



Avista Utilities

2016

**Customer Service Quality and Electric System
Reliability Report**

April 27, 2017

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I. Introduction

A. Executive Summary

Avista's Service Quality and Reliability Report for 2016 provides the annual performance results for the Company's "Service Quality Measures" program and for its overall electric system reliability. Results for the service quality measures have been incorporated into the electric system reliability report which the Company files each year with the Washington Utilities and Transportation Commission ("WUTC" or "Commission").

1. Background

Prior to the 2016 (2015 reporting year), Avista submitted an annual technical report to the Commission on its electric system reliability performance. For this report, the "electric system" is the overall network of electric transmission lines, substations, and the distribution lines, or "feeders," that carry electricity to every home and business in our service area. "System reliability" refers to the various measures of the number of times during the year that our customers experience an electric service outage (outage frequency) and the length of time it takes to restore our customers' service after an outage has occurred (outage duration). In accordance with the Commission's rules,¹ the Company established a baseline year (2005) for each of its reliability measures, and then compares the results for each reporting year with its baseline results. The reliability results Avista has measured and reported are determined on a "system basis" (i.e. the results represent the performance of its entire electric system in Washington and Idaho). Avista is also required to report any changes it may make to the methods used to collect and report the results of its system reliability. The report must also identify the geographic areas of greatest reliability concern on the Company's electric system and explain how it plans to improve its performance in those areas. Finally, the Company must report the number of complaints from its customers having to do with its electric system reliability and power quality. The detailed reporting requirements are listed under the title "Electric System Reliability Reporting Requirements" in Appendix A. Avista files its annual electric system reliability report with the Commission by April 30th each year.

In early 2015, Avista engaged Commission Staff and representatives of the Public Counsel Division of the Washington Office of the Attorney General and the Energy Project (collectively, the "Parties") to develop a set of service quality measures that would be reported to the Commission and Avista's customers each year (in addition to the electric system reliability report). This effort reflected the interest of Staff in having each of its regulated electric and electric/natural gas utilities report annually on their service quality performance, and was not driven by specific concerns regarding Avista's customer service performance. Through the course of these discussions Avista and the Parties agreed on a set of service measures and accompanying benchmarks and reporting requirements that, taken together, provide an overall assessment of the quality of the Company's service to its customers. These measures, referred to collectively as

¹ Washington Administrative Code (WAC) [480-100-393](#).

Avista’s “Service Quality Measures Program,” include: 1) six individual measures of the level of customer service and satisfaction that the Company must achieve each year; 2) the requirement to report on two measures of its electric system reliability; and 3) seven individual service measures where Avista will provide customers a payment or bill credit in the event it does not deliver the required service level (“customer guarantees”). The Company must report to its customers and the Commission each year on its prior-year performance in meeting these customer service and reporting requirements. Because these performance measures are related, at least in part, to electric system reliability, Avista chose to include this report as part of its annual electric system reliability report. Avista is currently reporting on its 2016 results of its Service Quality Measures Program.

2. Customer Service Measures - Results for 2016

Avista’s reporting requirements under this program are described in its Tariff Schedules 85 and 185,² which were approved by the Commission in June 2015. Listed in the table below are the six customer service measures, including their respective service requirements (benchmarks), and the Company’s performance results in meeting them in 2016. Avista achieved all of its customer service benchmarks for the year.

Table 1 – 2016 Customer Service Measures Results

Customer Service Measures	Benchmark	2016 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	92.7%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	94.7%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.25	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81.7%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	39.3 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	48.4 Minutes	✓

² Schedule 85 for electric service and Schedule 185 for natural gas service, in Dockets UE-140188 and UG-140189 (consolidated).

3. Electric System Reliability - Results for 2016

The tables below contain the two measures of electric system reliability to be reported by Avista each year as part of its service quality measures program. Because the annual electric reliability results often vary substantially year-to-year (for any electric utility’s system), it is difficult to derive a meaningful assessment of the Company’s system reliability from any single-year’s result. Consequently, in addition to reporting the current-year result for each measure, we also report the average value of each measure for the previous five years, the average for the current five-year period (which includes the results for the current year - 2016), and the “five-year rolling average” from 2005 – 2016 (current-year results). This data will provide our customers with some context for understanding each year’s reliability results.

Table 2 – 2016 SAIFI Results

Number of Electric System Outages per Customer for the Year	2016 System Results	5 Year Average (2012-2016)	5 Year Average (2011-2015)
Number of sustained interruptions in electric service per customer for the year (SAIFI) ³	0.86	1.04	1.09

Table 3 – 2016 SAIDI Results

Total Outage Duration per Customer for the Year	2016 System Results	5 Year Average (2012-2016)	5 Year Average (2011-2015)
Total Duration of all electric service outages for the per customer for the year (SAIDI) ⁴	133 Minutes	142 Minutes	139 Minutes

The two charts below show the “five-year rolling average” for each reliability measure from 2005 through 2016. As shown in the charts, the long-term trend for each reliability measure is fairly stable, with trends toward improvement, over this period. Though the Company formally reports its reliability results, as noted above, for its entire electric system, beginning in 2015 Avista agreed to report its annual results separately for its Washington system. The Washington-only number of average electric system outages per customer in 2016 was 0.83, and the average total outage duration per customer was 127 minutes.

³ See Appendix B for calculation of indices.

⁴ See Appendix B for calculation of indices.

Chart 1 – Historic Fiver-Year Rolling SAIFI

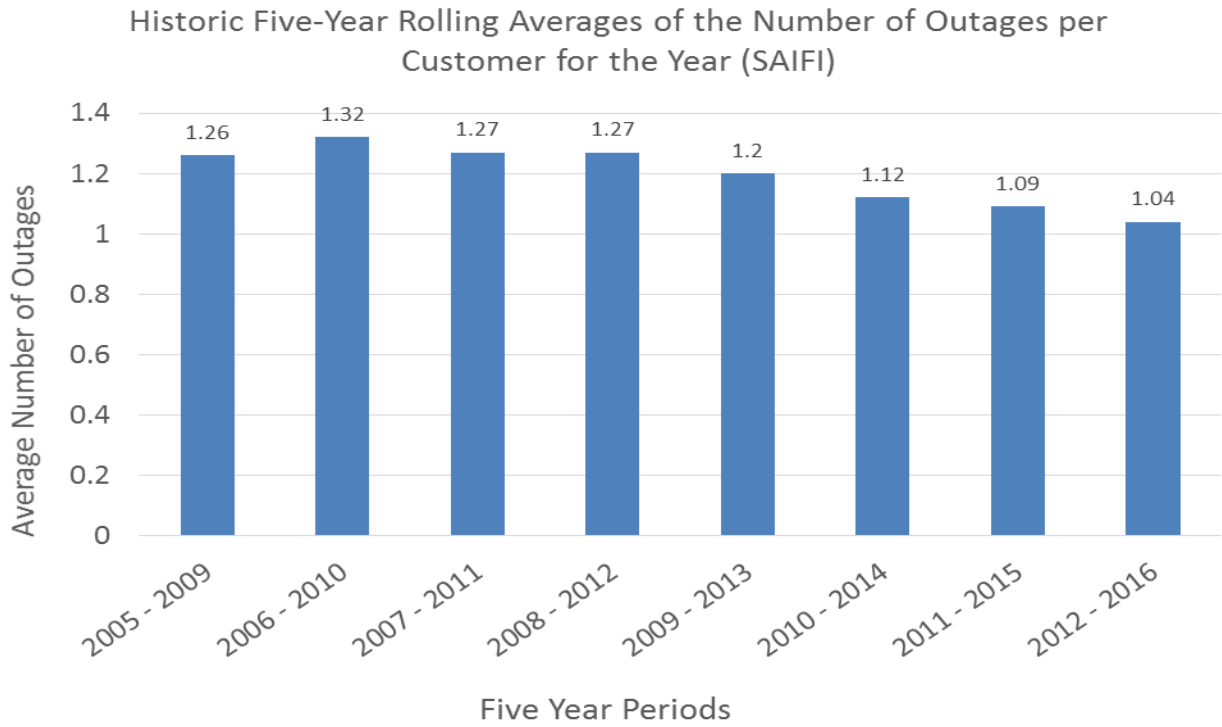
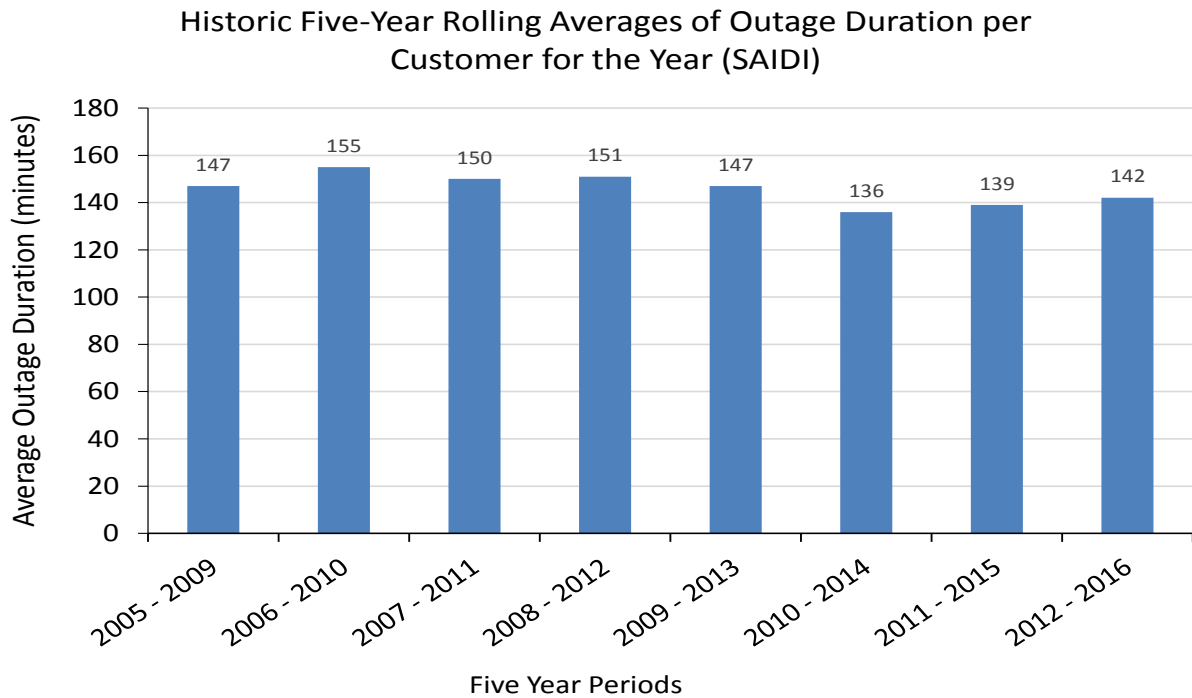


Chart 2 - Historic Fiver-Year Rolling SAIDI



4. Customer Service Guarantees – Results for 2016

Avista’s reporting requirements under this program are described in its Tariff Schedules 85 and 185,⁵ which were approved by the Commission in June 2015. Listed in the table below are the seven types of service for which we will provide “customer service guarantees” and the Company’s performance results in meeting them in 2016. In the cases that we do not fulfill a Customer Service Guarantee, a bill credit or payment in the amount of \$50 in recognition of that inconvenience. All costs associated with the payment of customer service guarantees will be paid by the Avista’s shareholders. These costs will not be paid by our customers.

Table 4 – 2016 Customer Service Guarantee Results

Customer Service Guarantee	Successful	Missed	\$ Paid
Keeping Our Electric and Natural Gas Service Appointments scheduled with our customers	1,477	10	\$500
Restore service within 24 hours of a customer reporting an outage (excluding major storm events)	26,344	1	\$50
Turn on power within a business day of receiving the request	3,380	3	\$150
Provide a cost estimate for new electric or natural gas service within 10 business days of receiving the request	5,024	0	\$0
Investigate and respond to a billing inquiry within 10 business days if unable to answer a question on first contact	1,760	0	\$0
Investigate a reported meter problem or conduct a meter test and report the results within 20 business days	309	2	\$100
Notify customers at least 24 hours in advance of a planned power outage lasting longer than 5 minutes	30,336	349	\$17,450
Totals	68,630	365	\$18,250

5. Electric System Reliability Report for 2016

Avista reports a range of detailed reliability statistics each year in its electric system reliability report filed with the Commission. Though two of these measures are the same as those reported under the Company’s service quality measures program, described above, this report follows a

⁵ Schedule 85 for electric service and Schedule 185 for natural gas service, in Dockets UE-140188 and UG-140189 (consolidated).

separate set of technical reporting requirements and is separate and distinct from those in the service quality measures program. The four primary reliability statistics (or indices) that Avista reports each year in its electric system reliability report are briefly described below:

- ✓ System Average Interruption Frequency Index or “SAIFI,” which is the average number of sustained interruptions per customer for the year.
- ✓ Momentary Average Interruption Event Frequency Index or “MAIFI,” which is the average number of momentary interruption events per customer for the year.
- ✓ System Average Interruption Duration Index or “SAIDI,” which is the average sustained outage time per customer for the year.
- ✓ Customer Average Interruption Duration Index or “CAIDI,” which is the average restoration time for those customers who experienced an outage for the year.

In addition to these four reliability indices, Avista also tracks the following additional measures:

- ✓ Customers Experiencing Multiple Sustained Interruptions or “CEMI,” which is the number of customers experiencing greater than a set number of interruptions.
- ✓ Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events or “CEMSMI,” which is the number of customers experiencing multiple sustained interruption and momentary interruption events.

All of these reliability statistics and the methods of their calculation are discussed in greater detail later in the report and in Appendix B.

For 2016, Avista’s results for its four primary reliability measures are listed in the table below. In addition to the current-year results we have also listed the past five-year average for each measure, and the 2005 baseline value.

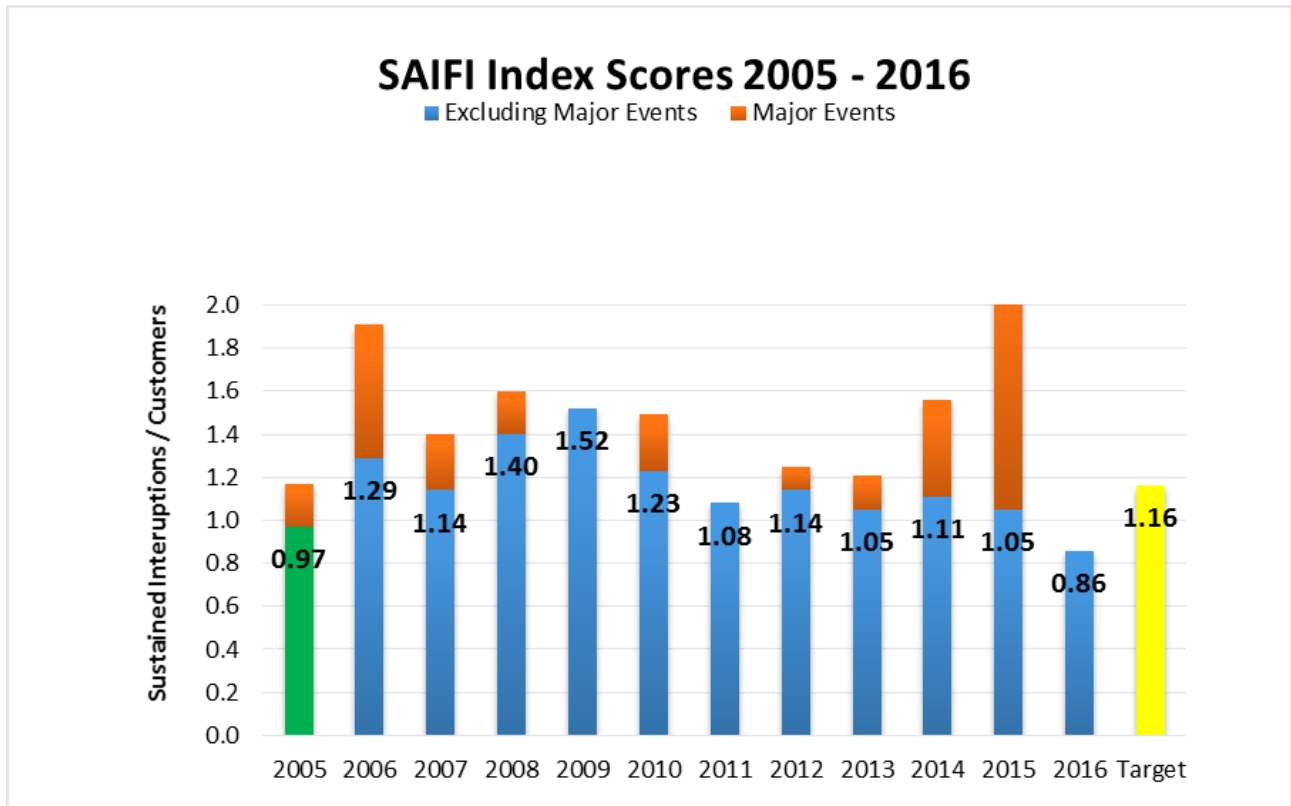
Table 5 – 2015 Reliability Measure Results

Reliability Index	Average 2011-2015⁶	Baseline Value 2005	Result for 2016 Reporting Year
SAIFI	1.09	0.97	0.86
MAIFI	2.32	3.58	1.88
SAIDI	139	108	133
CAIDI	128	112	154

For the index SAIFI, the average number of outages per customer reported by year on Avista’s system, is shown in the chart below. The chart distinguishes between the outages associated with and without Major Events.

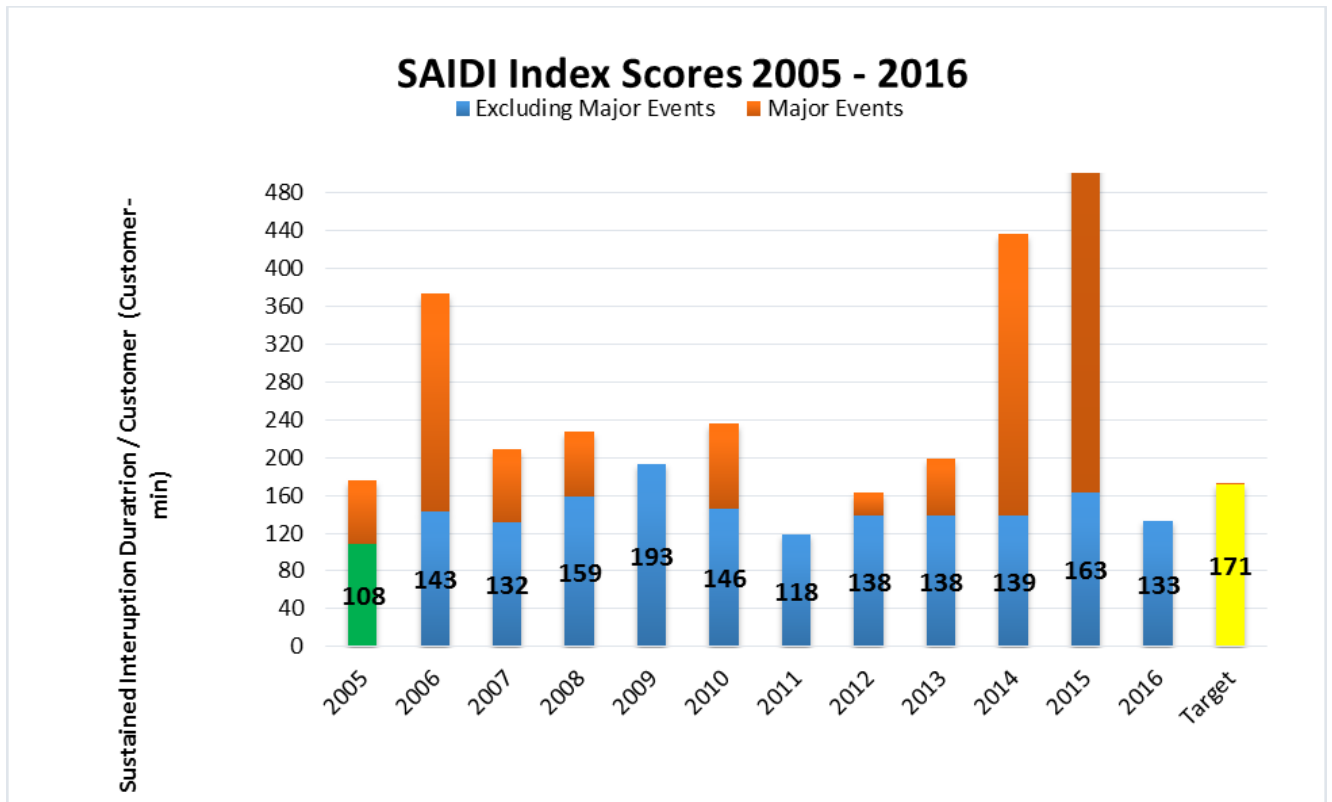
⁶ Excludes Major Event Days.

Chart 3 – SAIFI Index Scores 2005 - 2016



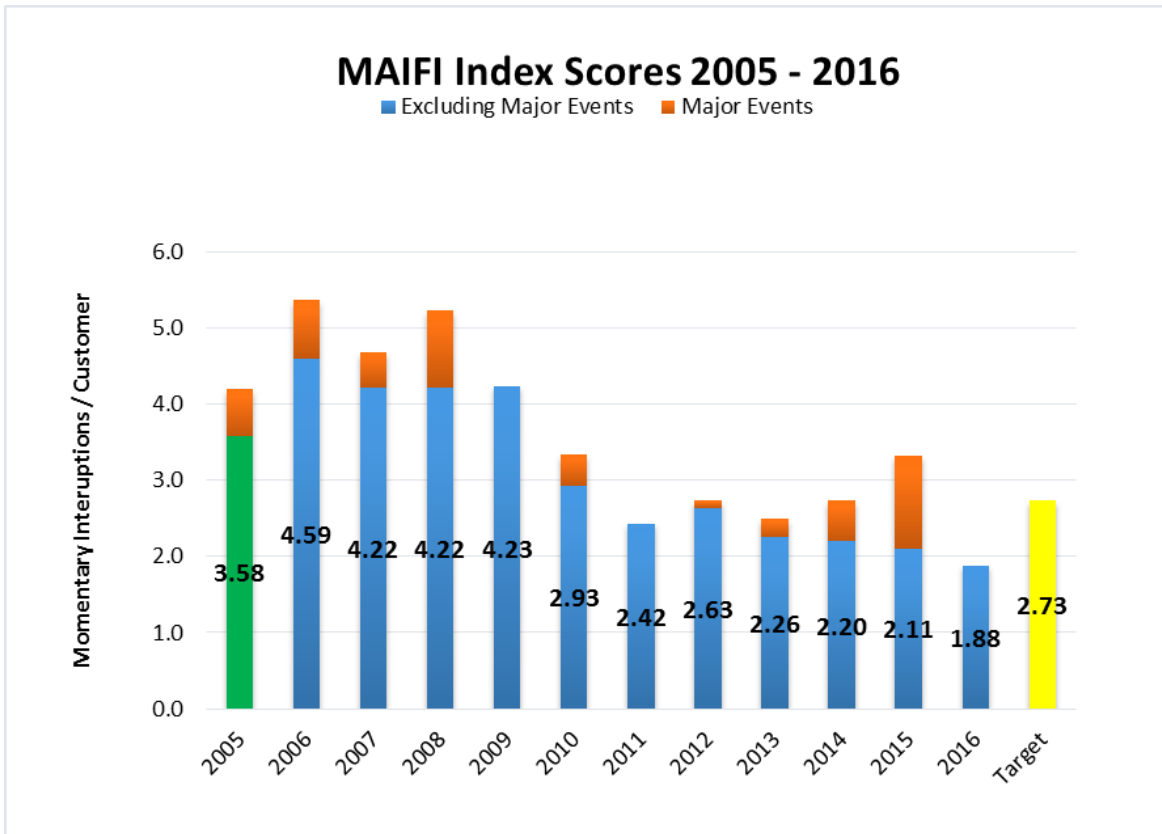
For the index SAIDI, the average duration in minutes of outages per customer reported by year on Avista’s system, the annual results for each year are shown in the chart below. The chart distinguishes between the outages associated with and without Major Events.

Chart 4 – SAIDI Index Scores 2005 – 2016



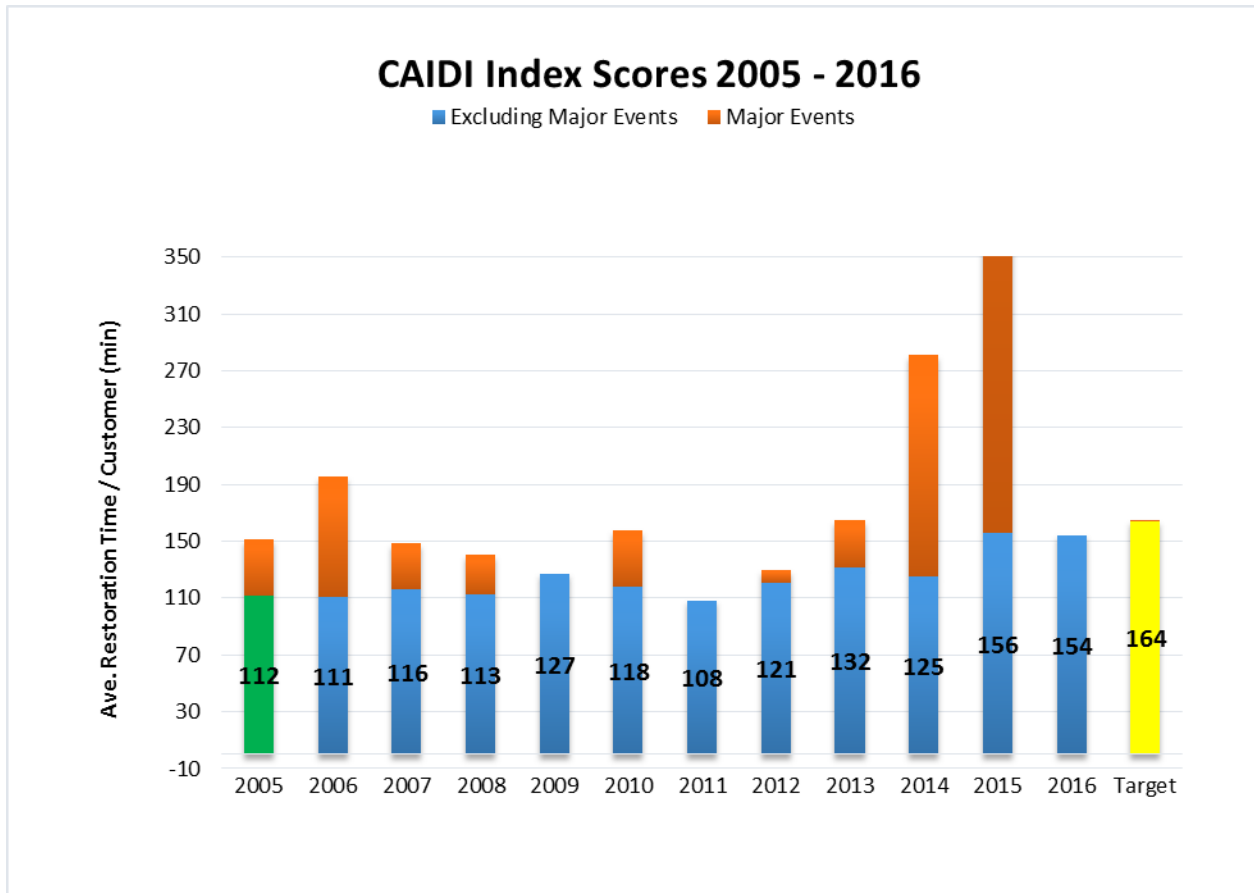
For the index MAIFI, the average number of momentary outages reported by year on Avista’s system, the annual results for each year are shown in the chart below. The chart distinguishes between the outages associated with and without Major Events.

Chart 5 – MAIFI Index Scores 2005 - 2016



For the index CAIDI, the customer average outage duration time (minutes) for those customers who experienced an outage on Avista’s system, the annual results for each year are shown in the chart below. The chart distinguishes between the outages associated with and without Major Events.

Chart 6 – CAIDI Index Scores 2005 - 2016



II. Service Quality Measures Program

A. Background

Avista has a long history of providing safe, reliable and cost-effective service to our customers. Our culture of service is the result of an enduring leadership focus, an organizational ethic of service, actively listening to our customers, and the dedication and commitment of our employees. We also understand the importance of setting goals, measuring performance, and responding through continuous improvement. For many years, we have conducted a quarterly survey of our customers to measure and track their satisfaction with the Company's customer and field services. We have also participated in other survey efforts, such as the JD Power customer satisfaction survey, and have worked to align our internal systems (such as incentive compensation) with our customer satisfaction and service performance. We understand that good customer service is more complex than is represented by a common suite of survey metrics, such as the contact center "average handle time." It requires awareness of, and attention to a host of factors that contribute in some way to the overall service experience of our customers. A few examples include the inherent complexity of a business process, the intuitiveness and appeal of our website, the availability and ease of our self-service options, the apparel worn by our employees, wearing protective booties while inside the customer's home, and calling the customer to make sure their service is working once we have finished restoring an outage.

1. Keeping Pace with Customer Expectations

We understand that customers' expectations are constantly changing and that the quality and/or nature of our service must evolve over time to keep pace. As an example, new technologies that emerged 20-30 years ago allowed us to better measure and track the service performance of our contact centers. Equipped with new and accurate measures of a broad range of service attributes, we were able to establish new and responsive performance goals and to implement the technology, process, behavioral, and training improvements required to achieve these goals. This concerted effort allowed us to effectively meet the changing service expectations of our customers, and resulted in some industry recognition when we were named the best utility call center in the nation in 1999 by Call Center magazine. Continuing improvements since that time have allowed us to continue to keep pace with the needs and expectations of our customers.

In contrast to the long-term cycle of continuous improvement described above, some improvements in service have come about more abruptly, such as in 1996 when the Company experienced an unprecedented ice storm that devastated many parts of our electric transmission and distribution system. The challenge of managing an event of that magnitude with then-conventional systems, accompanied by the natural frustration of our customers, prompted us to initiate the development of a state-of-the-art geographical information system (GIS)-based outage management system, launched in 1999. This system provided us much greater visibility of outage events, which enabled us to more-efficiently manage the restoration process. But just as importantly, it allowed us to provide our customers with timely information that is important to them during an outage, such as maps showing the location and extent of the outage, early and updated estimates of outage restoration time, and the option to receive an automated call from the Company when service has been restored.

In recent years we have placed an emphasis on improving our customers' experience and satisfaction by improving the quality of the many service "touchpoints" where our customers interact with Avista. In this effort we inventoried the many touchpoints across our business and developed a programmatic approach for evaluating and improving them - from the customers' perspective - one touchpoint at a time. From 2012 to 2014 we commissioned 39 employee "touchpoint teams" to assess and improve a range of service touchpoints. Through this process the Company has made numerous individual improvements to the overall quality of service we provide our customers.

Most recently, as customers' expectations regarding technology and self-service continue to advance, we are making strides to keep pace with these changes. In early 2015, the Company launched new customer information and work management systems. These new platforms provide the foundation for future technologies, such as the new outage information center launched in November 2015, a mere two weeks before a severe wind storm, the most devastating storm the Company has experienced in its history, hit our service territory. The new outage information center provides real time updates and alerts (via emails or text messages) to customers about outages in their area and can be accessed at www.avistautilities.com from a computer or smart phone. The next phase of the outage information center, released in June 2016, was a mobile application ("App") that customers are able to download to their smartphone. In February 2017, the Company launched a new payment experience as part of its overall website replacement effort. The new experience provides for easier self-service through the Company's website from a computer or mobile site from a smart phone. The full replacement of the customer website is expected to be completed in phases throughout 2017. Lastly, work is also underway for additional self-service functionality on the App. Future plans include the ability for a customer to manage their account just as they would on the website, including making payments.

2. Striking the Right Balance

As described above, Avista, like every business, is continuously engaged in the very granular and evolving work of assessing our customers' expectations and evaluating our capabilities and performance in meeting them. The key point here is that Avista must constantly judge whether its overall service quality meets the expectations of our customers, in balance with what it costs to deliver that level of service. We believe we are striking a reasonable balance among our customers' expectations, the characteristics of our extensive and often rural system, the quality of our services, and the cost associated with delivering those services. And when we sense that we are out of balance in a certain area, we make changes and investments needed to achieve, in our judgment, the optimal level of service. The examples described above help illustrate this point. In our customer contact center, we have for many years maintained a grade of service of answering 80% of our customer calls in sixty seconds. While there are numerous examples of industry norms where the grade of service is higher than Avista's, we have chosen to maintain our service level because, on balance, our customers are satisfied with our overall customer service. And we believe it is not cost effective to increase our staffing costs to achieve a higher level of service in this one area, when our customers are already very satisfied.

3. The Value of Setting Goals and Measuring Performance

We believe that measurement is, inherently, a good thing. It promotes organizational focus and accountability and always stimulates ideas for improvement. We also know from experience that it is very important to measure the right things, and for the right reasons. We all naturally take steps to promote the things that get measured, but sometimes at the expense of other things that (while unmeasured) are much more important. For many years we have measured the satisfaction of our customers through a quarterly survey we refer to as “Voice of the Customer.” The purpose of the survey is to measure and track customer satisfaction for Avista Utilities’ “contact” customers – i.e., customers who have contact with Avista through the Call Center and/or field personnel with work performed operationally in the field. Customers are asked to rate the importance of several key service attributes, and are then asked to rate Avista’s performance with respect to the same attributes. Customers are also asked to rate their satisfaction with the overall service received from Avista Utilities. Finally, customer verbatim comments are also captured and recorded. Our most recent 2016 year-end results show an overall customer satisfaction rating of 93.8% across our Washington, Idaho, and Oregon operating divisions. This rating reflects a positive experience for customers who have contacted Avista related to the customer service they received.

