



Electric Service
Reliability in
Pennsylvania

2009



ELECTRIC SERVICE RELIABILITY IN PENNSYLVANIA 2009

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Executive Summary

The Electricity Generation Customer Choice and Competition Act mandates that the Pennsylvania Public Utility Commission (“Commission”) ensure that levels of reliability that existed prior to the restructuring of the electric utility industry continue in the new competitive markets.¹ In response to this mandate, the Commission adopted reporting requirements designed to ensure the continuing safety, adequacy and reliability of the generation, transmission and distribution of electricity in the Commonwealth.² The Commission also established reliability benchmarks and standards to measure the performance of each electric distribution company (“EDC”).³

Given the uncertainty of weather and other events that can affect reliability performance, the Commission has stated that EDCs should set goals to achieve benchmark performance in order to prepare for those times when unforeseen circumstances push the indices above the benchmark.⁴ In recognition of these unforeseen circumstances, the Commission set the performance standard as the minimum level of EDC reliability performance. The standard is the level of performance beyond which the company must either justify its poor performance or provide information on the corrective measures it will take to improve performance. Performance that does not meet the standard for any reliability measure may be the threshold for triggering additional scrutiny and potential compliance enforcement actions.

In 2009, all of the 11 EDCs achieved compliance with the 12-month Customer Average Interruption Duration Index (“CAIDI”) performance standard for duration of service outages, and nine EDCs performed better than the 12-month CAIDI performance benchmark. When measured on a company-wide basis, these nine EDCs provided restoration of service in a manner that was statistically timelier than was experienced over the five years prior to the restructuring of the electric utility industry.

All of the 11 EDCs achieved compliance with the 12-month System Average Interruption Frequency Index (“SAIFI”) performance standards for the average frequency of service outages per customer, and have maintained the number of customer outages at a statistically acceptable level. Ten EDCs performed better than the 12-month SAIFI performance benchmark, thereby reducing average customer outage levels below those experienced over the five years prior to the restructuring of the electric utility industry.

As mandated, enforcement of the three-year rolling average standard began with the utilities’ filing of their 2006 annual reports. The three-year performance standard only allows a deviation of 10 percent from the reliability index benchmark, as compared with the 20 percent or 35 percent deviations allowed by the 12-month performance standard.⁵ This year, we have assessed the average reliability performance of EDCs over a three-year period, utilizing data from 2007, 2008 and 2009.

Ten of the 11 EDCs performed better than the three-year standard for average duration of service outages. For the average frequency of service outages per customer, eight of the 11 EDCs performed better than the three-year performance standard. Some of the EDCs that failed to perform better than

¹ Act of Dec. 3, 1996, P.L. 802, No. 138, 66 Pa.C.S. Sec. 2801 *et. seq.*

² Docket No. L-00970120; 52 Pa. Code §§ 57.191-57.197.

³ Docket No. M-00991220.

⁴ Docket No. M-00991220, Page 25.

⁵ For an explanation of performance standards, see Section 2, page 5.

their three-year standards were those that had performance issues in prior years. However, these EDCs have shown a trend toward improving performance that if continued, should bring those EDCs into compliance with the three-year standards.

In addition to monitoring the reliability performance of the EDCs, the Commission established inspection and maintenance standards that are appropriate for electric transmission and distribution systems.⁶ Biennial plans for the periodic inspection, maintenance, repair and replacement of facilities, designed to meet performance benchmarks and standards, were filed with the Commission on Oct. 1, 2009, by FirstEnergy, West Penn and UGI, to become effective on Jan. 1, 2011.⁷ On Dec. 1, 2009, the Bureau of CEEP accepted four of the five EDCs' I&M plans, as submitted. One I&M plan was rejected, in part, and an appeal was filed, pursuant to 52 Pa. Code § 5.44, and subsequently denied. I&M Plans are to be filed by Duquesne Light, PECO, PPL, Citizens', Pike County and Wellsboro by Oct. 1, 2010.

⁶ Docket No. L-00040167.

⁷ 52 Pa. Code § 57.198(a).

