

Integration of a DER Management System in Riverside

(Overview, Innovations, Challenges)

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Washington, DC, May 16, 2019

Team:

- University of California, Riverside
- Riverside Public Utilities
- Smarter Grid Solutions
- Pacific Gas & Electric
- GridBright
- Lawrence Berkeley National Lab
- Lawrence Livermore National Lab

- 1) Algorithm Development
- 2) HIL Simulation
- 3) Field Demonstration

1) Algorithm Development

2) HIL Simulation

3) Field Demonstration

- Phase Identification
- Topology Identification
- Topology Reconfiguration
- Volt/VAR Control
- Load and Power Flow Balancing
- State Estimation

- 1) Algorithm Development
 - 2) HIL Simulation
 - 3) Field Demonstration
- Phase Identification
 - Topology Identification
 - Topology Reconfiguration
 - Volt/VAR Control
 - Load and Power Flow Balancing
 - State Estimation

Monitoring Algorithms

- 1) Algorithm Development
 - 2) HIL Simulation
 - 3) Field Demonstration
-
- Phase Identification
 - Topology Identification
 - **Topology Reconfiguration**
 - **Volt/VAR Control**
 - **Load and Power Flow Balancing**
 - State Estimation

Control Algorithms

- 1) Algorithm Development
- 2) HIL Simulation
- 3) Field Demonstration

- 1) Algorithm Development
- 2) HIL Simulation
- 3) Field Demonstration



SolarEdge and SMA Inverters



ANM Elements



Cap Bank and
Switch Controller



Workstation



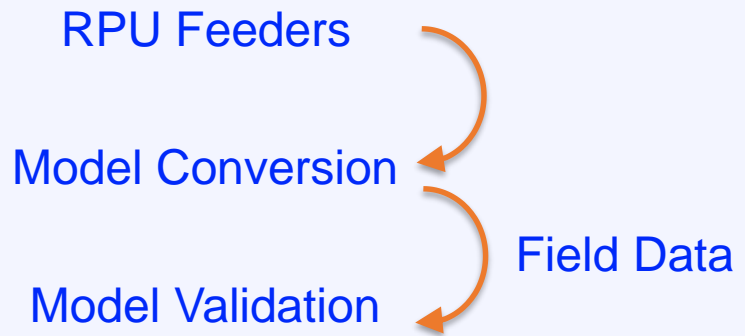
Micro-PMU



1) Algorithm Development

2) HIL Simulation

3) Field Demonstration



SolarEdge and SMA Inverters



ANM Elements



Cap Bank and
Switch Controller



Workstation



Micro-PMU

- 1) Algorithm Development
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DERs

