Evaluation of Data Submitted in APPA's 2011 Distribution System Reliability & Operations Survey

NOTE

APPA staff has used a high degree of care in developing this report. However, APPA does not accept any liability resulting from the use of this publication or from its completeness and fitness for any particular purpose. The data from this survey offer only a component of the conceptual benchmark/point for comparison and understanding of public power utility distribution system operations and reliability metrics.

Published November 2012
By Alex Hofmann, MPA, EIT, 202.467.2956
ahofmann@publicpower.org

Published by the American Public Power Association
1875 Connecticut Avenue, N.W., Washington D.C. 20009-5715

TABLE OF CONTENTS

INTRODUCTION

The 2011 Distribution System Reliability and Operations Survey was developed by the American Public Power Association to assist members in their individual efforts to understand and analyze a number of the issues that arise from maintaining and operating a distribution system. By asking members to identify and document existing reliability and operations-related metrics, the survey intended to elucidate general factors used by different utilities in their decision-making processes. Since the type of data collected in the survey is not commonly available to utilities, this report intends to serve as a supplemental tool to expand industry-wide understanding of the operations, procedures and practices that lead to distribution system reliability.

This report does not address reliability of the bulk power system. The bulk power system is defined by the Federal Energy Regulatory Commission, and is subject to reliability standards established through the North American Electric Reliability Corp. (NERC).

In many cases, municipally owned utilities are not subject to federal or state laws regarding the reliability of their distribution systems. This makes decisions regarding utility distribution system operations and the resultant degree of reliability inherently local. To help members understand the technical issues surrounding reliability and distribution system operations in more detail, APPA publishes and sells several guidebooks such as, *How to Design and Implement a Distribution Circuit Inspection Program* and *Making the Most of Your Distribution System*. These documents focus on the practical aspects of operating a distribution system and have served as a good starting point for many electric distribution reliability programs. The general information on distribution system operations contained in this report is designed to provide municipal electric utilities with a broader base of knowledge for formulating easy-to-administer and sound day-to-day practices.

Each section of this report summarizes survey results with supporting graphics. The organizational flow of the report corresponds to the order of questions as they appeared in the survey. A copy of the survey questionnaire is included in Appendix A.

To reduce comparison errors, this report attempts to match only comparable metrics, such as general reliability statistics, from previous surveys to the data collected in the 2011 survey.

In the survey, there were calls for certain confidential or proprietary information that may be sensitive. Responses have been aggregated to ensure confidentiality.

DISCUSSION

The discussion in this report strives to set the context for understanding the analysis of data presented and addresses a few of the fundamental questions surrounding distribution system reliability.

CUSTOMER SERVICE RELIABILITY

In the United States, a typical customer expects to have power at all times. In reality, a utility will be able to make power available between 99.9 and 99.999 percent of the time. To put it another way, the average customer may be dissatisfied if he/she is without electricity for more than 53 minutes a year.[1] While at times unrealistic, customer expectations are driven in part by a lack of understanding of the institutional and organizational work required to maintain a continuous supply of electricity. Regardless of customer perception, these expectations are driving an increasing public emphasis on utility reliability. Thus, standards-driven reliability programs can greatly assist in achieving reliability goals in a lowest-cost manner.[2]

Through their historical connection to consumers, publicly owned electric utilities are motivated to keep their local electricity system operating continuously and efficiently. Providing power as reliably as possible while keeping costs as low as possible is inherent to a nonprofit utility's nature. Maintaining reliable electric service is one of the core facets of a public power utility's business model. In this report, the scope of distribution system reliability includes the utility's electrical infrastructure -from distribution substations to customer meters.

SYSTEM RELIABILITY

Reliability, from a systems engineering perspective, is the ability of an electric system to perform its functions under normal and extreme circumstances. Reliability statistics document how well a system is performing its intended function. Reliability indices help engineers and other operations personnel see and show the interconnected nature of the many independent system components that make up an electric distribution system. This connection makes apparent the fact that overall system design impacts fundamental reliability. From substation and distribution design to fusing schemes, the physical factors of system design impact system reliability.

Many physical factors impact overall distribution system reliability. Among the commonly considered factors are system voltage, feeder length, exposure to natural elements (overhead or underground conductor routing), sectionalizing capability, redundancy, conductor type/age and number of customers on each feeder.

Since resources are limited, reliability-related system improvement decisions involve trade-offs. In some cases, improving system redundancy is the most important enhancement that can be identified through reliability studies. Additional redundancy can lead to resiliency, or the ability to withstand larger shocks to the system. This can improve reliability numbers during extreme events and catastrophes. In preparation for these events, key engineering-level tradeoffs are made between cost, transport efficiency (line-

[1] Reliability Aspects of Power Plants, Jacob Klimstra, 2009
[2] Electric Power Distribution Reliability, Richard E. Brown, 2009

losses), and fault tolerance.[3] Knowing where to start can be difficult. At a utility where reliability indices are collected, Engineers and other operations personnel will have better data to help choose a reasonable starting point for improvement.

When designing lines, utility staff constantly consider the trade-offs involved. For instance, when looking at line voltage, if an engineer decides to use a lower 4-kilovolt (kV) line voltage, he or she may experience fewer outages from line contact with vegetation. However, with lower voltage, the thermal line losses will be greater and the system will be less thermally efficient. On a line designed to operate in a higher 25-kV range, thermal line losses will be reduced, but a vigilant tree trimming program will be required to reduce the increased potential for ground fault by contact with vegetation. Reliability data can help an engineer make these types of decisions. Engineers are also challenged to address the negative influence of weather-related variables like ice, wind and heat.

Power quality is another important aspect of reliability. Typically described in terms of voltage flicker, sag and swell, power quality is a significant concern for utility engineers. Delivery of high-quality, flicker-free power is especially important to many large industrial loads. A momentary interruption can cause electronic industrial equipment to trip off, leading to costly production losses. To improve the power quality and reliability for industrial customers, a utility may track its voltage transients and employ transient voltage surge suppression, VAR support or other remediation. There are several resources available to help with this task.[4,5]

RELIABILITY STATISTICS AND THEIR USES

Reliability statistics are the quantitative basis for good decision making and come in many forms. On the whole, reliability statistics are excellent for self-evaluation. That's not to say utility-to-utility comparisons cannot be made, but differences in each electrical network, such as weather conditions, number of people served, customer willingness to pay for reliability, and equipment used, limit the value of such comparisons. Some regulators take the perspective that standardized metrics are paramount for cross-utility comparison. While such comparisons have benchmarking value, the metrics are most useful when examined from period-to-period (week, month or year) for a single electric system. The data can help each utility make the best decision possible in light of its specific circumstances.

It is important for a utility to track and evaluate reliability metrics. Public power utilities charge, on average, lower rates than investor-owned utilities.[6] Public power's rate advantage and superior reliability are key advantages of local public ownership of electricity resources and should be highlighted to customers to promote a utility. An APPA reliability study of small public power utilities included a comparison with results for all types of utilities that participated in an Institute of Electrical and Electronic Engineers (IEEE) study. In the APPA study, the 17 best-performing utilities were municipally owned.[7]

Electric reliability data are also useful for promoting local economic development. Businesses want reliable electric service. This need is driven by the fact that momentary interruptions and power quality issues can lead to expensive downtime for sensitive manufacturing equipment. Once sensitive equipment

[3] Atsushi Tero, Et al. Rules for Biologically Inspired Adaptive Network Design, Science, Jan 2010
[4] IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems, IEEE Std 142-2007
[5] IEEE Guide for Service to Equipment Sensitive to Momentary Voltage Disturbances, IEEE Std 1250-1995
[6] http://www.publicpower.org/files/PDFs/PublicPowerCostsLess1.pdf
[7] Reliability Statistics for Small Utilities, 2008, http://www.appanet.org/store/store.cfm

is powered off, it must be restarted. For large machines, this restarting process can take significant time. In addition, some manufacturing processes are time-sensitive. In those cases, an incomplete production run could be lost during a sustained outage.

An integral part of distribution system reliability is power quality. To promote its power quality, a utility may consider presenting a power quality index to potential customers. Typically, manufacturers operating in the area of Information Technology (IT) will rely on the Information Technology Industry Council (formerly known as the Computer & Business Equipment Manufacturer's Association) (CBEMA) curve to understand the quality of a utility's power supply.[8] This curve gives a voltage sag and event-duration envelope for alternating current (AC) systems that most IT equipment will tolerate. In addition, many businesses that use sensitive equipment will be attracted to comprehensive quantitative metrics, such as Momentary Average Interruption Frequency Index (MAIFI), for system performance.

STARTING POINTS FOR RELIABILITY

There are checklists for reliability metrics; however, a good place to start is with the industry standard metrics found in the IEEE 1366 guide. These metrics were designed by utility personnel to be an integral part of the framework for internal reliability benchmarking and external utility comparison. To benchmark internally or externally, statistics should be collected and evaluated for at least five years. After review of the 1366 document and its metrics, a utility may find that not all of the calculations it recommends will help in making better decisions. Where this occurs, it is important to decide which metrics would be best for your utility's particular circumstances.

The IEEE 1366 guide was developed to help create a general, uniform and understandable set of metrics for measuring electric distribution system service reliability. IEEE standards are tools to help guide decision making. They are developed as consensus documents by the IEEE societies and approved by the American National Standards Institute (ANSI). Due to the disagreement over the best ways for utilities to track and report reliability data, it took many years of debate before the first 1366 standard was released in 1998. The most current standard was released in 2012. It is important to note that the 1366 standard is not a design standard. In addition, the standard acknowledges that some utilities may not possess the tools necessary to calculate some of the indices.

To help small utilities with reliability metrics, APPA produces a guide titled *Reliability Statistics for Small Utilities.* This guide provides good introductory coverage of the standard IEEE 1366 metrics and shows their relevance to small utilities.

Calculating reliability metrics is a part of the pathway to continued exceptional performance. APPA's RP_3 (Reliable Public Power Provider) program designates 25 percent of its points for reliability. The RP_3 program is open to all utilities seeking to document and publicize their excellence in the areas of reliability, safety, work force development, and system improvement. The growing number of utilities applying to this program shows increasing utility interest in tracking and establishing reliability indicators based on sound metrics.

[8] ITI CBEMA Curve http://www.itic.org/clientuploads/Oct2000Curve.pdf

WHY RELIABILITY INDICES?

Reliability indices are significant components of any utility's ability to measure long-term electric service performance. Furthermore, IEEE 1366 is the de facto standard for the calculation of reliability indices. This does not mean that the 1366 indices are the only way to calculate distribution system reliability. Simply, the general level of acceptance makes 1366-defined indices useful as benchmarks and long-term average system performance measures. The idea is that together, indices, such as the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI), provide a comprehensive indicator of the total reliability of a utility's electric distribution system.

WHAT DOES A NUMBER MEAN IN THE CONTEXT OF RELIABILITY INDICES?

Reliability metrics are one indicator of system health or condition. The same way many complex systems have their own level of health, these indicators let a utility know if the system is getting better or worse over time. Since all systems are different and stressed by different factors, it can be very hard to make a legitimate comparison between two systems. This means reliability indices are situational in nature and will present different baselines depending on the many intrinsic factors affecting the system.

Reliability statistics can help drive utility improvement programs. Nonetheless, when pursuing reliability improvement, taking a splintered approach can be damaging.[9] As such, utility managers should be sure to include all departments in a uniform plan to understand and act on reliability data. In some cases, a system reliability meeting will help bring other departments into the process of reinforcing system reliability. Whether a utility decides to use meetings or have technical specialists focus on the issues, it should be sure to identify gaps and create a uniform approach to reliability.

There are differing philosophical approaches to the collection of reliability data. For example, a utility manager might choose not to remove any outage event while computing indices under the philosophy that all outages can be addressed or minimized and should be included in any calculations made. This approach has some merit. It allows higher emphasis on post-storm restoration and puts more accountability for restoration after major events on the utility manager. Alternately, the IEEE standard 1366 strives to allow managers to remove major event days and analyze them separately from the other normal 99 percent of the data set. However, when it comes to getting the lights back on, allowing large events to be treated differently in terms of management response comes with its own set of hazards. It may be useful to use both types of reliability measurements: removing the major events in long-term analysis and including them, where possible, with descriptions, for a detailed look at the way a utility handles its major events.

Since there are different methodologies for extracting and calculating major event days, it is also important for a utility to consider its controllable service quality results.[10] That is, what can a utility impact in terms of reliability, or where is the "juice worth the squeeze?" In times of extreme events, it may be unreasonable or impossible to keep track of customer outages. During and immediately after these events, the sole focus of every person in the utility becomes restoring electricity service. Little attention is paid to data collection when the lights are out.

