Energy Research and Development Division
FINAL PROJECT REPORT

# DISTRIBUTION SYSTEM FIELD STUDY WITH CALIFORNIA UTILITIES TO ASSESS CAPACITY FOR RENEWABLES AND ELECTRIC VEHICLES

Prepared for: California Energy Commission
Prepared by: The Regents of the University of California - California Institute for Energy and Environment

MARCH 2015
CEC-500-2015-058

**PREPARED BY:**

***Primary Author(s):***
Alexandra von Meier
Merwin L. Brown
Reza Arghandeh
Laura Mehrmanesh
Lloyd Cibulka
Bob Russ

California Institute for Energy and Environment
2087 Addison St., 2nd floor
Berkeley, CA 94704
Phone: 510-643-1440 | Fax: 510-643-9324
http://uc-ciee.org

***Contract Number: 500-11-019***

***Prepared for:***

**California Energy Commission**

Consuelo Sichon
***Contract Manager***

Fernando Piña
***Office Manager***
***Energy Systems Research Office***

Laurie ten Hope
***Deputy Director***
***ENERGY RESEARCH AND DEVELOPMENT DIVISION***

Robert P. Oglesby
***Executive Director***

**DISCLAIMER**

This report was prepared as the result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warranty, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this report.

# ACKNOWLEDGEMENTS

The authors are exceptionally grateful to the many expert colleagues we have known and worked with over the course of our careers in the electric industry, without whose generous sharing of their time and knowledge this report would not be possible. In particular, we would like to acknowledge the contributions of those who most recently gave unselfishly of their time and expertise to answer the Distribution Monitoring Survey and to participate in the Distribution Monitoring Workshop; they were invaluable to this project effort.

We would especially like to thank Consuelo Sichon, Jamie Patterson, Fernando Piña, Mike Gravely, and Laurie ten Hope of the California Energy Commission for their generous support, encouragement, technical direction, and strategic guidance for this project.

# PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The Energy Research and Development Division conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The Energy Research and Development Division strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

Energy Research and Development Division funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Technology Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

*Distribution System Field Study with California Utilities to Assess Capacity for Renewables and Electric Vehicles* is the final report for the Distribution System Field Study with California Utilities to Assess Capacity for Renewables and Electric Vehicles project (contract number 500-11-019), conducted by The Regents of the University of California – California Institute for Energy and Environment. The information from this project contributes to Energy Technology Systems Integration program area.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

# ABSTRACT

Large amounts of distributed generation (DG), especially solar, and electric vehicles may cause technical problems related to power quality, safety, and reliability on electric distribution circuits. These impacts are not yet well understood. Early evidence suggests that significant infrastructure upgrades and operational changes in utility distribution systems may be required as DG penetration levels reach a critical threshold. New empirical information gathered from the field is necessary to better define these requirements and the potential need for new technology developments. Data from distribution circuits must be collected and analyzed at higher resolution and with greater specificity so that the effects of distributed resources can be better understood and mitigated if necessary. Compared to transmission, distribution systems tend to lack visibility to operators, and exhibit considerable diversity, variability, and vulnerability to disturbances.

Better knowledge of distribution circuit behavior will allow California's clean energy policies to be implemented at least cost without degradation of electric service. This work provides the scientific knowledge base to help California ratepayers avoid three risks: spending too much money on unnecessary distribution infrastructure upgrades; suffering a loss of power quality and reliability from insufficient infrastructure upgrades; or compromising our state's policy goals by restricting the implementation of clean and green energy.

This report describes the results of a research effort that analyzed existing distribution system monitoring practices in California, evaluated the current and future needs for better monitoring to address trends and challenges due to renewables integration and other drivers of change, and proposed an Advanced Monitoring Plan that could be the basis of further research and development to address the demands of the future distribution grid.

**Keywords:** distribution monitoring, smart grid, distribution automation, advanced measurement methods, renewable energy, renewable generation, DMS, SCADA.

Please use the following citation for this report:

Von Meier, Alexandra, Merwin Brown, Reza Arghandeh, Laura Mehrmanesh, Lloyd Cibulka, Bob Russ. (California Institute for Energy and Environment). 2015. ***Distribution System Field Study with California Utilities to Assess Capacity for Renewables and Electric Vehicles.*** California Energy Commission. Publication number: CEC-500-2015-058.

# TABLE OF CONTENTS

**ACKNOWLEDGEMENTS** ..... i

**PREFACE** ..... ii

**ABSTRACT** ..... iii

**TABLE OF CONTENTS** ..... iv

**TABLE OF FIGURES** ..... v

**LIST OF TABLES** ..... Error! Bookmark not defined.

**EXECUTIVE SUMMARY** ..... 1

**CHAPTER 1: Overview** ..... 5

1.1 Introduction ..... 5

1.2 Goals and Objectives ..... 7

1.3 Technical Approach ..... 8

**CHAPTER 2: Establishment of Preliminary Data Inventory** ..... 12

2.1 Background & Objectives ..... 12

2.2 Approach for Obtaining Data from Partner Utilities ..... 13

2.3 Overview of Distribution Monitoring Efforts by Utilities ..... 15

2.4 Research Gaps ..... 23

2.5 Conclusions for the Preliminary Data Inventory ..... 23

**CHAPTER 3: Creation and Management of the Data Repository** ..... 25

3.1 Data Repository Architecture ..... 25

3.2 Circuit Selection by Utilities ..... 27

**CHAPTER 4: Distribution Feeder Behavior Characteristics** ..... 29

4.1 Overview ..... 29

4.2 Data Availability and Quality ..... 32

4.3 Data Cleaning and Data Recovery ..... 39

4.4 Feeder Behavioral Characteristics ..... 45

**CHAPTER 5: Validation of Preliminary System Model** ..... 69

5.1 Overview ..... 69

5.2 Modeling Software Tool Comparison ..... 72
5.3 A Unified Platform for Circuit Models ..... 79
5.4 Non-constant Time Sampling Rates in Utility Data ..... 93
5.5 Preliminary Circuit Model Validation ..... 98
**CHAPTER 6: Advanced Distribution Monitoring Design Plan ..... 105**
6.1 Status of Distribution Monitoring among California's Utilities ..... 105
6.2 Gaps in Present Monitoring ..... 108
6.3 Lessons Learned and Utility Viewpoints ..... 110
6.4 Goals for Future Monitoring ..... 114
6.5 Proposed Plan for Future Distribution Monitoring Systems ..... 121
**CHAPTER 7: Conclusions and Recommendations ..... 132**
7.1 General Conclusions ..... 132
7.2 Challenges of Project Design Unknowns ..... 132
7.3 Challenges of Project Deployment ..... 133
7.4 Challenges of Strategy ..... 135
7.5 Addressing the Challenges ..... 135
**GLOSSARY ..... 136**
**REFERENCES ..... 141**
**APPENDIX A: Presentations from Sept. 5, 2014 Distribution Monitoring Workshop .....**

## LIST OF FIGURES

Figure 1: SCADA System Generic Architecture ..... 36
Figure 2: Illustration of Some Challenges Specific to Distribution Networks ..... 38
Figure 3: Data Cleaning Process ..... 41
Figure 4: Example of Missing Data in SCADA Measurements ..... 42
Figure 5: Example of Zero Values in SCADA Measurements ..... 43
Figure 6: Example of Incorrect Values in SCADA Measurements ..... 44
Figure 7: Example of an Outlier in SCADA Measurements ..... 44

Figure 8: Average Daily Feeder Load Profile and Temperature for April ..... 48
Figure 9: Average Daily Feeder Load Profile and Temperature for August ..... 49
Figure 10: Load Duration Curve (Histogram) at Substation – 3 Feeders Aggregated ..... 50
Figure 11: Feeder 1.1 Load Duration Curve (Histogram) ..... 51
Figure 12: Feeder 1.2 Load Duration Curve (Histogram) ..... 51
Figure 13: Feeder 1.3 Load Duration Curve (Histogram) ..... 52
Figure 14: Substation Load Factor ..... 53
Figure 15: Feeder 1.3 Load Factor ..... 54
Figure 16: Phase Deviation of Current, Feeder 1.1 ..... 55
Figure 17: Phase Deviation of Current, Feeder 1.2 ..... 55
Figure 18: 15-minute Rate of Change of Load on Feeder 1.1 ..... 56
Figure 19: 1-minute Rate of Change of Load on Feeder 1.1 ..... 57
Figure 20: 12-second Rate of Change of Load on Feeder 1.1 ..... 57
Figure 21: Substation Voltage vs. Power ..... 58
Figure 22: Substation Power vs. Temperature ..... 59
Figure 23: Substation Voltage vs. Temperature ..... 60
Figure 24: Substation Current vs. Temperature ..... 61
Figure 25: Synchronized Voltage Data Sample ..... 64
Figure 26: Synchronized Voltage Data Sample at High Resolution ..... 64
Figure 27: Synchronized Voltage and Current Data Sample ..... 65
Figure 28: Substation Voltage and Current at Weekly Scale ..... 65
Figure 29: Substation Voltage and Current at High Resolution ..... 67
Figure 30: Distribution Circuit in UCI OpenDSS Environment ..... 70
Figure 31: Conceptual Illustration of the Proposed Unified Platform (UP) ..... 81
Figure 32: Snapshot of UP's Spreadsheet Containing Required Parameters of: (a) Transformer, (b) Cable, (c) Capacitor, and (d) Load. ..... 82
Figure 33: General Scheme for Importing Circuit Model Data from UP Spreadsheet into ETAP ..... 83
Figure 34: General Scheme for Importing Circuit Model Data from the UP into OpenDSS .. 86

Figure 35: General Scheme for Importing Circuit Model Data from the UP into DEW ..... 88

Figure 36: Snapshot of Component Manager in DEW to Transfer Circuit Model Data from UP into DEW ..... 89

Figure 37: General Scheme of the Developed Interpolation-Resampling (DIR) Application 95

Figure 38: Interpolation-resampling Error of Output Power of 3.5 MW Solar Plant, Resampled at 30-second Intervals ..... 96

Figure 39: General Scheme of the Resampling Error Calculation (REC) Application ..... 97

Figure 40: Output Graphs of the Resampling Error Calculation (REC) Application..... 98

Figure 41: Model of a Distribution Line or Cable ..... 99

Figure 42: Number and Overall Lengths of Line and Cable Types Used in Test Circuit..... 101

Figure 43: Cumulative Distribution of Loads Power Rating in the Test Circuit..... 104

Figure 44: Instrumentation on a Typical Distribution Feeder ..... 115

Figure 45: Possible AMP Architecture ..... 117

Figure 46: Alternative AMP Architecture: Collaborative Model ..... 118

Figure 47: Time Scales for Event Monitoring..... 122

## LIST OF TABLES

Table 1: List of Feeders with Available SCADA Data ..... 39

Table 2: Metrics for Feeder Temporal Characterization..... 45

Table 3: Bad Data Analysis for Utility 1..... 47

Table 4: Feeder Circuit Model Overview..... 62

Table 5: Capability of SIMULINK® in Simulation of Distribution System Components..... 73

Table 6: Capability of PSCAD in Simulation of Distribution System Components ..... 74

Table 7: Capability of Power World in Simulation of Distribution System Components..... 75

Table 8: Capability of PSLF in Simulation of Distribution System Components..... 76

Table 9: Capability of OpenDSS in Simulation of Distribution System Components..... 77

Table 10: Capability of GridLAB-D in Simulation of Distribution System Components..... 78

Table 11: Load Summary of IEEE Test Circuit..... 89

Table 12: Load Flow Results from IEEE Test Circuit ..... 90

Table 13: Partial Load Flow Results from Utility Circuit ..... 90

Table 14: Summary of Software Based on Load Flow Analysis ..... 92

Table 15: Output Power (MW) of Solar Plant Recorded at Unequal Time Intervals..... 93

Table 16: Interpolated Measurement Data of Solar Plant with Sampling Time Interval of 30 Seconds ..... 96

Table 17: Active and Reactive ZIP Coefficients by Customer Class ..... 103

# EXECUTIVE SUMMARY

## Introduction

A significant and growing amount of new energy generation sources, such as solar energy (photovoltaics, or PV), and new customer technologies such as electric vehicles (EVs), are being installed on the electric grid at the distribution level. "Distribution" comprises the medium-to-low voltage networks (lines, poles, transformers, switches, etc.) that connect residential and many commercial customers to the larger grid. Before the proliferation of these new technologies, distribution circuits were not very complex; the utility provided power from the distribution substation at the proper voltage, and the customers drew power from the line. There were few, if any, generation sources on a distribution circuit, so things were fairly predictable, and utility engineers did not require much real-time information to maintain adequate and reliable electric service. Typically, the utility measured the voltage, current, and total power at the substation meter, while customer use from meter readings was available from the billing department but not accessible by the operations departments. Very few sensors and associated communications systems were installed on the distribution lines, usually limited to a few switching points at key locations.

As a result of the variability and complexity introduced by new technologies, there is a growing need for real-time information about their behavior and their impacts on grid operations, as well as other customers on the distribution circuit. This necessity will become even more critical in the future. New analytical and control methodologies for distribution are being developed and used, but additional quality data about what's actually happening on the distribution system is required so that utilities can monitor and control the overall distribution system to ensure that ratepayers continue to receive reliable, safe, and economic electric service.

California utilities have, and are engaged in, a variety of monitoring studies, pilot projects, technology demonstrations and other activities. Most of these monitoring activities are related to projects that are being undertaken to understand a specific new technology or application, such as PV systems, energy storage installations, EV charging systems, smart meters, and so forth. Some projects also include analyses with a wider focus, such as volt/Volt-Ampere-Reactive (VAR) control algorithms. VAR is a portion of the total power that is used to regulate the system voltage; the other portion, expressed in watts, is the actual power consumed or used to perform work. There is considerable variation in data collection, data quality, data resolution and accuracy, placement strategies for the monitoring devices, and analytical methods. It is essential to study the available measurement data from utilities to learn about the impacts of, and issues related to integrating new technologies in the distribution system, and how monitoring practices should be expanded and improved to meet the challenges of new technologies.

## Project Purpose

This project advanced and supported the safe and reliable operation of the distribution system with more renewable generation, distributed generation (DG), electric vehicles (EVs), and other new technologies and applications. The researchers sought to obtain monitored data from participating California utilities to characterize the current operating state of the system, and to form a preliminary assessment of the impacts of new technologies on electric distribution system operation and performance. Expert opinion from California utilities was pursued about the monitoring requirements of the future distribution system. How much more information can and should be provided to distribution operators beyond the substation down to the customer meter to improve electric service? How can a better understanding of the impacts of new technologies help to revise and update interconnection standards and operational tools to accommodate the anticipated levels of renewables? This new information was used to develop an Advanced Monitoring Plan (AMP). The AMP is the basis for follow-on research that would demonstrate how a distribution circuit could be monitored to acquire the detailed, comprehensive data necessary to accurately assess the performance of the distribution system with expected new levels of renewables and other technologies. The AMP could also serve as a framework to implement monitoring systems by a utility for normal operations.

## Project Process

This collaborative research effort constituted the first systematic look at a representative sample of distribution circuits across California. It began with an evaluation of recent efforts by individual utilities to perform comprehensive monitoring on distribution circuits where renewables and other new technologies, such as storage or electric vehicle charging systems, had been installed. Next, an inventory of typical distribution circuit data was compiled from data collected from existing utility instrumentation. The data acquired from utilities was analyzed for spatial and temporal characteristics.These data were then analyzed as circuit characterization and validation of distribution system models. The results of the analysis were used to develop an AMP, intended to be a potential framework for additional research efforts in distribution monitoring.

The project technical approach consisted of two avenues of effort. First, a collaborative process of sharing data was established between the researchers and four California utilities: Pacific Gas & Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and the Sacramento Municipal Utility District. The data contained physical and electrical parameters for selected distribution circuits, and actual measurement data from existing measurement devices installed on those circuits. Intended to establish a baseline of current monitoring practices and methodologies, these existing measurements were analyzed to begin characterizing distribution circuits with and without distributed energy resources, validating distribution circuit models, and identifying gaps in available data.

The results and lessons learned were then combined with information from numerous other sources, including a utility survey and a workshop with invited experts and utility colleagues, to develop an AMP. The AMP is a blueprint or roadmap for follow-on research efforts that would build on the results of this project and expand the distribution system knowledge base.

Research based on AMP could, for example, obtain more comprehensive and detailed measurements from new line sensors and substation monitors installed by participating utilities in collaborative efforts. Such research could fill many of the gaps in available data and methods, aiding in better understanding of the impacts of renewables and other new technologies in the distribution system. It could also provide guidance on how monitoring practices should be expanded and improved to provide the real-time information required to operate the distribution system of the future. AMP could also serve as the basis of a platform for routine distribution monitoring; that is, a monitoring system that produces the everyday information that utility engineers must have to operate and maintain a safe, reliable, clean, and economical distribution system.

## Project Results

A data repository was established at the University of California, San Diego Supercomputer Center for the secure storage of the utility data. In all, physical data for six distribution circuits was provided by three of the participating utilities; measurement data consisting of Supervisory Control and Data Acquisition data sets for one year were provided for five of the circuits. More data would have been desirable; indeed, considerably more data is required to perform the circuit characterization originally envisioned for this project, categorizing circuits by general type, by levels of renewable generation, or other key parameters.

The project team acquired enough actual system data, for physical circuit models and the associated measured data, to validate the circuit models. While some, not all, utilities have made efforts to validate their system models, it is a requirement that must be fulfilled. Unless the physical system model is accurate, it is not possible to perform meaningful planning studies, to know or estimate what the actual system conditions are, or to operate the system reliably and efficiently. Therefore, model validation will likely be the necessary first task for utilities when acquiring data from new, advanced monitoring systems intended for use in advanced applications.

Data quality must also be addressed. The available measurements included missing data, bad data and non-uniform sampling intervals, which required additional evaluation and processing of the data so that it could be used in analysis programs. Also, since there are numerous software packages marketed to utilities for analysis of distribution systems, the data supplied by the utilities varied in formatting, and necessitated additional processing into a common format. Despite these challenges, the project team developed methods for dealing with these anomalies so that analysis could be efficiently performed, which should prove to be valuable time-savers in follow-on research efforts.

Finally, the AMP blueprint addresses the current gaps in available data and in data monitoring practices, as well as the future needs focused on high levels of new technologies, such as renewables and EVs. The results from the first part of the project provided information on current needs and monitoring practices; the second part of the project included a survey of distribution engineers and experts, and an all-day interactive workshop, to further explore and expand the design and features of the AMP. The blueprint is a practical basis for further research to learn more about distribution systems in California, and in particular, the impacts of

new technologies such as such renewables and EVs on the design and operation of those systems.

## Project Benefits

The benefits from this project include increased knowledge of the operation and performance of the distribution system in real time, resulting in more reliable and efficient operations, better planning for system upgrades and expansions, and proactive detection, analysis and mitigation of the potential impacts of new technologies and applications on distribution systems.

California electric ratepayers, customers, and stakeholders will benefit from distribution systems that will better handle the unprecedented challenges placed upon them. These benefits will increase levels of clean energy generation such as wind and solar; higher reliability by avoided customer outages and faster service restoration; and more economic operation, resulting in lower electric bills.

# CHAPTER 1: Overview

## 1.1 Introduction

With rapid growth of renewable generation capacity in California, a significant portion of this capacity is slated for installation at the distribution level. Governor Brown's goal of 12,000 megawatts (MW) of distributed renewable generation envisions significant new installations of photovoltaic (PV) generation throughout California's electric distribution system. At the same time, the population of plug-in hybrid and electric vehicles (EVs) is expected to grow substantially over the coming years. These developments pose unique technical challenges to distribution systems, in addition to concerns at the transmission level, that to address will require empirical data not routinely being collected from distribution systems.

Preparing California's electric distribution for more renewable energy and electric vehicles could involve substantial risks. Without infrastructure upgrades, power quality and reliability may be compromised as an unintended consequence of clean energy policies. Ratepayers want these policies to be implemented at least cost without electric service compromise.

The default solution until now, to allow a fixed percentage of PV penetration (i.e., 15 percent of maximum load) per feeder, is a conservative approach likely to impede state goals and the amount of renewable energy Californians can contribute through distributed generation. It also does not reflect the considerable diversity among distribution circuits to handle distributed generation, nor does it recognize the potential for new and emerging technological solutions to facilitate the integration of these new energy facilities into the electric grid.

One alternative would be to generally upgrade distribution capacity so as to allow unlimited access for all distributed resources anywhere. This would likely mean retrofitting feeders with modern voltage regulation and protection equipment, a strategy that could easily run into the billions of dollars.

Another solution is to revise the 15 percent rule to better discriminate among locations, e.g., by electrical distance from the distribution substation, and to estimate penetration limits that are more likely to reflect the actual technical PV hosting capacity of the feeder.[1]

The most informed and ultimately robust approach, however, would anticipate and mitigate explicit problems in specific situations, and accordingly build and enhance the infrastructure, e.g., through smart grid solutions. This approach requires more detailed baseline knowledge of the operational characteristics of existing distribution systems than is now available, as well as the expected and unknown impacts of distributed resources on the existing distribution systems. In fact, this strategy is very much in line with the recent California Public Utilities

1 Smith, Jeff. 2013. *Alternative Screening Methods: PV Hosting Capacity in Distribution Systems*. 2013 DOE/CPUC High Penetration Solar Forum. http://www1.eere.energy.gov/solar/pdfs/highpenforum2013_2_1_epri.pdf.

Commission (CPUC) requirement that California IOUs develop new methodologies for distribution planning in the context of high DG penetrations, along with tools for assessing in detail the location-specific impacts – both positive and negative – of DG siting on distribution feeders and identifying optimal locations for DG placement.[2]

Technical issues associated with a high local penetration of distributed generation (DG) and electric vehicles (EV) include a range of impacts on transformers, voltage regulation, circuit protection, and modeling of the system. The importance or severity of these impacts may vary substantially from one situation to the next. In some cases, DG will represent a benefit to the distribution system. In general, however, these technical factors are seen as a limitation to the integration of high levels of distributed resources.

To address this challenge, it is necessary to discover and characterize any problems, to specify the conditions under which problems would be expected to occur, and to identify solution approaches. A critical first step in doing so is to gather empirical data about distribution system performance, including measured effects of DG on distribution circuits to date. These empirical data can then be used to validate distribution feeder models by comparing the models' predictions to what was actually measured. While existing models are trusted to provide good characterizations of distribution circuits with little or no DG, their ability to make predictions about the circuits' behavior under high DG penetrations remains to be determined. Based on the empirical feeder data and any discrepancies between these data and existing models, modeling updates can be developed to account for any new observed behaviors attributable to renewable integration. Improved distribution feeder models will then be better able to answer questions about what impacts to expect from high penetrations of DG, and how to address these impacts in the most economical way.

Cognizant of these needs, California utilities have begun to study the distribution system impacts of DG. Ongoing work has focused primarily on voltage profiles and model validation for a small number of individual feeders under high DG penetration. However, since extensive monitoring of distribution circuits was historically not cost-effective given the lack of need for such information, there is little if any comparative data of sufficient quality to provide a baseline or reference for measurements on distribution feeders with and without high penetrations. Furthermore, monitoring systems are not currently in place for discovering any new unanticipated distribution system phenomena. Despite considerable design differences, time variation and many other idiosyncrasies of distribution circuits, operators have little visibility of electrical phenomena resulting from these new sources and users of electricity on distribution circuits. The lack of visibility also applies to transmission operators such as the California Independent System Operator (California ISO), who find it increasingly important to have some knowledge of what happens behind the substation because of its effects on the reliability and economic efficiencies of the total interconnected transmission system.

---

2 California Public Utilities Commission (CPUC). 2014. *Order Instituing Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M102/K036/102036703.pdf.

Thus, a better understanding of the present and future impacts of distributed energy resources on the electric system will require a more comprehensive characterization of distribution feeder behavior. This means selecting a larger, more representative sample of diverse circuits for study, notably including those with little or no DG at present. Also, because not all potentially problematic phenomena are known, it is necessary to observe circuit behavior at a higher resolution or granularity than before, down to the level of sub-cycle power quality measurements. These observations will provide information about what problems might be expected on different types of circuits at different DG penetration levels, and what granularity of monitoring will be needed in the future so as to detect and prevent problems.

Because individual utilities still have only a relatively small number of distribution feeders exposed to high DG penetrations, it is important to leverage every research effort, including American Recovery and Reinvestment Act of 2009 (ARRA) projects, by sharing information and creating a collective data repository. This collaborative effort will enable the first systematic look at a representative sample of distribution circuits across the State of California. It will begin with a thorough inventory of data that can be gleaned from existing instrumentation, where efforts have already been made by individual utilities to improve visibility on distribution circuits, and build on these efforts by systematically augmenting hardware and data streams.

This project was designed to establish a collaborative process of sharing data, using the highest resolution measurements available from existing devices. It also analyzed available data to begin characterizing distribution feeders with and without DG, validated distribution feeder models, identified gaps in available data, and designed the implementation of future monitoring beyond this project. Follow-on research would potentially expand the data repository with measurements from new line sensors and substation monitors installed by participating utilities specifically with this project in mind, according to parameters developed jointly in this project. With more complete data at higher resolution from a representative sample of distribution feeders across California, follow-on monitoring research can extend the empirical feeder characterization and the model validation. In addition, data from follow-on research will support the correction of circuit models and the development of new models that represent advanced components, such as advanced inverters.

## 1.2 Goals and Objectives

The goals of this project were to advance electric transmission and distribution science and technology in the public interest in the following ways:

- Support the safe and reliable operation of the electric transmission and distribution system with a substantially increased presence of DG and EVs.
- Characterize the impacts on electric distribution system operation and performance of increasing penetrations of distributed, intermittent, and renewable generation and EVs.
- Increase visibility and situational awareness beyond the substation for transmission and distribution operators.

- Provide a better understanding of the needs for strategic upgrades and new technologies in the distribution system infrastructure and operational tools to accommodate desired levels of DG.
- Inform updated DG specifications and interconnection standards that allow the increased use of distributed renewable generation resources without adverse impacts on safety and reliability.

The objectives of the agreement were to:

- Coordinate the collection of empirical data by several California utilities on a representative sample of distribution circuits.
- Analyze the data for critical information about the performance of different distribution circuits at different penetration levels of DG and EV.
- Extract and combine information from prior distribution circuit studies to build on existing knowledge and avoid duplication of effort.
- Test, validate, and develop models of distribution circuits with high penetrations of distributed resources that capture interactive effects at high resolution.
- Share results and conclusions among California utilities and California ISO.

## 1.3 Technical Approach

This research project was composed of two broad, consecutive parts. The first part aimed to establish a collaborative process of sharing data, using typical measurements available from existing devices installed in a number of utility distributions systems in California. It analyzed data made available from these existing measurements to begin characterizing distribution feeders with and without distributed energy resources (DERs), validating distribution feeder models, and identifying gaps in available data. The second part of the project was to develop the basic design features of a possible, more intentional monitoring effort, the Advanced Monitoring Plan (AMP), which is the principal deliverable of the project. Expressly designed to be a blueprint or roadmap for a follow-on research effort to this project, the AMP would expand the data repository with measurements from new line sensors and substation monitors installed by participating utilities. With a more complete data set at higher resolution from a representative sample of distribution feeders across California, the empirical feeder characterizations and the model validations could be extended. In addition, these data could be used to support the correction of circuit models and the development of new models that represent advanced components, such as advanced inverters that might be used in future PV distributed generators.

The results from existing measurement activities indicate that there is significant distribution monitoring being done or planned by utilities in California. Most of the recently completed or ongoing monitoring activities are “ad hoc” efforts associated with projects that are or were investigating the behaviors in the electric distribution system of such things as distributed PV, energy storage, EV charging, microgrids, smart meters, and demand response programs. These

projects can be generally described as field tests and demonstrations, some of which were or are funded in part by the California Energy Commission, and by the federal government via the United States Department of Energy (DOE) or the ARRA. The purpose of much of this monitoring is focused on the behavior of the devices, although some monitoring is directed at the behavior of the distribution feeder, e.g., volt/VAR control effects. Accordingly, data are generally not being collected and analyzed consistently across all efforts even within a utility, much less in California. The resolution, quality, and placement of monitoring differ for each specific measurement site and are based on the purpose of the project. Nonetheless, analysis of these results, and accompanying communications with participating utilities in the first part of this project, contributed to development of the AMP.

In addition, a number of meetings were held over the duration of this project in various forums and conversations involving utilities and technical experts regarding distribution monitoring. The general approach in each case was to ask the broad question in various versions, "What monitoring would be needed to characterize the California electric distribution grid for high penetrations of distributed renewable generation?" While none of these encounters resulted in a well-defined design for an AMP, they did produce, in the aggregate, some significant general findings. One major finding was that existing measurements and measurement practices would not be at all adequate for the future vision of the distribution system, and were in fact not adequate now in many respects. Another finding was that such a characterization of the distribution system was important and should be done. Finally, there seemed to be general agreement that the granularity of an AMP measurement and monitoring system should err on the high side, at least in the initial stages, to give some confidence that unknown behaviors, if they exist, could be empirically identified, directly or by modeling.

Given the vague and incomplete outcomes of these early meetings to develop an AMP, two additional approaches were employed. One approach was a questionnaire for utilities regarding current and future distribution system monitoring needs in electric distribution. The survey results provided a foundation of understanding of the current practices and perspectives of the utility industry regarding distribution system monitoring in California. Information was obtained from utilities regarding present-day practices in distribution monitoring; the critical issues and challenges to monitoring today; and the technologies, methodologies, applications, etc., needed (or desired) to meet the monitoring needs of the future distribution grid. Findings from this survey are discussed in Chapter 3.

A second approach was a workshop for utility engineers, utility managers, and distribution technical experts and vendors that was held in Berkeley, CA, on September 5, 2014. A "straw man" AMP was developed and presented at the workshop. This straw man AMP consisted of key assumptions for the function and design of an AMP using knowledge and insights gained from the survey previously described and from previous encounters mentioned above. Workshop attendees critiqued the AMP. The outcomes of the survey and this workshop were very productive, as described in Chapter 3, and considerably advanced the concept and detail for the AMP described in Chapter 4.

Nevertheless, there exist challenges to the implementation of such an AMP. A key challenge lies in the tension between monitoring for very specific applications and use cases, which utilities are already undertaking, versus exploratory research, which the AMP largely represents. While complementary and somewhat overlapping, these two approaches are quite distinct in their implementation because the nature of the research and monitoring philosophy determines what data should be collected.

Data for specific applications should:

- Support the characterization of the use-case problem.
- Provide actionable intelligence.
- Be commensurate in terms of effort and cost with the problem to be solved.

Data for exploratory research should:

- Establish an empirical baseline to serve as a reference for future monitoring data.
- Reveal the appropriate resolution of future data to be collected.
- Reveal any important phenomena even if not previously anticipated.
- Allow for generalization from the studied sample.

Benefits of an exploratory approach include:

- Identifying previously unknown phenomena.
- Providing a baseline for comparisons of distribution circuits at different penetration levels.
- Providing empirical knowledge to inform follow-on research design.
- Providing empirical data for model development, validation and modification.
- Avoiding mistakes that could result from incorrect assumptions about system behavior due to lack of empirical data.

While there is general support for exploratory research, the value of monitoring for this purpose is much more difficult to quantify in immediate economic terms than monitoring for specific use cases that are readily justifiable as a utility investment. It is therefore unsurprising and sensible indeed that most utility monitoring efforts focus on specific problem areas (e.g., an individual feeder with known voltage issues).

Some utilities have nevertheless begun more systematic, "intentional" distribution monitoring efforts that are more in line with the purpose of the AMP. Two examples are Pacific Gas and Electric Company's (PG&E's) Pilot Deployment Project, and Southern California Edison Company's (SCE's) planned monitoring of 30 typical circuits identified through a taxonomy

circuit approach developed by Pacific Northwest National Laboratory.[3] The fact that some utilities are considering or implementing intentional monitoring activities suggests that a monitoring program conceptually based on AMP can indeed be developed and implemented in California.

One caveat of note that was observed in the investigation for ongoing monitoring efforts is that the utilities in general are short of personnel and funds for these monitoring efforts, which has inhibited the timely availability of, and access to, data. This constraint will likely continue into the near future. Consequently, a collaborative approach has been proposed in this report's AMP that could be more cost-effective and productive for all stakeholders. While the advantages of collaboration as opposed to individual efforts by utilities are not yet proven, given the pressures facing California's electric power infrastructure at this time, the conditions may now be right to pioneer such an approach.

3 Schneider, Kevin, Yousu Chen, David Chassin, Robert Pratt, Dave Engel, Sandra Thompson (Pacific Northwest National Laboratory). 2008. *Modern Grid Initiative – Distribution Taxonomy Final Report.* United States Department of Energy. PNNL-18035.

# CHAPTER 2:
# Establishment of Preliminary Data Inventory

## 2.1 Background & Objectives

The objective of the Data Inventory was to establish a reference of distribution system measurements ("Preliminary Data Inventory") currently being collected by California electric utilities, either through regular operations or from specific studies. Additionally, physical data describing the distribution circuits for which the measurements were taken was also compiled, so that distribution feeders could be characterized by means of taxonomy methods, and simulations performed for the purposes of model validation. These tasks will be described more fully in later Chapters. The purpose of this Chapter is to summarize the preliminary status of this data inventory.

With rapid growth of renewable generation capacity in California, a significant portion of this capacity is slated for installation at the distribution level. Governor Brown's goal of 12,000 MW of distributed renewable generation envisions significant installations of photovoltaic (PV) generation throughout California's electric distribution system, in addition to residential and commercial rooftop systems initiated by utility customers. Most of these will be interconnected at various points in the electric distribution system, rather than at the high-voltage transmission level. At the same time, the population of plug-in hybrids and electric vehicles (EVs) is expected to grow substantially over the coming years. These developments pose unique technical challenges to distribution systems, in addition to concerns at the transmission level; to address these challenges will require empirical data not routinely being collected from distribution systems.

A key goal of this project was to coordinate the collection and analysis of empirical data by several California utilities on a representative sample of distribution circuits aimed at improving understanding of the impact of distributed renewables and electric vehicles. A first step in this process was the gathering of information on what data collection is already being undertaken by the partner California utilities. These utilities included PG&E, SCE, San Diego Gas and Electric Company (SDG&E), and Sacramento Municipal Utility District (SMUD). The Electric Power Research Institute (EPRI) provided additional inputs.

This chapter summarizes monitoring efforts by each partner utility that are pertinent to this project, either from regular operations or specific studies. The intent is to reflect measurement type (voltage, current, power); circuit type (loop, radial, distribution); data resolution, format, and accuracy; and use of the data.

The goal is to use this information with actual distribution monitoring data collected and reported by this project to better characterize the context for the monitored and collected data, and to begin a gap analysis to determine what kinds of data are still most needed, and what types of research efforts might address the data gaps.

Information regarding utility efforts to collect distribution data was collected through literature searches and discussions with knowledgeable utility representatives. For each data source, researchers sought to obtain information for a set of topics:

- Circuit Types and Location
- Measurement Types
- Uses of Data
- Funding/Partners
- Monitor Manufacturers
- Contact Person
- Project Dates

The data inventoried in this report were collected for original purposes unrelated to this project. As a result, the kinds of data collected, as well as the quantity and resolution of the data, vary considerably, and not all technical goals or topics are being addressed for all data sources.

## 2.2 Approach for Obtaining Data from Partner Utilities

Four California utilities cooperated with this data inventory effort at various levels. Each utility committed to providing some information on existing distribution data collection efforts and agreed to identify a number of circuits for future monitoring. In addition, EPRI also agreed to cooperate with additional data. Non-disclosure agreements (NDAs) were executed between each utility and the University of California, San Diego Supercomputer Center (SDSC), which had responsibility for receiving the data and ensuring that it was processed and handled with appropriate safeguards, as befits confidential information.

SCE provided information on seven projects and identified 20 circuits, which are representative of the vast majority of their feeders. All circuits were characterized by a number of parameters and each selected circuit is representative of about 100 feeders.

SDG&E expressed their intent to provide data collected on three projects. They identified a total of 26 circuits with 130 feeders located in a variety of climate areas. There was no specific information about the level of PV penetration in each circuit provided at this point.

PG&E provided monitoring data on three current projects. They chose two circuits with substantially different characteristics for which they will provide data for modeling. One has 2 MW of PV and a peak annual load of 27 MW while the other has a peak load of 35 MW and 1 MW of installed PV.

SMUD provided data on two existing projects. They selected 16 circuits with about half in urban areas and the remainder in small town or rural areas. PV content in each circuit ranges from very low up to 3,850 kW.

EPRI provided information on a single project, but an extremely relevant one – the Distributed Photovoltaic Feeder Analysis. This project currently conducts extensive monitoring of 26 circuits from 8 utilities across the United States. Individual PV systems were monitored as well as the selected feeders.

California has policies in support of renewable energy and reduced greenhouse gases. Both policy and market forces are driving dramatic increases in the penetration of renewable energy, especially photovoltaics, at the distribution levels. However, the distribution system was not historically intended to contain generation, and particularly not variable, non-dispatchable generation. Without generation at the distribution level, extensive monitoring of distribution has historically not been necessary, but the current status of monitoring is perceived to be insufficient in many situations now, and increasingly so in the future. This project is aimed at systematically evaluating current levels of distribution monitoring and determining what will be needed to successfully integrate the increasing penetration of distributed energy resources.

A better understanding of how distribution circuits perform in the presence of high penetrations of distributed renewables will improve the ability of utilities to manage the distribution system more efficiently. Ratepayers will benefit, as the improved understanding will allow mitigation of impacts, minimizing costs and helping to assure that high reliability is maintained. Determining the current state of distribution data collection is the base upon which the larger objectives of identifying the data gaps and planning future monitoring will be built.

### 2.2.1 Memoranda of Understanding (MOUs)

The input of California utility partners was seen as critical to the success of this project in several ways. First, the utilities would need to provide the project team with data from their distribution circuits: both physical (model parameters for conductors, transformers, switches, etc., as well as schematics and geographical information) and measured (voltages, currents, etc.). Second, the expert technical knowledge and informed opinion of the utility partners was needed to process and analyze the data. Third, and perhaps most important, the utilities would need to contribute to, and buy into the whole concept of, the Advanced Monitoring Plan. Because their participation was voluntary, and therefore no binding contracts were going to be executed, it was considered necessary to have, at the very minimum, "informal" agreements that would describe the purpose and scope of the project and the roles and responsibilities of the utility partners.

Because the term "Memorandum of Understanding" carries some legal connotations, the term "Participation Agreement" (PA) was considered more appropriate for this project. Participation Agreements were negotiated with each of the utility partners: PG&E, SCE, SDG&E, and SMUD. Some variations in language occurred among the PAs based on the individual review processes and priorities of the utilities. These Agreements can be found in Appendix A.

### 2.2.2 Non-Disclosure Agreements (NDAs) and Protection of Data

Utility data is almost universally considered to be sensitive and confidential information for a number of reasons, and utilities are usually reluctant to provide data to outside entities for any reason. Utilities require a Non-disclosure Agreement (NDA) to provide data, the purposes of which are: to specify the data being provided; whom it is being provided to; the prescribed purposes; the procedures the recipient must follow to protect the data; and when and how the data are to be returned, maintained, or destroyed once the term of the NDA is completed. NDAs were negotiated and executed individually between each of the four participating utilities and the SDSC, who was the designated recipient of the utility data.

SDSC team members have extensive technical knowledge and experience in transferring and processing large amounts of data, especially using industry-standard procedures and processes for securing the data and in "anonymizing" the data to meet utility requirements. Physical descriptions such as names of substations and transmission lines were internally modified so that the identifying information is replaced with names and labels that will not identify physical place names, should the data fall into unauthorized hands.

## 2.3 Overview of Distribution Monitoring Efforts by Utilities

California utilities have been cognizant of the need to gather data at higher resolution to ascertain the impacts of variable and distributed generation along with variability of loads. This section summarizes monitoring efforts by each partner utility that are pertinent to this project. Data were gathered for regular operations and the studies focused on evaluating the performance or impacts of specific distributed energy resources. Full details of these projects were described in the Task 2.0 Interim Report "Preliminary Data Inventory Report: Overview of Distribution Feeder Characteristics for Renewables Integration."

### 2.3.1 Southern California Edison Company

*Irvine Smart Grid Demonstration (ISGD)*

SCE is collaborating with researchers at University of California Irvine (UCI), the University of Southern California (USC), EPRI, and industrial partners to deploy a range of "Smart Grid" technologies on two distribution circuits in Irvine, CA. The intent is to predict how automated systems affect grid performance. Technologies deployed on these circuits include electric vehicle (EV) charging for buildings, looped circuit topology, residential energy storage, community energy storage, Volt/VAR control, dispatched renewable distributed generation, smart meters, cyber-security upgrades, and in-house monitoring of plug loads. Goals of the project include deep grid situational awareness, enhanced efficiency and power quality, circuit constraint management, and self-healing circuits. Other project initiatives are attainment of zero-net-energy (ZNE) for new homes (including gas usage), improved customer education, and power systems control.

The project focuses on two 12 kilovolt (kV) feeders from the MacArthur Substation in Irvine that connect homes with renewable energy and smart appliance systems. The layout includes some looped circuit topology with EV charging, utility-scale storage, and dispatched renewables.

Residential data collection on these circuits is performed by smart meters and Advanced Metering Infrastructure (AMI) and some plug loads inside selected homes. Utility-side circuit data monitoring is performed by conventional instrumentation augmented by substation-grade relays and communications using the International Electrotechnical Commission's standard for electrical substation automation design (IEC 61850) and GOOSE (Generic Object Oriented Substation Events) messaging protocol.

The project will evaluate zero net energy (ZNE) feasibility in homes, residential and community storage, Volt/VAR control on feeders for conservation voltage reduction (CVR), advanced protection schemes, workforce requirements, and demand response (DR) requirements.

This $80 million (M) project leverages funding from SCE, the DOE, and partner cost sharing from General Electric (GE), UCI, and Boeing. It is scheduled for completion in September 2015.

*Tehachapi Wind Energy Storage Project*

SCE is installing a battery energy storage system at the Monolith substation, where 4.5 gigawatts (GW) of wind resources are planned to come online by 2015. The lithium-ion (Li-ion) battery is rated at 8 MW of power and 32 Megawatt-hours (MWh) of energy storage capacity. The goal of this project is to demonstrate the ability to locally absorb the rapid power fluctuations that are often associated with the wind energy resource. Remarkably, the Li-ion battery is intended to be able to provide maximum capacity in less than 20 milliseconds (ms).

Grid services that the battery storage system will provide comprise a number of functions that are distinguished by the physical performance of the storage system – specifically, the time scale and range on which it is asked to increase, decrease, or reverse power flow – as well as the operational or economic context in which this performance is understood and evaluated. These distinct functions include grid stabilization, voltage support, system reliability, output shifting, frequency regulation, ramp rate compensation, and energy price arbitrage. The storage system at the Monolith substation is connected via a 66/12 kV transformer bank.

Instrumentation at the substation aims to capture the entire range of the storage system's performance across various time scales, for a proof-of-concept test of various operational modes and economic performance of the storage system.

The project is funded by the DOE and additional match funds of $52.5M.

*Inverter Testing*

SCE conducts inverter testing at its Smart Inverter Facility in Southern California, jointly with the National Renewable Energy Laboratory (NREL). The inverter project is testing inverters of interest to SCE by observing single-phase electricity profiles based on different scenarios created by the PV simulator, grid simulator, and load bank.

The tests are assessing the capabilities of one U.S. and six German inverters (dynamic voltage support, voltage and frequency ride-through, dynamic watts and over-frequency, and Volt/VAR control) for U.S. grid electric profiles. Measurements conducted at the facility are intended to examine steady-state performance, transient response, and performance relative to

interconnection standards (IEEE 1547, CPUC Rule 21, UL 1741), as well as performance beyond the restrictions of current standards including smart inverter functions, advanced storage functions, inverter behavior under abnormal grid conditions, and grid integration scenarios using hardware-in-the-loop techniques.

*NREL High Penetration PV Project*

SCE installed PV capacities up to 18 MW on 28 different 12 kV distribution circuits. In addition to PV, supplemental instruments and inverter modifications are being employed and tested.

Three feeders are being analyzed in the cities of Fontana, Porterville, and Palmdale. Fontana is host to 2.5 MW of installed PV capacity and shows some reverse power flow, although the voltage profile is regulated by capacitor banks. Porterville hosts 5 MW of PV and has generally light loads besides water pumping; it is a longer line (ca. 47 miles) and also shows reverse power flow. Palmdale hosts 3 MW of PV and is very lightly loaded; it shows reverse power flow during daylight hours and PV generation is thought to incur significant Volt/VAR issues.

Data are being collected directly from 500kW Satcon inverters. The project intends to use measured data to validate the Fontana, Porterville, and Palmdale circuits that are being modeled by NREL, using quasi-static, time-series analysis at multiple steps to predict and mitigate high-penetration PV impacts as well as to regulate voltage.

An additional goal is to develop active inverter mitigation methods for high-penetration PV, including active Volt/VAR control, based on data from this study. The inverters are being used to test advanced functions such as power flow set points and constant voltage regulation over simulated highly variable solar profiles.

This project is funded through the SunShot Initiative, DOE, and the CPUC's California Solar Initiative (CSI).

*Scalable Real-Time Decentralized Volt/VAR Control (Caltech)*

Caltech partnered with SCE to develop scalable, real-time, distributed methods for Volt-VAR control to enhance system-wide efficiency, reliability, and power quality in the presence of intermittent DER. It allows each DER to manage its own output power while simultaneously optimizing overall power flow within the grid.

The total project cost is budgeted at $1.35M, including funding by the Advanced Research Projects Agency – Energy (ARPA-E) of the DOE.