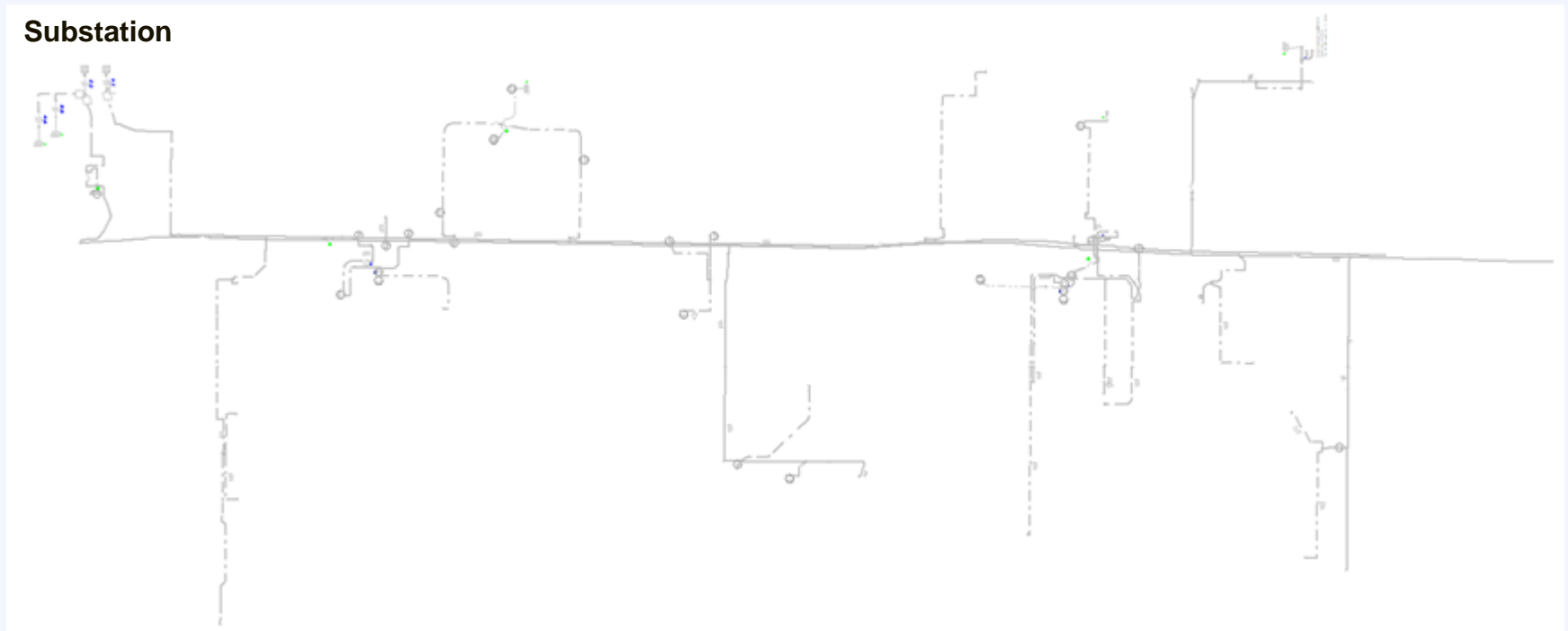


Advanced Sensors

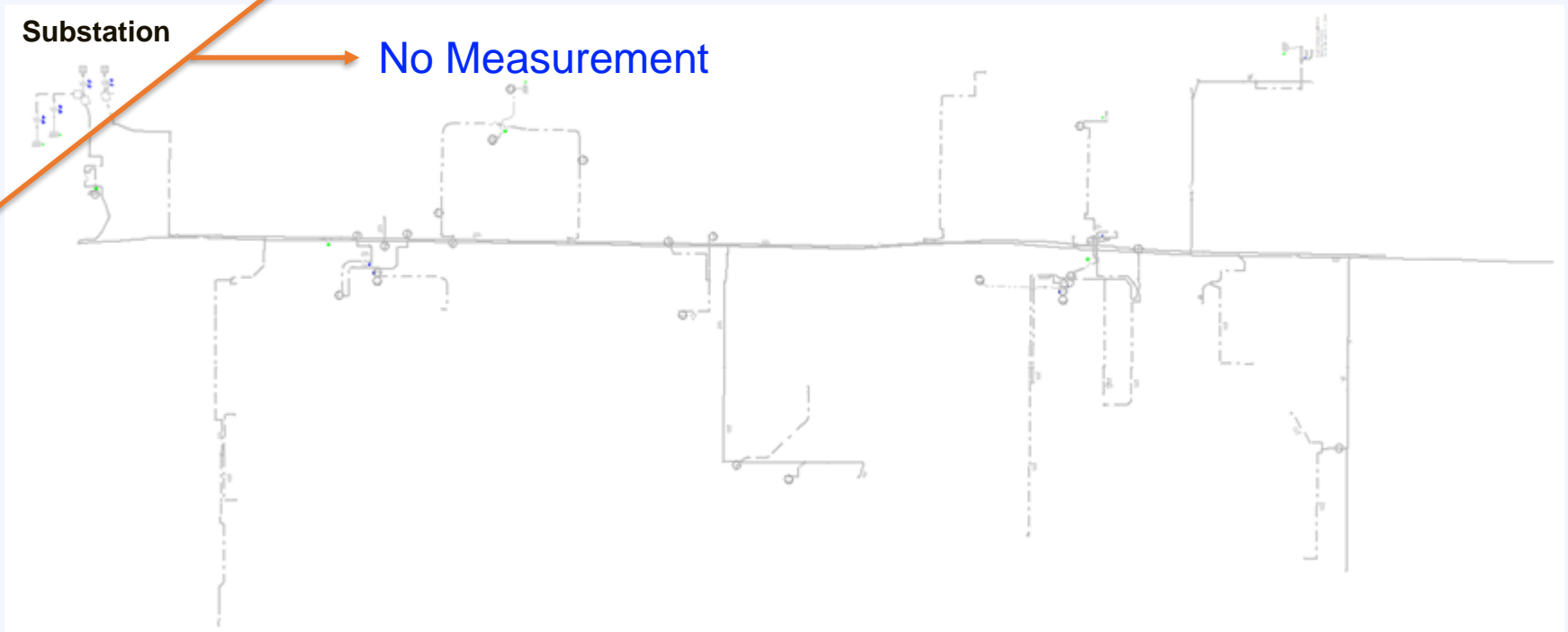


Micro-PMU and Line Sensor

One of the Feeders:

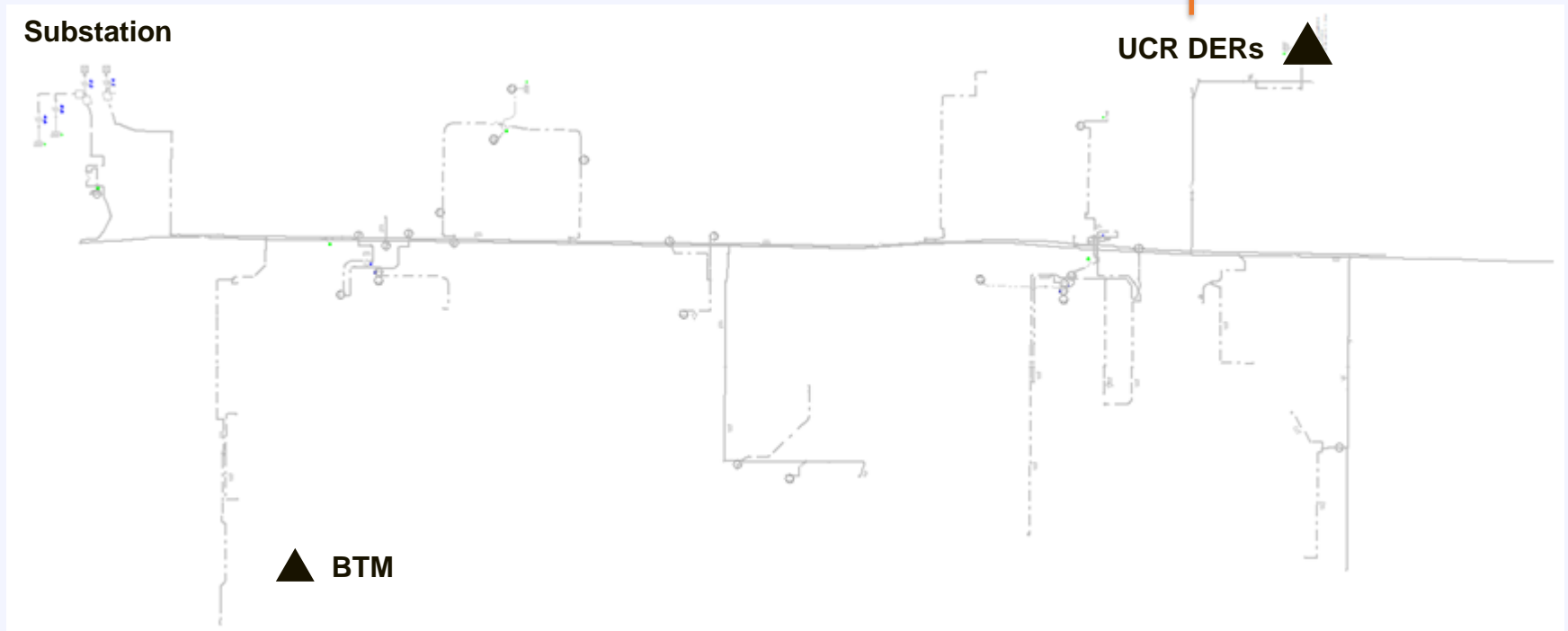


One of the Feeders:

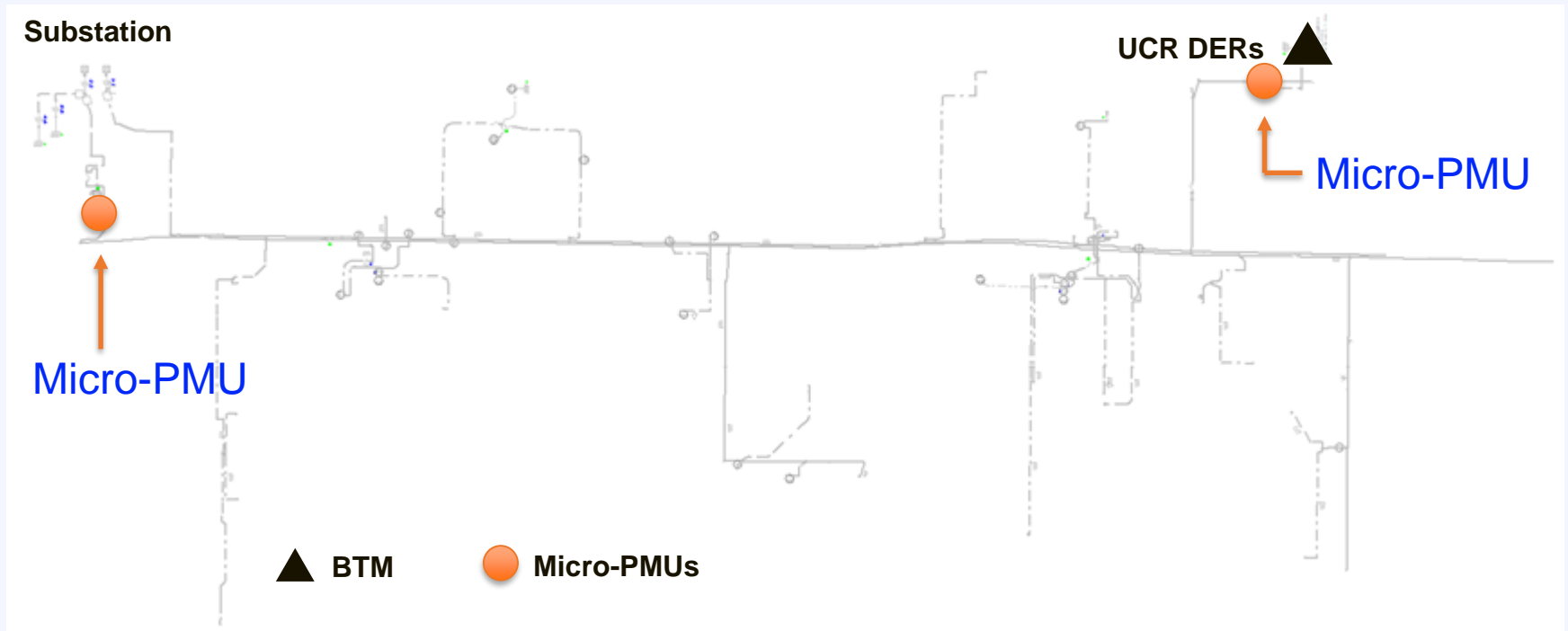


One of the Feeders:

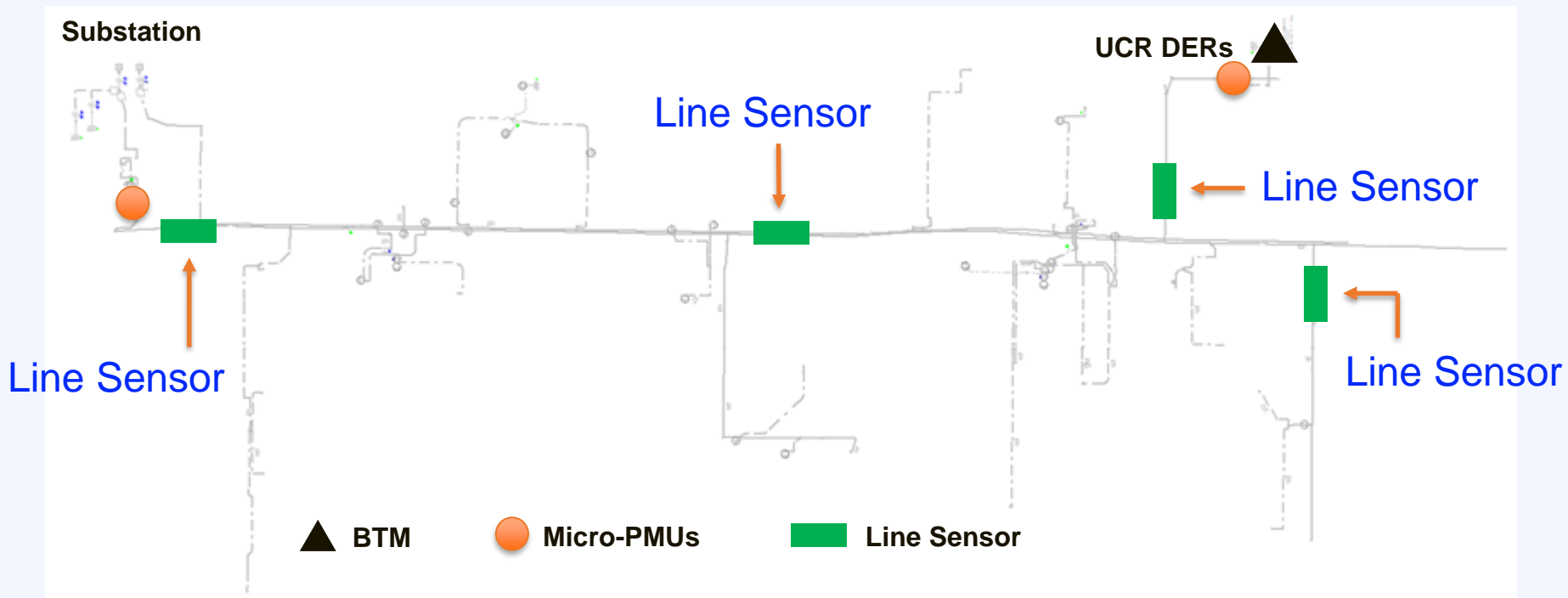
BTM Measurements



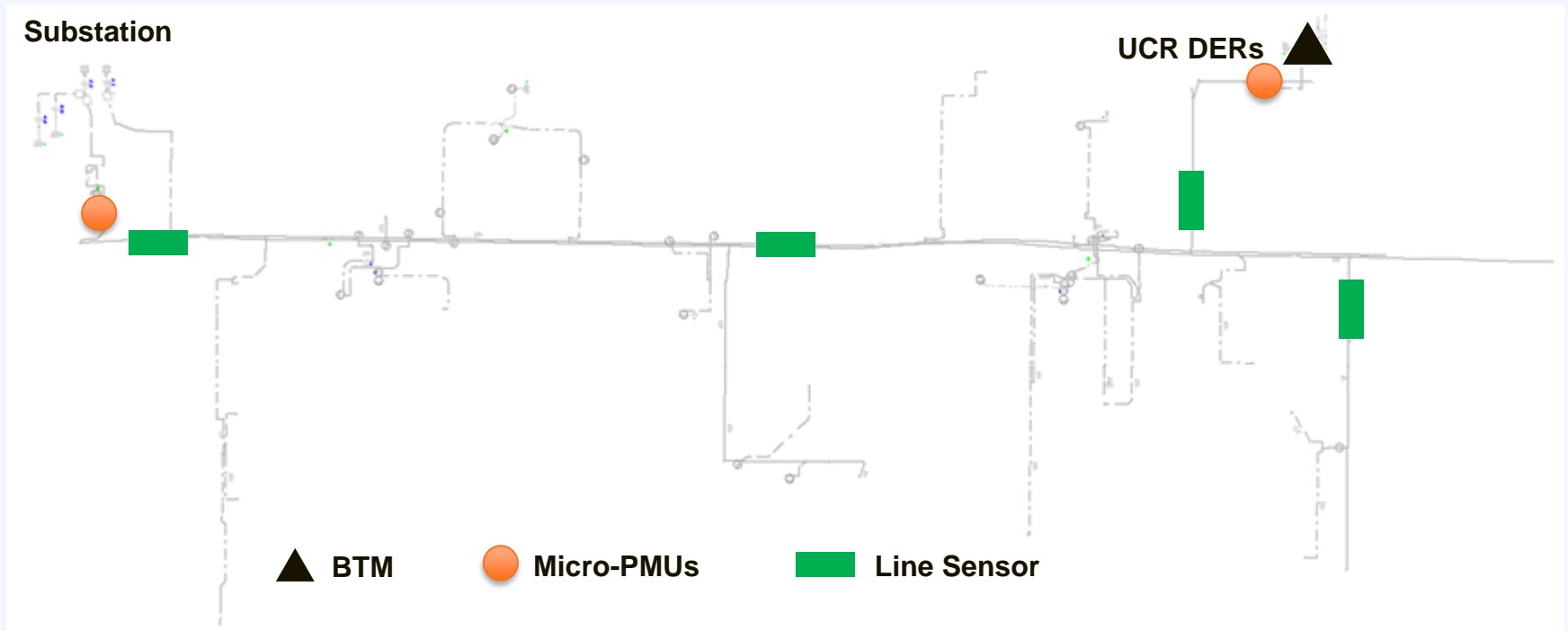
One of the Feeders:



One of the Feeders:



One of the Feeders:



With Two Micro-PMUs:

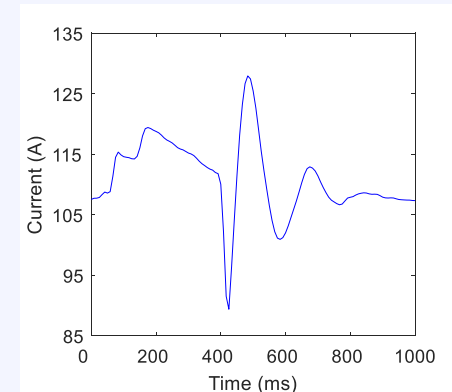
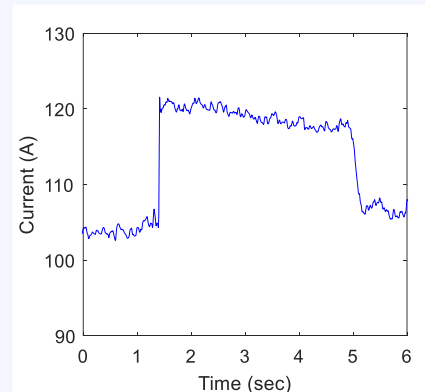
Micro-PMU Data Analytics Package

- Event Detection
- Event Classification
- Event Identification

With Two Micro-PMUs:

Micro-PMU Data Analytics Package

- **Event Detection** → 500 Events Per Day Per Feeder
- Event Classification
- Event Identification



With Two Micro-PMUs:

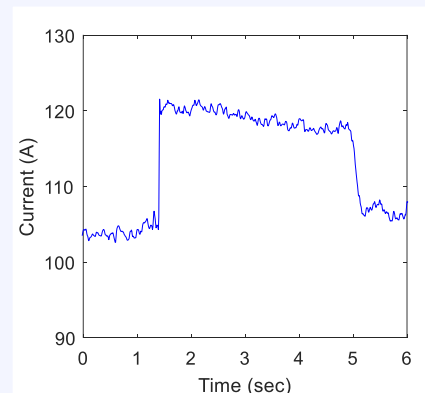
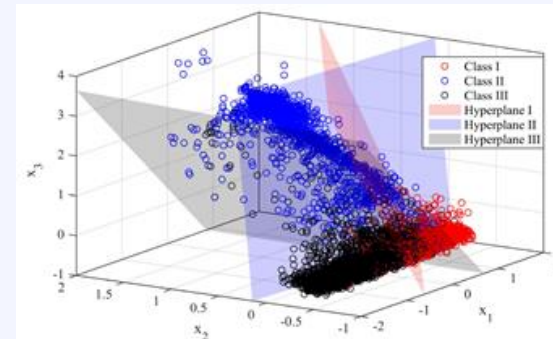
Micro-PMU Data Analytics Package

- Event Detection
- **Event Classification**
- Event Identification

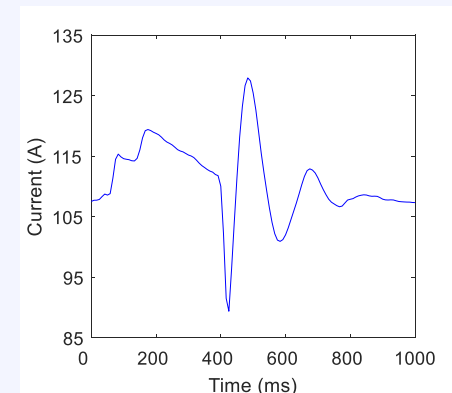
Feature Selection

Event Labeling

Machine Learning



Step Change



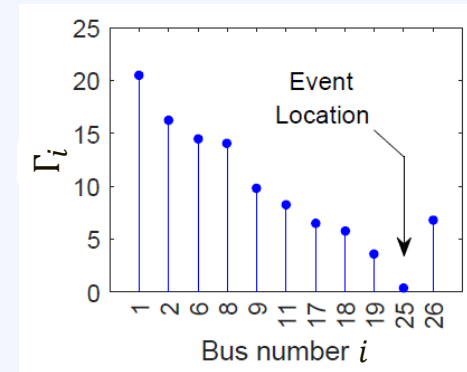
Dynamic

With Two Micro-PMUs:

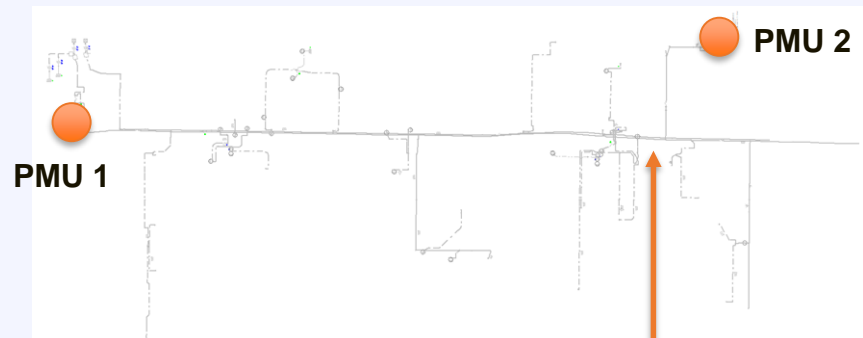
Micro-PMU Data Analytics Package

- Event Detection
- Event Classification
- **Event Identification**

Differential Synchrophasors
Compensation Theorem
Equivalent Circuit



Discrepancy



Event Location

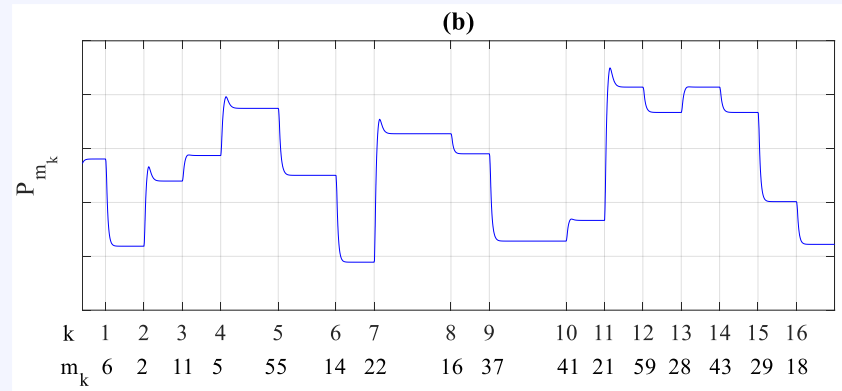
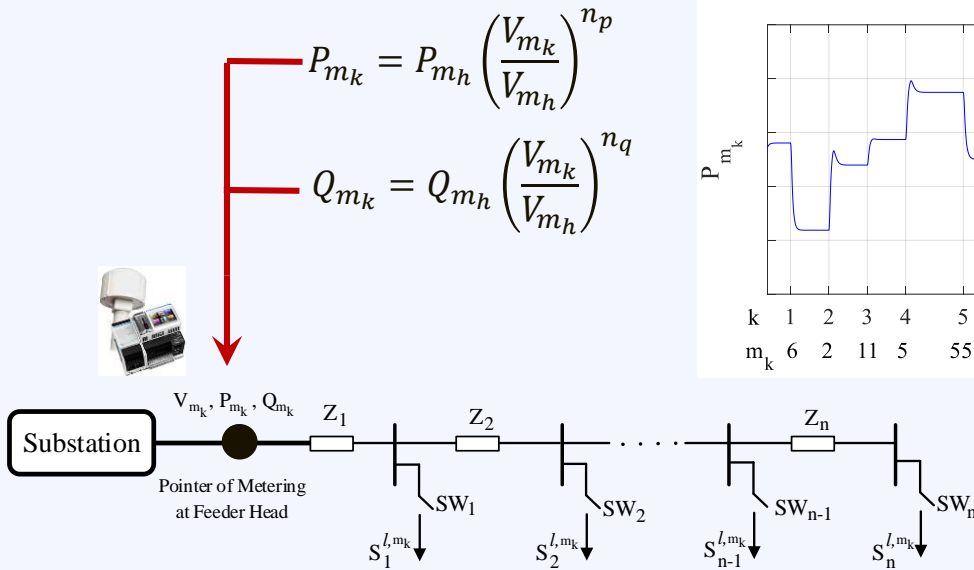
With Two Micro-PMUs:

Micro-PMU Data Analytics Package

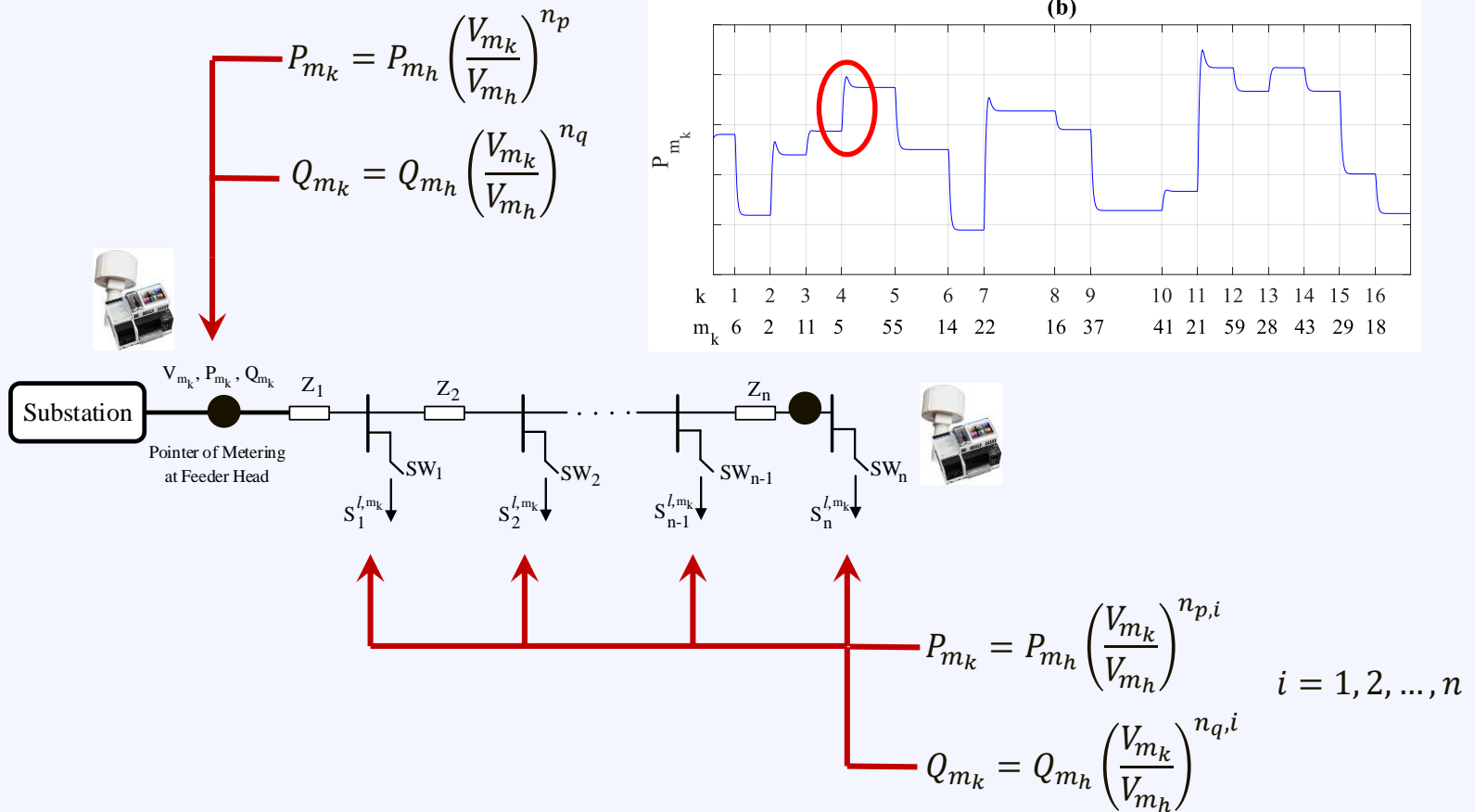
- Event Detection
- Event Classification
- Event Identification

Remote Asset and DER Monitoring
Static and Transient Load Modeling
Protection System Diagnostics
Situational Awareness
Cybersecurity
⋮

Feeder Aggregated Load Modeling:

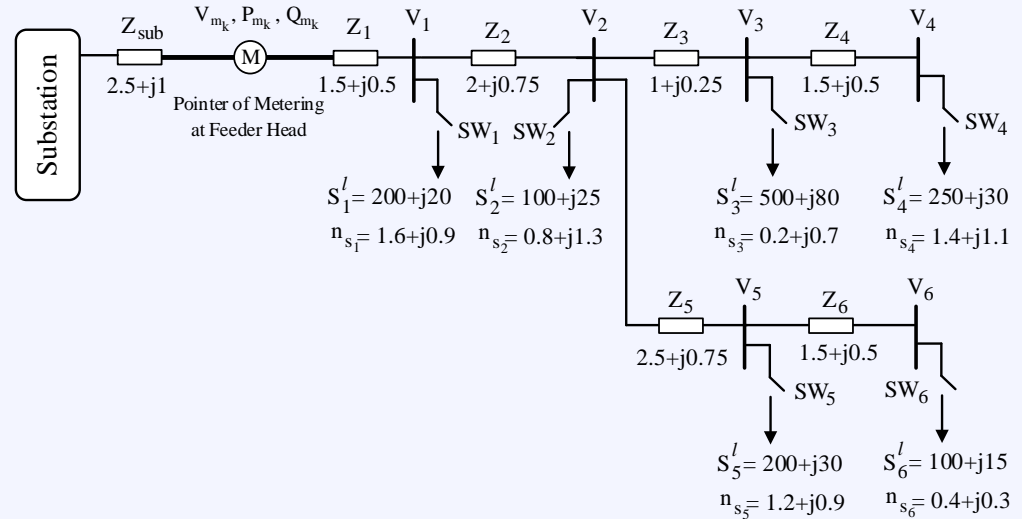


Individual Load Modeling:

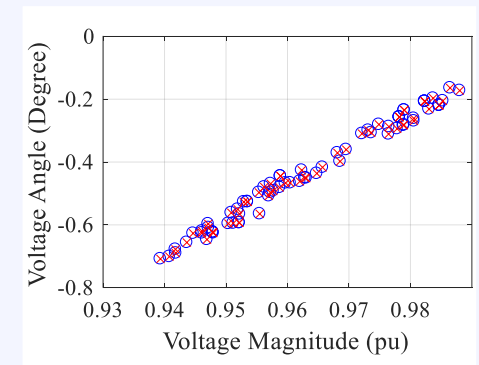
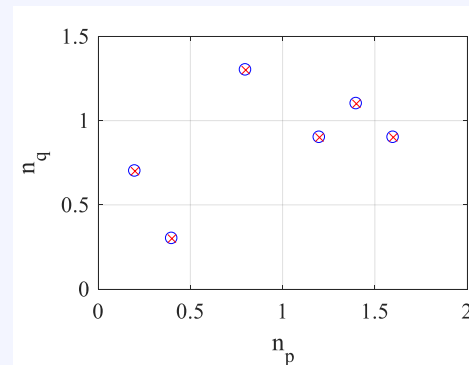


Individual Load Modeling:

Configuration	SW ₁	SW ₂	SW ₃	SW ₄	SW ₅	SW ₆	Time
m ₁	1	0	0	1	0	0	[0, t ₁]
m ₂	1	0	0	1	0	1	[t ₁ , t ₂]
m ₃	1	1	0	0	1	0	[t ₂ , t ₃]
m ₄	0	0	1	1	0	1	[t ₃ , t ₄]
m ₅	0	1	1	1	0	1	[t ₄ , t ₅]
m ₆	1	1	0	0	1	1	[t ₅ , t ₆]
m ₇	0	1	1	0	1	1	[t ₆ , t ₇]
m ₈	1	0	1	1	1	0	[t ₇ , t ₈]
m ₉	0	1	1	1	1	1	[t ₈ , t ₉]
m ₁₀	1	1	1	0	1	1	[t ₉ , t ₁₀]
m ₁₁	1	1	1	1	1	0	[t ₁₀ , t ₁₁]
m ₁₂	1	1	1	1	1	1	[t ₁₁ , t ₁₂]



	# of Equations	# of Unknowns
Circuit Model	84	120
Load Model	42	6
Combined	126	126



Distribution Synchronphasors

By Hamed Mohsenian-Rad,
Emma Stewart, and Ed Cortez

IN THE EVOLUTION OF ADVANCED SENSING TECHNOLOGIES, transmission systems have led distribution. The visibility and diagnostics of the transmission grid have been transformed over the past decade with the systematic deployment of phasor measurement units (PMUs). Similar and even more advanced new information sources are now becoming available at the distribution grid, using distribution-level PMUs, also called *micro-PMUs* (μ PMUs). μ PMUs provide voltage and current measurements at higher resolution and precision to facilitate a level of visibility into the distribution grid that is currently not achievable. However, mere data availability in itself will not lead to enhanced situational awareness and operational intelligence. Data must be paired with useful analytics to translate these data to actionable information. In this article, we explore some of the opportunities to leverage μ PMU data, combined with data-driven analytics, to help electrical distribution system planners and operators to get out in front of problems as they evolve.

The data generated by μ PMUs are a prominent example of big data in power systems. Each μ PMU generates 124,416,600 readings per day. Therefore, μ PMUs installed on a handful of utility distribution feeders can generate terabytes of data on daily basis. Because μ PMUs

stream their measurements continuously, the data must be collected, cleaned, and processed, all in real time.

The collected μ PMU data must then be dissected into descriptive, predictive, and prescriptive analytics. While descriptive analytics focuses on what happened in the past, predictive analytics aims at what may happen in the future. Both are stepping stones toward prescriptive analytics—optimizing the future with informed decisions. Here, we consider case studies in both descriptive and prescriptive analytics and provide a sampling of the benefits derived from μ PMU data.



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IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 33, NO. 4, NOVEMBER 2018

6343

Locating the Source of Events in Power Distribution Systems Using Micro-PMU Data

Mohammad Farajollahi¹, Student Member, IEEE, Alireza Shahsavari, Student Member, IEEE, Emma M. Stewart, Senior Member, IEEE, and Hamed Mohsenian-Rad², Senior Member, IEEE

Abstract—A novel method is proposed to locate the source of events in power distribution systems by using distribution-level phasor measurement units, a.k.a., micro-PMUs. An event in this paper is defined rather broadly to include any major change in any component across the distribution feeder. The goal is to enhance situational awareness in distribution grid by keeping track of the operation (or misoperation) of various grid equipment, assets, distribution energy resources, loads, etc. 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 synchronphasors that are captured by micro-PMUs. Importantly, 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. The effectiveness of the developed method is demonstrated through computer simulations on the IEEE 123-bus test system, and also on micro-PMUs measurements from a real-life 12.47 kV test feeder in Riverside, CA. The results verify that the proposed method is accurate and robust in locating the source of different types of events on power distribution systems.

Index Terms—Distribution synchronphasors, micro-PMUs, event source location, power quality and reliability events, data-driven method, compensation theorem, measurement differences.

I. INTRODUCTION

DISTRIBUTION-LEVEL phasor measurement units (PMUs), a.k.a., micro-PMUs (μ PMUs), have recently been introduced as new sensor technologies to enhance real-time monitoring in power distribution systems. Micro-PMUs provide GPS-synchronized measurements of three-phase voltage and current phasors at a high resolution, 120 readings per second [1]. Several emerging applications of micro-PMUs, including model validation, distribution system state estimation, topology detection, phase identification, distributed generation,

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Color versions of one or more of the figures in this paper are available online at <http://ieeexplore.ieee.org/>.

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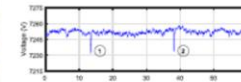


Fig. 1. Voltage phasor magnitude that is measured in a distribution substation in Riverside, CA. Only one phase is shown here. Event 1 has a root cause in the transmission system. Event 2 has a root cause in the distribution system.

and transient analysis, as discussed in a recent survey in [2] and the references therein.