[9] APPA Reliability Standards and Compliance Symposium, Caribe Royale Resort Orlando, Florida, January 10, 2007

[10] Joseph H. Eto, et al., Larence Berkely National Laboratory, Tracking the Reliability of the U.S. Electric Power System, 2008

The IEEE 1366 calculation of Major Event Days (MED) is an efficient way to evaluate major event days. The 2.5 beta method calculation emerged from a heuristic process designed to seek the relative proportion of MEDs that need to be removed in order to make a long-term reliability trend visible. The separation of event data allows for long-term trend evaluation as well as evaluation of the data in two frames: crisis and normal.[11]

Outside of major events, some outages, such as planned outages, give a utility a high degree of data certainty. At the time of an outage, a utility can record planned outages as a part of its statistics or separate planned outage minutes into a different category for analysis. This separate category can help a utility see how much down time is caused by its operations.

Reliability indices can be useful for many decision-making processes. Some utilities have suggested that reliability indices should form the basis for review of daily operational effectiveness and decision making. The degree to which your management and operations techniques rely on reliability indices will be impacted by how much confidence you have in the validity of the data you are collecting. Collecting useful data may involve using standardized reporting metrics, such as those used by the APPA reliability tracking software.[12] In operations, it is also up to each utility to decide the useful frequency of data evaluation and to set goals that make sense. Many utilities evaluate this information on a monthly basis.

This report attempts to present the survey data in a fashion that will help utilities that wish to create benchmarks from it. Utilities can use this report's data to help improve their performance. If a utility is looking for one place to start, it would be best to measure its System Average Interruption Duration Index (SAIDI) over the course of the year. This IEEE 1366 metric is both size-independent and the best indicator of system stresses.[13]

[11] IEEE 1366-2003, B.5.1
[12] See: http://reliability.publicpower.org
[13] Cheryl A. Warren, Measuring Performance of Electric Power Distribution Systems – IEEE Std. 1366-2003, Feb 13, 2005

OVERALL SURVEY INFORMATION

The data presented in this report are based on APPA's 2011 Distribution System Reliability and Operations Survey. The data reflect activity from January 1, 2010 to December 31, 2010. Any additional data presented are limited to specific reliability indices collected in the previous three bi-annual surveys. Where responses are translated to a percentage of participants or choices, they are often rounded to the nearest percentage point. Where a percentage is shown, it is the percentage of total respondents that answered the question. For example, 100 percent means that 100 percent of the utilities that responded to that question felt a particular way. Many respondents did not answer all of the survey questions. Many questions were multiple choice and a utility could select more than one option.

The adverse part of conducting a survey with voluntary participation is the significant reporting bias encountered. Though APPA feels that the participating utilities are reporting the data with honest intentions, there is always the possibility of non-intentional skewing of the overall data set. This skewing bias can take two extreme forms. First, a utility that is a likely participant in this survey will not be random. The participant has reliability metrics and most likely has a program to improve reliability. This type of informed participant could skew data toward the higher performing end of the spectrum. On the other hand, a utility with very poor reliability statistics wanting to participate and learn more about distribution system reliability, would submit its data without knowing if it would skew the data toward the lower-performing end of the spectrum.

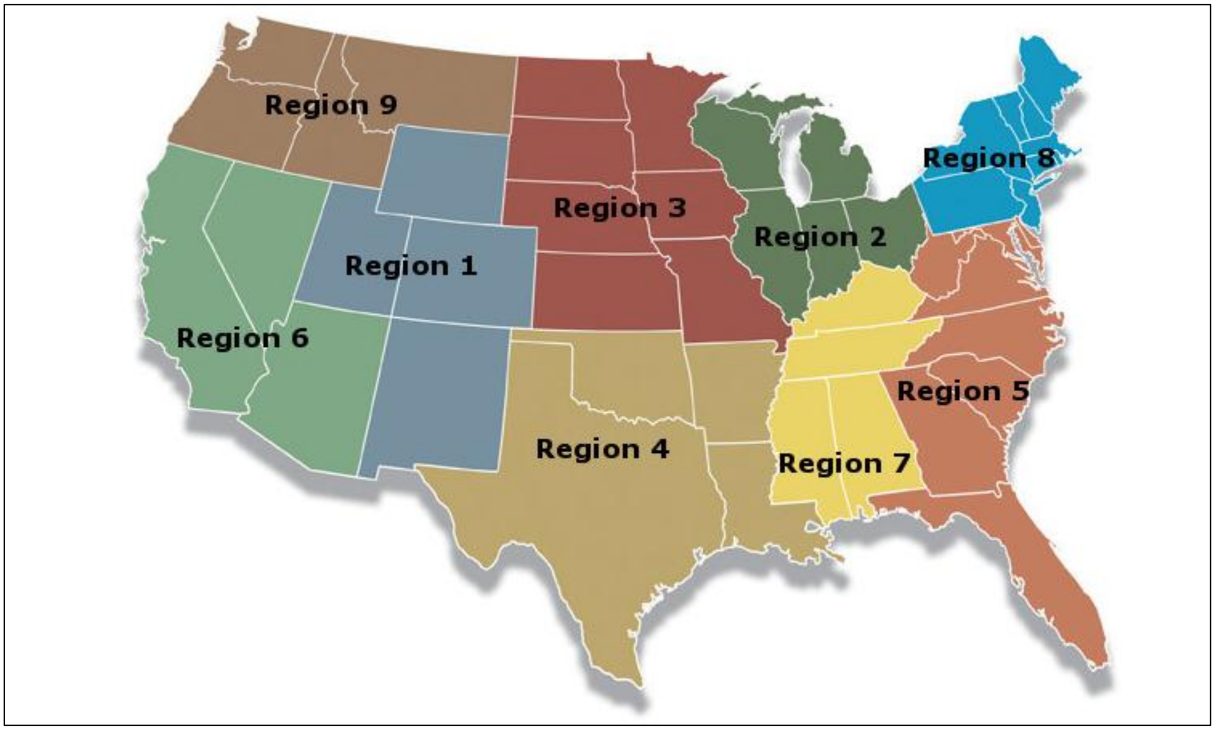

Figure 1: Geographical map of APPA regions

Beyond reporting bias, there are regional dissimilarities. For instance, extreme weather is a regionalized and localized phenomenon. Under weather dissimilarity, areas hit with severe floods or storms will report comparatively high numbers. This will be especially true for utilities that do not exclude major event days.

As with opposing reporting biases, the possibility of varied weather can provide balance. However, it is important to note that extreme weather events included in a survey with this sample size could influence the overall reliability numbers.

In total, 147 utilities from nine APPA regions participated in the 2011 reliability survey. This represents a 65 percent increase in survey participants from the 2009 survey. A graphical visualization of the different APPA regions can be seen in **figure 1**. As can be seen in **figure 2**, the highest concentration of participants came from regions two and five. The lowest concentration of participants was from region one. In all, this survey represents more than 7 percent of public power utilities in the United States and nearly 5 million utility customers.

In **figure 3**, the number of customers for each utility that participated in the survey is shown in order of increasing customer size. Utilities with a wide variety of sizes responded to the survey questions. However, the vast majority of participants were small utilities. The average participant utility size was 34,668 customers and the median size was 16,000 customers down from an average of 47,525 and median of 26,558 in the 2009 survey, respectively.

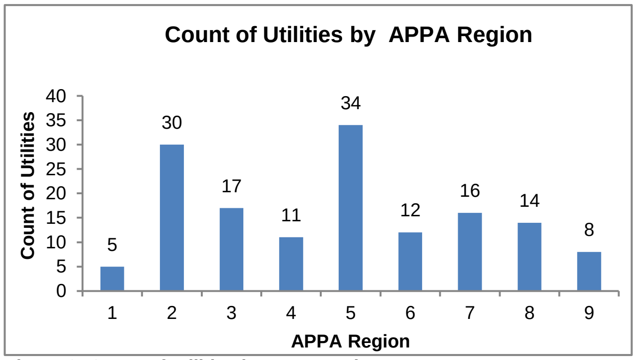

Figure 2: Count of utilities by APPA region

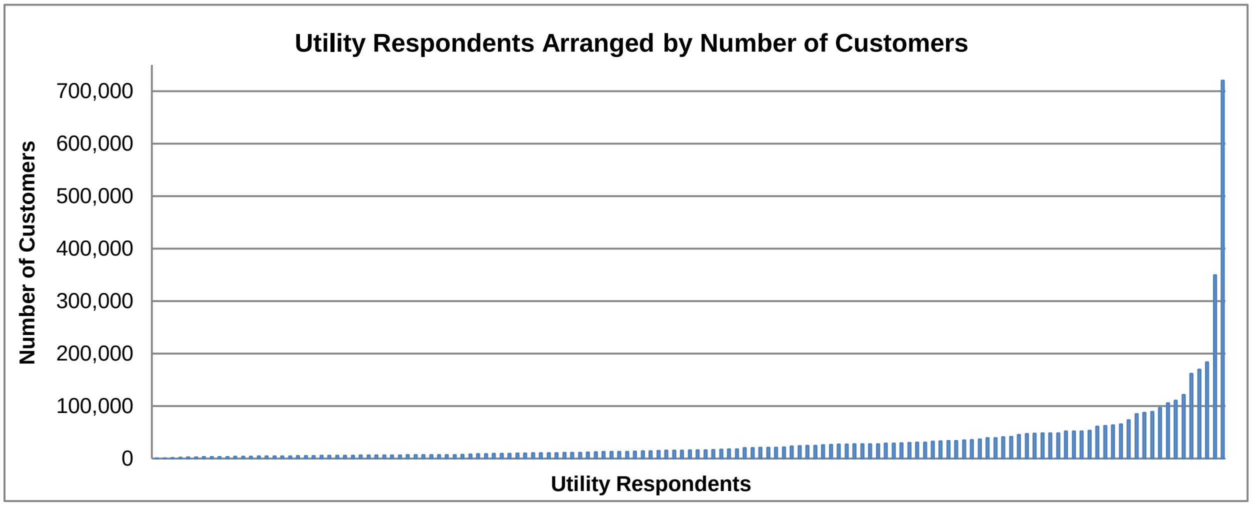

Figure 3: Utility respondents arranged in order of increasing number of customers

The following sections and their associated discussions are modeled after the layout and flow of the original survey.

SECTION I: OUTAGE TRACKING

Equipment failure, extreme weather events, wildlife and vegetation contact are some of the most common causes of electric system outages. Interruptions in electricity service are costly for both utilities and communities.[14] Tracking helps utilities understand and reduce outages. Yet, to track outages successfully, a utility must classify them.

Utilities can track outages that are long (sustained) and those that are short (momentary). Of the 96 percent of participant utilities that responded to this question, 63 percent track both sustained and momentary outages, while 36 percent track only sustained outages. As can be seen in **figure 4**, less than one percent track only momentary outages, or do not categorize the type of outage.

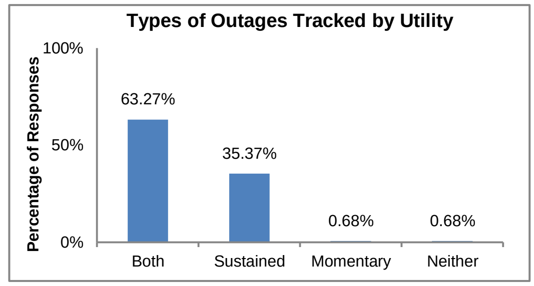

Figure 4: Type of outages tracked by utility

92 percent of utilities that participated in this survey used some type of outage tracking system. As can be seen in **figure 5,** 52 percent of utilities using tracking systems have both automated and manual tracking systems, while 36 percent have only manual outage tracking systems. These data show a 40 percent increase in the number of utilities reporting “both,” compared to the 2009 data. However, the survey did not define manual and automatic, so it does not identify specific differences between the tracking types.

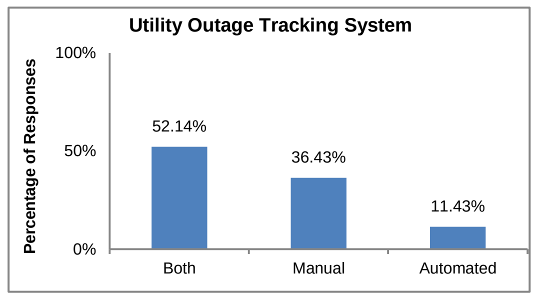

Figure 5: Outage tracking system

For utilities that track outages, the survey asked which outage information was kept on record. 99 percent of survey participants responded to this question. Utilities could select as many types of information as applied in this question. Responses are summarized in **table 1**. The table includes types of data a utility may use to calculate reliability statistics, understand outages and evaluate the long-term options for action.