*Full-Scale Implementation of Automated Demand Response (Honeywell)*

Honeywell partnered with SCE and PG&E to develop an automated demand response system for commercial and industrial customers with an average electricity demand higher than 200 kW. The automated demand response helps SCE and PG&E to automatically execute load shedding in response to peak load events or price signals, in accord with the California critical peak pricing tariff system.

The total project cost is budgeted at $22.768M with federal share of $11.384M from a Smart Grid

Investment Grant under the American Recovery and Reinvestment Act of 2009 (ARRA).

*Edison SmartConnect*

SCE's Edison SmartConnect project is one of the most advanced smart metering programs in the nation. The installed Itron smart meters and AMI empower customers to use electricity more efficiently and saving energy, money and the environment. EPRI is a funding partner.

### 2.3.2 San Diego Gas & Electric Company

*Smart Grid Communication System*

SDG&E installed a wireless communication system that will include 90% of its customers and facilitate the use of AMI and distribution automation equipment. The goal is to provide better system visibility, enhance reliability, reduce outage durations, and reduce costs. Total project cost was budgeted at $59.4 million with a federal share of @28.1 million from ARRA funding.

*Beach Cities Microgrid*

SDG&E's microgrid system at the Borrego substation is located in rural northeast San Diego County. This islandable microgrid includes solar generation and a total load over 10 MW on three feeders.

Data will be collected to evaluate the ability of the microgrid to achieve the following:

- 15% reduction of feeder peak load using price-driven load management (PDLM), energy storage, and integrated DER
- Demonstrate Volt/VAR control
- Develop and demonstrate integrated AMI, self-healing networks using Feeder Automation System Technologies, integrated outage/distribution management system (OMS/DMS), and ADR for intentional islanding
- Integrate PV, storage, plug-in hybrid electric vehicles (PHEVs), smart appliances

The total project cost is $12M, including $7.2M from DOE and $2.8M from the California Energy Commission. Partners include Itron (manufacturer of the monitors), GridPoint, University of San Diego (USD), Oracle, PNNL, Motorola, IBM, Xanthus, and Horizon Energy.

*Wholesale Market Pilot (DRWMP) program*

The DRWMP allows SDG&E customers to bid demand response directly into the California wholesale electric market. Siemens Energy and SureGrid are partners in the project to provide monitoring and a cloud-computing platform to automatically monitor building operating condition and occupancy in real time. The DRWMP optimizes load shedding while maintaining a comfortable environment for occupants in each building.

Data are collected to achieve the following targets:

- Optimize load shedding with maintain customers' comfort level
- Intelligent Load Management solution
- Networked energy meters installed at each building

The project partners include Siemens Energy and SureGrid.

### 2.3.3 Pacific Gas & Electric Company

*Pilot Deployment Projects*

The Pilot Deployment Project addresses four areas of interest (line sensors, Volt/VAR control, fault and outage detection and location, and short term forecasting) on a separate basis, with two other areas waiting for approval. For each area, PG&E will test and employ novel technologies and concepts, address gaps and concerns for fully implementing the programs, create methodologies for testing the cost effectiveness, develop a strategy for identifying the best practices for expansion, and develop standards for measuring the pilot outcomes. The project was approved on May 22, 2013.

Circuits were selected based on the following:

- A total of 30 distribution feeders for operation, evaluation, and demonstration of sensor line project.
- A total of 12 distribution feeders for Volt/VAR optimization and telecommunication system testing.

Data collection for the Smart Grid Line Sensors information project will evaluate the following:

- Volt/VAR Optimization, fault and outage detection and location, short term forecasting improvement, and technology evaluation
- Reduction of response time and duration of outages
- Higher granularity of loading information
- Use of field data with computer models for increased penetration of distributed renewable generation sources
- Self-healing and resilient lines
- Improvement of power quality
- Accommodation of all generation and storage options
- Increased penetration of intermittent power generation sources
- Determination of best technologies to meet needs

- Software that will control and use real-time information from Supervisory Control and Data Acquisition (SCADA) controlled distribution feeder equipment and Smart Meters to manage the distribution circuit voltage at primary, secondary, and service systems.
- Cyber security and controls
- Potential waveform analysis capability to avoid outages and find and resolve power quality issues

In the future, data may be used to assist standards development and testing.

The total project cost is budgeted at $100M including a Line Sensor Project ($16.5M), a Volt/VAR Project ($38M), a Fault/Outage Detection/Location Project ($12.5M), and a Short-term Forecasting Project ($13M).

For most applications, vendors will be selected after laboratory testing.

Potential vendors of line sensors include: Sentient; Tollgrade; QinetiQ; Grid Sentry; Schweitzer Engineering Laboratories, Inc.; Optisense, Cooper Power Systems, GridSense, Asea Brown Boveri (ABB), GE, and Siemens.

Potential vendors of Volt/VAR optimization systems include: Cooper, Telvent, ABB, IBM, Lockheed Martin, GE, Areva, Alstom Grid, Siemens, Utilidata, and Silver Springs.

Potential vendors of sensors for the Fault Location Project include: Cooper, Utilidata, ABB, GE, Areva, Siemens, Alstom Grid, and others.

A potential vendor for the Load Forecasting Project is Pattern Recognition Technologies.

*Cornerstone Improvement Project*

Cornerstone is a project intended to improve reliability. The project will install and/or upgrade equipment. Of particular interest is that a large number of medium voltage lines will be automated.

70 Circuits in Fresno and Bakersfield with Automated Demand Response (ADR).

Total project cost will be $355M, of which $182M will be for distribution automation.

*Full-Scale Implementation of ADR (Honeywell)*

Honeywell, with SCE and PG&E partnership, will develop an automated demand response system for commercial and industrial customers with average electricity demand higher than 200 kW. The automated demand response helps SCE and PG&E to automatically execute load shedding in response to peak load events or price signals.

This project is in accord with California critical peak pricing (CPP) tariff system.

Total project cost is budgeted at $22.768M, with Federal share of $11.384M from a Smart Grid Investment Grant, under the American Recovery and Reinvestment Act (ARRA).

### 2.3.4 Sacramento Municipal Utility District

*Distributed Energy Storage System (with Premium Power)*

This project is led by Premium Power, who is installing two 500 kW, 6-hour zinc bromide (ZnBr) battery systems in Sacramento in collaboration with SMUD. One will serve the SMUD campus microgrid, and the other will serve the substation for the Anatolia III SolarSmart Homes project. One of the project's goals is to demonstrate multiple approaches to battery integration with intermittent renewable energy systems with aggregated homes, in a micro-grid, and at a substation. Another goal is to develop and verify creative control algorithms to manage fleet operation of energy storage systems that are not co-located.

SMUD is collecting feeder monitoring data for the Anatolia site, uploading to Sharepoint, and making a data collection and analysis plan to document what data points are collected for each energy storage device. Weather data (temperature, pressure, wind speed and direction, humidity and solar irradiance) are updated hourly using a rotating shadowband radiometer.[4]

Circuit Types and Location:

- Distribution circuit for SMUD campus microgrid with a 3 MWh battery system.
- Distribution circuit for Anatolia III SolarSmart residential area with 3 MWh battery system. Homes equipped with renewable energy systems.

This is an ARRA Smart Grid Demonstration project with $12.5M total cost including three systems installed in Massachusetts. There is no breakdown for the California portion of the project. Partners include National Grid USA Service Company, Inc., Worcester Polytechnic Institute, Science Applications International Corp., and NREL.

*Smart Sacramento*

In this ARRA SGIG program, SMUD is deploying AMI system-wide and automated control and equipment on 102 distribution circuits out of the total of 635. The total project cost is $307 million, including $127 million from the DOE. Goals include optimization of grid assets and more control and transparency for customers. SMUD is also installing up to 220 plug-in electric vehicle charging stations on college campuses and residences, and conducting testing on performance criteria, charging patterns, and effects on distribution systems.

Distribution automation will be done on a variety of feeder types. EV charger data will be on feeders for residential and college campuses.

AMI is used. Meter data reporting, reviewing, and data validation and estimation are done on Itron Enterprise Edition Meter Data Management.

4 http://www.nrel.gov/midc/smud_anatolia/display/

Project vendors are Hertz Equipment, Keystone Electrical Manufacturing, Lockheed Martin, S&C Electric, Siemens, Spring Silver Networks, Trimark Associates, Inc., Utility Partners of America, and Western Electric Product Sales.

### 2.3.5 Electric Power Research Institute

*Distributed Photovoltaic (DPV) Feeder Analysis*

EPRI's DPV project will monitor PV output and analyze feeder impact for a very diverse range of feeders across many different locations, allowing analysis of geographic diversity and proximity to a feeder's substation. EPRI will monitor output, irradiance, and loads for individual PVs. This information will be used to validate models that use both steady-state and time series analysis. The project currently spans 8 different utilities in 26 cities across the United States. The sites vary between urban and rural for locations in the US identified as Southeast, West, Northeast, and East Coast.

250-300 monitoring sites will be used. Some are small, residential PVs; others are large, commercialized PVs. The distributed PV's single panel output and irradiance is monitored. Solar input is monitored at one per second.

Smart inverters are also being studied for Volt/VAR compensation of high penetration circuits.

Each monitor device has 8 sensors for voltage, current, resistance, temperature, etc. Up to 5 devices are connected to a Modbus device that uses RS485 Modbus communications to connect to a Data Logger.

A high fidelity, multi-phase model with incorporated regulation and controls that spans from customer meter to substation for time-varying loads is being validated using the measured data. EPRI intends to design a model that accurately responds when PV output goes from zero to full as well as corresponding measured PV irradiance data.

EPRI's work on PV location in relation to the substation has shown that PV closer to the substation has "no adverse impact" on regulation equipment, but PV an increased distance away requires more work from the load tap changer with different phases requiring different levels of tap operations. One circuit used steady-state analysis to determine the minimum amount of penetration that would case voltage threshold violations to occur. The analysis concluded that 25% to 100% more PV can be accommodated using Volt/VAR control.

Ultimately, EPRI intends to determine the required regulation and control changes for certain PV penetration levels, depending on feeder length, location, and operating practices. Future goals are addressing whether limits exist and developing analytical techniques for efficiently screening and assessing PV interconnection requests.

The power meters employed in this project are ELKOR Technologies Inc.'s WattsOn Universal Power Transducers. The data acquisition system utilizes Obvius AcquiSuite's A8810 series equipment.

## 2.4 Research Gaps

While the projects described in the previous section excel in building of models and infrastructure development, it is unclear what data are used for the validation of the models. Utilities do not specify what type of data streams are being collected, or the resolution and accuracy of the data measurements. These projects are validating models using their current data streams, but it is unclear if data they are using is at a resolution that captures the full extent of power data. It also unclear if the data collected are able to interface with other models for further validation.

One of the greatest gaps among all projects is a collaborative effort with other projects, especially between utilities. The projects listed above show that many of them have objectives and areas of development that are very similar, if not identical. This redundancy in work could be abated by more project transparency, less delay between project proposals and start dates, and a group responsible for coalescing and disseminating information to projects. These practices would allow each project to accomplish more and get over hurdles faster. It would also decrease redundant funding for similar projects. Finally, it would allow all utilities to progress faster and move on to other pressing issues of adapting to distribution circuits with high renewables penetration.

## 2.5 Conclusions for the Preliminary Data Inventory

Conclusions for the establishment of the Preliminary Data Inventory are presented in the context of the purpose of this project, which is to assess the distribution monitoring needs of California utilities according to a medium- to long-term vision of the likely evolutionary path of the distribution system. This project aimed to establish a collaborative process of sharing data, using the highest resolution measurements available from existing devices. It also analyzed available data to begin characterizing distribution feeders with and without distributed generation, validate distribution feeder models, identify gaps in available data, and design the implementation of future monitoring for a more intentional monitoring effort. A follow-on research project could expand the data repository with measurements from new line sensors and substation monitors installed by participating utilities specifically with this project in mind, according to parameters developed jointly in this project. With more complete data at higher resolution from a representative sample of distribution feeders across California, follow-on research could extend the empirical feeder characterization and the model validation. In addition, data from follow-on monitoring research would support the correction of circuit models and the development of new models that represent advanced components, such as advanced inverters.

The results of this project indicate that there is significant distribution monitoring activity being done or planned by utilities in California. Most of the current monitoring activities are “ad hoc” instances associated with projects that, through field tests and demonstrations, are investigating the behaviors in the electric distribution system of such things as distributed PV and energy storage, EV charging, microgrids, smart meters, and demand respond. The purpose of much of this monitoring is focused on the behavior of the devices, although some monitoring is directed

at the behavior of the distribution feeder, e.g., Volt/VAR control effects. Accordingly, data are generally not being collected and analyzed consistently across all efforts even within a utility, much less in California. The resolution, quality, and placement of monitoring vary for each specific measurement site and project.

Some utilities have begun more "intentional" distribution monitoring efforts that are more in line with the ultimate goal of this project, which is the collection of data at higher resolution from a representative sample of distribution feeders across California complete enough to characterize the expected and unexpected states of the California distribution systems under traditional and anticipated, e.g., high PV penetrations and loadings. As noted above, two examples are PG&E's Pilot Deployment Project and SCE's planned monitoring of 20 typical circuits, each picked to represent 100 others of similar type. The fact that some utilities are considering or implementing such intentional monitoring activities suggests that a conceptual plan for future monitoring efforts can be developed, and collaboration and support of future research by the utilities is possible.

One caveat of note that was observed in the investigation for ongoing monitoring efforts is that the utilities in general are short of personnel and funds for these monitoring efforts. This has inhibited the timely availability of, and access to, data, and this constraint will likely continue into the near future.

# CHAPTER 3:
# Creation and Management of the Data Repository

## 3.1 Data Repository Architecture

*Overview*

The University of California, San Diego (UCSD) archived data in the production OSIsoft PI server located in the SDSC data center using the OSIsoft PI System – the industry standard in enterprise infrastructure for highly scalable and secure management of real-time data and events. The PI system is administered and maintained by SDSC personnel. UCSD Active Directory and guest account controls are implemented on the system and enabling data access via the existing terminal server. The PI client data access tools are available to all users with valid terminal server accounts.

Each circuit description is composed of four files. For each circuit, the files include: (a) raw data from a PI system owned by the project participants, (b) annotated one-line diagram of each circuit, (c) load data, and (d) weather data. These four files used an Asset Framework (AF) repository development of each circuit.

*Asset Framework (AF) Naming Convention*

The IEC 61850 Standard for Power Utility Automation includes specifications for naming conventions, used in the PI meta-data system. The AF enables every data stream to have an alias name selected from a set of predefined names that meet the IEC standard. The names are formed as the concatenation of approved names contained in multiple tables. The entries in the tables require approval by the program manager. The concatenation rules follow "Hungarian notation," an identifier naming convention that adds a prefix to the identifier name to indicate the functional type of the identifier.[5]

*Data Acquisition*

There are two ingestion methods for the PI time series data into the UCSD PI server: (1) local data upload in .csv format, and (2) PI to PI data transfer. One of the key issues in data transfer is the access and security of the utility data accessed by PI servers. One of the simplest is receiving the raw data from each participating utility by using the "Piconfig" tool and Microsoft "Power Shell" macro system. In this scenario, the PowerShell script references an external Excel file prepared for each circuit. This file includes the individual tag names for each circuit, the start time, and the end time.

For example, a circuit may have hundreds of variables. These are listed in the first column of the Excel sheet. The header raw will include the start time in ASCII text as "mm/dd/yyyy hh:mm:ss.000," and the name of the circuit.

5 https://msdn.microsoft.com/en-us/library/aa260976(v=vs.60).aspx

The SDSC team prepares the PowerShell script and forwards this to each utility. The script is run against the PI servers holding the data. The script stores the resulting data in a .csv file on the directory containing the script. This file is then uploaded to the terminal server via secure FTP. There is typically one data file for each circuit. Additional information is uploaded via secure FTP as well.

Three additional files are required to complete the circuit description. These contain (a) information about the circuit topology, (2) load data, and (c) weather data.

*Circuit Topology*

A three-line diagram of each circuit is provided by the utilities in AutoCAD ".dwg" format. This drawing contains labels showing locations of all hardware on the circuit, and locations of the instruments sending data to the PI servers. The drawing typically includes switches and their normal settings information.

*Load Data*

Load data is supplied by the utilities as available. This includes similar information as outlined above for the continuous measured data. This will preferentially include name of variable, its location, time of measurement, and value of the measurement as available and provided by the utilities. Power measurements are more significant than energy measurements, but if energy is all that is available, they are used. The objective is to create a load profile for each load on the circuit. For example if the circuit includes 10,000 loads, the name of the load variable, its location on the circuit, and the 15-minute power consumption data is ideal.

*Weather Data*

Weather data is collected over the same time range as the measured data. The repository is able to ingest the Automated Surface Observing System (ASOS) data from the nearest airport or weather station.

*Delivery of Data to UCSD*

The files are uploaded via secure FTP on the terminal server. A designated user for each utility receives the login information and privileges to upload the data.

*Handling of Raw Data on the PI System*

The raw data is loaded into the PI server using Piconfig. Access rights to the data from the different utility participants are controlled by the PI Administrator using the UCSD Active Directory. Initially only the PI administrator and the designated utility PI administrator have access to their own data. Utilities are not able to see others' data, nor even know of its existence in the server. There is a separate "source" code for each utility. These are applied as the data is loaded into PI.

*Load Research Data*

The load data is not always available in easy-to-translate formats as received from the utilities. It most often has to be processed to estimate the interval power consumption of each load. The ideal case is that all loads on each circuit are measured. This is highly unlikely, so the load data needs to be processed to determine the best estimate of the loads. Ideally, these estimates should be at the same intervals and times as the raw measured data. The load research data is then converted into one-second power data. These data will then become inputs to the model as the load data at each solution time interval.

## 3.2 Circuit Selection by Utilities

*Sacramento Municipal Utility District*

Sacramento Municipal Utility District identified 16 circuits from five different substations as candidates for this project. These 12 kV circuits have a variety of primary conductor lengths, from 5 miles to 76 miles. In half of the circuits, customer types are mostly urban residential with some light industrial and commercial loads. The remaining circuits have rural and small town residential customers. The transformer capacity is 20 megavolt-amperes (MVA) or 12.5 MVA for most circuits.

All of the chosen circuits have installed PV sources. The PV installed capacity varies from 3 kW to 3,857 kW per circuit. The total PV capacity in all circuits is 10,355 kW.

Of the 16 selected circuits, 14 are equipped with SCADA data measurement systems.

*Southern California Edison Company*

Circuits selected by SCE for inclusion in this project were based on a list of metrics for more than 90% of SCE's 4,186 circuits and on an algorithm that clusters similar feeders together to find the 20 most representative circuits. Each of the selected 20 circuits is representative of approximately one hundred circuits in terms of behavior. Behavior parameters were ranked for peak loading, PV penetration, availability of voltage support, length of circuit, local climate (such as inland, coast, valley, or desert), class of customers, and relative amount of customers. All of the chosen circuits were required to provide an acceptable amount of PV generation and come from a diversity of climate zones.

The following methodology was applied to 20 unique circuits for this project. First a feeder database for most (90%+) of the circuits in SCE territory was compiled with important classifying traits such as: voltage class, single-, 2- or 3-phase circuit miles, percent of lines that are overhead, number of line voltage regulators, number of capacitor banks, number of feeder tie points, California climate zone, peak loading (MW), peak date, peak time, and percentages of each major customer class. These circuit characteristics do not represent all of the classifying traits that can be used for selecting distribution feeders, but this is the best data made available to the project team at the time.

The feeders were analyzed using the k-medoids algorithm that performs clustering for 20 clusters and their center points (centroids), which dictate the 20 circuits used in this study. The

reason 20 circuits were chosen is because that is the maximum number SCE could support with the project resources available. Five circuits were omitted from the analysis because of peculiar traits such as odd voltage classes.

After the centroids were calculated, the "closest" circuit within this abstract 20 dimensional geometric space that provided the acceptable amount of photovoltaic (PV) generation was chosen. Care was also applied to pick circuits across the different SCE climate zones.

This process went through several iterations before the project team was completely satisfied with the final circuit selection. The weighted total was 4,186 feeders.

*Pacific Gas & Electric Company*

PG&E chose two circuits for the project that also differ greatly in characteristics. Circuit A has PV with a capacity of almost 2 MW with summer loads of 27 MW while the Circuit B has summer loads of 35 MW but a PV capacity of 1 MW. Furthermore, 80% of Circuit A's load is industrial, with peak times of 3:00 PM and 4:30 PM in summer and winter, respectively. Circuit B has between 70% to 78% residential load, varying by season, with peak loads at 9:30 PM and 6:30 PM in summer and winter, respectively. Additionally, Circuit B has many overloaded transformers, making it attractive for increasing distributed PV levels.

These circuits were used to create techniques for simplifying methods for controlling high renewables penetration based on a circuit's characteristics.

*San Diego Gas & Electric Company*

SDG&E selected 26 circuits for this project. The selected circuits have a total of 130 feeders. These circuits are located in various climates – inland, coastal, and mountain. Primary voltage level is 12 kV in all circuits. Transformer capacity in most circuits is 30 MVA. A total of 41,026 customers are connected to the selected circuits. Residential customers comprise 89% of the total end users. The minimum number of customers in a circuit is 4 and the maximum is 4,525. There are no industrial customers in the selected circuits.

For each circuit, the number of reclosers, voltage regulators, and capacitor banks is provided but there is no information about PV penetration.

There are 11 circuits that are equipped with PQube measurement devices.

# CHAPTER 4:
# Distribution Feeder Behavior Characteristics

## 4.1 Overview

### 4.1.1 Background

Electricity transmission and distribution networks are complex and widespread systems that cannot be operated and controlled without reliable, secure, and sufficient measurement data. Distribution networks historically are much less advanced than transmission networks in terms of observability and monitoring system installation. With distribution systems generally characterized by radial (i.e., non-networked) topology and one-way power flow, it was only necessary to evaluate the envelope of design conditions, rather than continually observe the operating state.[6] However, with the arrival and continued growth of distributed energy resources, such as renewable generation, electric vehicles, demand response programs, etc., short-term and unpredictable fluctuations and disturbances are occurring on distribution systems, and planning, maintenance and especially safe and reliable operation are becoming successively more challenging. Moreover, distribution networks usually have larger numbers of components and more diverse operational conditions than transmission networks.[7] These factors suggest a need for more refined measurements and a more extended monitoring system, given both the challenge of managing increased variability and uncertainty and the opportunity for recruiting diverse resources for services in a more flexible grid.

Due to the dramatic changes in the electric grid industry in the last two decades, distribution networks will experience fundamental changes in their operation and service features. First, the predominantly one-directional electricity flow from bulk generators over power delivery lines to customer loads is going to be increasingly bi-directional due to the integration of distributed energy resources (DER). Second, energy storage in the form of stationary batteries and electric vehicles will be deployed in higher numbers.[8] Distribution networks were not designed for the complexity that high penetration of distributed energy resources and large number of electric vehicles will bring. Moreover, the distribution management system is not flexible enough to operate numerous controllable loads or to operate the distribution system via coordinated

---

[6] von Meier, Alexandra, Reza Arghandeh (California Institute for Energy and Environment). 2014. "Chapter 34 – Every Moment Counts: Synchrophasors for Distribution Networks with Variable Resources." *Renewable Energy Integration,* L.E. Jones (ed.), Academic Press, Boston, MA.

[7] von Meier, Alexandra, David Culler, Alex McEachern, Reza Arghandeh. 2014. *Micro-synchrophasors for Distribution Systems.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2014 IEEE PES Innovative Smart Grid Technologies Conference. ISGT.2014.6816509.

[8] Arghandeh, Reza, Jeremy Woyak, Ahmet Onen, Jaesung Jung, Robert Broadwater. 2014. "Economic Optimal Operation of Community Energy Storage Systems in Competitive Energy Markets," *Applied Energy,* Elsevier, Vol. 135.

control, which will undoubtedly be necessary.[9] New paradigms in distribution networks will require deep knowledge of feeder behaviors and system dynamics through measurement data analysis, system modeling, and monitoring system enhancement. Operators are facing many difficult questions regarding feeder capability to accept flexible loads, determining the acceptable levels of DER on a given feeder, requirements for monitoring systems to capture system behavior, and the required ramping rate from DERs to stabilize voltage and frequency, among others.

Answers to such questions are dependent on the availability of measurement data for each feeder and the level of information that the operator can extract from that data. Sufficient and clean data leads to more accurate feeder characteristics that pave the way for network operators and planners to improve system observability, efficiency, reliability and performance.

This chapter provides a summary version of the more detailed Task 4 Report, Distribution System Field Study with California Utilities to Assess Capacity for Renewables and Electric Vehicles – Task 4 Feeder Behavior Characterization, that addressed these principal questions:

1. What type of information can be extracted from measurement data?
2. What are the drawbacks of commonly used SCADA data for distribution network operation?
3. What are the impacts of bad data on feeder characterization?
4. How are feeders in each utility territory different from each other?

Distribution networks have a number of specific characteristics, such as the number and type of particular loads, multiphase connections, climate conditions and distributed resource adoptions, that define the character and general behavior of a given distribution feeder. While no two distribution feeders are identical, an analysis of the characteristics and *behavior* of distribution feeders can still lead to useful general conclusions about certain types of feeders, such as the classes of "prototypical" or "taxonomy" feeders developed by researchers at Pacific Northwest National Laboratory (PNNL).[10] For example, feeders in irrigation districts tend to be long, with relatively uniform pump loads distributed along the circuit, and little renewable generation. Urban feeders tend to be shorter, with denser load patterns, and some renewable energy, typically PV. They may also have mesh topology with underground cables that have different impedance patterns. Suburban feeders can have clusters of PV or electric vehicle loads. Classifying feeders by types or taxonomy according to physical construction and loading patterns can be useful in analyzing some general properties of an individual circuit, prior to

---

[9] Jaesung Jung, Yongju Cho, Danling Cheng, Ahmet Onen, Reza Arghandeh, Murat Dilek, Robert Broadwater. 2013. "Monte Carlo Analysis of Plug-in Hybrid Vehicles and Distributed Energy Resource Growth with Residential Energy Storage in Michigan," *Journal of Applied Energy,* Elsevier, Vol. 108.

[10] Schneider, Kevin, Yousu Chen, David Chassin, Robert Pratt, Dave Engel, Sandra Thompson (Pacific Northwest National Laboratory). 2008. *Modern Grid Initiative – Distribution Taxonomy Final Report.* Pacific Northwest National Laboratory. PNNL-18035.

focusing in on the idiosyncrasies of a particular feeder—for example, gauging the likely energy impact of conservation voltage reduction. Furthermore, analyzing feeders in the aggregate using characterization methods can be efficient and time- and cost-effective in performing large-scale system analyses and optimization.

However, before it is possible to draw robust conclusions from aggregate representations, the initial classification and characterization of feeders depends vitally on measurement data. Based on the available data from utilities, the most common problems are lack of enough data from different locations along each feeder, data quality issues, data format diversity, and data type differences.

Furthermore, the diversity of modeling software packages used by utilities represent a major challenge to the analysis and comparison of distribution systems. Different models from different utilities will frequently have different formats and nomenclature, requiring considerable preparatory work just to establish a consistent basis for a study.

Moreover, regulatory issues, tariff structures, and operational practices in each utility may vary due to differences in climate, customer behavior, and stockholder policies.

### 4.1.2 Goals & Objectives

The intent of this task was—to the extent possible with existing measurements—to identify power flow, voltage, and power quality behavior on distribution feeders and to determine the impacts of different variables, including feeder architecture and configuration, presence and penetration level of distributed energy resources, and operating strategies, such as voltage regulation, on the characteristics and behavior of distribution feeders.

More generally, the goal of this analysis was to identify the temporal and spatial resolution at which significant phenomena occur, or to determine shortcomings of existing data, to inform the design of the Advanced Monitoring Plan (see Chapter 6) and further research efforts that may result from this project.

The research team originally hoped to apply the taxonomy classification methodology developed by PNNL for the U.S. context to the California-specific context. This was not feasible with the limited data available over the period of the present study, although some groundwork has been performed to support future work in this important area. For example, the work done by PNNL is based on 575 different feeders from 151 substations.

This report describes the gaps in current monitoring systems that inhibit effective feeder behavioral analysis, thereby contributing to key aspects of the design of the Advanced Monitoring Plan (Chapter 6) to address these gaps.

## 4.2 Data Availability and Quality

### 4.2.1 Overview

Measurement data collected by utilities varies in terms of its quantity, quality, and timeliness. Moreover, different applications in operation and planning have different requirements in terms of data quality and data resolution. For instance, identifying power quality of a feeder would likely require sub-cycle sampling, timestamps, and analysis. Even finer resolution would be required to determine impacts of PV inverter injection of high harmonics, or control loop resonances, etc. The SCADA data and its inherent resolution was state-of-the art 20 years ago and could assist in characterizing many aspects of a distribution feeder, but the evolving challenges anticipated for the next 10 to 20 years may well be beyond the capabilities of traditional SCADA, and therefore could be a primary driver for implying higher granularity and higher resolution for measurement data. Faster dynamics of the grid in presence of DERs increases the emergence of data quality in coming years. This section distinguishes the following dimensions of data requirements for feeder characteristics.

*Sampling Rate*

Sampling rates range from 512 samples per cycle (approx. 30 kHz) for power quality recording and 120 samples per second for synchrophasor measurements, to data measurements every few seconds as in SCADA systems, to 15-minute and hourly measurements for typical revenue meters. The intended uses of the data can range from characterizing power quality, including harmonics or transients, which may require very high-resolution data, to measuring daily peak load, requiring much lower-resolution data.

*Temporal Resolution*

Temporal resolution refers to the time difference between reference points on the waveform (voltage, current, and power) at different measurement locations, translated into units of magnitude or angle. In other words, it is the degree of detail that can be recognized in time.

*Spatial Resolution*

Spatial resolution refers to how closely together the measurement devices must be placed on a distribution circuit to permit interpolation or appropriate inferences about the conditions at locations not directly measured. Related to spatial resolution, but distinct from the issue of proximity of measurement devices to each other, is the placement of measurement devices in network topological terms, i.e. at nodes or branch points.

In addition to sampling rate and resolution, measurement data are affected by data transfer rate and communication latency. Some applications have more sensitivity to data transfer latency, especially for real-time or near real-time control and operation cases.

### 4.2.2 Different Types of Measurements for Feeders

Distribution networks are traditionally locally monitored; more recently they have been controlled via a central Distribution Management System (DMS). Introduced to power distribution in the 1980s and '90s, SCADA systems form the standard backbone for visibility and remote operation of distribution circuits. SCADA systems transfer measurements, alarms, and control signals between control centers and SCADA-enabled components via Remote Terminal Units (RTUs). RTUs allow for the transmission and reception of signals for protection actions, topology reconfiguration, and Volt/VAR control. With the advent of distribution automation, Intelligent Electronic Devices (IEDs) such as relays and reclosers come into play. The IEDs perform distributed decision-making, which, in some cases, results in local protection schemes. To date, the number of IEDs and SCADA-enabled devices beyond the substation is still relatively low.

For the majority of distribution circuits in California, SCADA measurements of voltage, current, and power are available from the substation but no further. Where measurements do extend out into distribution circuits, line sensors are an important component. Line sensors may use a variety of clamping mechanisms for easy installation on overhead lines. A line sensor might continually measure line current and temperature for the purpose of loading monitoring and available capacity. Alternatively, it may measure line voltage, for example, in conjunction with a capacitor bank used to control voltage. Line sensor data can be integrated into SCADA, Energy Management System (EMS), and Distribution Management System (DMS). Outage detection and fault location are among the main applications for line sensors. AMI is another important source of measurements in distribution networks. Traditionally, utilities use meter data for billing and read their electromechanical watt-hour meters manually, typically once per month. The new electronic meters, or "Smart Meters," feature two-way communication links that allow utilities to send signals to the meters, and read customer meters seamlessly and even measure voltage and current. These meters also record different events from distribution network endpoints. Events originate from outages, service availability changes, switching operations, voltage drops, flicker, and many other events. The meters' measurement intervals are usually 15, 30, or 60 minutes, but the meters have the capability to measure at shorter time intervals, as fast as a second. Smart meters have the ability to enrich distribution network monitoring systems by providing higher resolution data from all customers.[11]

In principle, measurement data from AMI can be used to support network operation, but in reality, the use of AMI data today for purposes other than settlement is limited. Generally, it is more constrained by communication bandwidth and back-office data management than by the physical capability of the meters. For example, smart meters measure voltage at the customer service entrance, but typically do not communicate that information. Although AMI applications are presently limited, they could feasibly be enhanced to collect additional data

---

11 National Energy Technology Laboratory (NETL). 2008. *Advanced Metering Infrastructure.* [http://www.netl.doe.gov/File%20Library/research/energy%20efficiency/smart%20grid/whitepapers/AMI-White-paper-final-021108--2--APPROVED_2008_02_12.pdf]

from customers, including voltage, real and reactive power flow to the grid, and power quality, among others. These additional data would enhance the visibility of the distribution grid and its performance in planning and operations applications.

Power quality recorders are sometimes used in distribution networks to measure the deviations in the 60 Hz waveform that cause problems to customers, such as voltage deviations, frequency deviations, flicker, harmonics, phase imbalances, etc. With increased DER and power electronics devices, the AC waveform experiences more disturbances and harmonics. These recorders can measure voltage, current, and real and reactive power up to the 50th harmonic with 256 to 512 samples per cycle. Power quality measurements are not typically made by utilities except in specific cases where power quality issues are suspected or have been reported by customers.

### 4.2.3 Challenges in Measurement Data Acquisition and Data Handling with SCADA

This section presents a number of challenges related to data quality and monitoring stem from different perspectives. It is more focused on the SCADA system as an example of a monitoring system in distribution networks. However, the challenges discussed here for SCADA can be generalized to other monitoring and data acquisition systems. SCADA with EMS have been used for more than two decades for supervising, controlling, optimizing, and managing the transmission networks. SCADA with DMS has a similar functionality in distribution networks.

SCADA enables utilities to collect, store, and analyze data from hundreds of thousands of data points in wide area networks, perform modeling, simulate operational actions, locate faults, recover outages, and participate in electricity markets. It is the cornerstone for power networks and smart grid development. Considering the new paradigm of distribution networks and the integration of distributed energy resources, utilities will need to manage two-way power flows, maintain grid stability, and maintain acceptable power quality. However, present SCADA systems have a number of drawbacks for distribution networks. The following is a review of recognized challenges in SCADA from three different points of view: system architecture, enterprise level, and feeder. Clearly, an advanced monitoring platform, as proposed by the AMP in this report and possibly by others, will be a vital part of the modern grid to fill the gaps in conventional monitoring systems like SCADA.

*Architectural Level*

- A SCADA system is a combination of processors, controllers, instruments, actuators, communication networks, and human interfaces that manages the monitoring and control of systems and facilitates the data collection and processing in those systems.
- The SCADA architecture[12] typically includes the following components:
- HMI (Human-Machine Interface) is the visualization interface that helps operators to control and monitor the system.

[12] Boyer, Stuart A. 2009. *SCADA: Supervisory Control and Data Acquisition (Fourth Edition)*, The Instrumentation, Systems, and Automation Society. ISBN-13: 978-1936007097.

- Supervisory (computer) system is in charge for data gathering and sending comments, alarms and actuation signals to system components.
- Intelligent Electronic Devices (IED) generally are devices that perform distribution automation, protection, and local control with communication capability.
- Remote Terminal Units (RTUs) connect sensors to the data acquisition system. They convert analog measured signals into digital signals and send data to the supervisory system.
- Programmable Logic Controllers (PLCs) are installed in the field near sensors to perform control decisions. They can be standalone devices or part of IEDs.
- Communication infrastructure connects the supervisory system to the RTUs.

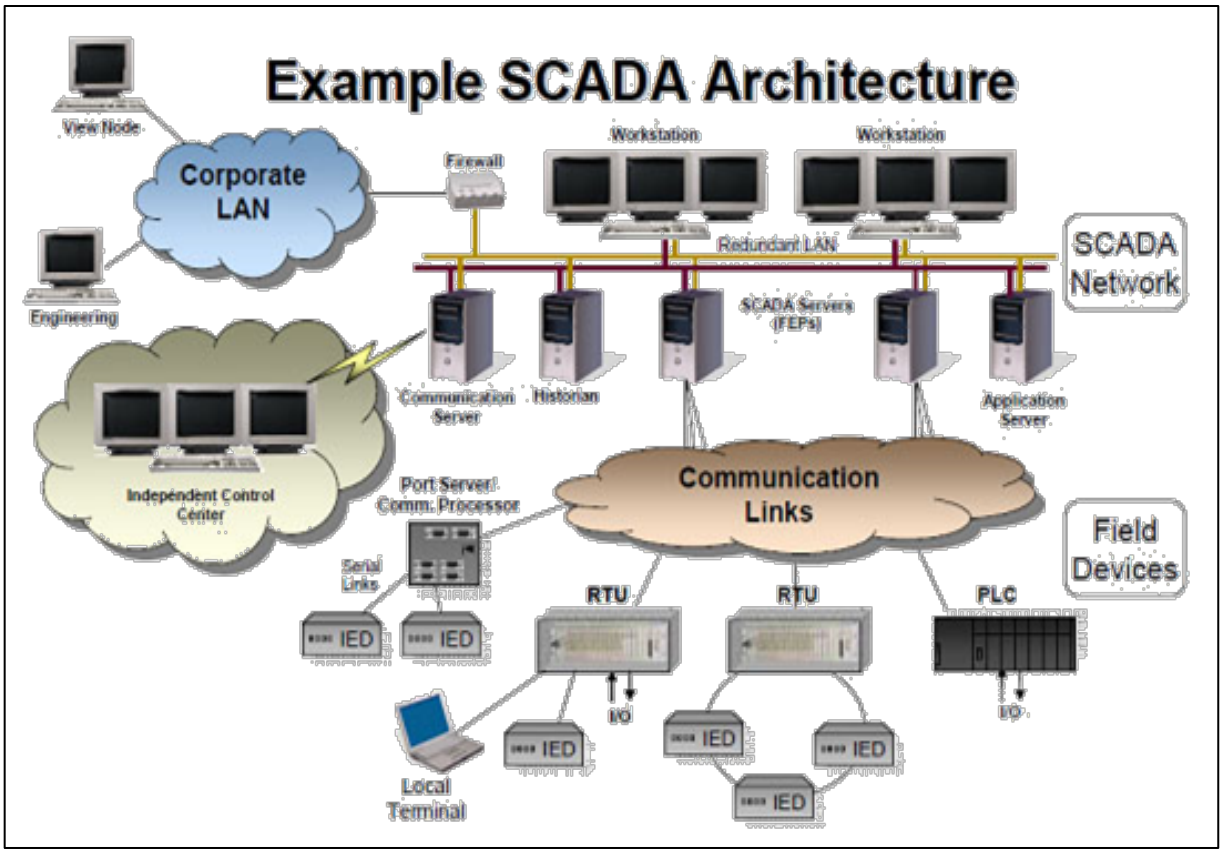
Figure 1 shows a generic architecture for SCADA systems. There are different points in the system that are vulnerable to failures in the physical layer or the network layer. Measurement data are exposed to errors, noise, disturbances, etc., because of the failures in hardware devices, software, communication links, or component integration.

*Enterprise Level*

At the enterprise level, the observability downstream of the substations is limited by measurement devices as well as accurate network models within which to interpret measurement data. For planning and operation purposes, the network operator needs to know the both the time-invariant, physical characteristics of the distribution network (for example, phase connectivity and line impedances) characteristics and its real-time behavior (e.g., voltage magnitudes at different locations on the feeder).

Moreover, data flow inside a utility organization is rarely frictionless. In some cases planning, operation, and revenue departments are interested in the same data sets, but there is no convenient and practical arrangement for data access between different departments. To achieve a more efficient data sharing and data management system, unified circuit models and measurement databases can be used by the various departments inside utilities.

**Figure 1: SCADA System Generic Architecture**




Source: Edgar, T.W., M.D. Hadley, D.O. Manz, J.D. Winn (Pacific Northwest National Laboratory). 2010. *Secure and Efficient Routable Control Systems.* Pacific Northwest National Laboratory. PNNL-19474.

Beyond the organizational dimension of the data-sharing challenge, a problematic issue throughout the electric power industry is that most analytic tools do not communicate or transfer data with each other readily. Standardization of data into common formats such as the Customer Information Model (CIM) would be a positive step to rectify the limitations imposed by this lack of communication, but software companies must adopt the common format. Although tool builders may be reluctant to share data formats for proprietary reasons, innovation will flourish if there is an open-source approach to building grid models. Developers would be driven to incorporate enhanced features and usability if they could not rely on their proprietary data formats to hold users captive; this would, in turn, reduce the need (and associated costs) for utilities to purchase multiple different types of software systems to perform their various analyses and work with data in various formats.

As the distribution system evolves into a complex, active, controlled, automated resource, the depth of analysis required will evolve also, as will the need for higher-fidelity measurement devices for more accurate data. The concerns regarding data security and big data computational burdens are also increasing.

*Feeder Level*

In actual distribution substations, SCADA is the most commonly installed monitoring system. There are known issues related to SCADA architecture and performance. Nowadays, a large number of DERs, power electronic inverters, and controllable loads are adding more dynamics to the grid. The data sampling and reporting times of SCADA protocols are typically a few seconds to minutes, and they are not time-synchronized. Also, measurement devices are not necessarily optimally placed to ensure or enhance distribution network observability.

Structural differences between transmission and distribution networks also need to be considered. Following are some of the crucial aspects of distribution systems that bear upon monitoring needs and analytics:

- Three-phase load imbalance, requiring explicit accounting for all three individual phases (rather than simplifying circuits into a one-line equivalent, as is standard practice for transmission systems);
- Smaller X/R ratios, requiring consideration of resistance (R) and reactance (X) of conductors (not permitting the assumption that X>>R, which simplifies many calculations);
- Asymmetry of untransposed lines, complicating the estimation of effective line reactances (which depend on geometry);
- Reduced load diversity and greater time variation, necessitating greater time resolution measurement to capture actual behaviors;
- Frequency of topology changes (switching operations);
- Vulnerability to external insults (weather, flora, fauna, etc.).

Figure 2 shows some of the geometrical and structural challenges specific to distribution networks.

The key consequence of these geometric and structural differences is that the accurate characterization of power flows and the operating state of a distribution network requires much more information than a transmission network that would, at first glance, seem to be of comparable complexity (e.g., the same number of nodes or branches). The fact that the three AC phases are not identical – neither in terms of the fixed physical network characteristics nor in terms of the real-time power flows – means that there are at least three times as many data points to be collected in distribution systems. Indeed, at the most refined level of analysis, it gets even more complicated because the three phases affect each other by way of magnetic fields in an asymmetrical manner that sometimes needs to be taken into account (see Chapter 5). Distributed energy resources along with large numbers of network nodes to be monitored combine to create a problem for network observability.

**Figure 2: Illustration of Some Challenges Specific to Distribution Networks**

Source: Power Standards Laboratory

### 4.2.4 Available Data from Utility Partners

The SCADA data for five different feeders from three utilities in California were analyzed for a one-year period. The analyzed SCADA data reveal a number of data quality issues. For the purposes of data anonymization, the utilities are referred to as Utility 1, 2, and 3.

*Utility 1*

Utility 1 provided one year SCADA measurement data for one circuit. The circuit primary voltage is 12 kV. Customer types are mostly urban residential with some light industrial and commercial loads. The transformer capacity is either 20 MVA or 12.5 MVA. The number of reclosers, voltage regulators, and capacitor banks was provided but there was no information about PV penetration. The data was taken in 2012 for three feeders from one substation.

*Utility 2*

Utility 2 provided SCADA data for one circuit. The selected circuit is representative of approximately one hundred circuits in terms of behavior. Behavior parameters were ranked for peak loading, PV penetration, availability of voltage support, length of circuit, local climate (such as inland, coast, valley, or desert), class of customers, and relative amount of customers. The selected circuit contained PV generation and a diversity of climate zones.

*Utility 3*

Utility 3 provided one year's worth of SCADA measurement data (KW, KVAR, V, and Amp) was provided for one of the feeders. The circuit has close to 2 MW of aggregated PV systems, with summer loads of 27 MW. Furthermore, 80% of the circuit loads are industrial, with peak times of 3:00 PM and 4:30 PM in summer and winter, respectively.

Table 1 shows the available SCADA data for feeders from the three California utilities.

**Table 1: List of Feeders with Available SCADA Data**

| Utility | Feeder | Feeder UID |
|---|---|---|
| Utility 1 | Feeder 1 | U1.1 |
| Utility 1 | Feeder 2 | U1.2 |
| Utility 1 | Feeder 3 | U1.3 |
| Utility 2 | Feeder 1 | U2 |
| Utility 3 | Feeder 1 | U3 |

Source: CIEE (UC-Berkeley)

## 4.3 Data Cleaning and Data Recovery

### 4.3.1 Overview

As the distribution system modernizes, time scales for operations are becoming shorter. As the distribution system becomes an active resource, the number of components on the system increases, which in turn increases the number of unknowns and thus the potential for error in system monitoring. Data errors are prevalent in the distribution system, leading to a lack of confidence in analysis and operations. This creates a reluctance to undertake advanced grid analysis.

If data is not matched to its standard and feasible range and generally doesn't mean what it is supposed to mean, it is not reliable or clean. Bad data can include garbage, glitches, gaps, and lack of metadata. Following are definitions of data quality characteristics that are used in different data-driven areas:

- Accuracy: The data was recorded correctly.
- Completeness: All relevant data was recorded.
- Uniqueness: Entities are recorded once.
- Timeliness: The data is kept up to date.
- Physical Consistency: The data agrees with the system.
- Synchronization: measurements are recorded with consistent time stamps at different locations.