A. Motivation

Consider one minute of voltage phasor measurements in Fig. 1 from a micro-PMU at a real-life 12.47 kV distribution substation in Riverside, CA. As expected, there are fluctuations in voltage magnitude, including two voltage sag events. Each event has a root cause at either transmission network or distribution network [3]. Common root causes of distribution level events include load switching, capacitor bank switching, connection or disconnection of distributed energy resources (DERs), inverter malfunction, a minor fault, etc. Accordingly, in this paper, we seek to answer the following question: *for those locations with root causes in distribution network, what is the location of such root cause, i.e., at what exact distribution bus does the load switching, capacitor bank switching, DER connection/disconnection, or device malfunction occur?*

Answering the above question is the key to achieving situational awareness in power distribution systems, so as to keep track of how various grid equipment, assets, DERs, and loads operate or misoperate. The applications are diverse, ranging from identifying incipient failures [1], [4] or cyber-attacks [5], to recruiting demand side resources to construct a self-organizing power distribution system [6]–[8]. Here, an event is defined rather broadly to include any major change in a component across the distribution feeder. This of course includes the two traditional classes of electric distribution system events, namely power quality (PQ) events, such as dropping below or exceeding above acceptable modal voltage limits, as well as reliability events, such as interrupting service due to faults that cause fuse blowing or relay tripping [9]. However, since the goal in this paper is to enhance situational awareness in power distribution systems, we are interested also in PQ events that do not necessarily violate PQ requirements or undermine reliability, but they

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Situational Awareness in Distribution Grid Using Micro-PMU Data: A Machine Learning Approach

Alireza Shahsavari, Student Member, IEEE, Mohammad Farajollahi, Student Member, IEEE, Emma Stewart, Senior Member, IEEE, Ed Cortez, Hamed Mohsenian-Rad, Senior Member, IEEE

Abstract—The recent development of distribution-level phasor measurement units, a.k.a. micro-PMUs, has been an important step towards achieving situational awareness in power distribution networks. The challenge however is to transform the large amount of data that is generated by micro-PMUs to actionable information and then match the information to use cases with practical value to system operators. This open problem is addressed in this paper. First, we introduce a novel data-driven event detection technique to pick out valuable portion of data from extremely large raw micro-PMU data. Subsequently, a data-driven event classifier is developed to effectively classify power quality events. Importantly, we use field expert knowledge and utility records to conduct an extensive data-driven event labeling. Moreover, certain aspects from event detection analysis are adopted as additional features to be fed into the classifier model. In this regard, a multi-class support vector machine (multi-SVM) classifier is trained and tested over 15 days of real-world data from two micro-PMUs on a distribution feeder in Riverside, CA. In total, we analyze 1.2 billion measurement points, and 18,700 events. The effectiveness of the developed event classifier is compared with prevalent multi-class classification methods, including k-nearest neighbor method as well as decision-tree method. Importantly, two real-world use-cases are presented for the proposed data analytics tools, including remote asset monitoring and distribution-level oscillation analysis.

Keywords: Machine learning, distribution synchrophasors, situational awareness, event detection, event classification, Big-Data.

I. INTRODUCTION

The proliferation in distributed energy resources, electric vehicles, and controllable loads has introduced new and unpredictable sources of disturbance in distribution networks. This calls for developing new monitoring systems that can support achieving situational awareness at distribution level; thus, allowing the distribution system operator to make the best operational decisions in response to such disturbances.

Traditionally, there have been three major challenges in achieving situational awareness in power distribution systems. First is the lack of high-resolution measurements. Metering in distribution systems is often limited to supervisory control and data acquisition (SCADA) at substations with minutely reporting intervals. As for smart meters, their report measurements occur every 15 minutes or hourly. Second is the lack of accurate and up-to-date models for most practical distribution circuits. Third, due to the lower voltage and the larger number and

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Application of Load Switching Events in Steady-State Load Modeling in Power Distribution Networks

Alireza Shahsavari, Mohammad Farajollahi, and Hamed Mohsenian-Rad
Department of Electrical and Computer Engineering, University of California, Riverside, CA, USA

Abstract—A novel event-oriented method is proposed to conduct steady-state load modeling in power distribution systems. It has two fundamental differences with the comparable methods in the literature. First, the type of events are different. Specifically, the existing event-oriented load modeling methods use upstream voltage events as the main enabler for load modeling. In contrast, here we use the load switching events across the distribution feeder itself. Second, the objective of the analysis is different. The existing event-oriented load modeling methods are intended to obtain a ZIP model for the aggregate load of the entire distribution feeder. The application of such feeder-aggregated load models is in analysis of sub-transmission and transmission systems. In contrast, here we seek to obtain a ZIP model for each individual load across the feeder. The application of such individual load models is in the analysis of the distribution system itself, such as with respect to the operation of distributed energy resources. The performance of the proposed method is examined on a real-feeder under various operating scenarios by considering the impact of errors in feeder-head measurements.

Keywords: Event-oriented method, steady-state load modeling, distribution system analysis, load switching events.

I. INTRODUCTION

A recent CIGRE report in [1] has found that the majority of the utilities use measurement-based methods to estimate the parameters of their load models. Measurement-based load modeling can be classified static and dynamic. Our focus in this paper is on static load modeling, where the goal is to estimate the parameters of the so-called ZIP load models.

An important class of measurement-based static load modeling methods is *event-oriented*, i.e., they analyze certain events and the responses of the loads to those events in order to estimate the load modeling parameters. When it comes to event-oriented static load modeling at distribution-level, one can identify two common features for the existing methods. First, they are concerned with obtaining a ZIP model for the *entire* load of the feeder as seen by the distribution substation, such as the methods in [2]–[7]. Second, they use the *upstream* events to enable load modeling, such as voltage events that are initiated from outside the distribution feeder, e.g., see [2]–[7].

In this paper, we explore making use of a different type of events and seek to achieve a different load modeling objective. Specifically, we seek to investigate the load switching events on the distribution feeder itself in order to obtain models for the individual loads that exist across the feeder that is being studied. Accordingly, the methodology in this paper is inherently different compared to the existing event-oriented static load modeling approaches, such as those in [2]–[7].

This work was supported by NSF grant 1462550 and 1253516; DoE grant EE-000801; and NNSA MRD grant NNX15AP99A. The corresponding author is H. Mohsenian-Rad, e-mail: hamed@ece.ucr.edu

Fig. 1. A distribution feeder with three loads, corresponding to the illustrative example in Section II. (a) The single line diagram of the feeder; (b) and (c) the measured voltage and active power at the feeder head, respectively.

Intuitively, the basic idea in this paper is as follows: once a load switches, the switching event changes the voltage in the rest of the loads on the same feeder, and this causes variation in their active and reactive power consumption; thus allowing us to estimate their load parameters. However, the challenge in implementing this idea is that such variations *cannot* be measured directly unless there is a meter at each load bus, which in that case individual load modeling is trivial. Thus, we assume that individual load meters are *not* available. Instead, we seek to achieve individual load models by using only the measurements at the feeder-head.

II. ILLUSTRATIVE EXAMPLE

Consider a distribution feeder with $n = 3$ buses¹ as shown in Fig. 1(a). Depending on which individual loads are *turned on* and which individual loads are *turned off*, there can be a total of $2^n - 1 = 7$ possible load configurations in this feeder, excluding the no load situation. Figs. 1(b) and (c) show the voltage and active power that are measured at the feeder-head during load configuration m_1, \dots, m_7 , respectively. The switches status corresponding to each load configuration is given in Table I. Our goal in this paper is to model each of the three individual loads in Fig. 1(a) by studying the sequences of measurements at the feeder-head in Fig. 1(b) and (c).