[14] Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Kristina Hamachi LaCommare and Joseph H. Eto, Lawrence Berkeley National Laboratory, 2003

Information Kept on Record When Tracking an Outage	Percent of Question Respondents Keeping Information
Date of Outage	100.00%
Cause of Outage	99.31%
Length of Outage	98.62%
Time Outage Began(first reported)	97.93%
Number of Customers Affected	97.24%
Location of Outage	96.55%
Identification - Substation	73.79%
Total Restoration	72.41%
Identification - Underground	68.97%
Identification - Overhead	67.59%
Identification - Protective Device	61.38%
Identification - Line (Single or Three)	60.69%
Partial Restoration of Power	60.00%
Weather Conditions	60.00%
Resolved/Needs Additional Work	58.62%
Identification - Pole	45.52%
Other	8.00%

Table 1: Summary of participant response to information they keep on record from an outage

In the survey, 96 percent of survey participants responded to the question asking how indices were applied to their utility. Of those respondents, 84.51 percent applied reliability indices on a system-wide basis. As seen in **figure 6**, 51.41 percent apply indices by feeder or circuit and 6.34 percent apply indices in some other way. Each respondent could select as many options as applied.

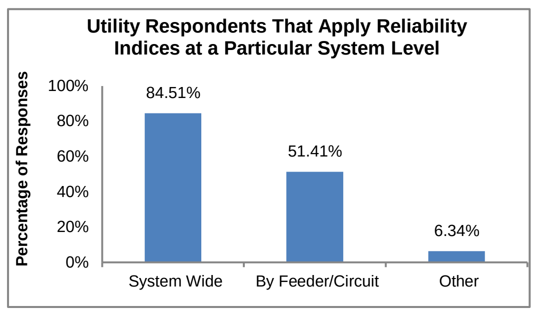

Figure 6: Reliability indices at particular level

Participants were asked to indicate the technologies they use to track outages. 98 percent of survey participants reported using at least one type of tracking technology. As shown in **table 2**, supervisory control and data acquisition (SCADA) was the most common technology used. Beyond the outage tracking methods listed in **table 2**, a utility can have additional methods or combinations of methods for collecting outage data. For example, some utilities rely on hand-written sheets and customer calls-ins, while other utilities have advanced real time SCADA systems. Additionally, even within a technology category, such as SCADA, there are different levels of data acquisition systems. Many SCADA systems can report only on certain key points, leaving a utility to rely on customer call-ins to report many outages. Since APPA staff is aware that some utilities use fiber optic and broadband over power line technologies to backhaul their SCADA data, the technologies that received zero responses are likely included as part of a SCADA system and not used independently.

Tracking Technology Used	Percentage of Question Respondents Using Technology
SCADA System	73.10%
Spreadsheet (for analysis and history)	67.59%
Database (for analysis and history)	57.93%
Outage Management System	33.79%
Automated Metering Infrastructure/Automated Meter Reading/Smart Meters	14.48%
Substation Bus Power Quality Monitor	12.41%
Other	4.83%
Broadband Over Power Line	0.00%
Fiber Optic	0.00%
Broadband	0.00%

Table 2: Summary table of responses to tracking technology used by a utility. Multiple answers per utility were allowed

Generating reliability reports is an important part of understanding any distribution system. Using the technologies listed in **table 2**, 91 percent of survey participants generated reliability reports for their utility. Taking that into consideration, 22 percent of utilities are required by a Public Utility Commission (PUC) to track reliability in some way. Interestingly, 46 percent of participants publicized their reliability reports and statistics.

Participants were asked if they calculated major outage events for separate analysis. 99 percent of participants responded to the question. 38 percent of participants indicated that they determine which events are major events as well as how major event status is determined. Respondents were instructed to check all methods for calculating major events that applied at their utilities. Among methods, the most common percentage “(X)” used to define a major event was 10 percent of customers without power, with 50 percent of customers without power being the highest threshold reported in the survey.

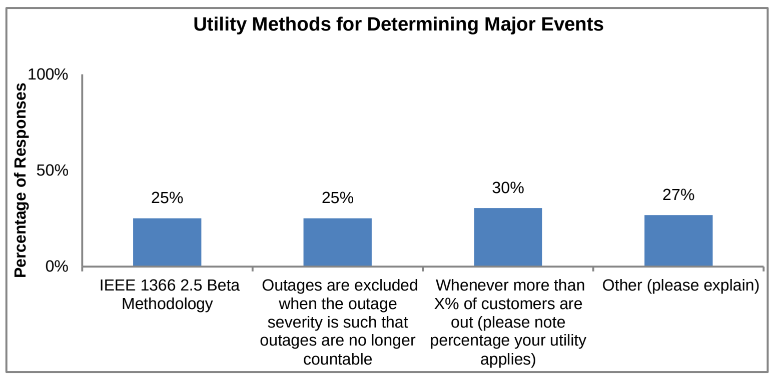

Figure 7: Utility methods for calculating major events

Participants were asked if they included planed outages in their reliability statistics. 99 percent of participants responded and, of those, 64 percent do not include planned outages in their statistics. Though it is a near certainty that planned outages are evaluated on some level by many utilities, the information gained by looking at planned outages is used differently than that gathered for un-planned outages.

In the following sections, this report makes a distinction between sustained and momentary outages. However, depending on the configuration of a circuit, including breakers, reclosers and sectionalizers, it is possible for customers to experience both momentary and sustained interruptions on the same circuit. Further, some customers can have power restored before other customers on the same circuit. The ability of a utility to capture this data can cause significant variations in final reliability statistics.

SECTION II: SUSTAINED OUTAGES

Sustained outages are the most commonly tracked outage type. When tracking outages, many utilities exclude scheduled outages, partial power, customer-related problems, and qualifying major events from the reliability indices calculations. While excluding these events in final reported statistics may be appropriate, all data should be reviewed internally for utility-level decision making. In this section, we evaluate participant outage definitions, reliability statistics and common causes of sustained outages.

As shown in **figure 8**, most utilities define a sustained outage as one that lasts more than one minute. However, a significant number of utilities define it as an outage that lasts longer than five minutes. The IEEE 1366 definition of a sustained interruption cites five minutes as the threshold for recording. At the system-wide level, the difference in definitions has the potential to impart significant differences in the outcome of reliability statistics. Consequently, if a utility is also tracking momentary outages, a decrease in the length of sustained outage statistics that might be seen with a longer sustained outage definition may result in an increase to the length of momentary statistics.

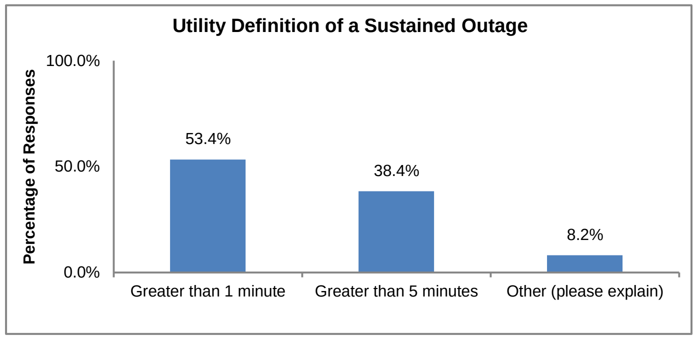

Figure 8: Participant definition of sustained outages

Table 3 illustrates how the definition of sustained outage matters in the final analysis of a utility's reliability statistics. As the technology and methodology used to collect outage information improves, reliability appears to decline. With higher resolution to observe outages, the higher outage numbers will become the new baseline for utility reliability analysis. As evidenced in **table 3**, utilities possessing supervisory control and data acquisition (SCADA) systems clearly had higher average System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) numbers. However, over the long term, enhanced outage detail allows utilities to improve reliability by making better informed decisions about system improvements.

Does utility have a SCADA system?	Average of SAIFI	Average of SAIDI
Yes	0.84	56.06
No	0.55	38.55

Table 3: Participant definition of sustained outages

The operations side of outage management has an underlying data component. Typically, a utility needs information on outages as quickly as possible in order to respond effectively. As such, a SCADA system can provide a strong backbone for any outage prevention and restoration plan.

As shown in **table 4**, as defined time of outage increases and planned outages are excluded, average SAIFI values improve. Despite overall differences in utility participation, this pattern is consistent with the data reported in the 2009 survey. However, the 2011 survey data do not show a similar improvement is in average SAIDI values. The data from utilities defining a sustained outage as greater than five minutes includes an unusual cluster of utilities with relatively higher SAIDI values. This cluster drags the average upward from the expected pattern.

Utility Defines Sustained Outage As:	Utility Counts Planned Outages As Part Of Stats: All responses	Yes	No
All responses	0.81	0.88	0.77
Greater than 1 minute	0.87	0.92	0.84
Greater than 5 minutes	0.71	0.86	0.58

Table 4: Difference in average SAIFI values between utilities defining sustained outages as greater than 1 minute and 5 minutes, respectively and relative to the utility use of planned outages in their statistics

Distribution service reliability indices, such as those defined in the IEEE 1366 standard, are an established way of measuring the availability of service for a particular electric distribution system. A key advantage of calculating reliability indices is the information they provide on short- and long-term system health. Long-term trends typically emerge after five years of data collection. Since all utilities are different and external conditions change constantly, a year-to-year comparison between utilities is less meaningful. Utilities that measure their indices are taking a good step toward informed reliability decision making. Many decision-making capabilities, such as worst circuit analysis, are enhanced through the use of these measurements. After five years of measurement, a utility can perform long-term trending analysis with a sufficient degree of certainty regarding major events and other anomalies.

In the survey, utilities were asked for sustained outage reliability statistics collected from January 1, 2010 to December 31, 2010. These metrics take the form of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI) and Average System Availability Index (ASAI). Definitions for the calculation of these indices appear in Appendix B of this report. **Table 6** displays the quartiles for the reliability statistics that were reported. 84 percent of participants reported SAIFI. 86 percent reported SAIDI and CAIDI, while 70 percent reported ASAI metrics. SAIFI is reported in average interruptions per year on the system. SAIDI is reported as the average duration in minutes of the interruptions. CAIDI is reported as the average length of time that a customer's outage lasts in minutes. ASAI is the percentage of time that the system was available per year.

In **table 5,** the data are broken out into quartile ranges. Rather than using the average of the quartile range, as was done in the 2009 report, the quartile demarcation is used to help utilities compare their metrics with more ease. Many readers will notice the inconsistency between the SAIDI and SAIFI calculations and the related CAIDI. In mathematical terms, CAIDI is SAIDI divided by SAIFI; however, the data reported do not suggest that. Approximately 10 percent of CAIDI metrics reported on this survey does not comport with the corresponding SAIFI and SAIDI numbers. This discrepancy may explain the differences between what one might expect for a CAIDI average and the CAIDI average of this data set. It is also important to note that it is unlikely for quartiles to result in a perfect SAIDI/SAIFI = CAIDI relationship.

Measure	SAIFI	SAIDI	ASAI	CAIDI
First Quartile	0.29	16.43	99.99991	46.31
Second Quartile (Median)	0.69	36.35	99.995	65.29
Third Quartile	1.08	65.91	99.99	88.39
Fourth Quartile	4.13	176.13	99.98	281.84
Average	0.81	46.36	99.86	73.86

Table 5: Summary statistics of the reliability data submitted to the survey

For comparison, similar average statistics from the survey years 2005, 2007 and 2009 --which represents data from years 2004, 2006 and 2008, respectively--are included in **table 6**. No clear pattern or trend emerges from the analysis of the data sets over the years.

Year	SAIFI	SAIDI	ASAI	CAIDI
2005	1.60	54.03	99.79	65.91
2007	4.18	69.80	99.97	90.06
2009	0.88	68.98	99.90	86.75
2011	0.81	46.36	99.86	73.86

Table 6: Average reliability statistics from previous surveys

Figures 9-12 show the average values for the reliability indices by APPA region. Since not all states had a utility submitting data for the survey, APPA regions were considered the most appropriate scale for display and analysis. For a list of states in each region, see Appendix C.