4. Adopting the Service Quality Measures Program

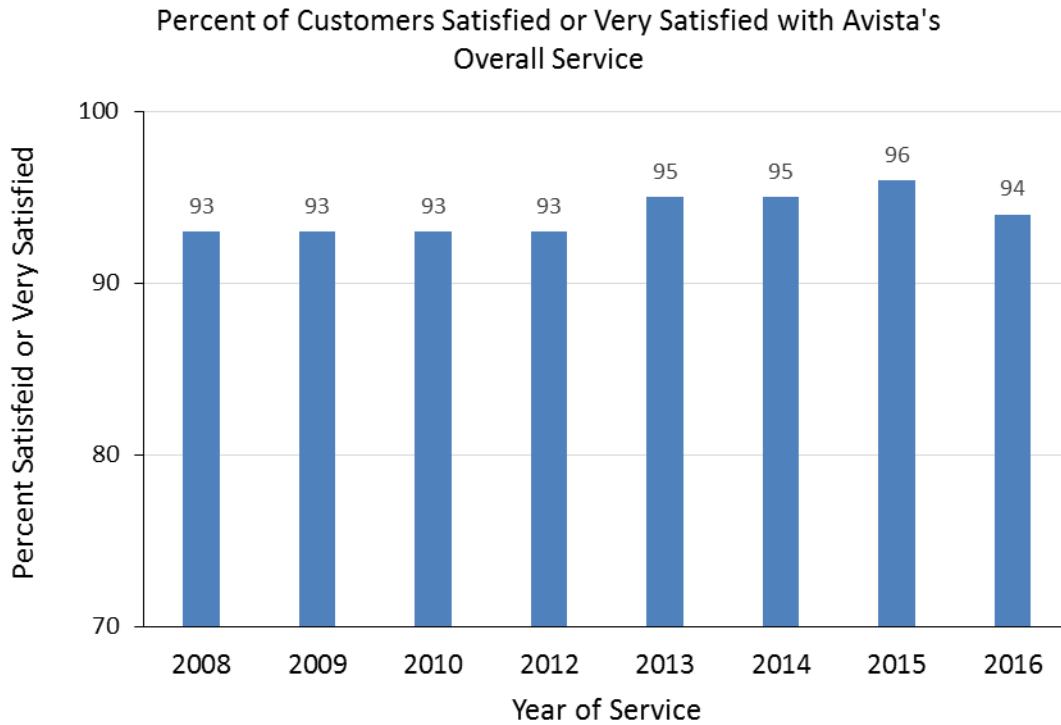
It is from the above perspective that we approached the process of working with Commission Staff and other interested parties in 2015 to develop and implement a set of service quality measures for Avista. We believe the Company’s history of customer service, including the level and quality of service we provide today, effectively meets the needs and expectations of our customers, and that it provides them with cost-effective value. We believe the service quality measures adopted by the Commission⁷ for Avista, as contained in this report, represent a reasonable set of service expectations for our customers, the Commission, and our Company.

B. Customer Service Measures

As noted above, there are many points of service our customers have with Avista and each contributes to the overall impression they have of the Company and the level of satisfaction they have with our services. While for many years we have tracked our customers’ satisfaction with primary services such as our customer contact center and field services, we have also been interested in knowing whether our performance is meeting our customers’ broader service expectations. As part of our Voice of the Customer survey we have asked our customers to rate their level of satisfaction with the overall service they receive from the Company. We believe this overall measure is an important barometer of our customers’ satisfaction with the entirety of the integrated services and value they receive from Avista. As show in the figure below, the overall satisfaction of Avista’s customers (either satisfied or very satisfied) has ranged between 93% and 96% over the past eight years. These results are similar to our customers’ satisfaction with our contact center and field services for this same time period. Accordingly, we believe the results of the six customer service measures contained in this report, taken together, provide a reasonable assessment of our customers’ overall satisfaction with the quality and value of our service.

⁷ On June 25, 2015 the Commission approved Avista’s Service Quality Measures Program as filed by the Company on May 29, 2015. Order 06 - Final Order Approving Avista’s Service Quality Measures Program Compliance Filing, in Dockets UE-140188 and UG-140189 (consolidated).

Chart 7 – Percent of Customer’s Satisfied or Very Satisfied with Avista’s Overall Service





1. Customer Satisfaction with the Telephone Service provided by Avista's Customer Service Representatives

As part of Avista's Service Quality Measures program, the level of our customers' satisfaction with the telephone service provided by the Company's contact center will meet or exceed a benchmark of 90%.⁸

Several factors influence our customers' satisfaction with the quality of telephone service provided by our customer service representatives and contact center. We measure the importance of these factors to customers as well as their satisfaction with them each year. These factors, including our customers' satisfaction (either satisfied or very satisfied) for each factor in 2016 are listed below.

- ✓ The customer service representative handling the customer's call in a friendly, caring manner. **(97%)**
- ✓ The customer service representative being informed and knowledgeable. **(94%)**
- ✓ The customer service representative meeting the customer's needs promptly. **(94%)**
- ✓ The customer service representative giving the customer all the information they need in one call. **(93%)**
- ✓ Being connected to a customer service representative in a reasonable amount of time. **(93%)**

In addition to making sure our customer service representatives are effectively trained and sufficiently staffed to deliver excellent service during the course of normal business operations, Avista also faced a significant challenge to our service levels when we launched a new customer information and work and asset management system in February 2015. The launch of any new customer information system typically results in customer calls taking longer than normal as the

⁸ The level of Customer satisfaction with telephone service, as provided by the Company's Contact Center, will be at least 90 percent, where:

- a. The measure of Customer satisfaction is based on Customers who respond to Avista's quarterly survey of Customer satisfaction, known as the Voice of the Customer, as conducted by its independent survey contractor;
- b. The measure of satisfaction is based on Customers participating in the survey who report the level of their satisfaction as either "satisfied" or "very satisfied"; and
- c. The measure of satisfaction is based on the statistically-significant survey results for both electric and natural gas service for Avista's entire service territory for the calendar year, and if possible, will also be reported for Washington customers only.

customer service representative learns to efficiently navigate the new system. And because calls are longer, there will be more calls on hold waiting to be answered by a representative, which will result in longer hold times. In addition to these challenges, Avista made several changes in its billing process including a new bill format and new customer account number. These changes caused an increase in the number and duration of customer calls in 2015.

In February of 2016 the Company celebrated its one year anniversary of launching its new customer information and work and asset management system. Since the launch our customer contact center has continued to learn and adapt to the new system. With the last customer information system being place for over 20 years we knew it would take time to adapt to the new system, while continuing to manage customer expectations. Our customer contact center successfully managed to maintain high levels of customer satisfaction in 2016. This outcome is due to the Company continued diligence in listening to its customers, being attentive to their needs, and continuously training and educating its contact center representatives.

2016 Results - The annual survey results for this measure of customer satisfaction show that 92.7% percent of our customers were satisfied with the quality of the telephone service they received from our customer service representatives. Overall, 78.5% of our customers were “very satisfied” and 14.2% were “satisfied” with the quality of our service.

Table 6 – 2016 Customer Satisfaction with Avista’s Contact Center Representatives

Customer Satisfaction with Avista’s Contact Center Representatives	Service Quality	2016 Performance	Achieved
Percent of customers either satisfied or very satisfied with the Quality of Avista’s Customer Contact Center Representatives	90% or Greater Satisfied	92.7%	✓

Prior to the development of the service quality measures program, Avista did not separately track or report results for any of our state jurisdictions, and for reporting our annual service quality performance under this program the Company will continue to use its system-wide results. We will, however, separately track and report the results for this measure for our Washington customers only. For 2016, the percent of Washington customers satisfied or very satisfied with the Company’s customer service representatives and contact center was 92.7%.



2. Customer Satisfaction with Avista’s Field Service Representatives

As part of Avista’s Service Quality Measures program, the level of our customers’ satisfaction with the Company’s field services will meet or exceed a benchmark of 90%.⁹

The quality of our field services and the satisfaction of our customers is influenced by several factors. Each year we measure the importance of these factors to our customers and their satisfaction with each aspect of our service. These factors, including our customers’ level of satisfaction (either satisfied or very satisfied) with each factor in 2016, are listed below.

- ✓ The service representative keeping you informed of the status of your job. **(92%)**
- ✓ The service representative or service crew being courteous and respectful. **(98%)**
- ✓ The service representative or service crew being informed and knowledgeable. **(97%)**
- ✓ The service representative or service crew leaving your property in the condition they found it. **(96%)**
- ✓ The service work being completed according to the customer’s expectations. **(95%)**
- ✓ The overall quality of the work performed by Avista Utilities. **(97%)**

2016 Results - The annual survey results for this measure, as reported in the table below, show that 94.7% percent of our customers were satisfied with the service provided by Avista’s field service representatives. Overall, 82.6% of our customers were “very satisfied” and 12.1% were “satisfied” with the quality of our field services.

⁹ The level of Customer satisfaction with the Company’s field services will be at least 90 percent, where:

- a. The measure of Customer satisfaction is based on Customers who respond to Avista’s quarterly survey of Customer satisfaction, known as the Voice of the Customer, as conducted by its independent survey contractor;
- b. The measure of satisfaction is based on Customers participating in the survey who report the level of their satisfaction as either “satisfied” or “very satisfied”; and
- c. The measure of satisfaction is based on the statistically-significant survey results for both electric and natural gas service for Avista’s entire service territory for the calendar year, and if possible, will also be reported for Washington customers only.

Table 7 – 2016 Customer Satisfaction with Avista’s Field Services Representatives

Customer Satisfaction with Avista’s Field Services Representatives	Service Quality	2016 Performance	Achieved
Percent of customers either satisfied or very satisfied with the Quality of Avista’s Field Service Representatives	90% or Greater Satisfied	94.7%	✓

Prior to the development of the service quality measures program, Avista did not separately track or report results for any of our state jurisdictions, and for reporting our annual service quality performance under this program the Company will continue to use its system-wide results. We will, however, separately track and report the results for this measure for our Washington customers. For 2015, the percent of Washington customers satisfied or very satisfied with the Company’s field service representatives was 95.5%.



3. Customer Complaints made to the Commission

As part of Avista’s Service Quality Measures program, the number of complaints filed by our customers with the Commission will not exceed a ratio of 0.4 complaints per 1,000 customers.¹⁰

When our customers are unhappy with any aspect of the service they receive from Avista, and the Company is made aware of the issue, our intent is work with the customer to quickly and fairly resolve the issue to their satisfaction. Though we are successful in resolving the majority of these customer issues, there are some that cannot be favorably resolved and result in the customer filing a formal complaint with the Commission. In addition to complaints arising in this manner, there are also instances where a customer files a complaint without having first notified the Company of their issue or concern. While past experience has shown that the Commission ultimately finds in the great majority of these complaints that the Company has acted properly, Avista agrees that the number of complaints filed does provide one indicator of the level of dissatisfaction our customers may have with our service.

2016 Results – Our Washington customers filed a total of 103 complaints with the Commission in 2016. The predominant areas of concern related to credit and collections and billing matters, just as in years past. The Company experienced an increase of 33 complaints in 2016 as compared to 2015. The primary reason for this increase was attributed to winter bills and the ensuing media coverage that occurred in January and February 2015, which resulted in 40 complaints being filed with the Commission in February 2015, compared to 6 the prior year. Avista’s customer count as defined for this measure was 416,100. The resulting fraction of complaints ($103 \div 416,100$) was 0.0002475, and the number of complaints per 1,000 customers ($0.0002475 \times 1,000$) was 0.25 (rounded up), as noted in the table below.

Table 8 – 2016 Percent of Avista’s Customers Who Filed a Commission Complaint

Percent of Avista’s Customers Who Filed a Commission Complaint	Service Quality	2016 Performance	Achieved
Number of Avista’s customers who file a complaint with the Commission (number of complaints per 1,000 customers)	Ratio of 0.4 or Lower	0.25	✓

¹⁰ The ratio is calculated by dividing the sum of all electric and natural gas customer complaints filed with the Commission by the average monthly number of Avista customers for the year. The rate is calculated by multiplying the percentage by 1,000.



4. Answering Our Customer's Calls Promptly

As part of Avista's Service Quality Measures program, the percentage of customer calls answered live by a customer service representative within 60 seconds will average 80% or greater.¹¹

This particular customer service measure is one of the subset of service attributes that contribute to the customer's overall satisfaction with our service representatives and contact center. Often referred to as the "grade of service," this measure is the average percentage of customer calls to our contact center that are answered live by a customer service representative within 60 seconds for those customers who wish to speak with a service representative. When a customer calls Avista's contact center their call is initially received by our automated (voice activated) phone system. The customer is presented the option of using the phone system for self-service (e.g. to check their account balance or pay their bill, etc.) or to speak with a customer service representative live to meet their service need. Avista's response time in answering the customer's call is the time that elapses between the customer's request to speak to a representative and when their call is answered live by a representative.

For many years Avista has maintained a service benchmark of 80% or greater, even though some utilities and businesses have established a higher "grade of service" (e.g. 90% or a goal of answering calls within 30 seconds). Because it requires an increased level of staffing and cost to customers to achieve a higher service level, Avista has focused on lower cost / no cost measures, such as effective employee training and coaching to achieve superior standards for attributes such as courtesy, caring, knowledge, and proficiency, to maintain our very high level of overall customer satisfaction with our service representatives and contact center.

In addition to responding to customers effectively, Avista has implemented measures to help reduce the overall volume of customer calls, which helps reduce the cost of service paid by our customers. These efforts include providing customers a way to communicate with the Company using their preferred "channel" of communication, such as e-mail, customer web, or the automated phone system. In addition to providing for numerous communication channels, the Company has

¹¹ The percentage of Customer calls answered by a live representative within 60 seconds will average at least 80 percent for the calendar year, where:

- a. The measure of response time is based on results from the Company's Contact Center, and is initiated when the Customer requests to speak to a Customer service representative; and
- b. Response time is based on the combined results for both electric and natural gas Customers for Avista's entire service territory.

focused on enhancing customer self-service options as discussed above. These efforts not only help reduce the volume of calls to our contact center and maintain a high level of service at lower cost, but also improves customer satisfaction.

2016 Results – Our Washington customers made a total of 726,644 qualifying calls to Avista that were answered live by a customer service representative in 2015. Of these calls, 593,667 were answered live in 60 seconds or less, for a score of 81.7%, as shown in the table below.

Table 9 – 2016 Percent of Avista’s Customer Calls Answered Live within 60 Seconds

Percent of Avista’s Customer Calls Answered Live Within 60 Seconds	Service Quality	2016 Performance	Achieved
Percent of Avista’s customer calls answered live by a customer service representative within 60 seconds	80% or Greater	81.7%	✓



5. Avista's Response Time for Electric Emergencies

As part of Avista's Service Quality Measures program, the average response time to an electric system emergency will not exceed 80 minutes for the year.¹²

When our customers call Avista to report an electric emergency we work with the customer to quickly ascertain the particular circumstances being reported, and instruct the customer on how best to ensure their own safety and that of others until help arrives. We immediately begin the dispatch of service personnel best situated to respond in the shortest time possible. Once at the scene Avista's first priority is to make the situation safe for our customers, citizens, other emergency responders, and our employees. Restoration of the problem can begin once the safety of the site is secured and needed resources arrive at the scene. The Company's ability to respond quickly to an electrical emergency is influenced by many factors, some of which include the urban or rural locale, the location of the nearest available respondent (especially in rural areas), the time of day, season of the year, weather conditions, traffic, and the presence of other simultaneous emergency events across the system. For this measure, the response time to an electric emergency is the elapsed time between the confirmation of the emergency with the customer (when the dispatch field order is given) and when the Avista service person arrives at the scene.

2016 Results –The average response time for the year is calculated by dividing the sum of all applicable electric emergency response times by the total number of qualifying electric emergency incidents. Avista received 434 qualifying emergency reports in 2016, which had a cumulative response time of 17,059 minutes. The average response time for the year is calculated by dividing the cumulative response time by the total number of responses. The resulting average for 2016 was 39.3 minutes as noted in the table below.

¹² The Company's average response time to an electric system emergency in Washington will not exceed 80 minutes for the calendar year, where:

- a. Response time is measured from the time of the Customer call to the arrival of a field service technician;
- b. "Electric system emergency" is defined as an event when police / fire services are standing by, or arcing/flashing wires down (unspecified location, pole to house, or pole to pole), or for feeder lockout; and
- c. Response times are excluded from the calculation for those periods of time when the Company is experiencing an outage that qualifies as a "Major Event Day" (or "MED"), as defined by the Institute of Electrical and Electronics Engineers, and which includes the 24 hour period following the Major Event Day.

Table 10 – 2016 Avista’s Response Time for Electric Emergencies

Avista’s Response Time for Electric Emergencies	Service Quality	2016 Performance	Achieved
Average time from customer call to the arrival of Avista’s field technicians in response to electric system emergencies	80 Minutes or Less	39.3 Minutes	✓



6. Avista's Response Time for Natural Gas Emergencies

As part of Avista's Service Quality Measures program, the average response time to a natural gas system emergency will not exceed 55 minutes for the year.¹³

When our customers call Avista to report a natural gas emergency, we work with the customer to quickly ascertain whether the presence of natural gas (odor) is likely coming from inside the customer's home or business or from facilities outside. If inside, the customer is instructed to immediately evacuate the building to a safe distance and await the arrival of emergency responders. If the leak is in facilities outside, instructions to the customer are based on the proximity and type of the leak to their (or others') home or business. Once the nature of the leak has been determined and the customer has been given precautionary instructions on how best to ensure their own safety and that of others until help arrives, we immediately begin the dispatch of service personnel best situated to respond at the scene in the shortest time possible. At the scene Avista's first priority is to make the situation safe for our customers, citizens, other emergency responders, and our employees. Restoration of the problem can begin once the safety of the site is secured and needed resources arrive at the scene.

The Company's ability to respond quickly to a natural gas emergency is influenced by many factors, some of which include the urban or rural locale, the location of the nearest available respondent (especially in rural areas), the time of day, season of the year, weather conditions, traffic, and the presence of other simultaneous emergency events across the system. Natural gas emergencies differ from electric emergencies, however, in that the risk of a potential consequence to a gas leak can increase with the passage of time as leaking natural gas may accumulate at the site. For this reason Avista's work practices and staffing levels aim to provide an average response time of 55 minutes or less. For this measure, the response time to a natural gas emergency is the elapsed time between the confirmation of the emergency with the customer (when the dispatch field order is given) and when the Avista service person arrives at the scene.

¹³ The Company's average response time to a natural gas system emergency in Washington will not exceed 55 minutes for the calendar year, where:

- a. Response time is measured from the time of the customer call to the arrival of a field service technician; and
- b. "Natural gas system emergency" is defined as an event when there is a natural gas explosion or fire, fire in the vicinity of natural gas facilities, police or fire are standing by, leaks identified in the field as "Grade 1", high or low gas pressure problems identified by alarms or customer calls, natural gas system emergency alarms, carbon monoxide calls, natural gas odor calls, runaway furnace calls, or delayed ignition calls.

2016 Results –The average response time for the year is calculated by dividing the sum of all applicable natural gas emergency response times by the total number of qualifying emergency incidents. Avista received 3,340 qualifying emergency reports in its Washington service area in 2016, which had a cumulative response time of 161,733 minutes. The average response time for the year is calculated by dividing the cumulative response time by the total number of responses. The resulting average for 2016 was 48.4 minutes as noted in the table below.

Table 11 – 2016 Avista’s Response Time for Natural Gas Emergencies

Avista’s Response Time for Natural Gas Emergencies	Service Quality	2016 Performance	Achieved
Average time from customer call to the arrival of Avista’s field technicians in response to natural gas system emergencies	55 Minutes or Less	48.4 Minutes	✓

Last year the Company reported results for 2015 of 798 qualifying emergency reports, which had a cumulative response time of 40,700 minutes or an average of 52 minutes. When compiling the data for the 2016 results the Company realized that it only included the highest priority emergency orders rather than all emergency orders in 2015. The 2015 result for all qualify emergency reports was actually 3,601 orders, which had a cumulative response time of 174,681 minutes or an average of 48.5 minutes.



C. Electric System Reliability

Providing safe and highly-reliable electric service for our customers at a reasonable cost is fundamental to our business. We believe our current level of reliability is reasonable and cost effective for our customers, and our long-term objective is to generally uphold our current levels of electric system reliability. Achieving this requires a constant focus on maintaining the health of the system and meeting the expectations of our customers regarding the reliability of their electric service. By electric “system” we are referring to the overall network of electric transmission lines, substations, and the distribution lines, or “feeders,” that carry electricity to every home and business in our service area. When we speak of “system reliability” we are essentially referring to the number of times in a year that our customers experience an electric service outage (outage frequency), and the length of time it takes to restore our customers’ service after an outage has occurred (outage duration).

The electric industry has adopted a fairly uniform set of measures (or indices) developed by Institute of the Electrical and Electronics Engineers¹⁴ to report various aspects of electric system reliability. Two of the most-commonly reported measures are very briefly described below, and are discussed in detail in in Section III of this report and in Appendix B. For its service quality measures program Avista will report its annual reliability results in the context of its historic five-year rolling average for these two measures.

- ✓ **Number of Outages Experienced per Customer for the Year** – This measure of system reliability, which is referred to as the System Average Interruption Frequency Index or (“SAIFI”) is equal to the total number of customers whose service is interrupted divided by the total number of customers served.
- ✓ **Total Outage Duration Experienced per Customer for the Year** – This measure, which is referred to as the System Average Interruption Duration Index or (“SAIDI”) is equal to the total outage time in minutes experienced by all customers who had service outages divided by the total number of customers served.

Many factors influence the frequency and duration of outages on any electric system. Some of these include the average age of the system, its engineering design, construction standards, general condition, the extent of the system that is rural, terrain, utility equipment and staffing levels, and its day-to-day operation. The type and proximity of surrounding vegetation and local and regional

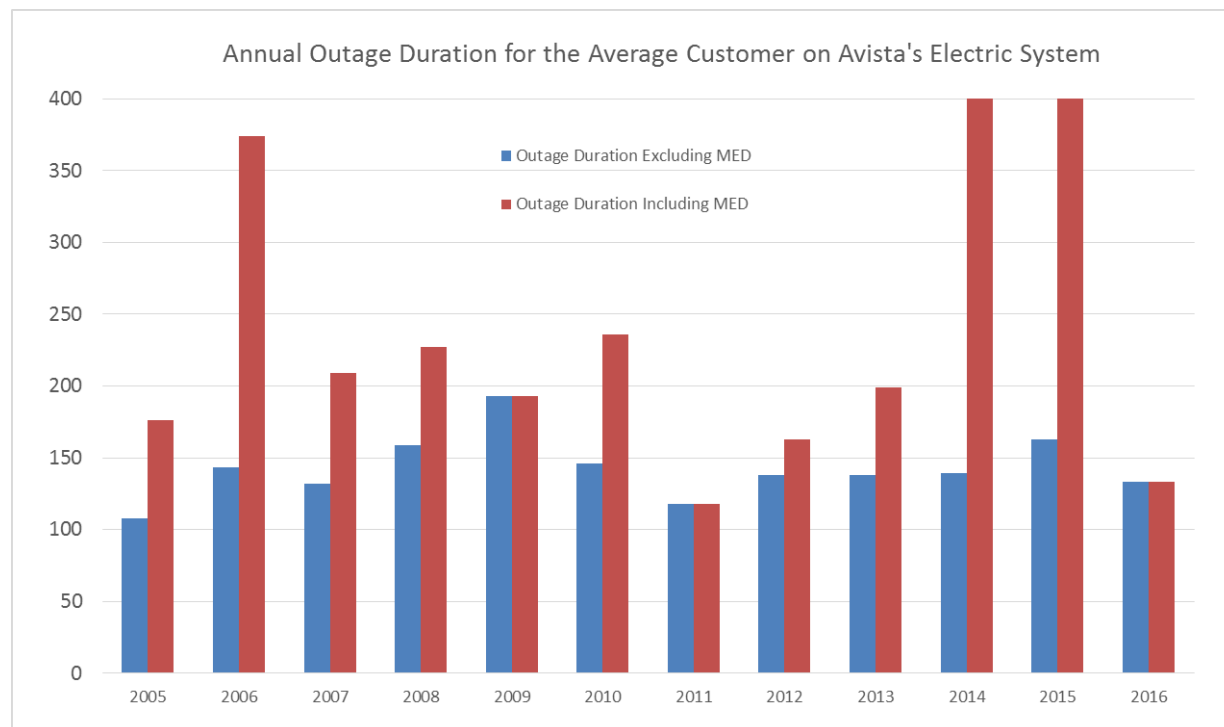
¹⁴ See Appendix B for definitions and index calculations.

weather patterns, including variability in weather, can have a pronounced impact on system reliability. Because the frequency and duration of the electric system outages that result from these factors can vary substantially from year to year, there is, naturally, substantial variability in the measures of overall system reliability over time.

For Avista, weather-related outages tend to have a predominant impact on the reliability of our system. This is because individual weather events often impact large portions of our system and can result in damage to many types of facilities. Weather caused outages, particularly from high winds, ice, and snow can also require substantial effort and time to restore. These storm events can result in many customers without service for an extended period of time. This was clearly evident in the substantial system outages caused by windstorms in the late summer of 2014, and the very significant wind storm event of November 2015. Fortunately in 2016 the Company did not experience any major storm events.

Because the impact of weather on system reliability is common to all electric systems, the industry has adopted standardized adjustments that remove most of the weather-caused variability in measures of outage frequency and duration. When storm damage to an electric system reaches a threshold level of severity the outage results for that day are qualified as a Major Event Day or (“MED”). The outages caused by any storm event that qualifies as a Major Event Day are removed from the data used to calculate the utility’s annual reliability results for outage frequency and duration. The figure below shows the results for the total duration of outages per customer for the year on Avista’s system (SAIDI). The blue columns represent the annual duration where the outages associated with Major Event Days are excluded, which is the standard format for our reliability reporting. The red bars show the annual duration for all outages, including the outages associated with Major Event Days.

Chart 8 – Average Outage Duration for Each Customer on Avista’s Electric System



Although the year-to-year variability in outage duration is substantially reduced by the adjustment for Major Events, there can still be a substantial weather impact on reliability. This is the result of storms that, while not qualifying as Major Events, can still cause substantial system outages during the year. As an example, in the figure above, with the Major Event Days included (orange line) the outage duration for year 2009 is in the lower third of the range of variability. But with the Major Event Days excluded (blue line) the 2009 results exceed those for any other year. This is because Avista experienced many storms that year that caused significant system outages, however, none of those storm events qualified as a Major Event. The result is that even with Major Event Days removed, weather can still have a significant effect on the overall system reliability.

The important point of this discussion is that the reliability results for any single year, considered in isolation, do not provide a meaningful measure of the overall reliability of the utility's system, or an assessment of whether the performance that year was "acceptable" or "unacceptable." Importantly, Avista is not trying to make the case that any particular level of reliability is acceptable to its customers. Regardless of the year-to-year variability in reliability, Avista must achieve a balance in the costs and benefits of its reliability investment and we must meet the service expectations of our customers every year. The reliability performance of our system (or any utility system) should be evaluated over the long term as the basis for evaluating whether our reliability is trending stably, improving, or degrading.¹⁵ Avista has agreed to report its annual reliability results to its customers in the context of its historic five-year rolling average. This approach provides our customers with the context for understanding how each year's reliability results fit into our long-term trend in overall system reliability.

¹⁵ This is similar to the approach now used by the California Public Utilities Commission to evaluate electric utilities' system reliability. In: Approaches to Setting Electric Distribution Reliability Standards and Outcomes, pages 130 - 136. The Brattle Group, Ltd. 2012.



1. Number of Electric System Outages

As part of Avista’s Service Quality Measures program, the Company will report its annual electric system reliability measure for the number of non-major storm power outages experienced per customer for the year (SAIFI).¹⁶

2016 Results – This measure, as noted earlier, represents how often an average Avista electric customer experienced a sustained¹⁷ interruption in service (outage) for the year. This measure is calculated by totaling the number of customers who experienced an interruption for the year divided by the total number of customers served. The 2016 result of 0.86 (slightly less than one outage per customer for the year) was below the average value for the previous five-year period (2011-2015) of 1.09, which resulted in a slight lowering of the average for the current five-year period. For 2016 the Washington only result was 0.83.

Table 12 – 2016 Number of Electric System Outages for the Average Avista Customer

Number of Electric System Outages for the Average Avista Customer	2016 System Results	Current 5 Year Average (2012-2016)	Change in 5 Year Average
Number of sustained interruptions in electric service for the average Avista customer for the year (SAIFI)	0.86	1.04	-0.05

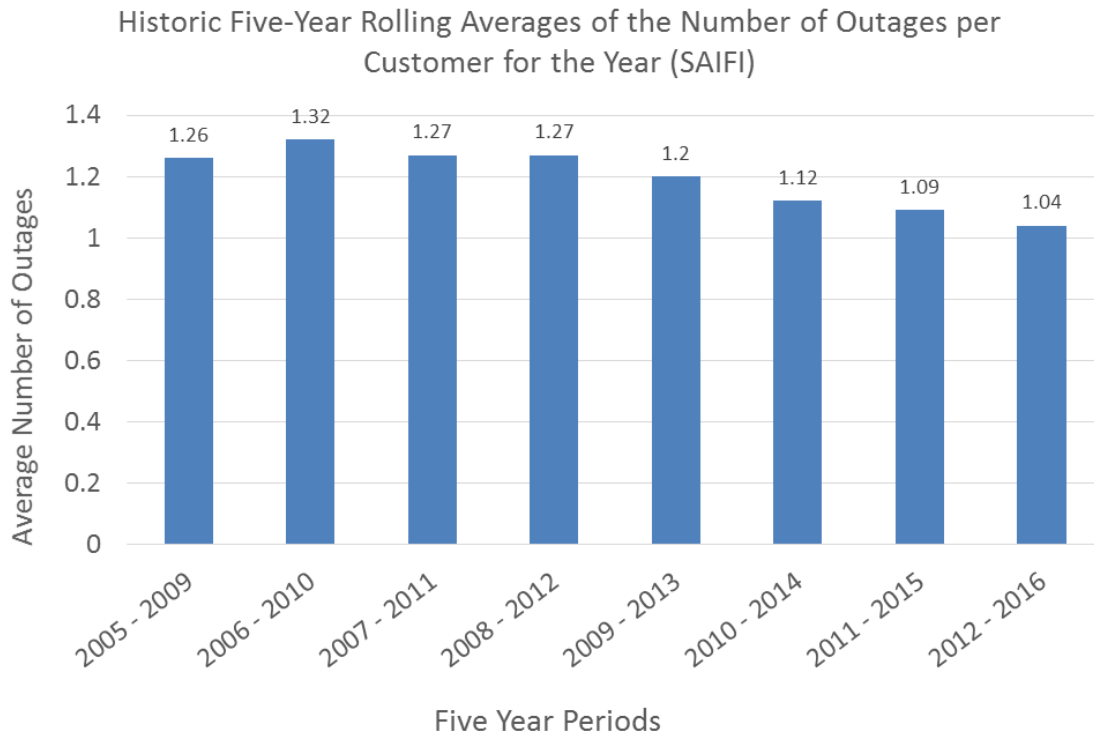
The figure below shows the rolling five-year average value for SAIFI for each five-year period from 2005 through 2016. Over this period, the general trend shows a slight increase in outage frequency during the middle years followed by decline in frequency in the later years of the period. Overall, the trend is relatively stable.

¹⁶ The Company will report the frequency of electric system interruptions per Customer for the calendar year, where:

- The interruptions are measured as the System Average Interruption Frequency Index (“SAIFI”), as calculated by the IEEE;
- The calculation of SAIFI excludes interruptions associated with any MED;
- The report will provide a brief description of the predominant factors influencing the current-year results, and in the context of the Company’s historic five-year rolling average of SAIFI; and
- The results will be reported on a system basis for Washington and Idaho and will include the annual SAIFI for Washington only.

¹⁷ Any service interruption that is greater than five minutes in duration.

Chart 9 – Historic Five-Year Rolling SAIFI



In 2016, the top three outage cause categories were: 1) overhead equipment; 2) planned outages; and 3) public caused.¹⁸ Their respective contributions were 19%, 17%, and 14%.

- Crossarm, conductor, and transformer failures were the leading causes of overhead equipment related interruptions for 2016.
- Planned outages continue to be a major factor in Avista’s outage mix as the Company continues to maintain and upgrade its system.
- The two leading types of incidents associated with public caused outages included cars striking poles or ground-mounted transformers, and wildfires. There were a couple of major wildfires in the Long Lake area in 2016, which resulted in full feeder outages and long outage durations because the outage restoration efforts were halted for fire control.

¹⁸ Such as car striking a pole and causing an outage for customers served from that line; “dig-ins” where an excavator cuts an underground line; wildfire caused outages; citizen-caused tree fall; and miscellaneous other causes such as theft of electricity.



2. Average Duration of Electric System Outages

As part of Avista’s Service Quality Measures program, the Company will report its annual electric system reliability measure for the total duration of non-major storm power outages experienced per customer for the year (SAIDI).¹⁹

2016 Results – This measure, as noted earlier, represents the total duration, in minutes, of the sustained outages experienced by the average Avista customer for the year. This measure, determined on a system basis, is calculated by totaling the number of minutes of service interruptions (outages) experienced by our customers for the year, divided by the total number of customers served. The 2016 value of 133 minutes was less than the average value for the previous five-year period (2011-2015) of 139 minutes. The current five-year period (2012-2016), increased from the prior five-year period (2011-2015) because the 2016 result of 133 minutes was greater than the 2011 result of 118. For 2015 the Washington only value was 127 minutes.