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Section 1 – Introduction

Purpose

This report discusses the reliability performance of EDCs operating under the Commission’s jurisdiction within the Commonwealth. Although the reliability of the bulk transmission system⁸ is integral to the overall reliability of electric service, this report focuses on the reliability of the electric distribution system.

The data contained in this report was obtained from the quarterly and annual reliability reports submitted by the EDCs pursuant to the Commission’s regulations.⁹ These annual reports provide an assessment of electric service reliability for each EDC’s service territory.

Background

The Electricity Generation Customer Choice and Competition Act¹⁰ (“Act”) amended Title 66 of the Pennsylvania Consolidated Statutes by adding Chapter 28 to establish standards and procedures to create direct access by retail customers to the competitive market for the generation of electricity, while maintaining the safety and reliability of the electric distribution system. Specifically, the Commission was given a legislative mandate to ensure that levels of reliability that existed prior to the restructuring of the electric utility industry would continue in the new competitive markets.¹¹

In response to this legislative mandate, the Commission established various reporting requirements designed to ensure the continued safety, adequacy and reliability of the generation, transmission and distribution of electricity in the Commonwealth.¹² On Dec. 16, 1999, the Commission entered a Final Order establishing reliability benchmarks and standards for the EDCs.¹³ The purpose of these reliability indices is to measure the performance of EDCs’ transmission and distribution systems in terms of the frequency and duration of unplanned electric service outages to ensure that the levels of reliability existing prior to retail competition do not deteriorate.

On May 7, 2004, the Commission adopted amendments to its existing regulations regarding electric reliability standards, which became effective on Sept. 18, 2004.¹⁴ In conjunction with the adoption of the amended regulations, the Commission adopted an Order amending its benchmarks and standards. Subsequently, the Commission adopted Orders granting adjustments to the benchmarks and standards of five EDCs.

On Jan. 31, 2007, the LB&FC¹⁵ released a performance audit of the Commission. The report observed that the Commission has enhanced the monitoring of electric reliability and generally has the processes

⁸ The high-voltage transmission system, nominally >100 kV, is regulated by the Federal Energy Regulatory Commission. The electric distribution system is under the purview of the Pennsylvania Public Utility Commission.

⁹ 52 Pa. Code § 57.195.

¹⁰ Dec. 3, P.L. 802, No. 138 § 4.

¹¹ 66 Pa.C.S. §§ 2802(12), 2804(1) and 2807(d).

¹² Docket No. L-00970120; 52 Pa. Code §§ 57.191-57.197.

¹³ Docket No. M-00991220.

¹⁴ Docket No. L-00030161; 34 Pa.B. 5135.

¹⁵ Legislative Budget and Finance Committee.

and procedures in place to adequately monitor electric reliability. The performance audit was directed by House Resolution 695 of 2006 and is available on the LB&FC's website at <http://lbfc.legis.state.pa.us>.

In order to further enhance reliability performance monitoring of the EDCs, the Commission initiated a rulemaking proceeding to determine the type and scope of inspection and maintenance ("I&M") standards that would be appropriate for electric transmission and distribution systems.¹⁶ A Final Rulemaking Order was adopted by the Commission on May 22, 2008. Biennial plans for the periodic inspection, maintenance, repair and replacement of facilities, designed to meet performance benchmarks and standards, were to be filed with the Commission beginning in Oct. 2009. The new regulation also sets forth inspection and maintenance intervals.¹⁷

Concurrently, based upon two consumer complaints involving the failure of neutral connectors, the Commission determined that the issue of whether EDCs should be subject to specific I&M standards regarding neutral connections should be evaluated. A rulemaking proceeding was initiated to consider revising Title 52 Pa. Code, Chapter 57, relating to electric distribution reliability.¹⁸ Based on the comments and reply comments received, the Commission found that standards regarding the inspection, maintenance, repair and replacement of neutral connections were unnecessary, cost prohibitive and of minimal value in comparison to a potential compliance cost of over \$85 million per year, in aggregate. Since neutral connection failures have been a relatively low cause of service outages, the Commission concluded that money could be better spent on other maintenance issues to improve the EDCs' reliability performances. On Feb. 25, 2010, the Commission adopted an order discontinuing the rulemaking proceeding and encouraging EDCs to voluntarily reimburse customers for damages caused by failed neutral connections.