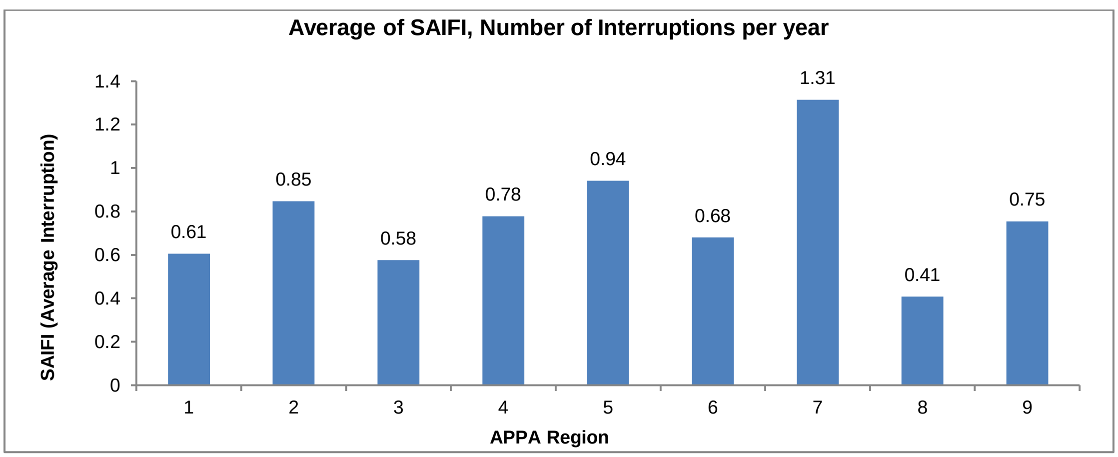

Figure 9: Average SAIFI by APPA region

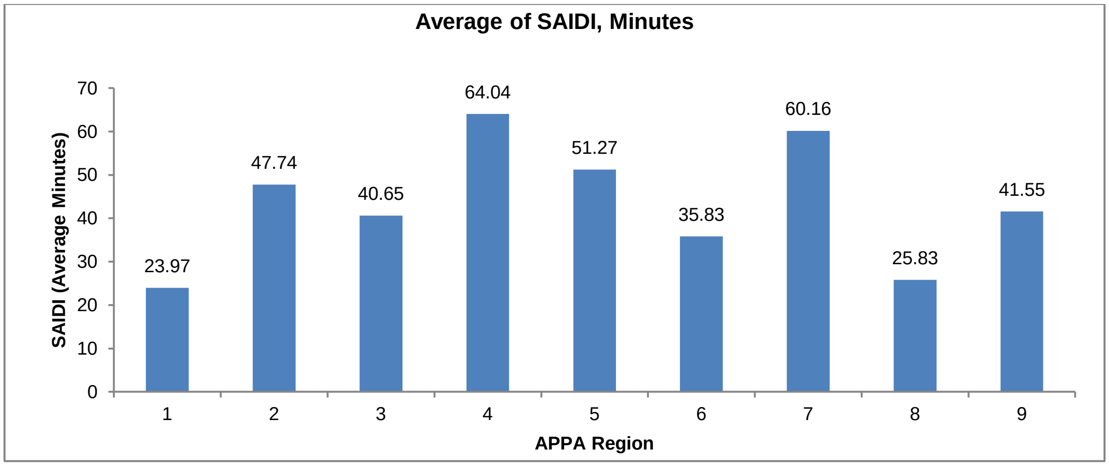

Figure 10: Average SAIDI by APPA region

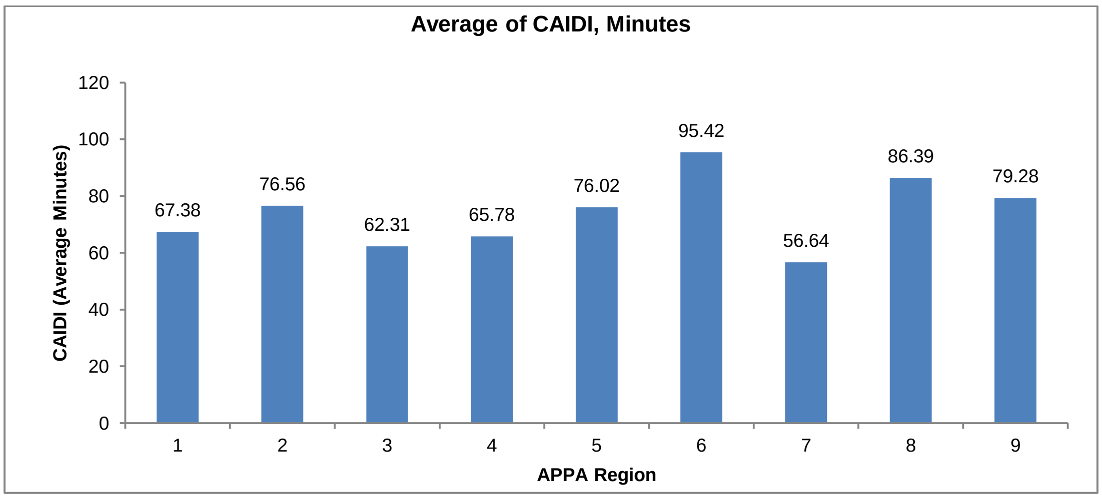

Figure 11: Average CAIDI by APPA region

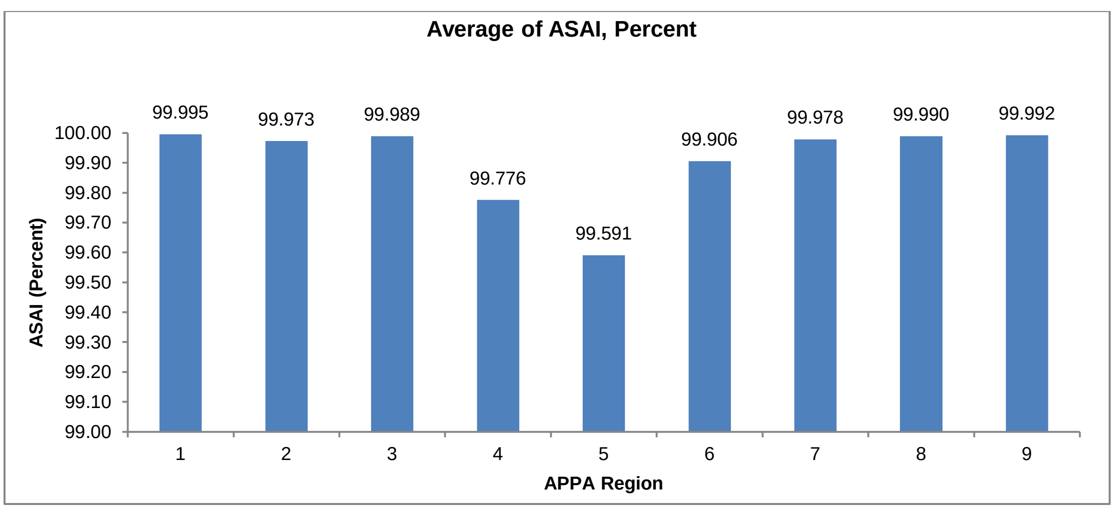

Figure 12: Average ASAI by APPA region

In addition to general outage statistics, utilities were asked to report any other statistics they found useful in describing the degree of reliability of their distribution system. Though few utilities reported other statistics, some interesting metrics include Average Number of Customers per Outage and Months Between Interruptions.

Outages have many possible causes. The survey asked utilities to supply the number of times per year they experienced outages from various causes. As shown in **figure 13**, overhead equipment failure and weather are the most significant cause of outages. Outages caused by humans were reported by 69 percent of survey respondents. The description of outages caused by humans ranged from vandalism and operator error to cross-phasing, incorrect fusing and incorrect connections. The use of the term “other” covered many outage causes not listed in the survey, such as load and station equipment.

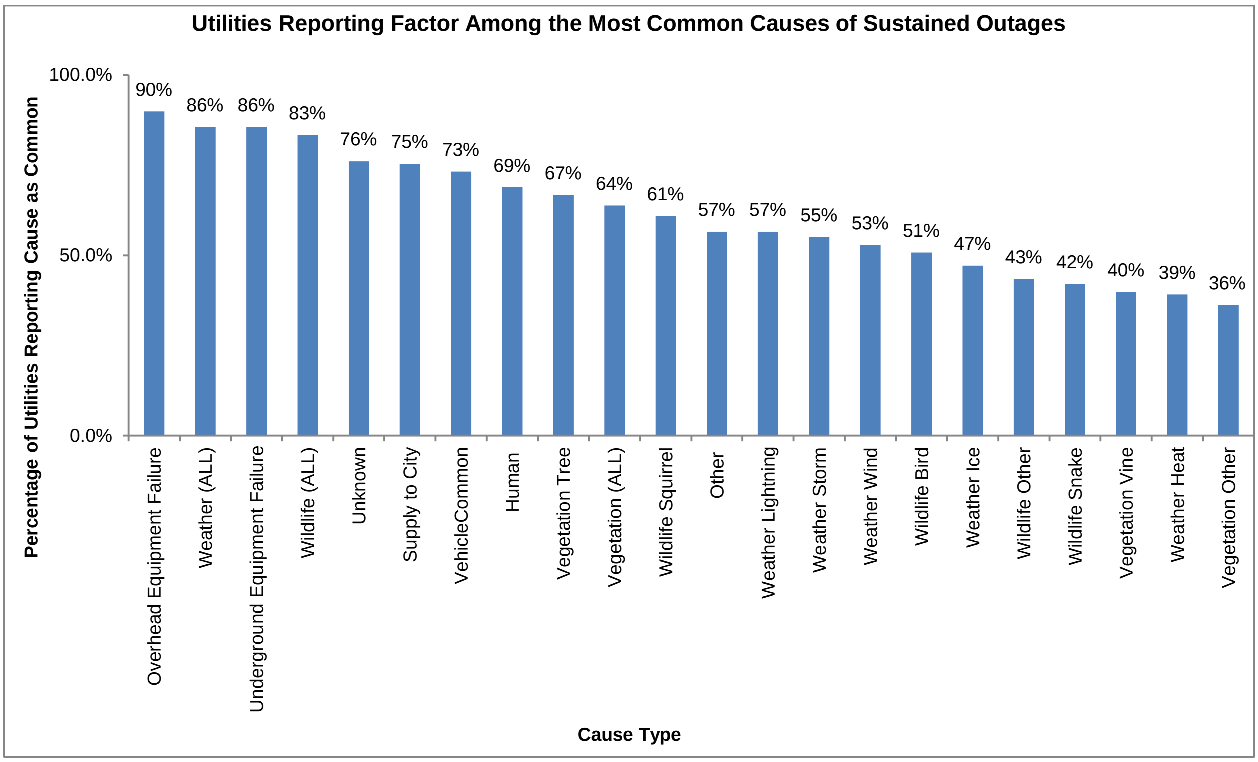

Figure 13: Percentage of utilities reporting cause type as a common cause of sustained outages

Interestingly, a Lawrence Berkeley National Laboratory study also found equipment failure to be a primary cause of outages.[15] The clear implication is that preventative maintenance programs can be a valuable tool to reduce outages.

System analysis and modeling for reliability can take many forms, including component modeling, failure probability distribution functions, thermographic scans of transformers and testing equipment to preempt failures. These techniques can lower the frequency of outages and improve the effectiveness of reliability spending. However, these modeling processes require valid data and data collection methods.

15 Reliability of the U.S. Electricity System: Recent Trends and Current Issues, Julie Osborn and Cornelia Kawann, 2001

At some utilities, a component modeling methodology is applied as a part of the system analysis to boost understanding of physical distribution system reliability. This methodology involves calculating reliability values for the many interconnected components in a system. The calculations can include more complicated metrics, such as, mean time to repair, probability of operational failure, and scheduled maintenance frequency. However, in cases where cumulative distribution and probability density functions can be used to describe the nature of distribution system component failures, a hazard function $\lambda(x)$ will be able to describe the probability of a component failing, if it has not already failed.[16]

For example, in a substation, a hazard value or probability of failure can be calculated for each component. These values can be used to produce an additive equivalent substation with a yearly probability of failure over time. This can then be translated into an expected annual outage rate and duration for each low-voltage bus of the substation.[17] From this calculation, a utility has one more data point to support its reliability-related decisions.

Failure rates and repair times are different for different system components and can be derived from historical data. Failure rates can be invaluable when attempting to determine the relative reliability of different distribution system arrangements.[18] This information, when integrated with maintenance strategy, can provide a strong quantitative basis for reliability-related decision making.

Figure 13 shows that weather events, such as storms, flooding, lightning, wind and ice, commonly cause outages. Often during storms, many components will fail at the same time for the same event. For example, wind can cause outages by blowing trees and poles over or by stimulating Aeolian vibration. To combat high wind conditions, utility engineers may increase phase-to-phase spacing and conductor tension to remediate areas where wind caused outages are more frequent.