### 4.3.2 Importance of Data Cleaning and Data Recovery

The first step of realization of any measurement data is to ensure recorded data is good enough to represent system behaviors and characteristics. The sensors, communication network, and data interfaces should be configured in a reliable manner for data recording and transmission. The planning and operation actions accuracy and correctness are limited to measurement data that they are using. Any shortcoming in data quality means possible challenges for actions and decisions that are made based on the data. Common problems in distribution network

measurement especially SCADA data are missing data, outliers, incorrect values, and zero values. This section presents different challenges that are seen in the provided SCADA data from utility partners.

Data correctness in databases is vital to avoid wrong and misleading conclusions. In computer science, this situation is appropriately called "garbage in, garbage out."

### 4.3.3 Data Cleaning Process

One of the first and the most important steps in any data processing application is verifying the correctness of measurement data. There are two fundamental ways to verify data: against a separate, independent source, or based on the internal consistency of a data set that indicates when certain data points do not make sense. Since there is little opportunity for comparative measurements in distribution systems, the emphasis here is on the latter approach.

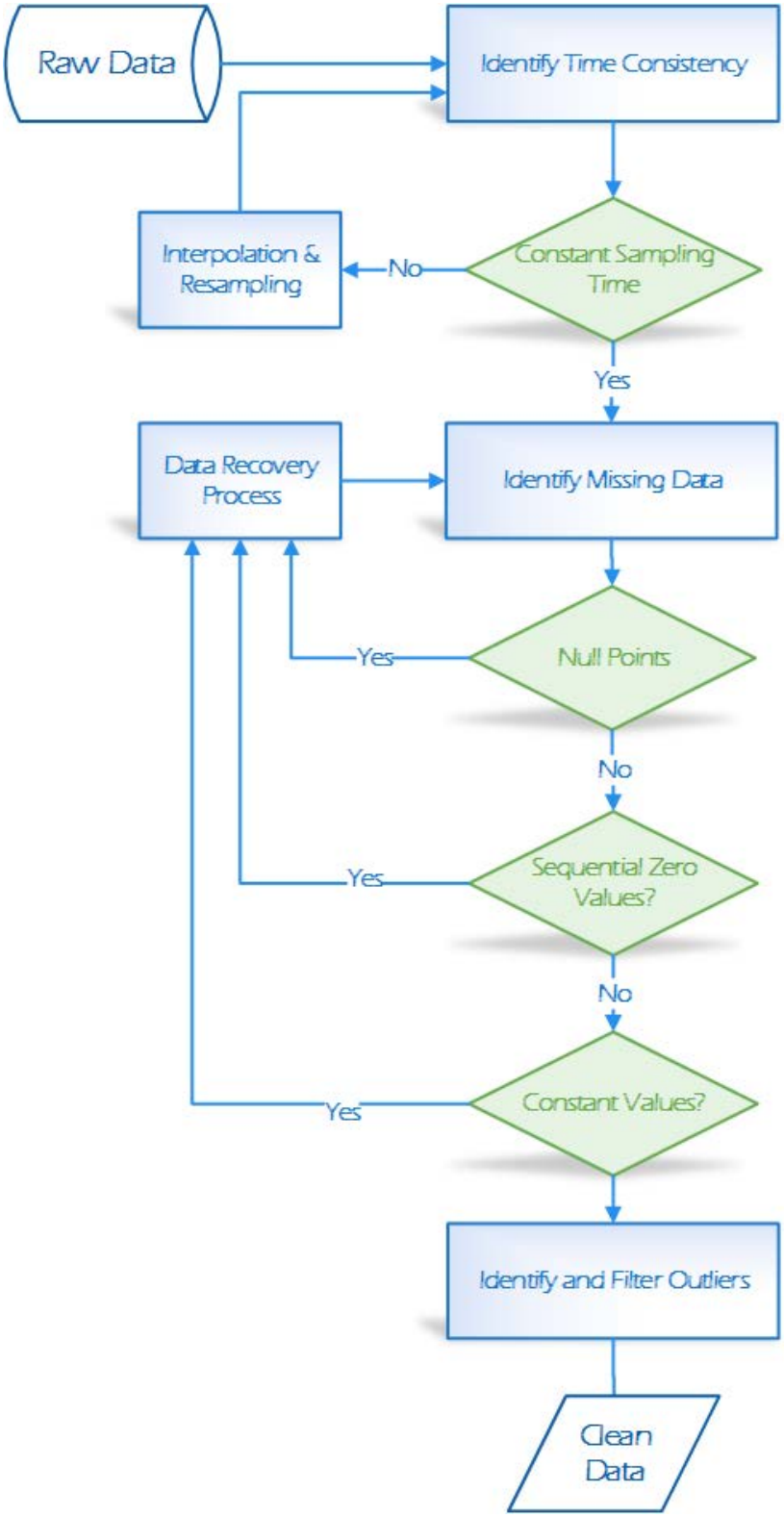
Figure 3 illustrates the basics of the process, also called data cleansing or data scrubbing, which is necessary for the construction of a database with minimal incorrect, incomplete, or duplicate data.[13] Data-intensive organizations such as utilities may need data cleaning performed in real time. Data cleaning tools include algorithms that are capable of finding data problems, correcting them, and removing data inconsistencies.

When multiple data sources or multiple data types are integrated in the database and cross-reference with each other, there will be a greater need for data cleaning. For example, to make a data warehouse for outage detection based on AMI, all meter data have to be consistent, time synchronized, and available. In the case of state estimation for the distribution management system (DMS), voltage, real power and reactive power measurements need to be available.

Because of the wide range of possible inconsistencies in SCADA data, data cleaning is the one of the largest challenges for data-driven network operation and planning. In this project, the data cleaning algorithm is looking for missing data points, zero values, outliers, incorrect values, and time inconsistency. These data quality problems in SCADA are addressed in the next section.

13 Rahm, Erhard, Hong Hai Do. 2000. *Data Cleaning: Problems and Current Approaches.* Institute of Electrical and Electronics Engineers. Bulletin of the IEEE Computer Society Technical Committee on Data Engineering, vol. 23, issue 4.

**Figure 3: Data Cleaning Process**



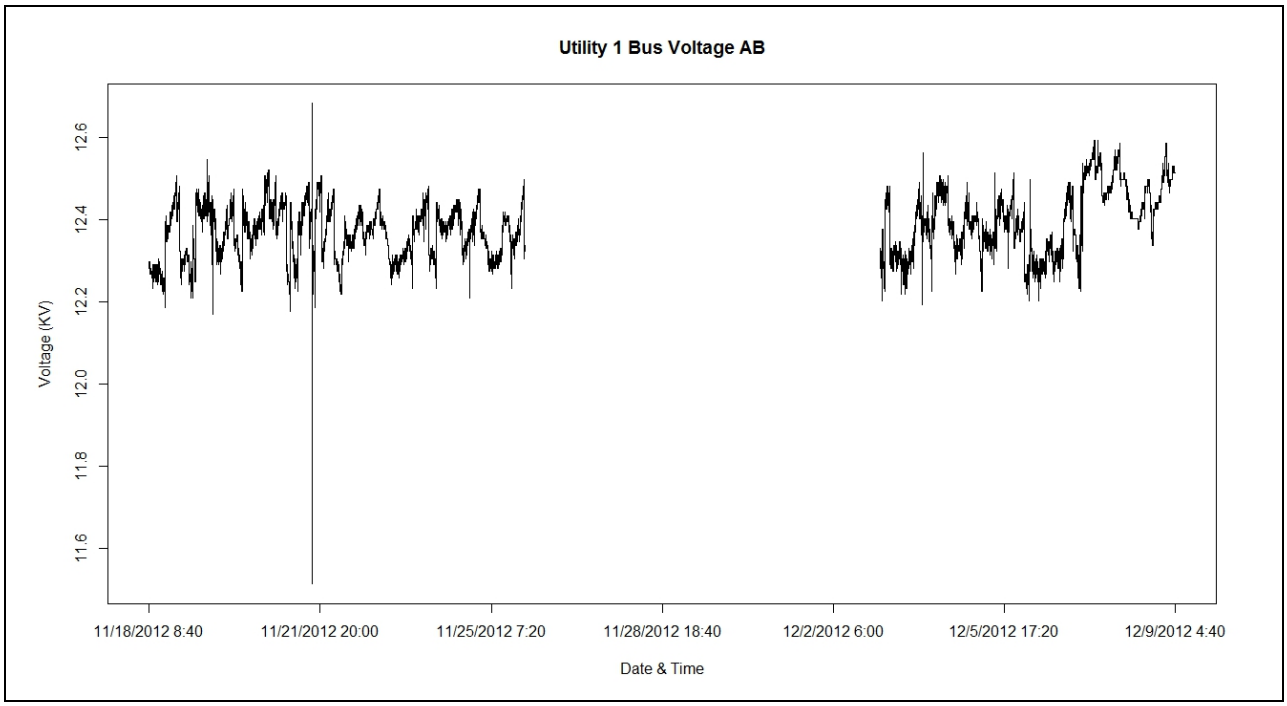

Source: CIEE (UC-Berkeley)

### 4.3.4 Major Data Quality Problems in SCADA Data

*Missing Data*

In the SCADA data analyzed for this project, there were some cases of missing data, possibly due to a measurement device malfunction, a communication loss, or a data network issue. Figure 4 shows an example of missing data in a voltage measurement data set.

**Figure 4: Example of Missing Data in SCADA Measurements**



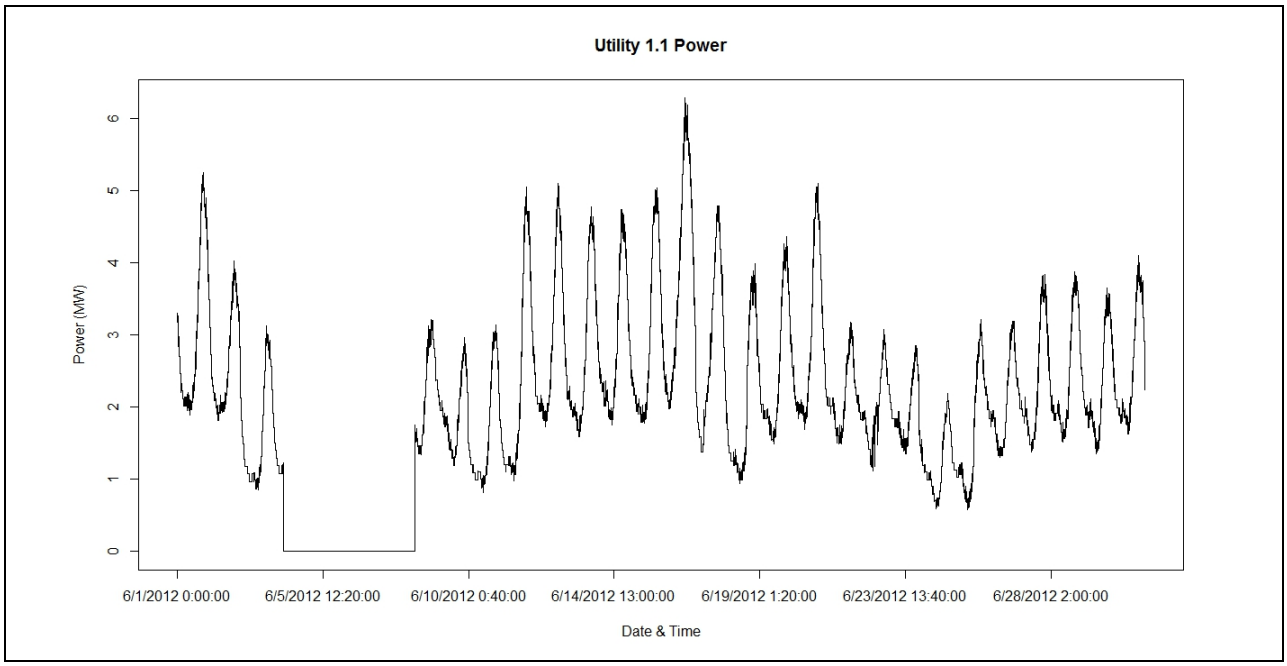

Source: CIEE (UC-Berkeley)

When missing data is sensed, a flag is raised and a log of missing points is maintained. Missing points can either be ignored in the data analysis process or they can be replaced with estimated values.

*Zero Values*

Another data quality issue encountered in SCADA measurements is the occurrence of ostensibly zero values. For example, in voltage and current substation measurements, voltage values of zero with non-zero current values on the same phase have been observed. Since this is physically implausible as a steady-state operating condition, the zero voltage values are identified as "bad data," possibly caused by malfunctions of potential transformers (PTs) used to link sensors to power lines. Figure 5 shows an example of power (MW) zero values in the SCADA data from one of the feeders belonging to Utility 1.

**Figure 5: Example of Zero Values in SCADA Measurements**




Source: CIEE (UC-Berkeley)

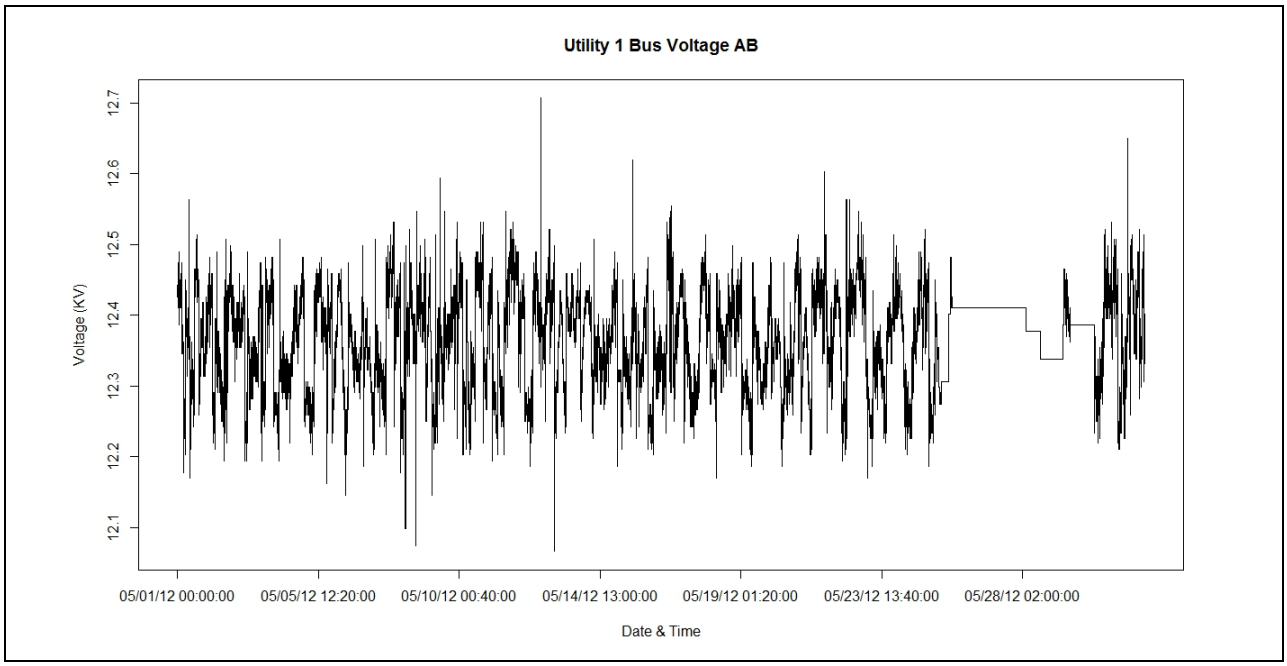
*Incorrect Values*

Incorrect values were also frequently encountered in the utility SCADA data. As illustrated in Figure 6, the voltage measurement values for some points in time appear to be constant, and therefore cannot represent the actual circuit voltage values.

*Outliers*

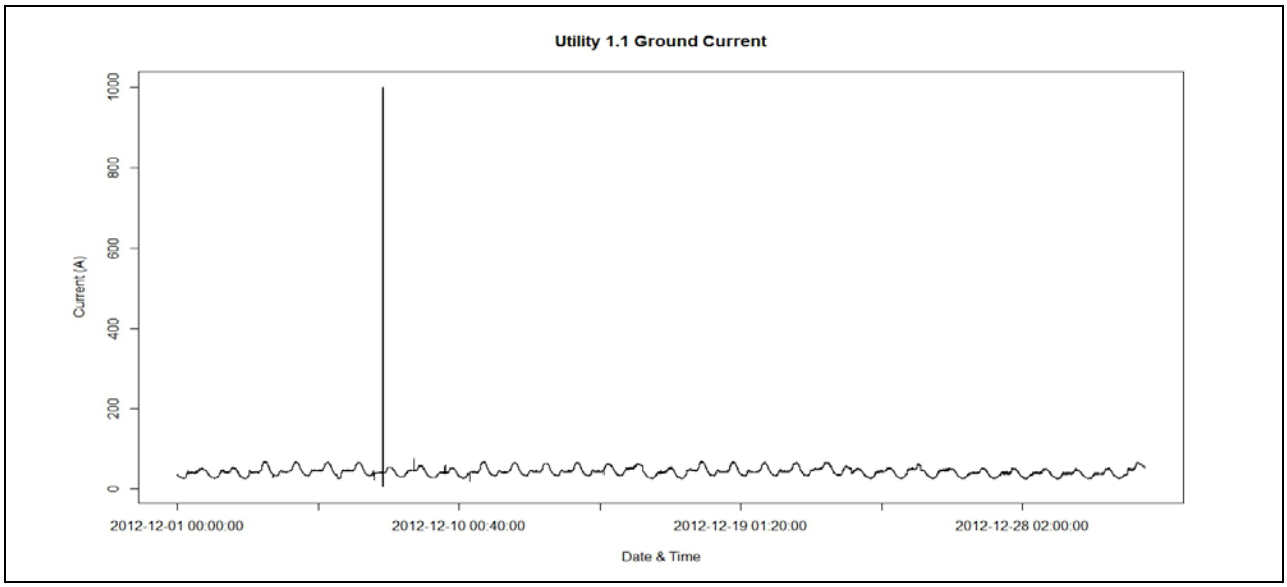
Outliers are data points that have apparent values considerably different from the majority of other measurements of a particular variable. An outlier may be due to noise, a voltage or current "spike," or some other unexplained occurrence or variability in the measured behavior, or may it be due to an error in the measurement system. In the SCADA data received from the utility partners for this project, some cases of outliers were observed. Figure 7 depicts an outlier in the current measurement data at the feeder level from Utility 1.

**Figure 6: Example of Incorrect Values in SCADA Measurements**




Source: CIEE (UC-Berkeley)

**Figure 7: Example of an Outlier in SCADA Measurements**




Source: CIEE (UC-Berkeley)

## 4.4 Feeder Behavioral Characteristics

### 4.4.1 Metrics for Feeder Characterization

In this project, we received SCADA data for 5 different feeders from three California utilities (labeled Utility 1, 2 and 3 to help preserve confidentiality of data). To analyze the SCADA data, a number of metrics are considered in this project for data time-series analysis.

Table 2 shows the indices and time-series characteristics that are examined in this study.

**Table 2: Metrics for Feeder Temporal Characterization**

| Index | Formulation | Description |
|---|---|---|
| Voltage Level | *V(t)* | Voltage at various points on the feeder as a function of time. |
| Load Average Profile | $P_{avg}$ | The average load profile for 24 hours based on monthly or yearly data; conveys typical load shapes. Load profile is a pattern of customers' behavior as individual or aggregated loads. Based on its timeliness, it shows loads behavioral changes in each month, season, or year. Load curve shows the average feeder capacity for adding more DER. |
| Load Factor | $\frac{Average\ Hourly\ Load}{Max\ Hourly\ Load}$ | Load factor is an indication of how the feeder is being utilized. Load factor shows how the feeder is lightly or heavily loaded. It can be the measure of feeder potential for handling more power flow. In terms of maintenance and operation, feeder utilization indicated the stress on network components such as transformers and conductors. It is a time-series based value. Therefore, the time dependent DG hosting capacity can be inferred from the load factor. |
| Load Profile Histogram | *Load Profile plus load histogram* | The distribution of load in a year in the form of a daily load profile. It is mixture of load profile and load histogram. Therefore, it has both time-varies and statistical information for DG hosting capacity analysis. |
| Load Duration | *Statistical histogram* | The distribution of load percentage versus the time percentage. Load is scaled to the peak and time is 1 year. Load duration is a benchmark for DER adoption. It is an indication of feeder capacity for adding more load or source on each feeder. Load duration curves presented in this report show how feeders are well utilized. Load duration is not a time-series value despite the load factor. The statistical DG hosting capacity can be inferred from the load duration. |

| Index | Formulation | Description |
|---|---|---|
| Phase Average | $I_{avg} = \frac{I_A + I_B + I_C}{3}$ | The average of current over three phases. It gives a scale for three-phase current balance. |
| Phase Deviation | $I_{dev} = \frac{I_i}{I_{avg}} - 1$, *i=1,2,3* | The ratio of current in each phase and how it deviates from the average three-phase current (balanced condition). Phase deviation is another indication for DG hosting capacity. For example adding more PV to lightly loaded phases increase the chance of reverse power flow on those phases. |
| Power & Voltage Dependency | *P(V)* | The relationship between power and voltage is illustrated via this dependency plot. It is useful for voltage conservation programs and load characterization. Moreover, it shows how voltage regulation and power factor correction schemes are impacting power loss and energy efficiency in feeders. |
| Rate of Change of Power | *dP/dt* | An indication of system ramp-up or ramp-down, potentially due to changes in generation dispatch or variable renewable resources. |
| Power & Temperature Dependency | *P(T°)* | Power and temperature dependency is a crucial indication of the system sensitivity to the ambient conditions. It is a valuable input data for health monitoring of network components. From the operation and maintenance point of view, network components have temperature margins for safe operation. On hot days, operators need to pay more attention to the power and temperature dependency. The other crucial information extracted from power and temperature dependency curves is related to load behaviors relative to ambient temperatures. Ambient temperature is a driver for load profile changes due to different air heating, cooling, and ventilation needs in houses. The water heating and refrigerator loads have similar condition. |
| Voltage & Temperature Dependency | *V(T°)* | Voltage variation as a function of ambient temperature. It is useful in network efficiency evaluation. Moreover, it provides similar information for operators to program volt/VAR control devices adaptively to weather condition. |

| Index | Formulation | Description |
|---|---|---|
| Current & Temperature Dependency | *I(T)* | Useful for evaluating feeder utilization as a function of ambient temperature. It helps operators to monitor network components temperature margins in days that current rise is more sensitive to temperature rise. |

Source: CIEE (UC-Berkeley)

### 4.4.2 Characterizing Feeders with Available SCADA Data

*SCADA Data Analysis Results for Utility 1*

The first utility provided data for three feeders, all connected to the same substation. They have mostly residential loads.

*Data Quality*

The 2012 data included some null values, outliers, zeroes, and incorrect values. Table 3 shows the data quality statistics for Utility 1.

**Table 3: Bad Data Analysis for Utility 1**

| Bad Data | # of Bad Data Points | % of Total Data Points |
|---|---|---|
| **Null** | 3008079 | 1.33% |
| **Outliers** | 1582307 | 0.70% |
| **Zeroes** | 2509883 | 1.11% |
| **Constants** | 6753494 | 2.98% |

Source: CIEE (UC-Berkeley)

*Average Load Profiles*

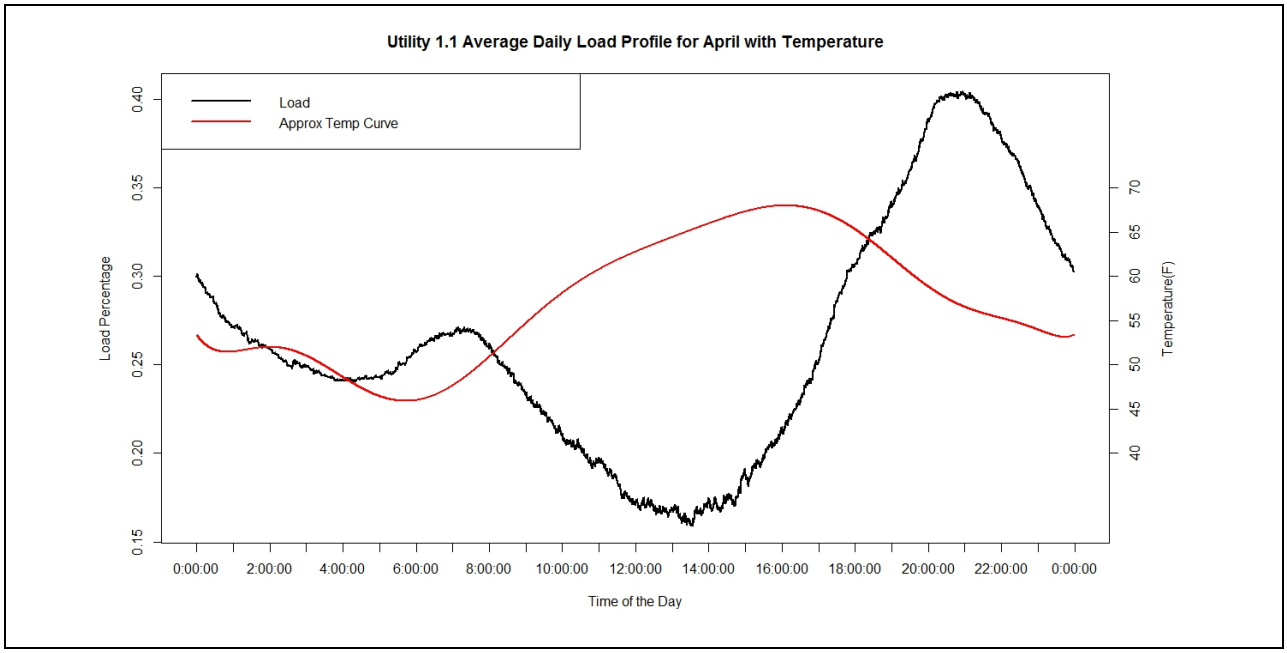
Two illustrative examples of average load profile plots for one feeder at Utility 1 are presented in Figure 8 and Figure 9 for the months of April and August, respectively. The black line shows total feeder load for a 24-hour period for the average April or August day, based on measurements taken at the substation. The data points are averaged for each minute of measurements. These plots also include the ambient temperature over the course of the average day (red lines). While daily peak loads are well known to correlate with temperature, the shape of the load profile over the course of a day is mostly driven independently by activity schedules. In terms of DG hosting capacity, load curves can show the feeder loading with different DG adoption levels.

The month of April in this example is noteworthy in that the daytime minimum load is at its lowest, about 16% of peak, while sunny weather can be expected and a relatively cool temperature means high efficiency of PV cells. These average monthly load profiles can be

taken as an indication of whether and when reverse power flow would most likely occur on a distribution feeder with high penetration of DG. Note that if the rated capacity of installed DG is at 15% of feeder peak load (which seems too conservative a limit for other times), the solar generation on a cold, sunny April day could easily equal or exceed load.

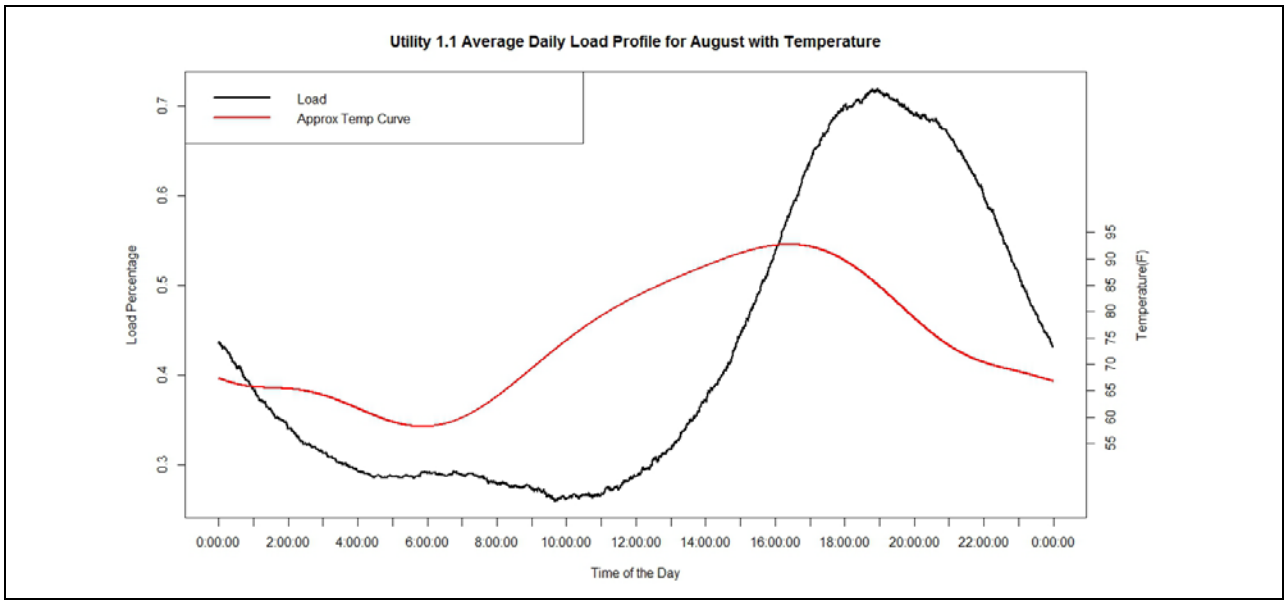
August, by contrast, is when the feeder load is at its highest, reaching just over 70% of rated feeder capacity in this example. This metric is of interest in the context of evaluating opportunities for peak shaving by DG, and possibly associated investment deferrals (such as upgraded transformer capacity). The time of the load peak in this example is about 7 pm, unfortunately, suggesting that solar generation without storage is unlikely to provide any relief on this feeder. In any event, this particular feeder is far from its capacity limit, so it would not be a good candidate for upgrade deferral benefits of DG.

**Figure 8: Average Daily Feeder Load Profile and Temperature for April**




Source: CIEE (UC-Berkeley)

**Figure 9: Average Daily Feeder Load Profile and Temperature for August**



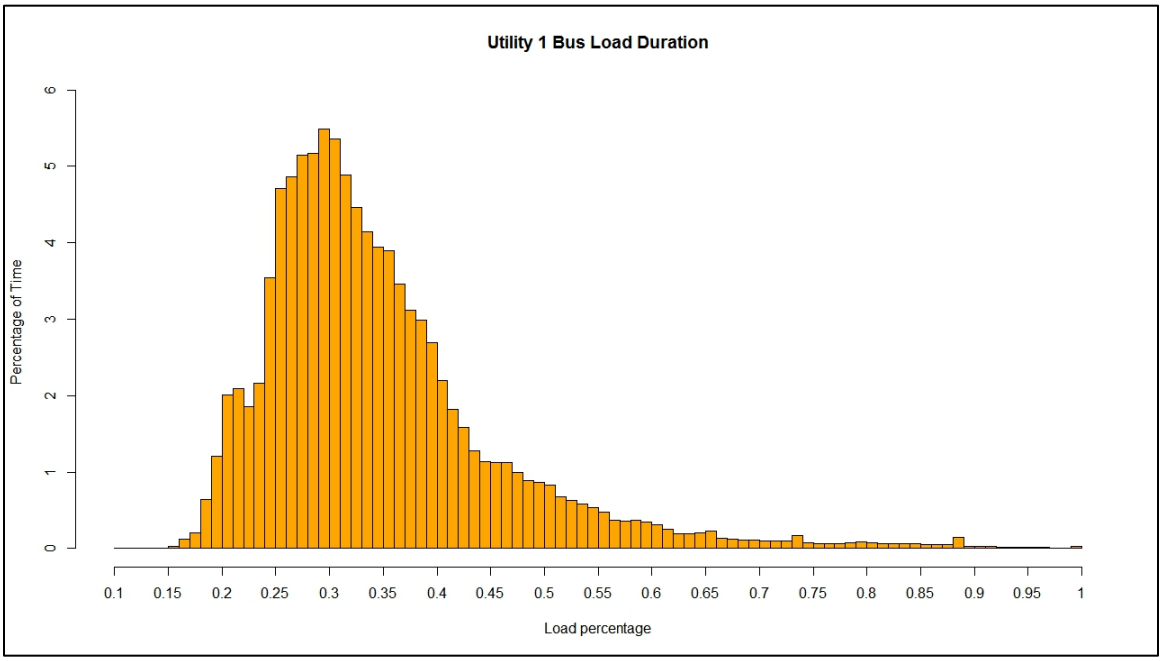

Source: CIEE (UC-Berkeley)

As seen in Figures 8 and 9, average load profiles have similarity to average temperature values. However, they are not fully correlated due to variations in customers' life styles and home occupancy schedules.

*Load Duration Histograms*

Load duration histograms can be used to represent the statistical distribution of demand in terms of load percentiles and their frequency of occurrence over a one-year measurement period. Load duration is a benchmark for DER adoption. It is an indication of feeder capacity for adding more load or source on each feeder. Load duration curves as presented in this report show how feeders are well utilized. Figure 10 illustrates the aggregated load histogram for three feeders at one substation.

**Figure 10: Load Duration Curve (Histogram) at Substation – 3 Feeders Aggregated**



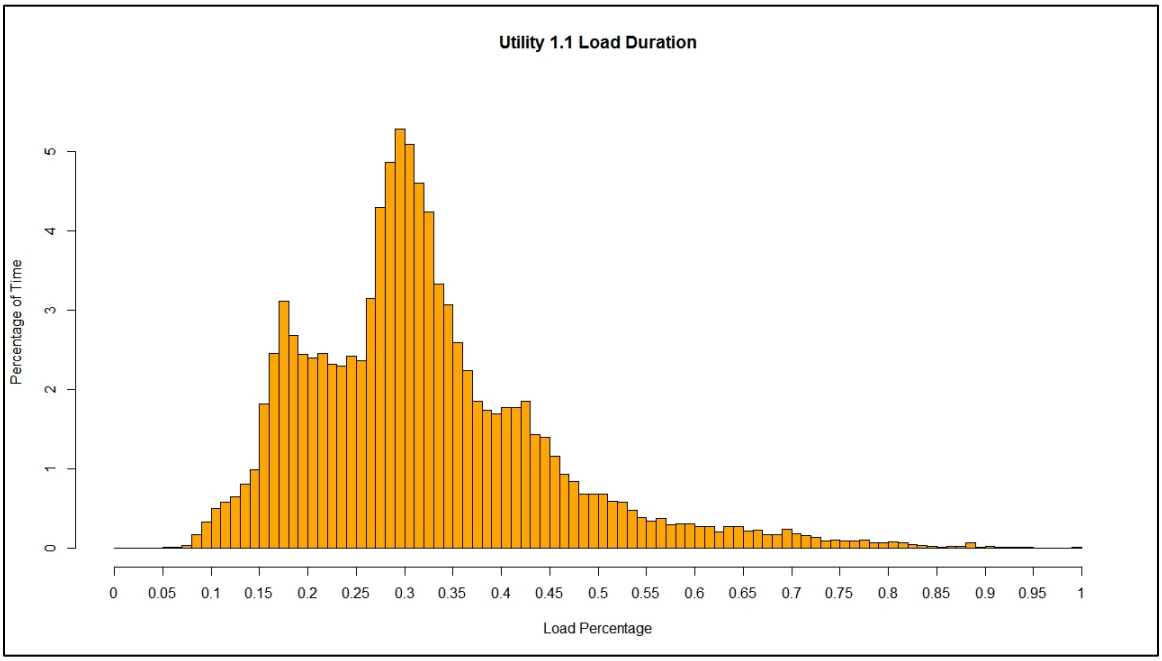

Source: CIEE (UC-Berkeley)

The substation histogram shows the most common load level to be about 30% of the peak load, an indication of a typically low substation utilization. Figure 10 shows that Utility 1 substation loading is around 30% of peak for 55% of the time, meaning the substation has around 70% idle capacity for more power flow 55% of the time. Operators can use this information for integrating electric vehicles, demand response or DER adoption. Planners can use the diagram to evaluate the economics of the feeder design. The results showed that this substation experiences peak load less than 0.1% of the time, less than 10 hours per year.

Stated conversely, the load peak is sharp; there are very few hours of the year where the loading approaches the total capability of the feeder. For the individual feeders 2 and 3, utilization drops to 22-23% of the feeder peak load. Histograms such as these can help utilities to fine-tune their feeder design for optimal peak capacity in view of present loading, load growth, and DER that may be available for peak shaving. They can also help estimate the potential local benefits or need for distributed storage on a feeder.

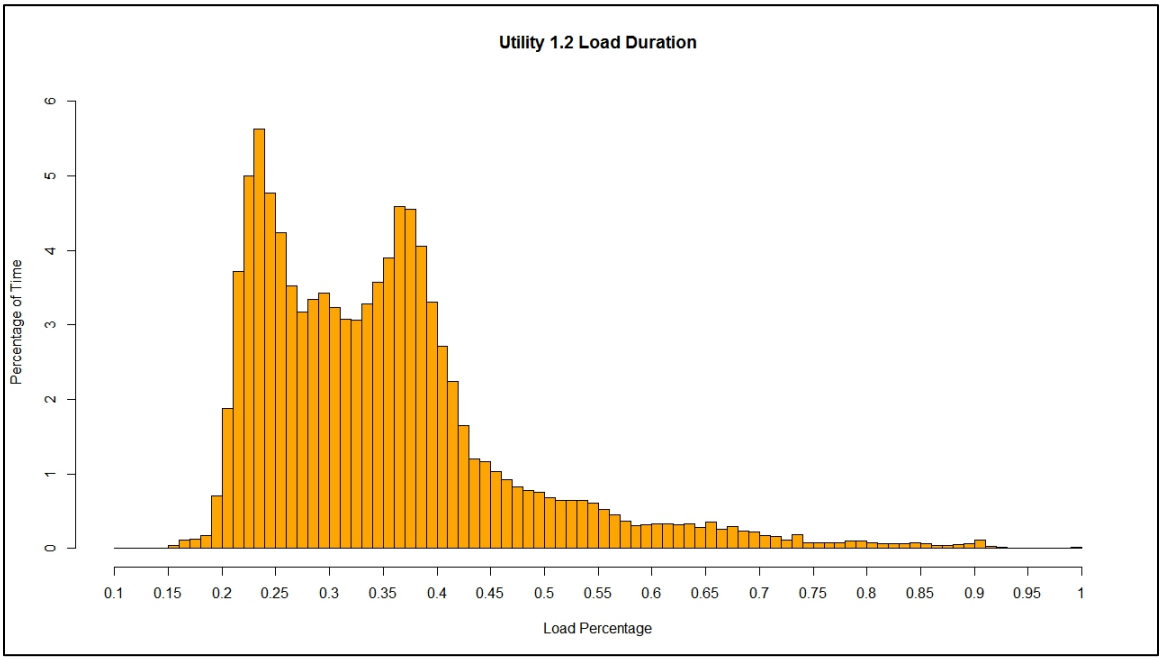
Figures 11 through 13 depict the individual load duration histograms for each of the three feeders. Comparing the individual feeder load duration curves with the substation's aggregated curve is revealing: The substation load has essentially a Gaussian form of statistical distribution; Feeders 1 and 2 exhibit a Multivariate Mixture Distribution, while Feeder 3 has a semi-normal distribution. The different distribution shapes illustrate the diversity even among neighboring feeders. Different statistical distribution functions for each feeder can be used for feeder clustering data for a large number of feeders. Statistical distribution functions are an indication of feeders' similarity or diversity in a pool of different feeders' data.

**Figure 11: Feeder 1.1 Load Duration Curve (Histogram)**



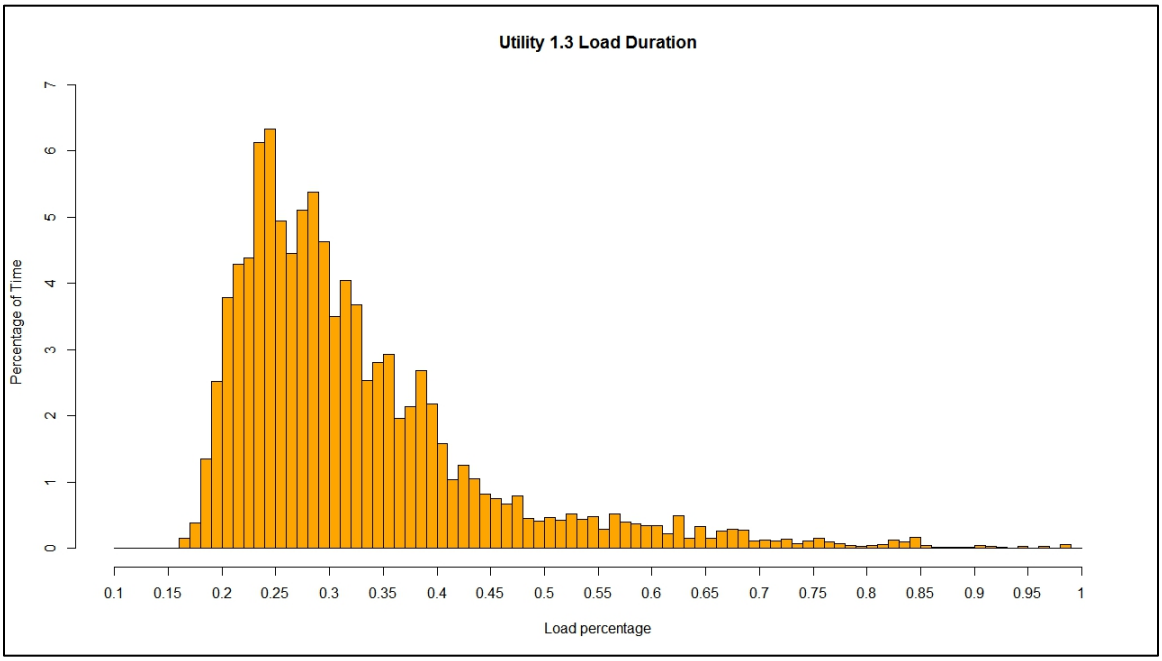

Source: CIEE (UC-Berkeley)

**Figure 12: Feeder 1.2 Load Duration Curve (Histogram)**




Source: CIEE (UC-Berkeley)

**Figure 13: Feeder 1.3 Load Duration Curve (Histogram)**



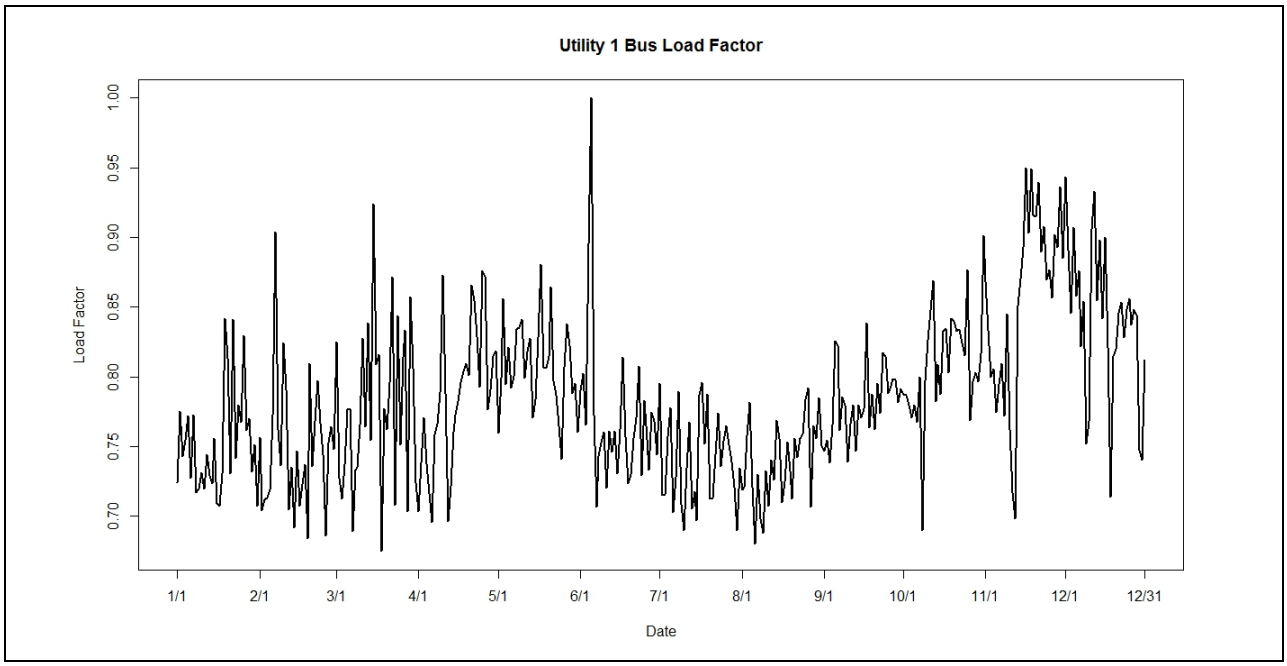

Source: CIEE (UC-Berkeley)

*Load Factor*

A simpler way to represent the information from the above histograms, within a single index, is in terms of the load factor. The load factor is the ratio of average load to the peak load (a number between zero and one) over the course of a chosen time period. While the load factor is often quoted for the entire year, Figure 14 shows the load factor for one substation and Figure 15 shows the load factor for one feeder for each individual hour. Note that even by aggregation of only three feeders, the load factor increases at the substation level compared to the individual feeder.

The load factor plots show directly how close a feeder is to its peak design values. It can indicate how much capacity is left for load growth, or whether and when DER and local storage could provide value.