Table 13 – 2016 Total Outage Duration for the Average Avista Customer

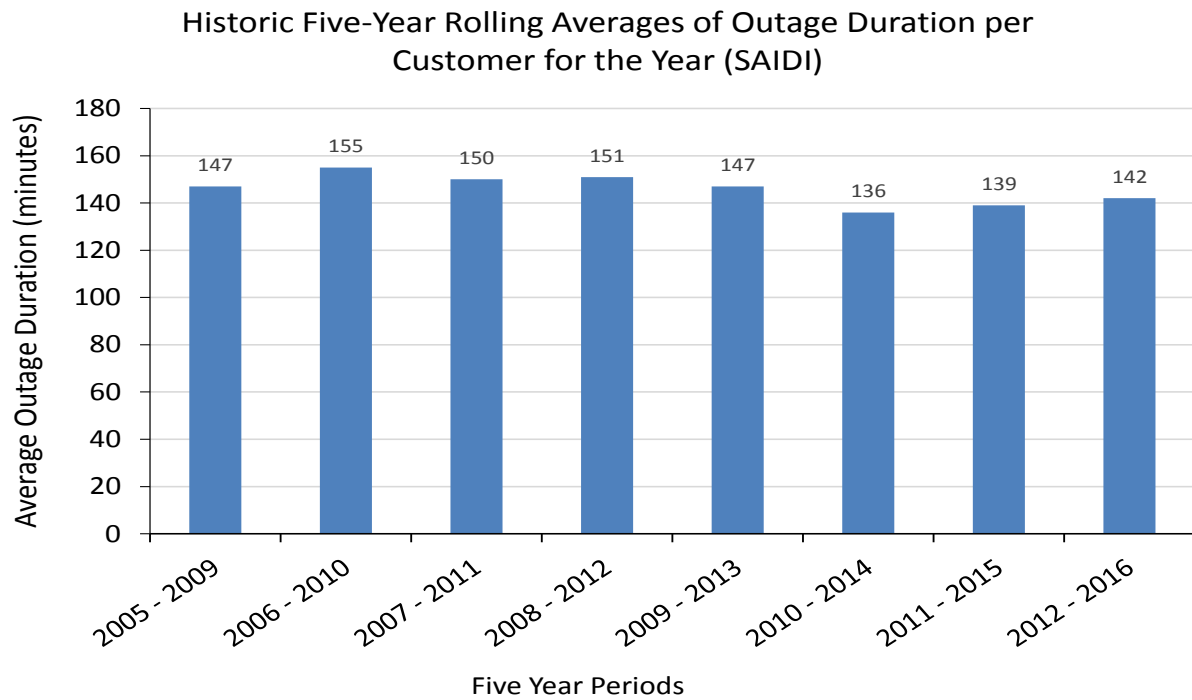
Total Outage Duration for the Average Avista Customer	2016 System Results	Current 5 Year Average (2012-2016)	Change in 5 Year Average
Total duration of all electric service outages for the average Avista customer for the year (SAIDI)	133 Minutes	142 Minutes	+3 Minutes

The figure below shows the rolling five-year average value for SAIFI for each five-year period from 2005 through 2016. Over this period, the general trend shows a slight increase in the average outage duration during the middle years followed by slight decline in average duration in the later years of the period. Overall, the trend is relatively stable.

¹⁹ The Company will report the duration of electric system interruptions per Customer for the calendar year, where:

- The interruption duration is measured as the System Average Interruption Duration Index (“SAIDI”), as defined by the IEEE;
- The calculation of SAIDI excludes interruptions associated with any MED;
- The report will provide a brief description of the predominant factors influencing the current-year system results, and in the context of the Company’s historic five-year rolling average of SAIDI; and
- The results will be reported on a system basis for Washington and Idaho and will include the annual SAIDI for Washington only.

Chart 10 – Historic Five-Year Rolling SAIDI



The increasing trend seen over the past two year can mostly be attributed to the SAIDI component of 2015, which was a result of the aftermath of the major November 2015 windstorms. The 2015 value of SAIDI was much higher than the other years from 2012-2016, and has subsequently bumped up the average. The 2016 value of 133 minutes is the lowest in the 2012-2016 range.



D. Customer Service Guarantees

Our service quality measures program includes seven types of service for which we will provide “customer service guarantees.” Our service commitments under the customer service guarantees reflect the level of service we currently provide, however, the guarantees recognize the customer inconvenience that can result when our delivered service does not meet our commitment. In these cases we agree to provide customers a bill credit or payment in the amount of \$50 in recognition of that inconvenience. All costs associated with the payment of customer service guarantees will be paid by the Avista’s shareholders. These costs will not be paid by our customers.

Following the approval of the Company’s program on March 29, 2015, the Company spent the remainder of 2015 setting up the processes required to implement, track, and monitor each of the seven guarantees in order to begin offering the guarantees on January 1, 2016. The Company is pleased to report that for the first year of the program it had a total of successful 68,630 events, which represented 99.5% of all events. The Company did miss 365 events in which it paid out \$18,250 to its customers.

1. Keeping Our Electric and Natural Gas Service Appointments

The Company will keep mutually agreed upon appointments for electric or natural gas service, scheduled in the time windows of either 8:00 a.m. – 12:00 p.m. or 12:00 p.m. – 5:00 p.m.²⁰

Avista provides its customer with appointments for certain types of electric and natural gas service requests. For electric service, the Company provides appointments for service drops or disconnects. For all other electric service work, the customer does not need to be present for the Company to perform the required work (i.e., check meter, meter test, voltage check...). For natural gas service, the Company provides appointments for dealer requested service, meter exchange and tests, meter unlock, no heat inspections, reconnects, relighting of Avista repairs, and repeated pilot light outages of natural gas appliances. The Company offers more gas service appointment types as the customer must be present for the employee to complete the work as they must enter the customer’s home. If the requested date and/or time of the service request is unavailable, the Company will still accommodate the customer’s request, but will not commit to a specific time

²⁰ Except in the following instances:

- a. When the Customer or Applicant cancels the appointment;
- b. The Customer or Applicant fails to keep the appointment; or
- c. The Company reschedules the appointment with at least 24 hours notice.

that an employee will arrive to work on the service request. Often times this practice results in better customer satisfaction as the Company makes every effort to accommodate a customer's request on that day, rather than schedule the work on a future date. Lastly, new service turn ons and credit reconnects are not available for appointments as the work orders are completed the same day of the request.

2016 Results – In 2016, the Company missed 10 appointments out of the total 1,487 appointments it made with customers. The primary reasons for the missed appointments were due to emergency work orders that came up, which prevented the Company from meeting its appointment time. Due to the risks and danger of electric and natural gas emergencies, the Company prioritizes emergency orders over all service work. The result of this prioritization is that the Company will miss some appointments as reflected in the 2016 results.

Table 14 – 2016 Service Appointment Results

Customer Service Guarantee	Successful	Missed	\$ Paid
Keeping Our Electric and Natural Gas Service Appointments scheduled with our customers	1,477	10	\$500

2. Prompt Restoration of Electric System Outage

When the Customer experiences an electric interruption, the Company will restore the service within 24 hours of notification from the Customer.²¹

The Company strives to restore power to its customers as quickly as possible, while maintaining the safety of its employees, customers, and the public as its top priority. Electric system outages can be complex and happen all hours of the day and all days of the year. In 2016 the Company fortunately did not experience any storms that qualified as a Major Event. In years such as these it could have been difficult to restore all customers affected by a system outage within 24 hours. However, that was not the case in 2016 as the Company successfully restored all customers affected by a system outage within the 24 hour limit and paid out no customer service guarantees for this measure.

2016 Results – In 2016, the Company's Washington customers experienced 5,151 outage events that affected a total of 202,887 customers. Of the customers affected, 26,345 notified the Company of the outage, in which all but one had their power restored within 24 hours.

²¹ Except for the following instances:

- a. During periods of time when the outage is associated with a MED, which includes the 24-hour period following the MED; or
- b. When an action or default by someone other than a utility employee that is outside the control of the company prevented the Company from restoring supply.

Table 15 – 2016 Outage Restoration Results

Customer Service Guarantee	Successful	Missed	\$ Paid
Restore service within 24 hours of a customer reporting an outage (excluding major storm events)	26,344	1	\$50

3. Promptly Switching on Electric Service When Requested

The Company will switch on power within one business day of the Customer or Applicant’s request for service.²²

When customers sign up for service they have an expectation that their service will be turned on as quickly as possible or on a future date they request. The Company strives to meet these customer requests by all means possible. Typically for electric service the meter is not shut off between tenants, so when a customer moves to a location the service is already on when they open an account for service at the location. In situations where the service is not already on at a customer location the Company must then send an employee to reconnect the meter at the location.

2016 Results – Out of the 3,383 requests to turn on electric service in 2016, the Company failed to turn on power within one business day to three customers. The number of customers and/or applicants successfully turned on within one business day was 3,380

Table 16 – 2016 Results of Switching on Power within One Business Day

Customer Service Guarantee	Successful	Missed	\$ Paid
Turn on power within a business day of receiving the request	3,380	3	\$150

4. Promptly Providing Cost Estimates to Customers for New Service

The Company will provide a cost estimate to the Customer or Applicant for new electric or natural gas supply within 10 business days upon receipt of all the necessary information from the Customer or Applicant.

When constructing a new home the process for having new electric or natural gas supply can be complex. Often times it may involve a customer, contractor, electrician, or dealer depending on

²² Except for the following instances:

- a. When construction is required before the service can be energized;
- b. When the Customer does not provide evidence that all required government inspections have been satisfied;
- c. When required payments to the Company have not been received; or
- d. The service has been disconnected for nonpayment or theft/diversion of service.

the nature of the new service. When the Company receives a request for new electric or natural gas service, typically through its customer contact center, it kicks off a process within the Company's gas or construction office. The new service request is assigned to a Customer Project Coordinator (CPC) who is responsible for discussing the request with the customer or applicant, meeting with the customer or applicant at the location, drawing up the potential job, and then providing a cost estimate for the new service back to the customer. The Company's goal for completing the cost estimate, and for which it offers a customer service guarantee, is 10 business days.

2016 Results – The Company successfully provided cost estimates to all customers or applicants for new electric or natural gas service within 10 business days of the request in 2016. The number of customers and/or applicants successfully who received a cost estimate within 10 business days was 5,024

Table 17 – 2016 Results of Providing Cost Estimates to Customer for New Service

Customer Service Guarantee	Successful	Missed	\$ Paid
Provide a cost estimate for new electric or natural gas service within 10 business days of receiving the request	5,024	0	\$0

5. Promptly Responding to Customer's Bill Inquiries

The Company will respond to most billing inquiries at the time of the initial contact, and for those inquiries that require further investigation, the company will investigate and respond to the Customer within 10 business days.

Utility bills are complex and can be confusing as they fluctuate greatly throughout the year and due to weather, may at times identify changes in rates, may be estimated in certain circumstances, and may vary in the number of billing days included in the billing period. When customers have questions about their bill and reach out to the Company's customer contact center to speak to someone about their questions, Avista's contact center representatives strive to address and resolve all inquiries on the initial customer contact. Some of the tools they use do address billing inquiries, which are often related to inquiries when customers feel their bill is too high, are:

- review the meter read and usage history to see if the bill is in line with the prior months or years;
- review the number of billing days for the bill in question;
- utilize the Company's bill analyzer tool, which is also available to customers on Avista's website, for a comparison of weather, average usage, and rates;
- discuss with the customer any life changes, new appliances, or maintenance needs and how those can impact their utility bill;
- offer tips on ways to save energy;
- direct the customer to Avista's website for additional energy savings advice; and,
- offer to mail Energy Use and Savings Guides or Energy Savings kits.

When the contact center representative is unable to address the billing inquiry on initial contact or the customer is not satisfied with the information provided on their inquiry, the Company will then create case to further investigate the customer’s inquiry. After a case has been created the Company will verify the meter read or obtain a new meter read and determine if the bill in question is accurate or not. If there was a billing error the representative will issue a corrected bill. After determining if the bill is accurate or not, the representative will then discuss the inquiry again with the customer along with the results of the verification of the meter read or new meter read. Typically after this process the customer is satisfied with the resolution. In situations where the customer is not satisfied and requests a meter test to ensure their meter is reading accurately, it triggers a separate process, which is covered by customer service guarantee number six, Promptly Responding to Customer’s Requests for Meter Testing.

2016 Results – The Company successfully investigated and responded to all billing inquiries that were not resolved upon the initial customer contact within 10 business days in 2016. The number of billing inquiries successfully investigated and responded to within 10 business days was 1,760

Table 18 – 2016 Results for Responding to Customer’s Bill Inquiries

Customer Service Guarantee	Successful	Missed	\$ Paid
Investigate and respond to a billing inquiry within 10 business days if unable to answer a question on first contact	1,760	0	\$0

6. Promptly Responding to Customer’s Requests for Meter Testing

The Company will investigate Customer-reported problems with a meter, or conduct a meter test, and report the results to the Customer within 20 business days.

WAC 480-100-183 and 480-90-183 state that an electric or gas “utility must test and report to the customer the accuracy of a meter within twenty business days after receiving an initial request from a customer.” Prior to the implementation of the Company’s customer service guarantees the Company complied with these requirements. With the guarantees now in place the Company will now provide a \$50 credit if it fails to meet this requirement.

2016 Results - In 2016, 311 customers reported a meter problem or requested the Company conduct a meter test. The Company successfully tested and reported the results to 309 customers that requested meter tests within 20 business days and failed to report the results to two customers within 20 business days.

Table 19 – 2016 Results for Responding to Customer’s Requests for Meter Testing

Customer Service Guarantee	Successful	Missed	\$ Paid
Investigate a reported meter problem or conduct a meter test and report the results within 20 business days	309	2	\$100

7. Providing Customers Advance Notice of Scheduled Electric Interruptions

The Company will provide notification to the Customer, through means normally used by the Company, at least 24 hours in advance of disconnecting service for scheduled interruptions.²³

WAC 480-100-148 requires electric utilities to provide “all customers affected by a scheduled interruption associated with facilities other than meters...notification...at least one day in advance.” With the customer service guarantee now in place the Company will now provide a \$50 credit if it fails to meet this requirement.

Managing and tracking this notification process proved to be quite complex in 2016, which was reflected in the Company’s 2016 results where it failed to notify 1.16% of customers affected by a planned outage at least 24 hours in advance. The complexity of notifying all customers of scheduled interruptions is due to the many areas within the Company involved with both scheduled work that results in service interruptions and notifying customers in advance. Some of the areas included are gas construction, electric operations, Customer Project Coordinators, asset maintenance program managers, distribution dispatch, service dispatch, and the customer contact center. Due to the coordination required to notify customers in advance of scheduled interruptions it required a detailed process to be restructured with additional check points put in place to ensure that all customers affected by a scheduled interruption are notified in advance.

2016 Results – In 2016, 30,685 customers were affected by scheduled interruptions. Out of all of the affected customers the Company successfully notified 30,336 customers and failed to notify 349 customers. For the 349 customers that were not notified in advance of their scheduled interruption the Company provided a \$50 credit for a total of \$17,450 in credits. The largest group of customers not notified of a scheduled interruption occurred in June 2016, which affected 78 customers

²³ Except for the following instances:

- a. When the interruption is a momentary interruption of less than five minutes in duration;
- b. When the safety of the public or Company personnel or the imminent failure of Company equipment is a factor leading to the interruption; or
- c. The interruption was due to work on a meter.

Table 20 – 2016 Customers Notified in Advance of an Electric Interruption

Customer Service Guarantee	Successful	Missed	\$ Paid
Notify customers at least 24 hours in advance of a planned power outage lasting longer than 5 minutes	30,336	349	\$17,450

III. Avista’s Electric System Reliability

1. Introduction

Pursuant to WAC 480-100-398, Avista Corporation dba Avista Utilities (“Avista” or “the Company”) submits its annual Electric Service Reliability Report. The report describes the Company’s reliability monitoring and reliability metrics for 2016. All numbers included in this report are based on system-data. The Company’s system includes 11 geographical divisions with two of those divisions overlapping the Washington and Idaho border leading to a commingling of jurisdictional customers. A map of Avista’s operating area is included on page 49 of this report.

WAC 480-100-393(3)(b) requires the establishment of baseline reliability statistics. The Company’s baseline statistics are included in this report, which compares the current year data to the baseline year of 2005 and the years in between. The Company also calculates a statistical range for each reliability index that is based on the average value for a period of time plus two standard deviations of the average. This range represents the statistical probability that the annual result for the current year will fall below the upper limit of the range 95% of the time. Accordingly, the year to year results should be within this range in most years, but they can exceed the range in years when conditions vary substantially from the normal pattern of variation. Over the years, Avista has referred to this range as the “target,” however, the term “target” should not be interpreted as a “level of performance” that Avista is trying to achieve each year. Rather, it simply represents the range of variability that is expected to encompass the results for each reliability statistic in most years.

Avista has reported in its previous annual reports that the completion of the transition to the Outage Management Tool (OMT) system had caused an increase in the variability of the data collected from 2001 to 2007. The 2009 Annual Report (UE-100659) indicated that a gradual increase in the SAIFI and SAIDI numbers that cannot be attributed to the transition to the OMT system was occurring. Through 2012, the trend lines for SAIFI and SAIDI were both showing an upward trend. The trend line for SAIFI now shows a downward trend with the inclusion of the 2016 data. The trend line for SAIDI is now showing a slight upward trend with the inclusion of the 2016 data. The charts on pages 45 and 47 show a trend line for SAIFI and SAIDI historical data.

The 2016 SAIDI and CAIDI reliability indices are both higher than the 2005 baseline, which may be partially due to the under reporting that may have occurred during the transition to OMT in 2005. The 2016 MAIFI reliability index is below the 2005 baseline. On another note, the 2016 SAIFI index is the lower than the 2005 baseline, and the lowest value since the 2005 benchmark was set.

Avista added a new section beginning in the 2007 annual report (UE-080787) which analyzes the areas where customers are experiencing multiple sustained outages. This section provides analysis of a reliability index called $CEMI_n$, which implies Customers Experiencing Multiple sustained Interruptions more than n times.

Avista continues to review its annual baseline reliability statistics in light of operational experience under current regulatory protocol. Avista may modify its baseline statistics as appropriate and will update the Commission accordingly.

2. Data Collection and Calculation Changes

WAC 480-100-398 (2) requires the Company to report changes made in data collection or calculation of reliability information after initial baselines are set. This section addresses changes that the Company has made to data collection.

Data Collection

Since Avista's Electric Service Reliability Monitoring and Reporting Plan was filed in 2001 (UE-011428), there have been several improvements in the methods used to collect outage data. In late 2001, centralizing the distribution trouble dispatch and data collection function for Avista's entire service territory began. The distribution dispatch office is located in the Spokane main complex. At the end of September 2005, 100% of the Company's feeders, accounting for 100% of the customers, are served from offices that employ central dispatching.

The data collected for 2016 represents the tenth full year of outage data collected through the Outage Management Tool (OMT). For 2016, all data was collected using the "Outage Management Tool" (OMT) based on the Company's Geographic Information System (GIS). The OMT system automates the logging of restoration times and customer counts.

Avista discovered a software coding error that has been within the OMT system since 2002 that caused a small increase in the SAIDI and CAIDI for 2008. Previous years were also evaluated to determine the overall impact to the Avista baseline statistics and at this time Avista is not proposing a change to the baseline numbers. The software error only occurred during very specific outage conditions when a group of customers with an initial outage starting time were "rolled" up into another group of customers that were determined to be part of the first group outage. The second group may have had a later outage starting time. When the first group of customer outage information was rolled up, the original outage starting time was lost and the second group outage starting time was used for both groups of customers instead of using the first outage starting time. The number of customers was counted correctly.

Even as good as the OMT system is at quantifying the number of customers and duration of the outage duration, there still are areas where the data collection is not precise. Determining the exact starting time of an outage is dependent on when a customer calls in, how well the Avista Distribution Dispatcher determines where the outage is and defines the device that has opened to remove the faulted section.

As AMR/AMI metering is implemented in the future and the customer meter provides outage information to the OMT system through an interface, the SAIDI and CAIDI numbers are expected to increase. This is similar to the above discussion.

Use of the OMT system and GIS data has improved the tracking of the numbers of customers without power, allowed for better prioritization of the restoration of service, and the improved dispatching of crews.

3. System Indices

The charts below show indices for Avista’s Washington and Idaho (“system”) electric service territory by year. Breakdown by division is included later in this report. Each chart shows twelve years of data along with the baseline reliability statistic which is highlighted in green. The statistically likely range of results, or the reliability target, as described above, is the average over the previous five years plus two standard deviations (shown in yellow on the reliability index charts).

The reliability targets have been adjusted by removing Major Event Days, MED’s, as defined in the previous section.

Table 21 – Reliability Statistic Target by Index

Index	2016 Result (Excluding Major Events)	2011-2015 Average (Excluding Major Events)	2005 Baseline	Reliability Target (Ave + 2 Standard Deviations)
SAIFI	0.86	1.09	0.97	1.16
MAIFI	1.88	2.32	3.58	2.73
SAIDI	133	139	108	171
CAIDI	154	128	112	164

Additional comparisons of the Reliability Indices are provided in the Office Indices section (page 49) and Monthly Indices section (page 68) of this report.

The Company continues to use the definition of major events as described above to be consistent with IEEE Standards. Therefore, the following charts show statistics including the effect of major events per this definition. Both the Baseline Statistic is shown for the year 2005 (green bar), along with the target (yellow bar).

Refer to Attachment D – SAIDI and SAIFI Historical Summary for additional historical information.

Chart 11 – SAIFI – Sustained Interruptions / Customer

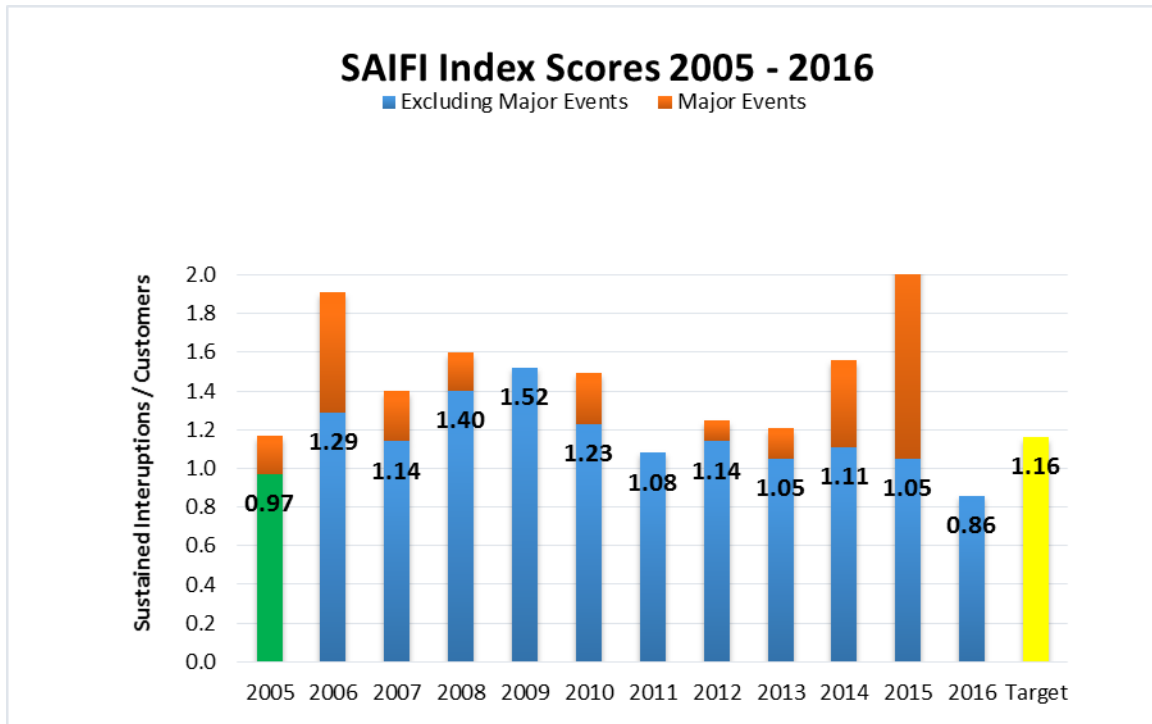
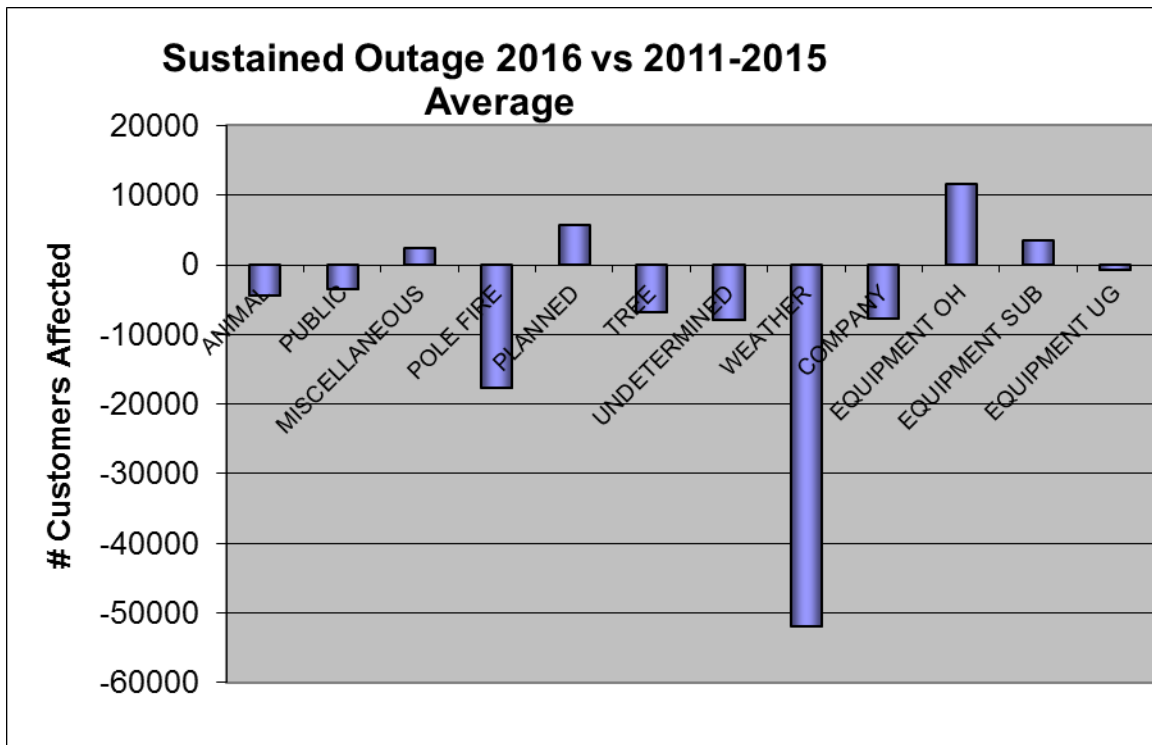


Chart 12 – Sustained Interruptions / Customer – Historic Comparison



SAIFI for 2016 was under the 2005 baseline statistic for the first time, and continues to represent a decreasing trend. The 2016 SAIFI index is the lowest value we've seen since the 2005 benchmark. Using a simple linear regression to establish a trend line, it would look like about a -0.023% growth in the number of customers affected. A chart of this analysis has been provided just after this discussion.

There were 27,879 customers affected by sustained outages caused by weather in 2016, not including major event days. This compares to the 2011–2015 average of 79,788.

Pole Fire outages affected 16,485 customers as compared with the 2011–2015 average of 34,200.

Planned outages numbered 51,070 customers for 2015 as compared to the 2011–2015 average of 45,331 customers.

Public outages affected 34,353 customers as compared to the 2011–2015 average of 37,881 customers.

Outages associated with Tree causes affected 30,952 customers as compared to the 2011–2015 average of 37,813.

Undetermined cause outages affected 42,506 customers as compared with the 2011–2015 average of 50,452.

Chart 13 – Historical SAIFI Trend

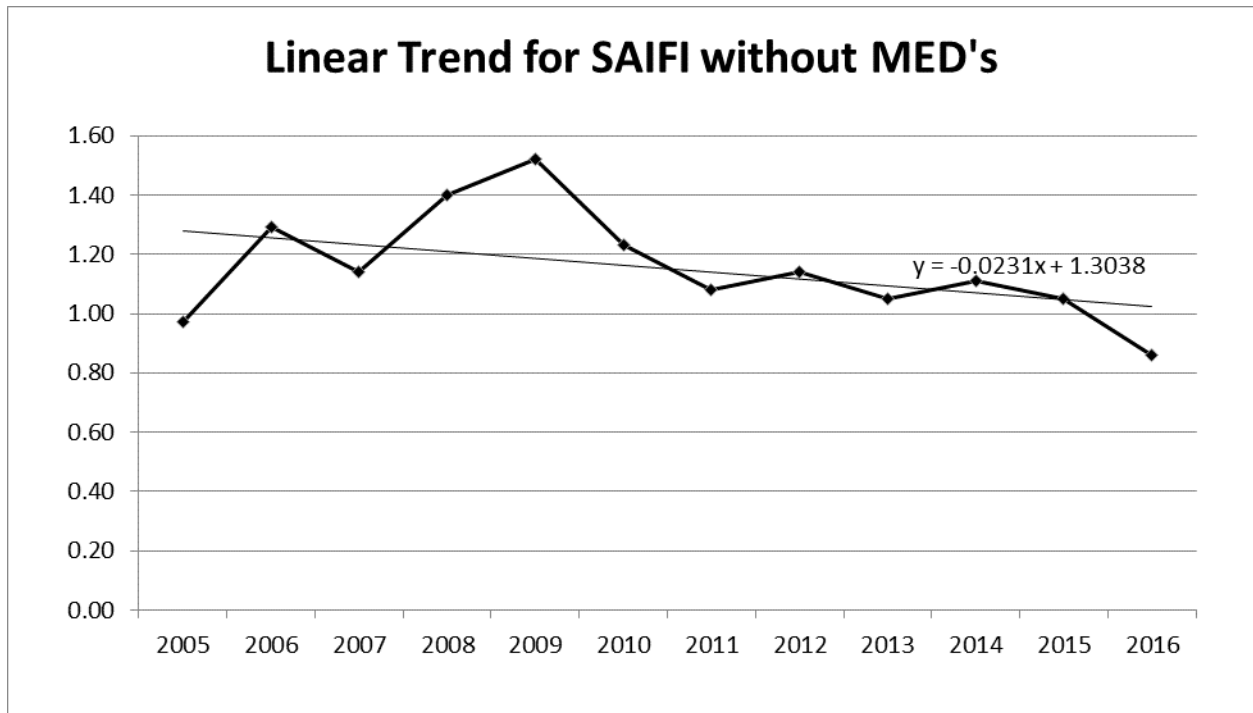


Chart 14 – MAIFI Momentary Interruption Events / Customer

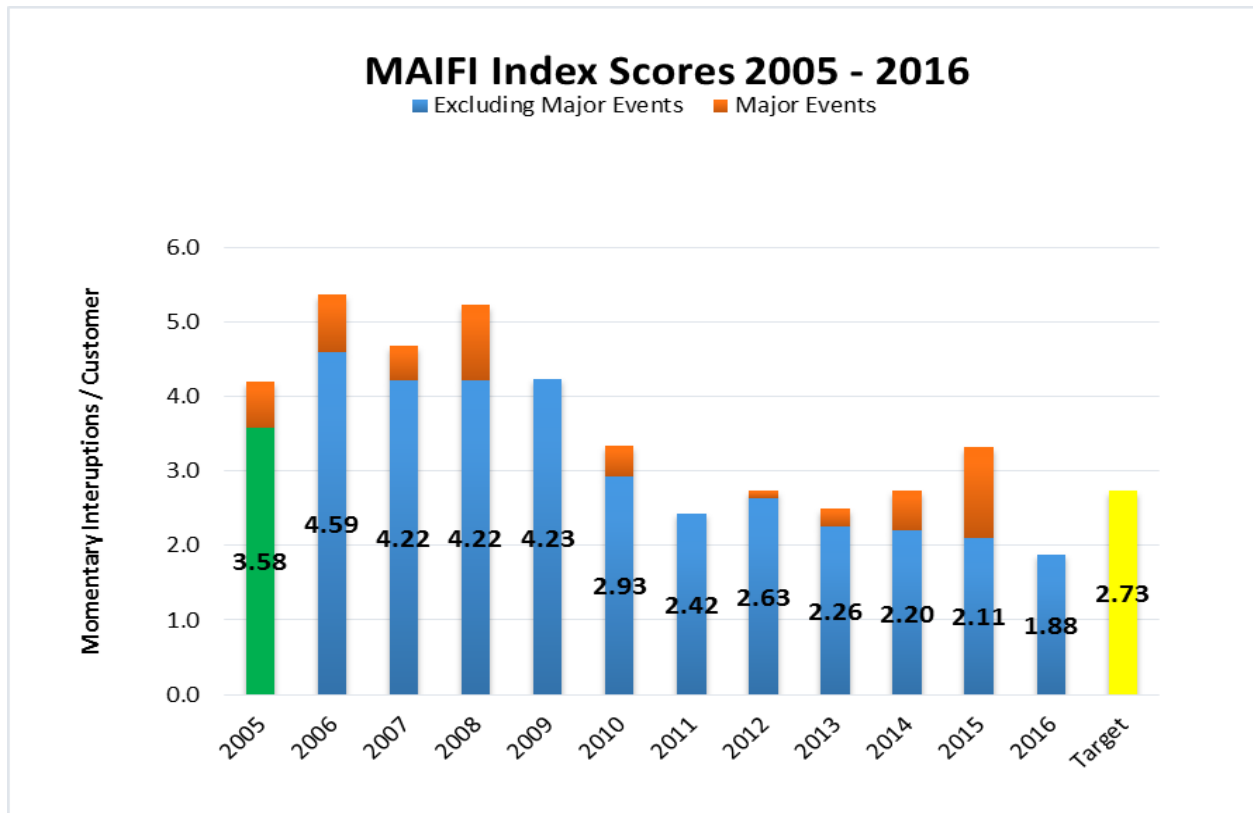
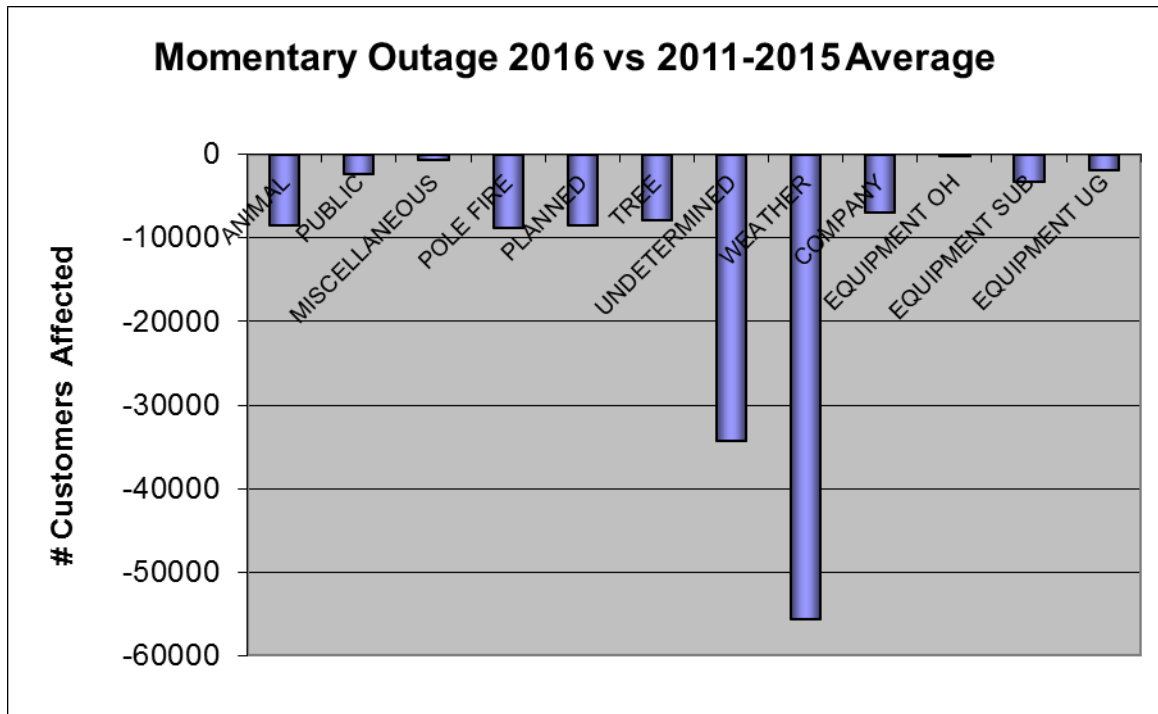


Chart 15 – Momentary Interruptions / Customer – Historic Comparison



The 2016 results for MAIFI show the lowest level we have seen, continuing the downward trend we have seen over the past few years. There was a decrease from the 5-year average for 2016 in the number of undetermined cause interruptions. This shift may be due to accuracy improvement efforts in Distribution Dispatch. The overall improvements in the MAIFI numbers may be due to tree trimming efforts along with Overhead Equipment replacement and Underground Equipment replacement. Some of the Urban areas have had the instantaneous trip function blocked, which reduces the total feeder customer momentary impacts, but may increase both SAIFI and SAIDI numbers for a few customers located downstream of a fused lateral.