Excessive heat is also a threat to utility reliability. When extended periods of unusually hot weather occur, cooling load increases dramatically. Since the hot weather prevents heat transfer, this added load strains the performance limits of conductors and transformers. As a result, many utilities design their systems to accommodate a level of disturbance in many outage areas. There are National Electrical Safety Code requirements to help utility staff in designing distribution infrastructure to tolerate high winds and avoid public danger from sagging lines in hot weather, or during temporary overload situations.

At the standards-making level, there is discussion of creating enhanced recommendations for the collection of data associated with outages. This includes tracking types of vegetation, equipment and other data related to an outage. APPA has developed reliability tracking software to help make this process easier for utilities and lineworkers.[19] Capturing this data, while potentially time-consuming, can provide a utility a wider quantified basis for making better operational decisions related to distribution system reliability.

[16] Probabilistic Engineering Design: Principles and Applications, James N. Siddall 1983
[17] Electric Power Distribution Reliability, Richard E. Brown, 2009
[18] Reliability Maintenance and Logistic Support: A Life Cycle Approach, Dinesh Kumar, 2000
[19] See: reliability.publicpower.org

SECTION III: MOMENTARY OUTAGES

For customers, momentary outages can be a hazard to electronic equipment. Since most new electronic equipment cannot tolerate a drop in voltage for even a fraction of a second, utility concern with the impact of momentary outages is increasing.[20] This kind of sensitive equipment has a nearly ubiquitous presence in customer workplaces and households. Though these new sensitive loads usually don't make up a significant portion of the total load served by a utility, it is important to be aware of them.

In the survey, 97 percent of utilities reported on their momentary outage practices. Information on momentary outages can be helpful in tracking down problems that may eventually lead to sustained outages and power delivery problems.

As with sustained outages, utilities define and capture momentary outages differently. **Figure 14** shows how survey respondents define a momentary outage. 37 percent of utilities reported the IEEE 1366 reliability statistic of Momentary Average Interruption Frequency Index (MAIFI). The average MAIFI for respondents was 1.97 events. As seen in **figure 15**, the average frequency of interruption events is greater when the definition of the outage is shorter. This is counter to the trend seen in **table 4** (SAIFI indices for sustained outages)**,** and may have to do with enhanced technical monitoring ability in utilities with shorter definitions of MAIFI and SAIFI.

Figure 16 shows the percentage of respondents using a particular technology to capture momentary outages.

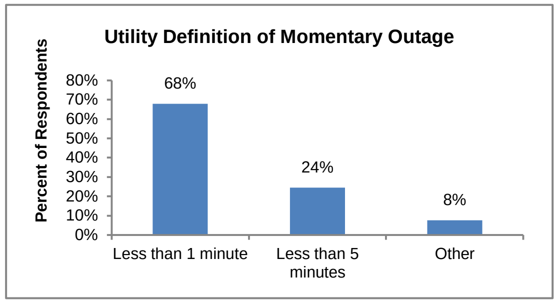

Figure 14: Percentage of respondent's time definition of a momentary outage

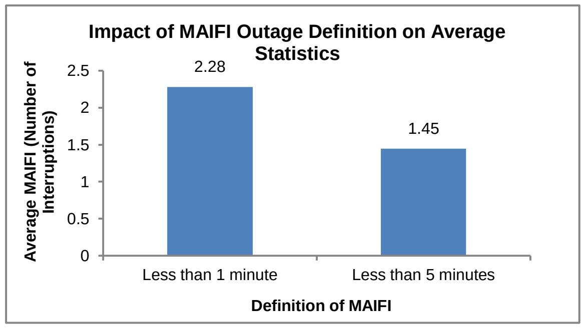

Figure 15: Impact of MAIFI outage definition on average reliability statistic

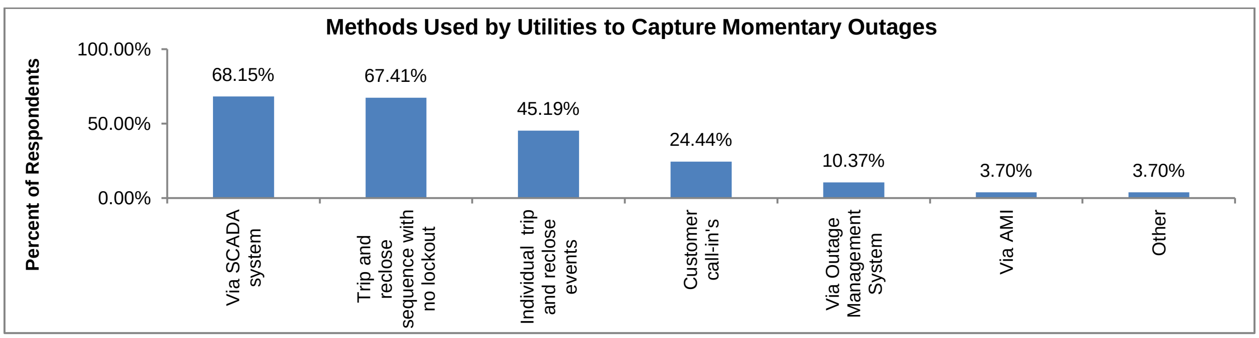

Figure 16: Percentage of respondent's methodologies for capturing momentary outages

Figure 17 shows that animals and weather are the most common reported causes of momentary outages. 91 utilities responded with their selections of commonly identified causes of momentary outages.

[20] LBNL -52048 A New Approach to Power Quality and Electricity Reliability Monitoring, 2003

In general, these data reflect the transient, hard-to-catch nature of momentary outages. Though many utilities are tracking them at some level, it is difficult for a utility to attain the tracking resolution required to identify momentary outages and their associated causes in more than a few key areas.

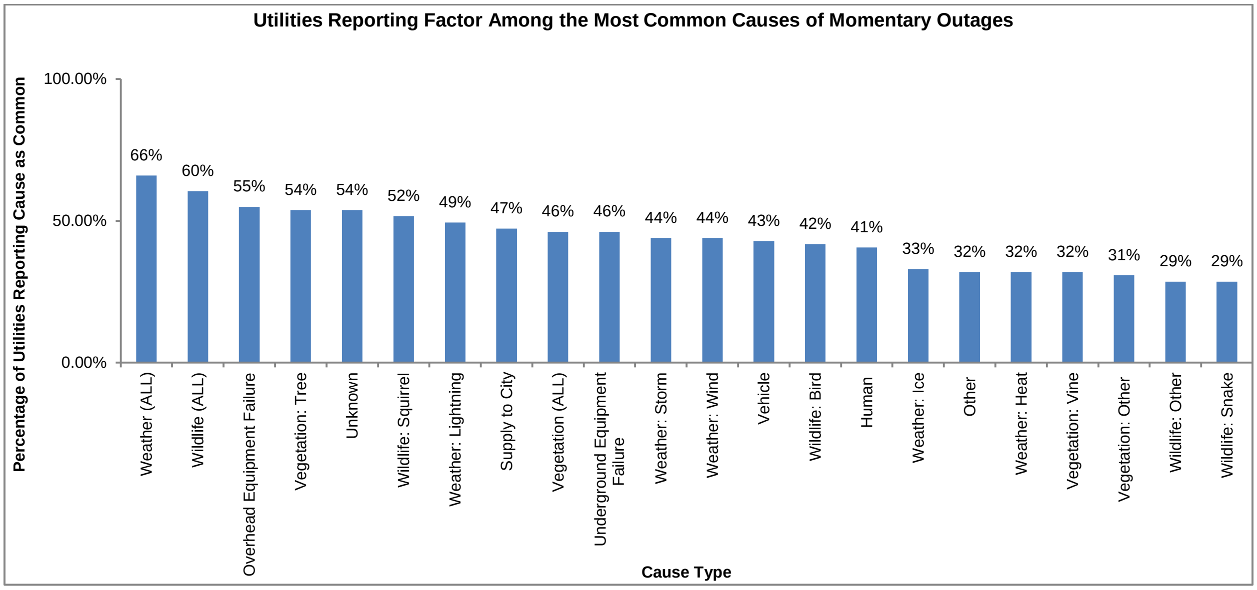

Figure 17 Average occurrence rates for common causes of momentary outages

SECTION IV: POWER QUALITY

Though seemingly an overarching term, power quality typically describes the quality of a distribution system's voltage and current in terms of its sinusoidal form, constant amplitude and constant frequency. Accordingly, APPA considers power quality to be an integral part of a utility's service to its customers; however, this report does not address power quality issues on a deep technical level. Rather, it examines the perceived and real links between power quality and distribution system reliability.

Many utilities limit the discussion of reliability to outages. However, power quality is a key component of reliability. Many standards address power quality.[21] Moreover, power quality issues vary in scope and addressability. On one hand, a utility can spend significant amounts of money to create a power system with a near-perfect sinusoidal voltage source, regardless of what is happening. On the other hand, a public power utility must pass all of its costs--including power quality control costs--on to the customer. Thus, utilities must find a middle ground that can accommodate customers' power quality needs, allow for addition of some amount of unexpected new load without significant impacts, and keep costs at a reasonable level.

As mentioned in the introduction to this report, increasing use of sensitive electronic equipment is creating more loads that respond to distribution system power quality indicators. This problem is compounded by the non-linear nature of many loads. Voltage sag and swell and harmonic currents can be created by switching or operating many high load devices.

There is a link between overall power quality a customer experiences and the power usage of other customers nearby. For example, a customer switching on high-wattage motors, arc-welders, or HVAC equipment can create voltage dips for other customers.[22]

145 utilities responded to our question on recording voltage deviations. Of them, 61 percent measure voltage deviations. **Figure 18** shows that, of the utilities that measure voltage deviations, 90.11 percent measure it at the substation. Survey respondents were instructed to select as many locations as applicable.

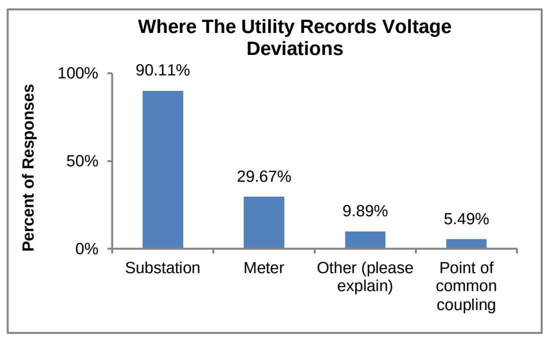

Figure 18: Location utility records voltage deviation

69 percent of the survey respondents perform power quality monitoring in some fashion on their system. Some utilities offer power quality monitoring services for their customers. For certain customers, this service can be valuable. Nearly three-quarters of respondents perform power quality monitoring at commercial and industrial sites. Of note, 60 percent of respondent utilities measure power quality at the feeder level.

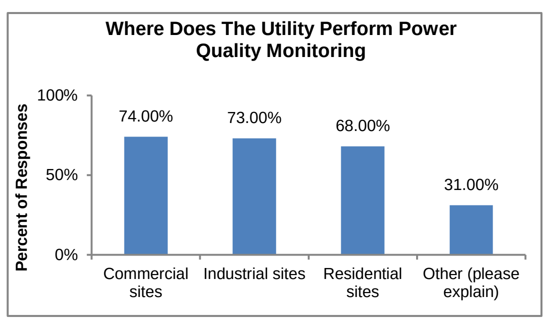

Figure 19: Location utility performs power quality check

---

21 See IEEE Std. 142, 519, 1159, 1250 and 1346

22 Power quality primer By Barry W. Kennedy, 2000

In an electric distribution system, customer actions can impact the quality of system operation. Many of these customer actions are visible at other customer points of use. For example, the operation of an industrial device that draws a large amount of current with significant cycle variations, such as an arc furnace, can cause rapid fluctuations in local system voltage. The visual effect of these fluctuations is commonly referred to as flicker. As a power quality problem, flicker can be seen visibly in incandescent lighting and can be irritating. To address this problem, some utilities have flicker standards. As shown in **figure 20**, of the 123 responses, sag is the power quality problem most cited by utilities as a concern. Flicker and transients are the next most-cited power quality problems. Without consistent power quality, many customers would be less satisfied. Utility respondents could select as many power quality problems as are concerns.

Another power quality measurement that can help utilities understand their distribution system is Total Harmonic Distortion (THD). Many respondents noted that they do not record THD. Among the group that measures THD, most measure it at the customer meter (see **figure 21**). In addition, 18 percent use a power quality indexing method. Among respondents that listed the method they used, the most popular method was the ITI CBEMA curve.