**Figure 14: Substation Load Factor**

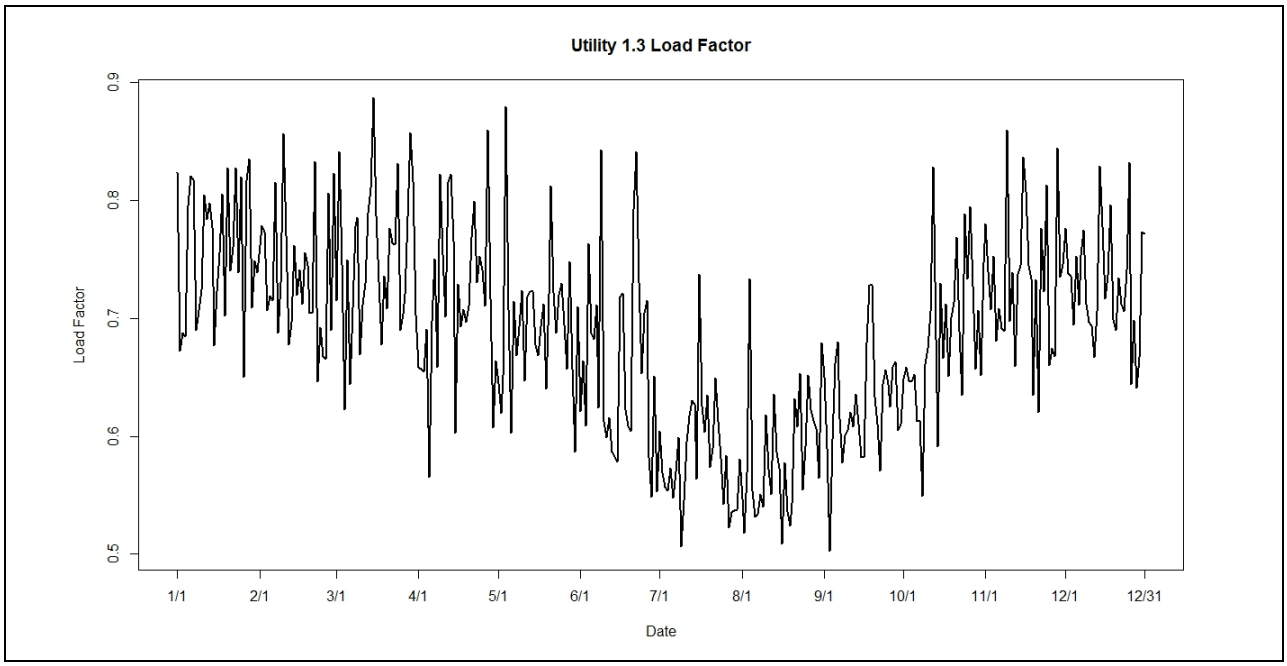



Source: CIEE (UC-Berkeley)

*Phase Deviation (Phase Balancing)*

Phase balancing is a crucial issue in distribution networks. Phase imbalance in three-phase systems causes unnecessary losses and can induce propagation of harmonic currents due to the change in power flow and the interphase couplings. Phase balancing reduces the neutral current and also tends to reduce third harmonic currents.

**Figure 15: Feeder 1.3 Load Factor**




Source: CIEE (UC-Berkeley)

To quantify phase imbalance, the following equations are used:

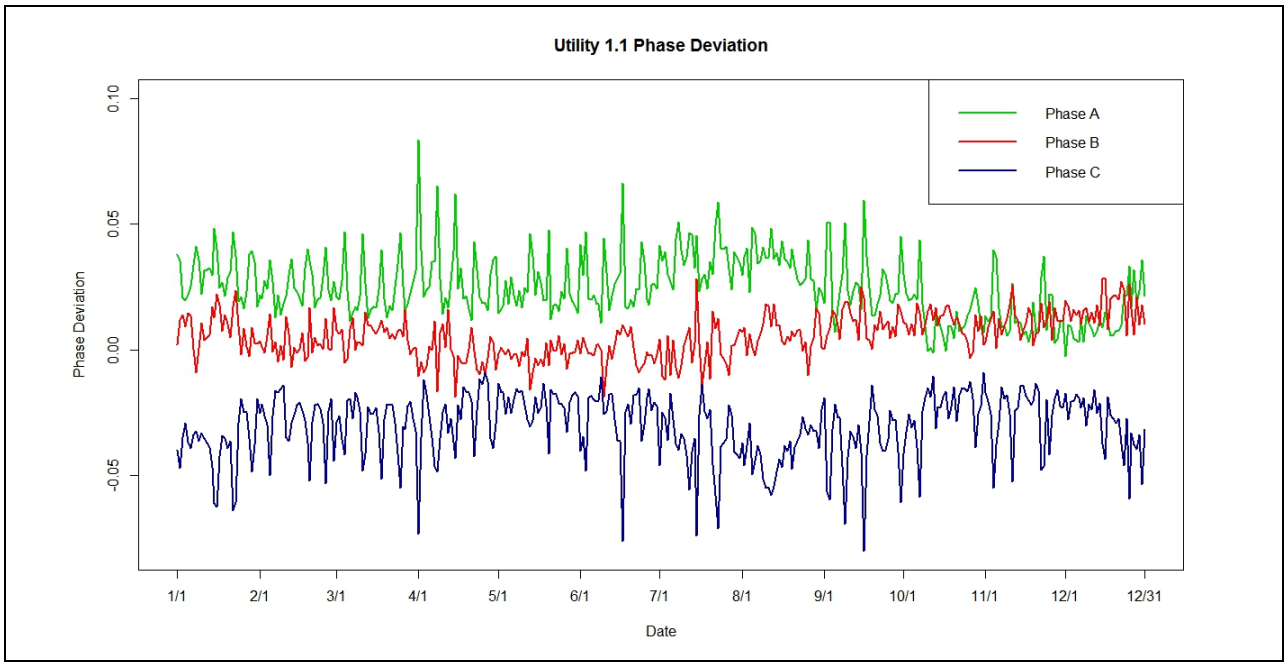
$$I_{avg} = \frac{I_A + I_B + I_C}{3}$$

$$I_{dev} = \frac{I_i}{I_{avg}} - 1 \qquad i = 1,2,3$$

$I_{avg}$ is the average of the three phase currents. The phase deviation $I_{dev}$ reflects the ratio of current in each phase and the average three-phase current (in the balanced condition). Figures 16 and 17 present the phase deviation for two feeders. Figure 16 shows currents on the three phases varying by several percent. Phase deviation is another indication for DG hosting capacity. For example, adding more PV to lightly loaded phases increase the chance of reverse power flow on those phases.

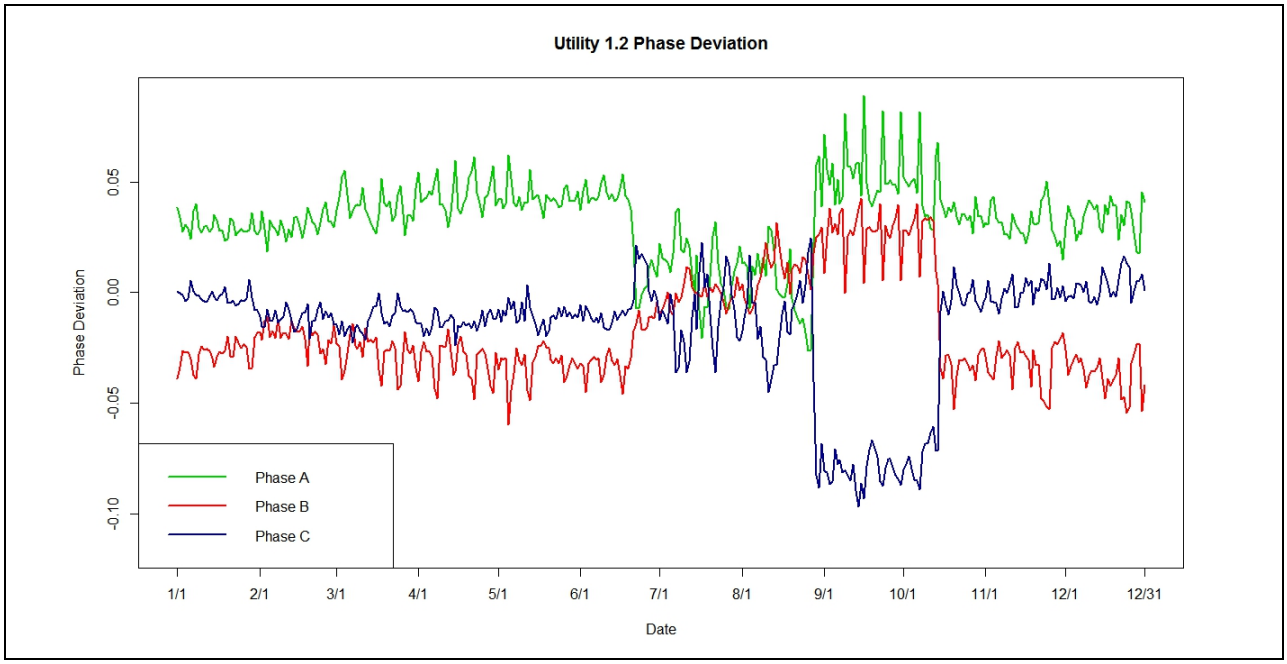
Figure 17 illustrates a somewhat greater imbalance, along with several changes of load connectivity in late June, late August and mid-October (it appears that some load was transferred from Phase A to B, then some load from C to A, and finally some load from B to C). The difference between phases can often be on the order of 10%. This illustrates the importance of considering each phase individually and using unbalanced three-phase models when analyzing the impacts of DG.

**Figure 16: Phase Deviation of Current, Feeder 1.1**




Source: CIEE (UC-Berkeley)

**Figure 17: Phase Deviation of Current, Feeder 1.2**



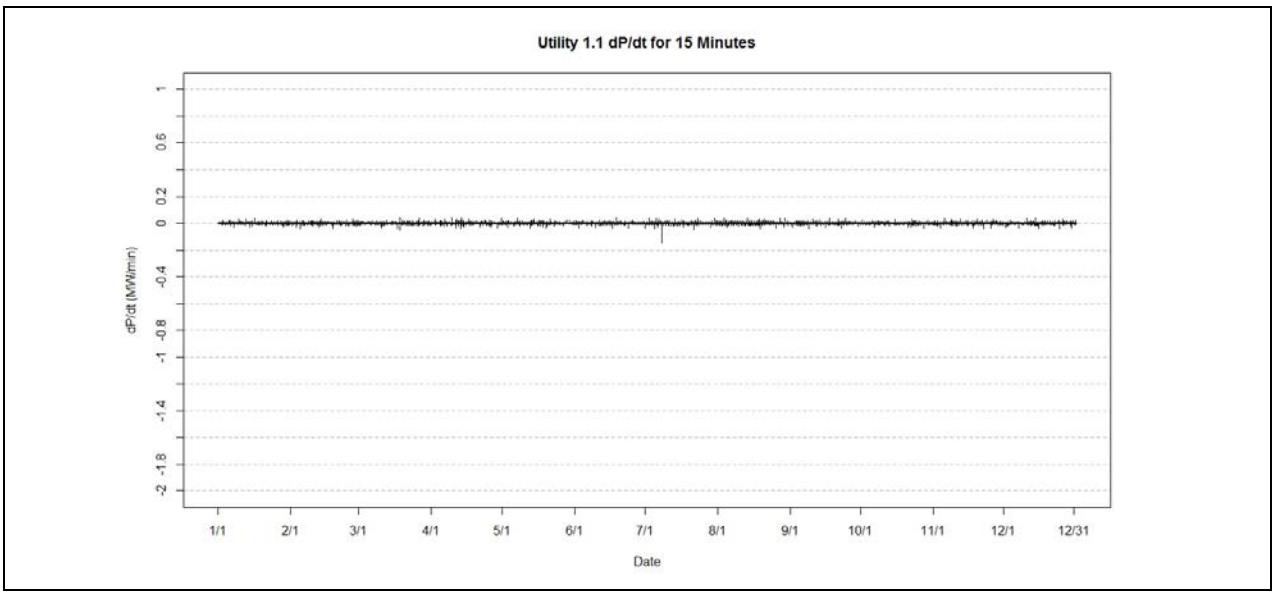

Source: CIEE (UC-Berkeley)

*Rate of Change of Loads*

Perhaps the most cited potential adverse impact of solar DG is its rapid variability. The time rate of change of net load on feeders with high PV penetrations has been a subject of concern throughout the industry. A likely consequence of more frequent and greater changes in net load is increased difficulty of sustaining effective voltage regulation with legacy equipment (load tap changers, voltage regulators, and/or capacitor banks). In this context, it is important to consider the variability of loads *per se*, even prior to the introduction of DG, as well as the additional impact of variable DG. Conventional metering does not provide many clues as to the actual ramp rates that are typical for feeder loads on very granular time scales, as a baseline against which the variability introduced by DG can be compared.

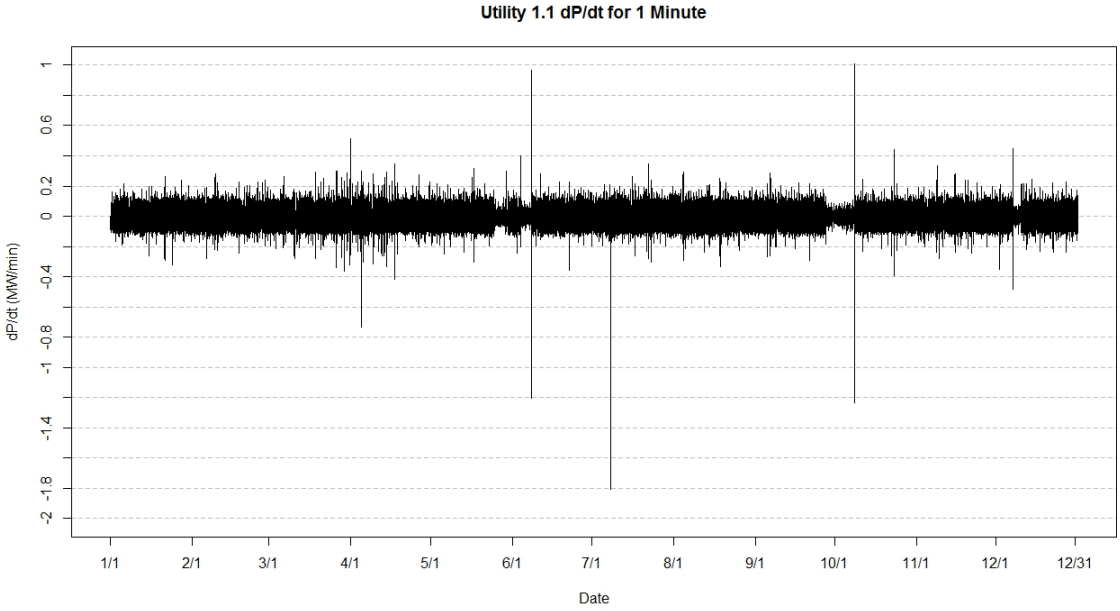
Higher measurement data resolution leads to capturing more dynamics of the loads and sources on the feeder. Figures 18 through 20 illustrate the rate of change of feeder load with respect to time, dP/dt, as computed on the basis of time-series data at three different levels of granularity. The same six-second data for this feeder were processed to reflect average measurements, as they would have been taken at longer intervals. The feeder shown here has no significant DG, so the variation is attributable to loads. The vertical axis shows the effective ramp rate in MW/min, obtained by comparing the change in load between successive time steps at the chosen granularity (an insightful analysis method introduced by Tom Bialek of SDG&E). For 15-minute data, dP/dt is very small. At the one-minute granularity, dP/dt tends to hover somewhat above 0.1 MW/min, or 100 kW/min, with occasional excursions on the order of +/-1 or 2 MW/minute. Twelve-second data, however, show a different picture. Noting the change in units on the vertical axis, we now see 1 MW/min variations consistently, and the large excursions up to +/-8 MW/min now can plausibly be interpreted as changes in connectivity (e.g., faults, disconnected or re-connected loads).

**Figure 18: 15-minute Rate of Change of Load on Feeder 1.1**



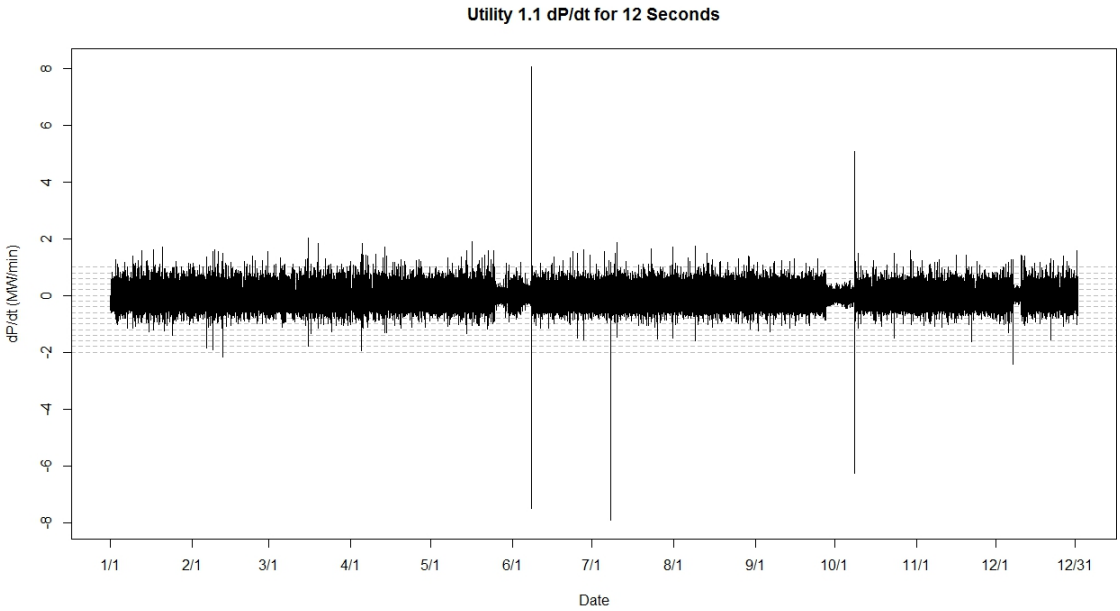

Source: CIEE (UC-Berkeley)

**Figure 19: 1-minute Rate of Change of Load on Feeder 1.1**




Source: CIEE (UC-Berkeley)

**Figure 20: 12-second Rate of Change of Load on Feeder 1.1**




Source: CIEE (UC-Berkeley)

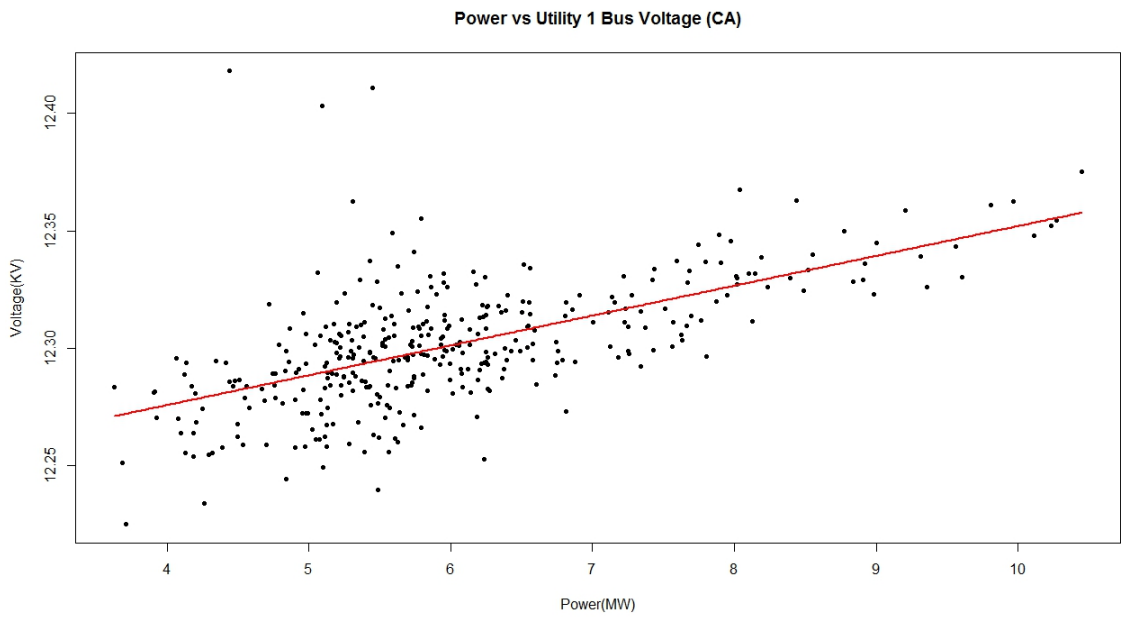
There are several lessons in these data. First, let us note that this particular feeder is not known to have power quality problems associated with load variability. Values of dP/dt like those seen here are not unusual. When considering the variability of DG, it is important to consider the baseline of comparison: what appears to be rapid variation of net load caused by solar generation could in fact be largely due to load variation that previously existed, but went unnoticed before DG installations motivated increased monitoring. This is one illustration of the importance of monitoring circuits without much DG presently installed.

Another crucial lesson is that the granularity of measurement determines what is observable. Based on the sample measurements shown here, monitoring at intervals much smaller than one minute, and certainly much smaller than 15 minutes, is indicated for any analysis having to do with variability of feeder loading. More measurement data resolution helps to see DG and energy storage ramp down and ramp up as they occur on feeders. More DG adoption leads to more dynamics.

*Correlations of Power, Voltage, Current and Temperature*

The scatter plots in Figures 21 through 24 depict best fits between pairs of variables including current, voltage, total feeder load, and temperature. It would be desirable to also include solar irradiance as an independent variable.

**Figure 21: Substation Voltage vs. Power**



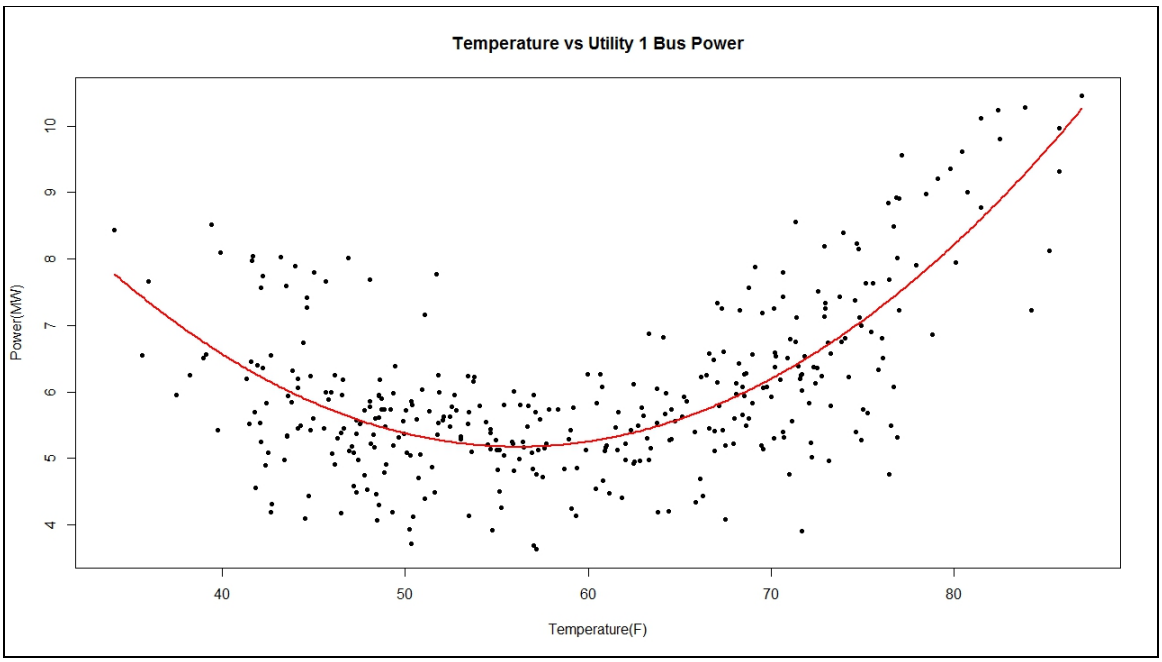

Source: CIEE (UC-Berkeley)

All dependency studies are possible with time-synchronized data. Due to the lack of synchronization in the available SCADA data, we used interpolation and resampling on the cleaned data to capture dependency between different parameters for each feeder. The information extracted from power, voltage, current, and temperature dependency are another motivation to use time-synchronized measurement technologies such as Phasor Measurement Units (PMU) in distribution networks.

The relationship between power and voltage is illustrated via the dependency plot presented in Figure 21. It is useful for voltage conservation programs and load characterization. Moreover, it shows how voltage regulation and power factor correction schemes affect power loss and energy efficiency in feeders.

Power and temperature dependency is a crucial indication of the system sensitivity to the ambient conditions as presented in Figure 22. It is a valuable input for health monitoring of network components. In terms of operation and maintenance, network components have temperature margins for safe operation. On hot days operators need to pay more attention to the power and temperature dependency in feeders with more installed PV. The other crucial information extracted from power and temperature dependency curves is related to load behaviors relative to ambient temperatures. Ambient temperature is a driver for load profile changes due to different space heating, cooling, and ventilation needs in houses in addition to electric water heating.

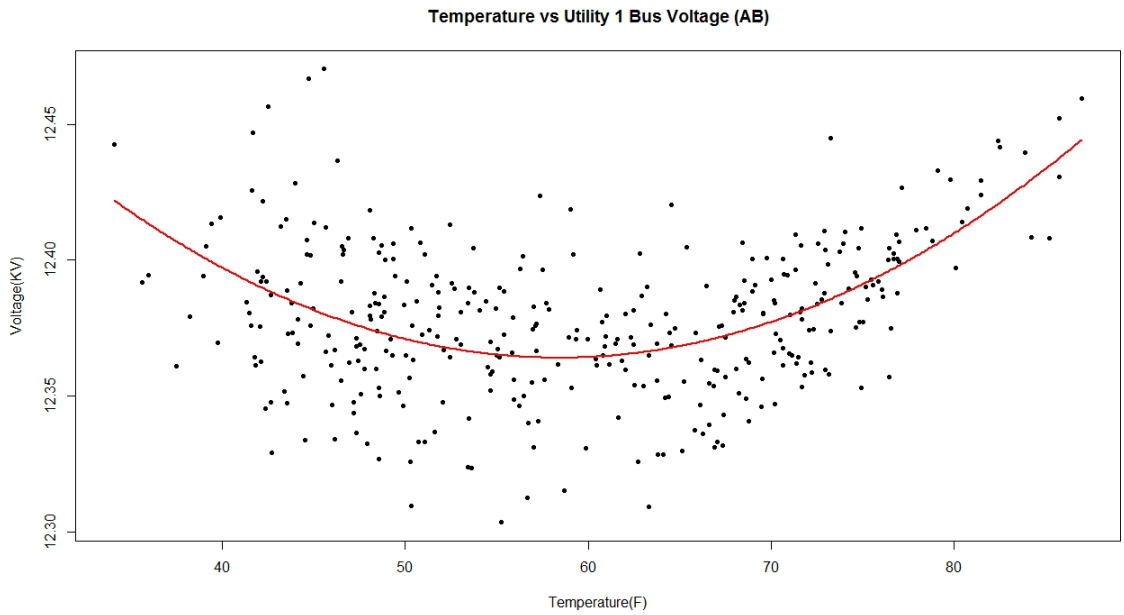
**Figure 22: Substation Power vs. Temperature**




Source: CIEE (UC-Berkeley)

Figure 23 shows the voltage variation as a function of ambient temperature. It is useful in network efficiency evaluation. Moreover, it provides similar information for operators to program volt/VAR control devices adaptively to weather condition. The voltage and temperature dependency profile is related to the feeder physical characteristics (e.g., feeder length and conductor type) and loading (e.g., type of loads and number of customers). For feeders with higher voltage-temperature dependency, higher PV adoption may cause more voltage variation because higher PV output occurs on summer sunny days with higher temperature.

**Figure 23: Substation Voltage vs. Temperature**




Source: CIEE (UC-Berkeley)

Current and temperature dependency is useful for evaluating feeder utilization as a function of ambient temperature, as shown in Figure 24, which would allow operators to monitor temperature margins of network components on days when current is closely correlated to ambient temperature.

### 4.4.3 Feeder Spatial Characterization

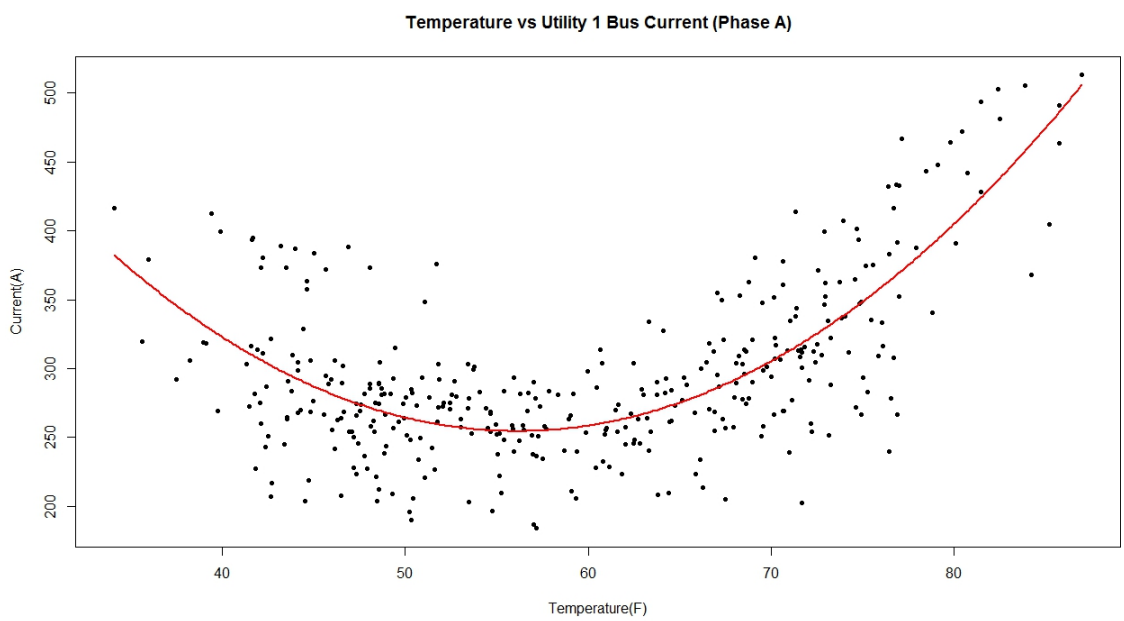
This section reviews the special characteristics of available feeder models that are converted via the Unified Platform for modeling that is presented in Chapter 5. Due to lack of information for feeder models, it was possible to convert only one feeder into UP format. Table 4 shows the special characteristics for the converted feeder model.

### 4.4.4 Noteworthy Events in Feeder Behavior

One of the project goals regarding analysis of the feeder data supplied by the utility was to look at "noteworthy events" in the data for clues to feeder behavior and characterization. A noteworthy event is anything that occurs on the distribution system that is not typical of normally expected behavior. Examples of such events might include, the following:

- "Reverse" KW or KVAR flow, i.e., in the direction from the distribution feeder toward the distribution substation.
- Overvoltage: voltages higher than 105% of nominal voltage level (e.g., higher than 12.67 kV on a 12 kV system).
- Undervoltage: voltages lower than 95% of nominal voltage level (e.g., lower than 11.4 kV on a 12 kV system).
- Topology changes, including switching operations and load and generator connections.
- Transients, i.e., fast disturbances that are over quickly, including faults, unintentional short-term effects of switching operations, loads switching on or off, generators ramping up or down, etc.
- Dynamics, such as oscillations in voltage, current, or power that do not die out quickly, and may be indicative of control system malfunction or interactions between systems.
- Harmonic currents or voltages.

**Figure 24: Substation Current vs. Temperature**




Source: CIEE (UC-Berkeley)

**Table 4: Feeder Circuit Model Overview**

| **Feeder Specifications** | | **Components Information** | |
|---|---|---|---|
| **Utility Name** | Utility 1 | Nodes | 289 |
| **Feeder Name** | Circuit 1.2 | Lines | 36(Line)+119(Cable)=155 |
| **Overhead Length** | 3.26 km (2.04 mile) | Voltage Regulators | None |
| **Underground Cable Length** | 12.71 km (7.9 mile) | Reclosers | None |
| **Voltage Level** | 12.47 – 0.21 kV | Three Phase Transformers | There are 10 step-up transformers that interface the solar inverters to the grid. |
| **Customer #** | 39 | Single Phase Transformer | None |
| **Peak Load** | 7.4 MVA | In the circuit models, the loads are directly connected to 12.47 kV. However, this may not be practical. In reality, a step-down transformer is needed for each load, which is not shown in the original model. There should be 6 single-phase and 33 three-phase transformers. | |
| **Residential %** | Unknown | | |
| **Commercial %** | Unknown | | |
| **Industrial %** | Unknown | | |
| **PV Capacity** | 1.5+3.5=5(MW) | | |

Source: CIEE (UC-Berkeley)

One goal of this project was to obtain enough feeder data from the California utilities that meaningful statistical analysis could be performed that would validate conclusions about feeder characteristics and behavior, such conclusions hopefully being valuable for further research and analysis. As explained previously, the amount of data actually obtained from utilities during the timeframe of this project was much less than was hoped for, and did not constitute a representative sample for statistical analysis. The collateral effect of obtaining limited data was that the number of "noteworthy events" in the data were naturally fewer, and no events in the data samples stood out as particularly interesting. For example, the only "noteworthy" events in the time-series measurements shown above are likely load transfers between phases (see Figure 17) and fault-related connectivity changes (Figure 20). None of the events observed are considered likely to be associated with DG. The shortest time step in the available data is 6 seconds, which is much longer than the time span for network dynamic behaviors (sub-cycle to a few cycles).

### 4.4.5 Advanced Data Samples

For future research efforts, especially for those based on the Advanced Monitoring Plan developed in this project (see Chapter 6), the capture and analysis of noteworthy, non-steady-state and/or non-typical events is an important endeavor when evaluating the impacts of renewable generation, EVs, demand response, volt/VAR control, and many other new technologies, on the operation of the distribution system. Such events can reveal many characteristics of the feeder, such as incorrect models, dynamic interactions, or susceptibility to faults that steady-state observations will not show.

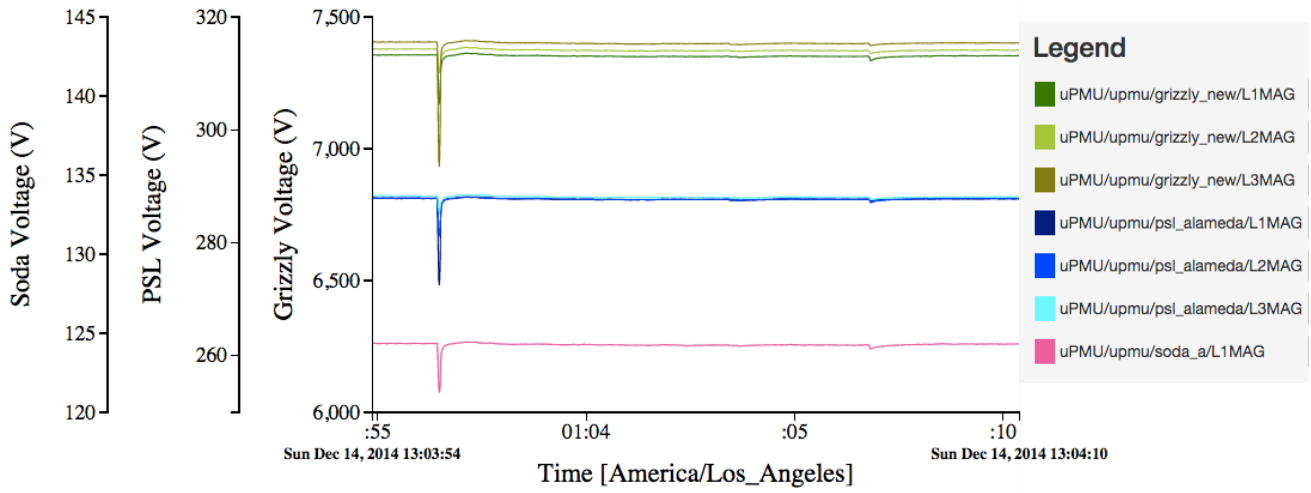
Another crucial attribute of advanced monitoring is the ability to cross-correlate measurements from different locations with consistent time stamping. For example, monitoring technologies such as micro-synchrophasors (or μPMUs, short for micro-phasor measurement units) make it possible to identify events and perform correlation studies between data streams. Time synchronization is a cornerstone for DG interaction studies, analyzing renewable resource dependency on weather data, and load behavior characterization. By necessity, synchrophasor measurements that identify the voltage phase angle must time-stamp the data very precisely to within a small fraction of a cycle (for example, one degree of angle at 60 Hz corresponds to 46 microseconds), typically by means of a GPS clock reference, to identify the phase angle shift (difference) between measurement points. Even if the phase angle is not of analytic interest, time stamping is valuable just for bringing magnitude quantities into a common context.

As an illustrative example of time-synchronized data, consider the voltage magnitude measurements in Figures 25 and 26, taken from three prototype μPMUs installed at UC Berkeley (Soda Hall), Lawrence Berkeley National Lab (Grizzly Substation), and in Alameda (Power Standards Lab) as part of an ARPA-E funded research project.[14] Voltages are measured line-to-neutral on each of three phases, except for the Soda location, which is plugged into a single-phase 120V AC receptacle. All three devices simultaneously recorded a small voltage sag (likely due to a fault elsewhere), followed ten seconds later by another blip (likely a recloser operation, whose delay indicates the fault occurred on another distribution circuit and not on the transmission system) expanded in the second graph. The time resolution is 120 samples per second; the time series in Figure 26 extends over approximately one second, with each dot representing one data point at 8.3 ms intervals. The ability to link measurements to specific events is due not only to the resolution and accuracy of the data, but crucially to the consistent time stamping among multiple devices.

---

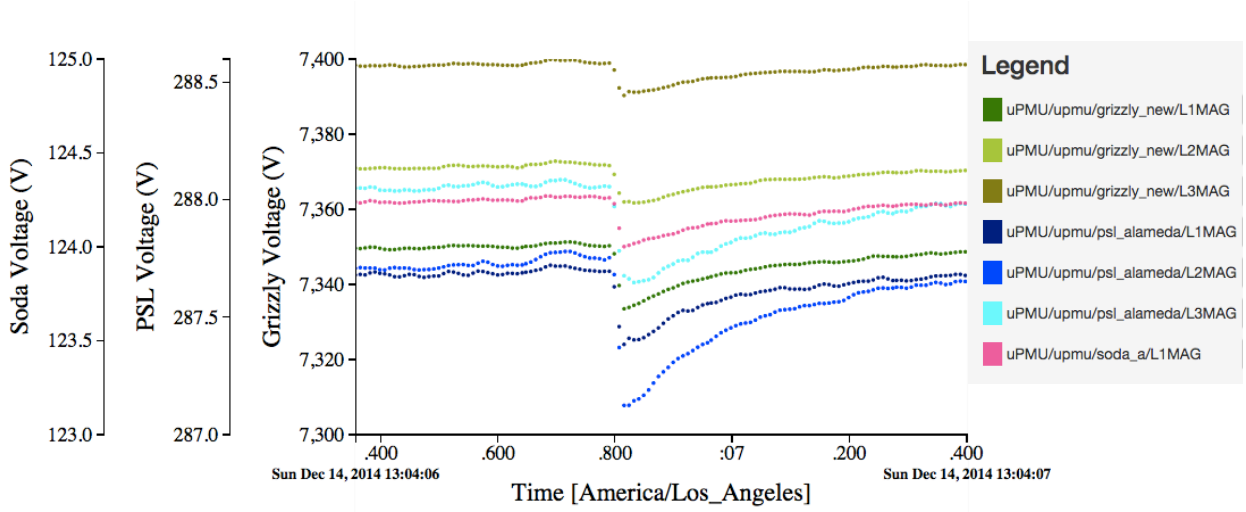
14 von Meier, Alexandra, David Culler, Alex McEachern, Reza Arghandeh. 2014. *Micro-synchrophasors for Distribution Systems.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2014 IEEE PES Innovative Smart Grid Technologies Conference. ISGT.2014.6816509.

**Figure 25: Synchronized Voltage Data Sample**




Source: CIEE (UC-Berkeley)

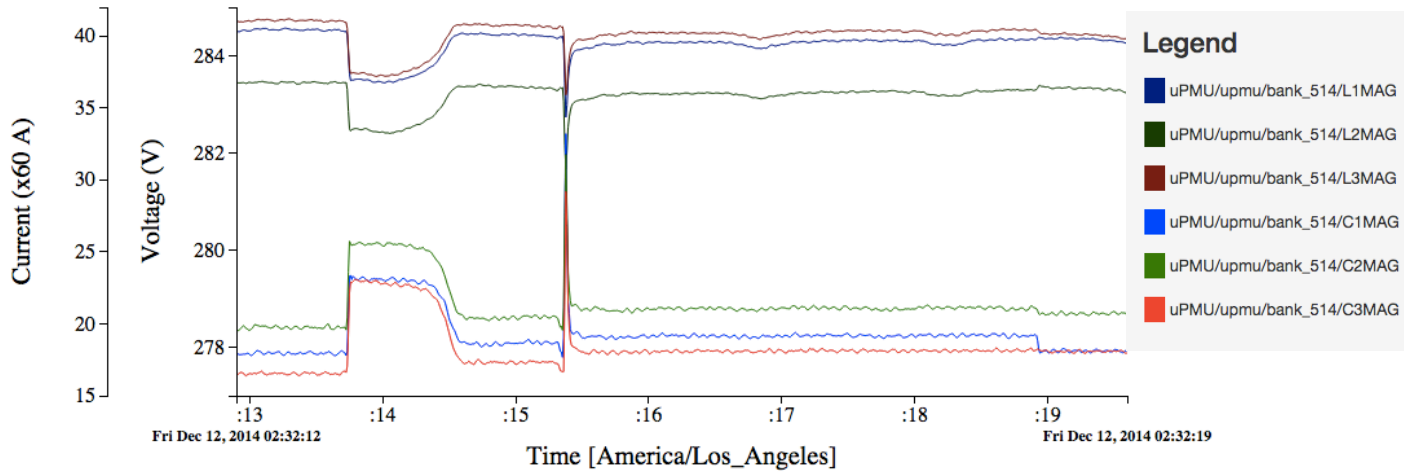
**Figure 26: Synchronized Voltage Data Sample at High Resolution**




Source: CIEE (UC-Berkeley)

Figure 27 illustrates time-synchronized voltage and current magnitude measurements on the secondary side of a three-phase transformer (the graph spans about six seconds). In this example, the changes in currents and voltages could be used to compute the effective impedance of the network.

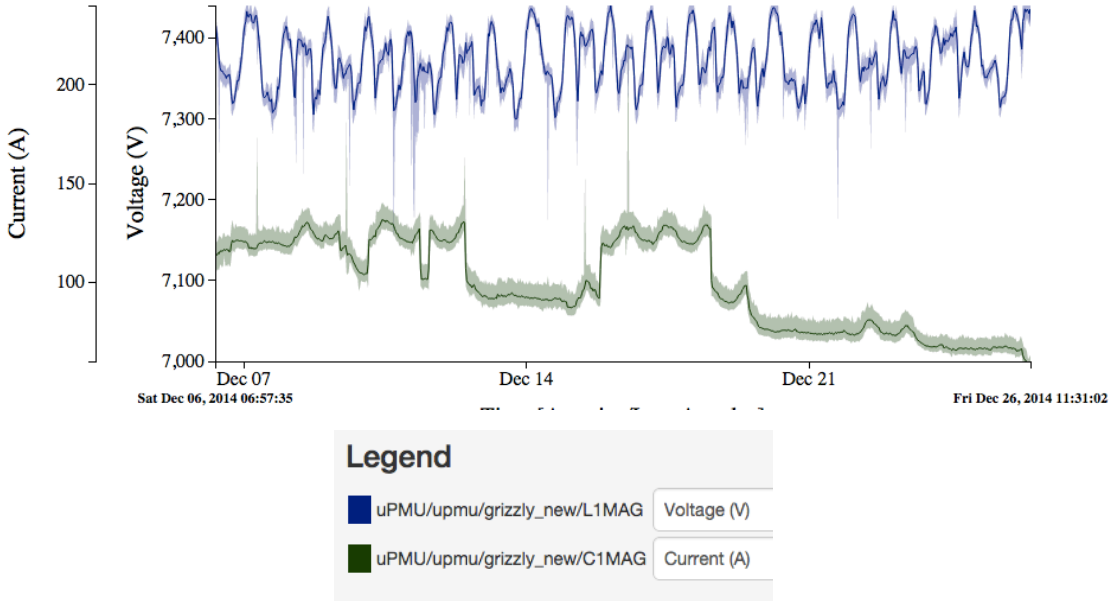
**Figure 27: Synchronized Voltage and Current Data Sample**




Source: CIEE (UC-Berkeley)

Examining data at different time resolutions reveals different behaviors. The graph in Figure 28 shows loads turned off for the holidays, and uncorrelated diurnal voltage variations originating from the transmission system. Zooming in on the same time series to a scale labeled in seconds,

**Figure 28: Substation Voltage and Current at Weekly Scale**




Source: CIEE (UC-Berkeley)

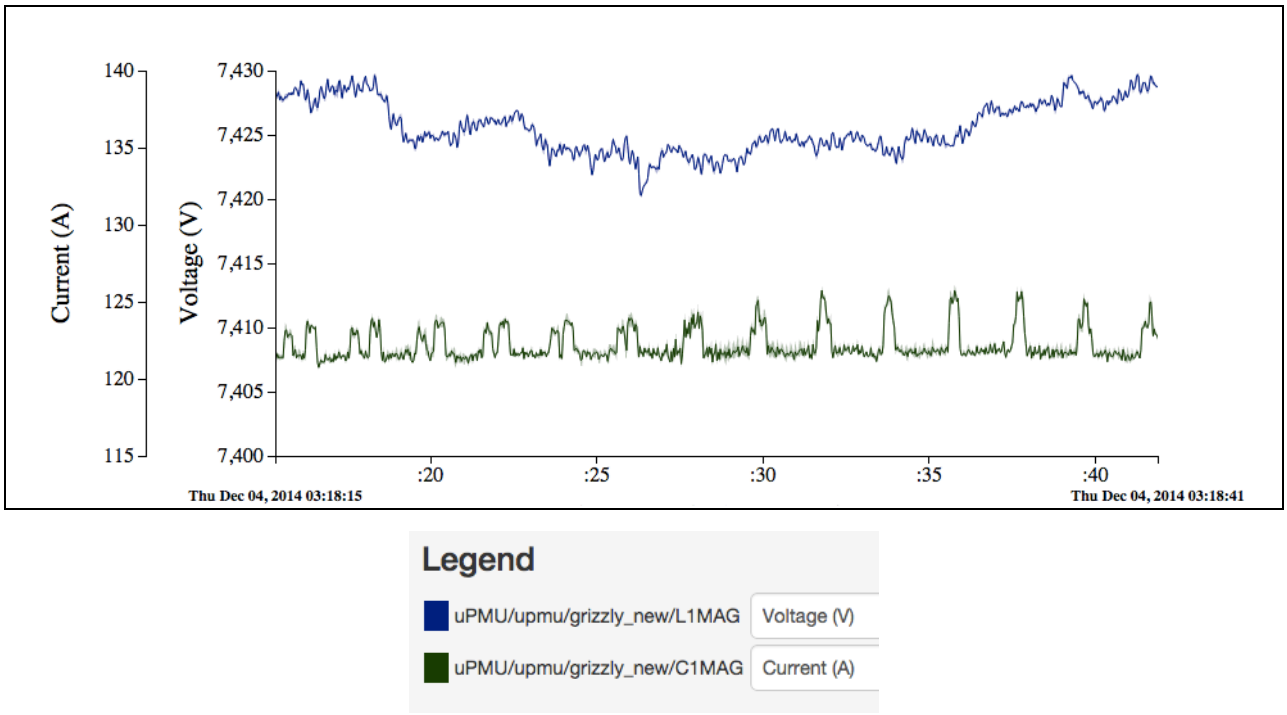
Figure 29 shows the cycling behavior of a major load. Power oscillations of small magnitude (a few percent) such as these are likely quite common on distribution circuits, and generally not associated with any perceptible power quality issues. It is desirable, however, to understand the presence of such variations before and after the introduction of DER, and the thresholds at which unintended consequences or device interactions might indeed occur. To do this with any confidence will require the introduction of high-resolution monitoring at a representative number of locations.

