D-PMU Based Applications for Emerging Active Distribution Systems: A Review

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Abstract: In recent years, the design of low-cost distribution phasor measurement units (D-PMU) together with the development of relevant applications for emerging active distribution systems are in ascendant. Pilot distribution systems have shown prominent evidence on the necessity and benefits of deploying D-PMUs for various applications. To this end, D-PMUs are recognized as indispensable in constituting the next-generation distribution systems. However, it is noticed that existing review papers on prevailing D-PMU based applications is very limited, let alone the state-of-the-art progresses in academic research field. To bridge the gap, this paper reviews four categories of D-PMU based applications in emerging active distribution systems, including: 1) system state awareness, 2) event detection, 3) auxiliary operation, and 4) data mining. In each category, backgrounds, current statuses, and future research directions of applications are discussed thoroughly. Among all reviewed applications, several are evaluated as containing high potential benefits but with low research interests, and consequently deserve immediate attentions.

Keywords: Phasor measurement unit, distribution PMU, Micro-PMU, active distribution system, synchrophasor.

1. INTRODUCTION

Phasor measurement units (PMUs) have been widely deployed in electricity transmission systems, accompanied with mature advanced applications in power system monitoring, protection, and control [1]. Statistics on PMU related publications indicates that researchers' interests on PMUs and their applications have been significantly increased since 2005 [2]. In contrast, PMU deployment in electricity distribution systems is still in an embryonic stage. Indeed, currently, one of the biggest obstacles in deploying PMUs at the distribution level is their high capital costs. However, advanced measuring and sensing systems are the foundation for realizing these characteristics in emerging active distribution systems. Emerging active distribution systems are envisioned to include a deeper penetration of distributed energy resources (solar energy, wind energy, bioenergy et al.) and active participation of consumers. Smart appliances and electrical vehicles are also representative components. In emerging active distribution systems, distributed assets could be optimized to improve operation economic efficiency, promote energy sustainability, enhance resiliency, and coordinate with transmission networks. Furthermore, outage management abilities, self-

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healing abilities, and islanding abilities are featured in dealing with contingencies.

PMUs specifically developed for distributions systems are generally referred to as D-PMU. Recently, two main driving forces have been facilitating D-PMU installations at the distribution level. The first one is technical advances of D-PMUs customized for distribution systems. For instance, Micro-PMU (μPMU), released by University of California (UC) in collaboration with Power Standards Lab (PSL) and Lawrence Berkeley National Lab (LBNL), is specially designed for distribution systems [3] and follows IEEE standard C37.118 which builds the foundation of phasor measurement power systems. μPMUs have advantages of higher measurement resolution, higher accuracy of phase angle measurement, and, the most important, much lower capital cost comparing with PMUs in transmission systems. Other D-PMUs have also been developed by different research groups [4]-[6], where "low cost" has been a striking keyword among design principles. In addition, associated hardware and software, such as phasor data concentrator (PDC) and communication networks, are also under development for distribution systems [7]-[8]. For example, OpenPDC [7] is an open source PDC platform that supports user defined functions.

The second force is the growing needs in distribution system situation awareness. These urgent needs are mainly driven by two facts: (i) the rapid growth of distributed energy resources (DERs), especially renewable energy resources, in distribution systems; and (ii) the higher requirements in reliability, resiliency, and power quality from customers. Although currently only a few distribution systems are equipped with D-PMUs, these pilot distribution systems have clearly demonstrated their necessity and benefit [9]-[10]. Reference [10] summarized and illustrated relevant applications that have been deployed and are being developed in pilot distribution systems, indicating the inevitable trend of deploying D-PMUs in distribution systems to achieve better situation awareness. Similarly, reference [11] describe realized and potential D-PMU applications in an actual innovative distribution network project that deploys D-PMUs, while such high-level discussions mainly focus on implementations, findings, and lessons in this specific project. In [12], potential applications of D-PMU based distribution system situation awareness are reviewed and categorized with respect to the level of the deployment challenges and urgency of the needs. Moreover, measurement requirements in terms of quantity, resolution, accuracy, and latency of corresponding applications are discussed in [11] and [13]. Majority of reviewed applications in [10]-[13] are consistent, although some are classified into different categories and represented via slightly different terminologies.

This paper reviews D-PMU based applications for emerging distribution systems and present their basic methods as well as state-of-the-art progresses in academic research field. Specifically, four categories of applications are reviewed thoroughly: (i) system state awareness related applications, (ii) event detection related applications, (iii) operation auxiliary related applications, and (iv) data mining related applications. All reviewed applications are listed under the four categories in Fig. 1 Some of these applications already exist but their performance could be improved via the adoption of D-PMUs, while others are new applications that are enabled by D-PMUs. For all applications in Fig. 1, potential benefits brought by D-PMUs are ranked, and research interests in the academic field are evaluated based on the number of related publications. For instance, some applications, such as State Estimation, Voltage Stability Monitoring, and Fault Detection & Fault Localization, are critical and gaining more research interests. This review is expected to build up a basic understanding of the existing methods and research statuses of D-PMU based applications, serve as a useful source of references and promote further research and development in this emerging area.