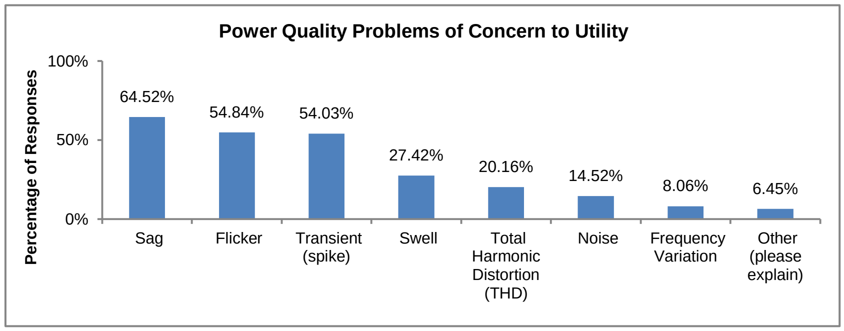

Figure 20: Power quality problems of concern to utility

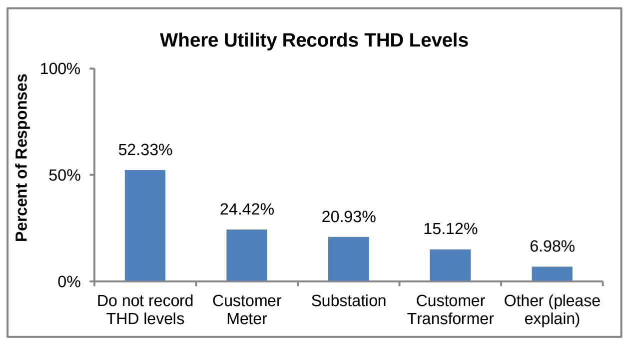

Figure 21: Location utility records THD

Power quality issues can take many forms. A utility may find itself in the position of mediator between a customer causing power quality problems and other nearby customers experiencing the problems. In these cases, it is not unusual for a utility to ask customers to take steps to curb power quality impacts to the electric system. Consequently, exposed customers may be asked to take steps to isolate sensitive equipment. Regardless of the power quality problem, having a policy or requirement to take action to resolve it is important.

SECTION V: OUTAGE PREVENTION

Many utilities have outage prevention programs as a part of their operations plan. This section looks at utility outage prevention plans, programs undertaken to improve vegetation management and utility participation in mutual aid.

The survey asked utilities to identify the types of outage-prevention programs they have undertaken. 145 utilities responded to this question. Among programs identified by respondents, tree-trimming was most frequent, with 98.6 percent of respondents reporting some type of tree-trimming program to help reduce outages. As a subset of vegetation management, tree-trimming is a logical focus for any outage prevention program.

Figure 22 shows that tree-trimming programs are the most common components of outage prevention plans. Trees, while beloved by most customers, are ever-growing hazards for electric lines. When a tree or other vegetation makes contact with a line, depending on the line's voltage and shielding, a path to ground may be created and an outage can occur. At times, when vegetation crosses two lines, a phase-to-phase fault can occur. When the contact happens, the phase-to-phase fault may not be immediate. The path between two wires can be created over time as the current from the wires dries out a small inner section of the branch making contact between the wires.[23] If a branch crossing between two wires is sufficiently desiccated, a fault can be created through the plant material.

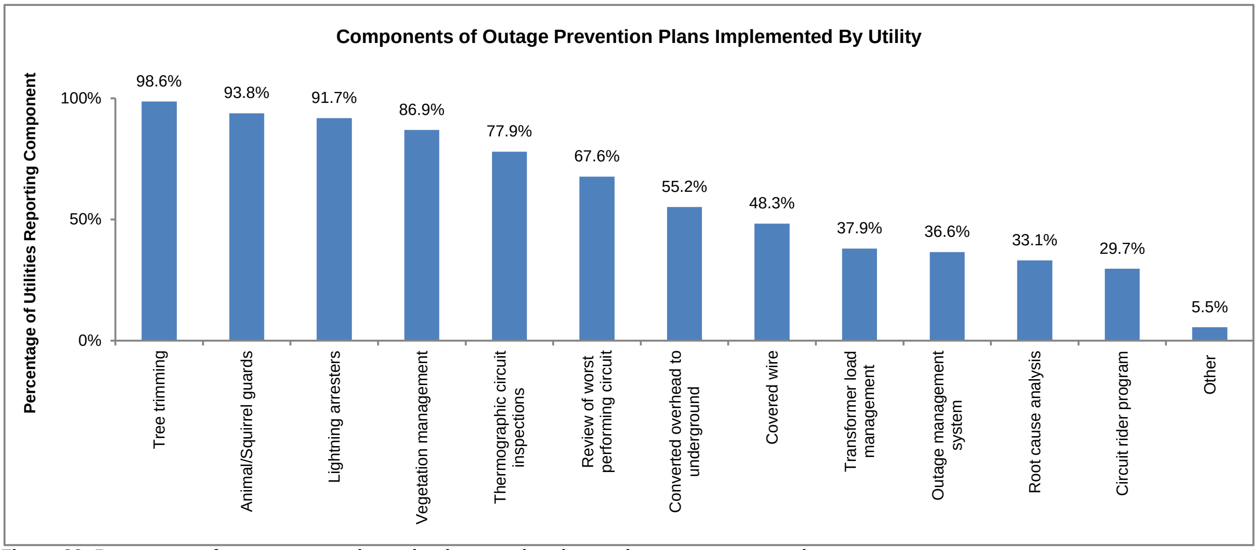

Figure 22: Percentage of survey respondents that have undertaken a given outage prevention program

Regular inspection, maintenance and outage-prevention programs can provide valuable reliability-related data to support decision making. Certain maintenance, such as tree trimming and visual inspection, should be performed regularly. Other popular outage prevention programs are animal guards and lightning arrestors. As seen in the sustained outages section of this report, lightning is a frequent cause of outages. Lightning arrestors and shield wires provide protection for circuits that are susceptible to lightning strikes. Squirrels are another common cause of outages. Since a utility pole is similar to a tree, squirrels frequently climb poles. The heat emitted by electric lines can attract a squirrel, particularly during

[23] Electric Power Distribution Reliability, Richard E. Brown, 2009

cold weather. Nearly all squirrel activities that cause outages on distribution transformers can be mitigated using squirrel guards.

Many utilities are searching constantly for more efficient methods of vegetation management. As shown in **figure 23**, removal of hazardous trees is the most popular improvement initiative. Where utilities noted “other” as their initiative, they listed items such as a tree-replacement program and tree-growth inhibitors.

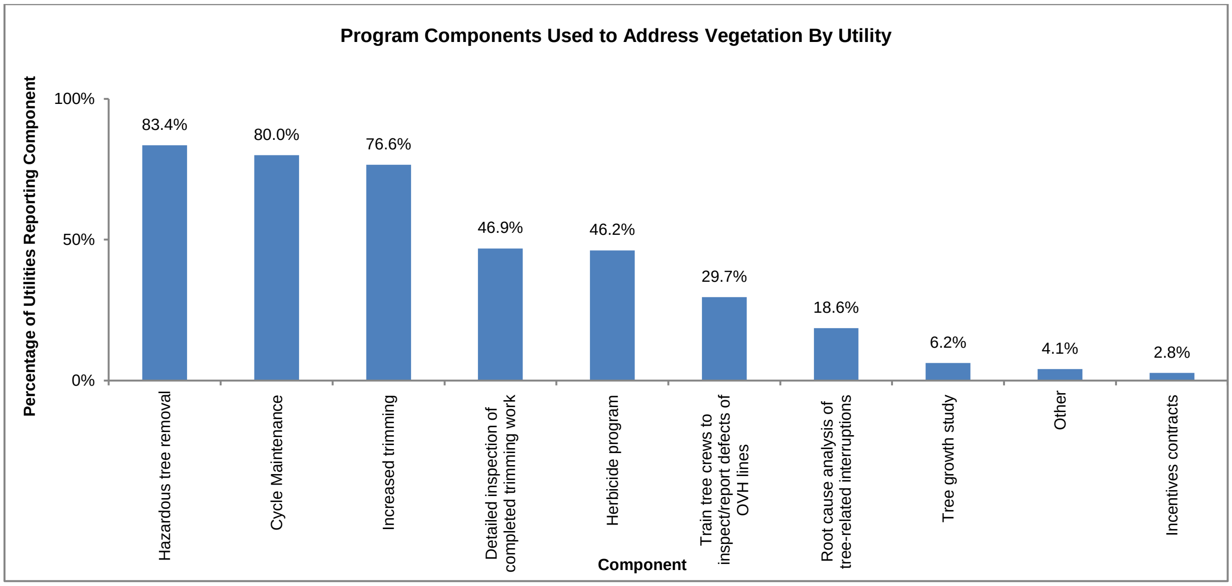

Figure 23: Percentage of respondents undertaking specific initiatives to improve vegetation management programs

There are many ways to trim trees without removing the entire plant. Methods include topping, side trimming and through trimming. The downside of a trimming program is that it is a continuous process.

Outside of regular outage management plans comes the management of major events and catastrophes. All utilities want to minimize the damage and risk of damage during a catastrophic storm or event. 91 percent of respondents have a major storm or catastrophe plan and 95 percent of those utilities have a written version of that plan. 97 percent of respondents indicated that they participate in a mutual aid agreement. Significantly, of those utilities, 71 percent have participated in mutual aid actions. Alternately, 44 percent of respondents have requested mutual aid using their agreements. This may reflect public power’s often quicker post-storm restoration times, compared with other utility types.

Public power should be proud of its superb mutual aid and assistance network and should continue to improve it. This can happen by signing new mutual aid agreements or improving existing disaster management plans. To date, more than 1,600 municipally owned and rural electric cooperative utilities have signed the APPA/NRECA Mutual Aid Agreement.

SECTION VI: WORK FORCE ISSUES

A work force that can maintain the distribution system is an essential part of any utility's operations. Of that work force, lineworkers are the primary staff charged with the maintenance and upkeep of the distribution system. Since there is 24-hour demand for electricity, it is important that a utility find a way to make lineworkers available at all times to solve delivery problems.

In the survey, participants were asked how their utility provided 24-hour crew coverage. Just over 76 percent of participants used one shift with lineworkers on call to meet their coverage needs. Fewer than 20 utilities used two or three shifts and one utility did not specify how it provides crew coverage.

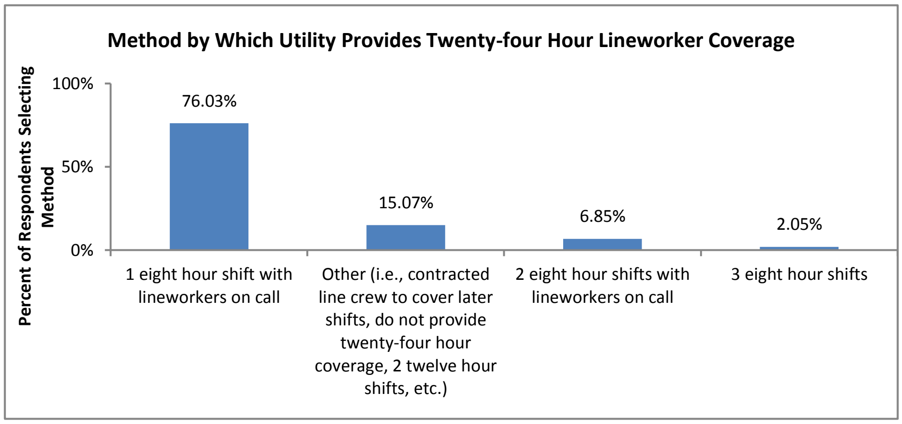

Figure 24: Method to provide 24 hour crew coverage

There was significant variety in the number of lineworkers each utility employs. In the survey, the average number of crews that each utility employs was broken down into the categories of apprentice, journeyman, mixed and contract. Of those crews, the average number of apprentice line crews is zero. The average number of solely journeyman line crews is three. The average number of journeyman and apprentice mixed crews is three. The average number of contract crews employed by participants is five. The average number of crews employed by participant utilities varied, based on the crew type. See **table 7**.

Average number of crews utility employs (rounded to nearest whole crew)	
Apprentice crews	0
Contracted crews	2
Journeyman crews	3
Journey and Apprentice mixed crews	5

Table 7: Average number of crews utility employs

The average number of lineworkers per crew also varied by the crew type. See **table 8**.

Average number of linemen utility has on a crew (rounded to nearest whole lineman)	
Apprentice Crews	0
Contracted Crews	2
Journeyman Crews	3
Journey and Apprentice mixed crews	4

Table 8: Average number of workers per crew by type of worker

By taking this analysis a step further, one can see that the number of lineworkers on a crew varies according to the composition of the crew and the number of people typically assigned to the crew. Many utilities used more than one type of crew. As shown in **table 9**, nine utilities said they have one-person apprentice crews. This is a small number of crews relative to the total selection of crews and therefore does not show up in the final rounded average numbers in **tables 7** and **8**. Selections of single-person mixed crews are likely considerations of special circumstances outside of the general coverage of this survey. **Table 9** shows that if two people are on the crew it is most likely to be composed of two journeyman lineworkers. The data also show that if three people are on a crew it is most likely to be a mixed crew with an apprentice or groundman.