#### *4.4.5.1 Conclusions and Recommendations*

Due to the limited amount of feeder data obtained from utilities, the analysis and characterization of distribution feeders in California could not be performed as originally intended. It would still be a valuable task to accomplish, especially in the context of a study based on the Advanced Monitoring Plan as set forth in this project (see Chapter 6). A better understanding of how distribution circuits perform in the presence of high penetration levels of distributed renewables will improve the ability of utilities to manage the distribution system efficiently. Ratepayers will benefit as well, as the improved understanding will minimize costs and increase reliability.

This project developed some initial approaches to analyzing utility data to gain insight into the temporal, spatial, and other characteristics of distribution feeders. These included load duration curves (histograms), rate of change of power on the circuit, phase imbalance, and dependencies of key factors such as voltage, current, and power on external variables, e.g., weather (ambient temperature). These indices are all useful for DG hosting capacity analysis. They indicate the feeder capability to accept more load or sources. However, future analyses should also include the probability of reverse power flow due to high penetration of renewables, especially during periods of low load.

**Figure 29: Substation Voltage and Current at High Resolution**




Source: CIEE (UC-Berkeley)

To compensate for the lack of time-synchronization and time consistency, we had to use interpolation and resampling between different data points. The analyses performed on the available data can be extended in future studies along the lines explored in this project. As of this writing, SCADA data is the most prevalent type of data being collected, although AMI and Smart Meter data should become more widespread and hopefully, more available for analysis. But as of today, SCADA data typically are available at the distribution substation but not at locations out on the feeders. More data, higher-resolution data, and diversity of data sources will all contribute to more focused analysis of distribution feeders.

Observability is a crucial issue in the distribution network due to feeder spatial characteristics. Monitoring devices will need to be placed at key points, such as renewable generation locations, switching points, large controllable or volatile loads, etc.; the expert knowledge that will allow engineers to specify such points in either future R&D efforts or in actual operating situations must be gained through additional research and experience, coupled with engineering judgment. To study the impact of each DG on the feeder, measurement data must be available at the point of common coupling. While SCADA systems are adequate for some purposes, and could feasibly be improved for additional types of analysis, it is almost a certainty that other types of more advanced monitoring systems will be needed for some applications. And for feeder characterization, it is not clear at this time that SCADA data alone will be adequate.

The quality of the data currently available from utilities, a product of the monitoring methods and practices currently in use, constitutes something of a cautionary tale: To analyze the data

and extract meaning from it, the data must first be processed ("cleaned") to remove bad data points. As a lesson learned, monitoring technologies and methods should aim to capture data as accurately and completely as possible, minimizing bad, missing and incorrect data, and should include data-cleaning algorithms to minimize post-processing effort and delay. Our studies on the available SCADA data showed that the posterior data cleaning is a complex and time consuming task. There is no guarantee for complete data recovery after missing the data. The dependency (correlation) studies in this project were based on post processing of the data. Moreover, for some feeders, we didn't have the location of each feeder to be able to incorporate associated weather data into the analysis. The utility itself didn't provide the temperature and solar irradiation data. In the case of weather data availability, DG adoption studies can be extended to include PV panel efficiency, temperate dependency, the impact of cloud activity on voltage fluctuation, and frequency volatility.

Applications in operation, planning, and engineering will have different requirements regarding the type, quality, granularity, precision, and resolution. Additional research will be necessary to address this issue, so that data requirements for specified applications can be known. Anecdotally, the researchers heard from several sources that the communications and data storage infrastructure of utilities is not adequate today to transfer and process even the limited amount of data currently being collected and stored; this infrastructure will require considerable upgrading to handle future demands, and it is almost certain that the manpower and budget available today is insufficient to achieve the required level of performance by the time it will be needed by a system with high levels of renewables, EVs, etc.

Also, conversion of variable-time-interval data (such as many SCADA files) to constant-time-interval data, validation of physical feeder data (e.g., line impedances), and conversion of model data from the different software system formats, are all necessary to accomplish proper feeder characterization; these topics are covered in detail in the next chapter.

The data available from utilities for this project did not allow for the intended comparison between feeders with high, medium, and low penetration levels of distributed resources. However, such a comparison remains an important goal for future work.

# CHAPTER 5:
# Validation of Preliminary System Model

## 5.1 Overview

The goal of this task was to validate circuit models of the distribution system using metered data to allow accurate prediction of system behaviors and effective management of high-penetration renewables. The technical approach is to validate up to three distribution circuit models to ensure that they yield accurate predictions for the effects of distributed energy resources, including various forms of distributed generation and EVs, and to pinpoint any areas where discrepancies occur. The model predictions for the circuits in the monitoring study can then be compared to each other, as well as to the actual monitored data, for validation. The standard operating procedure established herein will be applicable for model validation with advanced monitoring data for future monitoring, and ultimately extendable to all feeders in California.

### 5.1.1 Building Distribution Circuit Research Capability

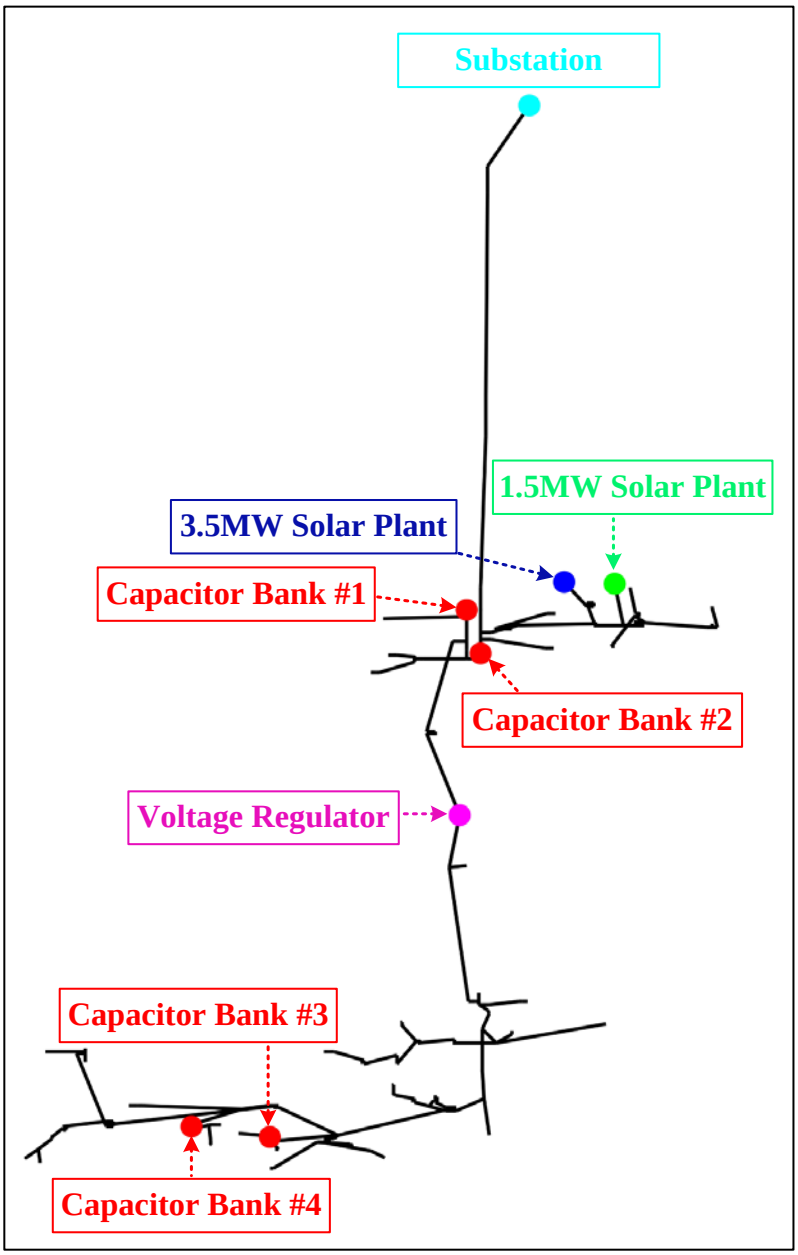
Many interactions with the California utility partners took place to understand their distribution circuit modeling practices and procedures as currently implemented. Through those interactions, we gained direct knowledge about how the circuit model data are developed or obtained, what methods are used to collect the metered data, and how all these data are stored and accessed for multiple applications. We requested representative circuits with different levels of PV and EV penetrations from our utility partners, ultimately obtaining data from three utilities. After many meetings and discussions with one particular utility, "Utility 1," we succeeded in transporting one circuit model from its native CYME environment to the OpenDSS environment. Additional consultation with our utility partners would be needed before we can fully reconstruct the models from the other two utilities in OpenDSS.

The utility companies typically store their circuit models in the software environment of their preference. Thus we expected to receive their models in various data structures and formats. To effectively perform model validation, the UCI team conducted software model comparison as part of our preparation for the work. Seven different modeling tools were compared, resulting in the determination that OpenDSS was most desirable as the native environment to store the circuit models and to perform model validation, due to its suitability for distributed circuit analysis and for its zero cost thanks to its open source nature. In addition, we also selected MATLAB as the platform for building specific applications for software interface, model transfer, and data processing due to its flexible customization capability. We made a systematic characterization of the seven software tools, which resulted in a set of guidelines for selecting a specific tool for a given simulation or analysis task. While working on the tools comparison, we also worked with UCSD to establish an NDA to develop secure data handling procedures to access the circuit models.

Upon receiving the circuit model from Utility 1 (as shown in Figure 30), which is in the CYME data structure, we realized that the circuit models from the utilities will likely be in different

software formats. It was necessary to convert data from one software tool to another to avoid purchasing multiple software tools for the purpose of handling data from multiple software environments. Accordingly, we designed a unified platform (UP) in a commonly available Excel spreadsheet format and built data conversion applications functioning as bridges to connect this

**Figure 30: Distribution Circuit in UCI OpenDSS Environment**




Source: UC Irvine

UP to various other software tools, including OpenDSS, ETAP, GridLAB-D, and DEW.[15] The UP enabled us to perform no-touch data transfer from CYME to these software tools. We envision that the UP and associated data conversion applications could be expanded over the next phase of research to include more software tools by using the approach developed for this project. The UP is described in detail in the next section.

During our visit to Utility 1, we found that their meter data are recorded using a dead-band method in which a variable is sampled if its increment exceeds a preset significant value. This method has the benefit of minimizing the amount of data recorded without losing significant data; however, the result is a time-series data set with unequal time intervals. Such data may be entirely adequate when plotted for humans to inspect, but it is incompatible with all simulation software tools, which require data input in constant time steps. Out of necessity, we developed a method and an associated application to perform data interpolation and resampling (DIR) in MATLAB to resolve this issue. The DIR application reads the unequally spaced time-series data from an Excel file, interpolates it, and resamples it based on a given (user-specified) sampling rate. Furthermore, we built a resampling error calculator (REC) application to assist the user in deciding a minimum sampling rate that yields acceptable error. This process enabled us to import the meter data into our OpenDSS software. The DIR and REC applications are described in detail later in this chapter.

Finally, we have both the circuit model and the meter data in our OpenDSS platform. Our model validation study suggests that the completeness of validation is highly dependent on the number and locations of metering points. We then designed a procedure to validate the model and derived guidelines for determining where and how many meters to install to yield a satisfactory result for a specific purpose. For the circuit models and meter data we received, we identified the load profiles and obtained close matches between the model and measurement data.

In summary, this research effort equipped us with extensive capability to navigate across several software simulation platforms, to simulate large distribution circuits, to synchronize meter data with simulation software tools, and to perform preliminary model validation. We produced several standardized software applications accompanied by relevant standard operation procedures and protocols that enable us to handle a large number of distribution circuit models, and these applications will be made available for our utility partners to perform similar tasks such as software tool selection, model transfer, data synchronization, etc. In addition, we developed the capability to work efficiently with our utility partners and with the utilities' systems for model development and analysis.

---

15 Khoshkbar-Sadigh, Arash, Mojtaba Heydari, Marco Tedde, Reza Arghandeh, Keyue Smedley, Alexandra von Meier. 2015. *A Unified Platform Enabling Power System Circuit Model Data Transfer among Different Software.* Institute of Electrical and Electronics Engineers 2015 Innovative Smart Grid Technologies Conference.

## 5.2 Modeling Software Tool Comparison

There are a number of powerful software tools available in the market for power system simulation. However, these tools are not created equal; each software package is unique, with different features and formatting structures, and geared toward different applications.

Simulation tools typically offer power-flow analysis capability, which is typically used to simulate and analyze system scenarios (i.e., various patterns of system configuration, generation, and loading) for various strategic purposes, such as long-range planning of new facilities, optimizing capacitor bank placement for voltage support, determining short-circuit duties, loss reduction, etc. An accurate model of the distribution system will also enable and facilitate the integration of high levels of renewable generation into existing electricity grids, and mitigate the issues associated with intermittency and variability of renewable generation.

In preparation for receiving distribution circuit model data from multiple utilities, and considering the many different simulation tasks to be performed, we launched a comparison study to identify the simulation tools most suitable for our model validation objectives. We compared the most commonly available software packages used for power systems analysis, including MATLAB, PSCAD, ETAP, PowerWorld, PSAT, OpenDSS, and GridLAB-D, using the IEEE 13-bus test circuit, a widely accepted industry benchmarking tool.

Software for distribution system modeling should be able to accurately model distribution components such as standard pole configurations, specific conductor and insulation types used on each line segment with single-phase, two-phase and three-phase configuration, different types of loads, capacitor banks, transformers with different functions such as automatic voltage regulation (AVR), reactive power control, phase shift control, etc. Other important features for distribution circuit study should include the ability to do "annual" type simulations (time series simulation), long-term transitory simulations (necessary for evaluating such phenomena as the effect of drop-in solar generation due to a passing cloud on grid voltage), and optimizing the management of demand and energy storage resources, among others.

One problem we encountered is data format compatibility. It appears that each software package has its own unique output data format, and is not generally compatible with other packages' formats. We translated the data by developing a procedure that allowed non-touch or minimum-touch data transfer, which is important for transferring the data of multiple feeders. This work was time consuming, since we had to (1) figure out all the differences and (2) develop script to automatically transfer the data. We successfully transformed data for a small test circuit, for which we did power flow simulation with accurate results. We completely reconstructed the circuit in the ETAP platform.

From extensive analysis and simulation, we systematically arranged the results in the form of tables (Tables 5 through 10), from which we selected OpenDSS to perform distribution circuit simulation. In addition, MATLAB's SIMULINK was also selected to develop applications for data conversion.

**Table 5: Capability of SIMULINK® in Simulation of Distribution System Components**

| Functions | | SIMULINK | Comments |
|---|---|---|---|
| **Available Models of Loads** | **Three-Phase Balanced Loads** | Yes | Constant PQ and constant Z |
| | **Distributed Loads** | No | |
| | **Single-Phase Loads** | No | |
| **Modeling Capacitor Bank (shunt)** | **Three-Phase** | Yes | |
| | **Single- Phase** | No | |
| **Modeling Reactors** | **Three-Phase** | Yes | |
| | **Single-Phase** | No | |
| **Modeling Three Phase Transformer** | **with regulator (Tapped)** | Yes | |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | Yes | |
| **Modeling Single Phase Transformer** | **with regulator (Tapped)** | No | |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | No | |
| **Modeling Unbalanced AC Distribution Lines** | **Three Phase** | Yes | Accepts both phase impedance matrix and sequence impedance matrix |
| | **Two Phase** | Yes | |
| | **Single Phase** | Yes | |
| **Modeling Balanced AC Transmission Lines** | **Three Phase** | Yes | Accepts both phase impedance matrix and sequence impedance matrix |
| **Converge in Minimum Iteration** | **Balanced Three Phase Network** | Strong | |
| | **Unbalanced Three Phase Network** | Weak | |
| **Types of Study** | **Load Flow** | Yes | |
| | **Transient Studies** | Yes | |
| | **Short Circuit Study** | Yes | |
| | **Cost Analysis** | No | |
| **Specific features:** Modeling power electronics elements, FACT devices, HVDC, SVC, and wind source and turbines, ability to build custom models | | | |

Source: UC Irvine

**Table 6: Capability of PSCAD in Simulation of Distribution System Components**

| Functions | | PSCAD | Comments |
|---|---|---|---|
| **Available Models of Loads** | **Three-Phase Balanced Loads** | Yes | Constant PQ, constant Z and constant I |
| | **Distributed Loads** | No | |
| | **Single-Phase Loads** | Yes | Constant PQ, constant Z and constant I |
| **Modeling Capacitor Bank (shunt)** | **Three-Phase** | Yes | |
| | **Single- Phase** | Yes | |
| **Modeling Reactors** | **Three-Phase** | Yes | |
| | **Single-Phase** | Yes | |
| **Modeling Three Phase Transformer** | **with regulator (Tapped)** | Yes | Cannot adjust phase shift angle. Can adjust tap ratio automatically or manually. Has R, X, no load loss, saturation, air core reactance, inrush decay time constant, knee voltage, time to release flux clipping and magnetizing current |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | No | |
| **Modeling Single Phase Transformer** | **with regulator (Tapped)** | Yes | Same as three-phase case. |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | No | |
| **Modeling Unbalanced AC Distribution Lines** | **Three Phase** | Yes | Accepts positive and zero sequence impedances. |
| | **Two Phase** | Yes | |
| | **Single Phase** | Yes | |
| **Modeling Balanced AC Transmission Lines** | **Three Phase** | Yes | Accepts positive and zero sequence impedances. |
| **Converge in Minimum Iteration** | **Balanced Three Phase Network** | Strong | |
| | **Unbalanced Three Phase Network** | Strong | |
| **Types of Study** | **Load Flow** | Yes | |
| | **Transient Studies** | Yes | |
| | **Short Circuit Study** | Yes | |
| | **Cost Analysis** | No | |
| **Specific features:** Modeling power electronics elements, SVC, TCR, TSC, HVDC, and wind source and turbines, ability to build custom models. | | | |

Source: UC Irvine

**Table 7: Capability of Power World in Simulation of Distribution System Components**

| Functions | | Power World | Comments |
|---|---|---|---|
| **Available Models of Loads** | **Three-Phase Balanced Loads** | Yes | Constant PQ, constant Z and constant I |
| | **Distributed Loads** | No | |
| | **Single-Phase Loads** | No | |
| **Modeling Capacitor Bank (shunt)** | **Three-Phase** | Yes | |
| | **Single- Phase** | No | |
| **Modeling Reactors** | **Three-Phase** | Yes | |
| | **Single-Phase** | No | |
| **Modeling Three Phase Transformer** | **with regulator (Tapped)** | Yes | Has transformer with adjustable tap ratio and phase shift angle, automatically or manually. Has R, X, B, G, magnetizing conductance and magnetizing susceptance. |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | Yes | |
| **Modeling Single Phase Transformer** | **with regulator (Tapped)** | No | |
| | **without Tap** | No | |
| | **With Phase Shifting** | No | |
| **Modeling Unbalanced AC Distribution Lines** | **Three Phase** | No | |
| | **Two Phase** | No | |
| | **Single Phase** | No | |
| **Modeling Balanced AC Transmission Lines** | **Three Phase** | Yes | |
| **Converge in Minimum Iteration** | **Balanced Three Phase Network** | Strong | |
| | **Unbalanced Three Phase Network** | - | |
| **Types of Study** | **Load Flow** | Yes | For balanced, three-phase networks only. |
| | **Transient Studies** | Yes | |
| | **Short Circuit Study** | Yes | |
| | **Cost Analysis** | Yes | |

Source: UC Irvine

**Table 8: Capability of PSLF in Simulation of Distribution System Components**

| Functions | | PSLF | Comments |
|---|---|---|---|
| **Available Models of Loads** | **Three-Phase Balanced Loads** | Yes | Constant PQ, constant Z, and constant I |
| | **Distributed Loads** | No | |
| | **Single-Phase Loads** | No | |
| **Modeling Capacitor Bank (shunt)** | **Three-Phase** | Yes | |
| | **Single- Phase** | No | |
| **Modeling Reactors** | **Three-Phase** | Yes | |
| | **Single-Phase** | No | |
| **Modeling Three Phase Transformer** | **with regulator (Tapped)** | Yes | Has transformer which can adjust tap ratio and phase shift angle; has R and X core loss conductance and magnetizing susceptance; on-load tap changer (OLTC), tap-changing under load (TCUL). |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | Yes | |
| **Modeling Single Phase Transformer** | **with regulator (Tapped)** | No | |
| | **without Tap** | No | |
| | **With Phase Shifting** | No | |
| **Modeling Unbalanced AC Distribution Lines** | **Three Phase** | No | |
| | **Two Phase** | No | |
| | **Single Phase** | No | |
| **Modeling Balanced AC Transmission Lines** | **Three Phase** | Yes | |
| **Converge in Minimum Iteration** | **Balanced Three Phase Network** | Strong | |
| | **Unbalanced Three Phase Network** | - | |
| **Types of Study** | **Load Flow** | Yes | For balanced, three-phase networks only. |
| | **Transient Studies** | Yes | |
| | **Short Circuit Study** | Yes | |
| | **Cost Analysis** | No | |

Source: UC Irvine

**Table 9: Capability of OpenDSS in Simulation of Distribution System Components**

| Functions | | OpenDSS | Comments |
|---|---|---|---|
| **Available Models of Loads** | **Three-Phase Balanced Loads** | Yes | Constant PQ, constant Z, and constant I |
| | **Distributed Loads** | No | |
| | **Single-Phase Loads** | Yes | Constant PQ, constant Z, and constant I |
| **Modeling Capacitor Bank (shunt)** | **Three-Phase** | Yes | |
| | **Single- Phase** | Yes | |
| **Modeling Reactors** | **Three-Phase** | Yes | |
| | **Single-Phase** | Yes | |
| **Modeling Three Phase Transformer** | **with regulator (Tapped)** | Yes | |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | No | |
| **Modeling Single Phase Transformer** | **with regulator (Tapped)** | Yes | |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | No | |
| **Modeling Unbalanced AC Distribution Lines** | **Three Phase** | Yes | |
| | **Two Phase** | Yes | |
| | **Single Phase** | Yes | |
| **Modeling Balanced AC Transmission Lines** | **Three Phase** | Yes | |
| **Converge in Minimum Iteration** | **Balanced Three Phase Network** | Strong | |
| | **Unbalanced Three Phase Network** | Very Strong | |
| **Types of Study** | **Load Flow** | Yes | Also harmonics, time series simulations, fluctuating generation, loss calculation, storage management, Volt and VAR management. |
| | **Transient Studies** | No | |
| | **Short Circuit Study** | Yes | |
| | **Cost Analysis** | No | |
| **Specific features:** Harmonics and time series simulations; transformers with n phases and m windings; supporting imbalanced loads; accepting CSV files; possibility to be coupled with other software through a COM DLL interface. | | | |

Source: UC Irvine

**Table 10: Capability of GridLAB-D in Simulation of Distribution System Components**

| Functions | | GridLAB-D | Comments |
|---|---|---|---|
| **Available Models of Loads** | **Three-Phase Balanced Loads** | Yes | Constant PQ, constant Z, and constant I; Commercial, industrial, and residential loads (heating/air conditioning, several household appliances). |
| | **Distributed Loads** | No | |
| | **Single-Phase Loads** | Yes | |
| **Modeling Capacitor Bank (shunt)** | **Three-Phase** | Yes | |
| | **Single- Phase** | Yes | |
| **Modeling Reactors** | **Three-Phase** | Yes | |
| | **Single-Phase** | Yes | |
| **Modeling Three Phase Transformer** | **with regulator (Tapped)** | Yes | |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | No | |
| **Modeling Single Phase Transformer** | **with regulator (Tapped)** | Yes | |
| | **without Tap** | Yes | |
| | **With Phase Shifting** | No | |
| **Modeling Unbalanced AC Distribution Lines** | **Three Phase** | Yes | |
| | **Two Phase** | Yes | |
| | **Single Phase** | Yes | |
| **Modeling Balanced AC Transmission Lines** | **Three Phase** | Yes | |
| **Converge in Minimum Iteration** | **Balanced Three Phase Network** | Strong | |
| | **Unbalanced Three Phase Network** | Strong | |
| **Types of Study** | **Load Flow** | Yes | Time series simulations taking climate and utilization into account,<br>Volt and VAR management, fluctuating generation, load control, and loss calculation. |
| | **Transient Studies** | No | |
| | **Short Circuit Study** | Yes | |
| | **Cost Analysis** | No | |
| **Specific features:** Solar panel and wind turbine modeling; use of climate files (TMY) for solar panels, wind turbines and heating/air conditioning; economic modules; distribution automation design; peak load management; load forecaster, load growth modeler, data collection, metering, and logging, end-use modeler, MATLAB MEX module integration, and weather player/synthesizers; ability to connect to any ODBC-compliant database for data archival/retrieval; accepts CSV files. | | | |

Source: UC Irvine

Since each utility may store circuits in its own proprietary data format, translation from one to another is often necessary, but may result in errors. Based on our experience in converting model data from CYME to ETAP, it was a time-consuming process, but a necessary step before simulation and analysis can be performed. It is crucial to preserve the characteristics of the model parameters with as much accuracy as possible, in order for the subsequent simulation and analysis to be meaningful.

There are dozens of powerful software packages available in the market to simulate the power grid. However, each of them was created with different features and formatting structures. Utilities often use specific software tools based on individual preferences, requirements, and applications, and therefore they store the data in a specific software database. The following section describes the process developed in this project to address this issue.

## 5.3 A Unified Platform for Circuit Models

### 5.3.1 Facilitating Model Transfer Between Various Software Tools

Although the main functions of the various power system simulation tools are similar, there exist significant differences in features and formatting structures to suit specific applications. This created challenges for transferring circuit models between different software environments. Utility companies typically use some specific software tools based on their needs and preferences; consequently, they store information about loads and circuit model in their own specific database structure.

With the emergence of new generation resources such as solar and wind, and other active components on distribution networks and microgrids, new circuit phenomena including dynamic behaviors will need to be studied. Utilities may need to use more than one software tool to investigate these new phenomena, requiring new features that may not be supported by their current software platform. Thus, it becomes necessary to transfer power system data (both static, "physical" system model data and measured or "metered" data) from one software environment to another. However, data sharing among different software environments is a cumbersome process that is labor-intensive. What is needed is a solution that enables cross-platform data transfer in the form of a complete distribution circuit starting from the substation transformer all the way down to individual loads.

We developed a Unified Platform (UP) to facilitate transferring data among different software packages, including ETAP, OpenDSS, GridLAB-D, and DEW, the objective being to mitigate the challenges of the circuit model conversion process. UP uses a commonly available Excel spreadsheet file with a defined format, for convenience of data entry and retrieval, via script-based applications. The main consideration in developing the UP is to minimize manual intervention when importing data for a single-line diagram of the circuit into the destination software and when exporting it from the source software, with sufficient preservation of detail to allow accurate load flow, short circuit, and other analyses.

Data transfer applications written in MATLAB were developed for each of these software tools to read the circuit model data provided in the UP spreadsheet. Each data transfer application

was verified by using two sample circuits, an IEEE 13-bus test circuit (a widely-accepted industry benchmarking tool) and an actual circuit from a utility company. When data are provided in the UP spreadsheet with the defined format, successful reconstruction of the circuit in a destination software is achieved. Load flow analysis is performed in ETAP, OpenDSS, GridLAB-D, and DEW for both sample circuits, and compared with the available results to verify the correctness of the circuit built by the data transfer application. The results we obtained were determined to match accurately in all software tools for both circuits.

### 5.3.2 Proposed Unified Platform (UP)

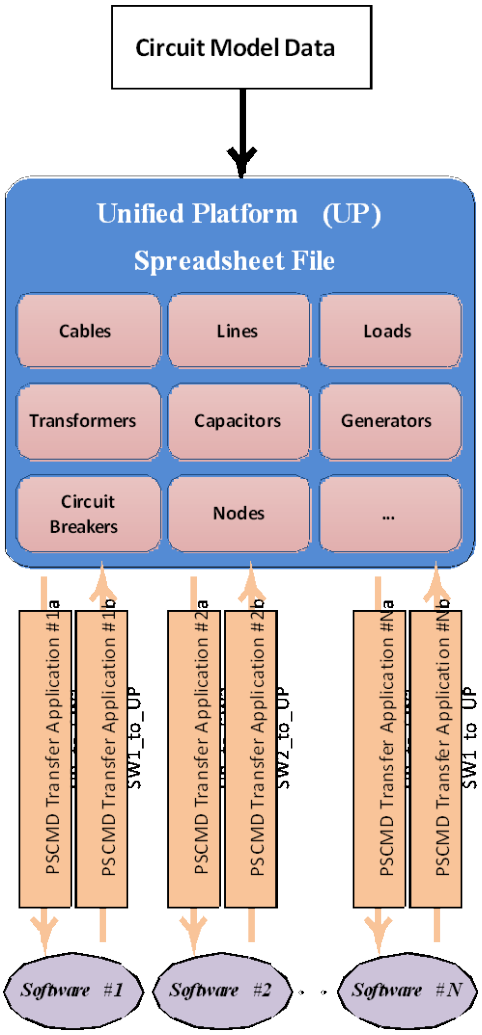
Conventionally, users develop their own custom-made applications to transfer data from one software platform to another as need dictates. These applications are typically unidirectional, i.e., one specific application can transfer data from software #1 into software #2, but not vice versa. Therefore, if there are N different software packages, N•(N-1) applications will be required if full translational ability is required. This approach can quickly become quite cumbersome and time-consuming, since there are literally dozens of software packages to be considered. To complicate things, each software package or tool typically has its own unique terminology. For example, software #1 may name the positive sequence resistance of a cable "Line R1 Ohms" while software #2 may name it "Pos. Seq R." Also, each software package typically has a unique database structure for storing the circuit model data. Therefore, prospective developers of data transfer applications need to be very familiar with the characteristics of both software systems and their internal languages (names of components and their parameter) in detail to be able to write the applications properly.

The Unified Platform (UP) developed in this project reduces the number of required applications to two for each software system, as shown in Figure 31: one to read data from the UP spreadsheet file and transfer it to the destination software, and another to read power system computer model data (PSCMD) from the source software and import it to the UP spreadsheet with the user-defined format. Consequently, the number of applications required to share data among N different software platforms is reduced from N•(N-1) to 2N.

The UP consists of an Excel spreadsheet file with a defined format containing individual sheets for specifying the physical circuit model data: bus (or node), cable, capacitor bank, circuit breaker, generator, load, overhead line, transformer, etc. Each sheet is a library of the parameters of available components in the circuit with details to enable various power system studies. For instance, the sheet called "cable" contains the required parameters such as ID, "from" node, "to" node, phase configuration, positive sequence resistance, positive sequence reactance, positive sequence admittance, zero sequence resistance, zero sequence reactance, zero sequence admittance, length, current rating, etc. A snapshot of the UP spreadsheet is given in Figure 32, illustrating the format and required parameters of some components such as transformers, cable, capacitors, and load.

The UP allows data transfer to and from the set of listed software tools. It enables software users to explore some new phenomena in their circuits by using a different software tool without the time consuming data transfer process.

**Figure 31: Conceptual Illustration of the Proposed Unified Platform (UP)**




Source: UC Irvine

### 5.3.3 Transferring Circuit Model Data from the UP into ETAP

ETAP electrical engineering software is a fully integrated power system analysis solution that includes analytical software modules for load flow, arc flash, short circuit, transient stability, relay coordination, cable ampacity, optimal power flow, and more. Its modular functionality can be customized to fit various simulation needs. Because of these attractive capabilities, ETAP is widely used by utilities.

The general scheme for importing model data into ETAP in shown in Figure 33. With the proposed UP, the circuit model data are imported into ETAP through a spreadsheet file with the defined format. One challenge in this process was to match ETAP's internal representation of data. For example, there are options in the ETAP graphical user interface (GUI) of cable parameters to define its unit of length (feet, mile, kilometer, or meter), and to define whether

**Figure 32: Snapshot of UP's Spreadsheet Containing Required Parameters of: (a) Transformer, (b) Cable, (c) Capacitor, and (d) Load.**

(a)

| A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Section Id | Code | Status | From Node | To Node | Cap Nom (kVA) | Prim Volt (kVLL) | Sec Volt (kVLL) | X0 R0 Ratio | X1 R1 Ratio | Z0 (%) | Z1 (%) | Primary Config | Secondary Config |
| TR1 | Transformer | Connected | N5 | N9 | 1500 | 12 | 0.48 | 10 | 10 | 6 | 6 | D | Yg |

(b)

| A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Section Id | From Node | To Node | Phase | Line R1 Ohms | Line X1 Ohms | Line B1 uS | Line R0 Ohms | Line X0 Ohms | Line B0 uS | Length ft | IA (Amps) | IB (Amps) | IC (Amps) |
| C1 | N1 | N2 | ABC | 0.01 | 0.012 | 12.091 | 0.054 | 0.015 | 12.091 | 341 | 473 | 473 | 473 |

(c)

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| Section Id | From Node | Cap. Control | Cap. Status | kV | Total Cap. kVAR | Phase | Config | Sensing ON | Sensing OFF | PT Ratio |
| CAP2 | N4 | Voltage | On | 7.2 | 1200 | ABC | Y | 121 | 126 | 60 |

(d)

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Section Id | From Node | Phase | Config | Spot kVAR A | Spot kVAR B | Spot kVAR C | Spot kW A | Spot kW B | Spot kW C |
| LD6 | N10 | AB | Yg | 600 | 360 | 0 | 800 | 480 | 0 |

Source: UC Irvine

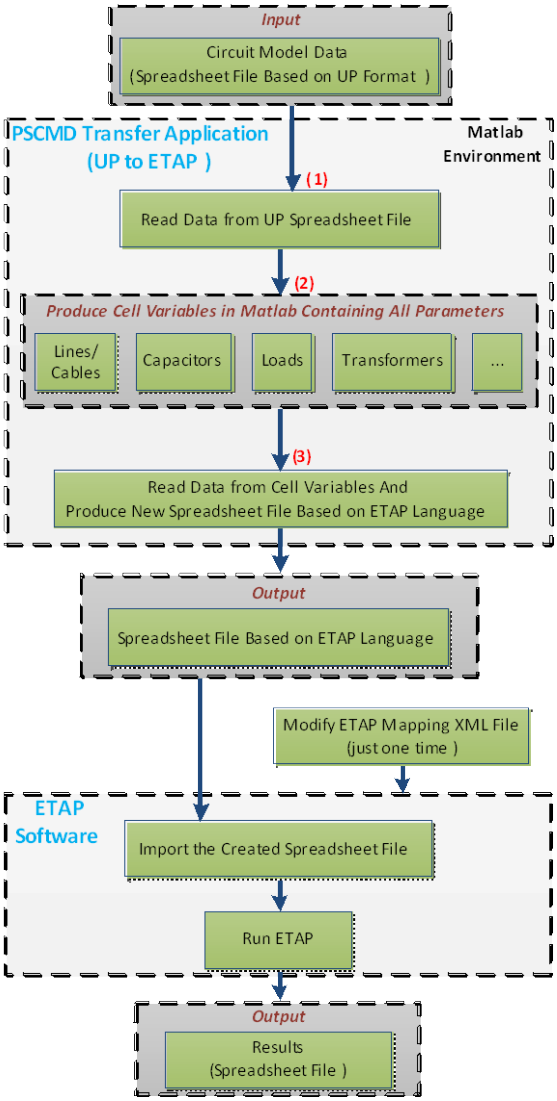
The assigned impedance is the total impedance of the cable, or the impedance per unit length. Similar options exist for other components. Therefore, it is necessary to understand how such options are translated in ETAP language and stored inside its database. To overcome this difficulty, a probing mechanism has been formulated to determine how the data should be transferred into ETAP.

To import data provided in the UP spreadsheet, some information must be modified. For example, ABC, A, B, C, AB, BC, CA for loads in the UP spreadsheet represent the phase configuration, while ETAP assigns them as 0, 0, 1, 2, 3, 4, 5 in field named "Phase Connection." Therefore, the circuit model data need to be translated. One option was to do this manually. However, this may cause some undetectable errors, and will likely also take more time if multiple circuits need to be transferred. In this case, we developed an application to do the translation in MATLAB script. Such a script is required for each component in the UP spreadsheet, including loads, capacitors, underground lines (cables), and overhead lines.

After understanding the internal representations of component parameters in ETAP, modifying the data in the UP spreadsheet, and producing a new spreadsheet file which is readable for ETAP, the final step was to expand the ETAP mapping XML file. (XML = Extensible Markup Language, a computer language used for encoding documents in a format which is both human-readable and machine-readable). This XML file contains all mapping data required to

import data from the new spreadsheet file into ETAP. The reason for this is that all internal representations of components and their parameters are not defined in the mapping XML file by default.

**Figure 33: General Scheme for Importing Circuit Model Data from UP Spreadsheet into ETAP**




Source: UC Irvine

### 5.3.4 Transferring Circuit Model Data from the UP into OpenDSS

OpenDSS is an open-source distribution system simulator (DSS) for supporting distributed resource integration and grid modernization efforts. The OpenDSS tool has been used since 1997 in support of various research and consulting projects requiring distribution system analysis. It performs nearly all frequency domain (sinusoidal steady-state) analyses commonly performed on distribution systems; however, it does not perform time-domain studies. It supports many new types of analyses that are designed to meet future needs related to smart grid, grid modernization, and renewable energy research. One of the significant features of OpenDSS is time-series simulation to study time-varying events, ranging from sub-seconds to years, of renewable energy resources in power systems. Many of this program's features were originally intended to support the analysis of distributed generation, and this continues to be a common use. It also supports analysis of phenomena such as energy efficiency in power delivery and harmonic current flow. OpenDSS is designed to be indefinitely expandable, so that it can be modified to meet future needs. The general scheme of importing model data from the UP spreadsheet into OpenDSS is illustrated in Figure 34.

OpenDSS is a script-based tool in which all circuit parameters and their connectivity are assigned in the script-based environment. In other words, it does not have any Graphical User Interface (GUI) to drag and drop a component (e.g., load) from its library and make any connection to another component (e.g., cable). Moreover, it does not have any built-in feature for importing data from spreadsheet file, as ETAP does. Therefore, it would take a considerable amount of time and effort to create a database in OpenDSS containing hundreds of lines, cables, loads, etc. For this project, an application was developed in MATLAB to read data provided in the UP spreadsheet. This transfer application creates a text file containing all lines, cables, loads, transformers, capacitors, circuit breakers, etc., based on the language of OpenDSS.

This data transfer application can be customized according to a user-defined format of the spreadsheet file, performed in step (1) of Figure 34. This means the application will work with spreadsheet formats that are not exactly the same as in the UP.

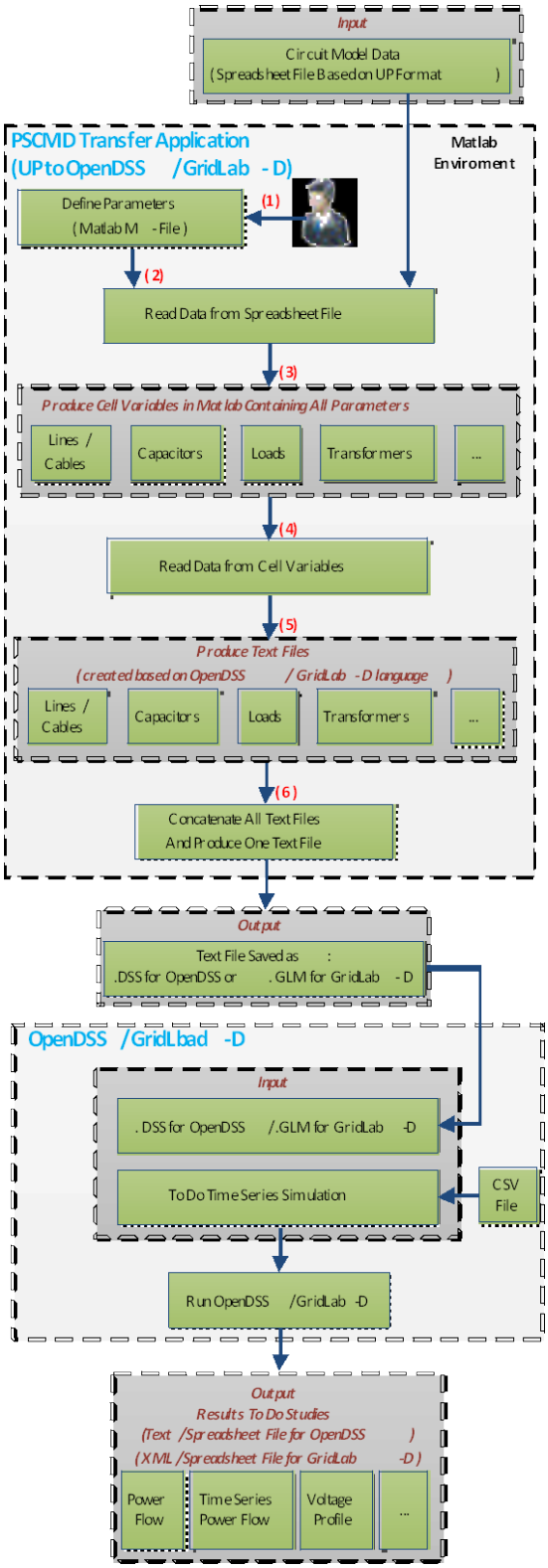
### 5.3.5 Transferring Circuit Model Data from Unified Platform into GridLAB-D

GridLAB-D is a DOE-funded open-source software developed at Pacific Northwest National Laboratory (PNNL) in collaboration with industry and academia. GridLAB-D is a multi-physical domain modeling (power, weather, market) and simulation tool to simulate and analyze power systems, including microgrids. GridLAB-D is a powerful modeling and simulation tools for time–series simulation in power systems with widely disparate time scales, ranging from sub-seconds to many years. Hence, GridLAB-D provides capabilities for users to analyze the progressive development of smart grids and the power systems with high penetration of renewable integration. GridLAB-D was first and foremost developed as a residential load simulator; other modules were then added for grid simulations.

GridLAB-D is similar to OpenDSS in that it is also a script-based tool, so it does not have a GUI to build a circuit. It also has the feature of users to initialize certain parameters. In addition to those mentioned for OpenDSS, these parameters may include AC frequency, the load-flow

solver method (e.g., Newton-Raphson, Forward-Backward-Sweep, etc.), the swing bus name (if the FBS method is selected), start and stop time of the time-series simulation, and the nodes where the user wishes to place meters. The application developed here for transferring data from the UP to GridLAB-D is based on a MATLAB m-file. It reads the circuit model data stored in the UP spreadsheet and, after some initializations by the user, it automatically builds the power system circuit model in a file in ".glm" format based on the GridLAB-D language and format. The general scheme of importing data from the UP spreadsheet into GridLAB-D is

**Figure 34: General Scheme for Importing Circuit Model Data from the UP into OpenDSS**




Source: UC Irvine

### 5.3.6 Transferring Circuit Model Data from the UP into DEW

The Distribution Engineering Workstation (DEW), developed by Electrical Distribution Design, Inc. (EDD), uses the Integrated System Modeling (ISM) methodology, which allows a single model to be used for different functions within a utility, such as design, planning, and operation. The DEW scope includes transmission and distribution networks in steady-state and time-series analyses. DEW has a user-friendly GUI and models can be displayed over geographical visualization tools such as Google Earth, Bin Maps, and GIS. DEW is the only solution that relies on a graph theory-based approach called graph trace analysis (GTA). GTA is a topology iterator method that iterates from one node to the neighboring node and updates the network connectivity and physical characteristics such as impedance, voltage, and current flow.

