GAINING VALUE FROM SMART METER DATA: POWER QUALITY AND OUTAGE EVENT ANALYSIS

By

Valdama E. Johnson

A THESIS

Submitted to
Michigan State University
in partial fulfillment of the requirements
for the degree of

Electrical Engineering - Master of Science

2016

ABSTRACT

GAINING VALUE FROM SMART METER DATA: POWER QUALITY AND OUTAGE EVENT ANALYSIS

By

Valdama E. Johnson

Electric utility companies are making significant investments in smart grid technologies to improve the way power is generated and delivered to customers. Investments such as the replacement of electromechanical meters with smart meters has provided several benefits including more accurate electricity bills and the ability to remotely connect or disconnect service. In addition to these benefits, smart meters can also be used to address the lack of visibility into the electric distribution system. While many utilities have visibility at substations through supervisory control and data acquisition systems, much of the distribution system beyond the substation remains unmonitored. The objective of this thesis is to show how utilities can gain more visibility into the distribution system by analyzing smart meter data. Smart meter outage events, when integrated into outage management systems, can help utilities locate outages faster and restore power to customers. In this thesis, smart meter outage events are compared with historical outage incidents from an outage management system. The results of the comparison show that there are several challenges to overcome before these events can be integrated into outage management systems. These challenges include processing momentary smart meter outages and ensuring that the electric model is correct. Smart meters can also be used to identify power quality issues such as drastic changes in voltage levels. An average voltage over a five-day period was obtained for 700,000 smart meters and roughly 1% had a voltage above the acceptable tolerance range. Many of these issues were caused by the failure of a distribution transformer or voltage regulator. By analyzing smart meter outage and voltage data, utilities can be more proactive in addressing customer and system issues.

ACKNOWLEDGMENTS

First, I have to thank GOD for all of the blessings he has given me. Without his help, there is no way I could have completed this thesis. There were times where I wanted to give up, but with GOD all things are possible.

I would like to thank Dr. Percy Pierre and the Sloan Engineering Program for supporting me throughout my time here at Michigan State University. Dr. Pierre, thank you for believing in me when I did not believe in myself. One day I hope to be in a position where I can help others the way you have helped me.

I would like to thank my advisor, Dr. Joydeep Mitra for all of his guidance and patience throughout this process. Thank you for believing in me and welcoming me into your lab. Your advice has been extremely valuable to me. I would like to thank Dr. Subir Biswas for his suggestions and agreeing to serve on my committee. To my lab mates: thank you for your friendship, encouragement, and support.

I would also like to thank my colleagues at Consumers Energy for providing me with the resources needed to conduct my research.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Chapter 1

Introduction

Electric utilities throughout the U.S. are modernizing an electric grid that has been providing electricity for more than a century. Today's electric power grid was originally designed for a one-way flow of electricity from centralized generators to customers through transmission and distribution systems. This electric system has not seen much innovation over the past few decades. In fact, much of the existing grid is analog-based and relies on an aging infrastructure to deliver electricity. Recent advances in grid technologies are allowing utilities to improve reliability while reducing greenhouse gas emissions. One way is through the use of smart grid technology.

Smart grids are networks that use digital and other advanced technologies to monitor and control electricity as it flows through the power grid [1]. Smart grid technologies enable a two-way flow of information between electrical devices and utility operators through advanced communications systems. These technologies also help facilitate the integration of renewable energy resources such as wind and solar into the grid. The electric power grid contains millions of miles of power lines, thousands of substations, protective devices, and transformers [2]. These components play an essential role in the delivery of electric power; however, most of them lack the technology needed to adapt to the changing energy demands of the 21st century. Smart grid technology allows transmission lines and substations to be retrofitted with devices such as phasor measurement units, flexible AC transmission system devices, and other advanced sensors that provide greater levels of control and visibility [3].

Modernization projects are not only occurring in transmission systems, but in distribution systems as well. In addition to distributed generation, utilities are upgrading electrical devices within the distribution system. For example, devices such as regulators, capacitors, and switches are being integrated with communications systems that enable voltage/VAr control and automatic feeder switching [4]. One of the most popular modernization projects, however, is the deployment of advanced metering infrastructures. An advanced metering infrastructure (AMI) is a combination of smart meters, communications networks, and data management systems that enables a two-way flow of information between customers and the utility [5]. The U.S. Department of Energy, together with the electricity industry, has invested over 7.9 billion dollars into 99 Smart Grid Investment Grant (SGIG) projects under the American Recovery and Reinvestment Act [6]. More than half ($4.050 billion) of the allocated funds went to the installation of smart meters, and the deployment of advanced metering infrastructures. Of the 65 SGIG AMI projects, many reported benefits such as: fewer physical meter reads, remote connect and disconnect functionality, identification of energy theft, and reduction of electricity demand. In addition to these benefits, smart meters can also be used for outage notification as well as detecting voltage or power quality issues. A few SGIG projects have integrated AMI systems with existing outage management systems (OMS) [7]. However, many electric utilities outside of the SGIG program are still in the deployment phase and have yet to use smart meters to analyze outage events and identify power quality issues.

1.1 Research Objectives

This thesis presents an analysis of two of the aforementioned benefits of AMI systems: outage event notification, and the identification of power quality issues. This analysis is conducted on an existing electric system that is in the process of deploying smart meters to its 1.8 million electric customers. For outage event notification, smart meter outage events are compared with historical outages in an outage management system to identify differences in outage/restoration times and the number of customers out for a given outage. The purpose of this comparison is to identify possible challenges that could arise when integrating smart meter events into outage management systems. In general, power quality can include a number of issues such as changes in system frequency, voltage levels, or harmonics. In this thesis, power quality refers to the deviation of voltage levels above a specified voltage range. Smart meter voltage data will be used to identify faulty electrical devices such as distribution transformers and regulators before significant damage is done to the electric system. Smart meters provide greater levels of visibility into the distribution system, which allows electric utilities to take a proactive approach to addressing both customer and system issues.

1.2 Organization of Thesis

This thesis contains five chapters, including this introduction. Chapter 2 presents background information including a brief history of electromechanical meters and a description of advanced metering infrastructures. This chapter also describes two systems that are essential to any type of outage or power quality analysis using smart meters—geographic information systems and outage management systems. Chapter 3 describes the analysis of outage events and presents a series of cases comparing the events generated by smart meters to those generated by an outage management system. Chapter 4 describes the analysis of smart meter voltage data to identify equipment issues and presents a series of cases describing the results. Chapter 5 provides concluding remarks and recommendations for future research.

Chapter 2

Background

2.1 History of Electromechanical Meters

The earliest forms of electricity meters can be traced back to the late 1800s. In the late 19th century, alternating current (AC) electric systems were beginning to gain popularity over direct current (DC) electric systems [8]. One of the major advantages of AC systems was the ability to transmit power over long distances using transformers. DC systems, on the other hand, were more expensive and required electricity to be generated near the end user. The widespread adoption of AC systems increased the need for meters that could accurately measure how much energy was being consumed. The previous meters that were used in DC systems were based on an electrochemical reaction in which an electric current passed through an electrolyte with two zinc plates inside of a jar [9]. At the end of the billing cycle, the plates were weighed to see how much zinc was transferred from one plate to the other, which determined how much electric current was supplied to the customer. Not only was it difficult to obtain an accurate reading of the actual amount of energy consumed, these meters were not suitable for AC systems.

To address this issue, engineers began developing several types of electromechanical meters. The majority of these meters were either ampere-hour or watt-hour meters. One of the most commonly used ampere-hour meters in AC systems was developed by Oliver B. Shallenberger in 1888 [9]. This induction meter contained two coils: a large oval shaped coil and a smaller coil placed at an angle inside of the larger coil. Inside of the smaller coil was an aluminum disk attached to a rod with aluminum blades that was used to control the speed of the disk. When an alternating current passed through the larger coil, a secondary current was induced in the inner coil. This created a magnetic field that induced eddy currents into the disk and caused it to rotate. The speed at which the disk rotated was directly proportional to the amount of current flowing through the meter.

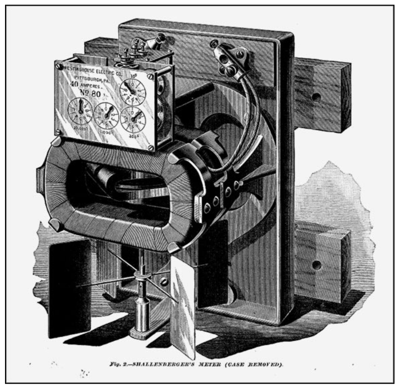

Figure 2.1: Shallenberger's Ampere-Hour Meter [10]

A major drawback of Shallenberger's meter was the fact that it only measured electric current and not the actual amount of power being consumed. This meter operated on the assumption that the current was being supplied to a purely resistive (lighting) load. In this case, the amount of energy consumed would be proportional to the current flowing through the meter. However, the introduction of inductive motor loads created a need for meters that could account for changes in power factor.

In 1889, a Hungarian engineer by the name of Ottó Bláthy patented the first induction watt-hour meter that could be used with both resistive and inductive loads [11]. Bláthy's meter consisted of two electromagnets, a rotating disk, and a permanent braking magnet. The two electromagnets were positioned in such a way that they created two magnetic fields displaced in phase when acted upon by the line voltage and load current. These changing magnetic fields induced eddy currents into the disk causing it to rotate at a speed proportional to the amount of energy being consumed.

A permanent magnet was used as a damping mechanism to control the speed of the disk. Bláthy's idea led Shallenberger to develop an induction watt-hour meter to be used in the U.S. in 1894 [9]. Over the next few decades, several meters were created to expand on the ideas of Bláthy and Shallenberger. These meters aimed to reduce the weight, cost, and improve the accuracy of the previous meters. In addition, meter manufactures such as GE and Westinghouse developed polyphase meters that were used for commercial applications.

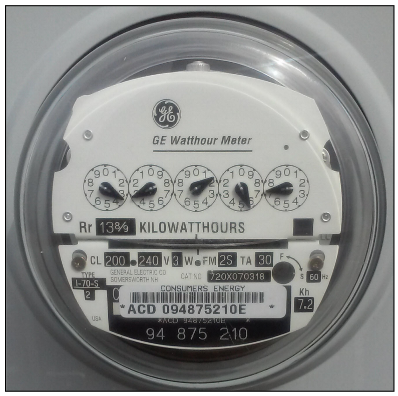

Figure 2.2: Single Phase Watt-Hour Meter

The electromechanical watt-hour meters in use today operate on the same fundamental principles. These meters generally contain similar components: an aluminum disk; display dials; permanent magnets; and a voltage coil and two current coils that are wrapped around an iron core. The voltage coil is connected to the supply voltage and placed above the disk. The two current coils are connected in series to the electric load and placed below the disk. As current flows through the voltage coil containing a large number of turns, a magnetic field is created that is proportional to the supply voltage. The current coils have fewer turns and create magnetic fields that are proportional to the amount of current drawn by the load. These changing magnetic fields induce eddy currents into the aluminum disk causing it to rotate at a speed proportional to the amount of power being consumed by the load. The aluminum disk is connected to a series of gears that turn display dials indicating the amount of power consumed in kilowatt-hours. The permanent magnets control the speed of the disk and prevent it from spinning when there is no power being consumed.

The introduction of digital electronics into the electricity metering industry has eliminated the need for electromechanical meters. Today, many of the existing electromechanical meters are being replaced with advanced meters that not only measure energy consumption but offer a wide range of benefits. These meters, also referred to as smart meters, will be described in the next section.

2.2 Advanced Metering Infrastructure

2.2.1 Smart Meters

A smart meter is a key component of any advanced metering infrastructure. Smart meters, unlike traditional electromechanical meters, have the ability to wirelessly transmit consumption data to the electric utility through a secure network. Prior to smart meters, utility companies had to send meter readers to the customer's location each month to obtain the amount of energy consumed. With smart meters, this consumption information can be sent to the utility daily or in intervals of 15, 30, or 60 minutes [12]. This information can be used to provide accurate electricity bills and develop programs to help customers better manage their energy usage. One major benefit of a smart meter is its ability to send notifications whenever it loses power or is restored. This information can help utilities determine the location and extent of a power outage and identify customers who are still out of power after crews have restored power to an area. Smart meters can also monitor voltage levels at the customer's location. This information can be used to improve power quality and ensure that customers are receiving voltages at levels suitable for power consumption.

The design of a smart meter can vary between manufacturers; however, most smart meters contain similar components. These include digital electronics such as sensors, microcontrollers, and LCD displays. All smart meters contain communications modules that allow data to be sent from the customer to the utility, and vice versa. A smart meter can also have a switch—usually rated at 200 amps—that allows utility companies to remotely connect or disconnect electricity without sending a service person to the location [13, 14].

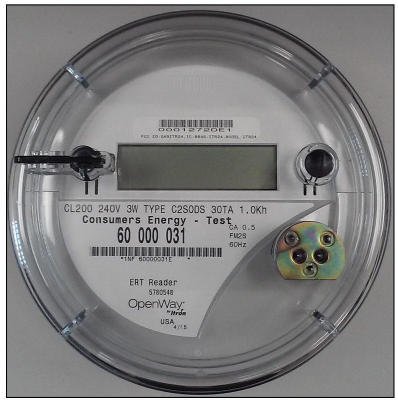

Figure 2.3: Single Phase Smart Meter

There are several ways that a smart meter can measure electricity. These techniques utilize voltage and current sensors. The voltage sensor is typically in the form of a simple resistor divider circuit with two large resistors that reduce the line voltage to a level suitable for the internal electronics of the smart meter [15, 16]. The most commonly used current sensors are shunts, current transformers, and Rogowski coils [15, 17]. The current shunt is a low resistance resistor that is placed in series with the load. As the load current flows through the resistor, a small voltage drop is created across it. This voltage drop and the known resistance of the shunt resistor are used to determine the current drawn by the load. A current transformer consists of a coil of wire wrapped around an iron core. As the current flows through the primary conductor(s) placed inside of the current transformer, a magnetic field is created that induces a current into the secondary coil of the transformer. A burden resistor is used to create a voltage signal that is proportional to the current flowing through the conductor [18]. A Rogowski coil is a coil of wire wrapped around a non-magnetic or air core. Like a current transformer, a Rogowski coil is placed around a conductor carrying load current. The output of a Rogowski coil, however, is a voltage that is a time derivative of the current flowing through the conductor. The induced voltage signal has to be integrated to obtain a signal that is proportional to the current flowing through the conductor [19, 20]. Once the analog voltage and current signals are obtained, they are processed by the internal electronics of the smart meter to display or transmit the electricity consumed by the customer.

2.2.2 Communications Systems

Advanced metering infrastructures enable two-way communication through the use of radio frequency (RF) technologies such as mesh, point-to-point, and cellular [21, 22]. In a RF mesh network, smart meters form local networks with each other and transmit information to nearby routers. These routers gather the meter data and communicate with each other before sending the information to a collector. The collector (usually a tower) provides the final link between the smart meter data and the utility. Mesh networks provide multiple paths for a smart meter to send information, which increases the chances of the data being received by the utility. However, in rural areas where customers tend to be spread apart, mesh technology can require additional infrastructure [21]. In a point-to-point network, each smart meter transmits its information directly to the collector. Since there are no intermediate nodes between the smart meter and the collector, there is less infrastructure needed compared to mesh networks. These networks are used in areas where there is considerable distance between each smart meter [23]. In a cellular network, smart meters utilize the existing networks of cellular companies to transmit data. Each smart meter is equipped with a SIM card that enables the meter to send a message containing its data directly to the utility. There are several advantages associated with cellular networks. To begin, these networks are maintained by the cellular company which helps to reduce the cost and time needed to set up the metering infrastructure. Cellular networks also maintain high levels of reliability and provide widespread coverage.