Distribution Dispatch continues to make improvements in correlating the momentary outages with subsequent sustained outages, which reduces the undetermined causes.

Chart 16 – SAIDI – Average Outage Time / Customer

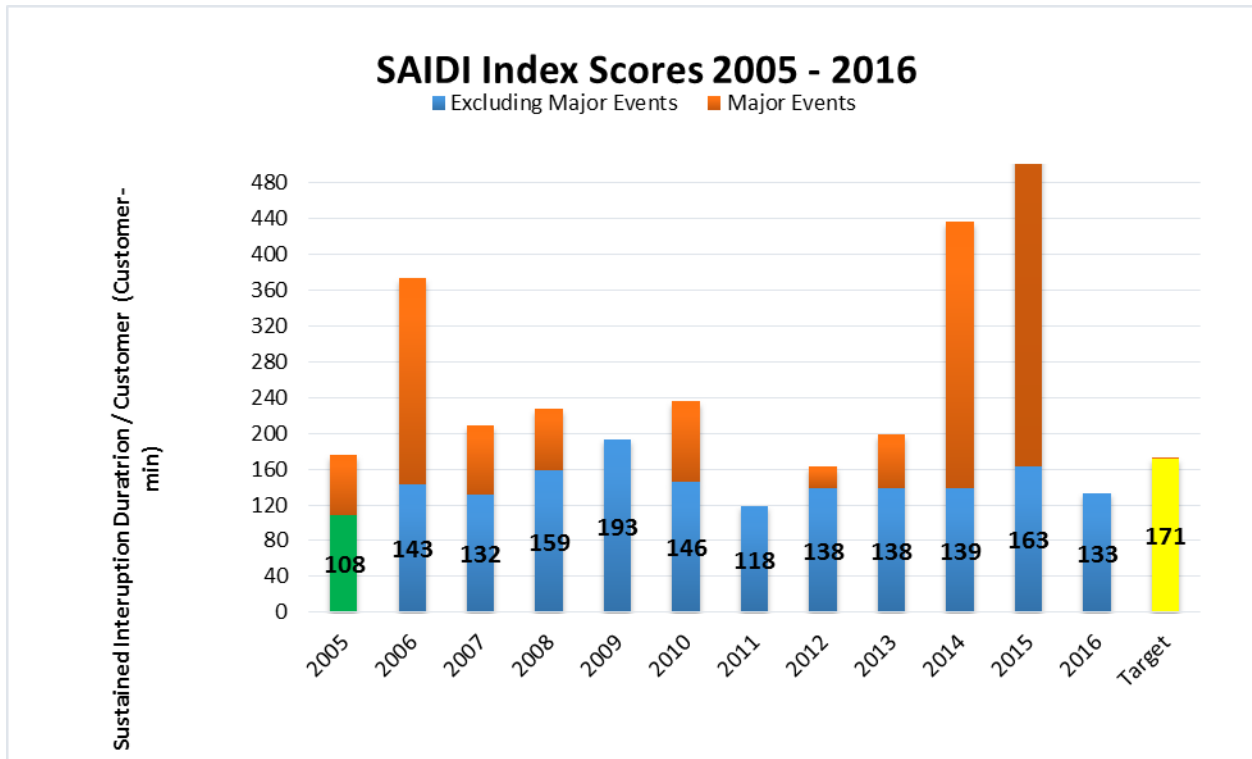


Chart 17 – Historical SAIDI Trend

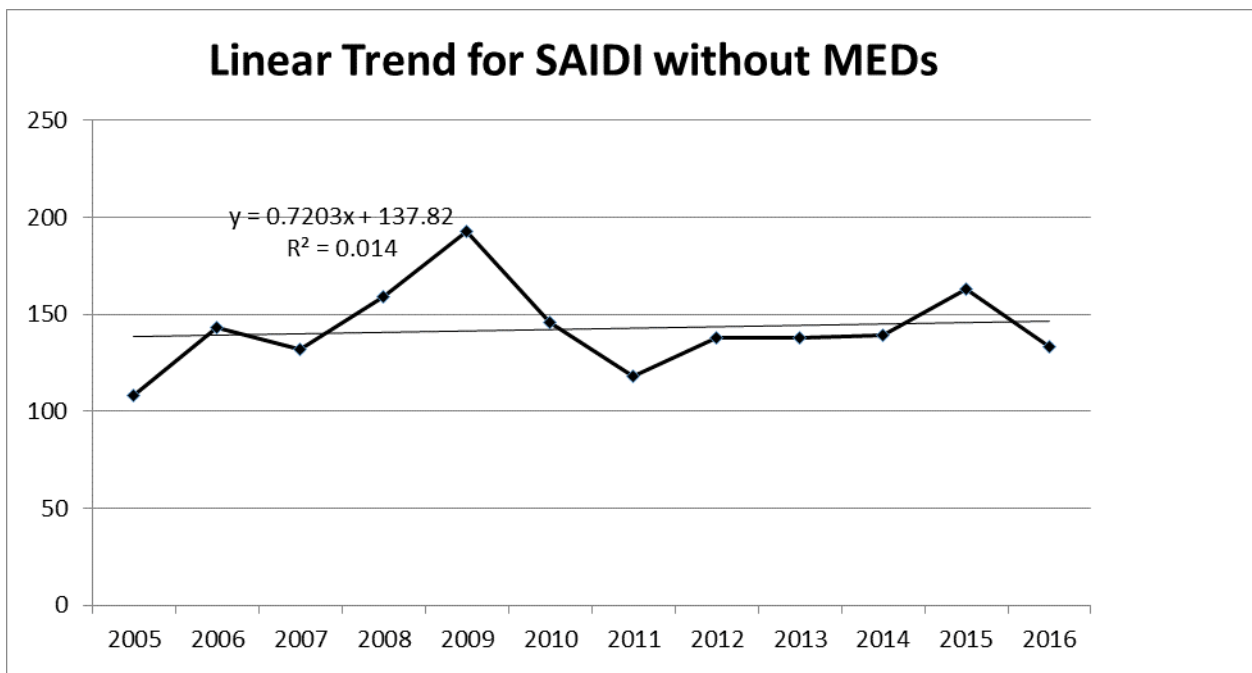
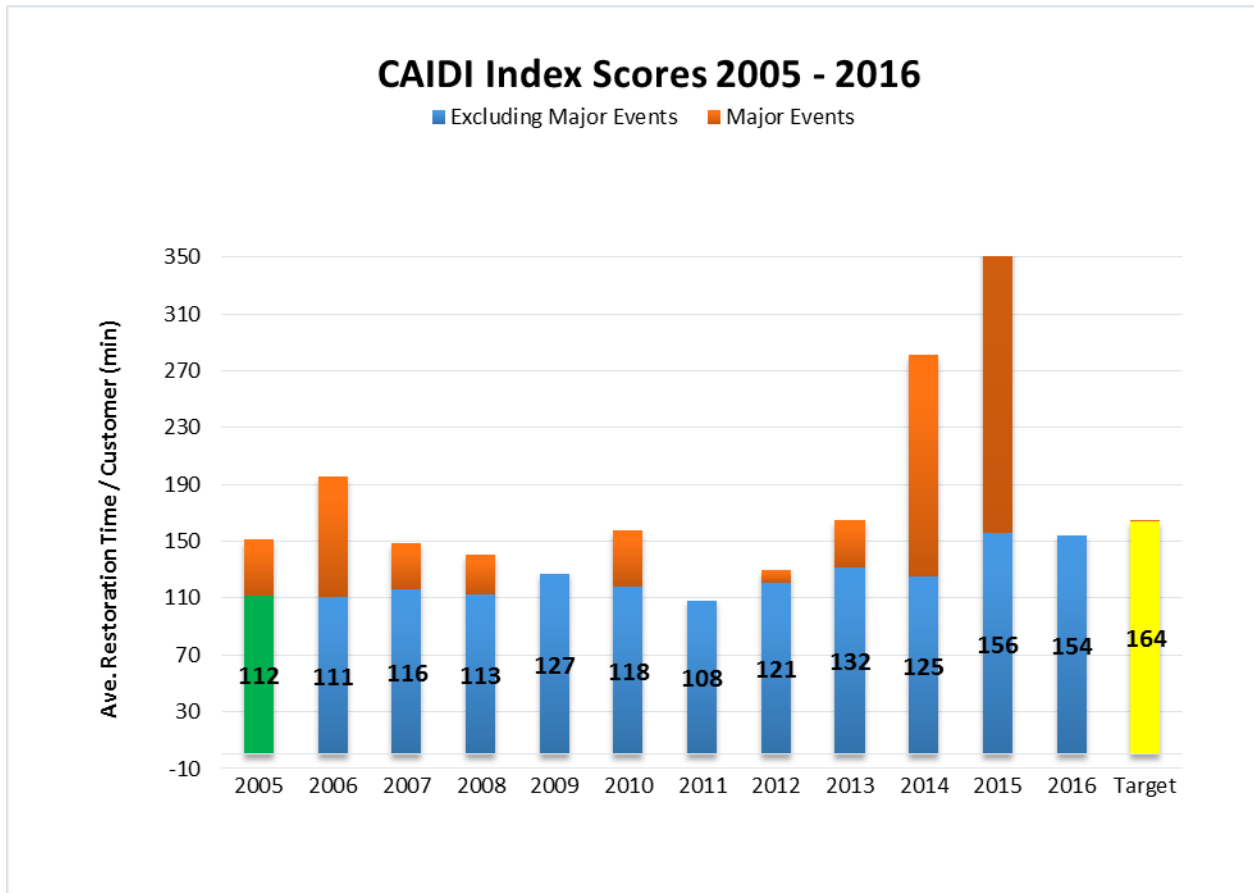
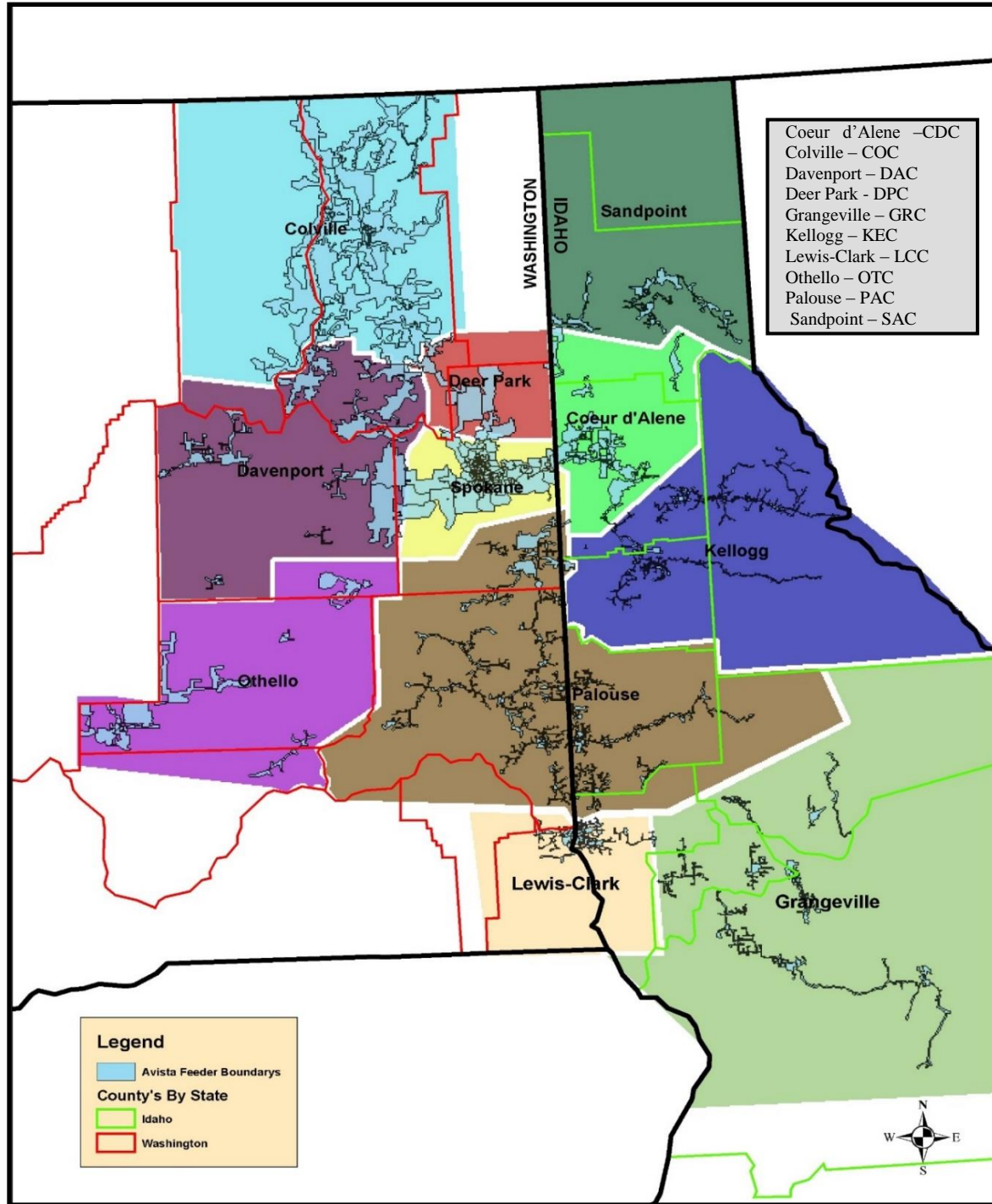


Chart 18 – CAIDI – Average Restoration Time



4. Office Area Indices

Chart 19 – Office Areas



The following numbers of customers were based on the customers served at the beginning of the year. These numbers were used to calculate indices for this report.

Table 22 – Number of Customers Served by Office Area

Office	Customers	% of Total
Coeur d'Alene	53,765	14.4%
Colville	19,536	5.2%
Davenport	5,934	1.6%
Deer Park	10,793	2.9%
Grangeville	10,114	2.7%
Kellogg/St. Maries	14,425	3.9%
Lewis-Clark	29,437	7.9%
Othello	6,888	1.8%
Palouse	40,057	10.7%
Sandpoint	14,752	3.9%
Spokane	16,8498	45.0%
System Total	374,199	

Chart 20 – SAIFI – Sustained Interruptions/Customer

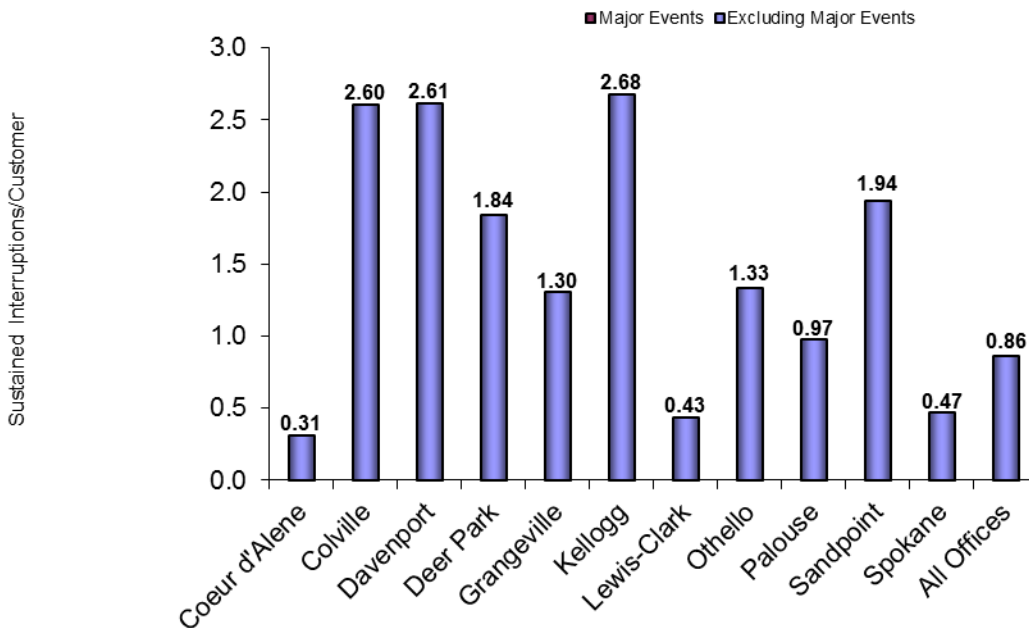


Chart 21 – MAIFI – Momentary Interruption Events / Customer

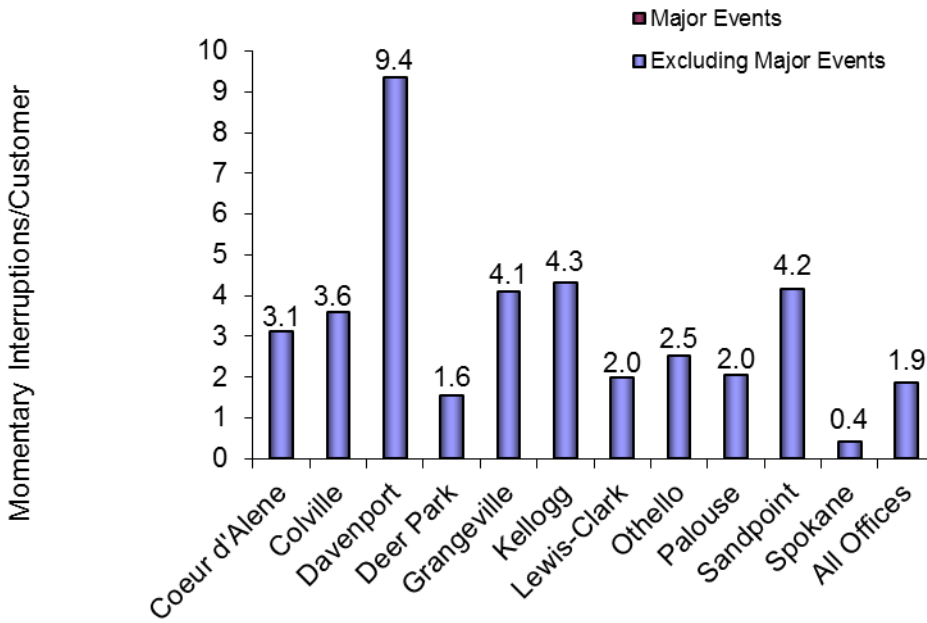


Chart 22 – SAIDI – Average Outage Time / Customer

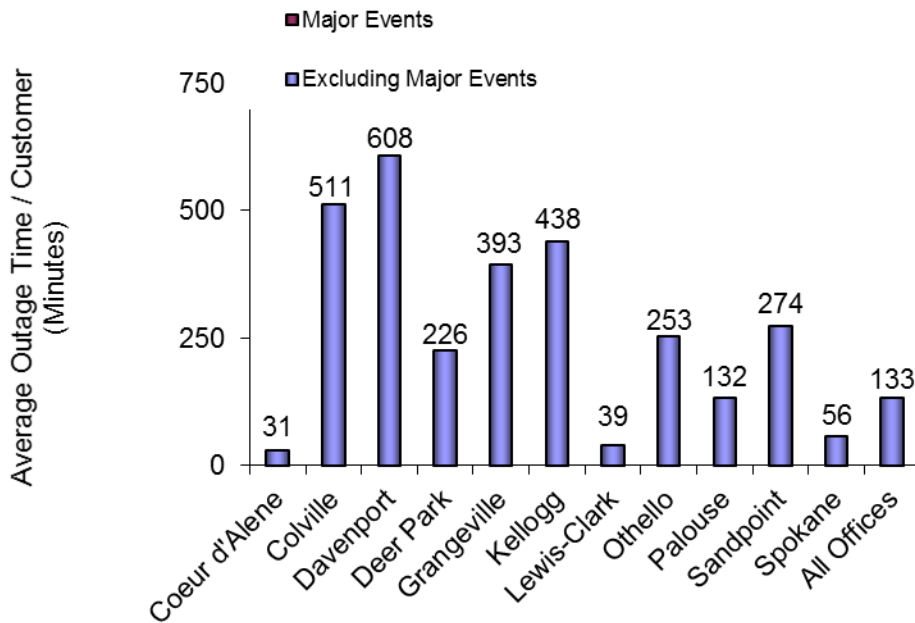
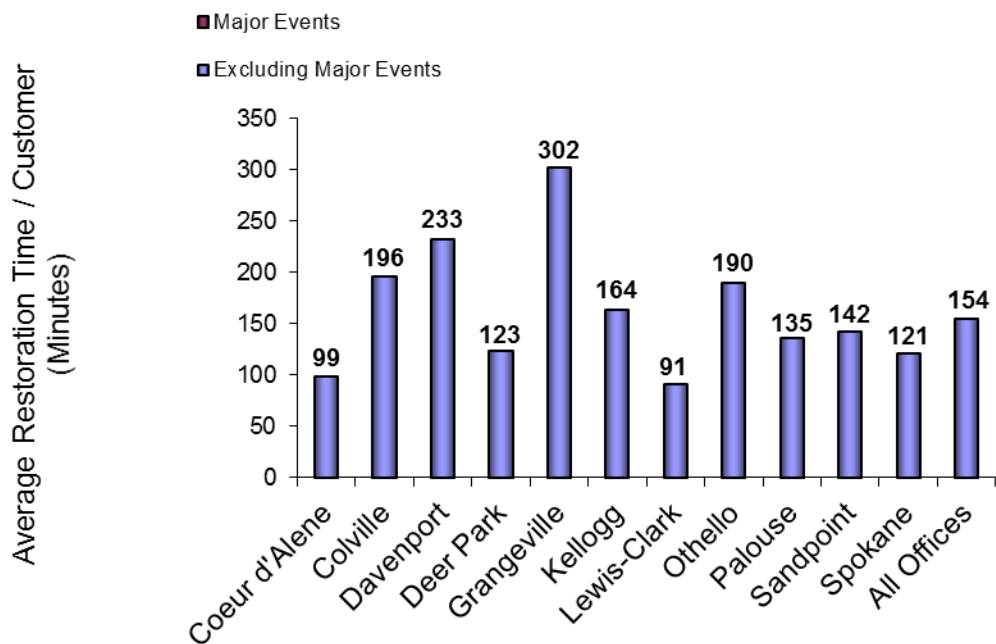


Chart 23 – CAIDI – Average Restoration Time



5. Major Event Days

Major Events and Major Event Days as used in this report are defined per the IEEE Guide for Electric Power Distribution Reliability Indices, IEEE P1366-2012. The following definitions are taken from this IEEE Guide.

Major Event – Designates an event that exceeds reasonable design and or operation limits of the electric power system. A Major Event includes at least one Major Event Day (MED).

Major Event Day – A day in which the daily system SAIDI exceeds a threshold value, T_{MED} . For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

The Company will use the process defined in IEEE P1366 to calculate the threshold value of T_{MED} and to determine MED's. All indices will be reported both including and excluding MED's. The comparisons of service reliability to the baseline statistics in subsequent years will be made using the indices calculated without MED's.

Table 23 – 2016 Major Event Days

Major Event Days	SAIDI (Customer- Minutes)	Cause
2016 Major Event Day Threshold	10.17	
No 2016 MEDs		

Avista’s electric system did not experience any Major Event Days in 2016.

The following chart shows the percentage SAIFI contribution by causes for outages during major event days.

Chart 24 - % SAIFI by Cause Code for the Major Event Days

There were no MEDs in 2016

The following table shows the SAIFI contribution and Customer hours by cause for the 2015 major event days.

Table 24 - % SAIFI by Sub Cause Code for the Major Event Days

There were no MEDs in 2016

The following table is provided as an initial review of Major Event Day information. The main premise of the IEEE Major Event Day calculation is that using the 2.5b method should classify 2.3 days each year as MED’s. The following table shows the previous major event days, the daily SAIDI value and the relationship of the yearly T_{MED} .

Table 25 – Yearly Summary of the Major Event Days

Year	Date	SAIDI	T_{MED}
2004	05-21-2004	7.11	6.35
	08-02-2004	7.36	
	12-08-2004	31.00	
2005	06-21-2005	39.53	4.916
	06-22-2005	9.03	
	08-12-2005	19.60	
2006	01-11-2006	12.10	7.058
	03-09-2006	8.58	
	11-13-2006	30.79	
	12-14-2006	29.26	
	12-15-2006	158.31	
2007	01-06-2007	9.98	8.017
	06-29-2007	32.64	

	07-13-2007	12.79	
	08-31-2007	21.30	
2008	01-27-2008	17.57	9.224
	07-10-2008	36.74	
	08-18-2008	9.49	
2009	None		9.925
2010	5/3/2010	21.04	11.110
	11/16/2010	68.67	
2011	None		10.848
2012	1/19/2012	9.93	9.489
	12/17/2012	14.35	
2013	8/25/2013	24.97	8.956
	8/26/2013	11.78	
	9/15/2013	14.01	
	11/16/2013	11.09	
2014	7/23/14	92.95	8.719
	7/24/14	35.66	
	8/25/14	121.05	
	8/3/14	38.52	
	8/12/14	9.84	
2015	8/29/15	13.42	8.219
	9/30/15	9.99	
	11/17/15	2093.19	
	11/18/15	399.34	
	11/19/15	147.97	
	11/20/15	66.96	
	11/21/15	47.30	
	11/22/15	32.61	
	11/23/15	15.38	
	11/24/15	12.19	
	12/23/15	29.35	
	12/24/15	19.24	
2016	None		10.171
2017			10.189

6. Customers Experiencing Multiple Interruptions

The IEEE Standard 1366P-2003 provides for two methods to analyze data associated with customers experiencing multiple momentary interruptions and/or sustained interruptions. Avista's Outage Management Tool (OMT) and Geographical Information System (GIS) provide the ability to geospatially associate an outage to individual customer service points. This association allows for graphically showing Customers Experiencing Multiple sustained Interruptions ($CEMI_n$) with Major Event Day data included onto GIS produced areas. Data can be exported to MS Excel to also create graphs representing different values of n. The calculation for $CEMI_n$ and Customers Experiencing Multiple Sustained and Momentary Interruptions $CEMSMI_n$ is provided in Attachment B.

Avista has used the data from the OMT system integrated with the GIS system to geospatially display reliability data for specific conditions. The specific conditions imply looking at the number of sustained interruptions for each service point (meter point). This would be similar to the SAIFI index, but would be related to a certain number of sustained interruptions. Avista includes all sustained interruptions including those classified under Major Event Days. This provides a view of what each customer on a specific feeder experiences on an annual basis. Momentary Interruptions are not included in the $CEMI_n$ index because by IEEE definition only applies to sustained outages. Other Momentary Indices are not included because of the lack of indication at many rural substations and line locations.

The first chart below provides a view of the percentage of customers served from the Avista system that have sustained interruptions. 80.1% of Avista customers had one or fewer sustained interruptions and 1.6% of Avista customers had six or more sustained interruptions during 2016.

The remaining geographic plots show the sustained interruptions by color designation according to the legend on each plot for each office area. Note the office area is designated as the area in white for each plot and that there is overlap between adjacent office area plots. The adjacent office areas are shown in light yellow.

The plots provide a quick visual indication of varying sustained interruptions, but significant additional analysis is required to determine underlying cause(s) of the interruptions and potential mitigation.