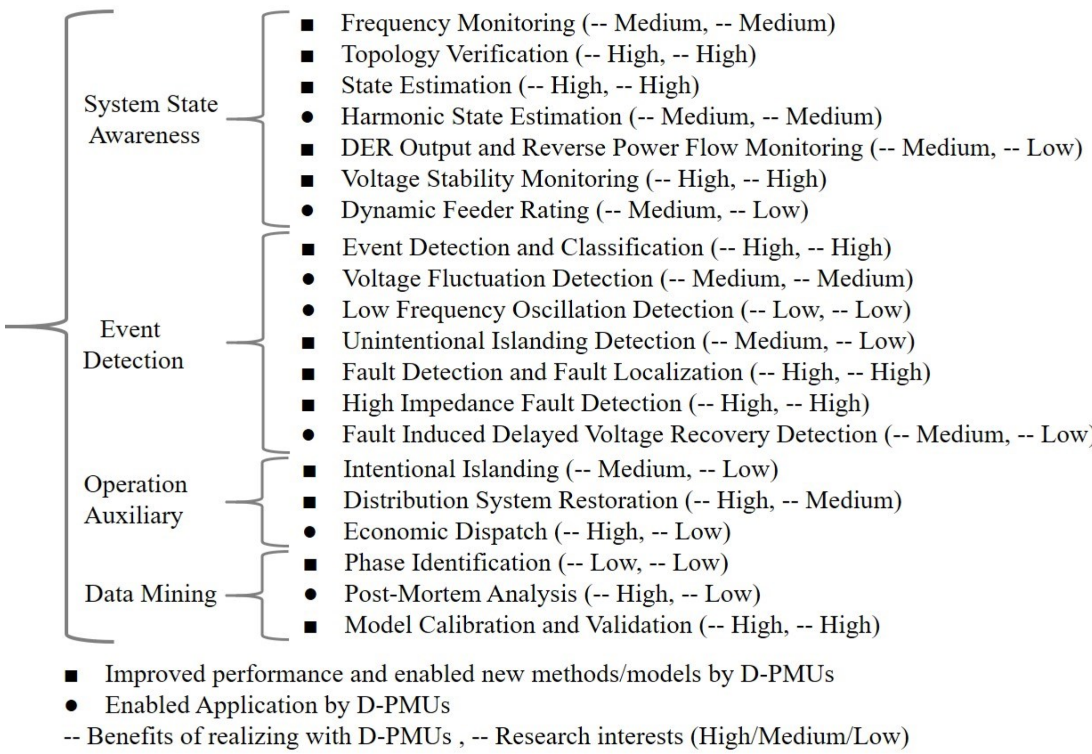

Fig. 1. Summary of D-PMU based applications

The rest of this paper is organized as follows: Section 2 describes synchrophasor techniques of D-PMUs. The four categories of D-PMUs based applications are respectively discussed in Sections 3-6. Final remarks are presented in Section 7.

2. Synchrophasor Technology

D-PMUs are measurement devices that can measure amplitudes and phase angles (i.e., phasors) of sinusoidal voltages and currents. In addition, frequency and rate of change of frequency (ROCOF) are the other two basic measurements that can be provided by D-PMUs. Moreover, additional measurements such as harmonic phasors and sequence components are also available for advanced D-PMUs with corresponding enabled functions.

A D-PMU is usually composed of data acquisition module, synchronization module, computation module, and communication module [14].

- *Data Acquisition Module* samples and digitalizes voltage and current waveforms that are scaled down via instrument transformers and filtered via anti-aliasing filters at a high frequency. For instance, a typical sampling frequency is 2880Hz (i.e., 48 samples per cycle for a 60Hz system).

- *Synchronization Module* synchronizes samples via the disciplined acquisition method or the free-running acquisition method, both relying on pulse-per-second (PPS) signals which are generated by synchronization module and synchronized by coordinated universal time (UTC) with an error of less than 1μs. Specifically, in the disciplined acquisition method, a PPS signal coordinates a local clock that controls sampling inside the PMU every second. In contrast, instead of coordinating with the PPS signal, the free-running acquisition method provides a time offset between the local clock and the PPS signal. That is, the free-running acquisition method is less accurate but applicable when the local clock is not accessible or adjustable.
- *Computation Module* receives samples and executes phasor estimation algorithms to extract phasors of fundamental frequency components. Discrete Fourier transform (DFT), direct model matching, and wavelet transform are among generally used algorithms, in which DFT and its enhanced versions are the most widely used [14]-[15]. Improvements to existing mature methods and developments of new algorithms for phasor estimation are being explored [16]-[17]. However, it is noteworthy that different methods could present various levels of accuracy. Reference [18] compared performance of several methods in estimating synchrophasor, frequency, and ROCOF of unbalanced systems. Specifically, for methods like DFT, the window function, such as rectangular or Hann window function that sets sample weights, as well as the window length, such as 2 cycles or 4 cycles that indicates sample coverages, are two main parameters that would highly impact phasor estimation accuracy [14]. On the other hand, frequency and ROCOF estimations could be derived either as byproducts of phasor estimation via post processing, or via a completely different estimation method particularly targeting on frequency and ROCOF calculations. Estimated results and corresponding time tags are usually generated at a frequency of 25Hz to120Hz.
- *Communication Module* packages and uploads results to PDCs, which further route and collect packaged data via different transmission medium (i.e., copper wire or optical fiber Ethernet networks) and protocols (i.e., TCP/IP) [14]. In addition to measurement data, a data packet would also contain descriptions to synchronization quality and errors, and other protocol-related information [14].

3. System State Awareness

D-PMU based system state awareness applications focus on monitoring system operation situations in real-time and providing system status continuously and periodically.

A. Frequency Monitoring

Frequency deviation is the most important index that can reflect system generation-load balance and indicate system stability and equipment safety. D-PMUs can directly measure frequency and ROCOF. Comparing with existing frequency monitoring devices, network configured D-PMUs could provide synchronized frequency monitoring of multiple points with higher accuracies.

It has been recognized that waveforms at the distribution level generally contain more noises and harmonics than the transmission level, so that more dedicated frequency estimation algorithms inside D-PMUs are required to achieve preferable accuracy [19]. Although a frequency estimation would be available with signals from a single phase [19], using signals from all three phases is preferred because of more robust estimations in unbalanced distribution systems [20]-[22]. A single displayed frequency value usually records the average of estimated values of available phases, or frequency of the positive sequence component when all three phase signals are available.

B. Topology Verification

Knowledge of distribution network topology is essential for system monitoring and control. However, topology data is often outdated due to asynchronization after reconfiguration or restoration actions. To this end, topology identification is executed periodically prior to system monitoring and control applications, such as state estimation and reconfiguration. Traditionally, the most common approach of topology identification is based on minimizing the state estimation residual [23]-[24]. This approach can be easily extended to incorporate synchrophasors from D-PMUs with enhanced performance.

Recently, pattern recognition-based methods with D-PMU measurements have been recognized to be able to derive more reliable results [25]-[26]. Reference [25] proposed a voting based topology detection method, according to similarities of possible topologies quantified by differences of voltage magnitudes and angles. Time series D-PMU measurements are leveraged in reference [26] to extract trend vectors from voltages with respect to a certain switching action, while actual switching actions are detected by matching real-time measurements with trend vectors in a library. This is based on the fact that similar switching actions would induce voltage profiles of similar patterns. In addition, an extreme situation is discussed in reference [27], which reconstructs the entire distribution grid via voltage measurements while assuming that no prior topology information is known. These works have shown a foreseeable development trend that, with data support from D-PMUs, approaches enabled by big data as well as approaches integrated with pattern recognition and machine learning are getting attention.

C. State Estimation

Distribution system state estimation (DSSE) is a key functionality for system state awareness, which processes redundant raw measurements, together with network information, to estimate system state variables. Comparing with transmission system state estimation (TSSE), DSSE is more challenging because of heterogenous devices and unsymmetrical system configurations [28]. References [29]-[30] thoroughly reviewed state-of-the-arts techniques and major challenges in current DSSE, and also discussed new directions in the next-stage DSSE development. Both papers indicate that incorporating synchrophasors from D-PMUs into DSSE is a promising direction to significantly enhance the accuracy of DSSE.