Power line carrier (PLC) technology can also be used within advanced metering infrastructures. PLC technology allows utilities to leverage the existing distribution system to send and receive information [24]. Smart meters can send information through miles of distribution lines to substations where it is collected and sent to the head-end system. Each of these technologies has its advantages and disadvantages. The choice of communications systems for AMI varies between utilities and can depend on a number of factors. These include the cost to deploy the system, the number of customers served by the utility, the service terrain, and the ability to expand in the future [21, 22, 25].

2.2.3 Meter Data Management Systems

The raw information from smart meters such as consumption data, voltage data, and outage or restoration notifications has to be processed in order to provide operational benefits to the utility. A meter data management system receives this raw data and prepares it for use within the utility. Meter data management systems validate and process smart meter data for a number of applications. These can include billing systems, outage management systems (OMS), and geographic information systems (GIS).

2.3 Geographic Information Systems

A geographic information system is a computer based system that relates asset data to a geographical location. Geographic information systems are built on top of relational databases that contain a variety of data sources stored in tables. These tables of information can be used to answer questions about a system and display the results on digital map. Electric utilities use GIS to create dynamic models of their electric systems. Prior to GIS, electric utilities relied on paper maps to locate electrical devices in the field. With GIS, electric utilities can not only locate electrical devices, they can ask questions based on that data and visualize the results on a map. For example, an electric utility may want to identify all of the customers with smart meters that are downstream from a protective device on a particular circuit. This can be made possible in GIS by querying the customer and protective device tables and creating a layer displaying the results.

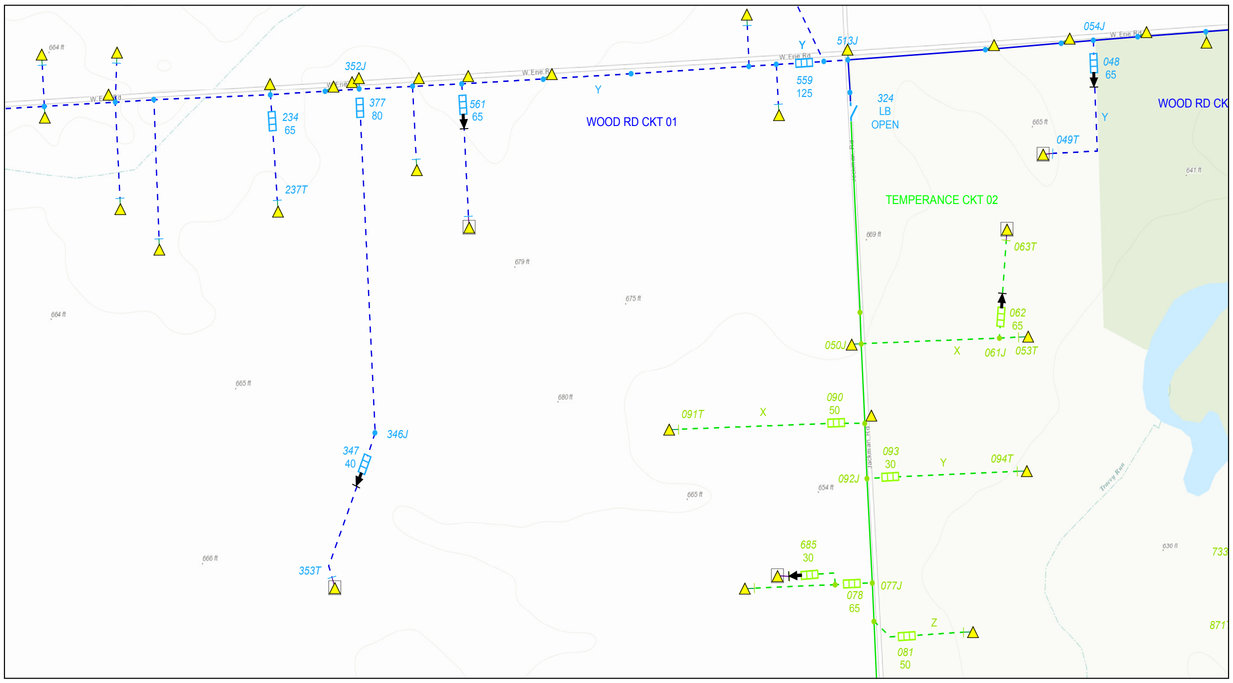

Figure 2.4: Electric Distribution Circuits in GIS

Figure 2.4 shows a portion of an electric distribution system modeled in a geographic information system. In the figure above, each yellow triangle represents a distribution transformer that feeds one or more electric customers. The solid blue and green lines are the three phase primary conductors while the dashed lines represent a single phase. Each fuse has two numbers associated with it. The top number represents the load concentration point (LCP) and the bottom number is the current rating of the fuse in amps. Geographic information systems are essential to any type of smart grid analysis. Smart grid technologies such as the deployment of AMI require an electric model that is up to date to fully realize the benefits. As a result, electric utilities are investing millions of dollars into GIS to correct distribution system models including customer to transformer to phase connectivity. The need for accurate models of the electric distribution system in GIS will continue to grow as more electric utilities begin distribution modernization projects.

2.4 Outage Management Systems

An outage management system is a system that allows electric utilities to manage the process of detecting customer outages and restorations during a storm or interruption. An outage management system is usually connected to several sources of information. This includes a customer information system (CIS) that processes customer trouble calls and a geographic information system that provides a model of the distribution system. As customers call to report outages, an outage management system uses a series of prediction algorithms to identify electrical devices common to the location of those customer calls. Once the upstream devices are found, the electric utility can dispatch service workers to the location to determine the extent of the outage and restore service to those customers.

Traditionally, outage management systems have relied on customer calls as the primary source of information about an outage. However, the deployment of advanced metering infrastructures has made it possible to use smart meters to identify customer outages and restorations. When a smart meter loses power, it sends a notification to the utility indicating the loss of power. These notifications, when integrated into OMS, can provide additional information to help utilities identify the exact number of customers affected by an outage. However, in order to successfully integrate smart meter outage events into OMS, the outage events generated by smart meters should be compared with the events of an outage management system.

Chapter 3

Outage Event Comparison

3.1 Introduction

This chapter introduces the comparison of outage events between smart meters and an outage management system. As mentioned in section 2.4, smart meters can be used as another way to identify customer outages or restorations. In this chapter, a series of cases will be presented to compare, for a particular incident in OMS, the number of smart meters that reported an outage or restoration event and the time in which the event was reported. It is important to note that the following analysis was done using historical outage event data. Comparing historical smart meter outage events with OMS incidents helps identify possible challenges when integrating real-time smart meter data into outage management systems.

3.2 Methodology

3.2.1 Obtaining Outage Data

The first step in the process of comparing smart meter outage events with an OMS is to obtain the data. Whenever a sustained outage occurs on the electric system—whether it's a scheduled outage or one caused by an animal or storm—an incident report is created in an outage management system. This report includes information such as the approximate time of the outage, the cause of the outage, the feeder/circuit impacted, and the predicted number of customers affected by the outage. After the outage has been cleared, the restoration time is recorded and the incident report is archived in a relational database.

INCIDENT_ID	CUSTOMER_COUNT	FEEDER_ID	TIME_OUTAGE	TIME_RESTORED	SUBSTATION	REMARKS_FIELD
2902695	68	082201	7/14/2015 12:50:58 AM	7/14/2015 4:40:00 AM	MONTEREY	TREE,COMPLETE
2902354	91	029102	7/14/2015 12:55:10 AM	7/14/2015 5:55:00 AM	HAMILTON	FUSE
2902354	91	029102	7/14/2015 12:55:10 AM	7/14/2015 5:55:00 AM	HAMILTON	FUSE
2902443	853	103503	7/14/2015 1:08:51 AM	7/14/2015 7:45:00 AM	KNAPP	complete
2903671	105	036804	7/14/2015 4:43:35 AM	7/14/2015 10:56:57 AM	APPLE	ESW CONFIRMED OPEN,cleared top of arrestor in and holding created ord
2903757	11	044202	7/14/2015 7:33:47 AM	7/14/2015 12:21:00 PM	MONTAGUE	part power trees had to resag wire tree crew had to come,tree crew re
2904879	48	067501	7/14/2015 11:44:10 AM	7/14/2015 2:00:05 PM	MCCRACKEN	
2906187	27	061901	7/16/2015 8:34:25 AM	7/16/2015 9:30:00 AM	BROADWAY	REFUSED
2906343	13	060701	7/16/2015 12:24:21 PM	7/16/2015 1:16:00 PM	GETTY	WILDLIFE
2906578	172	102701	7/17/2015 1:23:49 AM	7/17/2015 2:35:00 AM	SAVIDGE	SCOTT CONN FIXED EVERYTHING,car pole.
2906812	66	061902	7/17/2015 8:06:49 AM	7/17/2015 10:11:00 AM	BROADWAY	TREE,TREE,TREE BROKE PRIMARY
2906917	121	030201	7/17/2015 10:16:02 AM	7/17/2015 12:30:00 PM	HOLTON	TREE BROKE BROKE CROSSARM AND PRI
2909605	16	051903	7/17/2015 5:47:06 PM	7/17/2015 6:15:00 PM	SAUGATUCK	lcp 352 40a blown.,lcp 352 40a blown.,fused was 5a, replaced with 30a i & h.
2910030	11	030201	7/18/2015 9:16:26 AM	7/18/2015 6:01:00 PM	HOLTON	Closed LCP 192
2910091	16	082201	7/18/2015 9:47:08 AM	7/18/2015 11:20:00 AM	MONTEREY	REFUSE 280S
2910113	21	035002	7/18/2015 9:48:39 AM	7/18/2015 6:29:00 PM	FRUITPORT	REPLACED 2 BROKEN POLES. REPAIRED PRIMARY
2910357	12	061901	7/18/2015 9:53:13 AM	7/18/2015 4:03:00 PM	BROADWAY	wire down,wire down open 3 wire
2910355	190	124204	7/18/2015 10:16:20 AM	7/18/2015 3:30:00 PM	BRETON	CHANGED BROKEN CUTOUT
2910843	55	051902	7/18/2015 12:28:50 PM	7/18/2015 4:35:00 PM	SAUGATUCK	This three phase 6 copper pri. burnt down again.
2911100	261	051903	7/18/2015 2:13:22 PM	7/18/2015 4:20:00 PM	SAUGATUCK	REFOSED LCP
2911524	11	073101	7/18/2015 6:54:12 PM	7/18/2015 8:00:00 PM	MONA LAKE	arrestor blew and lcp blew. storm order created for arrestor,lcp 534 back in
2911524	11	073101	7/18/2015 6:54:12 PM	7/18/2015 8:00:00 PM	MONA LAKE	arrestor blew and lcp blew. storm order created for arrestor,lcp 534 back in
2911555	26	037301	7/18/2015 6:59:39 PM	7/18/2015 10:00:18 PM	RAVENNA	
2911696	12	031803	7/18/2015 7:04:23 PM	7/18/2015 8:39:00 PM	EAST MUSKEGON	refuse line
2911909	383	103503	7/18/2015 8:21:57 PM	7/18/2015 9:54:24 PM	KNAPP	OK
2912504	119	037301	7/19/2015 3:22:37 AM	7/19/2015 9:07:00 AM	RAVENNA	lem on phases also need tree crew put yellow tape by driveway
2912895	34	090702	7/19/2015 3:50:52 PM	7/19/2015 5:10:00 PM	CLUB	DONT KNOW WHY,UNKNOWN
2913415	29	051903	7/20/2015 12:50:41 PM	7/20/2015 1:00:00 PM	SAUGATUCK	TREE
2914864	27	061201	7/22/2015 2:59:27 PM	7/22/2015 5:42:00 PM	NUNICA	customer cut tree down on line
2915277	24	077601	7/23/2015 11:19:33 AM	7/23/2015 12:07:00 PM	KEATING	refuse tran
2916625	16	061902	7/26/2015 4:37:24 PM	7/26/2015 6:30:00 PM	BROADWAY	LIMB CAME DOWN AND TOOK DOWN PRIMARY. MADE OUR REPAIRS AND PR
2917231	133	062901	7/27/2015 8:15:39 PM	7/27/2015 11:14:00 PM	COOPERSVILLE	Need switching order and 50 kva 120/240, 4800 padmount.,bad can

Figure 3.1: Sample OMS Incident Archive

The next source of data is smart meter outage and restoration events. Smart meters are capable of sending "last gasp" outage notifications when a customer loses power. This is enabled through the use of internal capacitors. These capacitors store enough energy to allow the meter to send one or more messages back to the utility indicating the loss of power. In addition, whenever a smart meter is restored after an outage, a restoration event is created and logged within the smart meter's microprocessor.

Smart meter outage and restoration events are transmitted back to the utility everyday through a secure cellular network. While there are several manufacturers of smart meters on the market, the majority of the meters deployed in this system were developed by Itron (Centron) and General Electric (I-210+c). Each manufacturer has its own unique set of codes corresponding to outage and restoration events. However, once these codes are received by the head-end system they are converted into four major events: primary power down, register power down, primary power up, and register power up. These four events are generated whenever the supply of power to the customers' meter is lost or restored. The first two, primary power down and register power down both indicate the loss of power but come from different places within the meter and are generally within a few seconds of each other. Similarly, primary power up and register power up both correspond to the restoration of power but are within a few seconds of each other. This redundancy improves the chances of an event being recorded whenever an outage or restoration occurs.

Table 3.1: Smart Meter Outage and Restoration Event Codes

Event Code	Description
18001	Primary Power Down
18922	Register Power Down
18002	Primary Power Up
18923	Register Power Up

There are other incidents that can trigger the loss of power for a smart meter. These include an internal failure within the meter itself or a tamper event in which a customer attempts to remove the meter from its socket. In both cases, these incidents have unique event codes that proceed a power down event. However, in comparing outage events with known OMS incidents, the focus is primarily on the four meter events that are triggered by a loss of power to the customer.

3.2.2 Data Processing with Python

The electric system under study provides electricity to over 1.8 million customers. These customers are distributed across 1,145 substations (roughly 2,200 circuits or feeders) and are classified as either residential, industrial, or commercial. On the particular feeders that were selected, over 90% of residential customers had smart meters installed. Table 3.2 shows the total number of customers

Table 3.2: Feeders with a High Percentage of Smart Meters

Substation	Feeder ID	Customers with AMI	Total Customers	% of Customers with AMI
Knapp	103503	2,439	2,489	0.97
Becker	047502	1,840	1,912	0.96
Mccracken	067501	1,774	1,830	0.96
Dutton	051504	1,613	1,668	0.96
Norton	029902	2,044	2,134	0.95
Apple	036804	2,046	2,138	0.95
Broadway	061901	1,587	1,666	0.95
Getty	060701	3,024	3,183	0.95
Apple	036801	1,240	1,296	0.95
Mccracken	067504	1,222	1,284	0.95
Broadway	061902	986	1,030	0.95
Mona Lake	073101	2,492	2,627	0.94
Becker	047501	2,219	2,337	0.94
Holton	030201	1,688	1,808	0.93
Breton	124204	2,027	2,164	0.93
Evanston	012802	559	597	0.93
Ravenna	037301	651	693	0.93
Hickory	034202	911	990	0.92
Saugatuck	051903	1,330	1,442	0.92
Dutton	051501	1,133	1,228	0.92
Hamilton	029102	664	724	0.91

on each feeder as well as the number of customers with smart meters. The data used for the analysis was gathered from 16 different substations (21 feeders) between June and July of 2015.