All components, their parameters and their connectivity in DEW are stored in an MS Access database, with a GUI to drag and drop components. The model can be saved in the Access database along with component data, or the model can be stored as a standalone file. DEW does not have a built-in application to import models from Excel directly. However, it has the model data mapper tool to import models with MS Access into the DEW environment. Therefore, the first step is to convert the UP Excel sheet into an MS Access version. Figure 35 illustrates the general block diagram for UP model conversion into DEW; Figure 36 shows a snapshot of the DEW Component Manager for performing this task.

### 5.3.7 Simulation Results

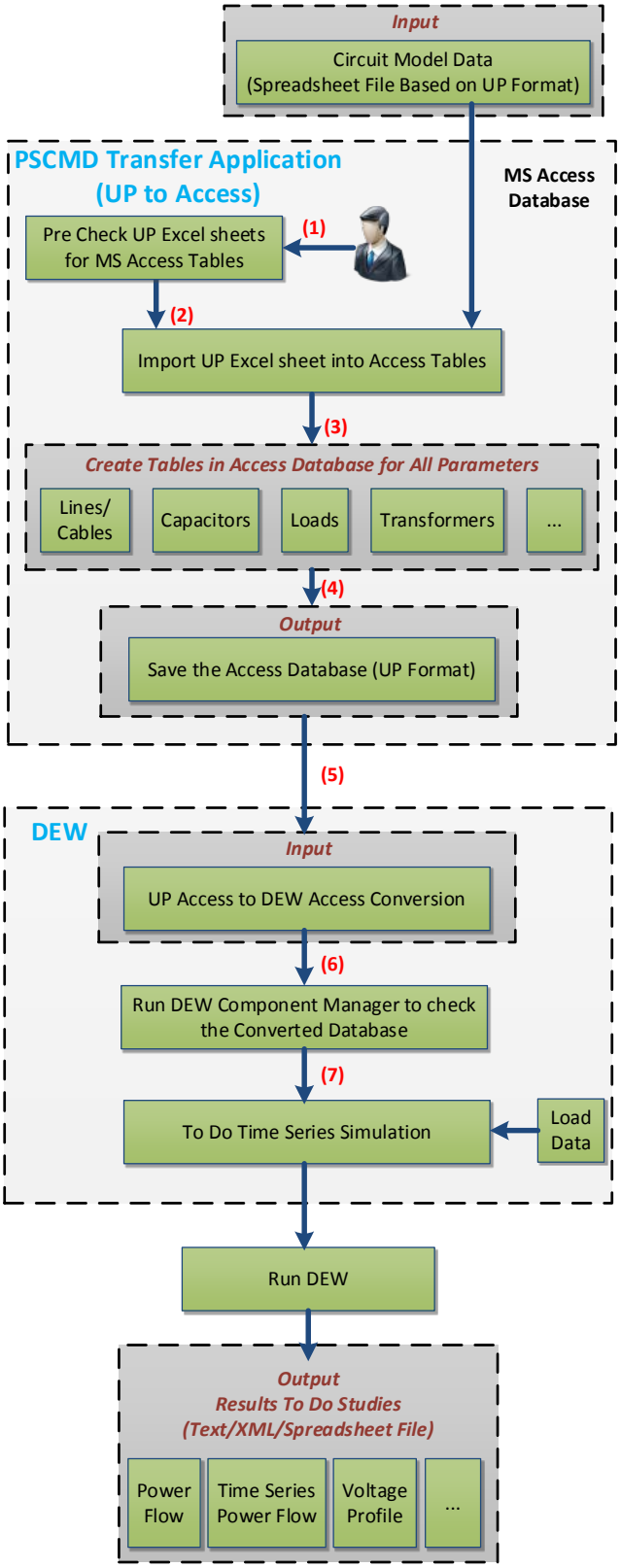
To verify the effectiveness of the proposed UP and test the functionality of developed PSCMD transfer applications, the circuit model data of two different sample circuits were imported into ETAP, OpenDSS, and GridLAB-D using the PSCMD transfer applications. One circuit was an IEEE test circuit and the other was an actual circuit from a California utility. The load-flow analysis of structured circuits is performed in each software tool and the obtained results are compared.

The circuit model data of the IEEE test circuit contained: 6 loads, which are illustrated in Table 11; two 1200-kVAR capacitor banks connected to nodes N4 and N8; 10 nodes (N1 to N10); 5 cables; one overhead line; and one transformer (12/0.48 kV) connected between nodes N5 and N9.

The actual utility sample circuit contained 39 loads with total rating of 6.4 MW and 4 MVAR; four 1800-kVAR capacitor banks (two of which are connected to the grid); 291 nodes; 119 cables; 36 overhead lines; 10 PV generators with total capacity of 5 MW; and 10 transformers (12/0.21 kV).

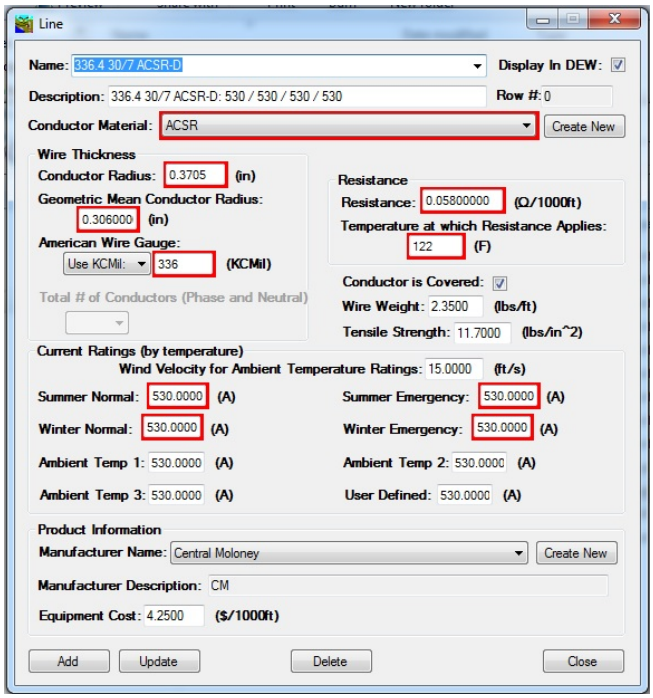
The load flow results obtained for the IEEE Test circuit and the utility circuit are illustrated in Table 12 and Table 13, respectively. The precise match of the results confirms the correctness of the reconstructed circuit and the proper functionality of PSCMD transfer applications to transfer the circuit model data from UP spreadsheet to each software platform.

**Figure 35: General Scheme for Importing Circuit Model Data from the UP into DEW**




Source: UC Irvine

**Figure 36: Snapshot of Component Manager in DEW to Transfer Circuit Model Data from UP into DEW**




Source: UC Irvine

**Table 11: Load Summary of IEEE Test Circuit**

| Name | Node | kW | kVAR | Voltage Rating | Power Factor (%) |
|---|---|---|---|---|---|
| LD1 | N4 | 3000 | 1800 | 7.2 kV | 80 |
| LD2 | N5 | 4500 | 2700 | 7.2 kV | 80 |
| LD3 | N7 | 3000 | 1307.7 | 7.2 kV | 90 |
| LD4 | N8 | 1500 | 653.7 | 7.2 kV | 90 |
| LD5 | N9 | 1500 | 900 | 0.48 kV | 80 |
| LD6 | N10 | 3000 | 1800 | 7.2 kV | 80 |

Source: UC Irvine

## Table 12: Load Flow Results from IEEE Test Circuit

| Bus | Active Power (kW) | | | | | Reactive Power (kVAR) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | CYME | ETAP | OpenDSS | DEW | GridLAB-D | CYME | ETAP | OpenDSS | GridLAB-D | DEW |
| N1 | 14527 | 14536 | 14534 | 14528 | 14535 | 7982 | 7989 | 7988.7 | 7988.6 | 7986 |
| N2 | 14510 | 14518 | 14516.8 | 14513 | 14517 | 7963 | 7969 | 7969.4 | 7969.2 | 7968 |
| N3 | 14510 | 14518 | 14516.8 | 14511 | 14517 | 7963 | 7969 | 7969.4 | 7969.2 | 7969 |
| N4 | 14501 | 14509 | 14508 | 14505 | 14508.6 | 7954 | 7960 | 7961.4 | 7961.25 | 7957 |
| N5 | 8925 | 8931 | 8930.4 | 8927 | 8931.51 | 4852 | 4857 | 4857.2 | 4857.65 | 4855 |
| N6 | 4117 | 4120 | 4119.6 | 4115 | 4120.16 | 1141 | 1144 | 1144.1 | 1144.17 | 1144 |
| N7 | 4050 | 4053 | 4052.4 | 4053 | 4052.9 | 1045 | 1048 | 1047.7 | 1047.94 | 1047 |
| N8 | 1349 | 1350 | 1349.8 | 1349 | 1350 | -265 | -263 | -263.1 | -263.5 | -263 |
| N9 | 1199 | 1200 | 1199.9 | 1200 | 1200 | 899 | 900 | 899.9 | 900 | 900 |
| N10 | 2400 | 2400 | 2400 | 2400 | 2400 | 1800 | 1800 | 1800 | 1800 | 1800 |

Source: UC Irvine

## Table 13: Partial Load Flow Results from Utility Circuit

| Bus | Active Power (kW) | | | | | Reactive Power (kVAR) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | CYME | ETAP | OpenDSS | GridLAB-D | DEW | CYME | ETAP | OpenDSS | GridLAB-D | DEW |
| 90091686_02658 (c104) | 276 | 277 | 276.7 | 276.7 | | 167 | 167 | 166.3 | 166.8 | |
| PME4896-3_02658 (sw123) | 357 | 357 | 356.9 | 356.9 | | 224 | 223 | 223.1 | 223.24 | |
| 833E_02658 (sw94) | 380 | 380 | 380 | 380.1 | | 238 | 237 | 237 | 237.2 | |
| 107988591_02658 (c95) | 403 | 402 | 402 | 402.3 | | 252 | 253 | 252.8 | 252.9 | |
| GS0713-2_02658 (sw46) | 449 | 447 | 447 | 447 | | 273 | 275 | 264.9 | 271.25 | |
| PME4896-4_02658 (C73) | 550 | 552 | 550 | 549.2 | | -1348 | -1349 | -1358 | -1363 | |
| J057-1P_02658 (SW113) | 576 | 576 | 575.5 | 575.5 | | 360 | 360 | 359.3 | 359.3 | |
| PME5100-1_02658 (C25) | 805 | 806 | 805.6 | 805.6 | | -1233 | -1226 | -1232.5 | -1225.4 | |
| RCSG777-3_02658 (sw111) | 833 | 827 | 832.1 | 832.6 | | 1098 | 1101 | 1103.9 | 1105.1 | |
| PMH5099-3_02658 (sw60) | 1106 | 1105 | 1105.4 | 1105.5 | | 693 | 693 | 692.8 | 693.18 | |
| 48201834_02658 (c92) | 1255 | 1253 | 1252.8 | 1252.8 | | -970 | -960 | -967.6 | -958.8 | |
| PMH5099-4_02658 (c20) | 1717 | 1716 | 1715.5 | 1715.7 | | -2419 | -2402 | -2415.9 | -2400 | |
| RCS5187-4_02658 (c19) | 2827 | 2826 | 2825.7 | 2826.3 | | -1730 | -1712 | -1727.1 | -1710 | |
| RCS5187-3_02658 (sw16) | 3150 | 3147 | 3146.7 | 3147.3 | | -1528 | -1509 | -1524.4 | -1507.4 | |
| 148639376_02658 (c89) | 3584 | 3584 | 3581.2 | 3583.7 | | -1301 | -1278 | -1299.2 | -1274.2 | |
| PS0372_02658 (sw7) | 4207 | 4209 | 4205.5 | 4208.7 | | -912 | -893 | -914.9 | -888 | |
| 2658 | 3723 | 3726 | 3720.9 | 3729 | | 542 | 557 | 547.8 | 585 | |

Source: UC Irvine

### 5.3.8 Discussion

While the conversion process was successful for all four software products used in this project, there are several differences among their features that merit discussion, and are summarized in Table 14:

- ETAP and DEW have a GUI to drag and drop components from a library, while both OpenDSS and GridLAB-D have a script-based environment. Thus, users of OpenDSS and GridLAB-D need to write a text file according to the language of related software to define all components, parameters as well as their connectivity. ETAP has a useful feature to display a visual circuit schematic even if the XY coordinates of nodes are not imported into ETAP, which helps in the debugging stage. OpenDSS and DEW require X-Y coordinates to create a circuit schematic. GridLAB-D does not produce a schematic at all.
- GridLAB-D, OpenDSS, and DEW can model the line or cable based on ABC (phase-to-phase) format of impedances, while ETAP can only model individual phase impedances; phase-to-phase impedances would need to be modeled explicitly. Moreover, ETAP, OpenDSS, and DEW can model the line or cable based on PNZ (positive-negative-zero) sequence format of impedances while GridLAB-D can only accommodate positive sequence impedances.
- Software varies in its capability to handle the capacitance of a modeled line or cable, which can be important in distribution level circuit studies since the capacitance of underground cables is considerable and may have a significant impact on the load flow results. ETAP, DEW, and OpenDSS have this capability while GridLAB-D does not. However, in the PSCMD transfer application the capacitances of lines are imported as individual capacitors (such as load) at the beginning and end points of the line or cable, effectively modeling the capacitance in the same way for all software packages. As the simulation results show in Tables 12 and 13, all the load flow results are closely matched.
- The voltage rating of all nodes must be assigned individually in GridLAB-D, while ETAP and OpenDSS assign them automatically after connecting the main feeding point and assigning the connectivity of the circuit.

**Table 14: Summary of Software Based on Load Flow Analysis**

| | ETAP | OpenDSS | GridLAB- | DEW |
|---|---|---|---|---|
| **GUI** | Yes | No | No | Yes |
| **Circuit** | Yes | Yes | No | Yes |
| **Line impedances in ABC format** | No | Yes | Yes | Yes |
| **Line impedances in PNZ sequence** | Yes | Yes | No | Yes |
| **Capacitance of lines/cables** | Yes | Yes | No | Yes |
| **Voltage rating of nodes is required to be** | No | No | Yes | No |

Source: UC Irvine

*Conclusion*

Emerging technologies are introducing new devices and phenomena to distribution circuits, creating a need for new software capabilities for the planning, analysis and operation of distribution systems. Consequently, users may need to transfer their circuit model data among different software tools to take advantage of the specific features in the various software tools. Due to the considerable diversity of software products on the market to simulate and study power system circuits, it has been a significant challenge to transfer model data and reconstruct circuits in different software tools with sufficient accuracy for valid results. With the UP scheme proposed in this project, all model data are presented in a spreadsheet file based on a single defined format. As a result, only two unidirectional applications are required to transfer data from the UP spreadsheet into any one software tool and vice versa, instead of a combinatorial number of conversion applications between multiple software tools. Model data transfer applications were developed in MATLAB for ETAP, OpenDSS, DEW, and GridLAB-D and tested on two circuit models to confirm that the load flow results agree and the circuit conversions are accurate.

The conversion applications developed in this project are in the public domain and will be made available to utility engineers and researchers via the Energy Commission website. Future development could expand the conversion applications to include other commonly used software tools.

## 5.4 Non-constant Time Sampling Rates in Utility Data

Utilities generally record and store measured data, such as for voltage, current, or load, based on the "dead-band" method, in which a data point is recorded if its increment exceeds a preset value. This method has the benefit of minimizing the amount of recorded data, thereby saving data storage space while not losing any significant information, but in so doing it generates unequally spaced time-series data. An example of actual measurement data for solar plant power generation is shown in Table 15, where the data are sampled and stored in an unequally-spaced time series. Such data are fine when plotted for humans to evaluate it graphically, but if

**Table 15: Output Power (MW) of Solar Plant Recorded at Unequal Time Intervals**

| Date | Time | Power (MW) |
|---|---|---|
| 8/2/2013 | 11:59:47 AM | 2.50500 |
| 8/2/2013 | 12:00:17 PM | 2.51200 |
| 8/2/2013 | 12:00:32 PM | 2.50500 |
| 8/2/2013 | 12:01:17 PM | 2.50200 |
| 8/2/2013 | 12:01:46 PM | 5.49800 |
| 8/2/2013 | 12:02:46 PM | 2.47600 |
| 8/2/2013 | 12:03:17 PM | 2.48000 |
| 8/2/2013 | 12:03:32 PM | 2.49400 |
| 8/2/2013 | 12:03:47 PM | 2.47600 |
| 8/2/2013 | 12:04:03 PM | 2.48000 |
| 8/2/2013 | 12:04:17 PM | 2.49100 |
| 8/2/2013 | 12:04:32 PM | 2.49400 |

Source: UC Irvine

The data needs to be imported into circuit simulation software, its format may not be compatible with the software input requirements, which typically can only run at a fixed time step and require input data formatted in equal time steps. For our model validation task, we imported measured utility data into the simulation software tools. (Another reason for using this process would be to synchronize different types of variables, e.g., voltage and power, related to the same circuit.)

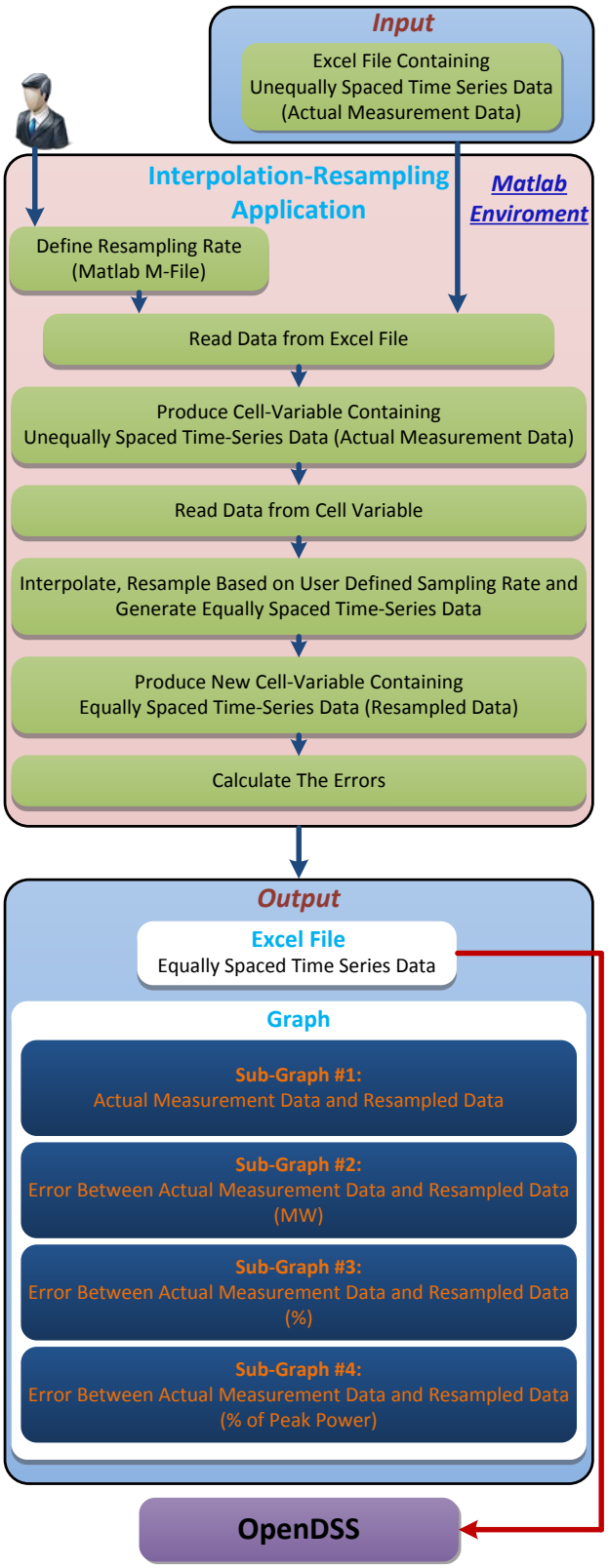
To resolve this issue, a data interpolation and resampling (DIR) application was developed and implemented in MATLAB. DIR first interpolates the measurement data and then resamples it with a fixed sampling time interval, resulting in equally spaced time-series data. The general scheme of the developed DIR application is depicted in Figure 37. A snapshot of the exported Excel file containing equally-spaced, time-series data with a sampling time interval of 30 seconds is shown in Table 16, based on the unequally-spaced input data of Table 15. The DIR application produces a graph with four sub-graphs.

Figure 38 shows the output graph of the DIR application for the solar plant with a sampling time interval of 30 seconds. The first sub-graph depicts the interpolated data. The second and third sub-graphs are the error between the actual and interpolated data in MW and percentage,

respectively. The fourth sub-graph is the error between the actual and interpolated data in percentage of peak value of solar output power for the day, about 2.5 MW (reading from the first sub-graph of Figure 38).

Although the DIR application provides detailed information about the amount of error caused by interpolation and resampling for a specific sampling time interval, such as 30 seconds in this example, it is desirable that the resampling rate be optimized for high accuracy and with minimum data storage. The proper selection of the resampling time interval aims to keep the error between the actual and interpolated data in the acceptable range and the amount of data as small as possible. A shorter sampling time interval results in lower error, larger size of data and increased simulation time, while a longer sampling time interval results in more error, smaller size of data and reduced simulation time. Therefore, a resampling error calculation (REC) application was developed in MATLAB to read the unequally spaced time-series measurement data from an Excel file, interpolate the data and resample with a sampling time interval in the range of $T_{min}$ to $T_{max}$ seconds with time increment of $T_{incr}$ seconds ($T_{min}$, $T_{max}$, and $T_{incr}$ are user-defined) and generate graphs to show error corresponding to each sampling time interval. The user can then vary the time increments and intervals, evaluate the errors produced, and then select the proper resampling time-interval, i.e., the one that produces an acceptable level of error. The general scheme of the REC application is shown in Figure 39. Output graphs for the REC are shown in Figure 40. The first graph shows the maximum error in MW as a function of sampling interval in seconds; the second graph shows the error in percent as a function of sampling interval in seconds; and the third graph shows the error in percent of the solar plant peak power as a function of sampling interval in seconds.

**Figure 37: General Scheme of the Developed Interpolation-Resampling (DIR) Application**



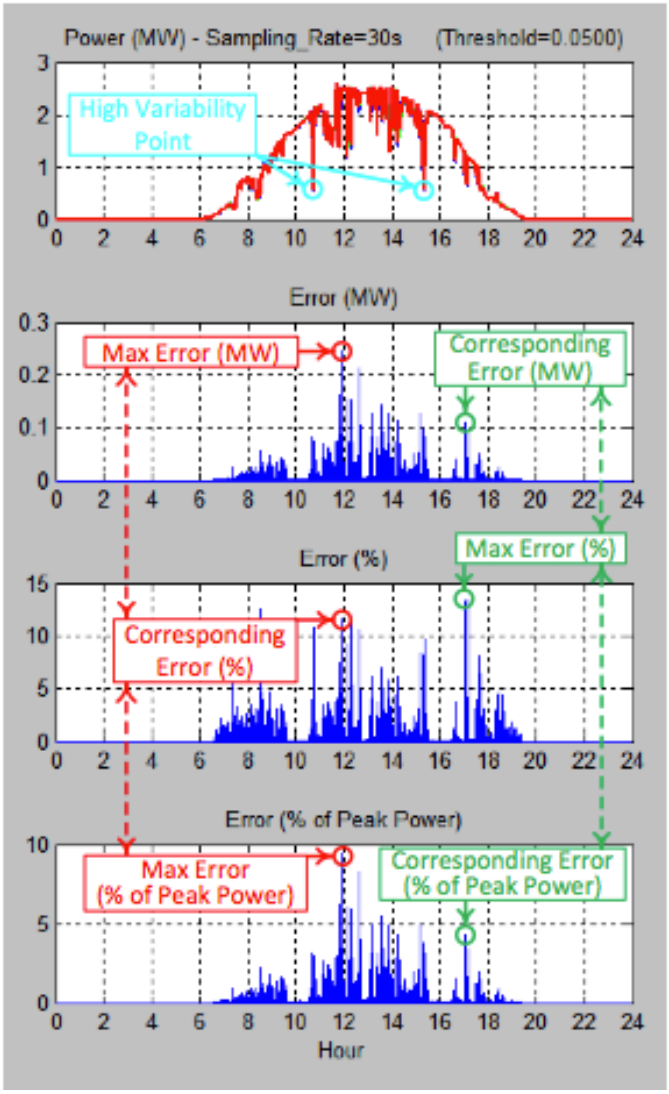

Source: UC Irvine

**Table 16: Interpolated Measurement Data of Solar Plant with Sampling Time Interval of 30 Seconds**

| Date | Time | Power (MW) |
|---|---|---|
| 8/2/2013 | 12:00:00 PM | 2.50803 |
| 8/2/2013 | 12:00:30 PM | 2.50593 |
| 8/2/2013 | 12:01:00 PM | 2.50313 |
| 8/2/2013 | 12:01:30 PM | 2.50021 |
| 8/2/2013 | 12:02:00 PM | 2.49287 |
| 8/2/2013 | 12:02:30 PM | 2.48187 |
| 8/2/2013 | 12:03:00 PM | 2.47781 |

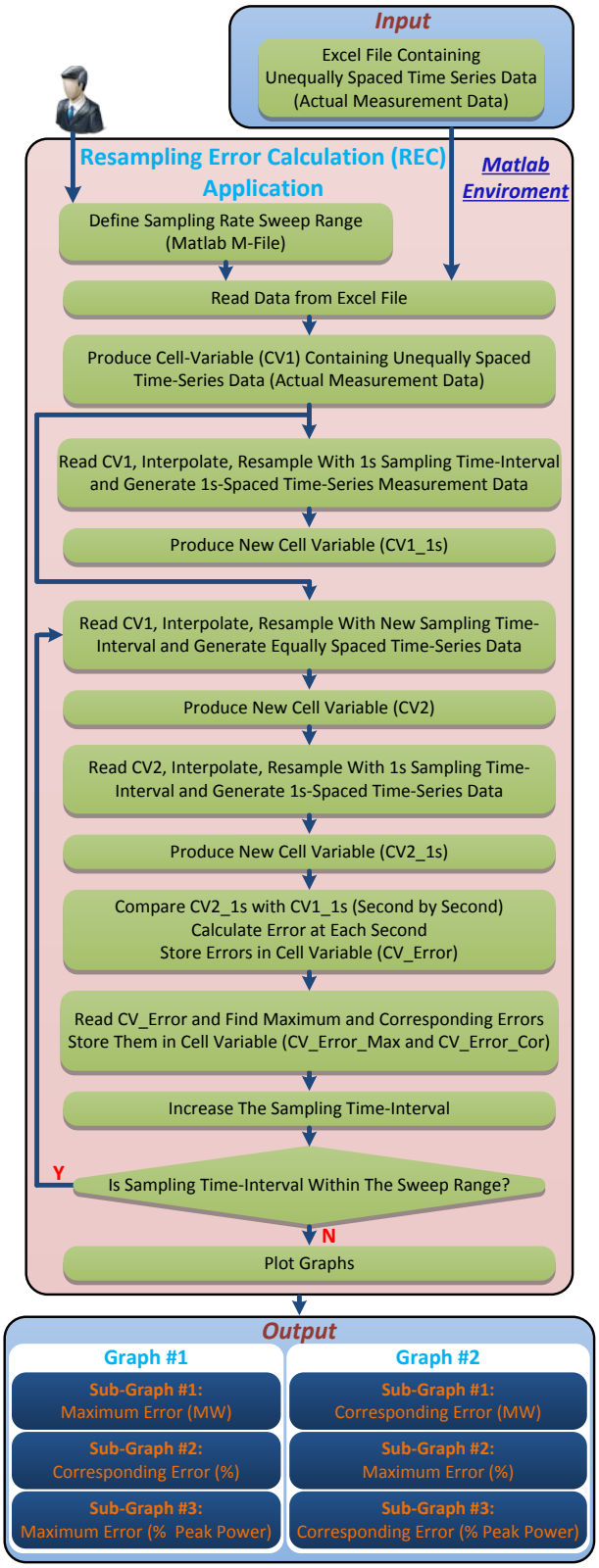
Source: UC Irvine

**Figure 38: Interpolation-resampling Error of Output Power of 3.5 MW Solar Plant, Resampled at 30-second Intervals**



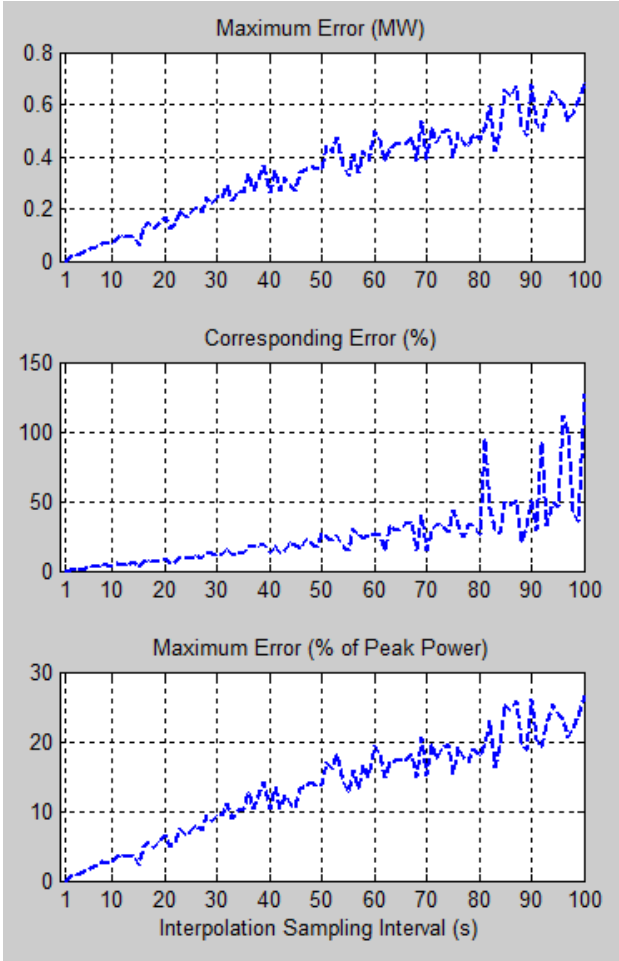

Source: UC Irvine

**Figure 39: General Scheme of the Resampling Error Calculation (REC) Application**




Source: UC Irvine

**Figure 40: Output Graphs of the Resampling Error Calculation (REC) Application**




Source: UC Irvine

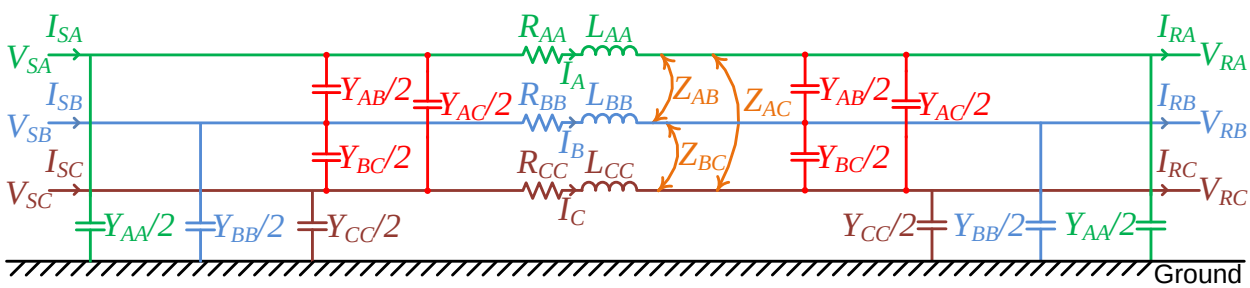
## 5.5 Preliminary Circuit Model Validation

Steady-state models of the power system (often called power flow cases) form the foundation of technical studies of the system. Because of this importance, these cases need to be periodically compared (benchmarked) to measured quantities and operational practices of the power system. Such a comparison validates that the power flow case closely resembles actual operating conditions. The comparison also identifies data errors and parameters that cause mismatch. These can then be corrected or adjusted so that cases more closely match the actual conditions. We validated three types for model validation: line or cable impedance, load, and solar generation.

### 5.5.1 Line and Cable Models

Calculating overhead line (conductor) and underground cable impedances can be complex and many factors can contribute to inaccuracy in the calculations. Every line or cable, spanning two buses or nodes, can be composed of multiple series segments, and each segment can be a different type of conductor or cable. Each segment must be modeled individually, then the total line model constructed from all the segment models. An approach is provided here which can be helpful to validate the line or cable model. Figure 41 shows the generalized model of an unbalanced distribution line or cable segment (referred to generally as a "line segment" hereafter), considering the parameters of resistance ($R_{XX}$), inductance ($L_{XX}$), and self admittance ($Y_{XX}$) for phase X, and mutual admittance ($Y_{XY}$) between phases X and Y.[16] (Admittance is the reciprocal of impedance.) Note that the self and mutual admittances are each divided in half, with one half placed at the beginning of the line or cable and the other half at the end, according to the typical "pi" model configuration used for line modeling in power system simulation tools.

**Figure 41: Model of a Distribution Line or Cable**




Source: Grainger, John, William Stevenson. "Power System Analysis." McGraw-Hill Publishing Company, 1994. ISBN-13: 978-0070612938.

[16] Grainger, John, William Stevenson. "Power System Analysis." McGraw-Hill Publishing Company, 1994. ISBN-13: 978-0070612938.

The first step of model validation for a given line/cable segment is to obtain the self and mutual admittance for that particular line/cable segment as follows:

$$\begin{bmatrix} I_{SA} \\ I_{SB} \\ I_{SC} \end{bmatrix} - \begin{bmatrix} I_{RA} \\ I_{RB} \\ I_{RC} \end{bmatrix} = \frac{1}{2}\begin{bmatrix} Y_{AA}+Y_{AB}+Y_{AC} & -Y_{AB} & -Y_{AC} \\ -Y_{AB} & Y_{BB}+Y_{AB}+Y_{BC} & -Y_{BC} \\ -Y_{AC} & -Y_{BC} & Y_{CC}+Y_{AC}+Y_{BC} \end{bmatrix} \cdot \begin{bmatrix} V_{SA} \\ V_{SB} \\ V_{SC} \end{bmatrix} + \frac{1}{2}\begin{bmatrix} Y_{AA}+Y_{AB}+Y_{AC} & -Y_{AB} & -Y_{AC} \\ -Y_{AB} & Y_{BB}+Y_{AB}+Y_{BC} & -Y_{BC} \\ -Y_{AC} & -Y_{BC} & Y_{CC}+Y_{AC}+Y_{BC} \end{bmatrix} \cdot \begin{bmatrix} V_{RA} \\ V_{RB} \\ V_{RC} \end{bmatrix} \quad (1)$$

$$\begin{bmatrix} I_{SA} \\ I_{SB} \\ I_{SC} \end{bmatrix} - \begin{bmatrix} I_{RA} \\ I_{RB} \\ I_{RC} \end{bmatrix} = \begin{bmatrix} Y_{AA}+Y_{AB}+Y_{AC} & -Y_{AB} & -Y_{AC} \\ -Y_{AB} & Y_{BB}+Y_{AB}+Y_{BC} & -Y_{BC} \\ -Y_{AC} & -Y_{BC} & Y_{CC}+Y_{AC}+Y_{BC} \end{bmatrix} \cdot \begin{bmatrix} V_{SA}+V_{RA} \\ V_{SB}+V_{RB} \\ V_{SC}+V_{RC} \end{bmatrix} \quad (2)$$

$$Y_{xx} = jB_{xx} \quad , \quad x = A, B, C \quad (3)$$

$$Y_{xy} = jB_{xy} \quad , \quad x, y = A, B, C \quad (4)$$

where: $B_{XX}$ (the self susceptance of the phase X) = $C_{xx}\omega$ , and

$B_{XY}$ (the mutual susceptance between phases X and Y) = $C_{xy}\omega$

After obtaining the matrix of self and mutual admittance, the current flowing through the series impedance of each phase can be calculated as follows:

$$\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \begin{bmatrix} I_{RA} \\ I_{RB} \\ I_{RC} \end{bmatrix} + \frac{1}{2}\begin{bmatrix} Y_{AA}+Y_{AB}+Y_{AC} & -Y_{AB} & -Y_{AC} \\ -Y_{AB} & Y_{BB}+Y_{AB}+Y_{BC} & -Y_{BC} \\ -Y_{AC} & -Y_{BC} & Y_{CC}+Y_{AC}+Y_{BC} \end{bmatrix} \cdot \begin{bmatrix} V_{RA} \\ V_{RB} \\ V_{RC} \end{bmatrix} \quad (5)$$

Afterwards, the voltage drop for the same line/cable segment is expressed as follows:

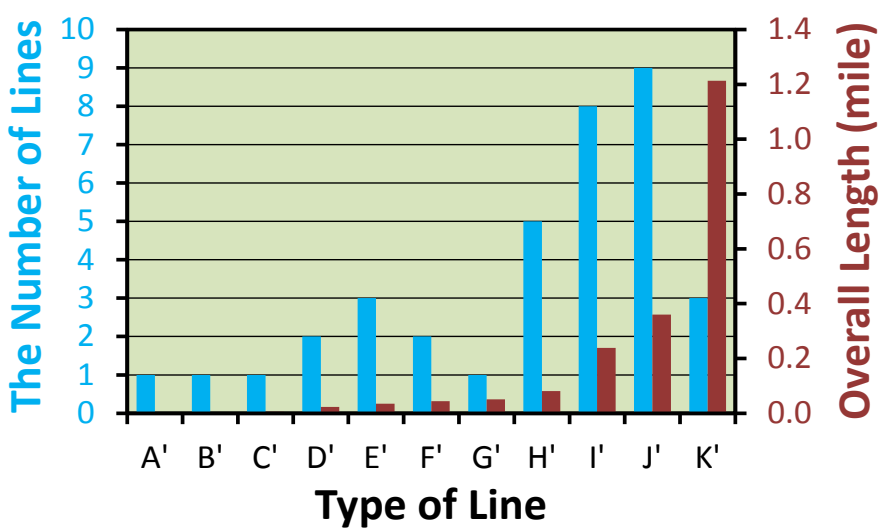
$$\begin{bmatrix} V_{SA} \\ V_{SB} \\ V_{SC} \end{bmatrix} - \begin{bmatrix} V_{RA} \\ V_{RB} \\ V_{RC} \end{bmatrix} = \begin{bmatrix} R_{AA}+jL_{AA}\omega & R_{AB}+jL_{AB}\omega & R_{AC}+jL_{AC}\omega \\ R_{AB}+jL_{AB}\omega & R_{BB}+jL_{BB}\omega & R_{BC}+jL_{BC}\omega \\ R_{AC}+jL_{AC}\omega & R_{BC}+jL_{BC}\omega & R_{CC}+jL_{CC}\omega \end{bmatrix} \cdot \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \quad (6)$$

Note that equation (2) has six variables, $Y_{AA}, Y_{BB}, Y_{CC}, Y_{AB}, Y_{AC}, Y_{BC}$, which need to be solved for. At first glance, it would seem to be impossible to obtain a solution for these six variables since equation (2) has only three algebraic expressions, after substituting for the voltage and current values that are obtained from measurements. However, each algebraic expression is a complex expression with one real and one imaginary term. Therefore, equation (2) actually has six algebraic expressions, which can be used to solve for the six aforementioned variables. On the other hand, equation (6) has twelve variables, $R_{AA}, R_{BB}, R_{CC}, R_{AB}, R_{AC}, R_{BC}$ and $L_{AA}, L_{BB}, L_{CC}, L_{AB}, L_{AC}, L_{BC}$, which need to be calculated. The same approach explained for equation

(2) can be used to solve equation (6). However, the difference between solving equation (2) and solving equation (6) is that voltage and current values at two different points in time are required to solve equation (6), while only voltage and current values at one time point are required to solve equation (2).

Although it would seem to be a labor-intensive effort to measure the voltage and current at both beginning and ending nodes of each line segment to validate the impedance parameters of the total line, it is not necessary to do all of them one by one. There are a limited number of types of lines or cables used in real circuits. For instance, the circuit considered here has approximately 36 lines and 90 cables, but there are only 11 types of lines and 11 types of cables used by this utility. Moreover, it is most likely that the same types of lines or cables are used in other distribution circuits. Therefore, the presented approach to validate the line models is practical and beneficial. Consider also the fact that some types of lines or cables are utilized in the circuit more than others, representing more of the overall length; Figure 42 illustrates the number of lines or cables of each type and their overall length in the test circuit. This information can be used to prioritize which types of lines or cables should be validated. For example, in Figure 42, 86% of the total circuit length can be validated by focusing on the cable types of G to K and line types of I' to K', a total of 9 types. Model validation for lines and cables can be carried out for a percentage of the circuit depending on the budget. The approach will be to install meters at both beginning and ending points of each selected types of lines and cables to measure their voltage and current to identify their impedances.

**Figure 42: Number and Overall Lengths of Line and Cable Types Used in Test Circuit**




Source: UC Irvine

### 5.5.2 Load Modeling

The general assumption in power system modeling is that the majority of the loads in the power system are predominantly constant power in behavior, the remainder being constant-impedance or constant-current. But this is not always the case in reality. Laboratory experiments on different appliances and pieces of equipment have been conducted and the results show that no load is entirely constant-power, constant-impedance, or constant-current. Each appliance or piece of equipment in the system has its own P-V and Q-V characteristics, which can be represented by its ZIP coefficients. The polynomial expression known as the ZIP coefficients model represents the variation (with voltage) of a load as a composition of three types of constant loads: constant impedance (Z), constant current (I), and constant power (P). The ZIP coefficients can be obtained by applying a least-square fitting on the test data obtained from laboratory experiments or the field measurement.

The P-V and Q-V curves for a particular service class depend on the load composition of customers in such class, for example, type of loads, rating of loads, duty cycle, and use factor. With all of this information, one can generate the ZIP coefficients of each load and consequently, an equivalent ZIP model for each class depending on the percentage contribution of each load to the total load of the class. Taking into account the percent load of users of each class in specific networks, a network-equivalent ZIP model can be obtained. In general, the ZIP coefficients model can be written with the following quadratic expressions:

$$P = P_0 \left[ Z_p \left( \frac{V}{V_0} \right)^2 + I_p \frac{V}{V_0} + P_p \right] \tag{7}$$

$$Q = Q_0 \left[ Z_q \left( \frac{V}{V_0} \right)^2 + I_q \frac{V}{V_0} + P_q \right] \tag{8}$$

As an example, the ZIP coefficients of different customer classes are listed in Table 17. The circuit with all loads considered as PQ loads was utilized in this example.

Another fact that can be helpful in model validation is the times-series power profile of the loads. In this study, power profiles of individual loads are not available to be attached to each load in time-series simulation studies. The only available measurements are start-of-circuit power measurement as well as the output power measurement of 1.5 MW and 3.5 MW solar plants. By adding the solar plants' output power to the start-of-circuit power measurements, the loads' native time-series power profile can be obtained, which is used as scaling factor for all loads. Therefore, all loads are assumed to operate with the same time-series power profile.

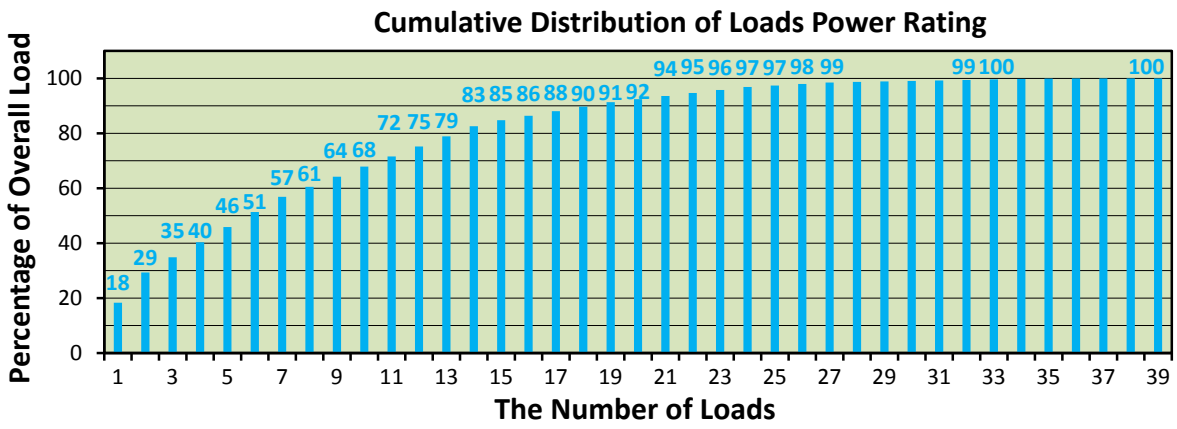
**Table 17: Active and Reactive ZIP Coefficients by Customer Class**

| Customer Class | | $Z_p$ | $I_p$ | $P_p$ | $Z_q$ | $I_q$ | $P_q$ |
|---|---|---|---|---|---|---|---|
| Residential | Stratum A | 1.5 | -2.31 | 1.81 | 7.41 | -11.97 | 5.55 |
| | Stratum B | 1.57 | -2.48 | 1.91 | 9.28 | -15.29 | 7.01 |
| | Stratum C | 1.56 | -2.49 | 1.93 | 10.1 | -16.75 | 7.65 |
| | Stratum D | 1.31 | -1.94 | 1.63 | 9.2 | -15.27 | 7.07 |
| | Stratum E | 0.96 | -1.17 | 1.21 | 6.28 | -10.16 | 4.88 |
| | Stratum F | 1.18 | -1.64 | 1.47 | 8.29 | -13.67 | 6.38 |
| Small Commercial | Duane Reade | 0.27 | -0.66 | 1.06 | 5.48 | -9.7 | 5.22 |
| | 5Guys Burger | 0.69 | 0.04 | 0.27 | 1.82 | -2.24 | 1.43 |
| | Laundromat | 0.77 | -0.84 | 1.07 | 8.09 | -13.65 | 6.56 |
| | Optics | 0.55 | 0.24 | 0.21 | 0.55 | -0.09 | 0.54 |
| Large Commercial | School | 0.4 | -0.41 | 1.01 | 4.43 | -7.98 | 4.56 |
| | Hotel | 0.76 | -0.52 | 0.76 | 6.92 | -11.75 | 5.83 |
| Industrial | | 1.21 | -1.61 | 1.41 | 4.35 | -7.08 | 3.72 |

Source: UC Irvine

However, this is not true in practice since the loads may have different time-series power profiles and dynamics. To have more precise modeling of the circuit, it is necessary to consider the loads with their individual times-series power profiles in the studies. This requires measuring the time-series power profile of the loads individually, which is not a simple task. However, all of the loads generally do not have the same power rating and consequently, they do not have the same effect on the circuit voltage profile. Therefore, as with the lines and cables, the way to validate the loads was to first sort the loads regarding their power rating, and then prioritize the loads whose time-series power profiles should be measured. Figure 43 illustrates the cumulative distribution of loads power rating in the studied circuit where 13 out of 39 loads constitute 79% of overall load regarding the power rating. This means that measuring the time-series power profile of only 13 loads (one third of all loads) provides almost 80% of the circuit's load behavior. Therefore, the cumulative distribution of loads power rating is an indicator that can be used in selecting the loads whose time-series power profile should be measured.