Indeed, comparing with non-synchronized module measurements from remote terminal units (RTU) with supervisory control and data acquisition (SCADA), synchronized phasor measurements from D-PMUs bring at least multiple benefits: (i) higher estimation resolution, (ii) higher accuracy on individual measurements, and (iii) synchronized magnitude and phase angle measurements.

Case studies are provided to intuitively illustrate the benefits of D-PMUs over SCADA on DSSE. The simulation is conducted on an unsymmetrical three-phase four-conductor configured system [31]. A WLS based DSSE model and the elimination approaches that process zero-injection phases and neutrals are applied [31]. The system diagram and measurement configuration are shown in Fig. 2. Current magnitude measurements from SCADA (maximum measurement error (MME): 3%) and voltage measurements from D-PMU (MME of magnitude: 1%, MME of phase angle: 0.01 rad) are installed at all three phases of the substation bus. Load pseudo measurements are supplemented. By deploying different measurements on all three phases of buses 15, 49, 63, and 75, the following three cases are studied:

- *Case A*: SCADA voltage magnitude measurements (MME: 3%) on buses 15, 49, 63, and 75.
- *Case B*: SCADA voltage magnitude measurements (MME: 1%) on buses 15, 49, 63, and 75.
- *Case C*: D-PMUs voltage measurements (MME of magnitude: 1%, MME of phase angle: 0.01 rad) on buses 15, 49, 63, and 75.

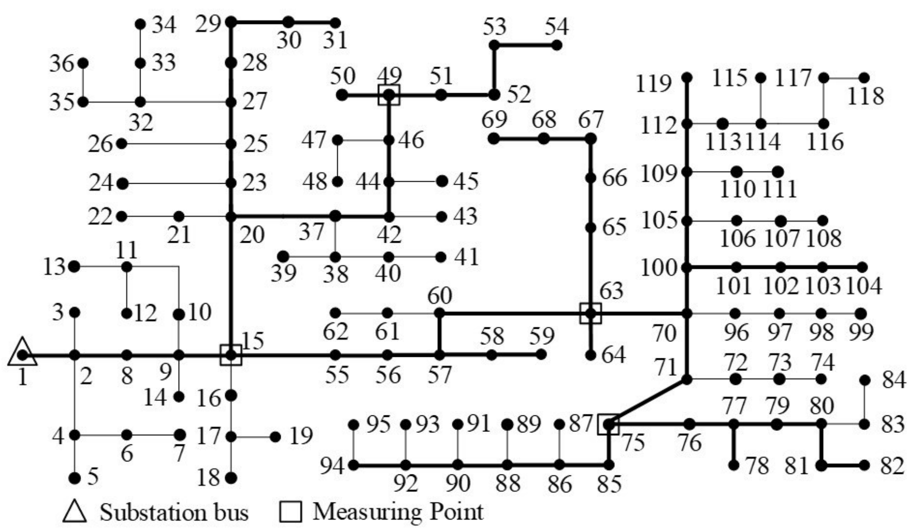

Fig. 2. System diagram and measurement configuration

In each case, 500 independent DSSE runs with randomly generated measurement errors are executed. Average relative root-mean-square error (RRMSE) of phase voltage magnitudes over 500 runs are compared in Fig. 3 and Fig. 4. Non-neutral phases of all buses are ordered from 1 to 244 (some laterals may only contain single or two phases). Fig. 3 shows that Case C dramatically outperforms Case A, which indicates the importance of measurement accuracy on overall performance of state estimation. Fig. 4 shows that although not RRMSE of every phase in Case C is smaller than Case B, majority phases (i.e., 170 out of 244 or 69.67%) have smaller RRMSE values. The average RRMSE over all phases of Case C is 0.1483%, smaller than 0.1551% of Case B. This demonstrates the importance of phase angle measurements in improving the performance of state estimation.

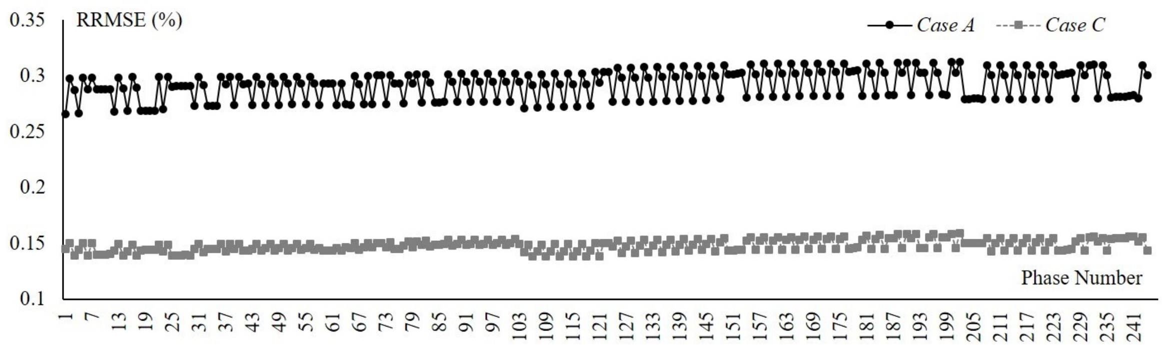

Fig. 3. Comparison of *Case A* and *Case C*

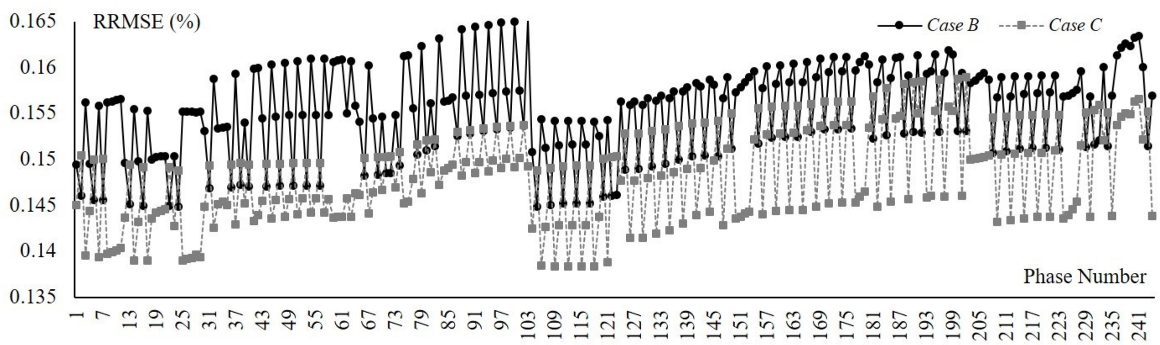

Fig. 4. Comparison of *Case B* and *Case C*

Moreover, with phasor measurements, DSSE models can be degraded to linear formulations and solved without iterations [32]-[33]. A linear DSSE model proposed in reference [32] receives D-PMU measurements and load measurements from smart meters, in which the latter is converted into currents to keep model linearity. With only phasor measurements, reference [33] performed a model reduction approach to reduce the needs on the number of measurements while guaranteeing observability and improved computational performance.