As previously mentioned, the two main sources of data for this analysis are smart meter outage and restoration events and the outage information from OMS. The outage and restoration events were extracted from the meter data management system and stored in two separate csv files. Both files contain information such as the time of the event, the meter number associated with that event, the name and address of the customer, and the feeder and transformer that the meter is connected to. The main difference between the files is that the two outage event codes, primary power down and register power down, are stored in one file and the two restoration event codes, primary power up and register power up are stored in another file. The OMS outage information is also stored in separate csv files. One file contains 30 outage incident reports with a varying number of customers affected. The other file has a list of each customer affected for a given incident ID. The number of customers affected is determined from the outage management system's prediction algorithm which factors in the electric GIS model and the location of customer trouble calls.

The python programming language was used for the outage event comparison. Python has a number of open source scientific packages and libraries for data analysis. One of the most popular libraries, and the one that will be used for the following analysis, is the *pandas* library. Additional information about the *pandas* library can be found in [26, 27]. The source code used for the analysis can be found in the appendix.

The program works by first reading in the data and storing it into tables or *pandas* DataFrames. Next, an empty list is created to store the results of the comparison. For each incident or outage, the predicted number of customers affected according to OMS is found. The outage time, restoration time, and feeder ID of the outage from the incident report is then extracted. A smart meter is generally expected to report an outage before a customer calls in. If a customer wakes up, notices that the power is out, and calls the utility at 8:00am, this is not necessarily the time that the customer lost power. The OMS will record 8:00am as the outage time; however, if that customer had a smart meter, that meter may have recorded an outage event at 7:00am. Therefore, in order to compare smart meter outage events with an OMS, there should be a sufficient time range. For this analysis, two hours before and one hour after an OMS outage or restoration is used.

The next step is to find smart meter outage and restoration events that are within the specified time range and on the same feeder as the OMS incident. After these events are found, they are sorted in ascending order by timestamp and any duplicate "last gasp" events are removed. The smart meter outages and the OMS customers are then combined into a single table. If a meter (or customer account number) appears twice in the table, this is a meter that was out according to both the OMS and the smart meter. Next, get the restoration times of the smart meters that matched the

OMS and combine the outage and restoration times of the meters that matched into a single table.

After the smart meters that matched the OMS are found, check for any meters that did not match. These meters can be found by searching the combined smart meter outages and the OMS customers table for unique account numbers. If a meter has a unique account number but does not have an event code associated with it, that meter was out according to the OMS and was either an electromechanical meter which does not have an event code or a smart meter that did not communicate. Conversely, if a meter has a unique account number and an event code, it was a smart meter that seen an outage during the specified time range but was not predicted by the OMS algorithm. The outage and restoration time of this meter is stored and the results of the outage event comparison are added to the initial comparison list. Figure 3.2 provides a flowchart of the outage event comparison.

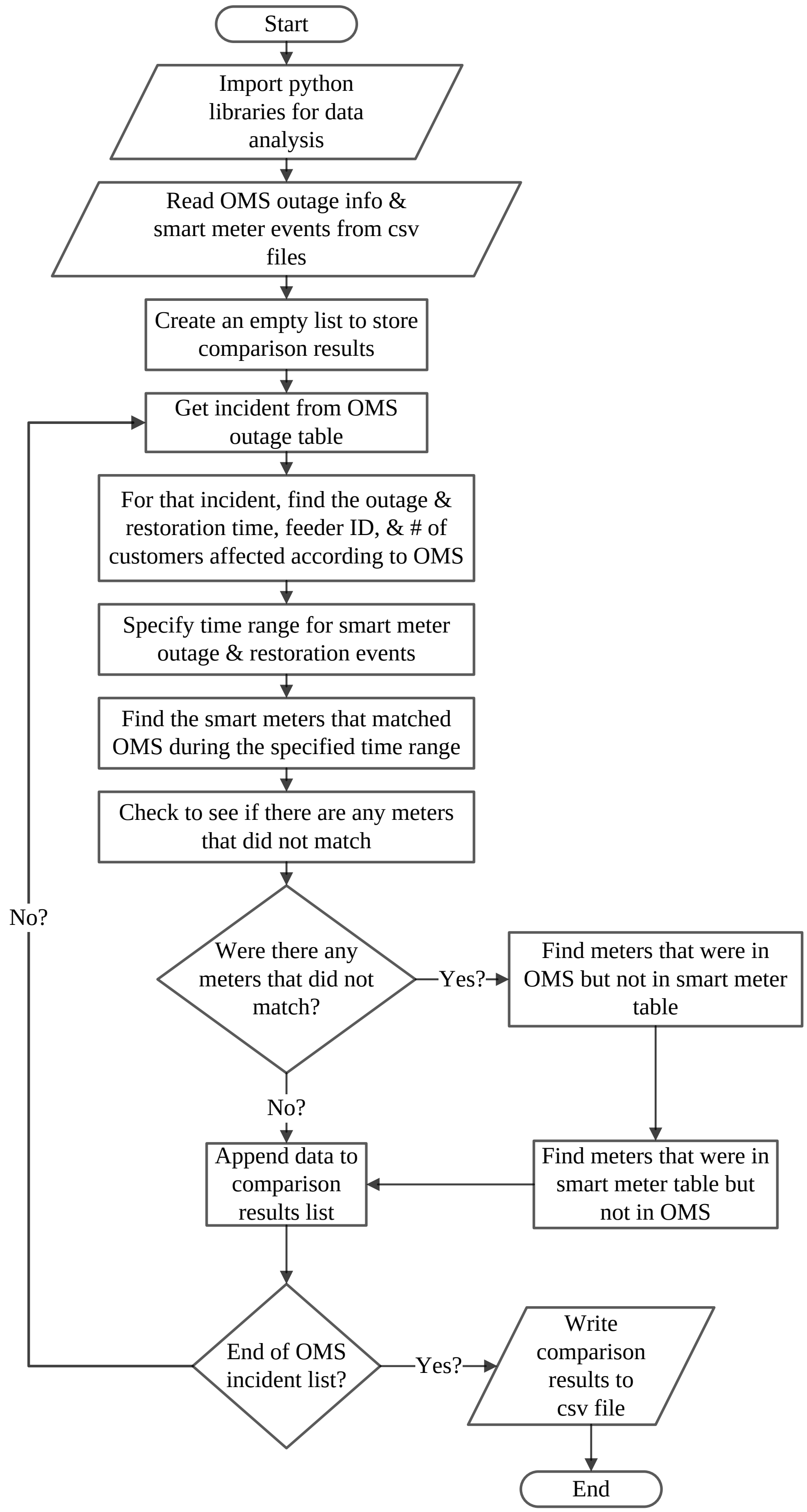

Figure 3.2: Flowchart of Outage Event Comparison

Table 3.3: Outage Event Comparison Results

Incident ID	Feeder ID	OMS Customers	# of SMs that matched OMS	# of Mtrs in OMS that did not communicate	Total # of SMs that reported an outage	Total # of SMs restored	Outage Cause
2884686	124204	21	21	0	21	21	Trees
2886483	034202	71	68	3	440	437	Trees
2893719	061901	12	11	1	12	12	Animal
2893970	047501	11	8	3	8	8	Transmission/Generation
2894541	103503	61	56	5	56	56	Planned/Scheduled
2896668	051504	113	107	6	107	107	Unique Incident
2897071	029102	37	35	2	73	73	Animal
2897614	037301	21	15	6	16	15	Trees
2897980	029902	36	35	1	307	307	Animal
2898607	103503	21	20	1	20	20	Animal
2898628	034202	71	68	3	68	68	Trees
2899241	036804	43	40	3	84	42	Equipment Failure
2899786	047502	13	13	0	14	14	Animal
2900028	103503	11	11	0	11	11	Animal
2900337	073101	78	63	15	882	882	Animal
2901004	103503	50	50	0	53	53	Trees
2901113	124204	13	12	1	13	13	Animal
2901343	036801	23	20	3	21	21	Trees
2901547	067504	18	12	6	13	12	Weather
2901600	012802	14	13	1	31	30	Weather
2902354	029102	91	89	2	90	90	Weather
2903671	036804	105	102	3	102	102	Trees
2904879	067501	48	35	13	37	37	No specific cause
2906187	061901	27	8	19	8	8	Unique Incident
2906343	060701	13	13	0	13	15	Animal
2906812	061902	66	62	4	70	69	Trees
2909605	051903	16	15	1	15	15	Unique Incident
2910030	030201	11	9	2	10	10	Trees
2911524	073101	11	9	2	179	180	Weather
2899212	051501	10	8	2	100	100	Public

3.3 Analysis

In this section, a series of cases will be presented to summarize the results of the outage event comparison shown in Table 3.3. The results from the 30 outage incident reports can be grouped into three categories. The first category, where the number of customers predicted by the OMS matched with the number of smart meters that reported an outage during the specified time frame, is covered in Case 1. Case 2 covers different scenarios where the number of OMS customers and smart meters did not match. The last case explores the impact of momentary smart meter outages—that is, meter outages that last between 5 and 10 seconds—on the outage event comparison.

3.3.1 Case 1

One outage in which the number of customers out according to the OMS matched with the number of smart meters that reported an outage is incident number 2884686. This outage was caused by a tree that fell on a primary conductor, affecting 21 customers. Table 3.4 shows the meter number, outage time, and restoration time of each customer. One thing to notice is that each meter has the same outage and restoration time according to the OMS. Table 3.5 shows the outage time, restoration time, and transformer of the smart meters that reported an outage during the specified time range and on the same feeder as the OMS incident. The smart meters that reported outages are fed from three different distribution transformers; ten meters are connected to transformer 0611091302, eight are connected to 0611091201, and the other three are connected to 0611091306.

The three smart meters connected to transformer 0611091306 were the first to experience an outage. These meters lost power at 01:40 on 6/20/2015. Figure 3.3 shows the location of the transformers in relation to the upstream protective device which is circled in red. The two transformers

Table 3.4: OMS Customers for Incident Number 2884686

Meter	OMS Outage Time	OMS Restoration Time	Feeder ID	Incident ID
10267930	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10263085	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10283738	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10279671	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10283740	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10285103	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10282715	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10245786	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10245787	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10245773	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10245785	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10245774	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10245788	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10248094	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10245775	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10248095	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10248096	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10248093	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10263086	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10267929	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686
10267932	6/20/2015 03:04:18	6/20/2015 06:30:00	124204	2884686

Table 3.5: Smart Meter Outages for Incident Number 2884686

Meter	SM Outage Time	SM Restoration Time	Feeder ID	Transformer
10267930	6/20/2015 02:55:39	6/20/2015 06:02:41	124204	0611091302
10263085	6/20/2015 02:55:41	6/20/2015 06:02:43	124204	0611091302
10283738	6/20/2015 02:55:49	6/20/2015 06:02:51	124204	0611091302
10279671	6/20/2015 01:40:08	6/20/2015 06:03:09	124204	0611091306
10283740	6/20/2015 02:55:48	6/20/2015 06:02:49	124204	0611091302
10285103	6/20/2015 01:40:08	6/20/2015 06:03:08	124204	0611091306
10282715	6/20/2015 01:40:08	6/20/2015 06:03:08	124204	0611091306
10245786	6/20/2015 02:55:46	6/20/2015 06:02:47	124204	0611091201
10245787	6/20/2015 02:56:04	6/20/2015 06:03:05	124204	0611091201
10245773	6/20/2015 02:55:46	6/20/2015 06:02:47	124204	0611091201
10245785	6/20/2015 02:55:46	6/20/2015 06:02:47	124204	0611091201
10245774	6/20/2015 02:55:47	6/20/2015 06:02:48	124204	0611091201
10245788	6/20/2015 02:55:47	6/20/2015 06:02:49	124204	0611091201
10248094	6/20/2015 02:55:37	6/20/2015 06:02:39	124204	0611091201
10245775	6/20/2015 02:55:44	6/20/2015 06:02:46	124204	0611091201
10248095	6/20/2015 02:55:47	6/20/2015 06:02:48	124204	0611091302
10248096	6/20/2015 02:55:44	6/20/2015 06:02:45	124204	0611091302
10248093	6/20/2015 02:55:41	6/20/2015 06:02:42	124204	0611091302
10263086	6/20/2015 02:55:42	6/20/2015 06:02:43	124204	0611091302
10267929	6/20/2015 02:55:40	6/20/2015 06:02:41	124204	0611091302
10267932	6/20/2015 02:55:41	6/20/2015 06:02:42	124204	0611091302

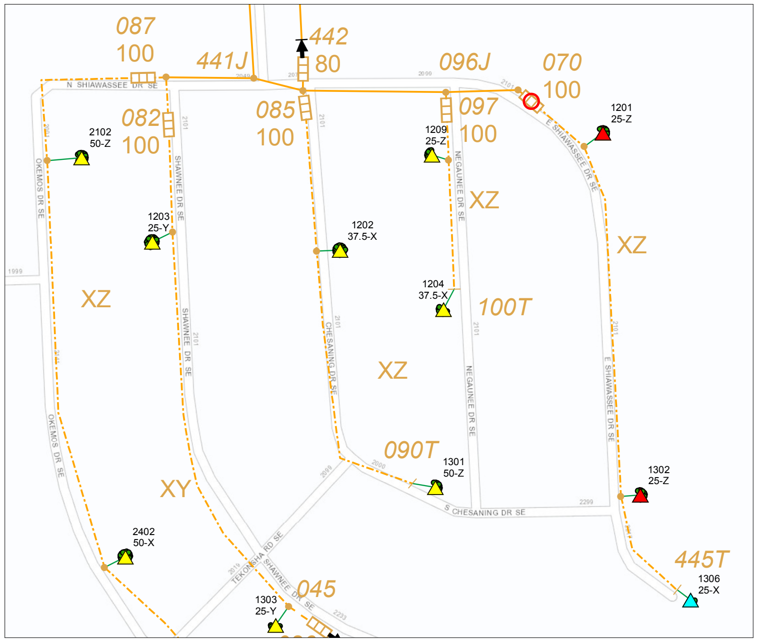

Figure 3.3: GIS Map for Incident 2884686

in red—0611091302 and 0611091201—are connected to the Z phase conductor. Transformer 0611091306 is shown in blue and connected to the X phase. According to the OMS incident call log, an emergency call was made at 01:50, which corresponds to the time that the three meters lost power. It is likely that the tree fell on the X phase conductor, since these three meters lost power around the same time that the call was placed.