¹⁶ Docket No. L-00040167.

¹⁷ 52 Pa. Code § 57.198(a) and (n).

¹⁸ Docket No. L-2008-2044821.

Section 2 – Reliability Performance Measures

Reliability Performance Indices

The benchmarks and standards established by the Commission are based on four reliability performance indices which have been adopted by the Institute of Electrical and Electronic Engineers Inc. (“IEEE”). These indices include: (1) Customer Average Interruption Duration Index (“CAIDI”); (2) System Average Interruption Frequency Index (“SAIFI”); (3) System Average Interruption Duration Index (“SAIDI”); and (4) Momentary Average Interruption Frequency Index (“MAIFI”).

- CAIDI is the average duration of sustained interruptions¹⁹ for those customers who experience interruptions during the analysis period. CAIDI represents the average time required to restore service to the average customer per sustained interruption. It is determined by dividing the sum of all sustained customer interruption durations, in minutes, by the total number of interrupted customers;
- SAIFI measures the average frequency of sustained interruptions per customer occurring during the analysis period. It is calculated by dividing the total number of sustained customer interruptions by the total number of customers served;
- SAIDI is the average duration of sustained customer interruptions per customer occurring during the analysis period. It is the average time customers were without power. It is determined by dividing the sum of all sustained customer interruption durations, in minutes, by the total number of customers served. SAIDI is also the product of CAIDI and SAIFI; and
- MAIFI measures the average frequency of momentary interruptions²⁰ per customer occurring during the analysis period. It is calculated by dividing the total number of momentary customer interruptions by the total number of customers served.

The actual values of these four reliability indices are submitted by the EDCs on both a quarterly (rolling 12-month average) and annual basis. Also included is the data used in calculating the indices, namely the average number of customers served, the number of sustained customer interruption minutes and the number of customers affected by service interruptions.

It is noted that some EDCs do not currently have the necessary equipment to collect meaningful data relating to momentary service interruptions (MAIFI). However, the Commission desires to assess, where possible, the affect of frequent momentary interruptions on EDCs’ customers. Thus, the provision of this data is required, if available.

In addition to the outage data mentioned above, the Commission’s regulations require EDCs to report a breakdown and analysis of outage causes, such as equipment failure, animal contact and contact with

¹⁹ The loss of electric service by one or more customers for the period defined as a sustained customer interruption by the IEEE as it may change from time to time – currently five minutes or greater. The term does not include “major events” or the authorized termination of service to an individual customer.

²⁰ The loss of electric service by one or more customers for the period defined as a momentary customer interruption by the IEEE as it may change from time to time – currently less than five minutes. The term does not include “major events” or the authorized termination of service to an individual customer.

trees. This analysis is helpful in identifying the primary causes of service interruptions and determining which causes, if any, can be prevented in the future through proposed solutions.

The regulations require EDCs to report reliability performance on a system-wide basis, rather than on an operating area basis, and provide an analysis of the worst performing five percent of circuits and major remedial efforts to improve those circuits.

Major Events

In order to analyze and set measurable goals for electric service reliability performance, outage data is separated into normal and abnormal periods so that only normal event periods are used for calculating reliability indices. The term “major event” is used to identify an abnormal event, such as a major storm, and is defined as either of the following:

- An interruption of electric service resulting from conditions beyond the control of the EDC which affects at least 10 percent of the customers in the EDC’s service territory during the course of the event for a duration of five minutes or greater; or
- An unscheduled interruption of electric service resulting from an action taken by an EDC to maintain the adequacy and security of the electrical system.

Outage data relating to major events are to be excluded from the calculation of reliability indices. In order to avoid the inappropriate exclusion of outage data, the Commission has implemented a process whereby an EDC must submit a formal request for exclusion of service interruptions for reporting purposes, accompanied by data which demonstrates that a service interruption qualifies as a major event.