However, since full system observability is unlikely to be guaranteed solely by D-PMUs in the close future, hybrid DSSE models and data fusion methods that coordinate measurements from multiple sources such as D-PMUs, SCADA, and intelligent electronic devices (IED) have been widely studied [34]. A highly compatible and easy to implement approach with existing DSSE function modules is proposed in reference [35]. In this method, DSSE without synchrophasors from D-PMUs is first executed, and the obtained result is refined in the second DSSE execution by integrating synchrophasors. Reference [36] incorporates D-PMU measurements using weighted least square (WLS) and least absolute value (LAV) estimators when refreshed SCADA measurements are available and unavailable respectively, considering resolution difference between D-PMUs and SCADA measurements. Similar strategy is adopted in [37] which uses Extended Kalman Filtering (EKF) and Unscented Kalman Filtering (UKF) based dynamic state estimation to track systems states, when SCADA measurements are not updated.

Indeed, coordinating measurements from different sources faces with two prominent issues of time granularity and synchronization (time skew) [38]-[39]. Specifically, synchrophasors from D-PMUs refresh dozens of times per second while non-synchronized SCADA measurements update every several seconds. To this end, a two-time-scale framework is proposed in [38] to coordinate sources of different refresh rates, and a credibility method is proposed in [39] to handle synchronization issues.

D. Harmonic State Estimation

Widely deployed power electronic devices, especially converters that connect renewable DERs and distribution grids, introduce significant harmonic pollutions in distribution systems. This could degrade power quality, damage equipment, and overheat distribution lines. D-PMUs can be embedded with harmonic phasor estimation functions to provide synchronized harmonic phasor measurements. Reference [40] discussed a design of D-PMUs to measure harmonic synchrophasors in three-phase distribution systems. Reference [41] reviewed algorithms adopted in D-PMUs to extract harmonic phasors, which are classified into non-parametric (i.e., DFT) and parametric (i.e., Kalman filter) methods. In addition, an inter-harmonic phasor estimation algorithm for D-PMUs is studied in [42], although few D-PMUs may realize this function in the close future.

Harmonic state estimation (HSE) is to locate major harmonic sources and estimate harmonic voltage and current distributions [43]. HSE can be enabled by harmonic phasor measurements from D-PMUs. HSE models based on harmonic synchrophasors from D-PMUs can be found in [44]-[45]. A straightforward extension from WLS DSSE of fundamental frequency is presented in [44]. Refence [45] further integrated upper/lower power consumption bounds of harmonics into HSE. Moreover, refence [46] proposed a weight adjustment method in a WLS based HSE to improve estimation accuracy. Generally, full system observability is not expected due to limited harmonic phasor measurements. Thus, singular value decomposition (SVD) method is often adopted to obtain an HSE solution [44]-[46]. At last, by providing harmonic distribution estimation, HSE can facilitate system harmonic management [47].

In fact, many distribution networks are equipped with harmonic monitors, which can be either offline or online. Online monitoring enables real-time assessment to harmonic phasors. However, measurements are with low resolutions and unsynchronized. Time skew could cause large errors on phase angle measurements of high-order harmonics. In addition, harmonic monitors are typically installed at connection buses of harmonic sources to supervise their harmonic currents injections, which may not be proper measurement points for HSE. Therefore, HSE with harmonic monitors would suffer larger estimation errors, especially when the full system observability is not guaranteed.

E. DER Output and Reverse Power Flow Monitoring

D-PMUs installed at interconnection points of DERs and prosumer subsystems with DERs can provide high resolution measurements to enable real-time performance monitoring. Outputs of DERs and prosumer subsystems as well as their reverse power flows are two main factors to be monitored. Such measurements can also help refine revenue settlements of DERs and prosumer subsystems.

- *DER Reverse Power Flow Monitoring*: With a deeper penetration of DERs, originally designed unidirectional power flow operation schemes of traditional distribution networks may not be suitable for bidirectional power flow operations of emerging distribution systems. Specifically, although reverse power flow is not necessarily problematic that has to be prohibited, because it is a main cause of voltage rise in distribution feeders [48]-[49], identifying flow directions is critical to protection and voltage control. Phase angle information provided by D-PMU measurements can help indicate power flow directions.

- *DER Output Monitoring*: Power outputs of front-of-the-meter DERs can be effectively measured if D-PMUs are available at their interconnection points, while power outputs of behind-the-meter DERs are difficult to be extracted because of information incompleteness. Date driven methods such as those proposed in [50]-[51] put in efforts to reveal generations of behind-the-meter DERs via massive data and data mining tools.

F. Voltage Stability Monitoring

The ability to maintain voltage stability is critical to operational security of distribution systems, especially with a high penetration of renewable DERs [52]. Proper definitions of and assessments to voltage stability in real time are of importance to system secure operation. Voltage stability assessment methods are reviewed and classified in two categories based on their related measurements: (i) single location measurement based methods, and (ii) wide-area measurement based methods [53]. The latter category is further divided into non-synchronized and synchronized measurement based methods. Although voltage stability index (VSI) that measures voltage instability margins could be accessed by single-port method, which matches the impedances of the load and the Thevenin equivalent of the remaining system via single location measurements [54], its low accuracy remains a prominent concern. The major reason is that this method assumes the monitored system keeps unchanged during load variations [55], which is far from realistic in practical situations. Obeying the idea of Thevenin equivalent, the coupled single-port method [56] and linear index method [57] that require wide-area measurements are able to consider system changes so that enhanced accuracy can be achieved. Moreover, synchronized measurements could help achieve even higher accuracy. Different variations of VSIs based on single-port method are reviewed in [58], and impacts of measurement uncertainties and accuracies on effectiveness of VSIs via Thevenin equivalent impedance matching are discussed in [59]-[60].