Number of People on Crew	Type of Crew	Number of Utility Responses to Question
One Person	Apprentice Crews	9
One Person	Apprentice Mixed Crews	3
One Person	Contracted Crews	1
One Person	Journeyman Crews	9
Two People	Apprentice Crews	9
Two People	Apprentice Mixed Crews	22
Two People	Contracted Crews	6
Two People	Journeyman Crews	42
Three People	Apprentice Crews	1
Three People	Apprentice Mixed Crews	50
Three People	Contracted Crews	11
Three People	Journeyman Crews	39
	Total	**202**

Table 9: Average number of workers per crew by type of worker

As shown in **figure 25**, 24 percent of utilities allow crews to take vehicles home.

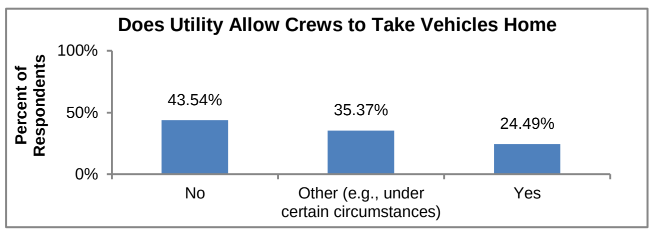

Figure 25: Average number of workers per crew by type of worker

Interestingly, the data showed a wide range of customers per lineworker. In this participant group, the number of customers per lineworker ranged from 215 to 4,588. These data are very different from the corresponding range reported in 2009, which was 1,300 to 1,700. However, the average and median number of lineworkers from this survey was much more consistent with 2009 data at 1,283 and 1,083, respectively. This range might be useful for a utility in determining the number of lineworkers a utility should employ. Since each utility is different both in condition and circumstance, deviation from this range should not be a cause for worry. Summary statistics appear in **table 10**.

The survey data indicated the average number of lineworkers per square mile of service territory at 0.59. This metric ranged from a low of 0.006 to a high of 3.57 lineworkers per square mile. Even though this metric is a general average, it might also be helpful in benchmarking utility operations. When considering this metric, it is important to consider number of lineworkers on a crew.

Minimum Customers per Lineworker	215
Maximum Customers per Lineworker	4588
Average Customers per Lineworker	1283
Median Customers per Lineworker	1083
Average Lineworkers per Square Mile of Service Territory	0.59

Table 10: Workforce benchmarking metrics at a glance

Figure 26 shows that the total number of lineworkers generally increases as the number of customers increase.

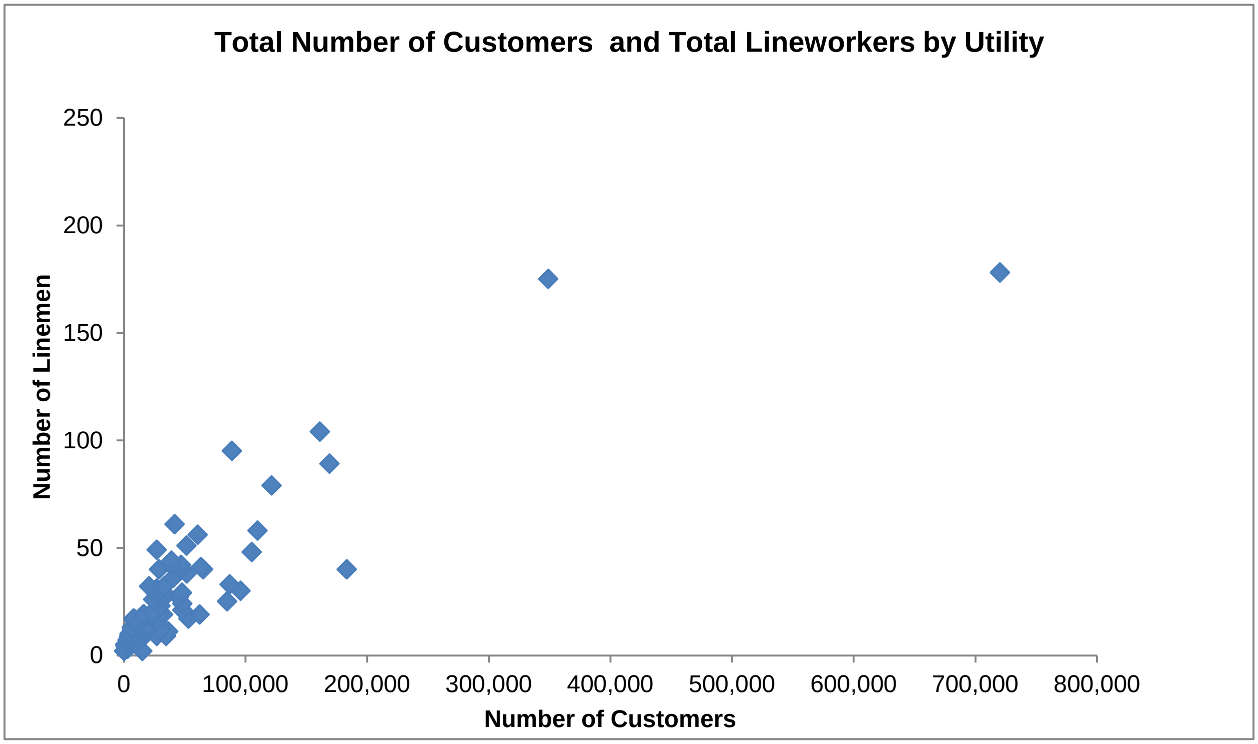

Figure 26: Number of customers and lineworkers by utility

The correlation coefficient is the degree to which one variable increases as another variable is increased. It is a statistical way of showing a relationship between two variables. More specifically, correlation coefficient is a measure of how well a linear trend in one variable follows the same linear trend in another variable. Citing a correlation coefficient will show a degree of linear relationship between two variables. A coefficient of 1 signifies a high degree of linear correlation, whereas a correlation coefficient of 0 signifies no correlation between two variables. For example, in this survey, the number of lineworkers increases as the number of customers increases, with a correlation coefficient of 0.86, meaning there is a generally linear relationship between number of customers and lineworkers at a utility.

The number of lineworkers and all major reliability statistics SAIFI, SAIDI, and CAIDI are not correlated. This hints that distribution system reliability is more about worker operations and system investment decisions and less about how many workers are available. To further that line of thinking, when the ratio of lineworkers per customer was compared to the reliability indices SAIFI, SAIDI, and CAIDI, they did not correlate.

SECTION VII: SYSTEM OPERATION

To find out more about system operations, the survey asked for information on substations and power quality maintenance practices. In a typical distribution system, the substation is the delivery point for power. As a result, maintaining and operating the substation transformers is important to the reliability of the power system. Every time a transformer is overloaded, its useful life is decreased. Typically this happens through the long-term degradation of the insulating medium.[24] In the survey, 76 percent of respondents have transformer overload guidelines, while 86 percent have an established maintenance program for transformers. All respondents test their transformer oil and 58 percent of respondents have a standardized substation design for all substations. This survey covered more than 1,800 distribution substations and the average number of distribution substations owned by utility respondents to this survey was 12, rounding to the nearest substation.

As the utility engineer knows, substations are important nodes in the electrical system. As central nodes, substations are of high concern to the overall reliability of the electric system. To protect transformers and ensure a problem on one circuit does not transfer to the transformer and other circuits, circuit breakers are used. The circuit breaker is typically the last line of protection between a circuit and a transformer and can be designed and built as part of a transformer protection scheme at many levels of technological complexity. 146 respondents identified the types of breakers that are used in their substations. As shown in **figure 27**, the most commonly used breakers are vacuum and sodium hexafluoride (SF6).

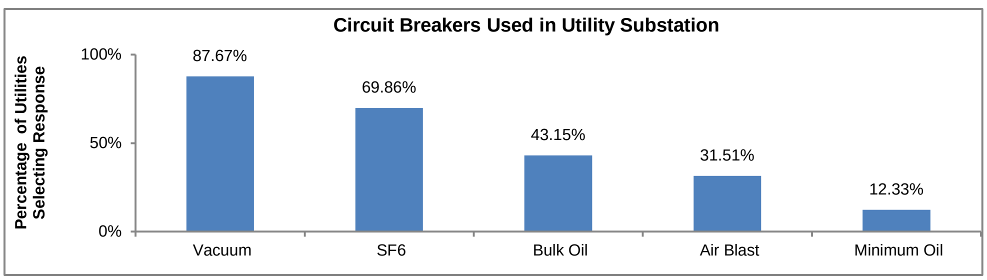

Figure 27: Type of breakers used in utility substation

Supervisory Acquisition and Data Control (SCADA) systems can be an important tool for a utility to detect outages and power quality problems. In the survey, 86 percent of respondents reported using a SCADA system of some type. The most popular systems are listed in **Table 11**, in alphabetical order. It is important to note that many utilities built their own SCADA systems by pulling parts from different vendors to achieve their desired outcome. 16 percent of respondent utilities have implemented automated switching schemes, such as distributed automation.

---

[24] Investigations of Temperature Effects on the Dielectric Response Measurements of Transformer Oil-Paper Insulation System, IEEE Transactions on Power Delivery, VOL 23, NO. 1, 2008

Most Common SCADA Systems (More than 3 utilities reported using the system)
Advance Control Systems
C3
Custom (utility designed in-house)
GE
QEI
Siemens
Survalent
Televent
Wonderware

Table 11: Most common SCADA system companies used by utilities in survey, listed alphabetically

83 percent of respondents have implemented a regular distribution system inspection and maintenance program. At its simplest, a maintenance plan will dictate that some equipment can be run to its failure point while other equipment will require periodic maintenance. At a more complex level, reliability-centered maintenance is a recommended practice where maintenance requirements are determined based on equipment condition, criticality to the functioning of the system, and cost.[25] A reliability-centered maintenance program can provide repair and replacement schedules that optimize for system reliability by selecting high maintenance priority for components that are "most likely to fail, have a high impact to customers when they fail, and can be maintained for a reasonable cost."[26]

At many utilities in areas of high customer density or where greater system redundancy is needed, a networked distribution system configuration is used. Networked distribution can be thought of as multiple interconnecting electrical nodes. Of the 91 utilities responding that they operated networked distribution, an average of 13,866 customers are served via that networked distribution.

The survey also asked utilities about the voltages they operate on their distribution system. Based on the ANSI C84.1 standard voltages, the most utilities indicated that they were using 12470Y/7200. Many utilities also noted that they were not using certain distribution system line voltages. This information has been included in **table 12**.

Voltage Operated	Yes-Voltage is Operated By Utility	No-Voltage is Not Operated By Utility
4160Y/2400	43	33
6900	4	43
8320Y/4800	6	42
12000Y/6930	3	43
12470Y/7200	80	18
13200Y/7620	27	38
13800Y/7970	22	36
20780Y/12000	2	43
22860Y/13200	6	42
23000	2	42
24940Y/14400	8	42
34500Y/19920	9	43
Other	7	31

Table 12: What voltage is operated or not operated by utilities. The sum of the "Yes" and "No" columns for a voltage row is equal to the number of utilities reporting information on a particular voltage

25 Reliability Centered Maintenance, John Moubray, 1998
26 Electric Power Distribution Reliability, Richard E. Brown, 2009

Voltage data were collected to help utilities understand the decisions other utilities are making about distribution system voltage. **Table 13** shows the average miles of line reported by the utilities reporting a particular voltage. The voltage is listed as the higher ANSI C84.1 voltage. Miles of line are cut at the nearest whole mile. These data show that utilities with 4,160-volt lines have fewer average miles of line. The table also confirms that most utilities in the survey are operating 12,470-volt lines.

Voltage of Line	Average Number of Miles at Utility	Number of Utilities Reporting "Miles of Line" at Voltage
4,160	92	29
12,470	834	61
13,200	750	14
13,800	335	18
22,860	234	5
24,940	1231	9
34,500	844	8

Table 13: Average miles of line and voltage of line by for survey participants

In addition, respondent miles of line, reported SAIFI and line voltages were analyzed. An interesting pattern was found when the system-wide SAIFI was applied to all of the line types operated by a utility respondent. This SAIFI was then summed for all utilities operating a particular voltage and divided by the sum of the miles of line for all utilities operating a particular voltage. This is clearly an inexact methodology, but there appears to be a pattern across multiple utilities and by different operating voltages across the survey. The data include 109 utilities and 89,000 miles of line and the ratio of SAIFI per mile of line across the data seem to relate to voltage across the data. As shown in **figure 28**, SAIFI per mile of line appears to go down as voltage increases. Another interesting feature of this data is that SAIFI is more likely to increase as miles of 34,500 -volt line increase while utility overall SAIFI is more likely to be higher per mile of line at a utility with lower voltage lines. There is an observable power law relationship between the three variables: miles of line, voltage and SAIFI.