A. System of Equations and Unknowns

In order to achieve the above goal, we need to solve a system of equations that comprises circuit models and load models. We start with writing the law of complex power conservation,

¹As we will see in Theorem 1(b) in Section III, the minimum number of buses to conduct the proposed event-oriented load modeling problem is three.

With Line Current Sensors:

Topology Identification

- 1. Reliable Solution
- 2. Fast Calculation
- 3. Light Computation
- 4. Switch Malfunction



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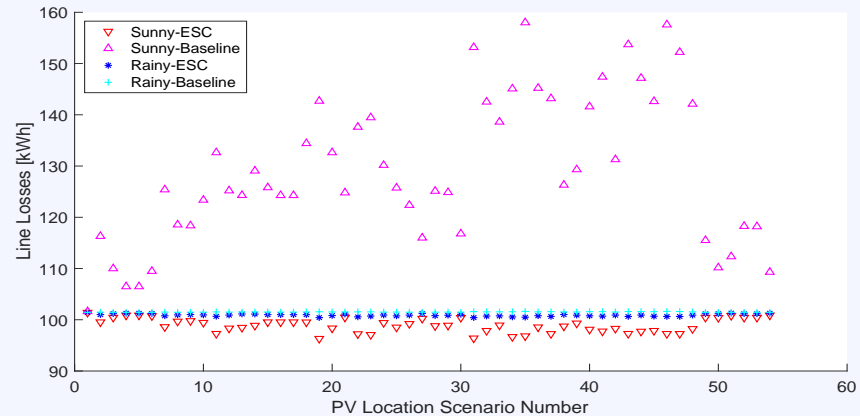
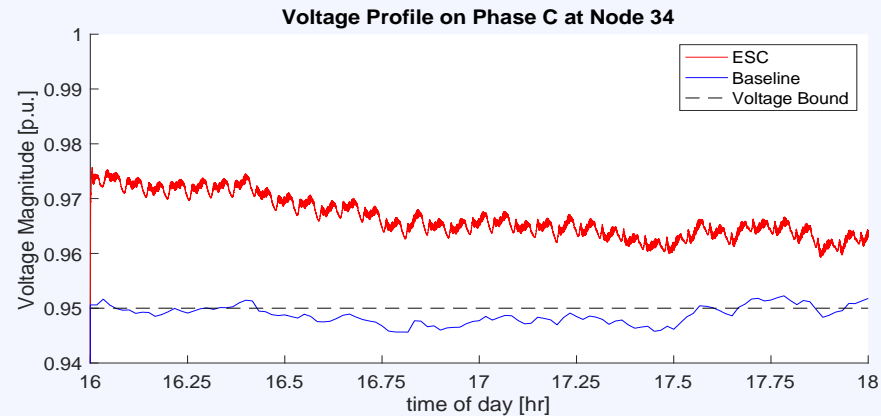
DER Control Based on Extremum-Seeking Iterations:

Model Free

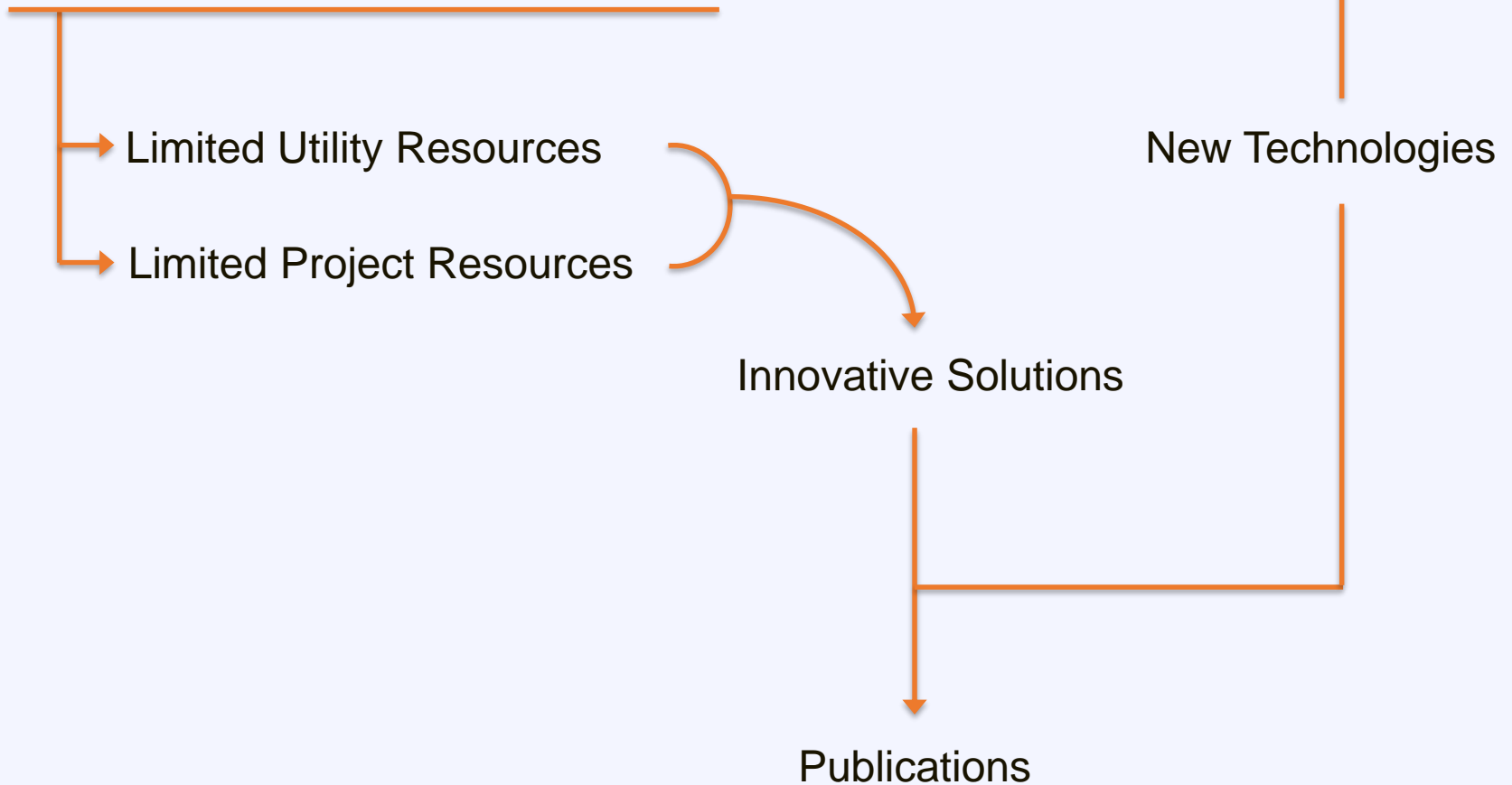
Probe Signal

Gradient Descent

(LBNL)



Realities in Field Implementation



DoE Energise Project DE-EE000800 I

Thank You!

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