In addition to Thevenin equivalent based methods, an offline trained and periodically updated decision tree based VSI assessment model is proposed in reference [61]. It conducts voltage stability analysis utilizing the past representative and forecasted system operation conditions. This method can be implemented with either non-synchronized or synchronized measurements, while the latter can lead to higher VSI accuracy. Indeed, synchronized measurements from D-PMUs not only improve the performance of aforementioned methods, but also enable a wider range of methods such as singular value decomposition and advanced VSI prediction method.

By leveraging the radial topology of distribution networks, VSIs of buses can be accessed individually by forward sweeping from substation buses with measurements only at substations and load pseudo measurements of all buses [62]-[63]. However, this method has low accuracy and causes error accumulations on VSIs of downstream buses. In addition, emerging active distribution systems are more frequently operated in looped structures, which would invalid the forward sweeping based method.

G. Dynamic Feeder Rating

Static feeder rating usually corresponds to the most severe situation, which could highly underestimate line current carrying capacities most of the time. In contrast, dynamic feeder rating reveals line capacities with respect to current line statuses and ambient situations, which could unlock network capacities. Benefits of dynamic feeder rating in reliable and economic operation were justified in reference [64]. A comparative analysis of dynamic line rating models was presented in reference [65]. High accuracy voltage/current synchrophasors from D-PMUs provide valuable inputs to dynamic feeder rating. It is noteworthy that based on dynamic feeder rating, congestion management of distribution systems can be well studied [66]-[67].

4. Event Detection

Distribution systems continuously experience various events ranging from normal operation actions (i.e., capacitor bank switching) to disruptive disturbances (i.e., faults). These events can be detected via valuable applications while their impacts can also be evaluated.

A. Event Detection and Classification

A variety of events can occur in distribution systems, and general event detection methods can be designed to detect certain types of events. Event detection is usually followed by an event classification routine to provide more detailed information of the event [68]. Some literatures on event detection mainly focus on disruptive events, i.e., anomalies or disturbances that could cause issues of operational security, system stability, and power quality [68]-[70]. D-PMU based event detection approaches have been extensively explored [69]-[72]. Reference [69] proposed a hierarchical detection approach that contains local and central rules by using local and wide area D-PMU measurements respectively. The detection methodology relies on the idea that the steady state equations are invalidated during transient process caused by disruptive events, i.e., violations on the steady state equations are taken as an indicator to infer the occurrence of possible events. A centralized event detection approach proposed in [70] considered D-PMU measurement errors and losses, while D-PMU measurement losses are compensated by a specifically developed PDC. The approach discussed in [71] targeted on detecting events that could change system admittance matrix. A hidden structure semi-supervised machine learning model is proposed in [72], which is compatible to labeled, partially labeled, and unlabeled D-PMU data as training data.

At last, it is emphasized that for certain types of fault events that can be detected without D-PMUs, the adoption of D-PMUs could achieve higher success detection and lower false detection rates. While D-PMUs can also enable the detection of other fault events that were not able to be detected, such as voltage fluctuations that only last several cycles. Furthermore, functions of several existing devices can be substituted by or integrated into D-PMUs. For example, the under/over frequency detection function in frequency measuring instruments can be provided by D-PMUs. At last, relying on real-time communication capabilities of D-PMUs, event trajectories can be tracked in real time instead of post reviewing.

B. Voltage Fluctuation Detection

Voltage sag and voltage swell are two relevant phenomena of voltage fluctuations and are important in power quality evaluation. Voltage sag refers to temporary voltage reduction that lasts from several cycles to several seconds, while voltage swell represents temporary voltage increase. Specifically, the sudden increase in intermittent renewable DERs, such as photovoltaics (PV) and wind generations, is more likely to trigger voltage fluctuations than traditionally main causes such as faults and motor startups [73]-[74]. In addition, different from transmission lines, distribution feeders have comparable impedances and resistances, which makes voltages also sensitive to active power injections and weakens the effectiveness of reactive power compensation-based voltage regulation technologies [75]. Consequently, sudden changes in solar irradiances and wind speeds would cause considerable fluctuations in power outputs, which can be easily propagated to voltages [76]. D-PMUs, by sampling voltage waveforms with high frequency and reporting voltage phasors with fine resolution, are capable of recording voltage fluctuations.

Comparing with SCADA, transient voltage fluctuations can be recorded by D-PMUs and then sent to detection modules. Detections can be done either inside D-PMUs with embedded algorithms to process samplings, or outside D-PMUs with uploaded phasor measurements. Reference [77] compared several detection algorithms with various performances against different occasions and parameter settings, in which the most classical algorithm is to calculate root mean squared values of voltage samplings with certain window functions. Voltage sags/swells are detected when the root mean square value is lower/higher than given thresholds. It is noteworthy that voltage fluctuations could impact the performance of phasor estimations [78].

C. Low Frequency Oscillation Detection

Low frequency oscillation is of particular concern in transmission systems, while may not be the case in distribution networks. In fact, low frequency oscillations could be propagated into distribution systems through substations. References [79]-[81] validated that low frequency oscillations occur in transmission systems can be effectively detected with D-PMUs deployed at the distribution level. A series of work [79]-[80] presented detected low frequency oscillation cases excited by various disturbances, using monitoring data from Western Interconnection of the North American power system via a frequency monitoring network consisted of D-PMUs at the end-user voltage level (120V). Similarly, the work in [81] monitored and analyzed low frequency oscillations via measurements from D-PMUs deployed in 120V distribution networks in Texas. In general, on one hand, low frequency oscillation detection with D-PMUs in distribution networks can supplement the detection in transmission networks. On the other hand, once detected, distribution networks could damp oscillations with available resources to mitigate their potential damages [82].

D. Unintentional Islanding Detection

Unintentional islanding can be triggered by faults, human/devices errors, and accidental protection disoperation. To this end, unintentional islanded regions would undergo severe unstable frequency and even blackouts. Detection methods can be classified into local and remote approaches. Local approaches are further classified as passive and active, while remote approaches mainly refer to power line carrier communication (PLCC), signal produced by disconnect (SPD), and SCADA based approaches [83]. Generally, local approaches are more economical but suffering from large non-detection zones, while remote approaches are with high investment costs but achieving small or zero non-detection zones [84].