To isolate this fault from the rest of the electric system, the upstream protective device—which is a 100A fuse—was opened. The incident report mentions that an electric service worker opened the fuse at 03:04 to repair the primary conductor. This is also the same outage time of the 21 meters in the OMS. The smart meters on the other two transformers downstream of that fuse recorded an outage time of 02:55, which is about 10 minutes earlier than the OMS outage time. After the repairs were made, the fuse was closed and power was restored to the affected customers.

Another outage that falls into this category is incident number 2900028. This outage was caused by a bird that came in contact with a pole mounted distribution transformer, which resulted in 11 customers losing power. Seven of the eleven customers called to report a power outage. According to the OMS incident call log, the first customer call was received at 08:55:36 on 7/11/2015 and the last call was received at 10:21:56. Since the outage management system typically uses the time of the first customer call as the outage time, all 11 meters connected to that transformer had an outage time of 08:55:36. The OMS restoration time of those meters was 11:00. All of the meters connected to that transformer were smart meters. Table 3.6 shows the outage and restoration time seen by each smart meter. The outage and restoration times were roughly the same between the smart meters and the outage management system.

Table 3.6: Smart Meter Outages for Incident Number 2900028

Meter	SM Outage Time	SM Restoration Time	Feeder ID	Transformer
10250194	7/11/2015 08:52:58	7/11/2015 10:53:51	103503	711171204
10056550	7/11/2015 08:53:02	7/11/2015 10:53:54	103503	711171204
10255474	7/11/2015 08:52:55	7/11/2015 10:53:48	103503	711171204
10255473	7/11/2015 08:52:54	7/11/2015 10:53:46	103503	711171204
10255475	7/11/2015 08:52:56	7/11/2015 10:53:48	103503	711171204
10255450	7/11/2015 08:52:57	7/11/2015 10:53:48	103503	711171204
10252798	7/11/2015 08:53:14	7/11/2015 10:54:05	103503	711171204
10255497	7/11/2015 08:52:56	7/11/2015 10:53:48	103503	711171204
10256001	7/11/2015 08:52:59	7/11/2015 10:53:51	103503	711171204
10256003	7/11/2015 08:52:59	7/11/2015 10:53:51	103503	711171204
10250198	7/11/2015 08:53:00	7/11/2015 10:53:52	103503	711171204

3.3.2 Case 2

This case describes outages where the number of customers out according to the OMS differs from the number of smart meters that reported an outage. Three outages will be covered that explain possible reasons for the differences in Table 3.3. The first one is incident number 2904879. The incident report mentions that a fuse opened, which resulted in 48 customers losing power, but does not indicate what caused the fuse to open. Each one of the 48 customers out according to the OMS customer list had an outage time of 11:44:10 and a restoration time of 14:00:05 on 7/14/2015.

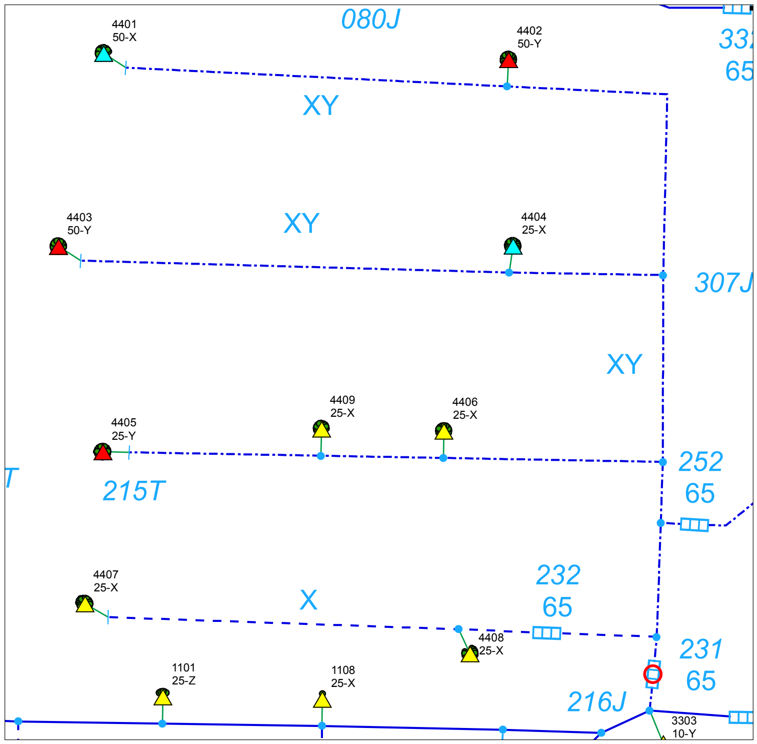

Figure 3.4: GIS Map for Incident 2904879

There were 37 smart meters that reported an outage on the same feeder as the OMS incident. All 37 lost power around 11:33 and were restored around 13:58 on the same day. Two of these meters were within the specified time range, but were not predicted by the OMS. The other 35 smart meters were predicted by the OMS. Figure 3.4 shows the three distribution transformers (0917024403, 0917024402, and 0917024405) that powered the 35 matching smart meters in red and the two transformers that powered the two smart meters that did not match in blue. From the GIS model shown above, the 35 smart meters that matched OMS are all connected to the Y phase. It is possible that the two smart meters that reported an outage are actually connected to the Y phase and not the X phase as shown in the model.

In the OMS customer list, there were 13 meters that did not communicate an outage. Two of these meters are electromechanical meters and are not capable of sending an outage event. The other meters are smart meters that did not communicate an outage. Table 3.7 shows the

Table 3.7: 13 Meters that did not communicate for Incident Number 2904879

Meter	OMS Outage Time	OMS Restoration Time	Transformer	Event Code
10120565	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024402	N/A
10124806	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024405	N/A
10124714	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024405	N/A
10124713	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024405	N/A
10124715	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024405	N/A
10124782	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024405	N/A
10124783	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024405	N/A
10124784	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024405	N/A
10121759	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024402	N/A
63154718	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024402	N/A
10122010	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024402	N/A
10107098	7/14/2015 11:44:10	7/14/2015 14:00:05	Removed from Service	N/A
65036386	7/14/2015 11:44:10	7/14/2015 14:00:05	0917024403	N/A

meter number and transformer associated with each meter. The meter numbers that start with 10* indicate that they are smart meters, and the meters that start with 6* are electromechanical. With the exception of one meter (10107098) that was removed from service, all of these meters were connected to one of the three matching transformers in Figure 3.4 so they should have recorded an outage event but did not.

The second outage is incident number 2906187. Like the previous outage, a fuse opened causing 27 customers to lose power. The outage time and restoration time of the 27 customers according to the OMS was 08:34:25 and 09:30 respectively on 7/16/2015. Out of the 27 customers that were out according to the OMS, only 8 smart meters reported an outage. These meters lost power around 08:17 and were restored around 09:46. The remaining 19 meters that were out according to the OMS are smart meters that did not report an outage. These 19 meters are connected to four transformers: seven of the meters are connected to transformer 0916041101, six meters are connected to 0916041102, three meters are connected to 0916041108, and three meters are connected to 0916041103. In Figure 3.5, all of the transformers were downstream of the 100A fuse. When that fuse opened, all 27 smart meters should have reported an outage. However, only 8 meters

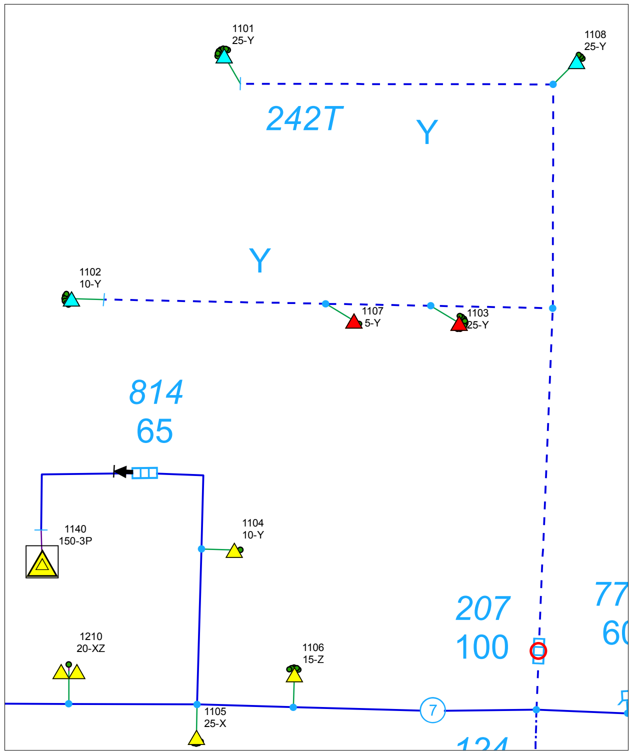

Figure 3.5: GIS Map for Incident 2906187

recorded an outage event. These meters are connected to the red transformers.

The third outage is incident number 2897071. The OMS incident report mentioned that an animal was the cause of this outage and that 37 customers were affected. However, there were a total of 73 smart meters (including 35 that matched the OMS) that reported an outage on the same feeder and within the same time range. The outage and restoration time of the 37 customers according to the OMS was 22:23:58 on 7/5/2015 and 02:35 on 7/6/2015, respectively. All of the 73 smart meters that reported an outage lost power around 22:30 except for one meter that lost power at 22:17:53. The customer associated with this meter was the first to call about the outage and mentioned arcing power lines.

Figure 3.6 shows the location of all 73 smart meters that reported an outage. The smart meters that matched with OMS are connected to the red transformers and the smart meters that did not match are connected to the light blue transformers. The dark blue transformer is the location of the

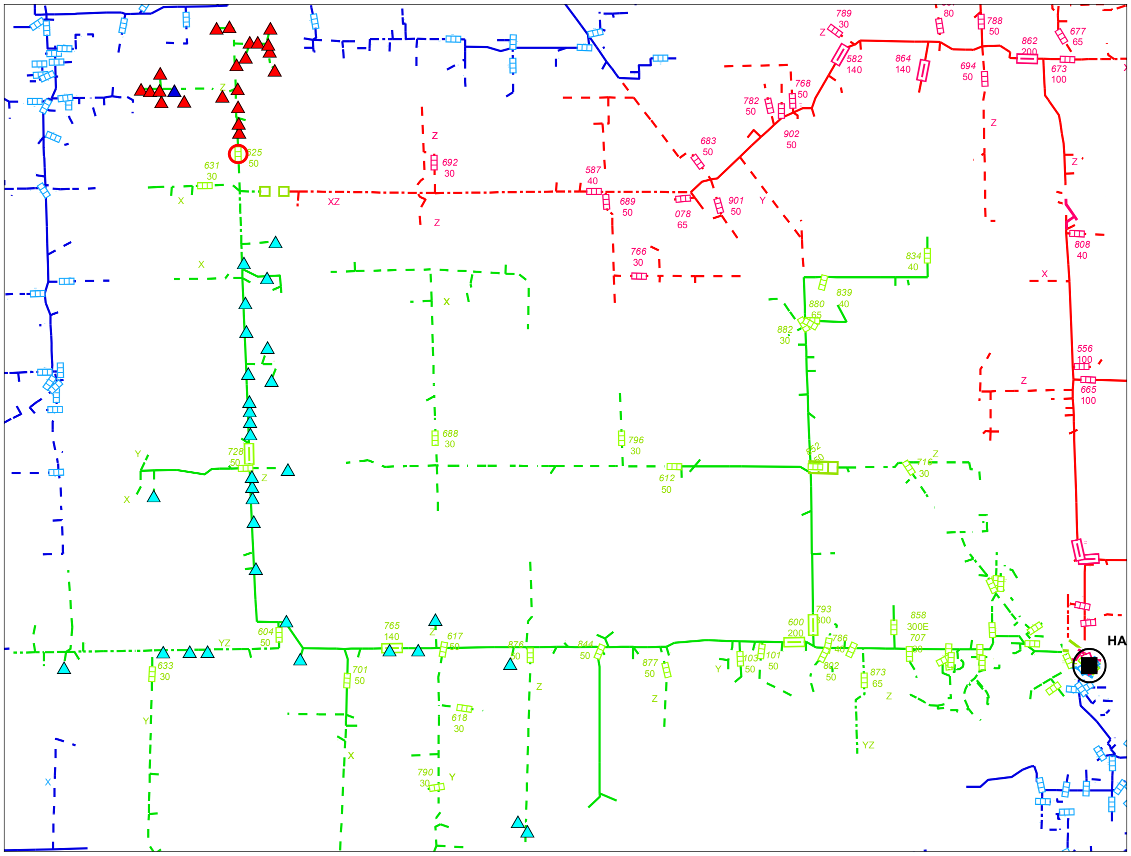

Figure 3.6: GIS Map for Incident 2897071

first customer who called to report the outage. According to OMS, the fuse (circled in red) opened which caused 37 customers to lose power. However, there were 38 smart meters upstream of that fuse that also lost power. These meters had the same restoration time of the meters downstream of the fuse but were not predicted by the OMS. Most of the 73 smart meters were connected to the Z phase.

3.3.3 Case 3

This case covers the impact of momentary smart meter outages on the outage event comparison. One outage that falls into this category is incident number 2911524. This outage resulted from bad weather that caused a fuse and arrestor to blow affecting 11 customers. The outage and restoration time of the 11 customers according to the OMS was 18:54:12 and 20:00 respectively on 7/18/2015. There were approximately 179 smart meters that experienced an outage during this time frame on the same feeder. The outage and restoration time of the 8 meters that matched the OMS customer list was 18:36 and 19:53 respectively. The remaining smart meters that reported an outage were smart meters that experienced a momentary outage that lasted a few seconds. Table 3.8 shows the outage and restoration time for three of these smart meters. The remaining smart meters had similar outage and restoration times.