Chart 25 – Avista Service Territory - CEMI_n

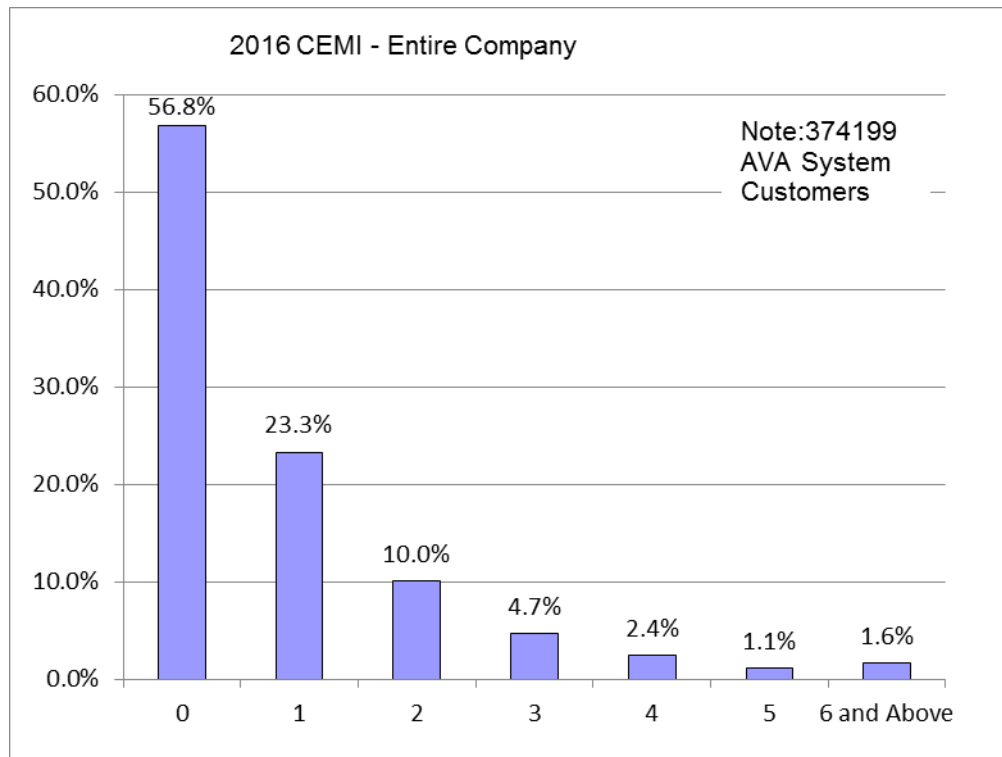


Chart 26 – Colville Office - CEMI_n

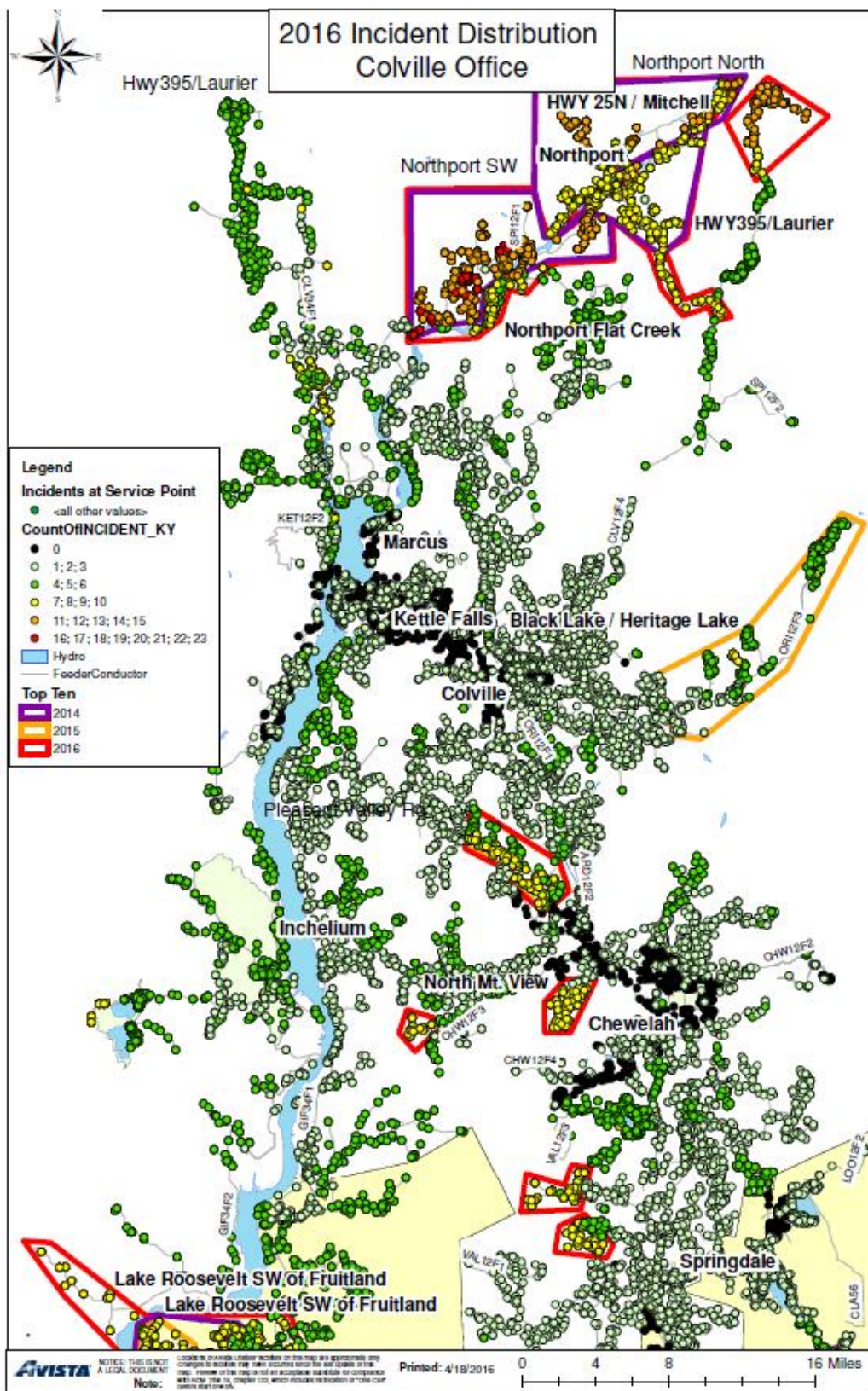


Chart 27 – Davenport Office – CEMIn

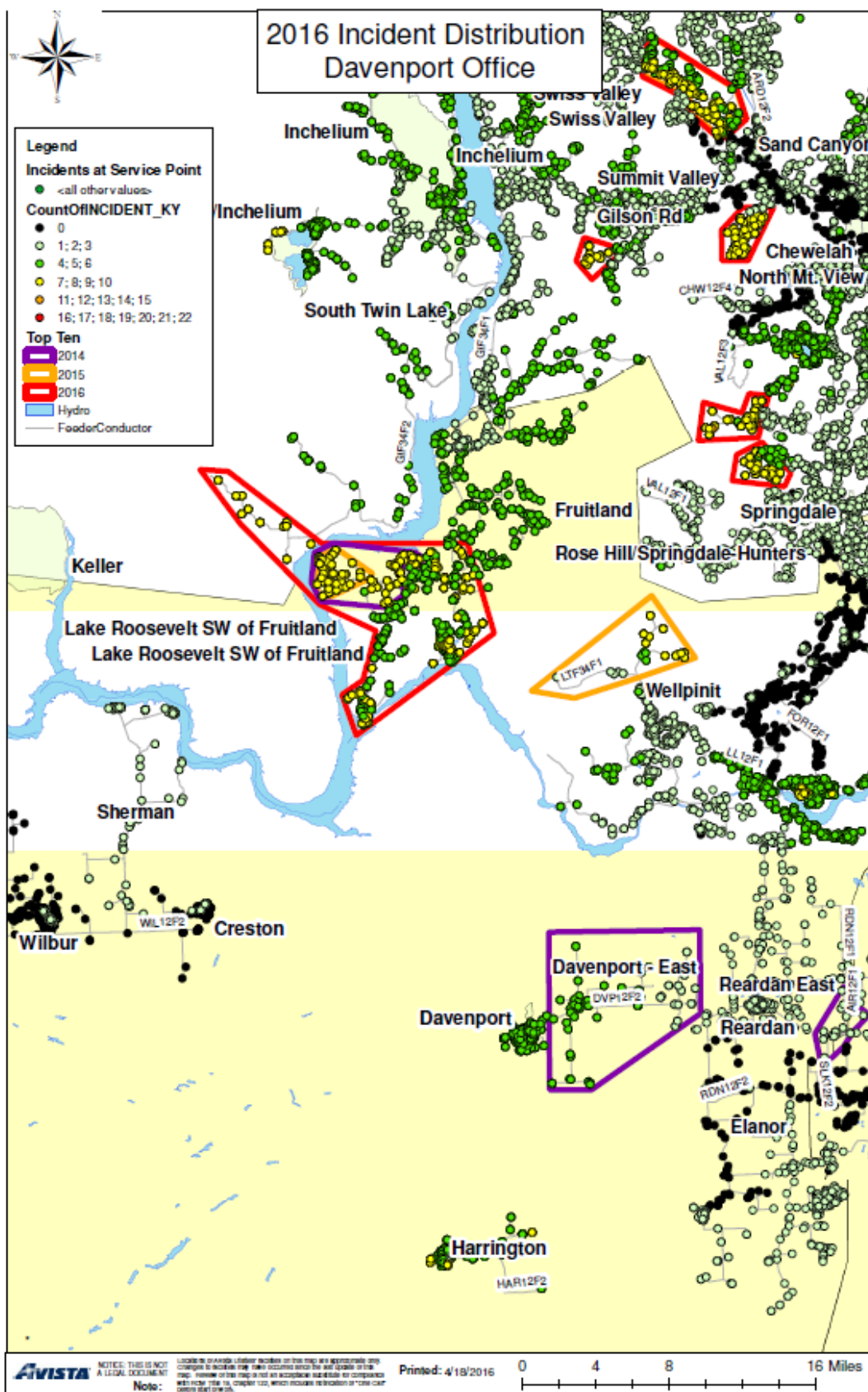


Chart 28 – Deer Park Office - CEMI_n

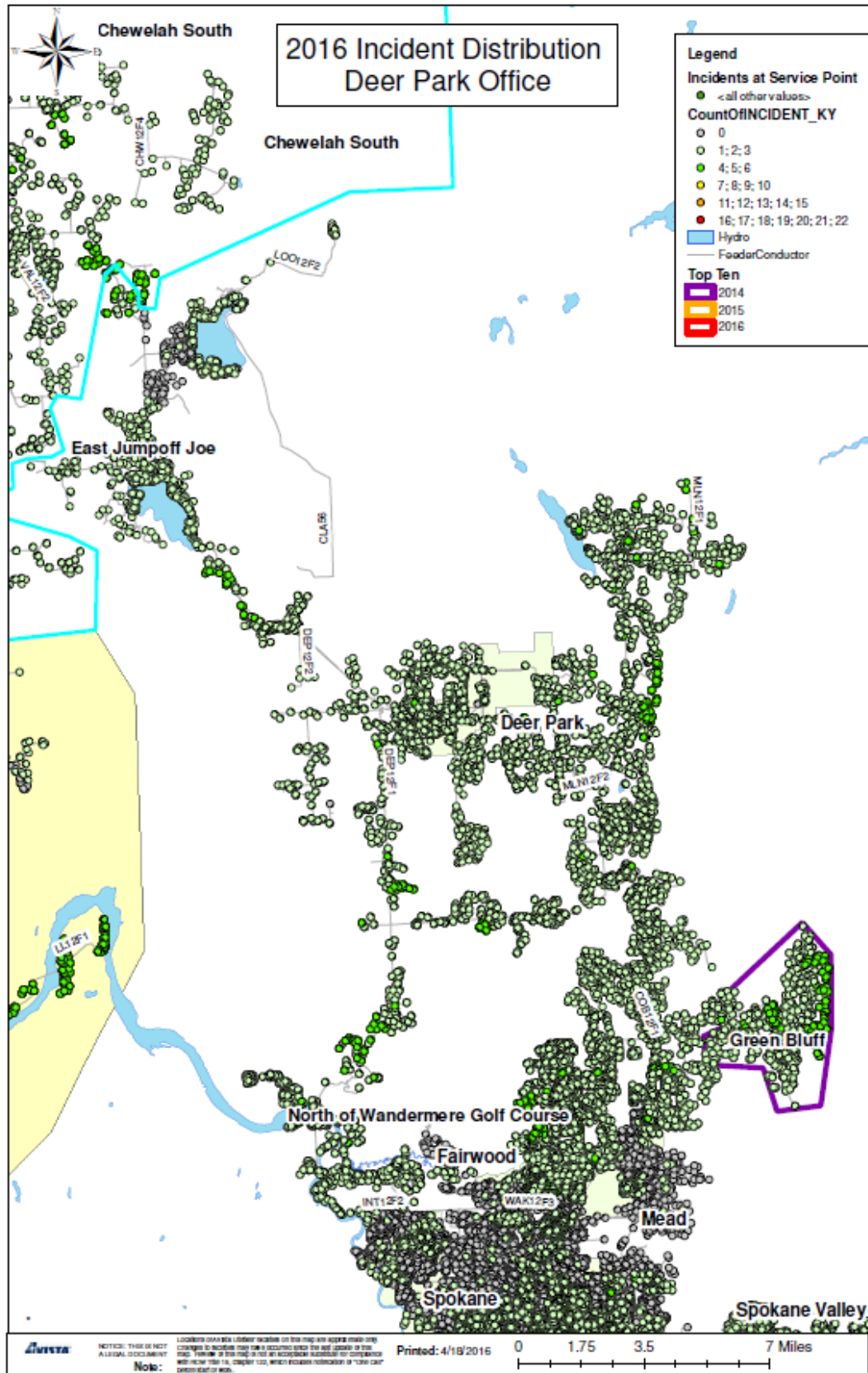


Chart 29 – Othello Office - CEMI_n

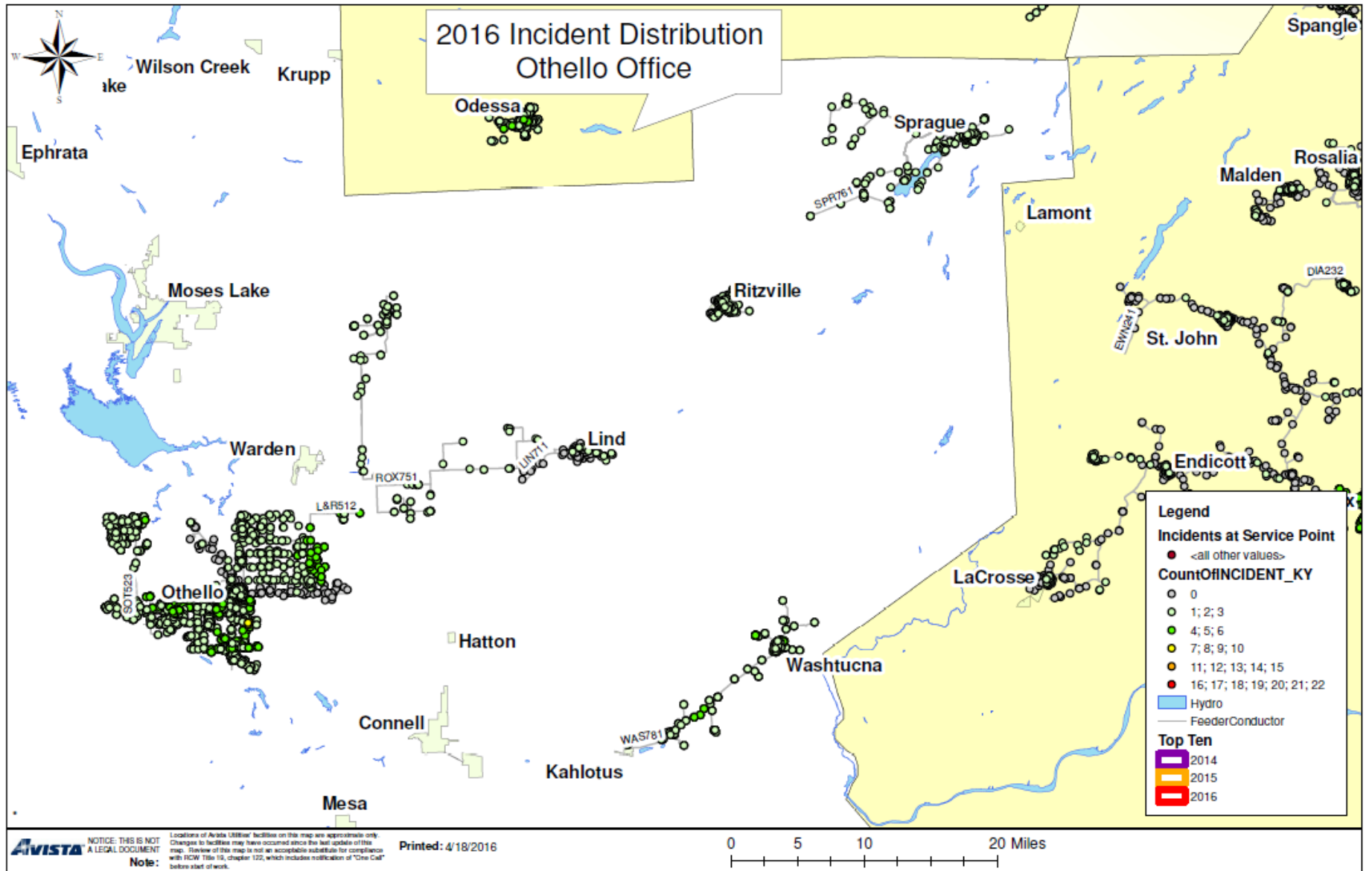


Chart 30 – Palouse Office - CEMI_n

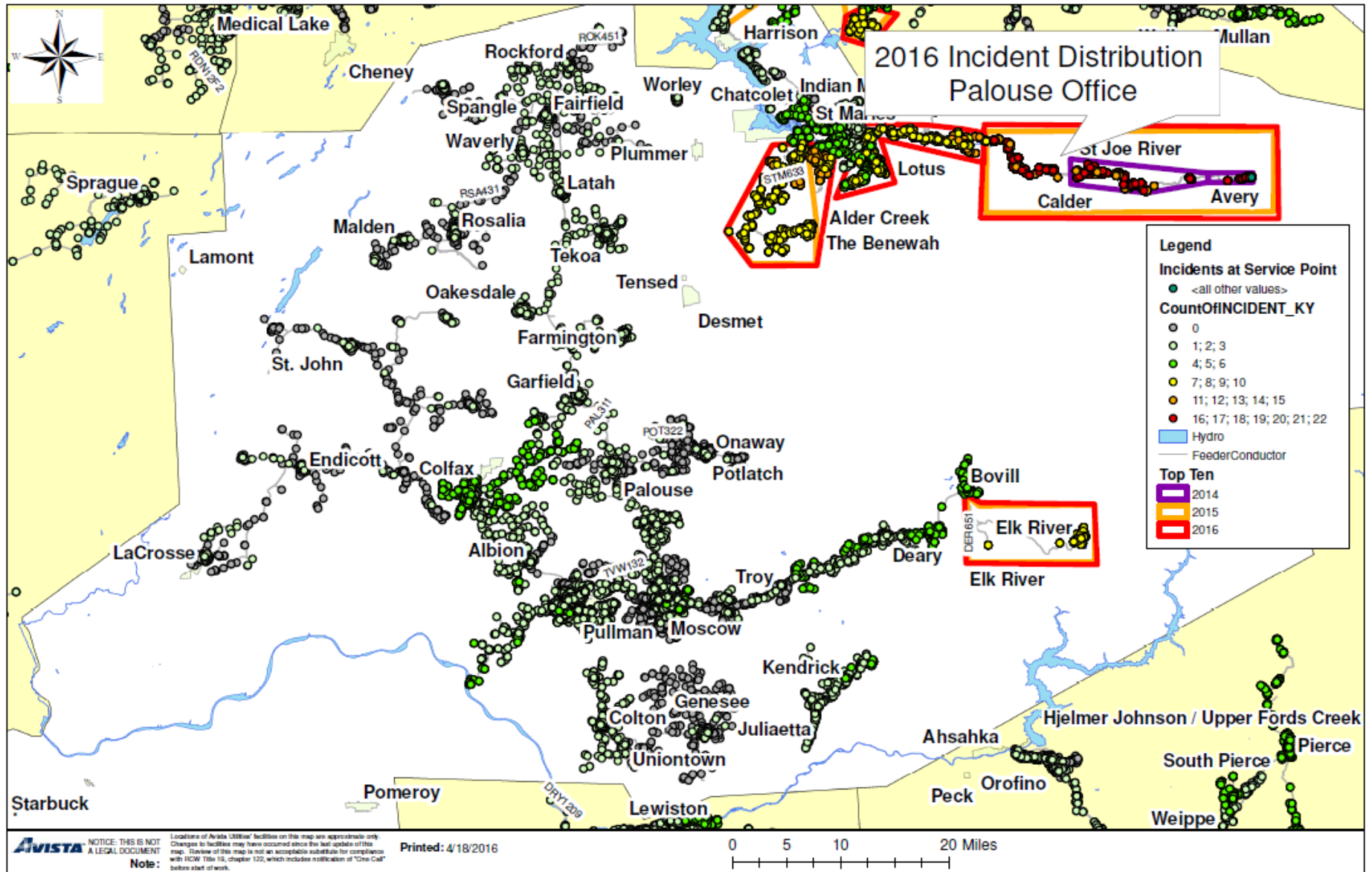


Chart 31 – Lewis-Clark Office - CEMI_n

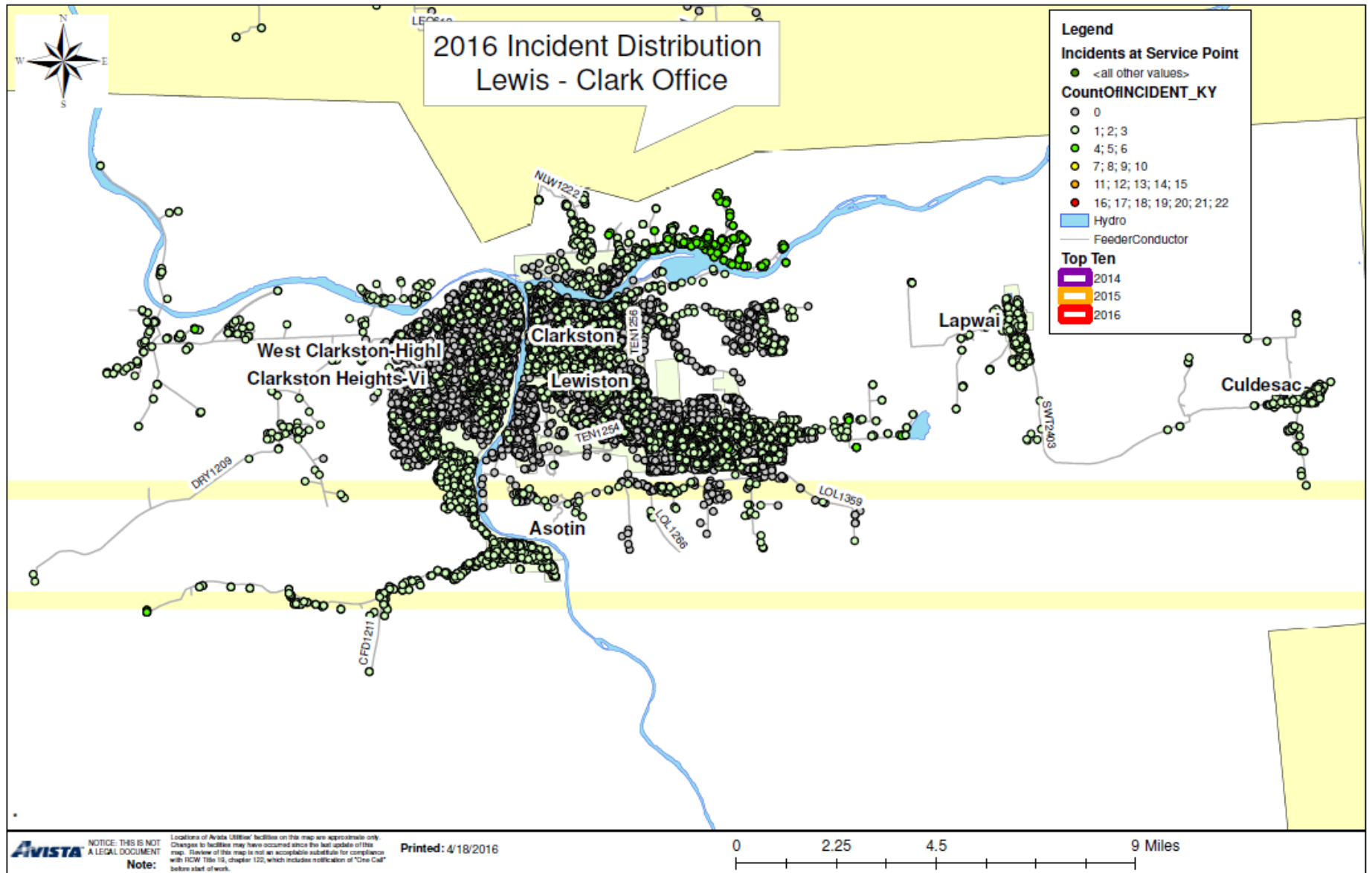


Chart 32 – Spokane Office - CEMI_n

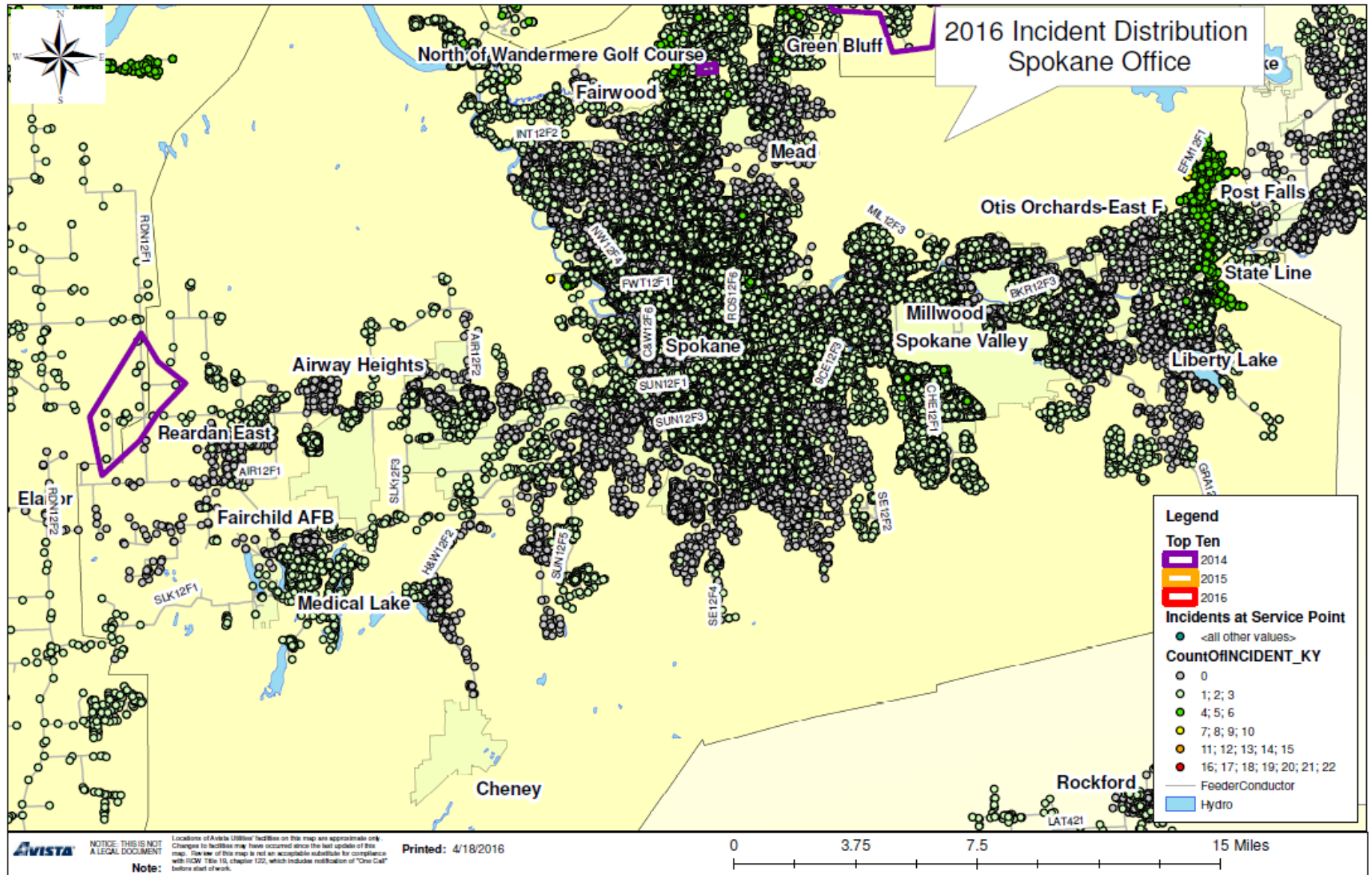


Chart 33 – Sandpoint Office - CEMI_n

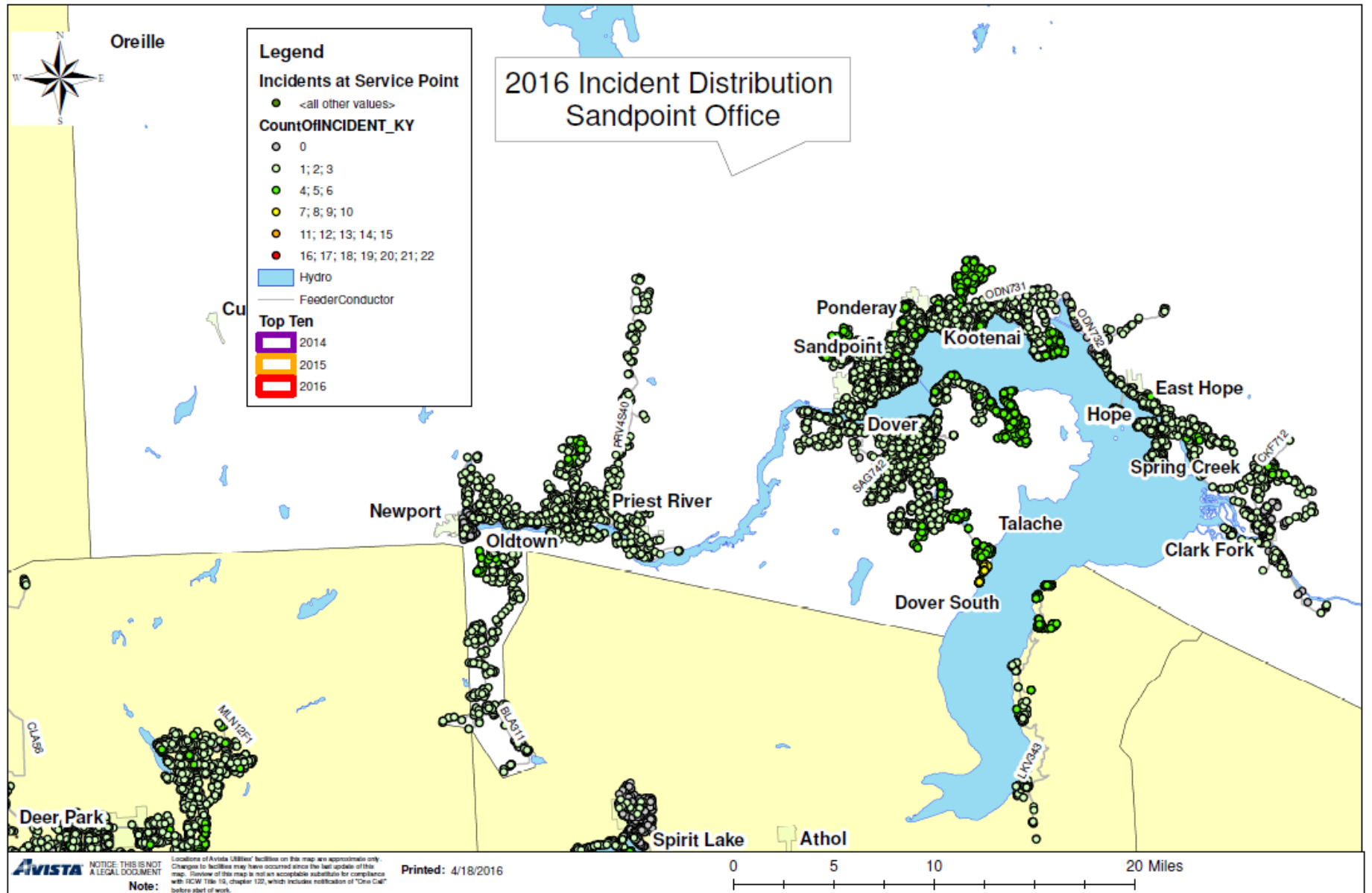


Chart 34 - Kellogg Office - CEMI_n

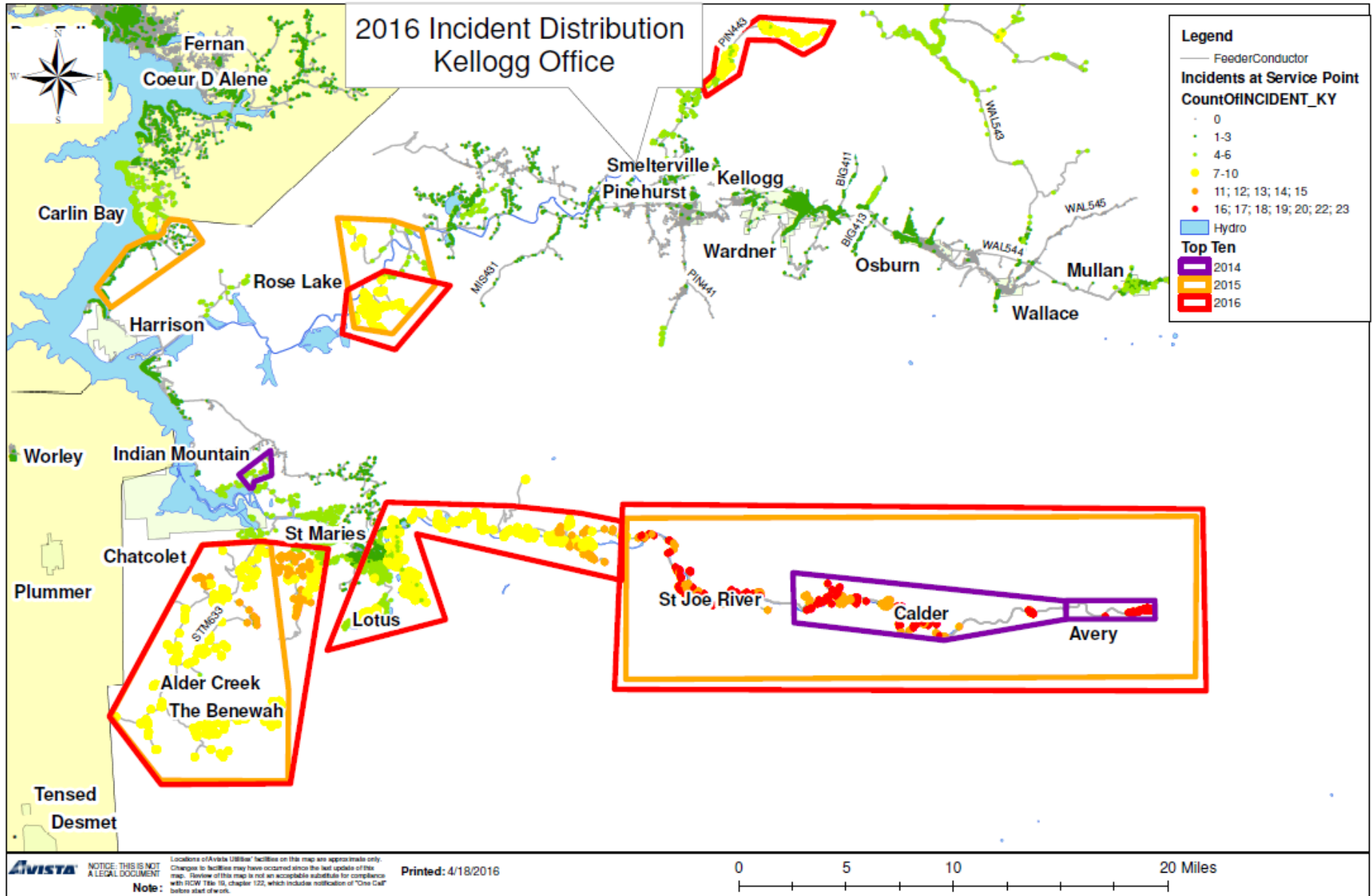


Chart 35 - Coeur d'Alene Office - CEMI_n

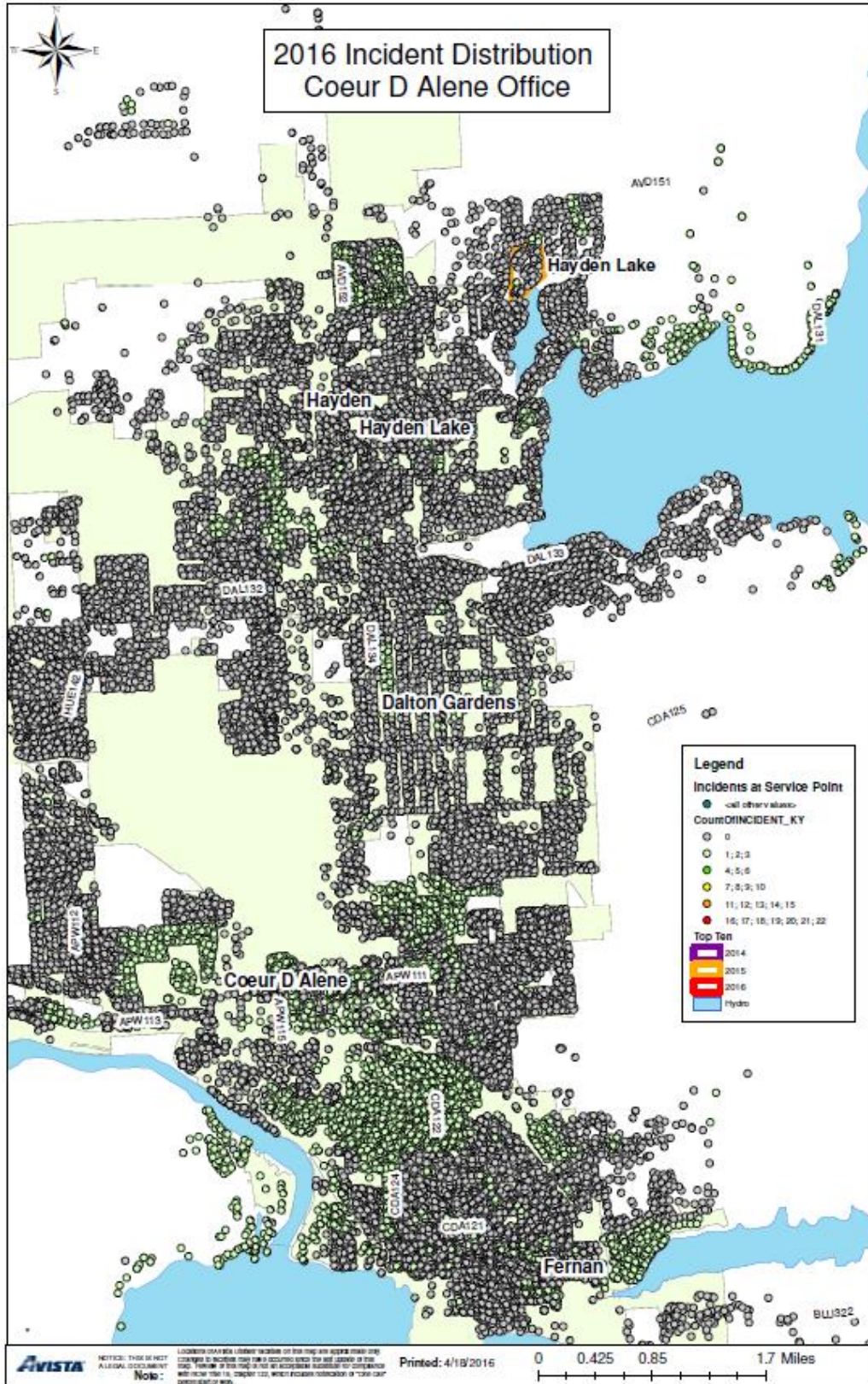
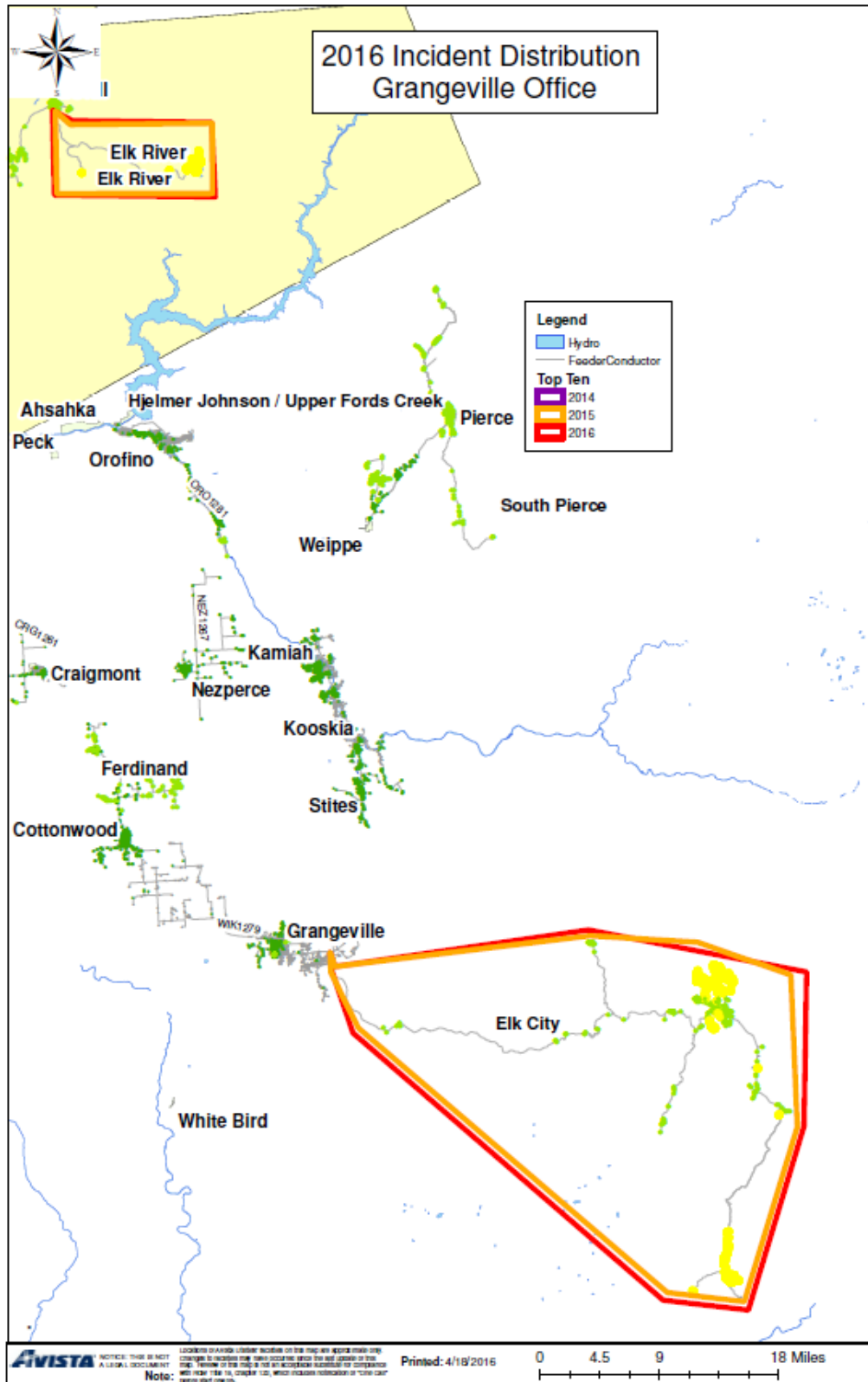


Chart 36 - Grangeville Office - CEMI_n



7. Monthly Indices

Each of the following indices, reported by month, shows the variations from month to month. These variations are partially due to inclement weather and, in some cases, reflect incidents of winter snowstorms, seasonal windstorms, and mid- and late summer lightning storms. They also reflect varying degrees of animal activity causing disruptions in different months of the year.