D-PMU based unintentional islanding detection approaches are in the type of remote method. Synchronized frequency and voltage phasor measurements from D-PMUs enable the direct comparisons of these values between the main grid and suspicious islanded regions. Unintentional islanding could be detected when their differences are larger than certain thresholds [84]. Other features extracted from D-PMU measurements, such as total harmonic distortions, ROCOF, and rate of changes of angle differences, could further assist in islanding detection [85]. Furthermore, if properly configurated, D-PMUs can even directly monitor circuit breaker Open/Close statuses. considering multiple available indicators from D-PMUs, principal component analysis (PCA) was adopted in references [86] and [87] to build up an artificial neural network classifier for obtaining a unified result, if disagreements between indicators occur. Comparing with other methods, D-PMU based approaches have incomparable smaller non-detection zones than local approaches, and obviously surpass SCADA based approaches. In addition, they do not require specific transmitters and receivers that are needed by PLCC and SPD. Analogously, several practically successful islanding detection cases using indicators of frequency difference and change of angle difference from PMUs in the transmission network are reported in [88].

E. Fault Detection and Fault Localization

Distribution system protection is undergoing an evolution process from conventional relaying based to microcomputer relaying based, in which the former compares acquired analog voltage/current quantities with preset thresholds to activate breakers while the latter not only compares measured quantities but also extracts features from measured quantities via signal processing techniques to characterize faults. Indeed, microcomputer relaying protection has advantages of enhancing detection reliability, function integration, and configuration flexibility. With the high-frequency sampling functionality as well as the built-in high-performance calculation and communication abilities, D-PMUs are suitable to be endowed with fault detection abilities and applied in fault detection [89]. Reference [89] reviewed signal processing techniques that are capable of extracting fault features, such as Fourier transform, wavelet transform, and S-transform. Without surprising, different methods may derive different feature extraction results and in turn affect fault detection performance [90].

When a fault is detected, certain breakers will trip to isolate the fault. Meanwhile, fault localization, which is critical to load restoration, will be activated [90]. As soon as the fault is localized, part or all of the out-of-service loads can be restored by further isolating the fault within a smaller outage area and transferring affected loads via network reconfiguration [91]. Fault localization can also help accurately direct staffs to the fault site, so that line inspection efforts can be significantly reduced. References [92] discussed a method to utilize D-PMU data for improving localization accuracy, which is mainly based on impedance and voltage sag calculation and comparison. Without D-PMU data, bus voltage angles are assumed as 0˚, 120˚ and -120˚ for three phases in the voltage sag based method in [93], which otherwise can be measured via D-PMUs to identify fault locations more accurately. Fault localization was studied in [94] by executing multiple state estimation scenarios with the same set of measurements but different potential fault locations, and the scenario with the smallest state estimation error is identified as the final fault location. Reference [95] proposed a compensation theorem based method to calculate voltage change sequences along a feeder with D-PMUs installed on both ends, and then identify the fault location as the place where the voltage difference between the corresponding values in the two sequences is minimized. The importance of phase angle measurements to this method is particularly enhanced in [95] with two design cases:

- Case A, A 40kW+80kVAR load is switched ON at bus 11, the pre-event and post-event voltages at a D-PMU measuring point are 2.332∠5.1183° kV and 2.296∠5.2583° kV. The voltage differences ΔV are 35.9∠176° V and 35.5 V with the phasor and module measurement respectively, namely from D-PMU and SCADA.
- Case B, A 40kW-80kVAR load is switched ON at bus 11, the pre-event and post-event voltages at a D-PMU measuring point is 2.332∠5.1183° kV and 2.331∠5.8693° kV. The voltage differences ΔV are 30.6∠97° V and 0.9 V from D-PMU and SCADA measurements respectively.

It can be seen that in Case A, the voltage differences ΔV at measuring point with and without including phase angle measurements are close, with which the voltage sequences and their differences are close as well. It leads to a correct identification of event location at bus 11. In comparison, in Case B, the voltage difference ΔV at measuring point without phase angle measurements is significantly bias, which invalids the voltage change sequence calculation and results in an incorrect identification of event location of bus 1.

F. High Impedance Fault Detection

Among all types of faults in distribution systems, high impedance fault (HIF) is worthwhile to be emphasized. A HIF occurs when an overhead line conductor contacts with ground through high impedance objects such as trees and poles, or falls down to asphalt, sand, or concrete ground surfaces [96]-[97]. Different grounding objects could induce fault currents of different levels and present different fault phenomena [96]-[97]. However, it is difficult to detect HIFs on distribution feeders via conventional relaying protection, because of relatively low fault currents restricted by high grounding impedances. Alternatively, HIF detection can be conducted via the microcomputer relaying protection and the evaluation approaches to extract characteristic features from voltage/current samplings [98]-[99]. Obviously, the aforementioned functions can be realized via D-PMUs and PDCs. Reference [98] proposed a HIF detection method using features like changes of current phasors and the 3rd harmonic phasors extracted from D-PMUs. An evidential reasoning approach that deals with multiple features extracted from D-PMUs is proposed in [99] to pursue a wider detection scope and a higher detection rate. The opening and closing transformations from mathematical morphology are introduced in [100], which develops an operation that is able to derive HIF signatures from voltage waveforms. It is shown in [100] that HIF can be distinguished from other voltage fluctuation events through substantially different signatures.

G. Fault Induced Delayed Voltage Recovery Detection

Fault induced delayed voltage recovery (FIDVR) is a phenomenon that voltage remains significantly low for a relatively long time following a fault clearing, usually lasting several seconds. FIDVR is usually caused by AC motor stalling, particularly air conditioners in distribution systems, triggered by instant low voltages during fault periods. Reference [101]-[102] reported interesting FIDVR events recorded by power quality devices in the Southern California Edison (SCE) network, showing the entire occurrence and development procedure of FIDVRs.

In an FIDVR event, the bus voltage drops instantaneously when fault happens and climbs slowly after fault is cleared. Interestingly, induced by improper switching of capacitor banks that are triggered by load shedding and reconnection during/after the fault, overvoltage and undervoltage may appear alternatively after fault is cleared. Indeed, it is possible to mitigate FIDVR and avoid overvoltage/undervoltage, if the FIDVR event can be timely detected. D-PMUs are able to not only record but also track the entire procedure of an FIDVR event in real time, which can support FIDVR detection and guide the corresponding mitigation steps. Reference [103] developed a data-driven probabilistic detector that uses wide-area high resolution voltage measurements to detect FIDVR events following disturbances and access their severities. However, as SCADA measurements are unable to meet its real-time and resolution requirements, FIDVR events are detected repeatedly at different time points after fault clearing. To this end, decisions tend to be more accurate at later decision time points due to more available information but would endure longer decision time. The case studies in [103] were implemented on the New England 39-bus system with three-phase faults occurred to give rise to FIDVR events. The number of decision time points is set as 20. The results of 1164 testing cases are reported in Table I. It can be seen that the proposed approach has high correct rate and can make decisions very fast (0.14 seconds for average and most cases are detected in early decision time points) in the early stage of FIDVR considering that FIDVR events can last minutes. Fast detections could gain more time to deploy control actions for mitigating FIDVR events [104].