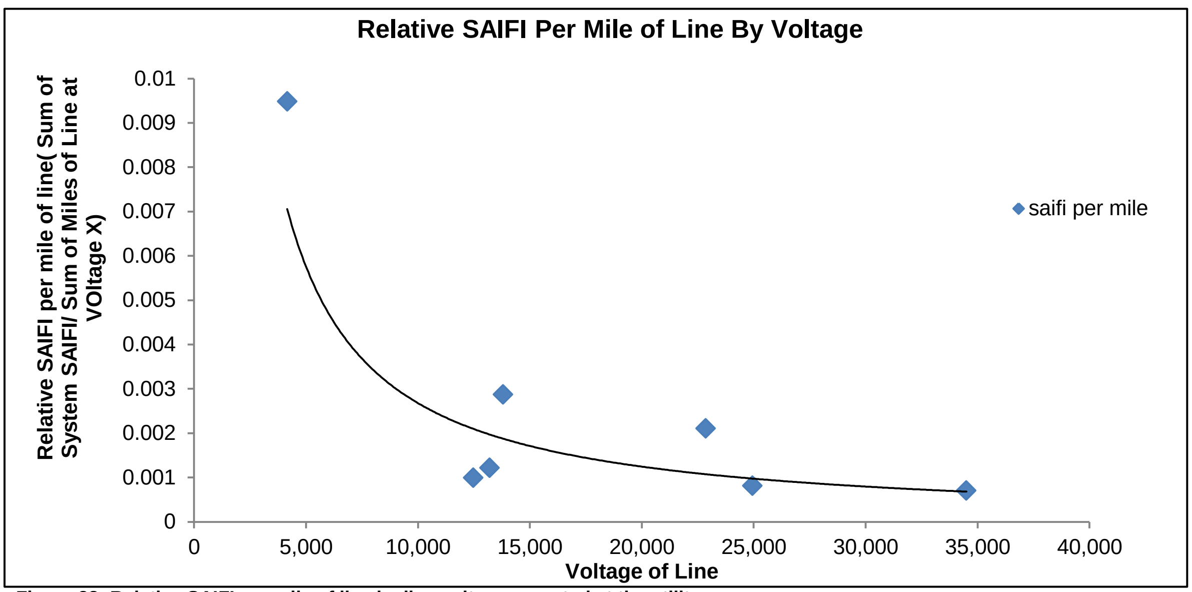

Figure 28: Relative SAIFI per mile of line by line voltage operated at the utility

To protect lines, equipment and customers against damage from electrical faults, utilities employ fuses, reclosers, switches, sectionalizers, relays and circuit breakers. Depending on its settings, a relay is commonly the first element to react to some type of electrical abnormality in a distribution line. Relays are the "brain" of the protection system for distribution components. Relays are often located in substations to monitor and take action upon the detection of various power conditions on feeder lines. Due to the emergence of cost-effective and reliable monitoring electronics, power quality-based distribution protection functions are being integrated into many protection devices.[27] Accordingly, nearly all relays have their reaction to power conditions "timed" to save or blow fuses. Among survey respondents, nearly 37 percent use a relaying practice designed to save fuses. Conversely, just over 62 percent of respondents use a relay practice designed to force fuse action. Fuse forcing generally implies that fuses are set to blow prior to switch or breaker operation. This is consistent with many larger utility sectionalization guides.

Number of recloses before system lockout	Percent of Respondents Using Number of Recloses
0	0.71%
1	3.55%
2	20.57%
3	56.03%
4	9.93%
6	0.71%

Table 14: Utilities using number of recloses

As seen in **table 14**, among 141 utilities, it is most common to allow three recloses before lockout. This assumes that utilities that responded have automatic reclosers, though respondents were not asked if they owned automatic reclosers. This particular strategy may provide more closing cycles to clear a fault or allow other switching devices on feeder lines to operate. The downside of this strategy would be the repeated short-term interruption of any customers with sensitive power quality needs on a particular line. As is shown in **table 15**, after the first close, many utilities choose to increase the amount of time a relay stays open. Relay practice widely varies between utilities; however, the close time for a relay after it has been open is often based on the time-current curve used by the utility. Some utilities do have a close timing specification set differently from the time-current curve.

Open Number	Average of Open Duration of Relay Prior to Reclosure (In Seconds)
1st Open duration	2.81
2nd Open duration	12.32
3rd Open duration	22.83
4th Open duration	26

Table 15: Average time relay stays open

Close Number	Average of Close Duration Prior to Open (In Seconds)
1st Close duration	7.17
2nd Close duration	5.92
3rd Close duration	5.35

Table 16: Average time relay stays closed after open

Where the time-current curve is not used, the average values for close become shorter as relay closes increase. As seen in **table 16**, the average duration of close time decreases as the relay closes more times in response to a condition.

[27] Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems, Schweitzer Engineering, 2010

SECTION VIII: GENERAL UTILITY INFORMATION

The general utility information section of the survey was designed to help APPA understand the basic quantitative metrics of the utilities participating in the survey. The utilities that submitted information to this section of the survey gave valuable information for APPA's analysis of relationships between customers, lineworkers and line mileage. In this survey, the average participant peak load was 5,968 megawatts. The average load is much higher than expected, due to the number of larger utilities that participated in the survey. The median peak load was 130 megawatts.

Since urban and rural were not strictly defined, a utility could use its definition or the definition of urban as an overall average density of at least 500 people per square mile. As shown in **table 17**, most utilities reported that they were more urban than rural. Since most public utilities are based strictly in city limits, this is a logical result.

	Load Concentration Urban (percent)
Average	83%
Median	95%

Table 17: Average Load Concentration

Additionally, utilities were asked to list the percentage of their system that was overhead versus the portion that was underground. One utility respondent had a 100 percent underground electric system. Participants were typically a majority overhead construction.

	Percentage of Distribution System Overhead
Average	64%
Median	68%

Table 18: Percentage of distribution system overhead

Among survey respondents, the average number of customers per mile of line was 56 and the median number was 51. This information may be useful for understanding the customer density of the utilities participating in this survey.

CONCLUSION

Starting or maintaining a program to track and evaluate reliability data is essential. Further, participation in APPA’s Distribution System Reliability and Operations Survey is a beneficial exercise for engineers and operations personnel in the public power field. It is only through consistent and thoughtful participation that we will be able to explore in depth the issues that confront us as an industry. APPA hopes readers find this report both informative and valuable in their quest for operational excellence.

To measure system reliability successfully, utility staff should commit to the long-term uninterrupted collection of reliability related data. Measuring reliability is a deliberate process and takes a significant number of observations before it yields meaningful data. Commitment to measuring system reliability is a best practice and by participating in best practice programs, such as APPA’s Reliable Public Power Provider Program (RP3), a utility stands to gain significantly.

In the future, it makes sense to collect and check for errors in the core values associated with SAIDI and SAIFI (minutes of interruption and number of interruptions, respectively). This would help eliminate some of the reporting errors associated with the submitted data. It might also be interesting to collect more detailed metrics from the utility regarding its individual circuits and substations.

The data used in this survey represent a multitude of different takes on distribution systems and reliability, with a varied consistency in questions. For some questions, a secondary clarifying question may have helped create more uniformity in responses. On the whole, APPA believes this survey provides interesting and valuable benchmarking information to members regarding the way electric distribution systems are run across the public power industry. At best, this report expands individual understanding of electric utility distribution systems and conveys the general data collected in our survey.

APPENDIX A – COPY OF QUESTIONS FROM DSR&O SURVEY

For a copy of the survey please see:

http://www.publicpower.org/files/2011DistributionSystemReliabilityandOperationsSurveyNoAppendix.pdf

APPENDIX B – SUSTAINED AND MOMENTARY INTERRUPTION INDICES

Sustained Interruption Indices

Calculations of reliability indices as shown on survey. Please refer to IEEE Std. 1366 for a full description of each index; indices listed below should be used only by individuals familiar with reliability indices.

Average **S**ervice **A**vailability **I**ndex – ASAI is a measure of the average availability of the sub-transmission and distribution systems that serve customers. It is the ratio of the total customer minutes that service was available to the total customer minutes demanded in a time period. It is normally expressed as a percentage.

$$\mathbf{ASAI} = \frac{\textit{Customer Hours Service Availability}}{\textit{Customer Hours Service Demand}}$$

System **A**verage **I**nterruption **F**requency **I**ndex (Sustained Interruptions) – This is defined as the average number of times that a customer is interrupted during a specified time period. It is determined by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is "interruptions per customer".

$$\mathbf{SAIFI} = \frac{\textit{Total Number of Customer Interruptions}}{\textit{Total Number of Customers Served}}$$

System **A**verage **I**nterruption **D**uration **I**ndex – This is defined as the average interruption duration for customers served during a specified time period. It is determined by summing the customer-minutes off for each interruption during a specified time period and dividing the sum by the average number of customers served during that period. The unit is minutes. This index enables the utility to report how many minutes customers would have been out of service if all customers were out at one time.

$$\mathbf{SAIDI} = \frac{\sum \textit{Customer Interruption Durations}}{\textit{Total Number of Customers Served}}$$

Customer **A**verage **I**nterruption **D**uration **I**ndex – This is defined as the average length of an interruption, weighted by the number of customers affected, for customers interrupted during a specific time period. It is calculated by summing the customer minutes off during each interruption in the time period and dividing this sum by the number of customers experiencing one or more sustained interruptions during the time period. The resulting unit is minutes. The index enables utilities to report the average duration of a customer outage for those customers affected.

$$\textbf{CAIDI} = \frac{\sum \textit{Customer Interruption Durations}}{\textit{Total Number of Customer Interruptions}}$$

Customer **A**verage **I**nterruption **F**requency **I**ndex - The average frequency of sustained interruptions for those customers experiencing sustained interruptions.

$$\textbf{CAIFI} = \frac{\textit{Total Number of Customer Interruptions}}{\textit{Total Number of Customers Interrupted}}$$

Note *(Per IEEE P1366 – Guide for Distribution Reliability Indices)***:** For CAIFI index, in tallying the Total Number of Customers Interrupted, each individual customer should be only counted once regardless of the number of times interrupted during the reporting period.

Momentary Outage Indices

Momentary **A**verage **I**nterruption **F**requency **I**ndex – Total number of momentary customer interruptions (usually less than five minutes) divided by the total number of customers served.

$$\textbf{MAIFI} = \frac{\textit{Total No. Customer Interruptions(Monetary)}}{\textit{Total Number of Customers Served}}$$

System **A**verage **R**MS (Variation) **F**requency **I**ndex - Corresponds to a count or rate of voltage sags, swell and/or interruptions below a voltage threshold. For example, SARFI90 considers voltage sags and interruptions that are below 0.90 per unit, or 90 percent of a system base voltage. SARFI70 considers voltage sags and interruptions that are below 0.70 per unit, or 70 percent of a system base voltage. And SARFI110 considers voltage swells that are above 1.1 per unit, or 110 percent of a system base voltage. The SARFIX indices are meant to assess short-duration rms variation events only, meaning that only those events with durations less than 60 seconds are included in its computation.

$$\textbf{SARFI}_{\text{X\%- RMS Voltage Threshold (10 –140\%)}} = \frac{\sum \begin{array}{l}\text{number of customers experiencing} \\ \text{short duration voltage deviations with magnitudes above X\%}\end{array}}{\begin{array}{l}\text{number of customers served from the section of the} \\ \text{system to be assessed}\end{array}}$$

APPENDIX C – APPA REGIONS

Region 1: Wyoming, Colorado, New Mexico, Utah

Region 2: Indiana, Illinois, Michigan, Ohio, Wisconsin

Region 3: Minnesota, Iowa, Missouri, Kansas, Nebraska, North Dakota, South Dakota

Region 4: Oklahoma, Arkansas, Texas, Louisiana

Region 5: Maryland, Delaware, West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida

Region 6: Nevada, Arizona, California

Region 7: Kentucky, Tennessee, Mississippi, Alabama

Region 8: Maine, New Hampshire, Vermont, Connecticut, Rhode Island, Massachusetts, New Jersey, New York, Pennsylvania

Region 9: Montana, Idaho, Washington, Oregon, Alaska