Chart 37 – SAIFI – Sustained Interruptions / Customer

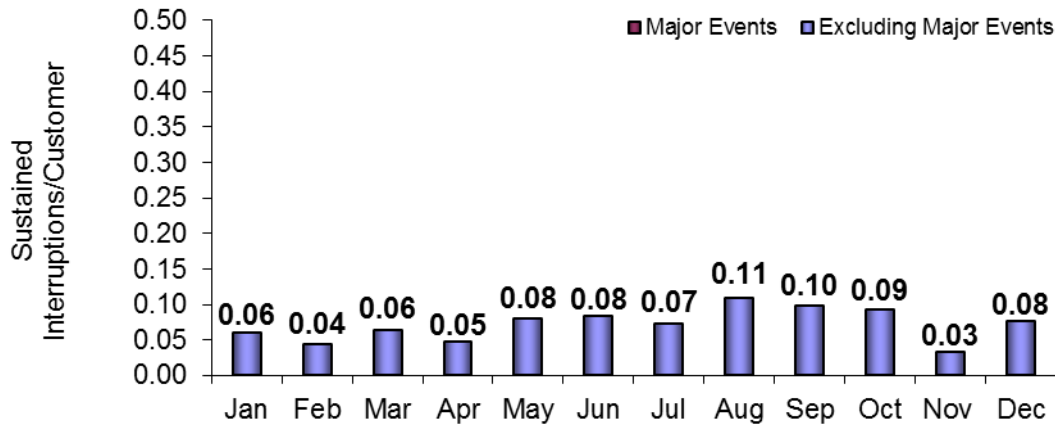


Chart 38 – MAIFI – Momentary Interruption Events / Customer

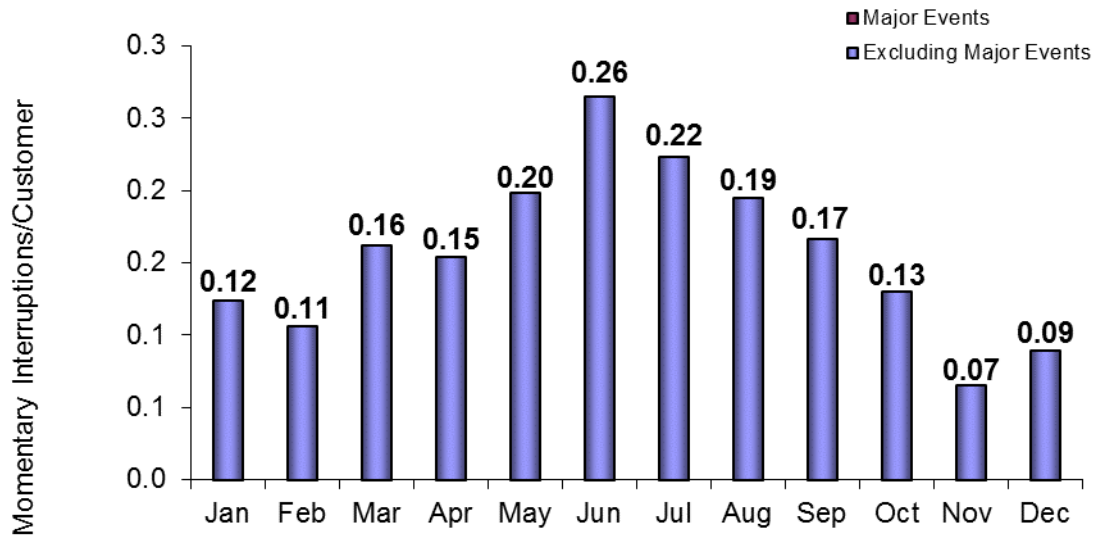


Chart 39 – SAIDI – Average Outage Time / Customer

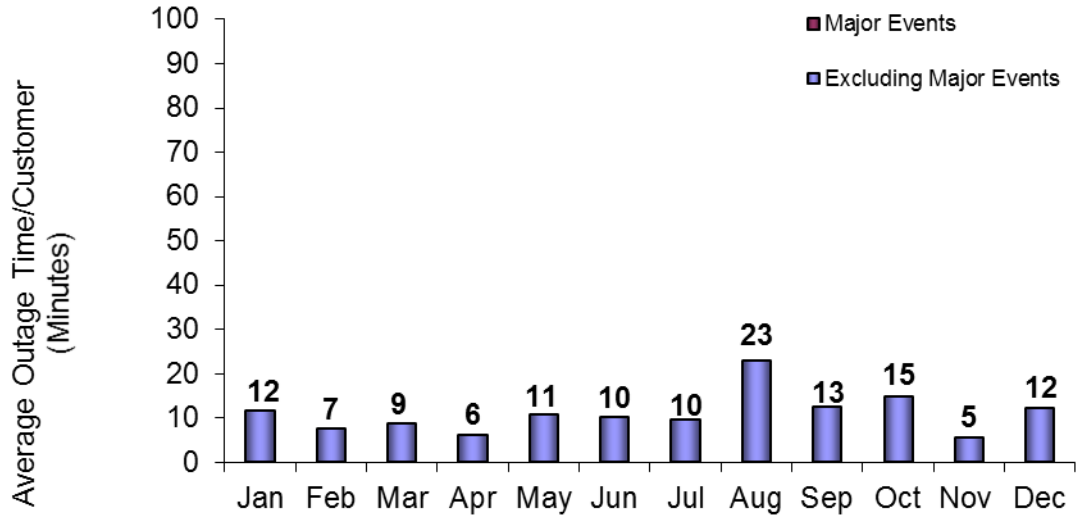
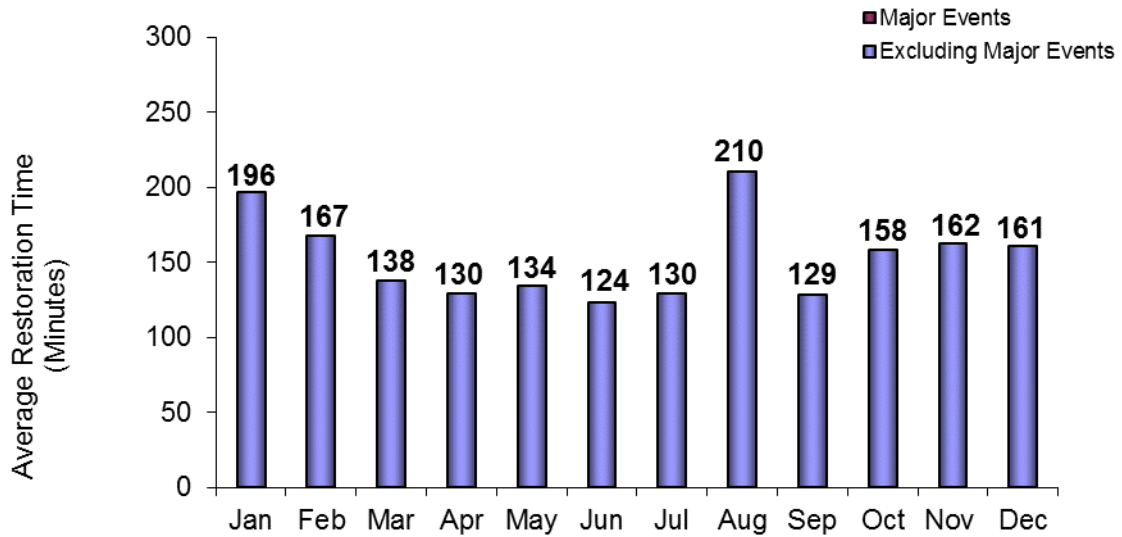


Chart 40 – CAIDI – Average Restoration Time



8. Sustained Interruption Causes

The following table lists the percentage SAIFI contribution by causes for outages excluding major event days.

Table 26 - % SAIFI per Cause by Office

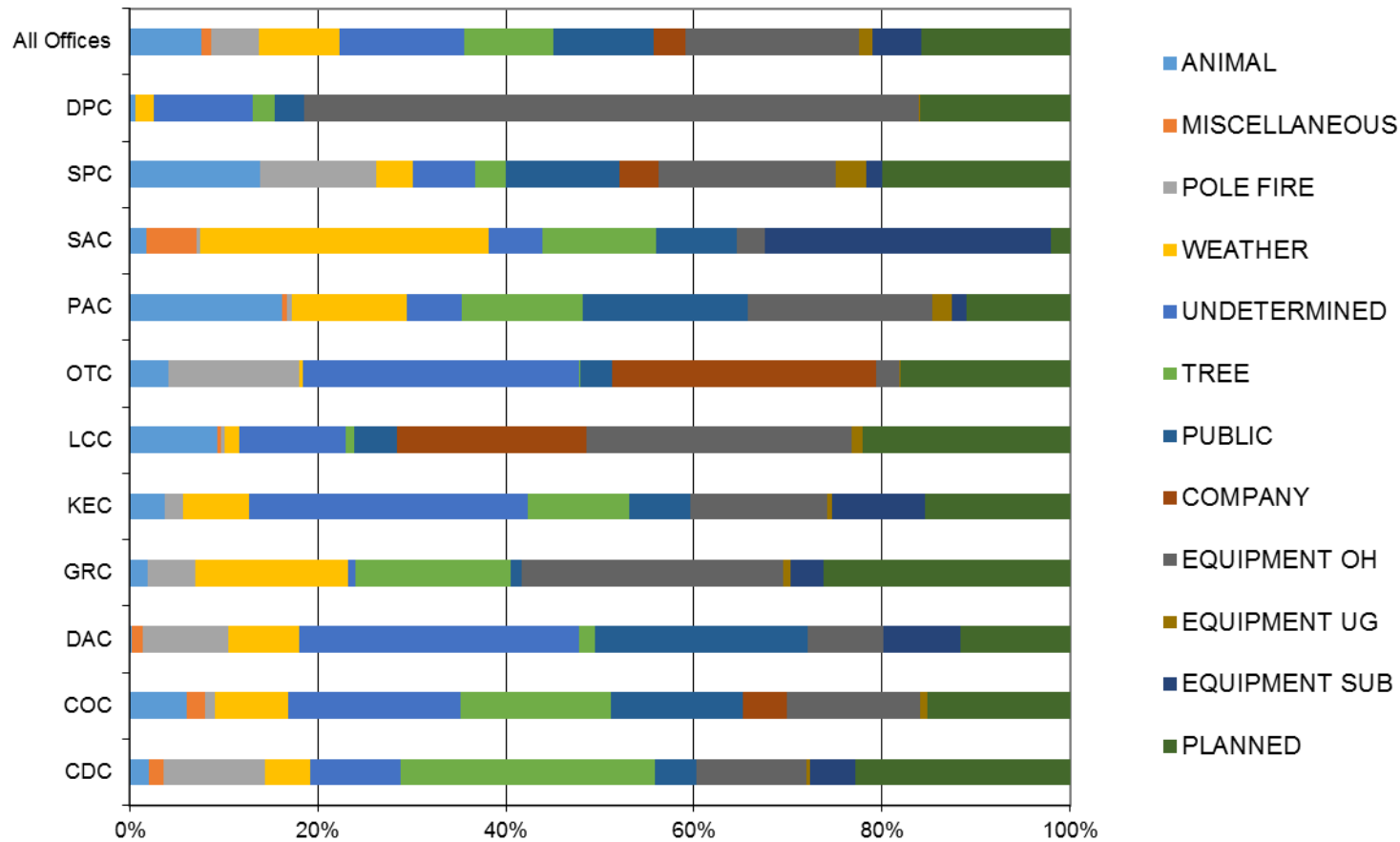
Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	2.0%	6.1%	0.2%	1.9%	3.8%	9.3%	4.1%	16.2%	1.8%	13.8%	0.6%	7.6%
MISCELLANEOUS	1.6%	2.0%	1.1%	0.0%	0.0%	0.4%	0.0%	0.4%	5.4%	0.1%	0.0%	1.0%
POLE FIRE	10.8%	1.0%	9.2%	5.0%	1.9%	0.5%	13.9%	0.6%	0.4%	12.3%	0.0%	5.1%
WEATHER	4.9%	7.8%	7.4%	16.4%	7.0%	1.5%	0.4%	12.1%	30.6%	3.8%	1.9%	8.6%
UNDETERMINED	9.6%	18.3%	29.8%	0.7%	29.6%	11.3%	29.4%	5.9%	5.7%	6.7%	10.6%	13.2%
TREE	27.0%	16.0%	1.7%	16.5%	10.8%	1.0%	0.1%	12.9%	12.1%	3.3%	2.3%	9.6%
PUBLIC	4.3%	14.1%	22.6%	1.2%	6.4%	4.5%	3.4%	17.6%	8.6%	12.0%	3.2%	10.6%
COMPANY	0.1%	4.7%	0.0%	0.0%	0.0%	20.2%	28.1%	0.0%	0.0%	4.1%	0.0%	3.3%
EQUIPMENT OH	11.7%	14.1%	8.0%	27.8%	14.6%	28.1%	2.5%	19.6%	2.9%	18.8%	65.4%	18.5%
EQUIPMENT UG	0.4%	0.7%	0.0%	0.8%	0.6%	1.3%	0.0%	2.1%	0.1%	3.3%	0.1%	1.4%
EQUIPMENT SUB	4.8%	0.0%	8.3%	3.5%	9.8%	0.0%	0.0%	1.5%	30.3%	1.6%	0.0%	5.2%
PLANNED	22.8%	15.2%	11.6%	26.2%	15.5%	22.0%	18.1%	11.0%	2.1%	20.0%	15.9%	15.8%

CDC Coeur d'Alene
 COC Colville
 DAC Davenport
 DPC Deer Park
 GRC Grangeville
 KEC Kellogg/ St. Maries

LCC Lewiston-Clarkston
 OTC Othello
 PAC Palouse
 SAC Sandpoint
 SPC Spokane

The following chart shows the percentage SAIFI contribution by causes for outages excluding major event days.

Chart 41 - % SAIFI per Cause by Office



The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

Table 27 - % SAIDI per Cause by Office

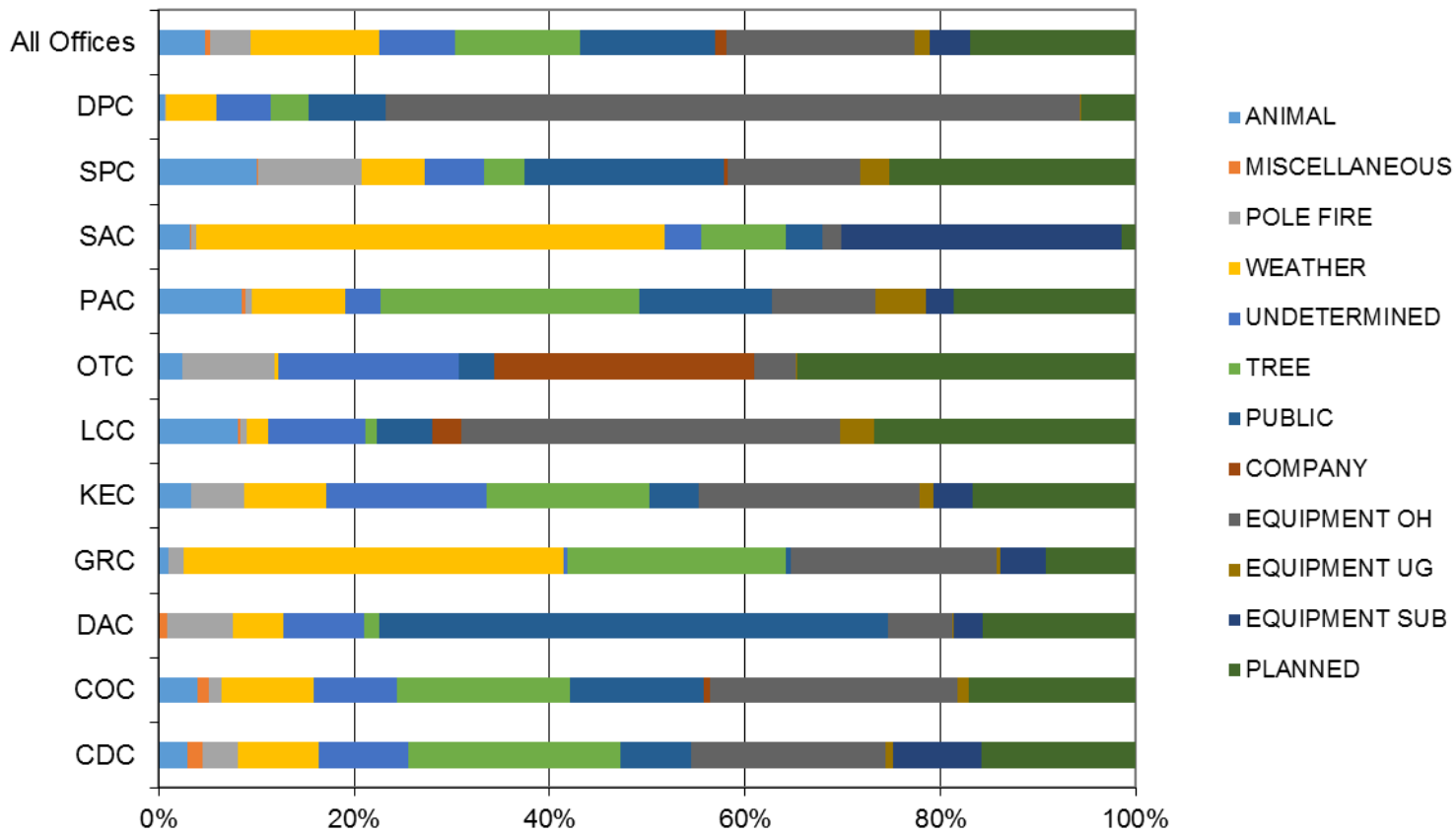
Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	2.9%	4.0%	0.1%	1.0%	3.3%	8.1%	2.3%	8.5%	3.1%	10.1%	0.6%	4.8%
MISCELLANEOUS	1.5%	1.2%	0.7%	0.0%	0.0%	0.2%	0.0%	0.5%	0.2%	0.1%	0.0%	0.4%
POLE FIRE	3.6%	1.3%	6.7%	1.6%	5.4%	0.7%	9.5%	0.5%	0.5%	10.6%	0.0%	4.2%
WEATHER	8.3%	9.5%	5.2%	38.9%	8.4%	2.1%	0.4%	9.6%	47.9%	6.5%	5.2%	13.2%
UNDETERMINED	9.2%	8.4%	8.3%	0.4%	16.4%	9.9%	18.4%	3.6%	3.7%	6.1%	5.6%	7.7%
TREE	21.7%	17.8%	1.5%	22.3%	16.7%	1.2%	0.1%	26.5%	8.7%	4.1%	3.9%	12.8%
PUBLIC	7.2%	13.7%	52.2%	0.5%	5.0%	5.6%	3.6%	13.7%	3.7%	20.4%	7.9%	13.8%
COMPANY	0.0%	0.6%	0.0%	0.0%	0.0%	3.0%	26.7%	0.0%	0.0%	0.4%	0.0%	1.2%
EQUIPMENT OH	19.8%	25.4%	6.6%	21.0%	22.6%	38.7%	4.3%	10.6%	1.9%	13.5%	71.1%	19.2%
EQUIPMENT UG	0.8%	1.1%	0.0%	0.4%	1.5%	3.5%	0.1%	5.2%	0.0%	2.9%	0.1%	1.7%
EQUIPMENT SUB	9.1%	0.0%	3.0%	4.7%	4.0%	0.0%	0.0%	2.8%	28.7%	0.1%	0.0%	4.0%
PLANNED	15.7%	17.1%	15.7%	9.2%	16.7%	26.8%	34.7%	18.7%	1.4%	25.1%	5.6%	17.0%

CDC Coeur d’Alene
 COC Colville
 DAC Davenport
 DPC Deer Park
 GRC Grangeville
 KEC Kellogg/ St. Maries

LCC Lewiston-Clarkston
 OTC Othello
 PAC Palouse
 SAC Sandpoint
 SPC Spokane

The following chart shows the percentage SAIDI contribution by causes for outages excluding major event days.

Chart 42 - % SAIDI per Cause by Office



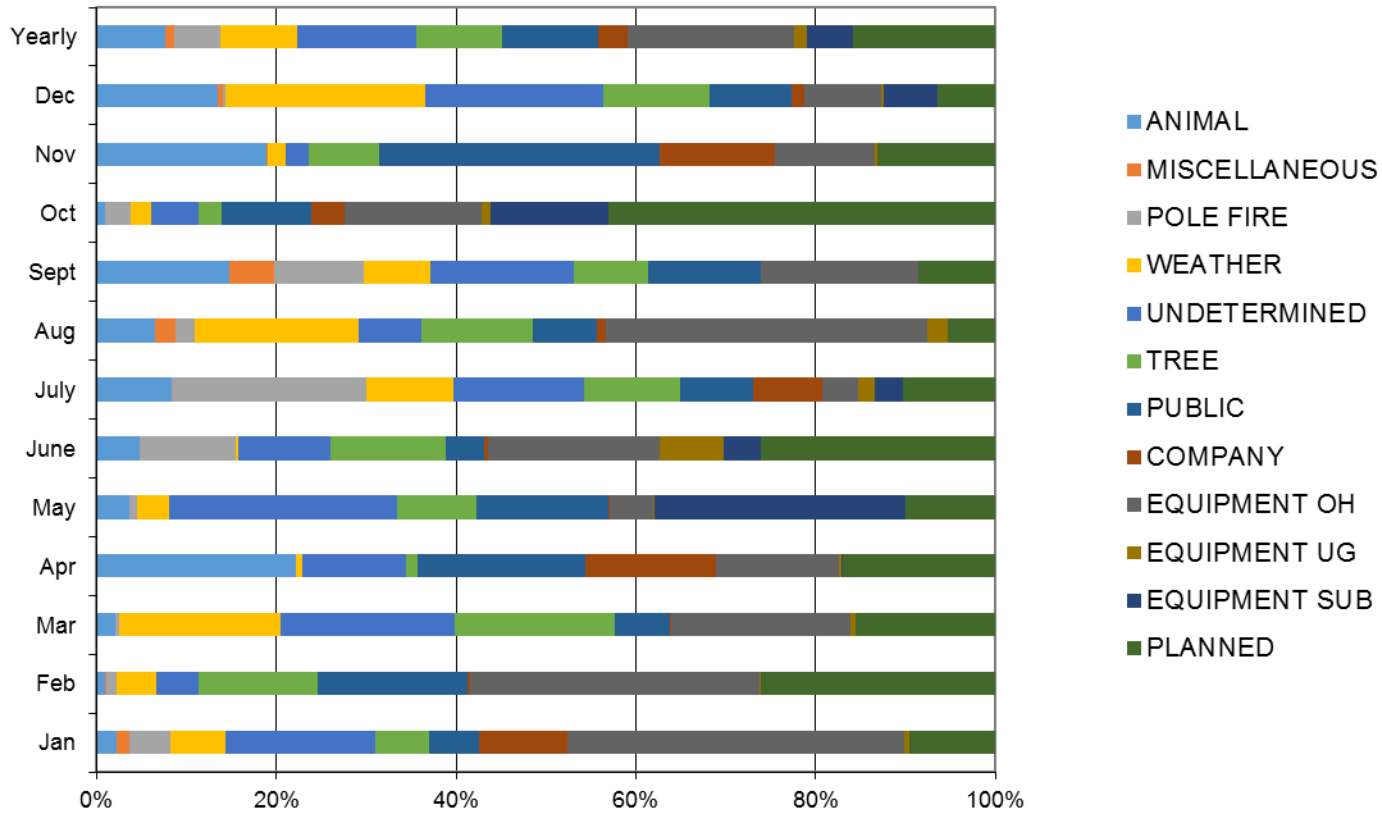
The following table lists the percentage SAIFI contribution by causes for all outages, excluding major event days.

Table 28 - % SAIFI per Cause by Month

Reason	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	2.2%	1.0%	2.0%	22.2%	3.7%	4.7%	8.4%	6.5%	14.8%	0.9%	18.9%	13.5%	7.6%
MISCELLANEOUS	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	4.9%	0.0%	0.1%	0.6%	1.0%
POLE FIRE	4.6%	1.2%	0.5%	0.0%	0.8%	10.8%	21.7%	2.2%	10.1%	2.8%	0.1%	0.2%	5.1%
WEATHER	6.0%	4.4%	18.0%	0.7%	3.6%	0.2%	9.6%	18.2%	7.4%	2.4%	1.9%	22.2%	8.6%
UNDETERMINED	16.7%	4.7%	19.3%	11.5%	25.3%	10.4%	14.6%	7.0%	15.9%	5.3%	2.6%	19.8%	13.2%
TREE	5.9%	13.3%	17.8%	1.2%	8.9%	12.8%	10.7%	12.4%	8.3%	2.5%	7.8%	11.9%	9.6%
PUBLIC	5.6%	16.7%	6.2%	18.7%	14.7%	4.3%	8.1%	7.1%	12.6%	10.0%	31.3%	9.0%	10.6%
COMPANY	9.7%	0.1%	0.0%	14.6%	0.1%	0.3%	7.6%	1.0%	0.0%	3.7%	12.8%	1.5%	3.3%
EQUIPMENT OH	37.5%	32.2%	20.0%	13.7%	4.9%	19.1%	4.1%	35.7%	17.5%	15.2%	11.1%	8.6%	18.5%
EQUIPMENT UG	0.6%	0.1%	0.5%	0.2%	0.1%	7.1%	1.8%	2.2%	0.1%	1.0%	0.3%	0.2%	1.4%
EQUIPMENT SUB	0.0%	0.0%	0.0%	0.1%	28.0%	4.1%	3.2%	0.0%	0.0%	13.2%	0.0%	6.1%	5.2%
PLANNED	9.6%	26.2%	15.6%	17.0%	10.0%	26.2%	10.3%	5.4%	8.6%	43.1%	13.2%	6.4%	15.8%

The following chart shows the percentage SAIFI contribution by causes for all outages, excluding major event days.

Chart 43 - % SAIFI per Cause by Month



The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

Table 29 - % SAIDI per Cause by Month

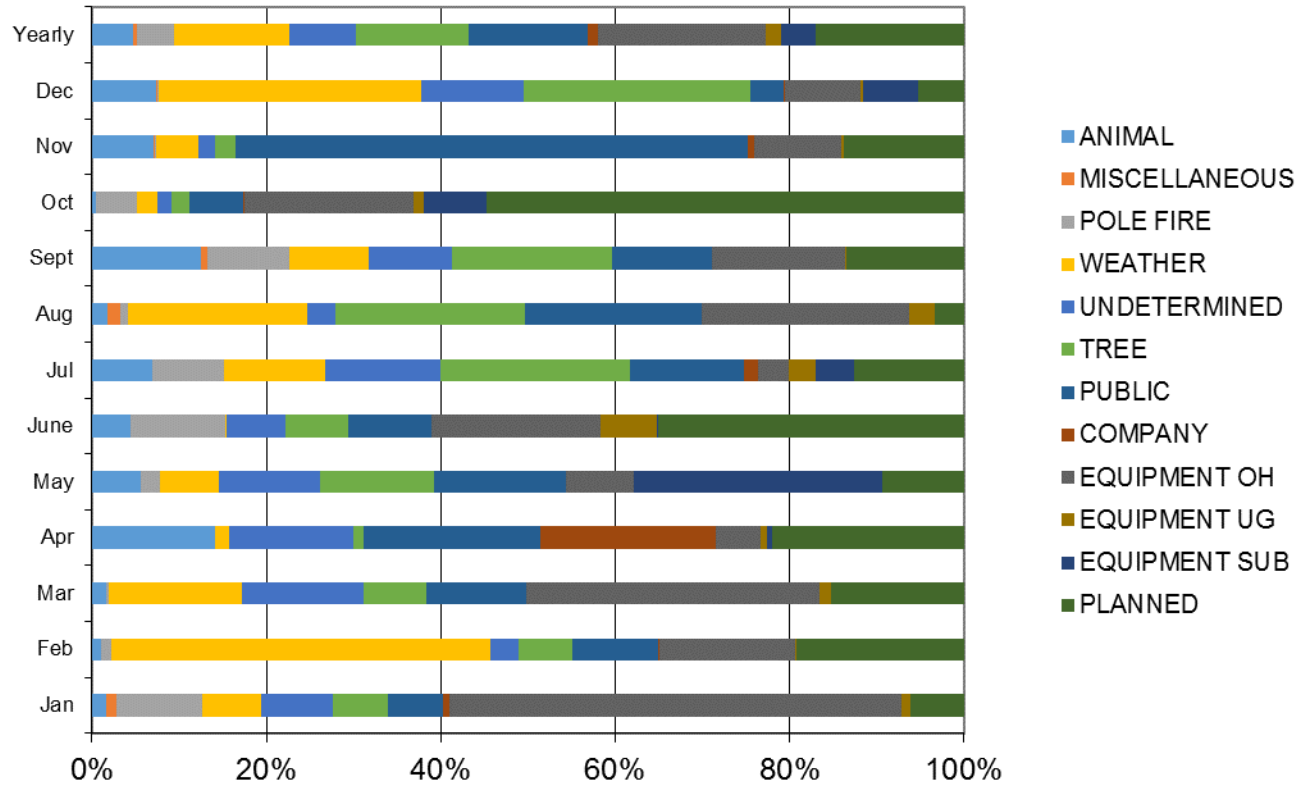
REASON	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	1.7%	1.0%	1.6%	14.2%	5.6%	4.4%	6.9%	1.8%	12.5%	0.5%	7.1%	7.3%	4.8%
MISCELLANEOUS	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.7%	0.0%	0.0%	0.1%	0.4%
POLE FIRE	9.7%	1.3%	0.3%	0.0%	2.2%	10.9%	8.3%	0.9%	9.4%	4.7%	0.2%	0.2%	4.2%
WEATHER	6.9%	43.4%	15.2%	1.5%	6.7%	0.2%	11.6%	20.6%	9.1%	2.4%	4.8%	30.1%	13.2%
UNDETERMINED	8.2%	3.3%	14.0%	14.3%	11.7%	6.7%	13.2%	3.2%	9.5%	1.6%	1.9%	11.7%	7.7%
TREE	6.3%	6.1%	7.3%	1.2%	13.1%	7.2%	21.7%	21.6%	18.4%	2.0%	2.3%	26.1%	12.8%
PUBLIC	6.3%	9.9%	11.4%	20.2%	15.1%	9.5%	13.1%	20.3%	11.5%	6.1%	58.8%	3.7%	13.8%
COMPANY	0.8%	0.1%	0.0%	20.1%	0.0%	0.1%	1.6%	0.0%	0.0%	0.3%	0.7%	0.2%	1.2%
EQUIPMENT OH	51.8%	15.5%	33.6%	5.2%	7.7%	19.3%	3.6%	23.7%	15.3%	19.3%	10.1%	8.7%	19.2%
EQUIPMENT UG	1.1%	0.1%	1.4%	0.8%	0.1%	6.5%	3.1%	3.0%	0.2%	1.1%	0.3%	0.3%	1.7%
EQUIPMENT SUB	0.0%	0.0%	0.0%	0.6%	28.4%	0.2%	4.4%	0.0%	0.0%	7.3%	0.0%	6.3%	4.0%
PLANNED	6.1%	19.2%	15.2%	22.0%	9.4%	35.0%	12.6%	3.4%	13.4%	54.7%	13.7%	5.3%	17.0%

Table 30 – Average Outage Time (HH:MM)

REASON	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Yearly
ANIMAL	2:32	2:51	1:50	1:22	3:24	1:53	1:46	0:59	1:48	1:19	1:01	1:27	1:36
COMPANY	0:15	2:32	1:17	2:58	0:51	0:26	0:26	0:06	0:52	0:10	0:09	0:19	0:55
EQUIPMENT OH	4:31	1:20	3:51	0:48	3:31	2:04	1:53	2:19	1:52	3:20	2:27	2:43	2:39
EQUIPMENT SUB				10:05	2:16	0:07	2:57			1:28		2:47	1:59
EQUIPMENT UG	5:59	2:38	6:05	7:20	3:24	1:53	3:46	4:43	6:22	3:03	3:00	4:19	3:08
MISCELLANEOUS	2:28	0:53	1:26					2:07	0:19	1:43	0:53	0:37	1:05
PLANNED	2:04	2:02	2:14	2:47	2:06	2:45	2:38	2:11	3:21	3:20	2:48	2:12	2:45
POLE FIRE	7:00	2:54	1:23		6:24	2:05	0:49	1:31	2:00	4:25	5:40	2:41	2:05
PUBLIC	3:40	1:39	4:12	2:20	2:17	4:35	3:29	9:57	1:57	1:37	5:04	1:05	3:19
TREE	3:28	1:17	0:56	2:11	3:18	1:09	4:22	6:05	4:46	2:06	0:49	5:54	3:26
UNDETERMINED	1:36	1:55	1:40	2:40	1:01	1:20	1:57	1:37	1:16	0:49	1:55	1:35	1:30
WEATHER	3:43	27:26	1:56	4:27	4:10	2:19	2:37	3:58	2:38	2:38	6:51	3:37	3:55

The following chart shows the percentage SAIDI contribution by causes for outages excluding major event days.