Benchmarks and Standards

The performance **benchmark** represents the statistical average of the EDC’s annual, system-wide, reliability performance index values for the five-year time period from 1994-98. The benchmark serves as an objective level of performance that each EDC should strive to achieve and maintain, and is a reference point for comparison of future reliability performance.

The performance **standard** is a numerical value that represents the minimal performance allowed for each reliability index for a given EDC. Performance standards are based on each EDC’s historical performance benchmarks. Both long-term (rolling three-year) and short-term (rolling 12-month) performance standards have been established for each EDC. The performance standard is the minimum level of EDC reliability performance permitted by the Commission and is a level of performance beyond which the company must either justify its poor performance or provide information on corrective measures it will take to improve performance. Performance that does not meet the standard for any reliability measure is the threshold for triggering additional scrutiny and potential compliance enforcement actions.

The rolling **12-month standard** is 120 percent of the benchmark for the major EDCs and 135 percent for the small EDCs.²¹ A greater degree of short-term latitude recognizes that small EDCs have fewer customers and fewer circuits than large EDCs, potentially allowing a single event to have a more significant impact on the reliability performance of the small EDCs' distribution systems. The 12-month standard became effective on Nov. 1, 2004.

The rolling **three-year standard** is 110 percent of the benchmark for all EDCs. This new performance standard was set at 10 percent above the historical benchmark to ensure that the standard is no higher than the worst annual performance experienced during the years prior to restructuring. The three-year average performance is measured against the standard at the end of each calendar year. Enforcement of the rolling three-year standard began with the submission of the annual reports due on or before April 30, 2007. The third rolling three-year standard analysis, contained in this report, utilizes 2007, 2008 and 2009 calendar year data.

It is noted that a lower number for any index indicates better reliability performance; i.e., a lower frequency of outages or shorter outage duration. A higher number indicates worse performance. For example, if an EDC has a CAIDI benchmark of 130 minutes, a rolling 12-month CAIDI standard of 156 minutes and an actual CAIDI for a particular year of 143 minutes, its performance is considered to be adequate. If CAIDI is 120 minutes, the performance is better than the historical average performance. A CAIDI of 180 minutes, on the other hand, indicates a failure to meet the reliability performance standard.

If any electric distribution company's reliability performance does not meet Commission standards, the Commission may require a report discussing the reasons for not meeting the standard and the corrective measures the company is taking to improve performance.²² In addition, Commission staff may initiate an investigation to determine whether an electric distribution company is providing reliable service.²³

Benchmarks and standards for EDC reliability performance and average reliability indices for 2009 are listed in Appendix A.

Inspection and Maintenance

The Act also addressed the promulgation of regulations for the establishment of standards for the inspection and maintenance of transmission and distribution systems. Specifically, 66 Pa. C.S. §2802(20) provides:

- (20) Since continuing and ensuring the reliability of electric service depends on adequate generation and on conscientious inspection and maintenance of transmission and distribution systems, the independent system operator or its functional equivalent should set, and the Commission shall set through regulations, inspection, maintenance, repair and replacement standards and enforce those standards.

²¹ Large EDCs currently include: Allegheny Power, Duquesne Light, Met-Ed, Penelec, Penn Power, PECO and PPL. Small EDCs include: UGI, Citizens', Pike County and Wellsboro.

²² 52 Pa. Code § 57.195(g).

²³ 52 Pa. Code § 57.197(a).

In its Final Rulemaking Order entered May 20, 2004, *Rulemaking Re Amending Electric Service Reliability Regulations at 52 Pa. Code Chapter 57*,²⁴ the Commission declined at that time to require specific inspection and maintenance standards reasoning that technological advances continue to improve the inspection and testing process. The Commission asked companies to report their own internal inspection and maintenance standards. The Commission measured the EDCs' progress towards meeting their individual goals and considered this information along with whether the EDCs were meeting their reliability standards to determine whether or not service was deteriorating within a given service territory due to the fault of the EDC.