Table 3.8: Momentary SM Outages for Incident Number 2911524

Meter	SM Outage Time	SM Restoration Time	Feeder ID	Transformer
10111597	7/18/2015 18:36:47	7/18/2015 18:36:53	073101	0916154104
10111541	7/18/2015 18:36:47	7/18/2015 18:36:52	073101	0916154104
10111543	7/18/2015 18:36:50	7/18/2015 18:36:55	073101	0916154140

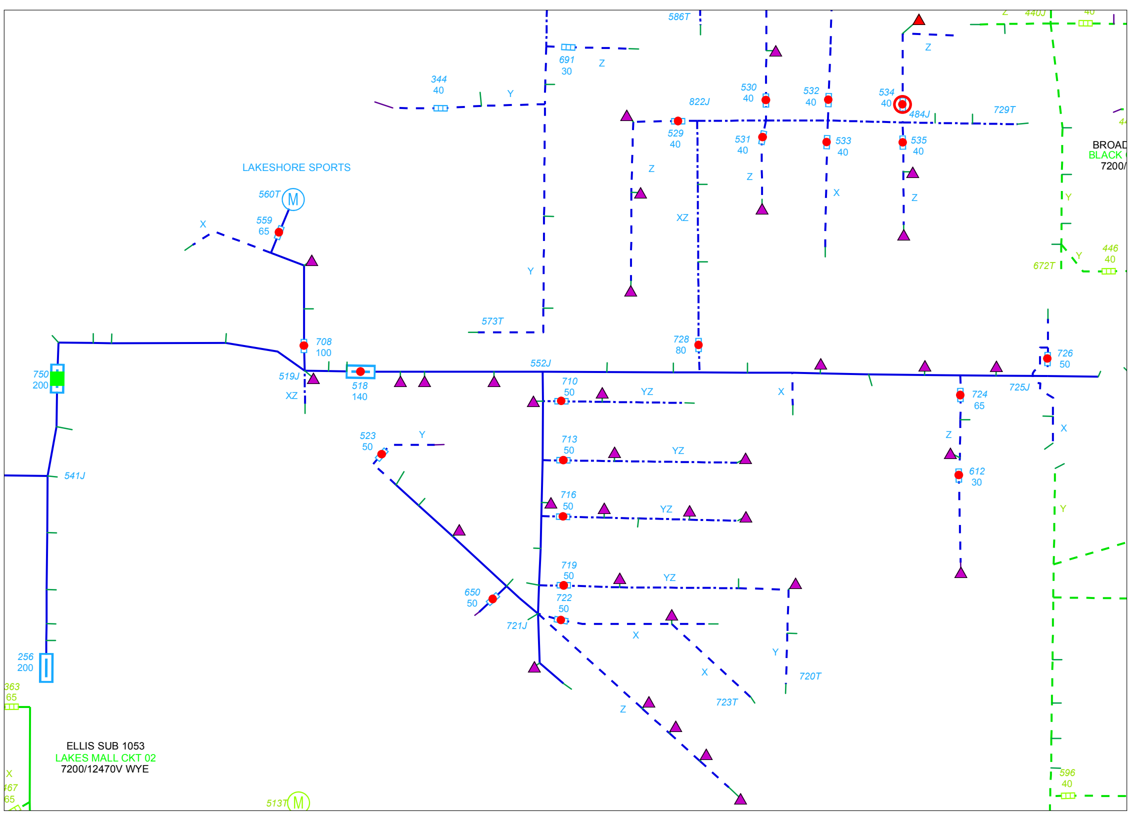

Figure 3.7: GIS Map for Incident 2911524

Figure 3.7 shows the location of the smart meters that reported an outage. In this figure, the 11 meters that were out according to the OMS are connected to the red transformer. The meters that experienced a momentary outage are connected to the purple transformers. The red dots indicate all of the protective devices that are downstream of the recloser. From the figure, we can see that the 200A recloser opened and closed which caused the momentary outages.

Another outage that falls into this category is incident number 2899212. This outage was caused by a car that hit a pole. The collision caused the primary lines to touch, which resulted in 10 customers losing power for about 50 minutes. The OMS and smart meter outage and restoration times of the meters that matched were roughly the same. There were a total of 100 smart meters that reported an outage around the same time; eight meters matched the OMS, and 92 meters experienced momentary outages similar to the previous outage. In Figure 3.8, the matching meters are connected to the red transformers and the meters that experienced momentary outages are connected to the purple transformers.

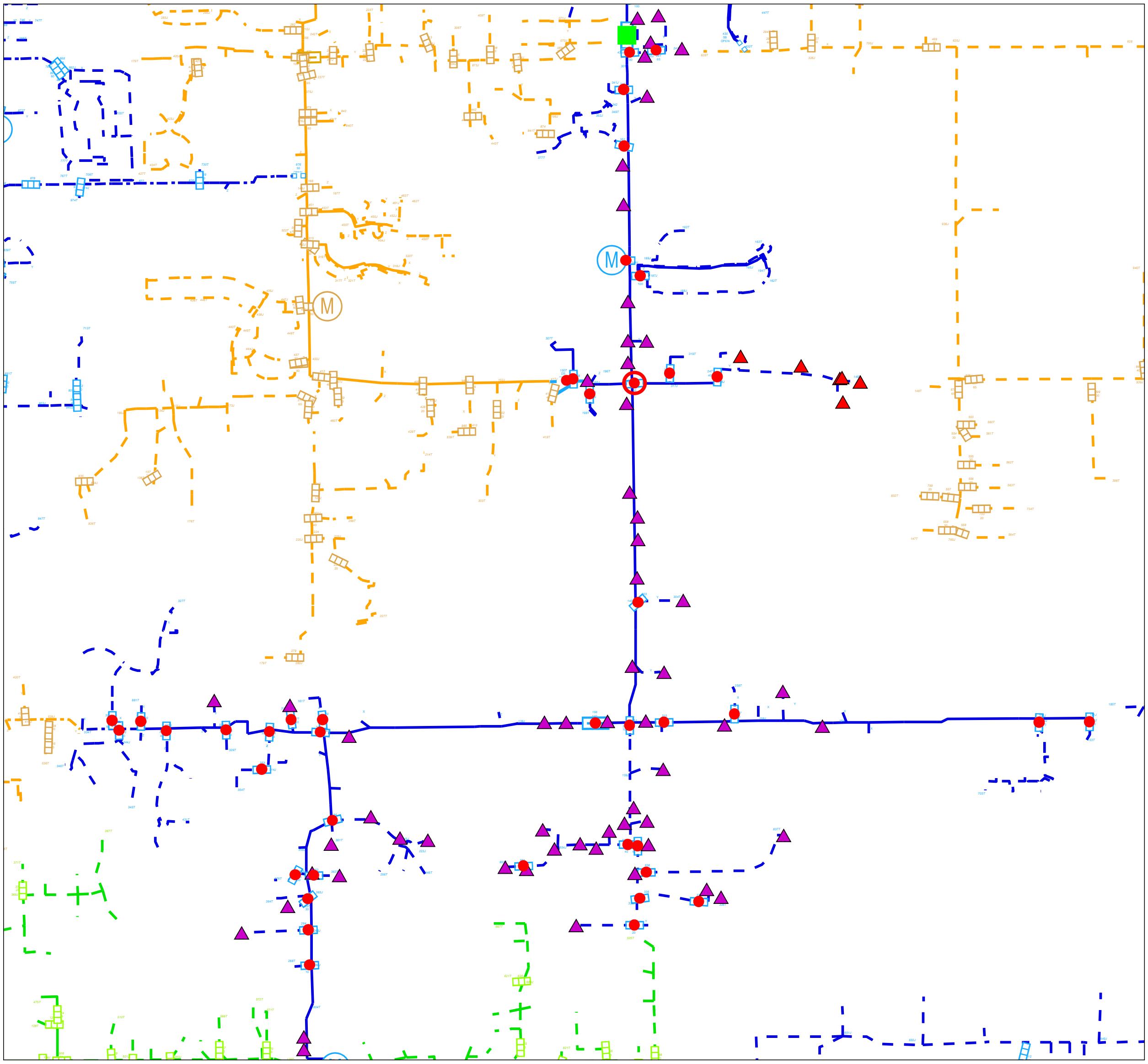

Figure 3.8: GIS Map for Incident 2899212

Chapter 4

Power Quality Analysis

4.1 Introduction

In addition to reporting power outages, smart meters can also be used to identify power quality issues. The term power quality can include a number of issues such as changes in system frequency, voltage, or harmonics. One definition of power quality that applies to the following analysis is given in [28]. Here, the authors define power quality as any power problem manifested in voltage, current, or frequency deviations that results in failure or misoperation of customer equipment. This chapter will primarily focus on power quality issues related to voltage deviations above a given threshold. These issues are identified through the use of smart meter voltage data.

The electric power grid provides power to millions of customers and is composed of three main levels—generation, transmission, and distribution. At the generation level, electric generators produce power at voltages between 11 and 35kV. These voltages, however, are too low to efficiently transmit power over long distances. The transmission system uses transformers and other equipment to increase the generation voltage to a level between 60 and 765kV. As power travels through the transmission system, the voltage is gradually reduced at substations until it reaches the distribution system.

Many residential and commercial customers are connected to the distribution system. Commercial customers are fed from primary distribution lines that operate at voltages between 4 and 35kV.

Residential customers, on the other hand, require voltages less than those at the primary distribution level. A distribution transformer reduces the primary voltage to a secondary level—typically at 120/240 volts.

Electric utilities are required to provide power to customers within a certain voltage range. The preferred service voltage range according to the ANSI C84.1 standard is $\pm$ 5% of the nominal voltage [29]. On a 120 volt nominal system, this range is between 114 and 126 volts. Exceptions are made for momentary voltage deviations that can result from load switching, starting electric motors, or weather events such as lightning. This standard applies to voltages that are outside of the threshold for a sustained period of time.

Before the use of smart meters, electric utilities took a more reactive approach to addressing voltage issues at the customer level. The only way for a utility company to know if a customer was experiencing voltage issues was through a customer complaint. In a typical scenario, a customer would call the utility after experiencing equipment failure or noticing dimming or flickering lights. The utility would then send a service worker to the customers' home to further investigate the issue. If the service worker could not directly determine the cause of the issue, a power quality monitor may be installed to record the customers' voltage over an extended period of time. If the results indicate that there is a voltage problem, steps would be taken to fix the issue.

A major benefit of a smart meter is its ability to monitor voltage at the customers' location. With smart meters, utilities can proactively monitor voltage levels to ensure that customers are receiving voltages within the tolerance range specified in ANSI C84.1. The next section describes the methodology used to identify voltage issues using smart meters.

4.2 Methodology

4.2.1 Service Lines and Meter Types

Service lines are conductors connected to the secondary bushings of a distribution transformer that provide power to an electric customer. A typical 120/240 volt single-phase residential service has three conductors; two "hot" wires and one neutral wire. The voltage between any hot wire and the neutral is 120 volts. The two hot wires are insulated to avoid contact with each other. Household appliances such as electric water heaters and dryers are connected between the two hot wires, which provide a voltage of 240 volts.

Depending on the service provided to the customer, there are different types of meters that can be installed. Most of the residential customers in this system have a 1PH, 3W, 200A, 240V, 2S meter. These abbreviations indicate that the meter is a single-phase meter (1PH) that has three service wires (3W) entering its meter socket at a current of 200 amps and a voltage of 240 volts. The 2S refers to the "form" type of the meter which explains the wiring configuration of the meter socket. Figure 4.1 shows a basic form 2S meter socket configuration.

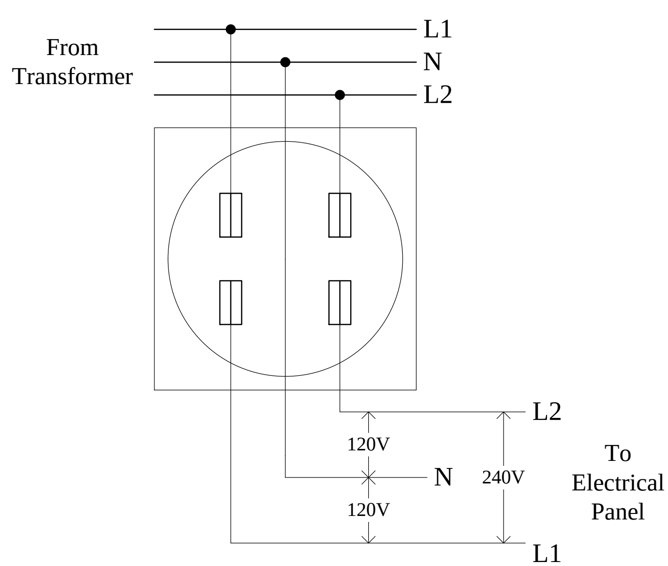

Figure 4.1: Simple Form 2S Configuration

4.2.2 Obtaining Voltage Data

The voltage data used in this analysis was extracted from the OSIsoft PI system. The OSIsoft PI system is a data historian that stores data from utility assets such as smart meters, capacitors, and other sensors [30]. The PI system allows utilities to actively monitor asset data and obtain insights from historical data. As mentioned in section 3.2.1, the majority of smart meters deployed in this system were developed by Itron and General Electric. The PI system has interfaces for each meter manufacturer allowing the data from different smart meters to be easily integrated into the historian.

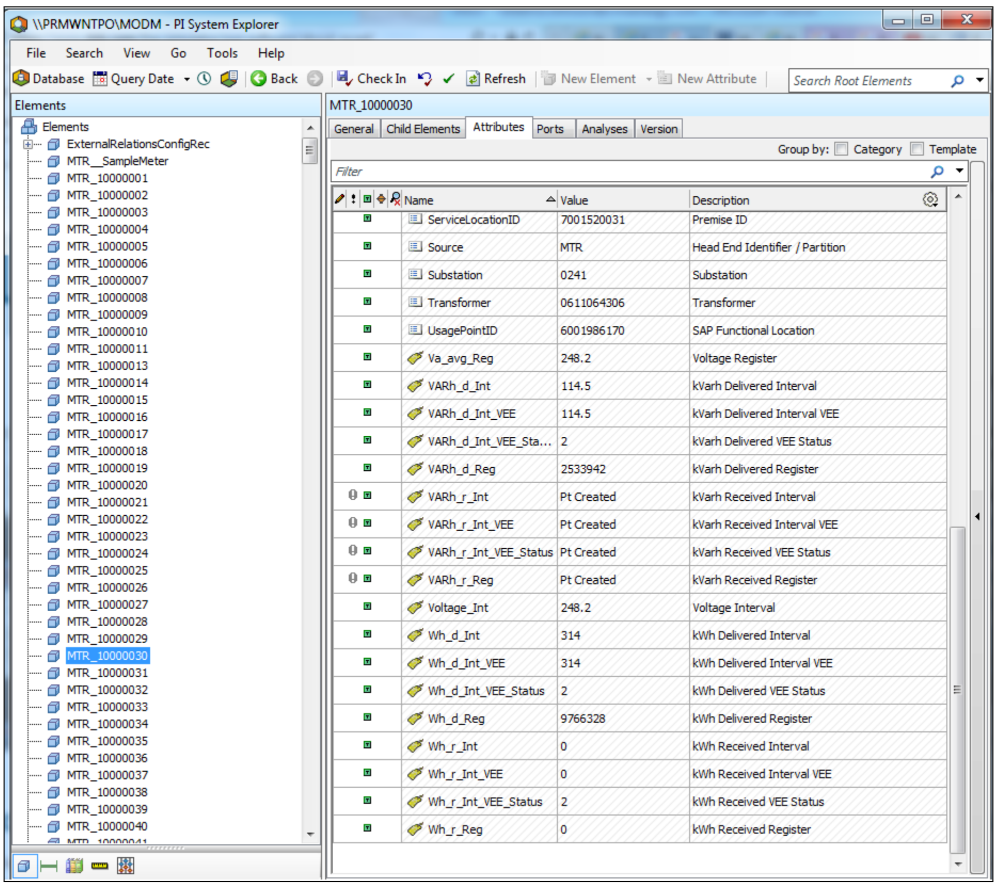

Figure 4.2: PI System Screenshot

Figure 4.2 shows a screenshot of the database that contains a list of smart meters deployed in the system. Each meter (or element) shown has several attributes associated with it. These include connectivity information such as the substation, feeder, and transformer of the meter, and interval data such as hourly voltage or consumption data. At the time of this analysis there were roughly 700,000 smart meters in the database.

The PI system has a number of client tools to extract meter data from the database. The most commonly used tools are PI ProcessBook, PI Coresight, and PI DataLink. PI ProcessBook allows users to graphically visualize attribute data. PI Coresight is a web-based tool used to create and share displays. In this thesis, PI DataLink was used to extract the smart meter voltage data. PI DataLink is a Microsoft Excel add-in that allows users to import PI system data into Excel for further analysis.