Table I FIDVR DETECTION RESULTS [103]

Decision time points	No. of decided cases	Correct rate	Decision time points	No. of decided cases	Correct rate
1	793	100%	11	13	100%
2	88	100%	12	5	100%
3	59	100%	13	8	100%

4	39	100%	14	6	100%
5	33	100%	15	3	100%
6	19	100%	16	2	100%
7	26	100%	17	1	100%
8	11	100%	18	2	100%
9	9	100%	19	0	/
10	14	100%	20	31	87.10%
Overall correct rate		99.66%	Average decision time		0.14 seconds

5. Operation Auxiliary

This section discusses applications that leverage D-PMUs to support reliable auxiliary services in system operations.

A. Intentional Islanding

When a major outage happens, microgrids as well as pre- or post- partitioned sub-regions could disconnect from the main grid and operate independently [105]. D-PMUs provide valuable supports to the islanding decision-making and automation control during islanding and load shedding processes [106]. Reference [107] presented valuable experimental data recorded by D-PMUs in intentional islanding, and concluded from the experiments that D-PMUs are of great support in decision making, control, and management of islanding events. In addition, after successfully islanded, D-PMUs resided in individual microgrids or sub-regions can continue providing situational awareness, similarly as in the normal operation mode.

B. Distribution System Restoration

A sophisticated system restoration strategy could improve system reliability by minimizing disruptions to energy services. Indeed, D-PMUs can enhance system restoration under different restoration situations. After a fault occurs and is isolated, we hope that loads in out-of-service areas will be restored as many as possible. In this process, D-PMUs can contribute by monitoring system frequency and voltage stability. A support vector machine (SVM) based method was conducted in [108], which leverages D-PMU measurements to predict system stability before energization.

Furthermore, microgrids that are islanded during disturbances of the main grid would be reconnected during restoration. Before reconnection, it is necessary to synchronize voltage magnitudes, frequencies, and voltage phase angles of islanded microgrids to the main grid [109]. Synchronization strategies of reconnection controllers proposed in references [110]-[111] use both voltage phasor and frequency measurements at both sides of the coupling circuit breaker as inputs, which shows the important role of D-PMUs in supporting data to reconnection controllers.

C. Economic Dispatch

Real-time optimal power flow (OPF) and economic dispatch (ED) instruct DERs' outputs in every few minutes to achieve minimum operation cost or other specific objectives. However, due to characteristics of asymmetric three-phase lines, imbalanced loads, and comparable resistance and reactance of lines, OPF of distribution networks have to be casted as AC optimal power flow (ACOPF) models, which are nonlinear and nonconvex and in turn difficult to solve efficiently and optimally. Semidefinite and second order conic programing relaxed models developed in recent years have shown potential ability in solving ACOPF problems optimally [112]. However, these acceleration strategies and tightness conclusions are only applicable on radial distribution networks, while becoming invalid in looped/meshed networks. However, emerging distribution systems are likely to be operated under looped/meshed topology.

Because of the aforementioned characteristics of distribution networks, analytical linearization to power flow models are inapplicable, while data driven linearization methods that directly access sensitivities between decision variables present an alternative way [113]. Power to voltage sensitivities are estimated dynamically with results from DSSE and further used in the bus voltage optimization [114]-[115]. With state equations that are linearized against the current operation points from DSSE, an incremental ED model is built in [116] to calculate ex-post distribution locational marginal prices. Indeed, the dynamic interactions between system operation optimization and DSSE in [114]-[116] essentially form a closed loop as shown in Fig. 5.

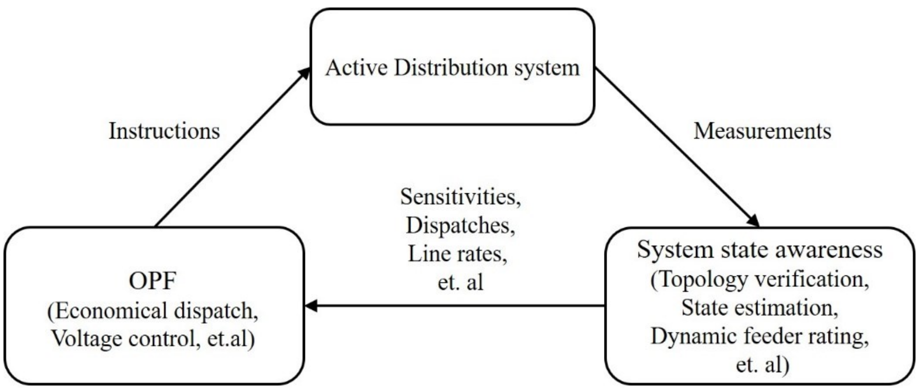

Fig. 5 A closed loop of measurement based OPF

At last, it is worthwhile to emphasize that more detailed system situation awareness , such as real-time actual outputs of DERs, voltage stability information, and line rating information, are available from D-PMUs, which could support the development of robust and efficient distribution system OPF models. This area of work is currently limited.

6. Data Mining

D-PMUs will generate a large amount of data, which could provide valuable information after being properly filtered and processed. Data driven applications discussed in this section intend to derive useful information from data to assist system modeling and analysis.

A. Phase Identification

Phase connection information of loads and laterals is usually unreliable/unavailable due to load and lateral shifting for phase balance, restoration, and maintenance purposes. Such inaccurate information could degrade performance of many distribution applications. Cross-correlation of voltage magnitudes is commonly used in phase identification, by recognizing that voltage magnitude time series at different nodes of a same phase are closely correlated [117]. Needless to say, as D-PMUs can enhance precision of voltage magnitude measurements with higher granularity, they are beneficial for phase identification applications. More importantly, synchronized voltage phase angle measurements from D-PMUs could enable direct comparison of phase angles, which brings important benefits in phase identification [118]. Reference [118], by leveraging voltage phasors from D-PMUs, identified phases by comparing voltage magnitude correlations and phase angle differences. Indeed, phase identification is mostly needed in low voltage distribution systems, in which smart meters, instead of D-PMUs, are widely deployed [119]. However, D-PMUs at low-voltage distribution system substations, if available, could provide accurate voltage references.