Chart 44 - % SAIDI per Cause by Month



9. Momentary Interruption Causes

The cause for many momentary interruptions is unknown. Because faults are temporary, the cause goes unnoticed even after the line is patrolled. Momentary outages are recorded using our SCADA system (System Control and Data Acquisition). On average, about 88% of Avista's customers are served from SCADA controlled stations.

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

Table 31 - % MAIFI per Cause by Office

Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	0.92%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.23%
POLE FIRE	0.00%	0.00%	1.43%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.11%
WEATHER	24.49%	12.87%	4.39%	10.24%	8.57%	4.62%	2.80%	33.39%	20.56%	8.68%	0.00%	16.11%
PUBLIC	0.00%	0.00%	3.46%	0.00%	5.41%	0.00%	0.00%	0.32%	2.55%	0.00%	0.00%	0.95%
COMPANY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.78%	0.12%
UNDETERMINED	74.59%	83.13%	73.57%	81.96%	84.49%	95.38%	79.55%	61.91%	76.63%	67.28%	30.57%	75.34%
EQUIPMENT OH	0.00%	0.00%	5.13%	6.10%	0.00%	0.00%	0.00%	0.00%	0.00%	9.28%	0.00%	1.61%
PLANNED	0.00%	0.00%	1.77%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	19.79%	0.63%
FORCED OUTAGE/SWITCHING	0.00%	4.00%	8.83%	1.69%	0.00%	0.00%	17.65%	4.38%	0.27%	14.76%	44.86%	4.68%
FORCED	0.00%	0.00%	1.43%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.11%
TRANSMISSION	0.00%	0.00%	0.00%	0.00%	1.53%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%

CDC	Coeur d'Alene	LCC	Lewiston-Clarkston
COC	Colville	OTC	Othello
DAC	Davenport	PAC	Palouse
DPC	Deer Park	SAC	Sandpoint
GRC	Grangeville	SPC	Spokane
KEC	Kellogg/ St. Maries		

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

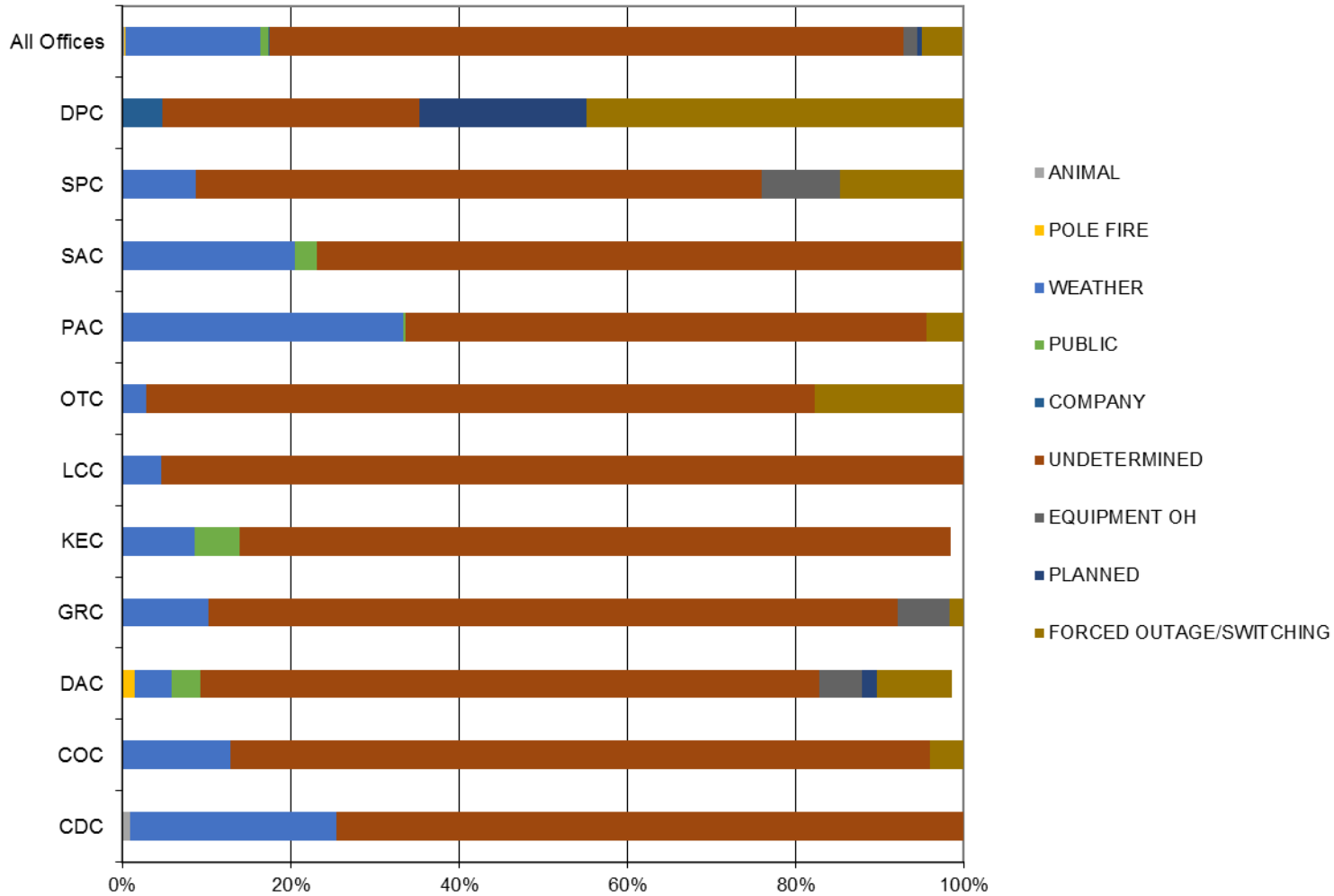
Table 32 - % MAIFI per Cause by Office (Washington Only)

Reason	COC	DAC	DPC	LCC - WA	OTC	PAC - WA	SPC	All Offices
COMPANY	0.0%	0.0%	4.8%	0.0%	0.0%	0.0%	0.0%	0.3%
POLE FIRE	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
PUBLIC	0.0%	3.5%	0.0%	0.0%	0.0%	0.7%	0.0%	0.7%
UNDETERMINED	83.1%	73.6%	30.6%	94.6%	79.5%	50.3%	67.3%	72.4%
WEATHER	12.9%	4.4%	0.0%	5.4%	2.8%	44.8%	8.7%	12.1%
EQUIPMENT OH	0.0%	5.1%	0.0%	0.0%	0.0%	0.0%	9.3%	2.9%
PLANNED	0.0%	1.8%	19.8%	0.0%	0.0%	0.0%	0.0%	1.4%
FORCED	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
FORCED OUTAGE/SWITCHING	4.0%	8.8%	44.9%	0.0%	17.7%	4.1%	14.8%	9.8%
Grand Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

COC	Colville	OTC	Othello
DAC	Davenport	PAC-WA	Palouse Washington
DPC	Deer Park	SPC	Spokane
LCC-WA	Lewiston-Clarkston Washington		

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.

Chart 45 - % MAIFI per Cause by Office



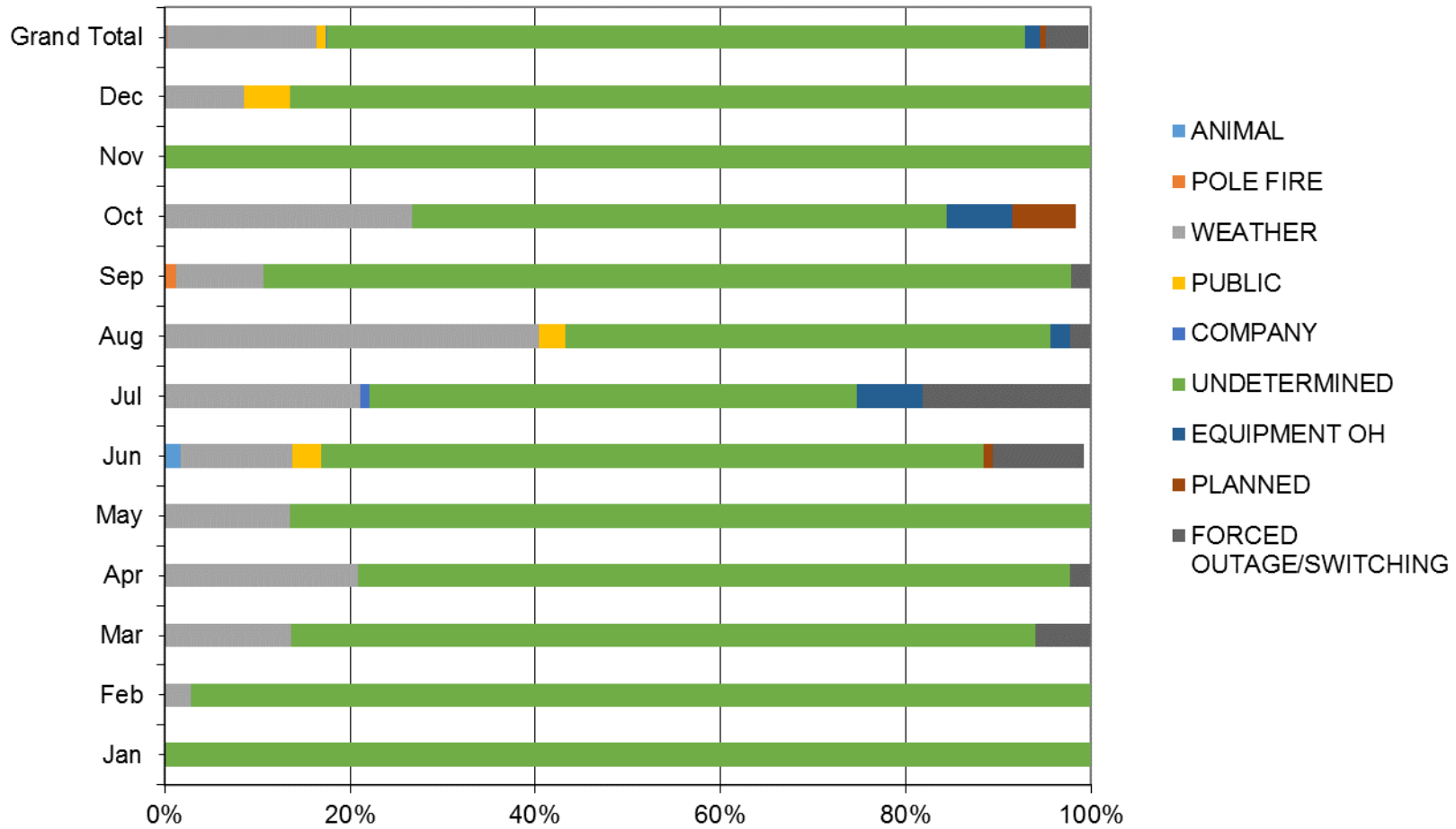
The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

Table 33 – % MAIFI per Cause by Month

Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
ANIMAL	0.00%	0.00%	0.00%	0.00%	0.00%	1.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.23%
POLE FIRE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.21%	0.00%	0.00%	0.00%	0.11%
WEATHER	0.00%	2.85%	13.66%	20.91%	13.48%	12.06%	21.15%	40.35%	9.45%	26.75%	0.00%	8.57%	16.11%
PUBLIC	0.00%	0.00%	0.00%	0.00%	0.00%	3.18%	0.00%	2.89%	0.00%	0.00%	0.00%	4.93%	0.95%
COMPANY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.99%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%
UNDETERMINED	100.00%	97.15%	80.35%	76.81%	86.52%	71.52%	52.53%	52.34%	87.17%	57.62%	100.00%	86.51%	75.34%
EQUIPMENT OH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.17%	2.17%	0.00%	7.09%	0.00%	0.00%	1.61%
PLANNED	0.00%	0.00%	0.00%	0.00%	0.00%	0.98%	0.00%	0.00%	0.00%	6.86%	0.00%	0.00%	0.63%
FORCED OUTAGE/SWITCHING	0.00%	0.00%	5.98%	2.28%	0.00%	9.78%	18.16%	2.25%	2.17%	0.00%	0.00%	0.00%	4.68%
FORCED	0.00%	0.00%	0.00%	0.00%	0.00%	0.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.11%
TRANSMISSION	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.67%	0.00%	0.00%	0.12%

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.

Chart 46 - % MAIFI per Cause by Month



10. Interruption Cause Codes

Cause code information is provided in this report to give readers a better understanding of outage sources. Further, the Company uses cause information to analyze past outages and, if possible, reduce the frequency and duration of future outages.

Since 2011, Avista has stopped using the subcategory “protected” under the “Animal” category. Almost all birds are considered protected, so there is little differentiation between the “Bird” and “Protected” subcategories. Avista will include additional information in the Remarks section as reported from the field personnel. .

Table 34 – Interruption Cause Codes

MAIN CATEGORY	SUB CATEGORY	Definition
ANIMAL	Bird Squirrel Underground Other	Outages caused by animal contacts. Specific animal called out in sub category.
PUBLIC COMPANY	Car Hit Pad Car Hit Pole Dig In Fire Tree Other Dig in Other	Underground outage due to car, truck, construction equipment etc. contact with pad transformer, junction enclosure etc... Overhead outage due to car, truck, construction equipment etc. contact with pole, guy, neutral etc. Dig in by a customer, a customer’s contractor, or another utility. Outages caused by or required for a house/structure or field/forest fire. Homeowner, tree service, logger etc. fells a tree into the line. Other public caused outages Dig in by company or contract crew. Other company caused outages

EQUIPMENT OH	Arrestors Capacitor Conductor - Pri Conductor - Sec Connector - Pri Connector - Sec Crossarm- rotten Cutout / Fuse Insulator Insulator Pin Other Pole - Rotten Recloser Regulator Switch / Disconnect Transformer - OH Wildlife Guard	Outages caused by equipment failure. Specific equipment called out in sub category. Wildlife guard failed or caused an outage
EQUIPMENT UG	URD Cable - Pri URD Cable- Sec Connector - Sec Elbow Junctions Primary Splice Termination Transformer - UG Other	Outages caused by equipment failure. Specific equipment called out in sub category.
EQUIPMENT SUB	High side fuse Bus Insulator High side PCB High side Swt / Disc Lowside OCB/Recloser Low side Swt / Disc Relay Misoperation Regulator Transformer Other	
MISCELLANEOUS		For causes not specifically listed elsewhere
NOT OUR PROBLEM <i>(Outages in this category are not included in reported statistics)</i>	Customer Equipment Other Utility	Customer equipment causing an outage to their service. If a customer causes an outage to another customer this is covered under Public. Outages when another utility's facilities cause an outage on our system.
POLE FIRE		Used when water and contamination causes insulator leakage current and fire. If insulator is leaking due to material failure list under equipment failure. If cracked due to gunfire use customer caused other.

PLANNED TREE UNDETERMINED	Maintenance / Upgrade Forced Tree fell Tree growth Service Weather	<p>Outage, normally prearranged, needed for normal construction work.</p> <p>Outage scheduled to repair outage damage.</p> <p>For outages when a tree falls into distribution primary/secondary or transmission during normal weather.</p> <p>Tree growth causes a tree to contact distribution primary/secondary or transmission during normal weather.</p> <p>For outages when a tree falls or grows into a service.</p> <p>When snow and wind storms causes a tree or branch to fall into, or contact the line. Includes snow loading and unloading.</p> <p>Use when the cause cannot be determined.</p>
WEATHER	Snow / Ice Lightning Wind	<p>Outages caused by snow or ice loading or unloading on a structure or conductor. Use weather tree for snow and ice loading on a tree.</p> <p>Lightning flashovers without equipment damage. Equipment failures reported under the equipment type.</p> <p>Outages when wind causes conductors to blow into each other, another structure, building etc.</p>

11. Areas of Concerns

As in previous years, Colville continues to have the lowest reliability of Washington’s operating areas. However, the Colville area continues to show improvement over previous years as work plans are implemented. Colville was judged lowest based on its performance in the yearly indices for SAIFI, SAIDI, CAIDI, and MAIFI. Within the Colville area, four feeders were identified as the Areas of Concern for 2016. Additionally, one feeder in the Spokane area and one in the Palouse area are included as areas of concern. These feeders are Gifford 34F1, Gifford 34F2, Colville 34F1, and Spirit 12F1 in the Colville Area, Colbert 12F2 in the Spokane area, and East Colfax 222. Both non-Colville area feeders are new areas of concern for 2016 while the remaining feeders have been identified in previous reports.

Cause Information

Generally, rural areas have a greater number of outages per customer. Colville is predominately rural and most feeders traverse forested areas. There are approximately 2,417 miles of distribution line exposed to weather, underground cable failures and tree problems. Unlike most of the Company’s system, lines in this area are built on the narrow, cross-country rights-of-way, typical of PUD construction practices prior to Avista acquiring the system. These conditions make patrolling, tree trimming, rights-of-way

clearing and other maintenance difficult. When cost effective, Avista moves sections of these overhead lines to road rights-of-way and/or converts them to underground.

Further, when outages occur in rural areas, the time required to repair damage is longer. More time is required for first responders to arrive and assess the damage and more time is required for the crew to reach the site. Often the damage is off road and additional time is required to transport materials and equipment to the site.

Snow loading on green healthy trees growing beyond the rights-of-way often causes them to bend or break and contact distribution lines. These trees are not cut as part of our vegetation management program because they are outside our rights-of-way and are considered healthy marketable timber.

Colbert 12F2 becoming an area of concern in 2016 was primarily due to three prolonged whole-feeder outages due to separate equipment failures. East Colfax 222 becoming an area of concern in 2016 was primarily due one prolonged whole-feeder outages due to a fallen tree. Due to the nature of these events, neither of these feeders are expected to continue to be areas of concern in the future.

Listed below is a summary of the specific cause data for each feeder. This is a compilation of data from the Avista OMT and the reporting from our local servicemen to Distribution Dispatch. Data from the reporting system is shown as a percentage of total customer outage hours for that feeder.

Colville 34F1

ANIMAL	4.2%
COMPANY	0.8%
PUBLIC	5.0%
TREE	5.0%
UNDETERMINED	37.8%
WEATHER	7.6%
EQUIPMENT OH	14.3%
EQUIPMENT UG	3.4%
PLANNED	21.8%

Colbert 12F2

ANIMAL	51.6%
PUBLIC	3.2%
TREE	9.7%
UNDETERMINED	3.2%
WEATHER	9.7%
EQUIPMENT OH	12.9%
PLANNED	9.7%

East Colfax 222

ANIMAL	8.6%
PUBLIC	8.6%
TREE	8.6%
UNDETERMINED	5.7%
WEATHER	2.9%
EQUIPMENT OH	5.7%
PLANNED	60.0%

Gifford 34F1

ANIMAL	9.1%
COMPANY	3.6%
POLE FIRE	3.6%
PUBLIC	1.8%
TREE	12.7%
UNDETERMINED	16.4%
WEATHER	12.7%
EQUIPMENT OH	16.4%
PLANNED	23.6%

Gifford 34F2

ANIMAL	2.5%
COMPANY	7.4%
PUBLIC	4.9%
TREE	14.8%
UNDETERMINED	13.6%
WEATHER	17.3%
EQUIPMENT OH	6.2%
EQUIPMENT UG	2.5%
PLANNED	30.9%

Spirit 12F1

ANIMAL	4.4%
COMPANY	0.9%
PUBLIC	5.3%
TREE	8.8%
UNDETERMINED	8.8%
WEATHER	7.0%
EQUIPMENT OH	4.4%
EQUIPMENT UG	1.8%
PLANNED	58.8%

Colville Area Work Plans

The improvement work that has been accomplished or planned for historically low reliability feeders in the Colville area is listed below. The Company's reliability working group is continuing to study these feeders to develop additional work plans. Each of the

identified feeders also had planned outages that correspond to the maintenance and replacement activities in the area.

Gifford 34F1

- Storm damage to lines led an effort to reconductor sections to 2/0 ACSR in 2012.
- A recloser is budgeted to be installed in 2014/2015 that will allow for better sectionalizing between the northern and southern sections of the feeder during outage events.
- \$167k was spent in 2014 to replace two miles of overhead distribution line with underground cable.
- \$250k was spent to reconductor two miles of overhead distribution line in 2015.
- Existing feeder will be split into two separate feeders; work to be completed in 2017.

Gifford 34F2

- Due to Cultural review issues on some of the Tribal lands only 3,000 feet of overhead conductor was replaced in 2010. Continued work and negotiations for the remaining 5,000 feet occurred in 2011. Final work was completed in 2012.
- Vegetation Management work planned for 2012 was re-prioritized to 2011 after circuit assessment showed a large number of dead or dying trees within radius of contact of our lines. Line clearance crews trimmed 651 trees and removed 867 trees in 2011.
- \$167k was spent in 2014 to reconductor two miles of overhead distribution lines.
- \$250k was budgeted to reconductor two miles of overhead distribution lines in 2015; however, project was been moved to 2017.

Colville 34F1

- Vegetation Management crews were called to trim three trees and remove 59 trees as “unplanned” work on this circuit in 2011. A fall 2011 assessment of this circuit showed a significantly high mortality rate of trees within radius of contact of lines on the feeder. A line clearance crew began Risk Tree mitigation work on this circuit in February, 2012.
- \$100k was spent in 2011 to replace outage prone overhead sections with URD cable.
- \$62k was spent to install wild life guards in 2011. Approximately 65% of the CLV12F1 feeder was completed in 2011. Remaining work was completed in 2012.
- \$250k was spent in 2013 to replace overhead line sections with URD cable to reduce tree exposure.
- \$50k was spent in 2013 to install a recloser to allow for better outage sectionalizing.
- \$250k was budgeted to reconductor two miles of overhead distribution line in 2015; however, project was moved to 2017.

Spirit 12F1

- Feeder was part of the Grid Modernization program in 2014. Additional Grid Modernization work on this feeder was scheduled to take place in 2016. Feeder will also have reconductor and fusing work performed as well as other upgrades that may improve reliability. Three reclosers will be added in 2017 as part of finishing up the grid mod process.

Table 35 – Colville Area Major Reliability Projects by Feeder

Feeder	Decisions/ basis	2016	2017 and Beyond
Gifford 34F1	Reliability improvements	Begin split into 2 shorter feeders.	Complete feeder split
Gifford 34F2	Reliability improvements	Reconductor work	No work planned in the next 5 years.
Colville 34F1	Reliability improvements	Reconductor work	No work planned in the next 5 years.
SPI12F1	Reliability Improvements	Grid Modernization Program Feeder	Finish Grid Modernization in 2017

Table 36 – Colville Area Historical & Proposed Future Reliability Projects by Feeder

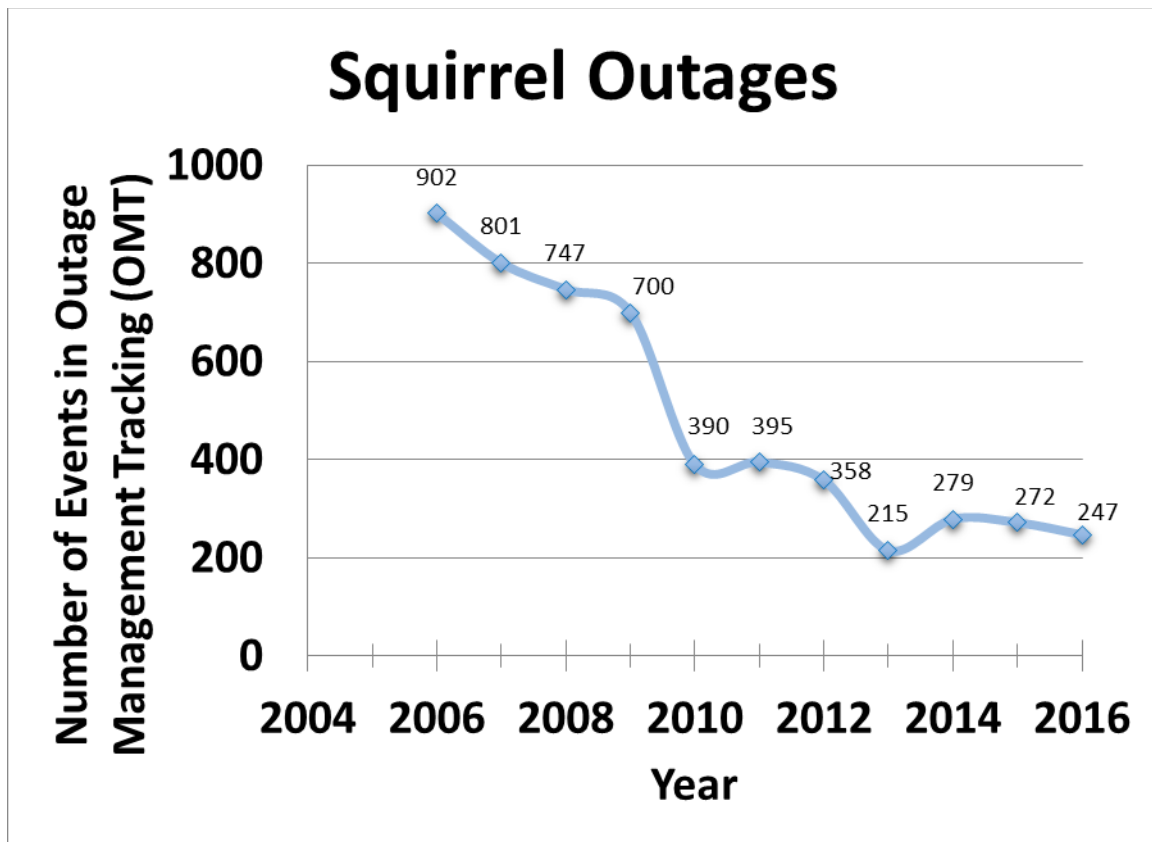
Feeder Name	Last WPM Insp.	Proposed WPM Inspection	Proposed WPM Follow-up	Transformer Change-outs	Last Veg. Mgmt.	Veg. Mgmt. Proposed Year	Wildlife Guards Proposed Year
GIF34F1	2011-2014	25% per year for 4 years	25% in 2012 25% in 2013 25% in 2014 25% in 2015	18 in 2014	2009	2015	Last 2011 N/A on Proposed
GIF34F2	1995	Past 2018 Plan AM will need to project	N/A	69 in 2013/2014	2011	2016	N/A
CLV34F1	2007	2027 20 year cycle	2028	49 in 2015	2007	2013	Last 2011 N/A on Proposed
VAL12F1	2010	2030 20 year cycle	Completed in 2011 (except for WSDOT ROW poles)	188 in 2013/2014	2010	2016	N/A
SPI12F1	2013	2033 20 year cycle	Grid Modernization Project	6 in 2013	2011	2016	N/A
VAL12F3	1998	2019 20 year cycle	2020	22 changed out since 2010 38 more by end of 2016	2010	2015	N/A

12. System Wide Work Plans

Material records show that some wildlife guards were installed on new distribution transformers installations starting in the mid 1980's. With the recognition of increases in animal caused outages, new materials and improvements have been made in the construction standards for new distribution transformer installations to reduce these types of outages. Initial indications show that the outage reduction on a feeder after wildlife guards are installed is significant.

2009 was the start of the multiyear wildlife guard installation program to reduce the squirrel and bird related outages on approximately sixty feeders in Washington and Idaho. Most of the wildlife guards were installed with a hot stick on existing transformers that do not have an existing wildlife guard.

Chart 47 – Historical Squirrel Related Outage Events



Asset Management in conjunction with the Wood Pole Management Program over the last four years has stubbed/reinforced or replaced numerous poles, replaced numerous pole top transformers and associated cutouts/arresters. Chart 48 and 49 below summarizes the Wood Pole Management activities.