Using PI DataLink, an average voltage over a five-day period (from October 16th to October 21st of 2015) was calculated for each of the 700,000 smart meters. The majority of these meters were 120/240 volt meters that had a nominal voltage of 240 volts. According to the ANSI C84.1 standard, the voltage of these meters should remain within $\pm$ 5% of 240 volts or between 228 volts and 252 volts. In this thesis, only the cases where the average voltage exceeded the upper threshold of 252 volts were analyzed. After the finding the meters with a high average voltage, the standard deviation of the hourly voltage data was calculated to see if there were any indications of erroneous data. For example, if a meter had an average voltage above 252 volts and a low standard deviation, this would indicate that the hourly voltage values of that meter were close to the average. On the other hand, if a meter had a high average voltage and a high standard deviation, this could indicate that one or more of the hourly values were far from the average value which would warrant further investigation.

4.3 Analysis

After obtaining an average voltage for all of the meters in the PI system, approximately 1% of the meters (6,873) had an average voltage greater than 252 volts. Table 4.1 shows the voltage range of the meters with high voltage. These meters were grouped into three voltage ranges. The first range contains the meters that had an average voltage greater than or equal to 10% of the nominal 240 volts. The second range contains the meters with an average voltage between 7 and 10%, and the third range contains the meters between 5 and 7%. The meters in the first range are examined in case 1. The meters in the second and third ranges are examined in cases 2 and 3, respectively.

Table 4.1: Voltage Range of Meters with High Voltage

Voltage Range (VRMS)	Percent from Nominal Voltage	Number of Meters
$V \geq 264$	$V \geq 10\%$	50
$256.8 \leq V < 264$	$7\% \leq V < 10\%$	891
$252 < V < 256.8$	$5\% < V < 7\%$	5,932

4.3.1 Case 1

There were 50 meters in the first voltage range. The average voltage of these meters range from 264 volts to 291 volts. Figure 4.3 shows the distribution of meters in this voltage range. The first step in addressing these high voltage issues was to check to see if any of the meters were on the same feeder or fed from the same transformer. In this case, the meters were connected to 39 circuits and 40 different transformers. Most of these high voltage events were isolated and resulted from the failure of a transformer.

One example is meter number 30173601. This meter had an average voltage of 286.5 volts and was the only meter connected to this specific transformer. Once this meter was identified as having high voltage, the hourly voltage data from the date that the meter was installed was obtained to see

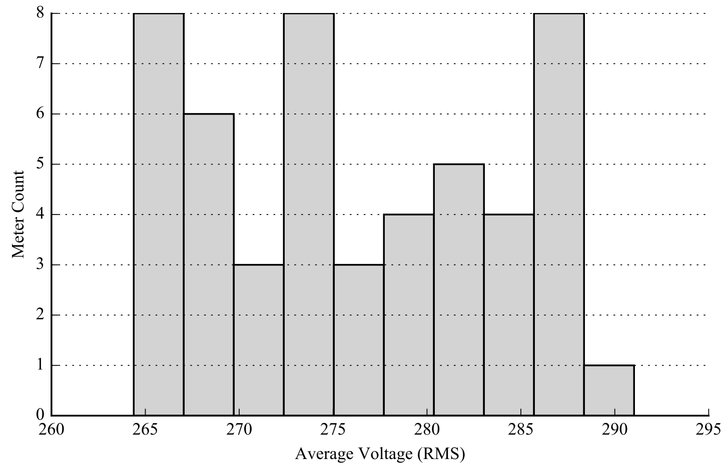

Figure 4.3: Distribution of Meters with an Average Voltage $\geq$ 10%

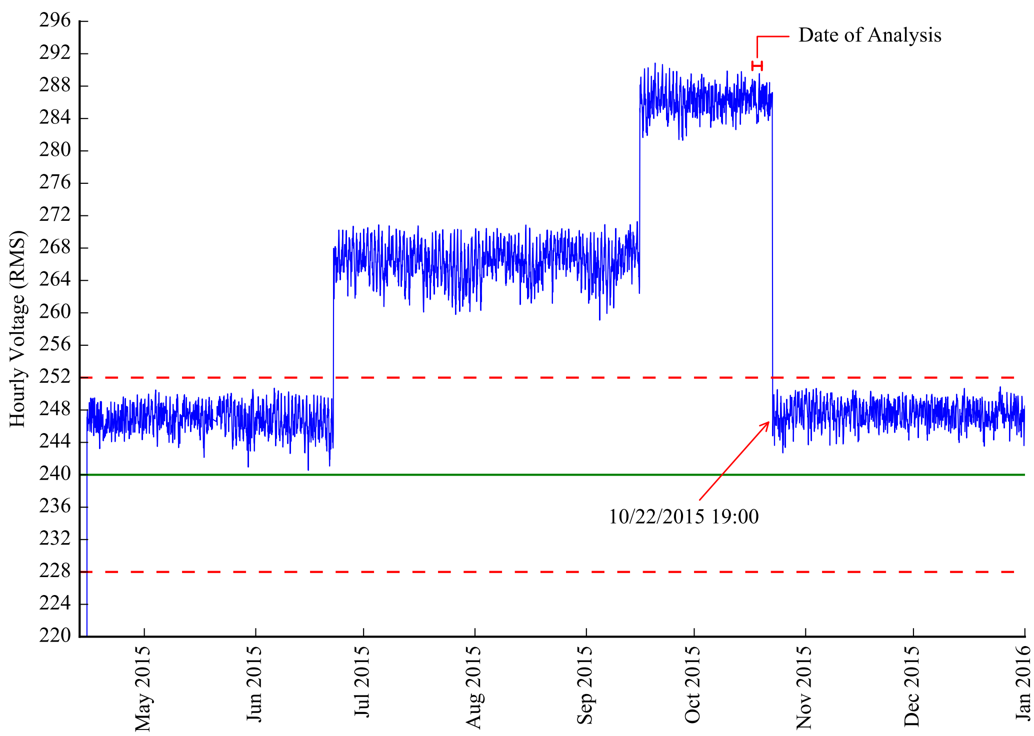

Figure 4.4: Voltage Profile for Meter 30173601

when the voltage exceeded the threshold. Figure 4.4 shows the voltage profile of this meter from when it was installed in April of 2015. The voltage at this meter remained within the acceptable tolerance range up until June 22nd when something happened that caused the voltage to increase to around 268 volts. The voltage remained at this level until it increased again to around 288 volts in mid September. On October 22nd, an electric service worker was sent to investigate the voltage and found that the distribution transformer was the cause of the high voltage. After this transformer was replaced, the voltage returned to the acceptable range.

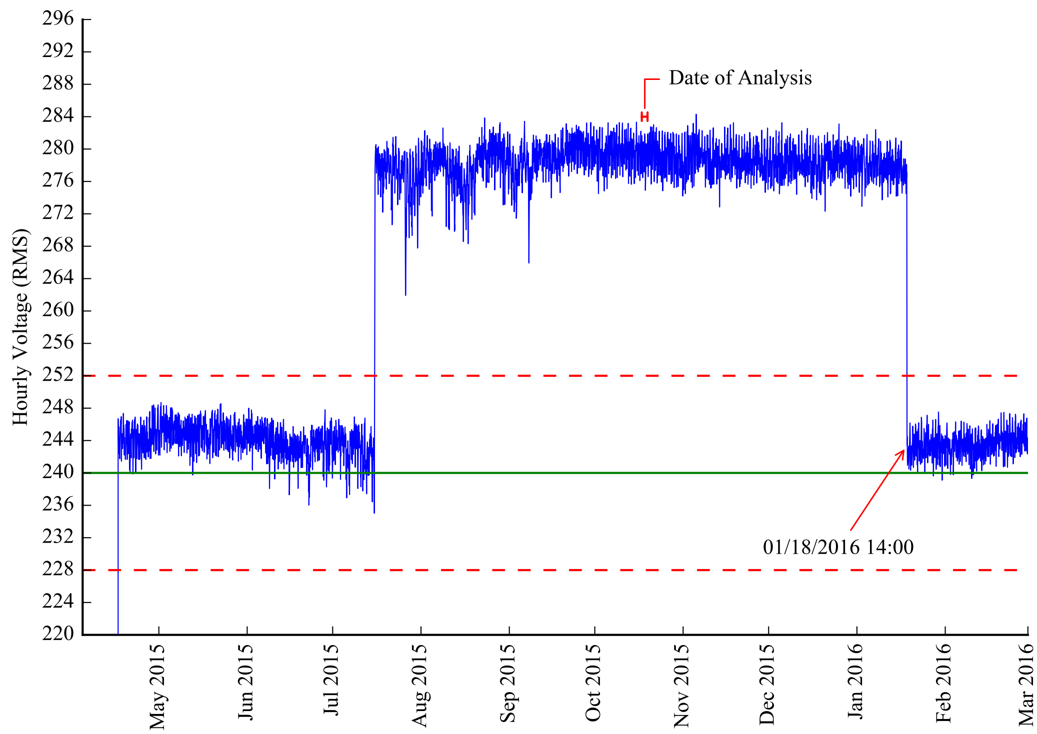

Figure 4.5: Voltage Profile for Meter 30172317

Another example is meter number 30172317. This meter had an average voltage of 279.4 volts. Similar to the last example, this meter was the only meter connected to the transformer. Figure 4.5 shows the voltage profile of this meter from when it was installed in April of 2015. The voltage at this meter remained within the tolerance range until something happened on July 15th that caused the voltage to increase to around 280 volts. After it was determined that a distribution transformer was the cause of the high voltage, it was replaced and the voltage returned to the acceptable range on January 18th.

After the bad transformer was replaced, it was taken to a service center to determine what caused the transformer to output such a high voltage. The service workers tried to test the turns ratio of the transformer, but were unsuccessful. This transformer (1007343405) was designed to have a turns ratio of 20:1 to reduce the 4.8kV primary voltage to 240 volts. However, when the service workers took the transformer apart, they found damage to the windings of the transformer shown in Figure 4.6. The damage lowered the turns ratio from 20:1 to around 17:1 which explains the increase in voltage from 244 volts to 280 volts.

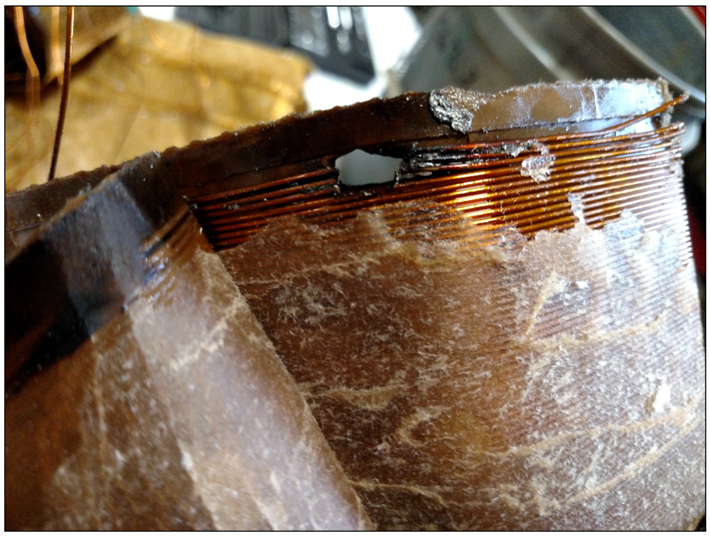

Figure 4.6: Damaged Windings of Transformer 1007343405

In addition to the examples above, there were also instances where multiple meters with high voltage were connected to a single transformer. One example is transformer number 0812164402. The average voltage and standard deviation of the 6 meters connected to this transformer is shown in Table 4.2. As expected, the voltage profiles of these meters were roughly the same from when

Table 4.2: Meters with High Voltage connected to Transformer 0812164402

Meter	Average Voltage	Standard Deviation	Transformer	Feeder ID
30179175	274.812	2.233	0812164402	081804
30179176	274.780	2.232	0812164402	081804
30179177	274.753	2.230	0812164402	081804
30179209	274.604	2.230	0812164402	081804
30179174	274.570	2.232	0812164402	081804
30179227	274.395	2.228	0812164402	081804

they were installed in August of 2015. The voltage remained around 270 volts until the transformer was replaced, which reduced the voltage to within $\pm$ 5% of 240 volts.

4.3.2 Case 2

This case examines the meters in the second voltage range between 7 and 10%. Figure 4.7 shows the distribution of meters in this voltage range. Of the 891 meters, 801 ($\sim$90%) were located on 10 feeders. The majority of meters on these feeders had high voltage due to the failure of a voltage regulator. The remaining 90 meters were connected to 40 different feeders.

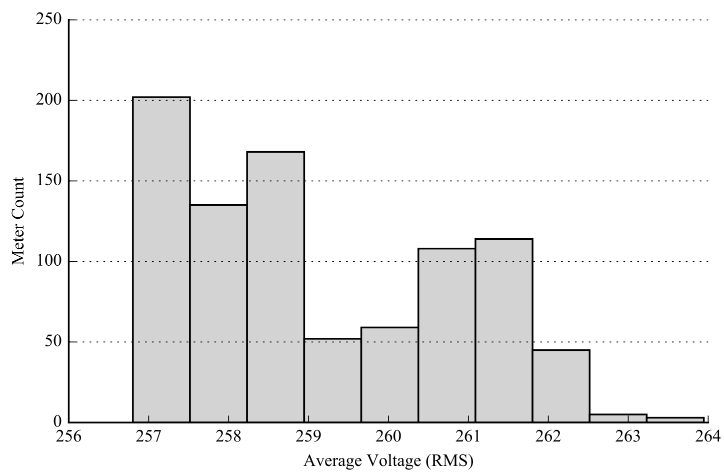

Figure 4.7: Distribution of Meters with an Average Voltage between 7 and 10%

Table 4.3: Top 10 Feeders with Meters between 7 and 10%

Feeder ID	Number of Meters
054601	250
022803	225
014502	154
022802	54
069802	36
010603	34
041003	18
075402	14
020101	8
024503	8

One example where the high voltage resulted from the failure of a voltage regulator is feeder 054601. The meters on this circuit were fed from 120 different distribution transformers that were all downstream of a voltage regulator. In Figure 4.8, the transformers are shown as triangles and the