B. Post-Mortem Analysis

By leveraging recorded measurement data, post-mortem analysis tries to rebuild the entire dynamic process of an event aftermath. Reviewing these rebuilt events, especially disruptive events, could help understand courses of event occurrences, accumulate experiences in dealing with similar disturbances, and refine strategies of control responses. Reference [120]-[122] respectively analyzed a capacitor bank operation event, a lightning event, and a single phase to neutral fault event rebuilt from D-PMU measurement data, from which occurrences and development of those events are clearly observed. The analysis conducted in capacitor bank operation event [120] contains two parts: (a) steady state analysis and (b) transient and dynamic analysis, in which the former accesses to bus voltage magnitudes, active power consumptions, and power factors within a wide timeline showing the long-term impacts of the event, while the latter accesses to both magnitude and phase angle changes of voltages and currents at the moment of capacitor bank switching. For the lightning event [121] and the fault event [122], only the transient and dynamic analysis is conducted due to their intrinsic transient features. It can be seen that the identified features of the events are more extracted and revealed by transient and dynamic analysis which requires higher resolution synchronized measurements. Thus, D-PMUs could provide significantly important data support to the post-mortem analysis. Without D-PMUs, these events may not be effectively recorded. Although fault recorders may be capable of recording certain events, but events like capacitor bank switching may not trigger recording which could result in missing records. In addition, fault recorders are only capable of recording transient events but fail to support steady-state analysis. Moreover, the analysis of events does not solely rely on records from a single D-PMU, but the integration of multiple D-PMUs. To this end, synchronization is particularly preferred.

In fact, besides rebuilding event processes, another important task of post-mortem analysis is to build up a continuously updated and maintained library that stories data sets of events and typical operation scenarios. Relying on the process of post-mortem analysis, trivial records can be filtered out, while representative records are extracted and tagged with analysis results including event types, event locations, system responses, et al. Those valid and representative materials are extremely important to data driven methods of various applications and data mining applications. Therefore, approaches to filter, extract, and tag valid information from massive D-PMU data as well as the structures and frameworks of the library is worth future research.

C. Model Calibration and Validation

Massive measurement data produced by D-PMUs could be used calibrate and validate equipment models. This was generally considered as a transmission level application. However, data from D-PMUs can enable models that are ignored or simplified at the distribution level. Model validation compares model predictions with real measurements. If differences are out of acceptable range, model calibration is executed repeatedly to further refine model parameters.

- *Load Models*: D-PMU measurement data could help validate and calibrate various load models, including static models (i.e., simplified constant power models with shifting factors [123] and constant impedance-current-power (ZIP) models) as well as complicated dynamic models (i.e., composite load models [124] and synthesis load models [125]).
- *Generator Models*: D-PMU measurement data can contribute to model validation and calibration of distributed generators in emerging active distribution systems. WLS based methods [126] and Kalman filter based methods [127] are commonly used. Reference [128] presented a guideline of steps including 1) measurement usability test, 2) measurement filtering, 3) generator model selection, and 4) key parameter screening before implementing calibration.
- *Line Models and Instrument Transformer*: Ohm's law is the basis of line parameter estimation. Line impedance can be calibrated via voltage and current synchrophasors from D-PMUs at one or two ends of the line [129]-[130] through WLS based estimators. Synchrophasors can lead to a higher accuracy comparing with non-synchronized SCADA measurements. Considering the drawbacks of rank deficiency and low timeliness of WLS based parameter estimators, reference [131] adopted a Kalman filter to dynamically track line parameters with voltage and current estimations from a three-phase state estimator, while feeding back calibrated line parameters to the state estimator. As discussed in [131], as distribution lines are essentially untransposed, the rigorous consideration of couplings among all three phases is preferable.

Instrument transformers (IT) transform high currents and voltages to low and measurable values. However, their accuracy would drift and deteriorate with time, temperature, and environmental conditions, which causes systematic errors in measurement system and in turn impacts all other applications. A model proposed in [130] jointly calibrates line and instrument transformer parameters with phasor measurements, considering that IT induced errors exist on both magnitudes and phase angles of measured phasors.

If enough D-PMUs are available, the aforementioned models can be calibrated and validated solely with D-PMU measurements. However, this is not usually the case because there may be no D-PMUs available on either side of a line, and no D-PMUs at the connection point of distributed generators and loads. Thus, data from SCADA, IEDs, smart meters, and fault recorders would be used alternatively. This also raises the issue of data fusion, as discussed in the state estimation section. It is also worth emphasizing that D-PMU measurements are more critical for dynamic model calibration, such as dynamic generator models and dynamic load models. This is because dynamic models often need to be calibrated and validated using measurements under the presence of system disturbances [128], while D-PMUs are ideal to record disturbance responses with enhanced precision and synchronization features.

7. Conclusions

In this paper, four categories of D-PMU based applications for emerging active distribution systems are reviewed, relying on D-PMUs' prominent features of high resolution, synchronization, and communication capabilities. All reviewed applications are either embedded in D-PMUs using internal samplings or implemented in control centers/PDCs with output measurements from D-PMUs. By observing a wide range of applications, D-PMUs will undoubtedly bring tremendous improvements in distribution system operation, reliability, and configuration through:

- Improved performance and simplified methods/models: With high resolution and synchronization features, performance of some applications in terms of accuracies and time granularities can be generally improved. Examples of such applications are Voltage Stability Monitoring and Fault Localization. Moreover, methods/models of certain applications, such as Islanding Detection and Phase Identification, can be simplified without compromising their performance.
- Enabled new applications and methods: D-PMUs can enable new applications, such as FIDVR mitigation and low frequency oscillation detection. Meanwhile, for existing applications, new and more effective methods based on D-PMUs are proposed, especially in the category of data driven methods.
- Simplified equipment configuration and data complexity: some applications in the current distribution networks, such as fault identification and harmonic monitoring, are realized with specific devices, such as fault recorders and harmonic monitors. Such functionalities can be replaced by D-PMUs with better performance. To this end, adopting D-PMUs can simplify equipment configuration and reduce data complexity, namely reducing data sources and unifying data interfaces.

Foreseeably, D-PMUs will coexist with other measurement sources, such as SCADA, IDEs, and smart meters in the near future. Data fusion is a potential issue worth further exploration, especially in applications of State Estimation and Model Calibration and Validation. Pattern recognition, machine learning, and other data-driven methods based applications have proliferated in literatures, while valid and representative data sets are extremely important. To this end, a continuously updated and maintained library of data sets that stories typical operation scenarios and events would be beneficial. Approaches to filter, extract, and tag valid information from massive D-PMU data as well as the structures and frameworks of the library is worth future research. Applications with high potential benefits but low relatively research interests are also discussed, while a typical example is the measurement assisted economical dispatch.

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