After the blackout of August 2003, new information arose which caused the Commission to reevaluate the need for specific inspection and maintenance standards. One of the causes of the blackout was the failure of FirstEnergy Corporation to adequately manage tree growth along its transmission lines.²⁵

On May 22, 2008, the Commission entered a Final Rulemaking Order implementing minimum I&M standards for EDCs operating in Pennsylvania. This created a new Section 57.198 in Title 52 of the Pennsylvania Code, effective Sep. 27, 2008.²⁶ Section 57.198(a) states that initial I&M plans are due by Oct. 1, 2009, for Compliance Group 1 and Oct. 1, 2010, for Compliance Group 2, as determined by the Commission.²⁷ The plans cover the two calendar years beginning 15 months following the October 1 filing, and must be filed biennially.

The I&M plans must detail a program for the inspection and maintenance of electric distribution facilities, including: poles, conductors, transformers, switching devices, protective devices, regulators, capacitors and substations, necessary for the distribution of electric current, and owned, operated, managed or controlled by the company, and for vegetation management. The plans must comply with the minimum inspection and maintenance intervals set forth in Section 57.198(n) and include a justification for the time frames selected. The plans are subject to acceptance or rejection by the Commission or the Director of the Bureau of Conservation, Economics and Energy Planning (CEEP) if they are found to be deficient. See Table 1.

Table 1 Inspection and maintenance intervals

<i>Program</i>	<i>Interval</i>
<i>Vegetation Management</i>	<i>4-6 years</i>
<i>Pole Inspections</i>	<i>10-12 years</i>
<i>Overhead Distribution Line Inspections</i>	<i>1-2 years</i>
<i>Overhead Transformer Inspections</i>	<i>1-2 years</i>
<i>Above-Ground Pad-Mounted Transformer Inspections</i>	<i>5 years</i>
<i>Below-Ground Transformer Inspections</i>	<i>8 years</i>
<i>Recloser Inspections</i>	<i>8 years</i>
<i>Substation Inspections</i>	<i>5 weeks</i>

²⁴ Docket No. L-00030161.

²⁵ *Final Report on the August 14, 2003 Blackout in the U.S. and Canada*, U.S. – Canada Power System Outage Task Force, pp. 17, 57-64 (April 2004).

²⁶ Docket No. L-00040167, 38 *Pa.B.* 5273; Docket No. M-2009-2094773.

²⁷ Compliance Group 1 includes Met-Ed, Penelec, Penn Power, Allegheny Power and UGI. Compliance Group 2 consists of Duquesne Light, PECO, PPL, Citizens', Pike County and Wellsboro.

On October 1, 2009, each Compliance Group 1 EDC filed its Biennial Inspection, Maintenance, Repair and Replacement Plan, pursuant to 52 Pa. Code § 57.198(a), to become effective on January 1, 2011. Most EDCs proposed modifications to the standards for some programs or parts of programs. The exemptions requested involved pole loading calculations and the intervals for overhead line and transformer inspections and substations inspections.

The Commission's regulations provide the following relating to inspection and maintenance time frames:

(c) *Time frames.* The plan must comply with the inspection and maintenance standards in subsection (n). A justification for the inspection and maintenance time frames selected shall be provided, even if the time frame falls within the intervals prescribed in subsection (n). However, an EDC may propose a plan that, for a given standard, uses intervals outside the Commission standard, provided that the deviation can be justified by the EDC's unique circumstances or a cost/benefit analysis to support an alternative approach that will still support the level of reliability required by law.

52. Pa. Code § 57.198(c).

On Dec. 1, 2009, the Bureau of CEEP accepted four of the five EDCs' I&M plans, as submitted. These approvals are contingent upon the possibility that subsequent audits, reviews and inquiries, in any Commission proceeding, may be conducted pursuant to 52 Pa. Code § 57.197(a). Plan revisions may be submitted as an addendum to the quarterly reliability reports. One I&M plan was rejected, in part, and an appeal was filed, pursuant to 52 Pa. Code § 5.44, and subsequently denied by the Commission.²⁸ Appendix B describes the exemptions which were requested by the EDCs in Compliance Group 1 and provides a summary of the justification for said exemptions.

