.

The higher the PMU reporting rate the better the voltage/current transient analysis will be done [14]. Protection applications require a high PMU reporting rate, e.g., 60 fps and higher [15]. The typical access delay in public LTE systems is around 10 ms and thus public LTE systems cannot support PMUs with reporting rate of 120 fps for protection applications. New communications scheme may be devised to overcome this limitation. On the other hand, 5G communication systems show promising solutions for delay sensitive smart grid communications and the related IoT applications [90]. Further research is needed to explore the novel outcomes of using 5G technology for synchrophasor networks.

3.4 Cyber-security aspects

The evolution of modern grids with high penetrations of controllable and sensing devices brings an increased urgency to the problem of secure, cyber-physical energy systems that rely on cyber components such as communications, computing, and closed-loop automatic controls for their physical operation. Sensing and communication systems are essential components of smart grids. Realistically, however, communication links and any connected devices are vulnerable to cyber-attacks. The resulting data impairments induce uncertainty and thus degrade the decision-making within protection and hierarchical control applications, including those that are sensitive and time-critical. Therefore, robust protection and control applications should be designed that can continue to operate even in the presence of cyber-attacks.

It is crucial to bridge the gap between resilient grids and realistic communications systems. Microgrids and distribution systems should employ learning algorithms and inference techniques as well as the knowledge of the system states to detect and mitigate cyber-attacks. It should be emphasized that data-driven protection methods can take advantage of the useful features of big synchrophasor datasets, such as correlations over both time and space, to improve the robustness of the protection applications against cyber-attacks. In the context of microgrids, it has been shown that synchrophasor data features along with the knowledge of the microgrid structure can potentially counteract false data injection (FDI) [91] and false command injection (FCI) attacks, while meeting the requirements of the grid protection [13].

In addition to the vulnerabilities described above, it is worth remembering that ICS systems have been targeted through malware integrated in IEC 61850 communications interfaces, which are extensively used throughout distribution systems in linking disparate vendor-supplied instrumentation. IEC 61850 is a critical international standard featured in substation modernization. This sophisticated attack, known as *Industroyer*, is key evidence that PMU systems are a major target of one of the nation's adversaries [92].

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