Chart 48 – Historical Wood Pole Management Related Outage Events

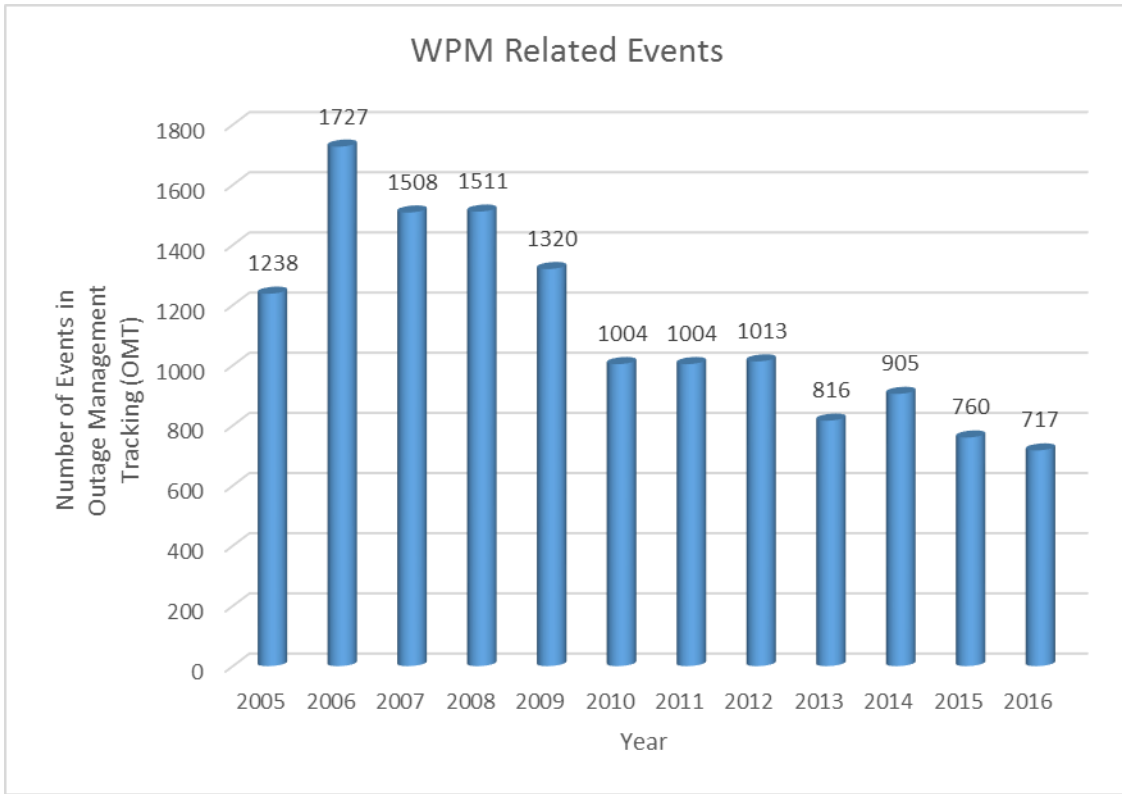
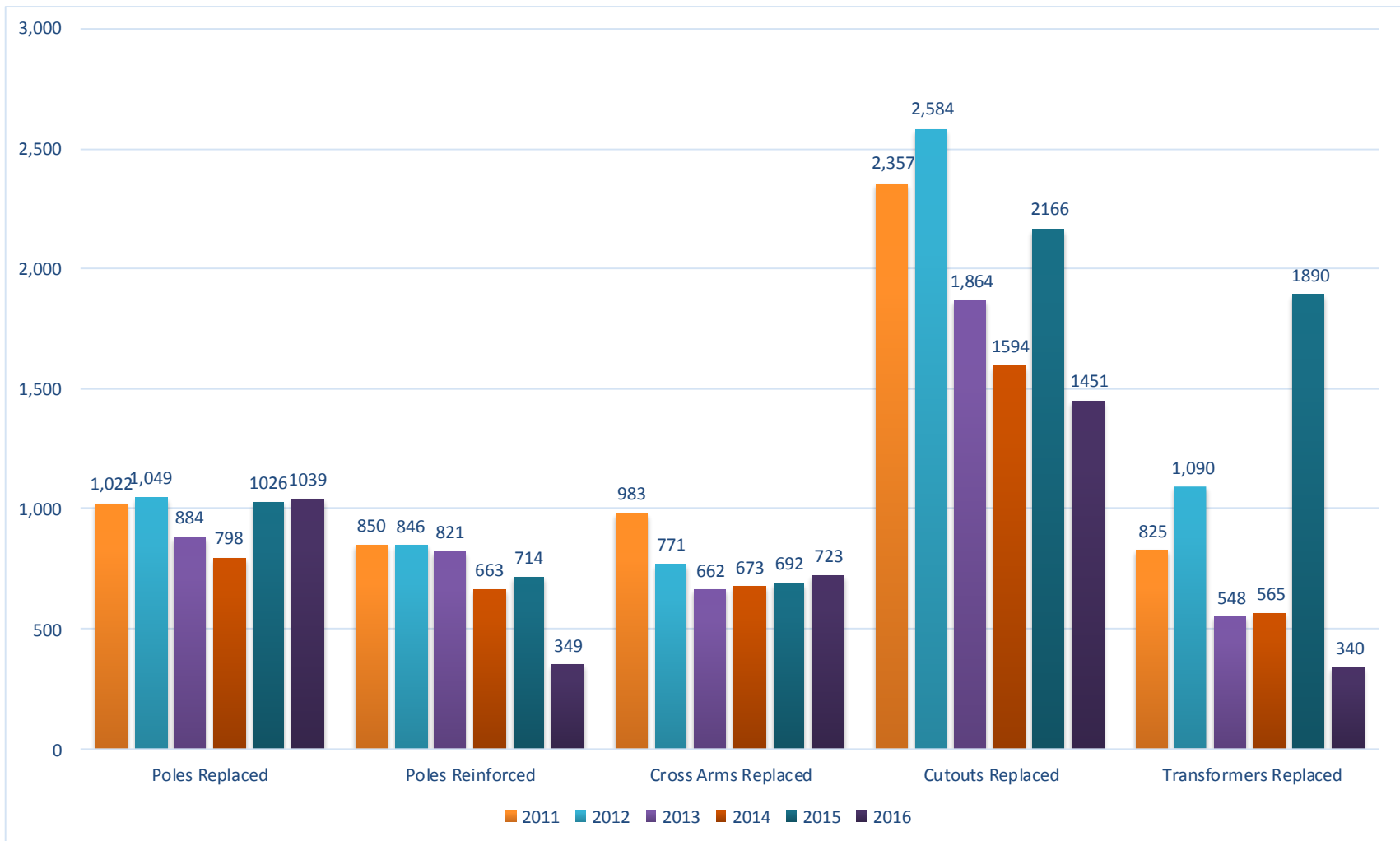


Chart 49 – Wood Pole Management Activities



13. Grid Modernization Program Overview

Beginning in 2004, Avista increased its emphasis on asset management with a focused analysis of total lifecycle costs, equipment reliability, maintenance expenses, and capital versus O&M spending. Reviews and analysis of specific equipment classes were prioritized based on historical failure rates, risk, and potential consequences. The results of these efforts led to the creation of a systemic Feeder Rebuild program with three primary objectives, specifically the reduction of maintenance expenses, reduction of energy losses, and increasing system reliability. For the identified feeders, the program's implementation included the addition of automated capacitor banks, replacement of high loss distribution transformers, and replacement of high loss conductors. The feeders were systematically rebuilt and data collected to determine overall effectiveness of the program.

Subsequent to the Feeder Rebuild program, Avista engineers began to utilize a Distribution Reliability and Energy Efficiency (DREE) program that could be considered as first defining the specific drivers for the opportunities, needs, and benefit considerations of a smart grid system. Using newly available sensors and systems to gain additional understanding and control of the distribution networks was found to provide an array of savings for the customer in long term O&M costs, increased reliability, and improved system efficiency. The DREE program leveraged geographic information and outage management systems installed several years prior, and was incorporated under a distribution management system integrated with additional sensors, switches, and controllers located throughout the grid.

The American Recovery and Reinvestment Act of 2009 (ARRA) provided the Office of Electricity and Energy Reliability within the U.S. Department of Energy (DOE) with \$4.5 billion to support modernization of the electric power grid and to fund Title XIII of the Energy Independence and Security Act of 2007. These funds were to be allocated by the DOE as grants to utilities to begin building and deploying the requisite smart grid infrastructure.

According to Section 3 of the ARRA, the purposes of the Act included:

- To preserve and create jobs and promote economic recovery.
- To assist those most impacted by the recession.
- To provide investments needed to increase economic efficiency by spurring technological advances in science and health.
- To invest in transportation, environmental protection, and other infrastructure that will provide long-term economic benefits.
- To stabilize State and local government budgets, in order to minimize and avoid reductions in essential services and counterproductive state and local tax increases.

In October 2009, through an open application process, the DOE selected and announced grant-based awards for 99 SGIG projects and 32 SGDP projects. As part of the DOE award process, Avista was selected to receive a \$20 million matching grant for a Smart Grid Investment Grant project to upgrade portions of its electric distribution system with

integrated smart grid equipment and associated technologies. The Company committed an additional \$22 million toward the project costs. The project, internally identified as the Smart Circuits project, significantly enhanced 58 electric distribution feeders and 14 substations in the greater Spokane area. The updated feeders demonstrated reduced energy losses from electric line loss, improved reliability, and increased operational efficiency of this portion of the feeder system. The substation upgrades included intelligent transformers, line devices, and control system software to enable smart grid capabilities. Tangential benefits included reducing the requirement for additional energy resources and a decrease in greenhouse gas emissions. The upgraded distribution feeders were primarily located in high-density population areas of north and south Spokane, serving approximately 110,000 customers.

Additionally, and in conjunction with the DOE award process, Avista participated in a Smart Grid Demonstration Project that created the first “smart community” in the Pacific Northwest, located in the City of Pullman Washington and the nearby area. The funds for the \$38 million project were a portion of a larger \$178 million DOE grant for the Pacific Northwest Smart Grid Demonstration project that was administered by the Battelle Memorial Institute²⁴. Avista’s designated portion of the matching funds was approximately \$13.1 million. Avista, in conjunction with several other companies including Itron, Hewlett-Packard (now Agilent), Spirea, and Washington State University, used this project to illustrate how a system with the ability to share information between the utility and its customers can achieve the benefits of a functional smart grid. Avista’s contribution to the project helped to transform Pullman into a “smart city” by providing the Advanced Metering Infrastructure, including 13,000 smart electric meters and 5,000 natural gas encoder receiver transmitters, placed at customers’ homes and businesses. In the homes of a subset of residential customers, Avista also installed smart thermostats with the capability to display energy consumption information for the customer and to also communicate that data to Avista through the AMI communication network. Battelle Memorial Institute’s Technology Performance Report noted this project “was one of the largest and most comprehensive demonstrations of electricity grid modernization ever completed.” (Hammerstrom, 2015, p. iii)

Referencing back to Avista’s original Feeder Rebuild program, 100% of the Smart Grid Investment Grant project costs in Spokane and approximately 60% of the Smart Grid Demonstration Project costs in Pullman would likely have been expended under the original rebuild program. The timeliness and availability of the ARRA grants allowed these investments in Avista’s infrastructure and the related system-wide benefits to be made at a 50% discount to Avista customers.

The success of both the SGIG and SGDP projects has led Avista to develop a systematic approach to feeder expansion and extensions. The premise of this Grid Modernization

²⁴ The Battelle Memorial Institute is an international science and technology enterprise that explores emerging areas of science, develops and commercializes technology, and manages laboratories for customers. Battelle supports community and education programs to promote an enhanced quality of life for its community neighbors. The Battelle Memorial Institute’s Pacific Northwest Division operates the Pacific Northwest National Laboratory.

program is to consider all necessary upgrades to the feeder infrastructure at one time, essentially optimizing the investments by merging the objectives of the Wood Pole Management, Smart Grid, and the Feeder Rebuild programs. With over 340 feeders in its Washington and Idaho service territories, this program intends to upgrade six feeders each year. Each feeder will be individually assessed to determine the suitable level of automation and smart technologies, like those deployed through SGIG and SGDP projects, will be installed as appropriate. The following are the primary objectives of the Grid Modernization program.

Grid Modernization Program Objectives

- Safety – Focus on safe practices for crew work by designing work plans to avoid safety risks.
- Reliability – Replacing aging and failed infrastructure that has a high likelihood of creating an unplanned crew call-out.
- Energy Savings – Replace equipment that has high energy losses with new equipment that is more energy efficient and improve the overall feeder energy performance.
- Operational Ability – Replace conductor and equipment that hinders outage detection and install smart grid devices that enable isolation of outages.

14. System Wide Vegetation Management Plan

Avista has an annual vegetation management plan and budget to accomplish the plan. The budget is allocated into distribution, transmission, administration, and gas line re-clearing.

Distribution

Avista's distribution system is managed by Avista's Utility Arborist. Every distribution circuit is scheduled to be line clearance pruned on a regular maintenance cycle of four to six years depending on tree species, growth rates, and densities. The program also identifies risk trees system wide every two years or more often as needed due to tree mortality rates, storms, fires, etc... Risk tree management includes:

- Improved mid-cycle (two to three years after planned maintenance work is completed) Risk Tree assessment and mitigation on circuits in our more heavily vegetated areas (such as the Colville Division).
- Herbicide program to assess and address needed work on each circuit over a five year cycle (three years after line clearance work performed).

Transmission

The transmission system is managed by Avista's forester. All 230 kV lines are patrolled annually for hazard trees and other issues, and mitigation is done in that same year. Approximately one third of the 115 kV transmission system is patrolled annually for hazard tree identification and assessment of right-of-way clearing needs. Right-of-way clearing maintenance is scheduled and performed approximately every ten to fifteen years (for each line). Interim spot work is done as identified and needed. Engineering specifications for

various voltages, line configurations are followed when clearing the right-of-way. Currently, the work is bid to a variety of contractors.

Appendix A - Definitions

"Baseline reliability statistic" – Avista will compare its reliability statistics to the year 2005.

"Commission Complaint" – When a customer is not satisfied with the Company as it relates to Electric Reliability and files a complaint directly with the Commission.

"Customer Complaint" - When a customer is not satisfied with the Company as it relates to Electric Reliability and makes a complaint directly to a Company representative.

"Electric Service Reliability" - The continuity of electric service experienced by retail customers.

"Electric System Reliability Reporting Requirements" – The minimum reporting requirements are as follows:

(1) The report must be consistent with the electric service reliability monitoring and reporting plan filed under WAC [480-100-393](#). As set forth in the plan, in an identified year, baseline reliability statistics must be established and reported. In subsequent years, new reliability statistics must be compared to the baseline reliability statistics and to reliability statistics from all intervening years. The utility must maintain historical reliability information necessary to show trends for a minimum of seven years.

(2) The report must address any changes that the utility may make in the collection of data and calculation of reliability information after initial baselines are set. The utility must explain why the changes occurred and explain how the change is expected to affect comparisons of the newer and older information. Additionally, to the extent practical, the utility must quantify the effect of such changes on the comparability of new reliability statistics to baseline reliability statistics.

(3) The report must identify the utility's geographic areas of greatest reliability concern, explain their causes, and explain how the utility plans to address them.

(4) The report must identify the total number of customer complaints about reliability and power quality made to the utility during the year, and must distinguish between complaints about sustained interruptions and power quality. The report must also identify complaints that were made about major events.

"Full-system" - All equipment and lines necessary to serve retail customers whether for the purpose of generation, transmission, distribution or individual service.

"Interruption Cause Code" – Used to describe the cause of an interruption (i.e., animal, tree, public, etc...).

"Major Event" – Designates an event that exceeds reasonable design and or operation limits of the electric power system. A Major Event includes at least one Major Event Day (MED).

"Major Event Day" – A day in which the daily system SAIDI exceeds a threshold value, T_{MED} . For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

"Momentary Event Interruption" – An interruption(s) of duration 5 minutes or less. Each event consists of one trip and one reclose operation that occur within 5 minutes. For example, if an interrupting device operates three times and then holds, this would be counted as three events with the number of customers affected as three times the N_i .

"Power Quality" – Characteristics of electricity, primarily voltage and frequency, that must meet certain specifications for safe, adequate and efficient operations.

"Reliability Statistic" – Standard Statistics measures and calculation methods are per the IEEE Standard 1366-2003 (or latest version) Titled "IEEE Guide for Electric Power Distribution Reliability Indices". Same as Reliability Indices.

"Reliability Target" - A statistical method developed in 2004 for calculating the statistical range of variability for each baseline statistic that should encompass the annual result for each year 95% of the time. The method is defined as the average over a specific timeframe and 2 times the standard deviation. For 95% of the time. While over the years Avista has referred to this range as the "target," this term should not be interpreted as a "level of performance" that Avista is trying to achieve each year. Rather, it simply represents the range of variability that we could expect to see in our reliability results in most years.

"Sustained Interruption" - An interruption lasting longer than 5 minutes.

Appendix B - Index Calculations

SAIFI – System Average Interruption Frequency Index

- The average number of sustained interruptions per customer
- =
$$\frac{\text{The number of customers which had *sustained interruptions*}}{\text{Total number of customers served}}$$
- =
$$\frac{\sum N_i}{N_T}$$

MAIFI_E – Momentary Average Interruption Event Frequency Index

- The average number of momentary interruption events per customer
- =
$$\frac{\text{The number of customers which had *momentary interruption events*}}{\text{Total number of customers served}}$$
- =
$$\frac{\sum ID_E N_i}{N_T}$$
- MAIFI can be calculated by one of two methods. Using the number of momentary interruptions or the number momentary events. This report calculates MAIFI_E using momentary events. The event includes all momentary interruptions occurring within 5 minutes of the first interruption. For example, when an automatic interrupting device opens and then recloses two, or three times before it remains closed, it is considered a single event.

SAIDI – System Average Interruption Duration Index

- ✓ Average sustained outage time per customer
- =
$$\frac{\text{Outage duration multiplied by the customers effected for all *sustained interruptions*}}{\text{Total number of customers served}}$$
- =
$$\frac{\sum r_i N_i}{N_T}$$

CAIDI – Customer Average Interruption Duration Index

- Average restoration time
- =
$$\frac{\text{Outage duration multiplied by the customers effected for all *sustained interruptions*}}{\text{The number of customers which had *sustained interruptions*}}$$
- =
$$\frac{\sum r_i N_i}{\sum N_i}$$

Quantities

i = An interruption event;

r_i = Restoration time for each interruption event;

T = Total;

ID_E = Number of interrupting device events;

N_i = Number of interrupted customers for each interruption event during the reporting period;

N_T = Total number of customers served for the area being indexed;

$CEMI_n$ – Customers Experiencing Multiple Sustained Interruptions more than n .

- $CEMI_n$
- = $\frac{\text{Total Number of Customers that experience more than } n \text{ sustained interruptions}}{\text{Total Number of Customers Served}}$
- = $\frac{CN_{(k>n)}}{N_T}$

$CEMSMI_n$ – Customers experiencing multiple sustained interruption and momentary interruption events.

- $CEMSMI_n$
- = $\frac{\text{Total Number of Customers experiencing more than } n \text{ interruptions}}{\text{Total Number of Customers Served}}$
- = $\frac{CNT_{(k>n)}}{N_T}$

MED - Major Event Day

A major event day is a day in which the daily system SAIDI exceeds a threshold value. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events.

T_{MED} is calculated (taken from the IEEE 1366-2003 Standard)

The major event day identification threshold value, T_{MED} , is calculated at the end of each reporting period (typically one year) for use during the next reporting period as follows:

- a) Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.
- b) Only those days that have a SAIDI/Day value will be used to calculate the T_{MED} (do not include days that did not have any interruptions).
- c) Take the natural logarithm (ln) of each daily SAIDI value in the data set.
- d) Find a (Alpha), the average of the logarithms (also known as the log-average) of the data set.
- e) Find b (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
- f) Compute the major event day threshold, T_{MED} , using equation (25).

$$T_{MED} = e^{(a+2.5b)} \quad (25)$$

g) Any day with daily SAIDI greater than the threshold value TMED that occurs during the subsequent reporting period is classified as a major event day. Activities that occur on days classified as major event days should be separately analyzed and reported.

When an event has reached the threshold to constitute a MED described in subpart (f) above, all outage incidents associated with the MED will be flagged in the Company's Outage Management Tool. As the Company further assesses damage in the field while making repairs, new subsequent outage incidents that were a result of the MED may be created as more accurate information is made available. The subsequent incidents will be flagged and included as part of original outage event and MED.

Appendix C - Customer Reliability Complaints

Commission Complaints

Commission Complaints are complaints received by the Washington Utilities and Transportation Commission specifically related to the Company's SQM Program, power quality, electric reliability, or Major Events.

City, State Feeder	Complaint	Complaint Category	Resolution
Davenport, WA HAR12F2	<p>In the last six months, the customer has been receiving numerous power interruptions about 2 or 3 times a week. When the customer contacts the company, it's difficult to get a live rep, and he just wants someone to answer his questions.</p> <p>The customer has lived in the area for more than 25 years and he has never experienced such frequent anomalies. The customer inquired when the outages will be addressed and resolved.</p>	Outages	Company upheld

Customer Complaints

Customer Complaints are complaints received by the Company specifically related to the Company's SQM Program, power quality, electric reliability, or Major Events.

City, State Feeder	Complaint	Complaint Category	Resolution
Spokane, WA MEA12F2	Customer is complaining that his specific cul-de-sac is associated with a different feed than the rest of his neighborhood development. This causes him to suffer outages that surrounding neighbors do not. Customer requested to start the ball rolling with feeder change out. They are on a rural feeder and outages are often	Outages	Called customer and let him know we've reached out to CPCs and Engineering.
Spokane, WA 9CE12F2	<p>All comments are related to aftermath of November wind storm:</p> <ol style="list-style-type: none"> 1. Hot lines in yard caused by November wind storm. She only learned about downed lines after she and her kids were near the lines a few weeks after the event. 2. Customer was told by crews in the field removing a tree in her yard would be Avista responsibility, she eventually had tree removed and made claim with her insurance company, called 2 times and was told NOP. 3. Not getting the lights on when we promised - no specific info. 4. Not repairing street light after line broke after reported a month ago. Remarks on account show line connected to street lite was ok? <p>Customer would like a call back to discuss.</p>	Outages	Foreman contacted the customer in response to her concerns and will be following up with a face to face at her convenience.

Coeur d'Alene, ID APW111	Customer is frustrated that she received notification of planned outage with less than 24 hours to prepare. She would like to be notified further in advance of any planned outages. No call back necessary, customer would just like complaint to be filed.	Outages	Complaint filed as requested.
Springdale, WA VAL12F1	Customer is very upset about power outage in his area on Oct 24th from 11 P.M. to 6 A.M., he was just notified today Friday Oct 21 st . He feels Avista knew in advance we were going to do this and we could have given customers more notice so they had time to prepare. He said he has a generator he can use but it takes two weeks to get fuel delivered, and also states there are people who are not fortunate enough to have a generator and it gets cold at night. He wanted to know if Avista is going to pay to put customers up in hotels for night, and feels we should have done this during the summer months. He also feels this is very poor customer service and is requesting a call back.	Outages	Called Customer and discussed outage, went over our thought process behind planning this outage with him. Advised that we try and schedule these when there is the most limited impact to businesses and residential customers. He was upset on when we decided to notify. He said we should notify customers as soon as we know power is going to be taken down. Passed his info on to the manager of the crew taking down the power.
Kettle Falls, WA KET12F2	Customer says her business and house which are next door to each other have had power outages 4 times in 5 days over the past week ranging from an hour to 4 hours, shutting down her business, causing lost money, she has been unable to turn cabins, do check-ins and unable to do online business. At this time she has declined a claim and requested a formal complaint be put through.	Outages	Complaint filed as requested.

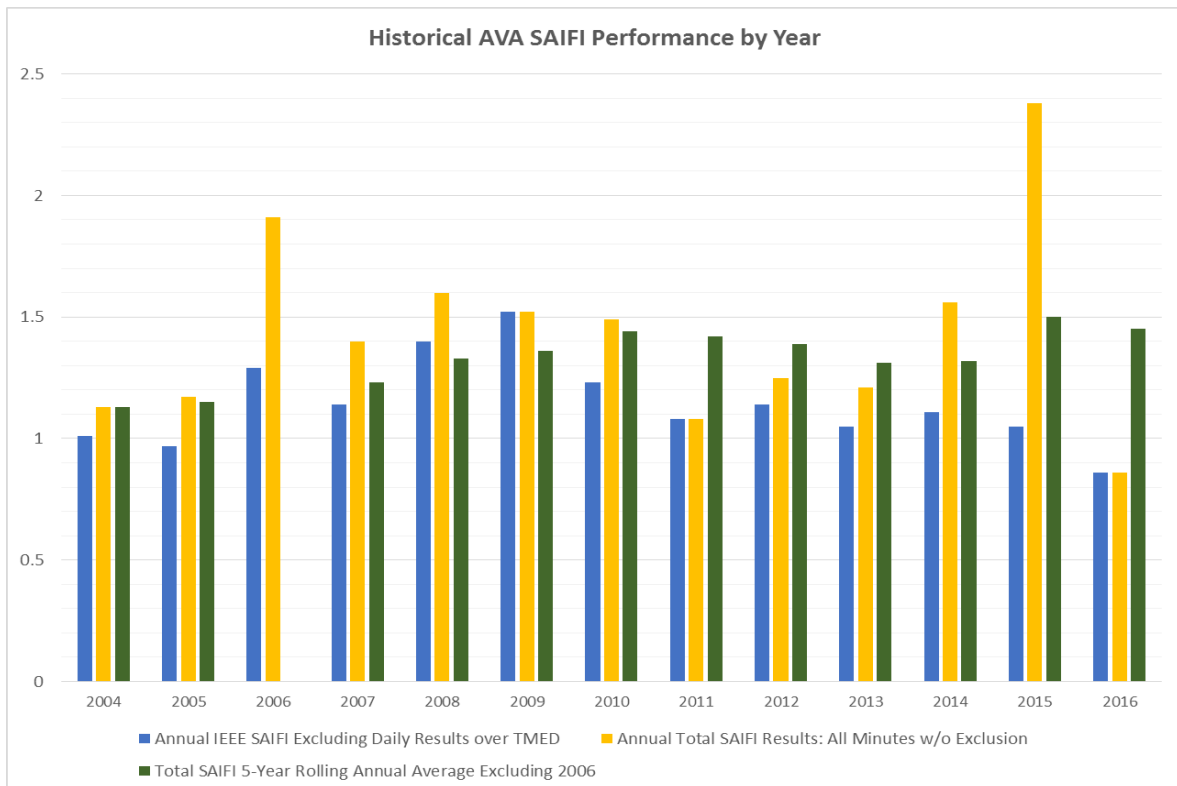
St. Maries, ID STM631	Pastor of the church called and is upset that the planned power outages are occurring on Sundays which are known church days. Customer would like to report that these outages interrupt the ability to have services as some families are not able to attend during the week and only able to attend on Sundays. Customer would like to have his complaint documented and passed along to the higher ups. Customer would also like to request that outages begin being planned on Saturdays so that neither work, church nor school is interrupted that day.	Outages	Area manager spoke with Pastor, explained situation and assured him that we will take his concern under consideration.
Colbert, WA COB12F1	Customer is very tired of how many times they lose power in the Colbert area. Says all of her neighbors are upset with us and the fact we keep raising our rates but they go without power so much in town. They had friends coming over for dinner and had to cancel because of the outage on Sunday 8-7-16. Just wants message shared up the line so we are aware of how dissatisfied she and her neighbors are.	Outages	Manager called back to discuss outages
St. Maries, ID STM633	Planned outage on 10/2 from 6am-noon, Customer is upset about interruption of church services. She said last planned outage we had in St. Maries was on a Sunday as well and would like to know if there is a specific reason why we plan these days/times when it is a known church timeframe. She does understand that there is never a time that will please everyone, but would like resolution or reasoning about why we choose Sunday mornings.	Outages	Manager called back to discuss outages.
Reardan, WA RDN12F1	Customer called in to let us know that she was upset that there is a planned outage tonight 6-3 from 10-10:30. They are having their annual town days. There is a play and many other things going on in town at this time. She feels like it was bad planning on our part. She doesn't want a call back but she wants us to	Outages	Manager called back to discuss outages for his service point

	know that we should look into things such as this before scheduling outages.		
Newman Lake, WA EFM12F1	Customer is frustrated about the amount of outages that have happened in the last couple of weeks. She feels that Avista should be upgrading the system so the animals will stay out of the lines and not cause outages.	Outages	Spoke w/ customer & went over outages w/her. Explained that we try our hardest to not have outages, but sometimes they are beyond our control. Resolved issue.
Sprague, WA SPR761	Customer has infant in home and is currently out of power. The city told him it was a planned outage. They are the only house out of power and didn't get any notification. Wife is primary phone number on account and she didn't get any phone calls. He is upset due to having new infant in home. Wants a manager to call back please.	Outages	Area Manager will contact customer regarding lack of notification for outage.
Davenport, WA DVP12F1	Customer is concerned about the frequency of small brief blips of power. He is upset as it messes up equipment at his business and in 36 years here he's never had this many. 1-3 per week for last few months.	Outages	Filed claim since complaint is in regards to past outages
Colbert, WA COB12F1	Customer requested complaint due to frequent outages. Customer said she understands wind storms, snow, etc. but it seems every time there is even a slight bit of thunder/rain her power goes out.	Outages	Filed complaint.

Appendix D – SAIFI and SAIDI Historical Summary

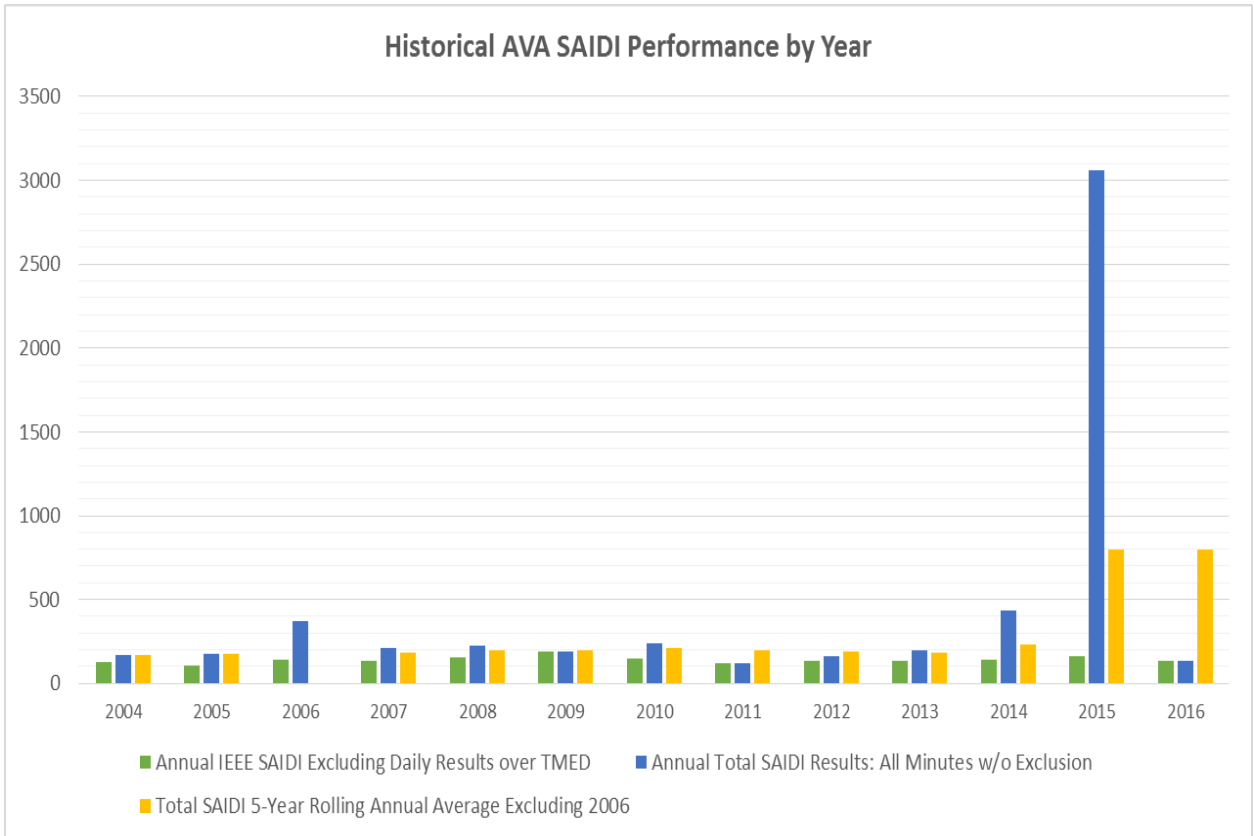
2004 - 2016 AVA SAIFI Performance by Measurement by Year

Year	Calendar Year	Annual IEEE SAIFI Excluding Daily Results over TMED	Annual Total SAIFI Results: All Minutes w/o Exclusion	Annual Total SAIFI Results Excluding 2006	Total SAIFI 5-Year Rolling Annual Average Excluding 2006	
1	2004	1.01	1.13	1.13	1.13	
2	2005	0.97	1.17	1.17	1.15	Baseline
3	2006	1.29	1.91			
4	2007	1.14	1.40	1.40	1.23	
5	2008	1.40	1.60	1.60	1.33	
6	2009	1.52	1.52	1.52	1.36	
7	2010	1.23	1.49	1.49	1.44	
8	2011	1.08	1.08	1.08	1.42	
9	2012	1.14	1.25	1.25	1.39	
10	2013	1.05	1.21	1.21	1.31	
11	2014	1.11	1.56	1.56	1.32	
12	2015	1.05	2.38	2.38	1.50	
13	2016	0.86	0.86	0.86	1.45	
		1.16				Target



2004-2016 AVA SAIDI Performance by Measurement by Year

Year	Calendar Year	Annual IEEE SAIDI Excluding Daily Results over T _{MED}	Annual Total SAIDI Results: All Minutes w/o Exclusion	Annual Total SAIDI Results Excluding 2006	Total SAIDI 5-Year Rolling Annual Average Excluding 2006	
1	2004	126	172	172	172	
2	2005	108	176	176	174	Baseline
3	2006	143	374			
4	2007	132	209	209	186	
5	2008	159	227	227	196	
6	2009	193	193	193	195	
7	2010	146	236	236	208	
8	2011	118	118	118	197	
9	2012	138	163	163	187	
10	2013	138	199	199	182	
11	2014	139	437	437	231	
12	2015	163	3056	3056	795	
13	2016	133	133	133	798	
		171				Target



Appendix E – Service Quality Measures Report Card



Each year Avista measures how well we perform in meeting our goal to provide the best customer service possible. In line with that tradition, we established a set of Service Quality Measures in collaboration with the Washington Utilities and Transportation Commission (WUTC) and others. We will be providing this annual report card to customers showing how we are doing on meeting these goals. For more information, visit www.avistautilities.com.

Customer Service Measures	Benchmark	2016 Performance	Achieved
Percentage of customers satisfied with our Contact Center services	At least 90%	92.7%	✓
Percentage of customers satisfied with our field services	At least 90%	94.7%	✓
Number of complaints filed with the WUTC annually per 1,000 customers	Less than 0.40	0.25	✓
Percentage of calls answered live within 60 seconds by our Contact Center	At least 80%	81.7%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies	No more than 80 minutes	39.3 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies	No more than 55 minutes	48.4 Minutes	✓

Electric System Reliability	5-Year Average (2012-2016)	2016 Performance	Change in 5-Year Average
Number of non-major storm-related power outages annually per customer	1.04	.86	-0.05
Length of non-major storm-related power outages annually per customer	142 Minutes	133 Minutes	+3 Minutes

Customer Service Guarantees	Successful	Missed	\$ Paid
Keep service appointments scheduled with our customers	1,477	10	\$500
Restore service within 24 hours of a customer reporting an outage (excluding major storm events)	26,344	1	\$50
Turn on power within a business day of receiving the request	3,380	3	\$150
Provide a cost estimate for new electric or natural gas service within 10 business days of receiving the request	5,024	0	\$0
Investigate and respond to a billing inquiry within 10 business days if unable to answer a question on first contact	1,760	0	\$0
Investigate a reported meter problem or conduct a meter test and report the results within 20 business days	309	2	\$100
Notify customers at least 24 hours in advance of a planned power outage lasting longer than 5 minutes	30,336	349	\$17,450
Totals	68,630	365	\$18,250

2016 Performance Highlights

Thankfully 2016 was a relatively quiet year for customer outages compared to 2015, which included the unprecedented wind event on November 17th in the Spokane area that impacted a substantial portion of Avista's electric system. In 2016 we experienced no major storm events in terms of customer outages and only a few storms that had a significant impact on our service. The leading cause of outages in 2016 was damage to overhead equipment, followed by planned outages needed to allow Avista to safely perform work on its system.

On January 1, 2016, Avista launched its Customer Service Guarantees program listed above. Our commitments under the customer service guarantees reflect the level of service we currently provide. However, the guarantees recognize the customer inconvenience that may arise when our delivered service does not meet our commitment. In these cases we provide customers a bill credit or payment in the amount of \$50 in recognition of their inconvenience. All costs associated with the payment of customer service guarantees are paid by Avista's

shareholders, not by customers. We are pleased to report that for the first year of the program there were 68,630 successful interactions, which represents 99.5% of all customer interactions that are part of the Customer Service Guarantees. We missed our service commitment 365 times in 2016, which resulted in total payments to those customers of \$18,250.

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