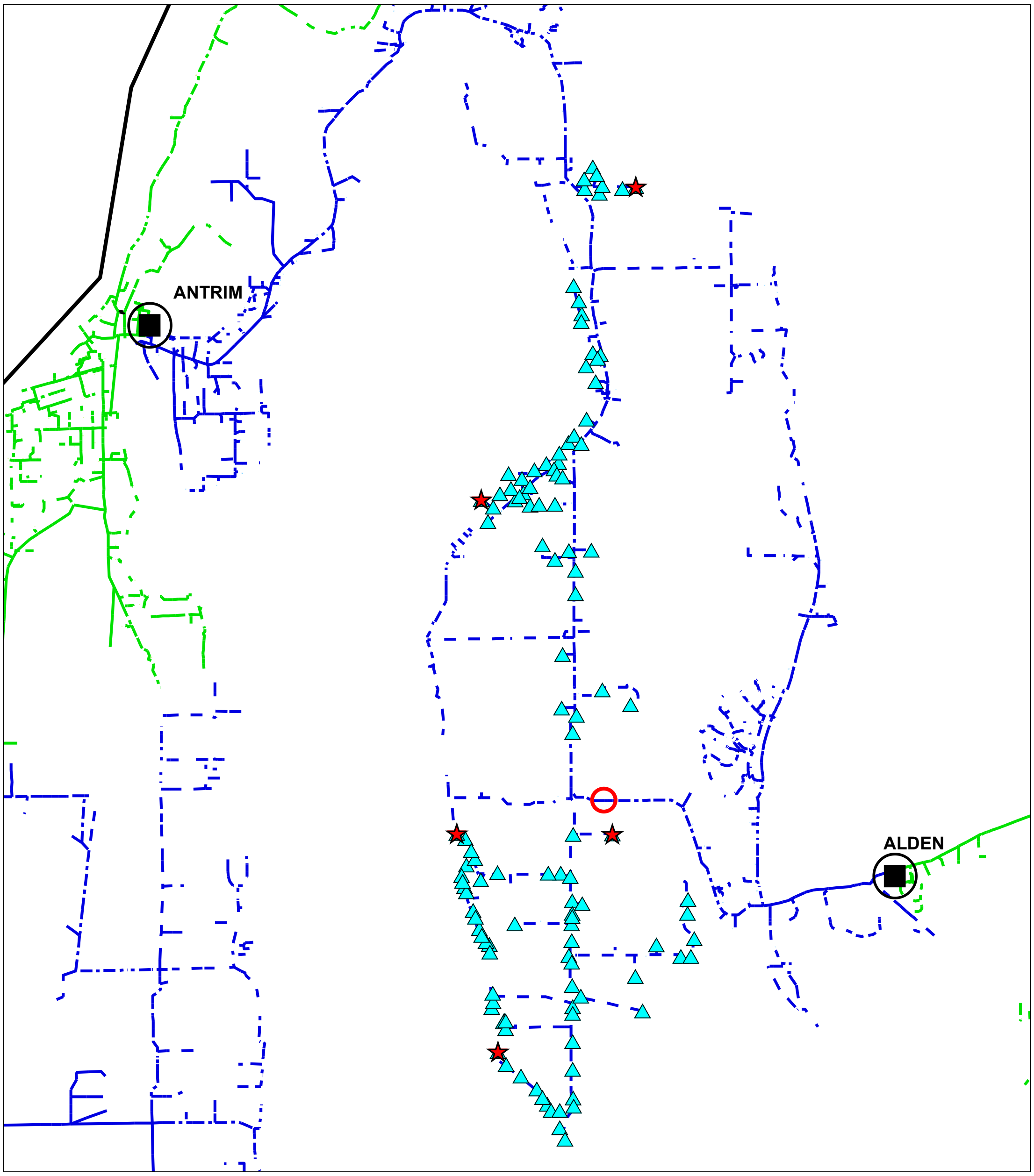

Figure 4.8: GIS Map for Feeder 054601

voltage regulator is shown as a circle. The hourly voltage data at five different meters downstream of the regulator was obtained to see if they had similar voltage profiles. If the meters had a similar voltage profile, this would confirm that the regulator was the source of the voltage issues. If the profiles were different at each location, this could indicate that the problem was related to each transformer.

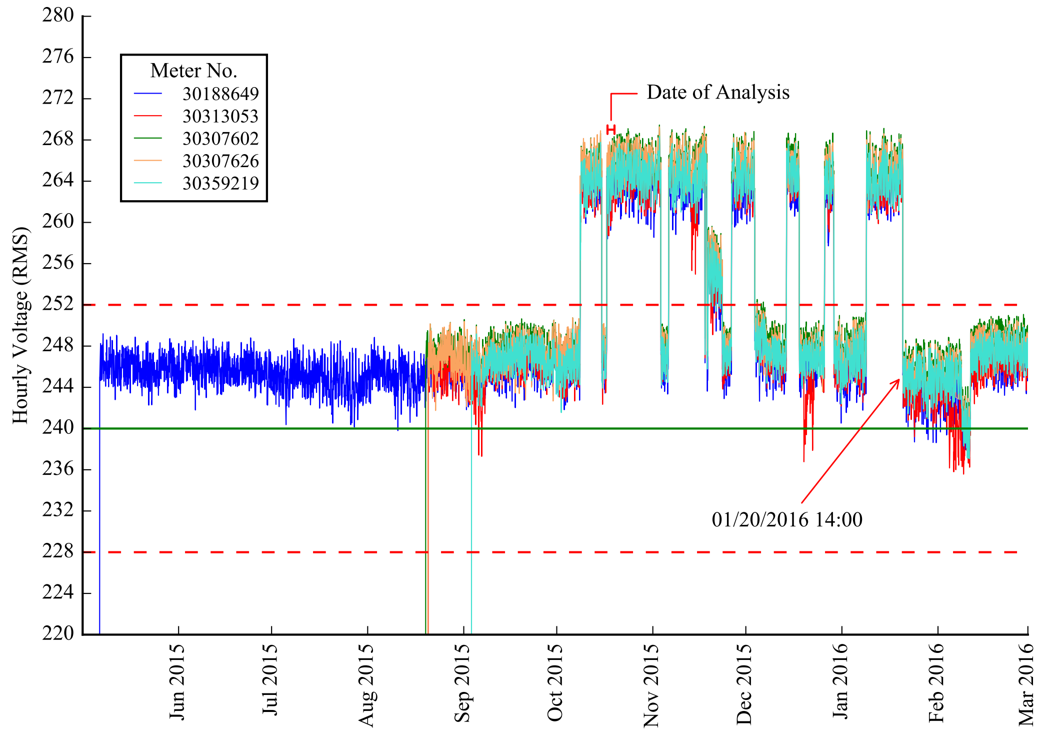

Figure 4.9: Downstream Meter Voltage Profiles for Feeder 054601

Figure 4.9 shows the voltage profiles of the five meters. Although the meters were installed at different times, the voltage profiles were similar. The taps of the voltage regulator were adjusted several times (between mid October and January) to attempt to reduce the high voltage. In January this voltage trend was reported to the circuit owner who confirmed the failure of the voltage regulator. On January 20th, the regulator was replaced and the voltage returned to the acceptable range.

Another example is feeder 010603. The 34 meters that had high voltage were connected to 23 different transformers and had an average voltage between 259 volts to 263 volts. Figure 4.10 shows the location of the transformers in relation to the voltage regulator. The 23 transformers

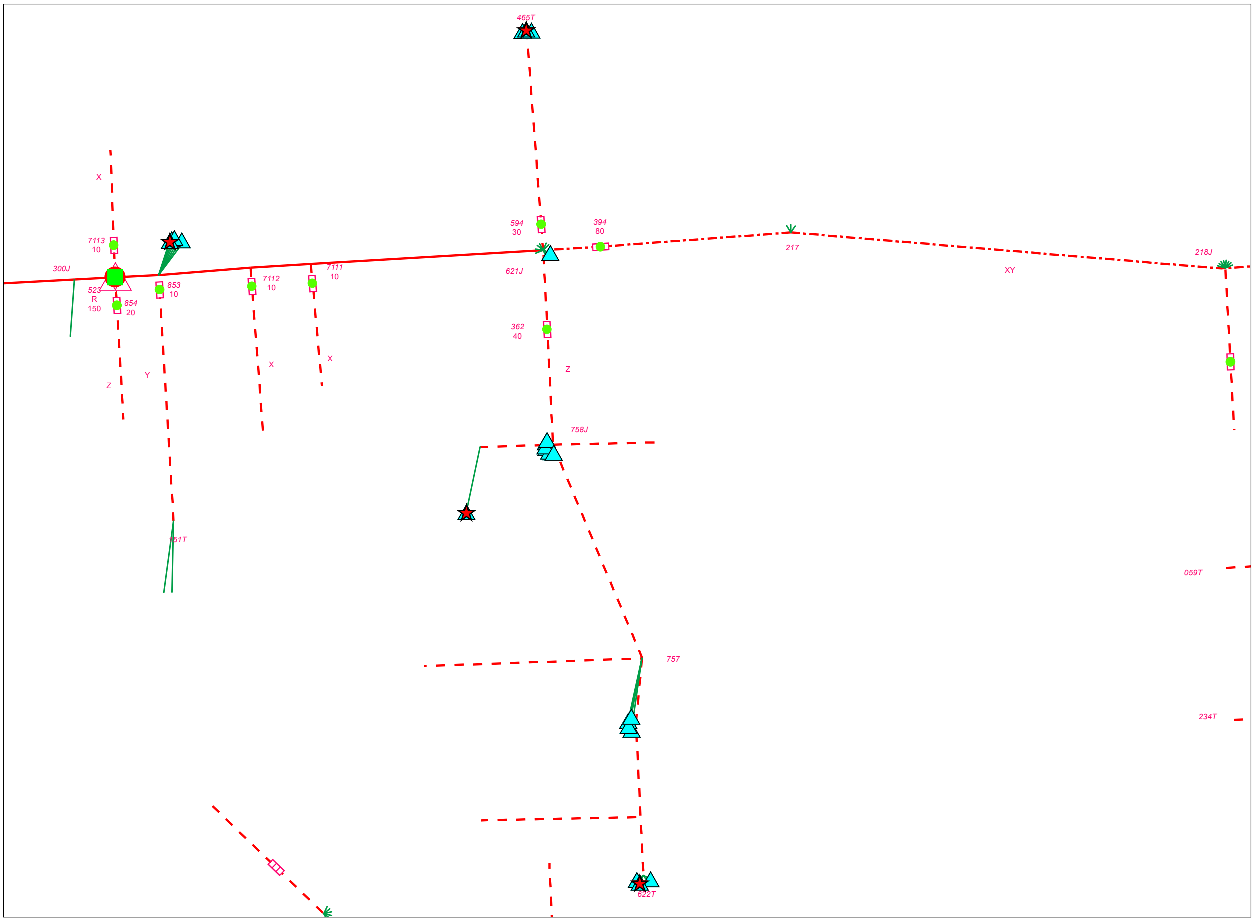

Figure 4.10: GIS Map for Feeder 010603

were all downstream of the regulator and connected to the Z phase. The voltage profile of four meters at different locations was obtained and all four had a similar voltage profile which is shown in Figure 4.11. In November of 2015, a service worker was sent to check the regulator and found that the Z phase was stuck on a higher tap setting. On November 30th, the voltage regulator was repaired and the voltage returned to the acceptable range.

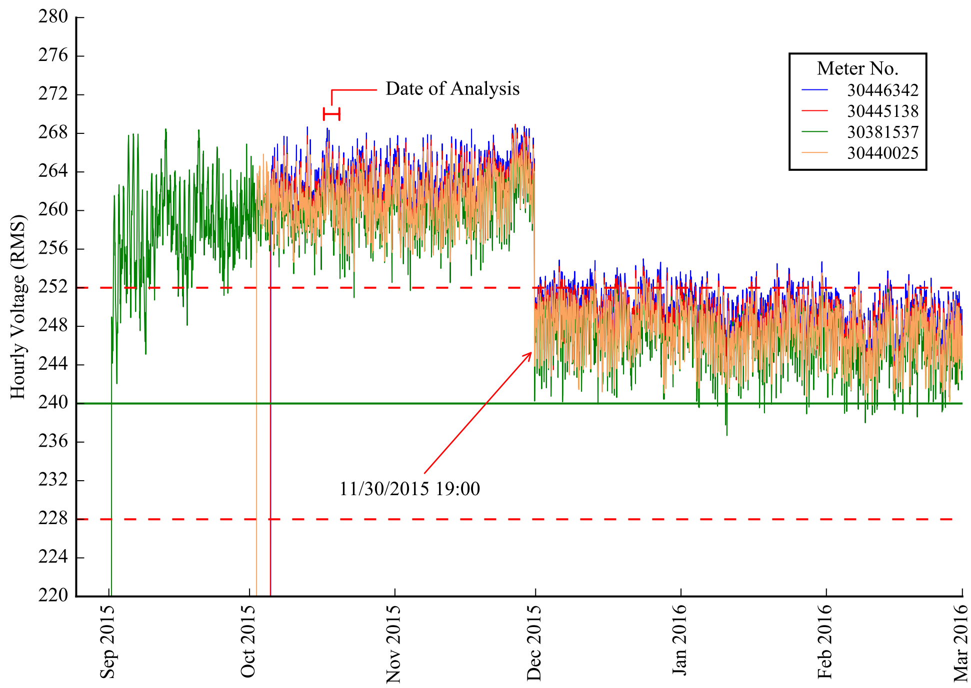

Figure 4.11: Downstream Meter Voltage Profiles for Feeder 010603

4.3.3 Case 3

The last case addresses the meters in the third voltage range between 5 and 7%. Figure 4.12 shows the voltage distribution of the 5,932 meters. The average voltage of these meters range from

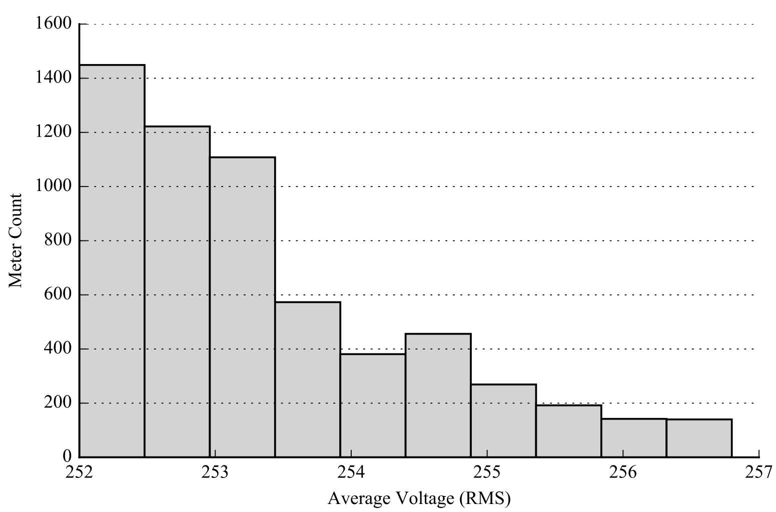

Figure 4.12: Distribution of Meters with an Average Voltage between 5 and 7%

252.0002 volts to 256.799 volts. Many of these meters had an average voltage that was right at the upper limit of the 252 volt (240V + 5%) threshold specified in the ANSI C84.1 standard. There were 2,786 meters with an average voltage within 1 volt of the threshold and 4,410 meters with an average voltage within 2 volts. These meters account for about 75% of the meters in this voltage range. The meters in this voltage range were connected to 184 different feeders. Thirty-two of these feeders were also in case 2. This is attributed to how close the lower voltage limit of case 2 is to the upper voltage limit of case 3.

Chapter 5

Conclusion

In this thesis, an analysis of smart meter outage and voltage data was presented. In Chapter 3, the outage and restoration events of smart meters were compared with the outage incidents of an outage management system. The results from the outage event comparison show that while smart meter events can be used as another way to notify electric utilities of power outages there are several challenges that must be overcome before these events can be integrated into outage management systems. One challenge lies in ensuring that the electric GIS model is up to date. This includes making sure that the meter to transformer to phase connectivity in the field matches the electric model in GIS. During a severe storm, devices such as distribution transformers can be reconnected to a different phase which in some cases is not updated in the GIS model. Another challenge lies in processing momentary smart meter outage events. In the event of an outage that causes a recloser to operate, the outage management system can get flooded with smart meter outages that only last for a few seconds. The outage management system should be capable of filtering out these momentary outages. One way to filter these outages is to have the outage management system wait a few minutes before receiving smart meter events.