**Figure 43: Cumulative Distribution of Loads Power Rating in the Test Circuit**




Source: UC Irvine

In light of the above discussion, model validation for loads can be carried out for a percentage of the circuit's loads depending on the budget or time available. The approach would be to have one meter for each selected load to measure voltage and current to identify the associated time-series power profile as well as the ZIP coefficients of the load model.

### 5.5.3 Solar Generation Modeling

Intermittency or discontinuity of output power is one of the inherent traits of solar energy that imposes a barrier to distributed energy resources (DER) penetration in a utility system. Solar energy generation is based on solar irradiance, which is the amount of incident electromagnetic power received per unit area of a given surface, usually in units of watts per square meter ($W/m^2$). Insolation is the total amount of solar irradiance received on a given surface area during a given time, expressed in units of watt-hours per square meter ($Wh/m^2$). Generally, PV panels are rated in peak watts, which is the power generated at a reference insolation level of 1,000 $W/m^2$. A 1 kW panel will produce that much power if it is oriented perpendicular to the sun's rays at peak insolation periods. Insolation levels need to be gathered at the location where the PV will be installed to best approximate insolation profiles. They can be obtained from a variety of resources such as TMY2 (Typical Meteorological Year), NREL PVWatts, and NSRDB (National Solar Radiation Database). Insolation levels at the panels vary based on their angle of orientation and tracking method (if used). A review of the specifications, spacing, and orientation of the PV arrays is needed to most accurately model the nature of its power output characteristics and intermittencies. To obtain the most accurate model of distributed solar energy penetration, the time-series output power of each solar inverter must be measured. Note that the circuit used in this study has two solar plants (1.5 MW and 3.5 MW) whose time-series output power profiles are available individually.

# CHAPTER 6:
# Advanced Distribution Monitoring Design Plan

## 6.1 Status of Distribution Monitoring among California's Utilities

### 6.1.1 Routine Monitoring Practices in Utilities

California has made policy decisions in support of renewable energy and reduced greenhouse gases. These policy and market forces are creating dramatic increases in the penetration levels of renewable energy, especially photovoltaic sources, at the distribution level. The distribution system, however, was not historically intended to include generation, and particularly not variable, non-dispatchable generation. Without generation occurring at the distribution level, extensive monitoring of the distribution system was historically unnecessary. However, the situation has changed, and present-day monitoring is perceived to be insufficient now, and will be increasingly so in the future. This project was aimed at systematically evaluating current levels of distribution monitoring and determining what will be needed to successfully integrate increasing penetration levels of distributed energy resources (DER). Increased DER impacts distribution systems more than transmission systems because distribution feeders differ from each other in many respects and distribution circuits are more vulnerable to both local and wide area phenomena.

A better understanding of how distribution circuits perform in the presence of high penetration levels of distributed renewables will improve the ability of utilities to manage the distribution system efficiently. Ratepayers will benefit as well, as the improved understanding will minimize costs and increase reliability.

Distribution networks are traditionally centrally controlled. Supervisory Control and Data Acquisition (SCADA) systems transfer measurements, alarms, and control signals between control centers and SCADA-enabled components via Remote Terminal Units (RTUs). RTUs allow for the sending and receiving of signals for protection actions, topology reconfiguration, and Volt/VAR control. With the advent of distribution automation, Intelligent Electronic Devices (IEDs) such as relays and reclosers come into play. The IEDs perform distributed decision-making, which, in some cases, results in local protection schemes. However, the number of IEDs and SCADA-enabled devices beyond the substation is still low.[17]

AMI is another source of measurements in distribution networks. Traditionally, utilities use meter data for billing and read their electromechanical watt-hour meters manually, typically once per month. The new electronic meters, or "Smart Meters," feature two-way communication links that allow utilities to send signals to the meters, read customer meters seamlessly, and even measure voltage and current. These meters also record different events from distribution network endpoints. Events originate from outages, service availability

17 Della Giustina, Davide, Sami Repo, Stefano Zanini, Luigi Cremaschini. 2011. *ICT Architecture for an Integrated Distribution Network Monitoring*. Institute of Electrical and Electronics Engineers. 2011 IEEE International Workshop on Applied Measurements for Power Systems (AMPS). AMPS.2011.6090435.

changes, voltage drops, and flickers. The meters' measurement intervals are usually 15, 30, or 60 minutes, but the meters can measure at shorter time intervals, such as one second. Smart meters have the ability to enrich distribution network monitoring systems by providing higher resolution data from all customers.[18] Measurement data from AMI can be used for network operation, but many utilities need communications and data management systems to manage and analyze the large volumes of AMI data generated with real-time and batch processes.

Power quality recorders are the final category of measurement devices used in distribution networks. With increased DER and power electronics devices, the AC waveform experiences more disturbances and harmonics. Power quality recorders measure voltage deviations, frequency deviations, voltage fluctuations and flicker, harmonics, imbalances, instantaneous over-voltages, and momentary over-voltages. These recorders can measure voltage, current, and active and reactive power up to the 50$^{th}$ harmonic with 256 to 512 samples per cycle.

Combinations of SCADA and EMS (Energy Management System) have been used for more than two decades for supervising, controlling, optimizing and managing transmission networks. The combination of SCADA and DMS (Distribution Management System) has served a similar role in distribution networks.

SCADA enables utilities to collect, store, and analyze data from hundreds of thousands of data points in wide-area networks. It allows utilities to create detailed models of their networks, simulate operational actions, locate faults, recover from outages, and participate in electricity markets. It is one of the most important technologies available for power networks and a key building block for smart grid development. Given the new reality of integrated DER, utilities need to be able to handle distribution level two-way power flow and maintain grid stability and power quality (proper voltage and frequency). However, present SCADA systems have a number of drawbacks in distribution networks. The following is a review of the current challenges in SCADA from three different points of view. The AMP can play a vital role in the modern grid, helping to pick up where conventional monitoring systems such as SCADA leave off.

### 6.1.2 Special Monitoring Practices in Utilities for Research and Demonstration

SCE is collaborating with researchers at UCI, the University of Southern California (USC), EPRI, and with industrial partners to deploy a range of "Smart Grid" technologies on two distribution circuits in Irvine, California. The intent is to predict how automated systems affect grid performance. Project results are expected in late 2015. Technologies deployed on these circuits include electric vehicle (EV) charging for buildings, looped circuit topology, residential energy storage, community energy storage, Volt/VAR control, dispatched renewable distributed generation, smart meters, cyber-security upgrades, and in-house monitoring of plug loads. Goals of the project include deep grid situational awareness, enhanced efficiency and power

[18] National Energy Technology Laboratory (NETL). 2008. *Advanced Metering Infrastructure.* [http://www.netl.doe.gov/File%20Library/research/energy%20efficiency/smart%20grid/whitepapers/AMI-White-paper-final-021108--2--APPROVED_2008_02_12.pdf]

quality, circuit constraint management, and self-healing circuits. Other project initiatives are attainment of zero-net-energy (ZNE) for new homes (including gas usage), improved customer education, and power systems control. SCE has also installed PV systems with capacities up to 10 MW on 24 different 12 kV distribution circuits. Four additional sites (two 12 MW and two 18 MW) are currently in construction. In addition to PV, supplemental instruments and inverter modifications are being employed and tested.

SDG&E installed a wireless communication system that includes 90% of its customers and facilitates the use of AMI and distribution automation equipment. The goal was to provide better system visibility, enhance reliability, reduce outage durations, and reduce costs.

PG&E is conducting a Pilot Deployment Project that addresses four areas of interest: line sensors, Volt/VAR control, fault and outage detection and location, and short term forecasting, with two other areas of interest waiting for approval. Each area will test and employ novel technologies and concepts, address gaps and concerns for fully implementing the programs, create methodologies for testing cost-effectiveness, develop a strategy for identifying the best practices for expansion, and develop standards for measuring the outcomes of the pilot project.

SMUD partnered with Premium Power for their ARRA-funded project, the Distributed Energy Storage System. The project installed two 500-kW, 6-hour zinc-bromine (ZnBr) battery systems in Sacramento. One battery system serves the SMUD campus microgrid, and the other serves the substation for the Anatolia III SolarSmart Homes project. One of the project's goals was to demonstrate multiple approaches to battery integration with intermittent renewable energy systems with aggregated homes, in both a microgrid and a substation. Another goal was to develop and verify creative control algorithms to manage fleet operation of energy storage systems that are not co-located with loads.

SMUD is collecting feeder monitoring data for the Anatolia site, uploading it to Sharepoint, and developing a "data collection and analysis plan" to document what data points are collected for each energy storage device. Weather data (temperature, pressure, wind speed and direction, humidity and solar irradiance) are updated hourly using a rotating shadowband radiometer.[19]

The Smart Sacramento Project is an ARRA Smart Grid Investment Grant (SGIG) program in which SMUD is deploying AMI and Distribution Automation equipment on 102 distribution circuits (out of their total of 635 circuits). Goals of the project include optimization of grid assets, increased control and transparency for customers. SMUD is also installing up to 220 plug-in electric vehicle (PEV) charging stations on college campuses and residences, and conducting testing on performance criteria, charging patterns, and effects on distribution systems.

19 http://www.nrel.gov/midc/smud_anatolia/display/

## 6.2 Gaps in Present Monitoring

### 6.2.1 Challenges for Sensors and Instrumentation

The growth of distributed energy resources, electric vehicles, and controllable loads has introduced more short-term, unpredictable fluctuations in distribution networks. This suggests a need for more refined measurements and higher data granularity, leading to a greater demand for methods of processing large amounts of data ("Big Data").[20]

Chapter 2 of this report, titled Preliminary Data Inventory, provided a list of utilities' current measurement projects on advanced monitoring systems. Unfortunately, the available information on those utility measurement projects did not specify what type of data streams were being collected, the resolution of the measurements, or the accuracy of the measurements. One of the biggest gaps in these projects is a lack of coordination with other utility measurement projects, especially between utilities. Many of the projects have objectives and areas of development that are very similar, if not identical. This redundancy could be abated by more project transparency, less delay between project proposals and start dates, and the creation of a coordination group responsible for coalescing and disseminating information to various projects. These changes would help each project accomplish more and get over hurdles faster. The changes would also decrease redundant funding for similar projects. Finally, the changes would allow all utilities to progress faster and move on to other pressing issues in adapting to high renewables penetration in distribution circuits.

Other challenges in distribution monitoring systems at the enterprise level are as follows:

- Lack of updated and accurate distribution network models.
- Lack of a quick and easy measurement data-sharing procedure between various departments at a utility, e.g., revenue, operations and planning.
- Lack of a unified data format for transferring data between different software packages and applications.
- Concerns about data security.
- Concerns about analytical capabilities for handling "Big Data."

At the feeder level, monitoring system challenges are mostly related to the number of measurement devices present, their placement, and their data granularity:

20 von Meier, Alexandra, Reza Arghandeh (California Institute for Energy and Environment). 2014. "Chapter 34 – Every Moment Counts: Synchrophasors for Distribution Networks with Variable Resources." *Renewable Energy Integration,* L.E. Jones (ed.), Academic Press, Boston, MA.

- SCADA systems are usually installed only at substations. Consequently, there is typically a lack of observability downstream from the substation.
- DG, inverters, and controllable loads add more dynamic behavior to the grid and need more monitoring downstream from the substation.
- SCADA protocols were not designed for very-high-resolution data; they typically assume a 4-second sampling interval.
- Conventional SCADA systems lack time synchronization.

Finally, distribution networks have a wider range of variations in structure compared to transmission networks. Therefore, distribution monitoring systems must be able to handle more complexity. The reactance/resistance ratio (X/R) of a typical distribution line is less than the X/R of a typical transmission line. Distribution system measurements also contain more noise, making signal extraction more difficult [Von Meier, Culler et al., 2014].[21] Furthermore, there are many more points where loads connect; each such point effectively constitutes a bus or network node. Yet the number of available empirical data points per network node is much smaller in distribution systems than in transmission systems. Three-phase transmission systems exhibit balanced characteristics and can be effectively represented by a simpler, single-phase model. In contrast, in distribution systems, high penetration levels of DG sources, dual load-generator and dynamic behaviors, and variation in load types lead to unbalanced conditions that require an explicit measurement of all three phases [von Meier & Arghandeh ("Diagnostic Applications"), 2014].[22] Moreover, switching and reconfiguration actions are typically more frequent in distribution networks, so the actual topology status of the system is frequently less clear.

### 6.2.2 Challenges for Data Handling, Processing and Visualization

Chapter 4 addressed the issues encountered with missing, bad, or incorrect data. To summarize, these issues are:

- missing data
- zero values
- incorrect values
- outliers

---

21 von Meier, Alexandra, David Culler, Alex McEachern, Reza Arghandeh. 2014. *Micro-synchrophasors for Distribution Systems.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2014 IEEE PES Innovative Smart Grid Technologies Conference. ISGT.2014.6816509.

22 von Meier, Alexandra, Reza Arghandeh (California Institute for Energy and Environment). 2014. *Diagnostic Applications for Micro-synchrophasor Measurements.* Advanced Research Projects Agency for Energy (ARPA-E).

These data issues are an unfortunate fact of life with distribution system monitoring. The process of data cleaning described in Chapter 4 is a necessary prerequisite to data processing, analysis and visualization.

## 6.3 Lessons Learned and Utility Viewpoints

### 6.3.1 Conclusions from Data Collected

In general, existing distribution measurement and monitoring systems were designed and built for conventional distribution grid architectures and operational regimes intended for serving traditional electricity customers. However, the growth of distributed energy resources, electric vehicles and power electronics in loads has introduced more variability and uncertainty into distribution system management, while also providing opportunities to recruit diverse resources for grid services. The modern grid needs advanced monitoring systems to serve the needs of the utility and its customers for both today and tomorrow.

The following are recommended action items for filling the gaps between conventional and future monitoring systems:

- Enhance databases to store and manage the necessary volume of measurements ("Big Data").
- Add more intelligence to measurement data handling systems for "bad data" detection, data classification, data analytics, and data-driven operations.
- Integrate AMI data into operation and planning applications.
- Use higher-resolution measurement data to monitor distribution network dynamic behaviors.
- Enhance system observability with new and/or advanced types of sensors (e.g., line sensors, fault detectors, harmonics measurement devices, synchrophasors).
- Improve and update system models and use data for model validation.

### 6.3.2 Conclusions from Formal Survey

#### *6.3.2.1 Purpose and Goals of the Survey*

A major task of this project is to collect and analyze distribution system data made available from existing individual monitoring efforts by utilities in California, to attain a comprehensive understanding of current practices and perceived needs for distribution system monitoring. The ultimate goal is to develop and describe an "intentional" Advanced Monitoring Plan for High Penetration of Renewables that would close any gaps in the ongoing monitoring efforts being done individually by utilities. This plan was provided to the Energy Commission as the basis for further proposed research efforts to advance the state of the art in distribution monitoring. Since the needs and perspectives of California utilities and other electric industry stakeholders are vital ingredients for such a plan, the research team developed a survey document and distributed it to a number of utility colleagues, stakeholders, and experts to solicit a wide range of information, perspectives and input on key aspects of current distribution system monitoring

practices; gaps, challenges and issues with distribution monitoring; and opinions on how distribution system monitoring could or should be done to address future needs, especially in light of the trends in renewable energy integration, growth in electric vehicle usage, and other key drivers of change in distribution systems.

Specific goals of the survey were to:

- Provide a foundation of understanding of the current practices and perspectives of the utility industry in California, regarding distribution system monitoring.
- Understand the critical issues and challenges to distribution monitoring faced by utilities today.
- Develop a general picture of what the future distribution system looks like in the eyes of utilities, and what the new challenges and issues in distribution monitoring will be for effective operation and control of the future grid.
- Identify the technologies, methodologies, applications, etc., that will be needed (or are desired) to meet the monitoring needs of the future distribution grid.
- Use this information as input in developing a "strawman" Advanced Monitoring Plan as a basis for research activities that will advance the state of the art of distribution monitoring in the California electric system.

What follows is a summary of the information received from the survey. The full details of the responses from the survey were provided in the Task 6 Interim Project Report, "Advanced Monitoring Plan," for this project.

*Takeaways from the Survey*

An analysis of the responses to the survey led the research team to the following preliminary conclusions:

- Better distribution system monitoring is needed now, and even better monitoring will be needed in the future.
- Visibility & situational awareness for operators is key: they need to know the status of DGs, key loads, and system devices.
- Advanced applications to aid operators will be needed.
- There is a lot of uncertainty about the requisite data resolution and accuracy specifications, as these are strongly applications-driven.
- Communications will be a big (and probably costly) challenge.
- There is a considerable variety of visions about the future distribution system control structure.
- Budget and manpower are seen as big challenges, in general.

- There is no common vision of an "ideal" distribution monitoring system, although there are lots of interesting aspects that people foresee or want.

The detailed technical responses from the survey were used as input to the development of the AMP. The initial draft of this AMP, termed the "Strawman," was used as a point of departure for the interactive discussions in the Distribution Monitoring Workshop described in the next section.

### 6.3.3 Conclusions from the Distribution Monitoring Workshop on Sept. 5, 2014

#### *6.3.3.1 Purpose and Goals of the Workshop*

On September 5, 2014, an all-day workshop was held, hosted by the California Institute for Energy and Environment (CIEE), on the University of California, Berkeley campus. The purpose of the workshop was to utilize the expertise and informed opinions of knowledgeable people from the electric industry to further articulate and refine the AMP. The AMP should address gaps in the ongoing distribution monitoring efforts being done individually by utilities, and to identify and explore the issues and challenges in distribution monitoring that will be presented by high-penetration renewables and other distributed energy resources in the near future. Those invited to attend hailed from California utilities, consulting firms, and research organizations; approximately 30 people participated who have with extensive background and expertise in distribution systems and monitoring practices.

*Workshop Agenda*

The workshop agenda was as follows:

1. Introduction and Background of the Distribution Monitoring for Renewable Integration (DMRI) project
2. Distribution Monitoring and Renewable Integration: Technical Concerns that Motivate Monitoring Efforts
3. Characterization of Distribution SCADA Data: Some Lessons Learned from Existing Measurement Data
4. Results of DMRI Survey: What Colleagues Say about Distribution Monitoring Needs
5. "Straw Man" Advanced Monitoring Plan: A Wish List for Filling Gaps and Answering the Questions at Hand
6. Facilitated Discussion: Questions, Observations, and Suggestions for the Straw Man Plan
7. Beyond the DMRI Project: Fulfilling the Plan
8. Conclusions and Next Steps

The first five agenda items were presentations by the CIEE research team to set the stage for the attendees. The team discussed the overall project objectives, described the current status and progress of the project, described the proposed AMP, described the draft 'Straw Man' AMP and

how we intended to refine it during the afternoon workshop session, and how the AMP will be used to guide future research efforts in distribution monitoring. These presentations are provided in Appendix A. After the first five presentations with their associated discussions, a facilitated discussion of the Strawman AMP was conducted.

*Brainstorming and Discussion*

The discussion of the Strawman AMP was quite energetic and wide-ranging. The participants were genuinely supportive of the AMP approach and provided a wealth of suggestions for what features should go into the AMP, as well as additional helpful comments. The notes taken by the CIEE team were grouped into two categories, as follows:

1. Suggested AMP Features:

    - AMP should support the DER siting and locational pricing analysis that utilities will be preparing for the CPUC under Assembly Bill 327 (AB 327), which addresses net energy metering tariffs for rooftop solar customers by extending current net metering rules for new customers through July 1, 2017, and requires the CPUC to develop a new net metering tariff by the end of 2015.
    - AMP should provide intelligence about generation and GHG impacts.
    - 30 million AMI data points should be incorporated in some manner; legal issues are perhaps not such a large impediment.
    - Data should generally be collected at locations near customers. Ideally, monitoring would reveal granularity of loads on an individual transformer.
    - AMP should bring together data from different systems.
    - There should be a substantial (multi-million dollar) management system behind monitoring data collection.
    - AMP should associate data with good circuit models.
    - It will be advantageous to work with common, anonymized models (cf. International Smart Grid Action Network, ISGAN).
    - Monitoring should include "good actors" and "bad actors" among DER and characterize their behavior.
    - AMP needs to address the challenges of knowing the topology, and the diverse and potentially changing ownership of DER.
    - Placement of sensors could be 5-10 per circuit, or at least at feeder head, midpoint, and end of line, with additional points determined by switch positions.
    - AMP will need three-phase voltage, current, and real and reactive power measurements (note that capacitor banks often measure only single phase).
    - Will need to perform phase identification.

- Solar irradiance data would be helpful to complement electrical measurements (although it can be cumbersome to install).
- High granularity will be needed for measuring the effectiveness of demand response.
- As a rule, sampling rate should be 10x the frequency of phenomena one intends to observe.
- Power quality (i.e., sub-cycle) measurements will be needed near large DER, but power quality measurements can introduce an issue with memory space for long events (e.g. fault-induced delayed voltage recovery [FIDVR]).
- Report by exception (e.g., if measured values exceed a certain range, or if there is a status change) is a possible approach for reducing data volumes to be communicated, stored and analyzed; note that the threshold for reporting must be remotely configurable.

2. Additional comments:

- Outage management may be a driver for increased, ongoing monitoring.
- Note that AMI data won't be available around outages.
- Note that distribution circuits may not stay radial. Networked/looped topology in transmission was a driver for increased monitoring.
- Among DER, one will want to distinguish controllable actors and "bad actors" that can be "rehabilitated" with better monitoring.
- Offline analysis and operations will have different priorities for monitoring.
- Effects of harmonics from 5 kHz to 15 kHz inverter switching are still unknown.
- Reactance to resistance (X/R) ratios of feeders are important for fault duty calculations, but perhaps less so for power quality.
- A major practical concern is whether potential transformers (PTs) need to be installed along with sensors; this would entail significant labor cost.

## 6.4 Goals for Future Monitoring

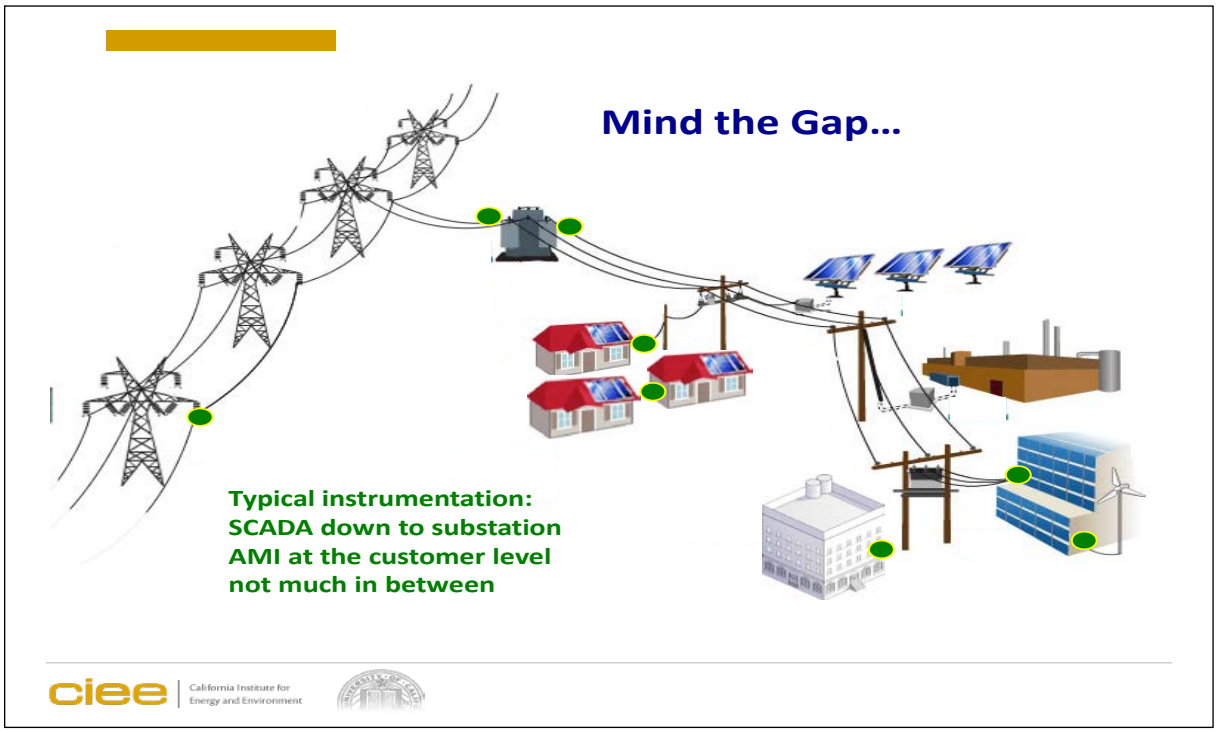
### 6.4.1 Overview

As has been described in earlier chapters, it was not possible to obtain statistically significant high-resolution data for distribution feeder characterization and modeling efforts in this project. Consequently, the proactive strategy for the distribution AMP proposed in this report was based on somewhat limited, but still highly useful, data from several distribution feeder circuits, other sources of anecdotal information, Distribution Monitoring Survey and Workshop feedback from utilities and industry experts, qualitative reasoning, and conjecture. This section outlines the overall approach, general considerations, objectives (technical and non-technical), and a wish list for AMP features and specifications that are recommended as a starting point for

developing a full-featured AMP. With the up and coming implementation of AB 327 that mandates the determination of optimal DER locations and total hosting capacities, a thoroughly conceived and executed AMP is critical to these DER location requirements and analyses. In addition, longer-term considerations and issues in developing an AMP beyond this project are also addressed.

Figure 44 captures the fundamental need to be able to measure not only new, additional feeder points and distribution grid impacts (e.g., PV, EV, other DG, ESS, etc.), but also to specify the type, resolution, and sampling frequency of the data. Data requirements range from simple end-of-line voltages to "smart" inverter impacts (some with solid-state switching frequencies of >15 kHz) on Volt/VAR support, to high-harmonic injections affecting local customer power quality. An argument could be made that locating high-resolution distribution sensors associated with locational marginal pricing (LMP) will be critical in future years as more granular pricing takes place to account for regional differences in both energy generation and distribution. These higher resolution functions cannot be captured by the traditional SCADA systems shown in the diagram and must be captured by an assortment of other sensors. It is also important to recognize that depending upon the SCADA topology and communications framework, data latencies of 30 seconds to 2 minutes are possible, so any long-term use of SCADA for state estimation or distribution operations may be limited. Today some utilities are reconfiguring certain distribution feeders twice daily. Additionally, current rules of thumb such as the 15% threshold for DG penetration are too simplistic, since some feeders are seeing localized reverse power flows even at lower DG penetrations.

**Figure 44: Instrumentation on a Typical Distribution Feeder**




Source: CIEE (UC Berkeley)

### 6.4.2 General Considerations

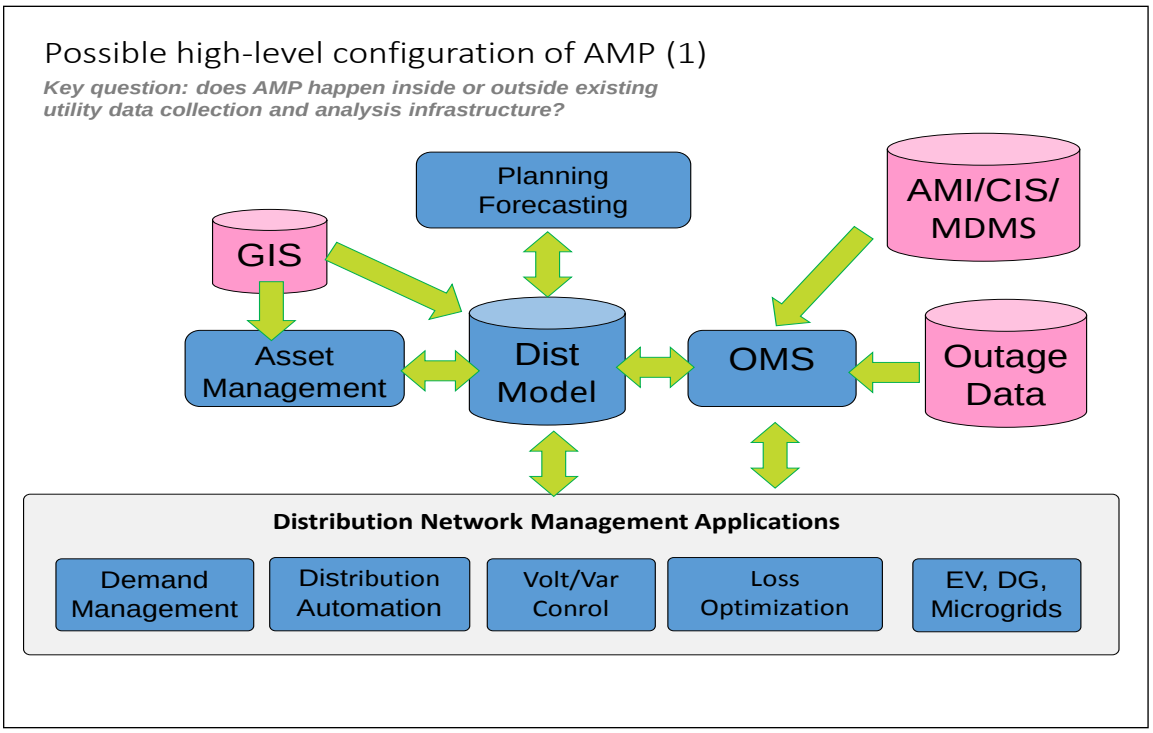
Each utility has its own unique ecosystem including organizational sensitivities and priorities; available budgets, resources, and people; technology maturity; legacy issues; etc. There may very well be dozens of prospective AMPs that could be designed to meet particular needs at different times.

For instance, is an advanced monitoring project simply a "one-off" research effort to be decommissioned and removed at its conclusion, or is it meant to be part of a larger, more fully integrated "Big Picture" effort to assist a utility in understanding, monitoring, and even optimizing operational and economic decisions at the distribution level to better handle a wide range of high penetration DER scenarios on a variety of distribution feeder types? In addition to DER considerations, many long-term distribution trends (e.g., low inertia, bi-directional power flow, solid-state devices, networks replacing radial feeders, "active" systems, a myriad of sensors, etc.) should also be considered in developing an AMP. Many long-standing radial feeders are being transformed into more robust configurations that will need both monitoring and model creation and validation. Another important consideration is funding: for instance, does the advanced monitoring project simply need to fit within a short-term limited R&D budget, or is it also justified by a more comprehensive, "bottoms-up" financially driven analysis based on projected losses, risks, avoided costs, liability, savings, energy theft, etc.? Energy theft is still prevalent in many areas and can still be a major driver for distribution monitoring and analysis.

Figure 45 outlines a more traditional diagram for how an advanced monitoring project might be integrated into a utility's other infrastructure and systems. A key assumption of this framework is that all monitoring, characterization, modeling, and applications are accomplished entirely within the utility with no room for collaboration or sharing of data or models.

Although the authors recognize the very real short-term constraints often put on utility R&D budgets, this report encourages decision-makers to also seriously consider the potential impacts and contributions that a more fully integrated advanced monitoring project can provide in the longer-term evolution of a utility's planning, operations, and overall business model. This bigger-picture perspective includes the larger context of distribution monitoring and operations that are being impacted by other evolving areas, including: customer-premise equipment and new, variable loads (HAN, ESS, EVs, DG, etc.); the "Internet of Things" and many other "edge" devices; migration from centralized to more local control and generation; the ever-decreasing costs of electronics (especially in data processing and storage) and the implications for data mining; algorithm development; and management by utilities.

**Figure 45: Possible AMP Architecture**



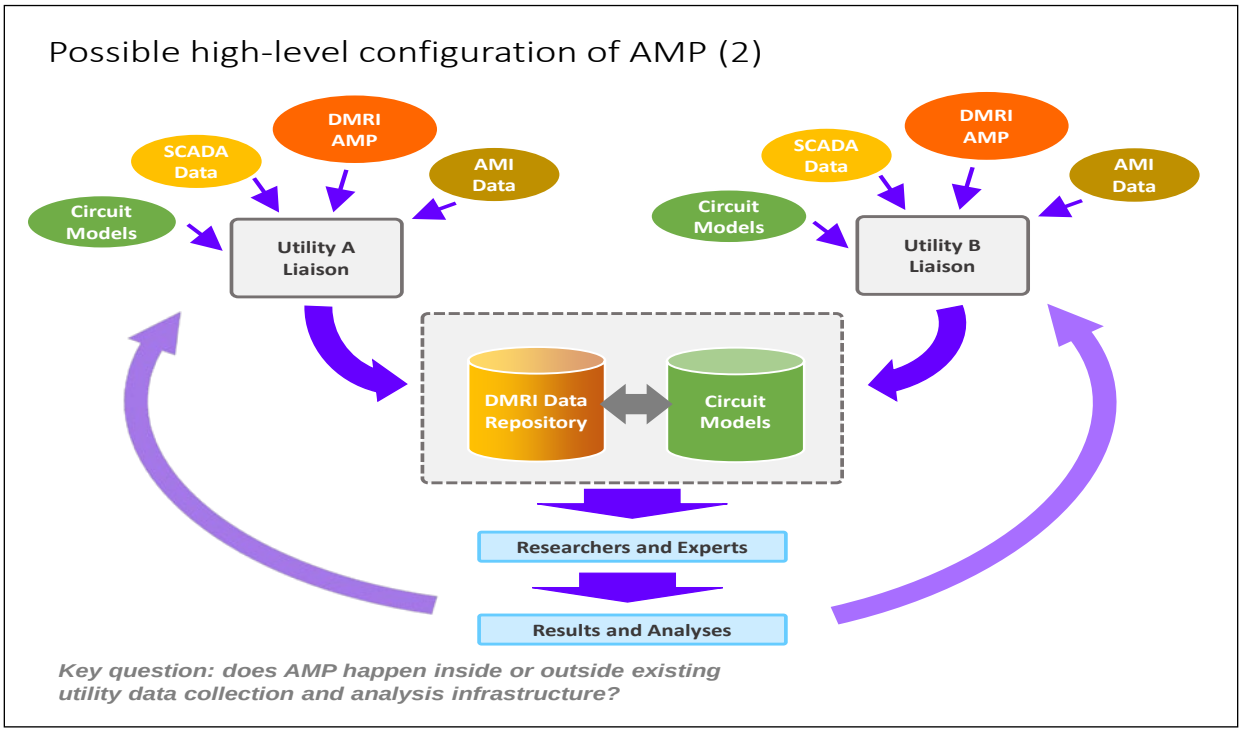

Source: CIEE (UC-Berkeley)

A key challenge for utilities to consider is that an advanced monitoring project does not have to be a cost center; it can be part of a bottoms-up technology approach and financial analysis that potentially pays for itself over the longer term. For example, EPRI and other groups have estimated that U.S. utilities implementing Conservation Voltage Reduction (CVR) can save 2-5% of total costs (~$10 – 20 billion/year) or approximately $50 – 100K per distribution feeder. In California, this translates to over 6,000 distribution feeders in PG&E territory, over 4,500 in SCE, and over 900 in SMUD. This anecdote is likely greatly enhanced and multiplied by other economic drivers such as enhanced dynamic capacity (thermal and stability), avoided cost, grid support, distribution optimization, and condition-based maintenance (CBM) for asset lifetime enhancement. Nevertheless, it is believed that, when full consideration is given to the many other facets of distribution feeder automation, monitoring, operations, and economics, a more fully integrated advanced monitoring project spanning much of a utility's distribution circuits may move it from being considered a cost center to being able to pay its own way. The remainder of this section discusses the likely near-term requirements, objectives, and outline for an AMP.

A more collaborative model for an AMP is shown in Figure 46. Here, each utility still maintains their independent control of all aspects of gathering, monitoring, modeling, and applying applications to their AMPs; however, it is done in a way that encourages collaboration with other utilities and researchers. This is accomplished by using techniques to anonymize distribution feeder data, defining data formats and fields in a standard "open" way that can be

readily used with publicly standardized modeling and simulation software such as OpenDSS, GridLAB-D, or other common (anonymized) models such as ISGAN. This approach will allow California utilities and other stakeholders to leverage each organization's individual efforts in creating a larger superset of models that apply to all distribution feeders in the state whether they be rural, urban, downtown, spot, auto-loop, network, or other configurations.

**Figure 46: Alternative AMP Architecture: Collaborative Model**




Source: CIEE (UC-Berkeley)

### 6.4.3 Technical Needs for Monitoring of Future California Distribution Networks

As has been covered earlier in some detail in Chapter 2: Establishment of the Preliminary Data Inventory, a range of immediate technical objectives should be considered in designing the AMP. These items are repeated below for clarity and include the following:

- Capacity limitations (secondary transformer overload).
- Reverse power flows and detailed power flows on all phases.
- Protection coordination problems (relay desensitization).
- Undesirable voltage profiles (range violation, inverted profile).
- Rapid voltage variations (excessive tap changes, premature wear).
- Harmonics (excessive losses, impact on sensitive loads).

- Phase imbalance (excessive losses, nuisance trips); shown to be largest source of losses on feeders.
- More accurate placement (relocation) of capacitor banks for optimum feeder performance.
- Risk of unintentional islanding.
- Collective behavior of inverters (cascading disconnect).
- Impact of advanced inverter functions (LVRT, LFRT, Volt/VAR support).
- Visibility to transmission/ISO level (vulnerability to fast ramps).
- Unknowns and anomalies, such as oscillations ("sharks in the water").

Additionally, further technical objectives for an AMP would also likely include the following:

- Identification of each phase (even after field changes and swaps).
- Establish Baseline for DFs for later comparison (with installed DG/DER).
- Forecasting, e.g., 15 sec ahead for PV volatility tie-in to cloud movements.
- Identification of and mitigation for potential "bad actors" such as fast DC chargers.
- Identification of potential energy theft and meter tampering.
- Time-stamped and synced high-resolution data throughout a distribution feeder.
- Identification of loads "masked" by DER and other impacts.
- Obtain power data near major customers and/or adjacent to new larger DER installations.
- Determine min/max DER hosting capacity and simulate DG penetration levels of 50%, 75%, and even higher.
- Improve monitoring/measurement, control, and communications.
- Near-real-time State Estimation on feeders and real-time thermal and stability limits.
- Real-time estimates exceeding ANSI voltage specs or local stability margins.
- FIDVR, FLISR, high-impedance faults, and others.
- OMS and effective "self-healing," enhanced mean time to restoration (MTTR) for outages.
- Data used to verify or validate individual feeder models, including both utility and customer equipment inclusion.

Several of these bullets are worth highlighting. Both in surveys and workshop interactions, the ability to identify individual feeder phases in the field (especially after field repairs, swaps, or

circuit reconfigurations) is called out as a valuable feature. It has been shown that operating feeders with unbalanced phases is a key contributor to power (and economic) losses and phase identification and balancing are more than justified for inclusion in an AMP. Additionally, as DG penetration increases, situations where very large DER or loads are connected to only one phase are much more likely to occur and could result in very high inter-phase imbalances.

Many aspects of DER have already become troublesome and range from some very large recorded power ramps (both up and down) that can be 50% of the DG resource's peak rating over several seconds (e.g., a 5 MVA PV installation may change its power output by +/- 500 kW/sec). Additionally, a utility simply being able to have a baseline characterization of feeder behavior prior to the installation of DG (especially larger sites, >100 kVA) will be important in determining how the new DER installation has impacted feeder behavior as well as in possible commissioning validation analyses.

Although characterizing any potential load as a "bad actor" may be considered overly dramatic, these loads at least present challenges that a utility must not only be able identify where, who, and how much impact might result, but also how best to mitigate and manage the impacts which may result in additional complexity and costs.

In the U.S., energy theft is often considered not to be consequential; however, more detailed studies indicate that it is often in the range of 1% on the low side to as high as 5% in some areas. As electric rates and costs have increased, theft has become much more creative than the old method of reversing the meter and re-inserting it into its socket. Cases of tapping into energized overhead lines or underground cables (using backhoes and digging trenches at nighttime and then reburying the splice before daytime), running some normal house loads from special EV sub-meters (at lower rates), and other creative tampering techniques have greatly increased. Consequently, quickly detecting these breaches and repairing them offer both economic and safety benefits to utilities and their personnel.

Finally, a few longer-term and more qualitative objectives for developing an AMP would likely include the following:

- Enhanced reliability and robustness
- Grid stability and responsiveness
- Security, safety, and protection
- Disaster robustness and responsiveness
- Recovery and resiliency
- Redundant data capture during fault event recording
- Informing future monitoring and infrastructure investments
- Improved distribution operations
- Near- and long-term planning/forecasting for each distribution feeder

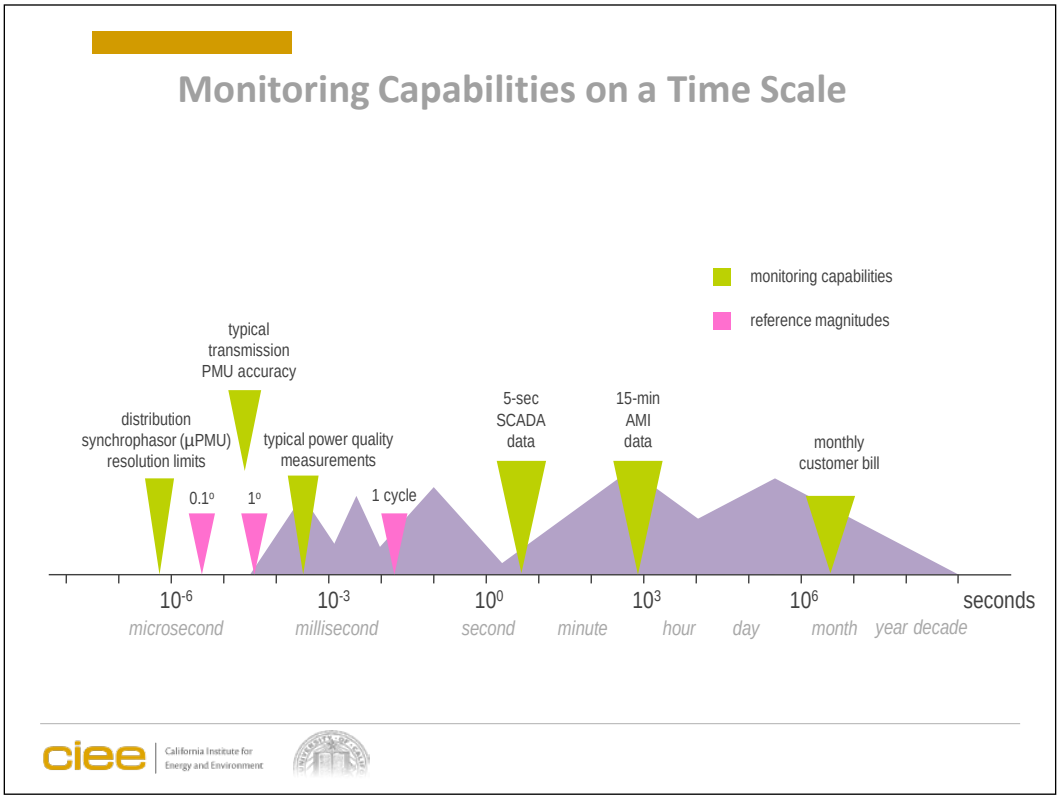
Although these are fairly broad and qualitative descriptions, an overarching assumption in the development of this report's proposed AMP is that each of these bullet points will be better understood, more accurately measured and monitored, and the utility will be better able to manage and control its distribution assets.

## 6.5 Proposed Plan for Future Distribution Monitoring Systems

Based on the previous description of technical objectives and working assumptions, the following outline and process for developing an AMP is proposed. It is understood that each utility will have to determine the set of distribution feeders that an AMP is expected to include. This could be initially limited only to known problem circuits, but it is recommended that a more holistic perspective be considered to maximize the long-term benefits of a more integrated and capable AMP.

The diagram in Figure 47 emphasizes the importance of extracting "meaning from data" and planning for the unknown. For instance, identifying an individual phase of a feeder would likely require sub-cycle sampling, timestamps, and analysis. Even finer resolution would be required to determine impacts of PV inverter injection of high harmonics, or control loop resonances, etc. As described earlier, SCADA data and its inherent resolution was state-of-the-art twenty years ago and can assist in characterizing many aspects of a distribution feeder, but the evolving challenges anticipated for the next 10 to 20 years may well be beyond the capabilities of traditional SCADA, and therefore could be a primary driver for developing an AMP.

**Figure 47: Time Scales for Event Monitoring**




Source: CIEE (UC-Berkeley)

Each of the following sub-sections addresses specific aspects of the proposed AMP in greater detail.

### 6.5.1 Capturing Existing Information for Each Distribution Feeder

Ideally, the first step in developing an AMP is to gather whatever baseline data are available for each utility feeder. Hopefully this would include some of the following:

- GIS and all locational data, any SCADA data and history, associated weather data, event history.
- Creation and/or verification of utility's connectivity model of each feeder.
- Detailed descriptions of each feeder: overhead/underground circuit-mil½ 1/2/3 phases, regulators, reclosers, capacitor banks, transformer taps, switches, fuses, circuit nodes and geometrics, transformers and equipment (for Residential, Commercial, Industrial, and Agricultural customer classes), climate zone, etc.
- Capture any operating behaviors: capacity factor, minimum and peak loads, seasonal variations, major event variations, quality of existing information.

- Capture existing customer generation: PV, wind, ESS, fuel cells, other DER, size, type of inverter(s), controls, behaviors and statistics, etc.

PNNL's taxonomy methodology[23] is a suggested helpful reference; it uses 35 descriptors, cluster analysis (bobby) and related approaches to provide a solid starting foundation for the type of information to assemble for each feeder.

### 6.5.2 Determine Best Classification/Taxonomy of Each Feeder (or Priority Circuit)

Designing, planning, and executing an AMP which includes the thoughtful integration and interfacing with appropriate feeder modeling and simulation techniques is a critical aspect of the AMP process. As such, it might be useful to address and outline here some of the pros and cons concerning one of the key aspects of model creation and refinement, which is: "Does each utility develop their own taxonomy of feeder models independently or as part of a California statewide collaborative model-sharing effort?" Arguments in favor of each utility developing their own feeder taxonomies and associated models are justified as much on practical and political bases so that each utility is not tied-down with legal, intellectual property, liability, privacy, different priorities and budgets and schedules, anonymization, as well as coordination and delays that might stem from working closely with other utilities/organizations to develop and refine feeder taxonomies and models jointly. After each utility has developed and refined their individual feeder taxonomies, they could then choose to share it with other groups to create a superset of California feeder taxonomies.

On the other hand, a more collaborative approach might allow many California utilities to spread their research costs over a broader and more statistically significant base of feeder models, allowing them to concentrate and "go deeper" on their own unique feeder types and take advantage of starting from a common set of feeder model taxonomies, input/output formatting, type of models used, pre-processing and clean-up techniques, etc. In addition, a more collaborative approach might allow additional incremental public funding to be utilized by university and other researchers to refine models and algorithms that can then be customized by each utility, as opposed to each utility wholly funding all aspects of their AMP and model development and simulations. CIEE is agnostic in these choices of simulation and modeling tradeoffs as well as choice of model platform (e.g., GridLAB-D vs. OpenDSS vs. many other alternatives). However, for the purposes of this report, it is assumed that distribution feeder taxonomies are developed that will provide adequate representation over each utility's actual spectrum of feeders.

Utilizing either existing feeder data (if available) or actual AMP data, each circuit under consideration is characterized to the appropriate taxonomy or classification. Several references are cited in this report that can provide a starting point for this effort. Regardless of whether a hierarchical, partitional, or other statistical clustering technique is used, it is important to begin to capture feeder data in a consistent, uniform, standard method which helps with data

---

23 Edgar, T.W., M.D. Hadley, D.O. Manz, J.D. Winn (Pacific Northwest National Laboratory). 2010. *Secure and Efficient Routable Control Systems.* Pacific Northwest National Laboratory. PNNL-19474.

usability within a utility, as well as potentially, collaboratively sharing data and modeling techniques with other utilities and outside researchers. Again, a good starting point would be to use PNNL's taxonomy approach that provides approximately 24 non-urban taxonomies utilizing 35 significant descriptors. In addition, other references can be used to build other models including auto-loop, spot, and other network (meshed) configurations.

Many of PNNL's non-urban feeder taxonomies would be applicable to the wide-ranging distribution feeders present in California. Collaboratively sharing these models, appropriate data and formats, and other information would allow a library of California feeder taxonomies to be compiled that both utilities and researches could tap and refine. Additionally, a collaborative approach would also help to identify and refine model gaps for distribution circuits that are not adequately modeled and simulated with existing models.

A key reason for calling out the use of models at the beginning of developing an AMP is to help identify what parameters will likely be important to monitor, where to monitor, how often to monitor and why, and what resolution – all aspects of developing an AMP.

### 6.5.3 Ideal Locations for Placement of Distribution Sensors

From cited references, subject matter experts, and DMRI Workshop feedback, the following distribution sensor locations are proposed:

- Substation feeder origin and all significant end-of-line feeder branches (estimated as ~5-10 points per feeder).
- Every mile and/or every 20% of circuit length and/or every major vertex (estimated as ~5 points per feeder).
- Every generation source > 100 kVA and every peak load sink > 250 kVA.
- Consideration for geocentricity of data and locational spacing.
- Account for clustering and distributive effects (especially DER clustering that can exacerbate local power flow anomalies and impacts).
- Measure as close as possible to customers of interest (often SCADA data is too far away).
- Don't forget other relevant location considerations (e.g., convenience of installations for accessibility, exposure to elements, transformer proximity, etc.).

### 6.5.4 Extent of AMP Rollout

As has been described, the extent of the scope of any particular utility's AMP depends on many factors. If the primary purpose is purely for a one-off pilot, that defines one very simple extreme. However, other AMP strategies might be to:

(a) Go to the most urgent place first, where there is most likely a problem. In this way, a specific business case can be made for this investment. This approach is often one that utilities are following.

(b) Capture a more representative sample of high-resolution data to develop a proactive strategy that covers both currently known problem feeder as well as other feeder in the utility's broader taxonomy.

If a utility has an interest in understanding these different feeder taxonomies, it might lead to some of the following ballpark numbers to be included in an AMP. These are based on the idea that between both urban and non-urban taxonomies, a total of approximately 30 to 40 models apply.

- If coverage objective includes only a few known problem feeders or typical feeders (e.g., (30-40)/2 = 10-20 feeders).
- If coverage objective includes at least one example for each DF taxonomy (e.g., 30-40 feeders).
- If coverage objective includes statistical numbers of each major DF taxonomy (e.g., (30-40) x 5 = 100-200 feeders).
- Or, plan to roll out to most or all of the utility's feeders over some longer period of time.

Each of these approximate ranges for the number of feeders to be included in an AMP rollout can then be used to estimate the total number and types of sensors, low and high resolution points, budgets, priorities, and schedule.

### 6.5.5 Proposed Data Requirements

In general, although it is assumed that the sampling rate would be at least 2 times the reporting requirement (per Nyquist), it is widely agreed that a 10 times sampling rate to support any given reporting requirement may be more realistic, given the broad range of field issues and other real-world knowledge and experience. The following broad requirements are proposed:

- For general purpose reporting: minimum 1 sample/second (sec) and sync/cycle on each phase.
- For PQ and high-resolution reporting: minimum 128 reports/sec per phase (i.e., 2/cycle).
- Detailed data (V, A, VA, VAR, harmonics, flicker, sags and swells, etc.).
- Time-stamped and synced with all other sensors.
- General reporting at 0.1 sec.
- PQ and high-resolution at 1 microsecond.
- Accuracy of data requirements.
- Additional non-feeder data streams (e.g., weather, temperature, humidity, solar, wind, California ISO, etc.).

In addition, the following scheme is proposed for consideration as a way of capturing broader, logarithmically-scaled data (e.g., PQ) and data surrounding a key previously defined event, such as a status change, switch operation, threshold exception, fault events, etc.:

- Detailed reporting: minimum at 256 samples/cycle; plus or minus 40 sec around any defined event.
- Detailed reporting for 1 cycle every 1 sec (e.g., 5 gigabyte/month/sensor).
- Detailed reporting for 10 cycles every 100 sec.
- Detailed reporting for 100 cycles every 1,000 sec.
- Detailed reporting for 1,000 cycles every 10,000 sec.

### 6.5.6 Communications and Storage

Given the rapidly decreasing cost trends in both communications and storage, it is recommended that the AMP design err on the side of utilizing more storage and higher bandwidth capabilities. For ballpark estimation purposes, the following is proposed:

- Each distribution sensor average-data rate for reporting at 1/sec requires approximately 100 MB/month/sensor.
- For PQ or high-resolution reporting less than 5 kilobyte/sec and feeder data rate less than 200 kB/sec.
- For general purpose reporting less than 500 baud and feeder data rate less than 2 kB/sec.
- Will likely need data buffering and local sensor battery storage for data integrity.
- Precise description of all data fields, lengths, delimiters, etc.
- Each feeder requires storage of approximately 100 GB/month (will be part of utility's "Big Data").
- Ideally would use agnostic or open standards for communications (e.g., cellular, IEEE 61850, etc.) to facilitate greater collaboration with other utilities and researchers as well as facilitate scalability from one or a few feeders to many feeders.
- Choice between utility using their existing communications capabilities or some standardized approach and commonality across all utilities.
- Data protection, channel access, and cybersecurity.
- Privacy and access to data by others (within company / from other companies).
- Although traditional data historian suppliers are workable, other less expensive options are available from large data-mining companies that may also be a way to encourage utility and research collaboration capabilities.
- Can AMP data, formats, and communications be standardized for ease of collaboration?

### 6.5.7 Data Processing

As discussed in Chapter 2, many challenges exist in data processing, including clean-up, gaps, outliers, etc. Data and storage requirements will likely be greater than 100 GB per feeder and could total many terabytes when all feeders are included. Important considerations will therefore include the front-end and clean-up requirements, accessibility as relational database(s) with full query, consistent formatting for both import/export functions and use with statistical packages, modeling data input, algorithm development, and financial analyses. Also, dashboard and other visualization interfaces to more easily grasp issues and trends will be critical to be able to extract meaning from the data. Finally, there may be a need to specify different levels of detail or anonymity depending upon whether the data is to be used for internal or external use (e.g., other utilities and/or researchers).

### 6.5.8 Model Validation

A key aspect of measuring more highly resolved and time-stamped data is its greater ability to refine and verify distribution feeder models. The determination of the appropriate range of initial and boundary conditions, operating regimes, and other system constraints is very important in creating a realistic model (for each taxonomy of feeder circuit). Ideally, to facilitate collaboration with other utilities and researchers, the use of open-source models (e.g., OpenDSS, GridLAB-D, etc.) is recommended. Each of these models should be validated over a full range of minimum and peak variable loads, weather variability, and DG generation and using a statistically significant number of simulations. In this way, each feeder model can be iteratively refined to more accurately reproduce the measured behaviors of each feeder. Ideally, the models would be created in a baseline characterization involving little DG penetration.

It is hoped that in the broader spirit of collaboration, utilities who have already made commitments to gather AMP data and to refine models for dozens of feeders would be able to share some of their lessons learned, refined models, and data processing techniques with other California utilities.

### 6.5.9 Modeling and Algorithm Development Objectives

Once validated models have been created for each of the major feeder taxonomies in a utility's territory, more detailed steady-state, dynamic, and transient analysis simulations of each circuit taxonomy can be performed. Each feeder model can then be used over a range of future scenarios and mitigations (see next sub-section) to simulate the impacts of both increasing DG penetration as well as even a commissioning tool for larger DG installations. Over time, these models can be enhanced with appropriate customer-premise equipment (CPE) models that are integrated into the utility feeder model to further refine circuit behavior associated with particular loads or generation sources.

Once a given feeder model has been validated, it can then be used both to simulate feeder behavior under a variety of future assumptions and scenarios, as well as to develop operating algorithms that can be used for optimized feeder operation and performance, which could achieve a mix of tradeoffs for reliability and economy.

Create a Range of Future Scenarios for Model Simulations

The creation of a range of potential scenarios is key to getting the most out of having monitored feeders and creating detailed, validated feeder models. These future scenarios should include both technical issues as well as economically driven issues. Some of these scenarios might include the following:

- Estimate appropriate timeframe(s) for operating envelope range extremes.
- Minimum/maximum PV penetration percentage and best/worst variability.
- Minimum/maximum EV penetration percentage and timing variability.
- Other potential customer-driven impacts (ESS, Volt/VAR support, wind, etc.).
- Impact of changes in IEEE 1547 or Rule 21 (anti-islanding, smart inverters, request coordination with aggregated DG greater than 500 kVA, etc.).
- Assist in determination of optimal future DG/DER location and other parameters to meet requirements of AB 327.
- Growth of minimum/maximum loads (VA, VAR and phase balancing issues).
- Potential utility and/or customer equipment mitigation investments.
- Range of natural/man-made events (vegetation, storms, sabotage, disasters, etc.).
- Range of likely DF Operations scenarios (CVR, VVO, Volt/VAR support, ESS, CBM, tap changer lifetimes, etc.).
- Explore possibility that California ISO may include DER dispatching as granular as a single feeder.
- Possible LMP granularity down to each individual feeder.
- Create other future scenarios for other technical/economic tradeoffs, e.g., include tracking of ownership model of DER.

*Considerations for an AMP for Future Research*

Although the previous outline for an AMP meets the research needs of this project, this section outlines additional considerations in establishing an AMP as an integral element of potential research in the evolving ecosystem of utilities, regulators, consumers, and the many other stakeholders.

In the same way that some industries have been forever created, destroyed, or changed by breakthrough or "paradigm-shifting" technologies, the evolving distribution grid may be the signal of such change for the traditional utility business model. Just as paradigm shifts occurred with the wide adoption of PCs, the Internet, mobile phones, and now the "Internet of Things," the connected home, or wearable devices, the distribution grid is forever being changed. The choice of whether utilities and other stakeholders embrace this evolution or are left behind is

uncertain. Several key drivers that push the distribution grid into the "breakthrough" realm might include:

- Legislative (e.g., AB 327 and other mandates)
- Governor-driven (e.g., 33 percent renewables by 2020 mandates, 12 GW, etc.)
- CPUC and Energy Commission directives
- Utility Board or executive directives
- Shareholder-driven
- Customer-driven (e.g., consumer advocates, large consumers, ESPs and aggregators, new energy markets and opportunities)
- Other stakeholder-driven, including: Rule 21, IEEE 1547 changes, new grid-support and ancillary services, smart inverters, FERC, NERC, local monitoring or measurement of GHG production, etc.

Given these broader drivers, a more appropriate context for developing a long-term AMP would include the following issues:

- Is the AMP part of a fully integrated, utility-wide, across-all-departments architecture, with shared access, and evolved corporate culture?
- How organizationally integrated should the AMP be (siloed, R&D, AMI, operations, IT, finance, planning, CIS, etc.)?
- What are the best and most relevant Use Cases to determine significant technical and business issues, types of services, and transactions associated with feeders?
- How are legacy issues to be integrated or worked around, versus dealt with head-on ("bite the bullet")?
- Can the AMP evolve and adapt to new equipment, software, needs, customers, etc.?
- Asset management and lifetimes (CBM, avoided cost, equipment stress, etc.).
- Better coordination/cooperation with customers (μgrids, ESS, Volt/VAR support, ancillary services, full-range of DG/DER).
- Better workforce management and priority team assignments.
- Explore new revenue sources (e.g., enhanced reliability or lower down times, or other derivatives of better OMS optimization, etc.).
- More comprehensive and integrated grid models that can simulate transmission and distribution modeling techniques on all 3 phases and interconnections between transmission and distribution.

To help address how some of these big-picture issues are included in the process of developing a comprehensive, fully integrated and fully supported AMP, the following steps are proposed:

- Start this process now (refine, update, verify, and iterate)!
- Require a project champion to lead the effort.
- Require senior executive participation, possibly via a technical advisory committee.
- Determine stakeholders to be included.
- Determine timeframe(s) and/or later stages (e.g. short, near, long-term).
- Explicitly determine AMP objectives (e.g., R&D, reliability, operations, financial, CIS, others).
- Team ideally includes cross-departmental participants (R&D, operations, AMI, GIS, IT, CIS, financial, planning, forecasting).
- Gather/categorize/clean-up currently available data (e.g., SCADA, OMS, GIS, AMI, etc.) and map information to each distribution feeder.
- Identify feeders with little or no information and other gaps.
- Determine what DG/DER exists now and fully categorize it with 8,760 hours/year generation and load data profiles.
- Identify feeders with known issues or high penetration of DG, EVs, and other variabilities.
- Prioritize feeders for AMPs given funding, timeframes, and objectives.
- Identify what feeder models and taxonomy exist now and what needs to be developed.
- Do feeder load profiles and generation profiles exist?
- Create a range of future scenarios for feeder model simulations.
- Perform a range of use cases to develop future scenarios to compare against the feeder models.
- Characterize feeders as "red, yellow, or green" for degree of out-of-specification or not meeting stability criteria.
- Model economic impacts including CBM, CVR, potential equipment damage or shortened life, avoided cost analysis, potential CIS and customer relations management (CRM) value, etc.
- Model mitigation strategies for the most critical feeders and estimate the economic costs or gains, to begin to get an estimate for $/feeder over time for input to priorities and budgets.

In addition to the technical objectives described earlier for an AMP, the following list also details additional objectives that should be considered for a more fully integrated and supported AMP:

- Improved distribution operations.
- OMS and effective "self-healing," and reduced MTTR for outages.
- Potentially use signature analysis to determine types of customer premise equipment (CPE), e.g., inverter types, EVs, slow/fast charge, etc.
- What are appropriate metrics (e.g., $ losses/gains, SAIDI/SAIFI, complaints, power interruptions, run-to-failure)?
- Better implementation, measurement, and verification for DR, DSM, TOU, CPP, load shifting, load shedding, etc.
- Better chance of being able to analyze, troubleshoot, and mitigate what we don't know or can't measure (i.e., the unknown "sharks")

Finally, a key aspect for long-term success includes periodic reviews, updates, and organizational integration. Some of these might be accomplished by utilizing the following tactics:

- Summarize simulation results as high-level "red/yellow/green" flags.
- Perform estimates of CAPEX, OPEX, incremental revenues and costs for cash-flow streams with and without mitigation implemented.
- Determine how best to integrate into DMS, operations, dashboards, key parameters.
- Identify what events and controls can be managed; autonomously, manually, flagged, etc.).
- Further review and analyze operations/financial optimization, coordination with customer equipment, other utility systems (OMS, AMI, etc.)
- Conduct monthly review meetings to discuss, refine, or problem-solve observed trends, simulation results, and other issues.

# CHAPTER 7:
# Conclusions and Recommendations

## 7.1 General Conclusions

Each utility is faced with a multitude of challenges driven by many different stakeholders in developing the appropriate AMP. The determination of the key objectives to be accomplished, and during what timeframe, driven by a process/project champion as well as executive backing and oversight, are important factors for success. Several critical mandates such as the passage of AB 327, which requires determination of optimal DER locations and hosting capacities, have strongly pulled the thorough design and implementation of an AMP to the forefront. Although there exist a myriad of AMP attributes and desired wish-list features, it is recommended that sensor data, formats, models, and other information be designed to facilitate a collaborative approach with other utilities as well as researchers.

Bearing in mind that if the distribution grid is currently facing a paradigm-shifting breakthrough change, then developing a fully-integrated and supported AMP that has been customized to meet each utility's specific ecosystem needs should not be viewed as a cost-center, but should be viewed as a profit source in a larger bottoms-up analysis that includes both technical and economic considerations for capacity enhancement, avoided costs, enhanced revenues, reliability and safety, and long-term distribution optimization. Change is coming, so we believe this process should begin now so that we're ready in ten years!

## 7.2 Challenges of Project Design Unknowns

One difficulty with developing an advanced distribution monitoring system stems from some key unknowns and the uncertainty they create for making decisions regarding the cost, scope, and quality of the monitoring project. Much is unknown about the current distribution system characteristics because of a traditional lack of a business or operating need to know much detail. Accordingly, there might be unseen behaviors on the current distribution system that don't matter now, but could become significant later on as the demands on distribution performance change and become greater and more complex with higher penetration of these distributed resources. An advanced monitoring capability must be of higher granularity than traditional SCADA systems, both in terms of how many things and places must be monitored and how often. It also is reasonably clear that currently available monitoring installations that were specifically installed as part of field tests, demonstrations, and early commercial deployments of distributed resources, while perhaps of higher temporal granularity than SCADA, are too sparsely deployed to answer the research question.

The challenge arises in deciding how much greater the information granularity should be. A tradeoff is required between paying a higher cost for more sensors, communications, data storage and analysis for unneeded or unjustified granularity, and deploying a lower-cost advanced monitoring project that inadequately captures the data sufficient to answer the research question. Given the particularly high level of unknowns in this situation, it probably would be wise to err on the side of collecting data of higher granularity, and then, if there is an

attendant cost saving for the project, later reduce that level of data granularity if it proves excessive for answering the research question. To do the converse would increase the risk of realizing too late that some important information was missed that might seriously jeopardize the value and validity of the monitoring project and overshadow any cost savings in the budget.

Another uncertainty has to do with the quantity of distributed energy resource installations, e.g., what fraction of the electric resource does the distributed resource contribution need to be to be considered representative of high penetrations when considered in the distribution system as a whole, and in concentrations in subsections of the total system? A related uncertainty has to do with the quality of the distributed resources, largely referring to their technical maturity. Since the technologies, like inverters, of these new resources are rapidly changing, and will likely continue changing due to such things as changes in standards for interoperability, so will their effect on the distribution system. At what stage of technical maturity will distributed resources being monitored for their effect on the distribution system for this project be too immature to be representative to adequately answer the research question? Again the challenge equates to making a tradeoff between paying a higher cost for additional installations, or for model simulations of newer distributed resources, or relying on existing installations, and risking that they will not be representative enough to answer the research question with sufficient accuracy.

Another unknown is future state or federal energy policy changes that might have an effect on the nature of the physical behaviors or deployment patterns of distributed resources, and in turn the effect the new distributed resources will have on the electric distribution system. To design and deploy an advanced monitoring system that could accommodate such changes, one might have to incorporate a certain degree of extra robustness and flexibility, which again poses a decision tradeoff between cost and capability of the monitoring system.

## 7.3 Challenges of Project Deployment

A substantial challenge regarding deployment of an advanced monitoring project to answer the research question is paying for it. It raises three questions: Is the project worth the cost? If so, who will benefit? And who should pay for it? The answers will likely come only from a number of discussions among various public and private participants and stakeholders. There are some high level aspects about such a project that might be considered to help launch such discussions. In general the utilities that own and operate the distribution systems and the customers who use them will benefit through better planning for investment decisions and preparation for future operation requirements, and financial opportunities and costs regarding high penetrations of distributed resources. Policy makers, regulators, and the public will have a better idea of the effects of new policies promoting distributed resources on the electric distribution owners and users, and on distributed resource users and businesses. In short, the information from this project could result in better preparedness for effects on the electric distribution systems, and more effective policies having fewer unintended adverse consequences.

One way to characterize the cost of this project is to consider it as the costs of a minimum infrastructure and supporting operations and maintenance with a monitoring capability for owning, operating, and using the electric distribution system with high penetrations of distributed resources, plus the additional costs of extra infrastructure and supporting operations and maintenance, and data collection, modeling, and analysis required to answer the research question. Given that the dividing line between these two sets of costs is not sharp, and could be a moving target over time, here again final answers will likely be agreed to only after a number of discussions and negotiations among various public and private participants and stakeholders. This challenge is discussed in a strategic context later in this chapter.

Since it appears that electric distribution utilities must be a major class of participants in an advanced monitoring project, some unavoidable challenges arise. One of these challenges is staff availability for such an effort. Because of safety and reliability issues, a utility is responsible for, and must control, whoever installs, uses, or maintains certain equipment on its system or collects and handles its data. Utilities, like any other successful businesses, attempt to minimize their costs of doing business successfully by maximizing the use of their human resources. Experiences with obtaining data from existing utility measurements for this project revealed that there is very little margin for getting the time of utility personnel for installation of equipment, and collecting and preparing the data for timely use. Equipment installation can pose an additional schedule challenge if it interferes with the operations and availability of the utility system to serve customers, and often must wait until the situation occurs when that particular part of the system can be taken out of service, or worked on when reliability or safety standards are not threatened. A successful advanced monitoring project should anticipate that the availability of adequate utility personnel and access to the distribution system will be tight, so either the project schedule needs to reflect the extra time that will be required for personnel or system availability, or must include budget for additional utility staff.

Use of utility data and information for an advanced monitoring project, when third parties are active participants and/or project results are to become public, creates customer, corporate, and other information privacy and security challenges. An advanced monitoring project needs to anticipate the time required to negotiate data and information privacy protection agreements, and have privacy and security safeguards embedded in the project design and implementation activities. One potential solution is data anonymization, which is a data management process where encryption is used, or certain identifying information is removed, such that persons, locations, etc., remain anonymous. For an advanced monitoring project, however, anonymization will likely create complications and extra costs associated with some information required, such as the weather at specific times and places.

There are thousands of electric distribution circuits in California, and it is common among and within utilities that each circuit is unique. Theoretically, for an advanced monitoring project that characterizes electric distribution for California, one should monitor every circuit, but the cost and feasibility of doing so would be challenging. The differences among circuits can range from minor to substantial. As a compromise, one can perform an analysis that develops representative circuits, i.e., taxonomy feeders, that characterize the substantial differences, but

mitigates the minor ones. The challenge arises in being able to develop a manageable number of representative circuits that will yield sufficiently accurate results.

## 7.4 Challenges of Strategy

The operation of an electric distribution system is an extremely critical function. The deployment of a research project, such as an advanced monitoring project described here in the AMP, raises a number of strategic-level challenges regarding interactions and interoperability of operational requirements and the research project. First and foremost, the installation and conduct of the research project cannot interfere with operation of the electric distribution system, yet the monitoring effort needs to be successful.

It's a natural inclination for expediency and efficiency to attempt to piggy-back onto the distribution management system in the advanced distribution monitoring project, and involve the operations people as much as possible. Yet such a strategy can be quite complex and intrusive. The alternative is to install and operate parallel sensing and communication equipment with its own cost and complexity implications. A similar challenge arises with the choice of which utility personnel should be engaged in the research effort. Research staff will by nature be more aligned with the advanced monitoring project's mission, but some utilities may have difficulties gaining access to the necessary operations facilities. On the other hand, using operations staff means competing with their principal operations mission for attention to, availability for, and alignment with the research mission of the monitoring project. Similar personnel discontinuities can occur between those utility people involved in the planning of the monitoring project, and those who will have to install and operate it.

It is characteristic of many research projects having monitoring purposes that the equipment is often treated as expendable. Yet, if one anticipates that utilities will likely need advanced monitoring systems to manage the distribution system of the future, as discussed in the early chapters of this report, it might make sense to design the research project as the baseline or platform for an ongoing advanced monitoring system for the future operations of the electric distribution system. While this approach would add significant strategic value to the research monitoring project, it also will likely add significant complexity to its design and time to its schedule.

## 7.5 Addressing the Challenges

Some of the challenges described here can be addressed in the installation and performance phases of an advanced monitoring project to answer the research question. Most of these challenges, however, will need to be addressed during the project design and development phases, and consequently can create a long lead time for getting the effort underway. Given the rapidity with which distributed resources are being, and are expected to be, deployed to meet state energy policy goals as early as 2020, there is an urgency to begin addressing these challenges right away, in part to make sure that possible solutions are well known early on, and reflected in procurement processes and budgets, and to enter the installation and performance phases as soon as possible.

# GLOSSARY

| Term | Definition |
|---|---|
| A, Amp | Ampere |
| A-FLISR | Automatic Fault Location, Isolation and Service Restoration |
| AB | Assembly Bill |
| ABB | Asea Brown Boveri |
| AC | Alternating Current |
| AF | Asset Framework |
| AMI | Advanced Metering Infrastructure |
| AMP | Advanced Monitoring Plan |
| ANSI | American National Standards Institute |
| ARPA-E | Advanced Research Projects Agency – Energy |
| ARRA | American Recovery and Reinvestment Act of 2009 |
| California ISO | California Independent System Operator |
| CAPEX | Capital Expenditure |
| CBM | Condition-based Maintenance |
| CEP | Complex Event Processing |
| CIM | Customer Information Model |
| CIS | Customer Information System |
| CPE | Customer-premise Equipment |
| CRM | Customer Relationship Management |
| CSI | California Solar Initiative |
| CT | Current Transformer |
| CVR | Conservation Voltage Reduction |
| DER | Distributed Energy Resource |
| DEW | Distribution Engineering Workstation |

| | |
|---|---|
| DC | Direct Current |
| DF | Distribution Feeder |
| DG | Distributed Generation |
| DIR | Data Interpolation and Resampling |
| DMRI | Distribution Monitoring for Renewables Integration |
| DMS | Distribution Management System |
| DR | Demand Response |
| DOE | United States Department of Energy |
| DPV | Distributed Photovoltaics |
| DR | Demand Response |
| DRP | Distributed Resource Plan |
| DSM | Demand-side Management |
| EPIC | Electric Program Investment Charge |
| EPRI | Electric Power Research Institute |
| ESP | Electric Service Provider |
| ESS | Energy Storage System |
| ETAP | Electrical Transient and Analysis Program |
| EV | Electric Vehicle |
| FERC | Federal Energy Regulatory Commission |
| FIDVR | Fault-Induced Delayed Voltage Recovery |
| GHG | Greenhouse Gases |
| GIS | Geographic Information System |
| GOOSE | Generic Object-oriented Substation Events |
| GW | Gigawatt |
| HAN | Home Area Network |
| Hz | Hertz |
| IEC 61850 | International Electrotechnical Commission's standard for the design of electrical substation automation. |

| | |
|---|---|
| IED | Intelligent Electronic Device |
| ISGAN | International Smart Grid Action Network |
| ISGD | Irvine Smart Grid Demonstration |
| ISO | Independent System Operator |
| IT | Information Technology |
| kV | Kilovolt |
| kW | Kilowatt |
| ICT | Information and Communications Technology |
| IEEE | Institute of Electrical and Electronics Engineers |
| IOU | Investor-owned Utility |
| L | Inductance |
| LFRT | Low-frequency Ride-through |
| LMP | Locational Marginal Pricing |
| LVRT | Low-voltage Ride-through |
| μPMU | Micro-Phasor Measurement Unit, aka "micro-synchrophasor" |
| M | Million |
| MTTR | Mean Time to Restore |
| MVA | Megavolt-Ampere |
| ms | millisecond |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NERC | North American Electric Reliability Corporation |
| NREL | National Renewable Energy Laboratory |
| OMS | Operations Management System |
| OpenDSS | EPRI's Open-source Distribution System Simulator |
| OPEX | Operations Expenditure |
| PEV | Plug-in Electric Vehicle |

| | |
|---|---|
| PMU | Phasor Measurement Unit |
| PG&E | Pacific Gas & Electric Co. |
| POU | Publicly-owned Utility |
| PQ | Power Quality |
| PSCMD | Power System Computer Model Data |
| PT | Potential Transformer |
| PV | Photovoltaic |
| R | Resistance |
| REC | Resampling Error Calculation |
| RTU | Remote Terminal Unit |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | System Control and Data Acquisition |
| SCE | Southern California Edison Co. |
| SDG&E | San Diego Gas & Electric Co. |
| SDSC | (UC-) San Diego Supercomputing Center |
| SGIG | Smart Grid Investment Grant |
| sec | second |
| SI | Situational Intelligence |
| SMUD | Sacramento Municipal Utility District |
| TOU | Time-of-use |
| UCI | University of California – Irvine |
| UCSD | University of California – San Diego |
| V | Volt |
| VAR | Volt-Ampere Reactive |
| VVO | Volt/VAR Optimization |
| X | Reactance |

| | |
|---|---|
| XML | Extensible Markup Language |
| Z | Impedance (Resistance + Reactance) |
| ZnBr | Zinc-Bromine |
| ZNE | Zero Net Energy |

# REFERENCES


Arghandeh, Reza, Ahmet Onen, Jaesung Jung, Robert Broadwater. 2013. "Harmonic Interactions of Multiple Distributed Energy Resources in Power Distribution Networks," *Electric Power Systems Research,* vol. 105, pp. 124-133.

Arghandeh, Reza, Ahmet Onen, Jaesung Jung, Robert Broadwater, Virgilio Centeno. 2014. "Phasor-based Assessment for Harmonic Sources in Distribution Networks," *Electric Power Systems Research,* vol. 116, pp. 94-105.

Arghandeh, Reza, Jeremy Woyak, Ahmet Onen, Jaesung Jung, Robert Broadwater. 2014. "Economic Optimal Operation of Community Energy Storage Systems in Competitive Energy Markets," *Applied Energy,* Elsevier, Vol. 135.

Bank, Jonathan (National Renewable Energy Laboratory). 2012. *Development of a Distribution Level Data Acquisition System and Preliminary Results.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2012 IEEE PES General Meeting. PESGM.2012.6345089.

Bank, Jonathan, Barry Mather (National Renewable Energy Laboratory). 2013. *Analysis of the Impacts of Distribution Connected PV Using High-Speed Datasets.* Institute of Electrical and Electronics Engineers. 2013 IEEE Green Technologies Conference. GreenTech.2013.3.

Bialek, Tom (San Diego Gas & Electric Co.). 2009. *SDG&E Beach Cities MicroGrid Project*. Lawrence Berkeley National Laboratory. 2009 Symposium on Microgrids. [https://der.lbl.gov/sites/der.lbl.gov/files/Bialek_2009.pdf]

Brown, Keith, Farrokh Shokooh, Herminio Abcede, Gary Donner. 1990. *Interactive Simulation of Power Systems: ETAP Applications and Techniques.* Institute of Electrical and Electronics Engineers. Conference Record of the 1990 IEEE Industry Applications Society Annual Meeting, vol. 2. IAS.1990.152451.

Boyer, Stuart A. 2009. *SCADA: Supervisory Control and Data Acquisition (Fourth Edition)*, The Instrumentation, Systems, and Automation Society. ISBN-13: 978-1936007097.

Bravo, Richard, Bob Yinger, Steven Robles (Southern California Edison Co.). 2013. *Three Phase Solar Photovoltaic Inverter Testing.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2013 IEEE PES General Meeting. PESMG.2013.6672977.

Brooks, Daniel, Jeff Smith (The Utility Variable-Generation Integration Group). 2011. *EPRI Distributed PV (DPV) Feeder Analysis Project.* [http://www.uwig.org/mauisolar/Brooks_DPV-FeederImpacts.pdf]

California Public Utilities Commission (CPUC). 2014. *Order Instituing Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.* [http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M102/K036/102036703.pdf]

Clark, Kara, Reigh Walling, Nicholas Miller. 2011. *Solar Photovoltaic (PV) Plant Models in PSLF.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2011 IEEE PES General Meeting. PES.2011.6039117.

Coddington, Michael, Barry Mather, Benjamin Kroposki (National Renewable Energy Laboratory); Kevin Lynn, Alvin Razon (United States Department of Energy); Abraham Ellis, Roger Hill (Sandia National Laboratories); Tom Key, Kristen Nicole, Jeff Smith (Electric Power Research Institute). 2012. *Updating Interconnection Screens for PV System Integration*. National Renewable Energy Laboratory. NREL/TP-5500-54063. [http://www.nrel.gov/docs/fy12osti/54063.pdf]

Dasso, Kevin (Pacific Gas & Electric Co.). 2010. *Cornerstone Improvement Project*. Pacific Gas & Electric Co. 2010 PG&E Supplier Conference. [http://www.pge.com/includes/docs/pdfs/b2b/purchasing/suppliers/cornerstone_project.pdf]

Dasso, Kevin (Pacific Gas & Electric Co.). 2012. *Smart Grid Update.* Pacific Gas & Electric Co. 2012 PG&E Supplier Conference. [http://www.pge.com/includes/docs/pdfs/b2b/purchasing/suppliers/Smart_Grid_Update.pdf]

Della Giustina, Davide, Sami Repo, Stefano Zanini, Luigi Cremaschini. 2011. *ICT Architecture for an Integrated Distribution Network Monitoring*. Institute of Electrical and Electronics Engineers. 2011 IEEE International Workshop on Applied Measurements for Power Systems (AMPS). AMPS.2011.6090435.

DeMartini, Paul. 2014. *More than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient.* Greentech Leadership Group. [http://greentechleadership.org/wp-content/uploads/2014/08/More-Than-Smart-Report-by-GTLG-and-Caltech.pdf]

Edgar, T.W., M.D. Hadley, D.O. Manz, J.D. Winn (Pacific Northwest National Laboratory). 2010. *Secure and Efficient Routable Control Systems.* Pacific Northwest National Laboratory. PNNL-19474.

Grainger, John, William Stevenson. "Power System Analysis." McGraw-Hill Publishing Company, 1994. ISBN-13: 978-0070612938.

Honeywell International, Inc. 2009. *Full-Scale Implementation of Automated Demand Response*. United States Department of Energy – Office of Electricity Delivery & Energy Reliability. [http://www.smartgrid.gov/project/honeywell_international_inc_full_scale_implementation_automated_demand_response]

International Electrotechnical Commission (IEC). 2014. *IEC 61850 Standard for Power Utility Automation.*

Ishak, Nurul, Iza Sazanita Isa, Samihah Abdullah, Syafrudin Masri, Faizal Mohamad Twon Tawi. 2010. *Performance Comparison of Electric Power Flow Solutions Using PSCAD.* 2010 International Conference on Science and Social Research (CSSR). CSSR.2010.5773838.

Jaesung Jung, Yongju Cho, Danling Cheng, Ahmet Onen, Reza Arghandeh, Murat Dilek, Robert Broadwater. 2013. "Monte Carlo Analysis of Plug-in Hybrid Vehicles and Distributed Energy Resource Growth with Residential Energy Storage in Michigan," *Journal of Applied Energy,* Elsevier, Vol. 108.

Khoshkbar-Sadigh, Arash, Mojtaba Heydari, Marco Tedde, Reza Arghandeh, Keyue Smedley, Alexandra von Meier. 2015. *A Unified Platform Enabling Power System Circuit Model Data Transfer among Different Software.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2015 IEEE PES Innovative Smart Grid Technologies (ISGT) Conference.

Khoshkbar-Sadigh, Arash, Keyue Smedley. 2015. *Model Validation of Southern California Edison Distribution Circuit with Large-Scale PV Installation.* (In preparation.)

Montenegro, Davis, Miguel Hernandez, Gustavo Ramos. 2012. *Real Time OpenDSS Framework for Distribution Systems Simulation and Analysis.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2012 Sixth IEEE PES Latin America Transmission and Distribution Conference and Exposition. TDC-LA.2012.631906.

Muljadi, Eduard, Mohit Singh, Richard Bravo, Vahan Gevorgian. 2013. *Dynamic Model Validation of PV Inverters Under Short-Circuit Conditions.* National Renewable Energy Laboratory. CP-5500-57341. [http://www.nrel.gov/docs/fy13osti/57341.pdf]

National Energy Technology Laboratory (NETL). 2008. *Advanced Metering Infrastructure.* [http://www.netl.doe.gov/File%20Library/research/energy%20efficiency/smart%20grid/whitepapers/AMI-White-paper-final-021108--2--APPROVED_2008_02_12.pdf]

Neal, Russ, Barry Mather. 2013. *NREL High Penetration PV Project at Southern California Edison*. United State Department of Energy and California Public Utilities Commission. 2013 DOE/CPUC High Penetration Solar Forum. [http://www1.eere.energy.gov/solar/pdfs/highpenforum2013_1_12.sce.pdf]

Ochoa, Luis, Douglas Wilson. 2010. *Angle Constraint Active Management of Distribution Networks with Wind Power*. Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2010 IEEE PES Innovative Smart Grid Technologies Conference – Europe. ISGTEUROPE.2010.563896.

Rahm, Erhard, Hong Hai Do. 2000. *Data Cleaning: Problems and Current Approaches.* Institute of Electrical and Electronics Engineers. Bulletin of the IEEE Computer Society Technical Committee on Data Engineering, vol. 23, issue 4.

San Diego Gas & Electric Co. 2013. *SDG&E Smart Grid Communication System (SGCS).* United States Department of Energy – Office of Electricity Delivery & Energy Reliability.

[http://www.smartgrid.gov/project/san_diego_gas_electric_company_sdge_grid_communication_system]

Schneider, Kevin, Yousu Chen, David Chassin, Robert Pratt, Dave Engel, Sandra Thompson (Pacific Northwest National Laboratory). 2008. *Modern Grid Initiative – Distribution Taxonomy Final Report.* Pacific Northwest National Laboratory. PNNL-18035.

Schneider, Kevin, Jason Fuller, Francis Tuffner, Ruchi Singh (Pacific Northwest National Laboratory). 2010. *Evaluation of Conservation Voltage Reduction (CVR) on a National Level.* Pacific Northwest National Laboratory. PNNL-19596.

Singh, Ruchi, Francis Tuffner, Jason Fuller, Kevin Schneider (Pacific Northwest National Laboratory). 2011. *Effects of Distributed Energy Resources on Conservation Voltage Reduction (CVR).* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2011 IEEE PES General Meeting. PES.2011.6039702.

Smith, Jeff. 2013. *Alternative Screening Methods: PV Hosting Capacity in Distribution Systems*. 2013 DOE/CPUC High Penetration Solar Forum. [http://www1.eere.energy.gov/solar/pdfs/highpenforum2013_2_1_epri.pdf]

Southern California Edison Co.: *SmartConnect Customer Fact Sheet.* [https://www.sce.com/NR/rdonlyres/05A12223-94CE-48D2-989845606F8EAD3D/0/090611_EdisonSmartConnect_CustFactSheet.pdf]

Southern California Edison Co. 2013. *Smart Meter Description*. [https://www.sce.com/wps/portal/home/customer-service/my-account/smart-meters/resourcecenter/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOINLdwdPTyDDTz9jzdDDyDfH38AwP8DcwCzPSDU_P0C7IdFQEAgu68/]

Transmission & Distribution World. 2013. *SDG&E Installing New Technologies to Create "Self-Healing" Electric Grid for San Diego*. [http://tdworld.com/test-monitor-amp-control/sdge-installing-new-technologies-create-self-healing-electric-grid-san-dieg]

United States Department of Energy. 2013. *Honeywell International, Inc. – Full-Scale Implementation of Automated Demand Response Fact Sheet*. Office of Electricity Delivery & Energy Reliability. [http://www.smartgrid.gov/project/honeywell_international_inc_full_scale_implementation_automated_demand_response#sthash.biDocMqn.dpuf]

United States Department of Energy. 2013. *Premium Power – Distributed Energy Storage System Fact Sheet.* Office of Electricity Delivery & Energy Reliability. [https://www.smartgrid.gov/sites/default/files/pdfs/project_desc/OE0000224_Fact%2520Sheet_Premium%2520Power%2520Aug2013_3.0%5B2%5D.pdf]

United States Department of Energy. 2010. *Sacramento Municipal Utility District – SmartSacramento® Project Fact Sheet*. Office of Electricity Delivery & Energy Reliability.

[http://www.smartgrid.gov/project/honeywell_international_inc_full_scale_implementation_automated_demand_response]

United States Department of Energy. *Irvine Smart Grid Demonstration Fact Sheet.* Office of Electricity Delivery & Energy Reliability. [http://www.smartgrid.gov/project/southern_california_edison_company_irvine_smart_grid_demonstration.]

United States Department of Energy. 2013. *Tehachapi Wind Energy Storage Project Fact Sheet.* Office of Electricity Delivery & Energy Reliability. [http://www.smartgrid.gov/sites/default/files/OE0000201_Fact%20Sheet_SoCal%20Edison%20Aug2013_3.0_0.pdf]

von Meier, Alexandra, Reza Arghandeh (California Institute for Energy and Environment). 2014. "Chapter 34 – Every Moment Counts: Synchrophasors for Distribution Networks with Variable Resources." *Renewable Energy Integration,* L.E. Jones (ed.), Academic Press, Boston, MA.

von Meier, Alexandra, Reza Arghandeh (California Institute for Energy and Environment). 2014. *Diagnostic Applications for Micro-synchrophasor Measurements.* Advanced Research Projects Agency for Energy (ARPA-E).

von Meier, Alexandra, Merwin Brown, Reza Arghandeh, Laura Mehrmanesh, Lloyd Cibulka (California Institute for Energy and Environment), Bob Russ. 2014. *Advanced Monitoring Plan.* California Energy Commission.

von Meier, Alexandra, Lloyd Cibulka, Merwin Brown, Larry Miller (California Institute for Energy and Environment). 2013. *Preliminary Data Inventory Report: Overview of Distribution Feeder Characteristics for Renewables Integration.* California Energy Commission.

von Meier, Alexandra, David Culler, Alex McEachern, Reza Arghandeh. 2014. *Micro-synchrophasors for Distribution Systems.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2014 IEEE PES Innovative Smart Grid Technologies Conference. ISGT.2014.6816509.

von Meier, Alexandra, George Rodriguez. 2013. *Monitoring for Impacts of Distributed Resources: Initial Planning Considerations.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2013 IEEE PES General Meeting. PESMG.2013.6672386.

Wang, Dan, Brandon de Wit, Simon Parkinson, Jason Fuller, David Chassin, Curran Crawford, Ned Djilali. 2012. *A Test Bed for Self-regulating Distribution Systems: Modeling Integrated Renewable Energy and Demand Response in the GridLAB-D/MATLAB Environment.* Institute of Electrical and Electronics Engineers (IEEE), Power and Energy Society (PES). 2012 IEEE PES Innovative Smart Grid Technologies (ISGT) Conference. ISGT.2012.617580.

# APPENDIX

Appendix A: Presentations from Sept. 5, 2014 Distribution Monitoring Workshop

This appendix is available as a separate volume, publication number CEC-500-2015-058-AP