In Chapter 4, smart meter voltage data was used to identify instances where the voltage delivered to a customer was above a given threshold. The 1% of meters that were found were grouped into three categories. The three voltage ranges were chosen to group the meters in terms of severity so that the meters with the highest voltage could be addressed first followed by the remaining meters. From the analysis, many of the meters with the highest voltage were connected to a bad distribution transformer. There were also instances where a failing voltage regulator was the source of the high voltage sensed by the smart meter.

Many of the meters that had a more severe high average voltage during the five-day analysis period had a high voltage for a sustained period of time. In most cases, the customer was unaware of the high voltage issue. High voltage issues are typically less noticeable than low voltage. The effects of low voltage can include brownouts or dimming lights that would prompt the customer to call the utility to report the issue. High voltage can also damage customer equipment, but the effects usually go unnoticed. In future work, both high and low voltage will be analyzed to ensure that customers receive power at voltages suitable for utilization.

APPENDIX

Appendix

Python Code

```python
#Importing python libraries for data analysis
import pandas as pd
from pandas.tseries.offsets import *
from odo import odo

#Reading smart meter data (outages and restorations) from csv files
# "converters = {...}" is used to convert select columns to a string.

GD_outages = pd.read_csv("GD_outages.csv",
                         converters = {"ACCOUNT":lambda x: str(x),"FEEDER_ID":lambda x: str(x),"TLM":lambda x: str(x),
                                       "METER":lambda x: str(x),"Street1":lambda x: str(x)},parse_dates = ["DateTime"])

GD_restorations = pd.read_csv("GD_restorations.csv",
                         converters = {"ACCOUNT":lambda x: str(x),"FEEDER_ID":lambda x: str(x),"TLM":lambda x: str(x),
                                       "METER":lambda x: str(x),"Street1":lambda x: str(x)},parse_dates = ["DateTime"])

#Reading OMS data from csv files
OMS_outages = pd.read_csv("incidentlist.csv",
                          converters = {"INCIDENT_ID":lambda x: str(x),
                                        "FEEDER_ID":lambda x: str(x)},parse_dates = ["TIME_OUTAGE","TIME_RESTORED"])

predicted_OMS_customers = pd.read_csv("Customers_per_IncidentID.csv",
                                      converters = {"ACCOUNT":lambda x: str(x),"METER":lambda x:str(x),
                                                    "FEEDER_ID":lambda x: str(x),"INCIDENT_ID":lambda x:str(x)})

#Create an empty list to store the comparison results
comparisondatalist = []

#For each outage/incident in the "OMS_outages" table:
for incident in OMS_outages["INCIDENT_ID"]:

    # Find the customers predicted by OMS:
    OMS_customers = predicted_OMS_customers[predicted_OMS_customers.INCIDENT_ID == incident]

    #Get the feeder_id, outage and restoration time for the OMS incident:
    OMS_outage_time = OMS_outages[OMS_outages.INCIDENT_ID == incident]["TIME_OUTAGE"]
    OMS_restoration_time= OMS_outages[OMS_outages.INCIDENT_ID == incident]["TIME_RESTORED"]
    feeder_id = OMS_outages[OMS_outages.INCIDENT_ID == incident]["FEEDER_ID"]

    #Specify time range for smart meter outage/restoration events (2 hours before and 1 hour after the OMS
    #outage/restoration):
    time_b4_outage = OMS_outage_time - DateOffset(hours = 2)
    time_aftr_outage = OMS_outage_time + DateOffset(hours = 1)

    time_b4_restoration = OMS_restoration_time - DateOffset(hours = 2)
    time_aftr_restoration = OMS_restoration_time + DateOffset(hours = 1)

    #Find the smart meters that reported outages/restorations between the time range
    #and on the same feeder as the OMS incident
    outages_frm_GD = GD_outages[(GD_outages.DateTime > time_b4_outage.values[0])&
                                (GD_outages.DateTime < time_aftr_outage.values[0])&
                                (GD_outages.FEEDER_ID == feeder_id.values[0])]

    restorations_frm_GD = GD_restorations[(GD_restorations.DateTime > time_b4_restoration.values[0])&
                                          (GD_restorations.DateTime < time_aftr_restoration.values[0])&
                                          (GD_restorations.FEEDER_ID == feeder_id.values[0])]

    #Sort the outage/restoration times and drop any "last gasp" events:
    outages_frm_GD_sorted = outages_frm_GD.copy().sort_values("DateTime",axis=0,ascending=True)
    restorations_frm_GD_sorted = restorations_frm_GD.copy().sort_values("DateTime",axis=0,ascending=True)
```

```python
    smart_meter_outages = outages_frm_GD_sorted.copy().drop_duplicates("ACCOUNT")
    smart_meter_restorations = restorations_frm_GD_sorted.copy().drop_duplicates("ACCOUNT")

    #Combine the OMS customers and the smart meter outages into one table:
    combined_outages = pd.concat([OMS_customers,smart_meter_outages])

    #Find the number of times an account number appears in the combined table:
    out_acct_number_count = combined_outages.ACCOUNT.value_counts()

    #Find the account numbers that appeared twice in the table. If it appears twice,
    #it means that the meter was initially in both the OMS and Smart Meter Outage tables:
    find_dupl_outage_acctnums = out_acct_number_count[out_acct_number_count == 2].index


    outages_that_matched_OMS = combined_outages[(combined_outages.ACCOUNT.isin(find_dupl_outage_acctnums))&
                                                (combined_outages.Code.notnull() == True)]

    #Combine the outages that matched OMS with the smart meter restorations to find the
    #restoration times of the meters that matched:
    combined_restorations = pd.concat([outages_that_matched_OMS,smart_meter_restorations])

    rest_acct_numb_count = combined_restorations.ACCOUNT.value_counts()

    find_dupl_rest_acctnums = rest_acct_numb_count[rest_acct_numb_count == 2].index

    restor_that_matched_OMS = combined_restorations[(combined_restorations.ACCOUNT.isin(find_dupl_rest_acctnums))&
                                                    (combined_restorations.Name.notnull())]

    #Combine the outage and restoration times of the matching smart meters into one table:
    Smart_Meters_that_Matched_OMS = outages_that_matched_OMS.merge(restor_that_matched_OMS,on="ACCOUNT")[["ACCOUNT",
                                                "METER_y","DateTime_x","DateTime_y","FEEDER_ID_x","TLM_x"]]
    #Rename columns:
    Smart_Meters_that_Matched_OMS.columns = ["ACCOUNT","METER","OUTAGE_TIME","TIME_RESTORED","FEEDER_ID","TLM"]

    #Find the unique account numbers, (i.e. the account numbers that only appear once,
    #either in the OMS table or the Smart Meter outage Table):
    unique_acct_num = out_acct_number_count[out_acct_number_count == 1].index

    #If it doesn't have a event code, it was originally in the OMS outage Table.
    Mtrs_in_OMS_not_in_SmrtMtrtbl = combined_outages[(combined_outages.ACCOUNT.isin(unique_acct_num))&
                                                     (combined_outages.Code.notnull() == False)][["ACCOUNT","METER",
                                                     "TIME_OUTAGE","TIME_RESTORED","Code"]]

    #Find the Smart meters that were in the Smart Meter Outage Table but not in the OMS customer table
    #If it has a Code, it was originally in the Smart Meter Outage Table
    Mtrs_in_SmrtMtrtbl_not_in_OMS = combined_outages[(combined_outages.ACCOUNT.isin(unique_acct_num))&
                                                     (combined_outages.Code.notnull() == True)]

    #Find outage and restoration times of the remaining smart meters
    remaining_outages = Mtrs_in_SmrtMtrtbl_not_in_OMS.copy()
    remaining_restorations = smart_meter_restorations[smart_meter_restorations.ACCOUNT.isin(remaining_outages.ACCOUNT)]

    #Combine the two tables together:
    Smart_Meters_that_didnt_Match_OMS = remaining_outages.merge(remaining_restorations,on="ACCOUNT")[["ACCOUNT",
                                        "METER_y","DateTime_x","DateTime_y","FEEDER_ID_x","TLM"]]

    #For each incident, append the comparison results to the initial empty
    #list ("comparisondatalist"):
    comparisondatalist.append((incident,feeder_id.values[0],len(OMS_customers),
                               len(Smart_Meters_that_Matched_OMS),len(Mtrs_in_OMS_not_in_SmrtMtrtbl),
                               len(smart_meter_outages),len(smart_meter_restorations)))


#Store the comparison results of each incident in a new table
Comparison_Results = pd.DataFrame(comparisondatalist,columns = ["Incident ID","Feeder ID","OMS Customers",
                                                                 "# of SMs that matched OMS",
                                                                 "# of Mtrs in OMS that did not communicate",
                                                                 "Total # of SMs that reported an outage",
                                                                 "Total # of SMs restored"])

#Write the results of that table to a .csv file
odo(Comparison_Results,"Comparison_Results.csv")
```

BIBLIOGRAPHY

BIBLIOGRAPHY

[1] U.S. Department of Energy. *What is the Smart Grid*? Available: https://www.smartgrid.gov/the_smart_grid/smart_grid.html

[2] U.S. Department of Energy. "Enabling Modernization of the Electric Power System" in *QTR: An Assessment of Energy Technologies and Research Opportunities*. Available: http://energy.gov/sites/prod/files/2015/09/f26/Quadrennial-Technology-Review-2015_0.pdf, pp. 53, Sept. 2015.

[3] International Energy Agency. *Technology Roadmap: Smart Grids*. Available: https://www.iea.org/publications/freepublications/publication/smartgrids_roadmap.pdf, pp. 18-19, 2011.

[4] U.S. Department of Energy. *2014 Smart Grid System Report*. Available: http://energy.gov/sites/prod/files/2014/08/f18/SmartGrid-SystemReport2014.pdf, pp. 7-8, 2014.

[5] *Advanced Metering Infrastructure and Customer Systems*. Available: https://www.smartgrid.gov/recovery_act/deployment_status/sdgp_ami_systems.html

[6] U.S. Department of Energy. *Smart Grid Investment Grant Program Progress Report II*. Available: https://www.smartgrid.gov/files/SGIG_progress_report_2013.pdf, Oct. 2013.

[7] U.S. Department of Energy Office of Energy Delivery and Energy Reliability. *Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Responses*. Available: https://www.smartgrid.gov/files/B2-Master-File-with-edits_120114.pdf, pp. 8-9, 2014.

[8] J. Cowdrey, "The War of the Currents" in *Home Power Magazine*, vol. 111, Available: http://www.uvm.edu/~gflomenh/CDAE06/readings/ACDC.pdf, pp.88-92, 2006.

[9] C. R. Riker, "The Engineering Evolution of Electrical Apparatus - XXXV: The History of the Watt-Hour Meter in America" in *The Electric Journal*, vol. 15, pp. 504-509, 1919.

[10] A. Madrigal, *Measuring the History of Electricity*, Image: Library of Congress. Available: http://www.wired.com/2008/09/gallery-electrical-meter/

[11] O. T. Bláthy, "Electric Meter for Alternating Currents," U.S. Patent 423 210, March 11, 1890.

[12] U.S. Energy Information Administration. *An Assessment of Interval Data and Their Potential Application to Residential Electricity End Use Modeling*. Available: https://www.eia.gov/consumption/residential/reports/smartmetering/pdf/assessment.pdf, pp. 15-19, Feb. 2015.

[13] Itron. *OpenWay Centron Meter*. Available: https://www.itron.com/PublishedContent/OpenWay%20Centron%20Meter.pdf, 2016.

[14] GE Digital Energy. *Residental Electrical Metering*. Available: http://www.choptankelectric.com/sites/choptankelectric/files/GE%20Meter%20Information.pdf, 2015.

[15] K.S.K Weranga, S. Kumarawadu, and D. P. Chandima, "Evolution of Electricity Meters," in *Smart Metering Design and Applications*. Singapore: Springer, 2014, ch. 2, pp. 17-33.

[16] J. Ekanayake, "Smart Metering and Demand-Side Integration," in *Smart Grid: Technology and Applications, 1st ed.* Chichester, UK: Wiley, ch. 5, sec. 5.3.1, pp. 87-88, 2012.

[17] M. Conner, *Tamper-resistant smart power meters rely on isolated sensors*. Available: http://www.edn.com/design/power-management/4313844/Tamper-resistant-smart-power-meters-rely-on-isolated-sensors, 2009.

[18] X. Jiang, "Design and Implementation of a High Fidelity AC Metering Network," in *Int. Conf. on Information Processing in Sensor Networks*, San Francisco, CA, pp. 3-4, 2009.

[19] D. A. Ward and J. La T. Exon, "Using Rogowski coils for transient current measurements," *Eng. Sci. Edu. J.*, vol. 2, no. 3, pp 105-113, Jun. 1993.

[20] V. Skendzic and B. Hughes,"Using Rogowski Coils Inside Protective Relays," in *Proc. 66th Ann. Conf. for Protective Relay Engineers*, College Station, TX, pp. 1-10, Apr. 2013.

[21] L. Dally and R. Edwards, "Evaluating the Communications Component of Your Smart Grid Solution," Landis+Gyr, Available: http://www.landisgyr.com/resources/evaluating-the-communications-component-of-your-smart-grid-solution/, Dec. 2013.

[22] U.S. Department of Energy. *Operations and Maintenance Savings from Advanced Metering Infrastructure - Initial Results*. Available: http://energy.gov/sites/prod/files/AMI_Savings_Dec2012Final.pdf, pp. 4-5, Dec. 2012.

[23] Public Technology Institute. *Smart Grid 101 for Local Governments*. Available: http://www.cadmusgroup.com/wp-content/uploads/2013/03/Smart_Grid_101_for_Local_Governments_201112.pdf, p. 6, 2011.

[24] Edison Electric Institute. *Smart Meters and Smart Meter Systems: A Metering Industry Perspective*. Available: http://www.eei.org/issuesandpolicy/grid-enhancements/documents/smartmeters.pdf, pp. 11-12, Mar. 2011.

[25] National Energy Technology Laboratory. *NETL Modern Grid Strategy Powering our 21st-Century Economy: Advanced Metering Infrastructure*. Available: https://www.smartgrid.gov/files/NIST_SG_Interop_Report_Postcommentperiod_version_200808.pdf, pp. 8,11, Feb. 2008.

[26] Python Data Analysis Library, available at: http://pandas.pydata.org/

[27] W. Mckinney, "Getting Started with pandas," in *Python for Data Analysis: Data Wrangling with Pandas, NumPy, and IPython*, 1st ed. Sebastopol: O'Reilly, 2013, ch.5, pp. 107-153.

[28] R. C. Dugan, "Introduction" in *Electrical Power Systems Quality*, 3rd ed. New York: McGraw-Hill, 2012, p. 3.

[29] *American National Standard for Electric Power Systems and Equipment—Voltage Ratings (60Hz)*, ANSI Standard C84.1-2016.

[30] OSIsoft PI System, available at: http://www.osisoft.com/pi-system/#tab2