²⁸ Docket No. M-2009-2094773.

Section 3 – Statistical Utility Performance Data

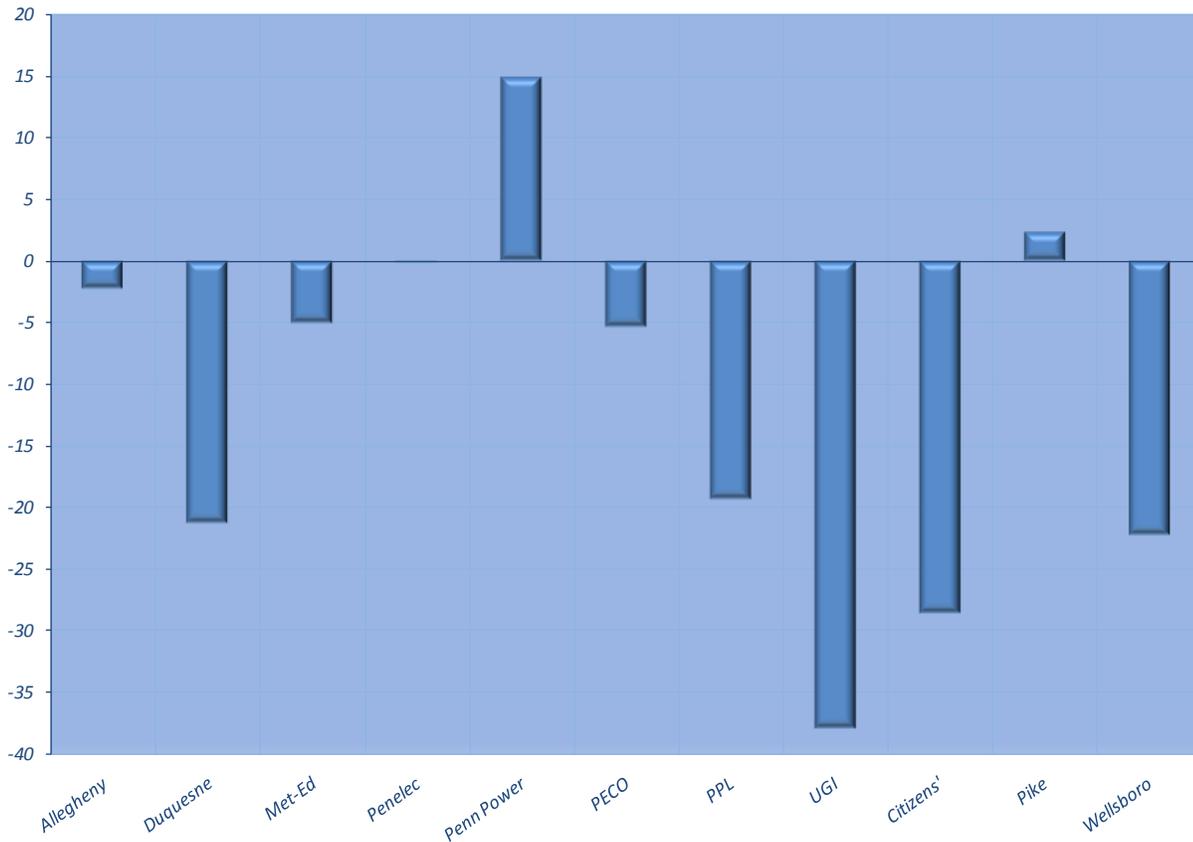
Statewide Summary

The 2009 reliability data submitted by the EDCs indicates that all of the 11 EDCs achieved compliance with the 12-month CAIDI performance standards for duration of service outages. Also, nine of the EDCs performed better than their CAIDI benchmarks, at an average reduction in outage duration of 15.8 percent or 21 minutes. Ten of the eleven EDCs had SAIDIs better than the benchmark.

All of the EDCs met their rolling 12-month SAIFI performance standard for the average frequency of service outages per customer. Ten EDCs performed better than their 12-month SAIFI performance benchmarks, at an average reduction in outage frequency of 10.3 percent or 0.11.

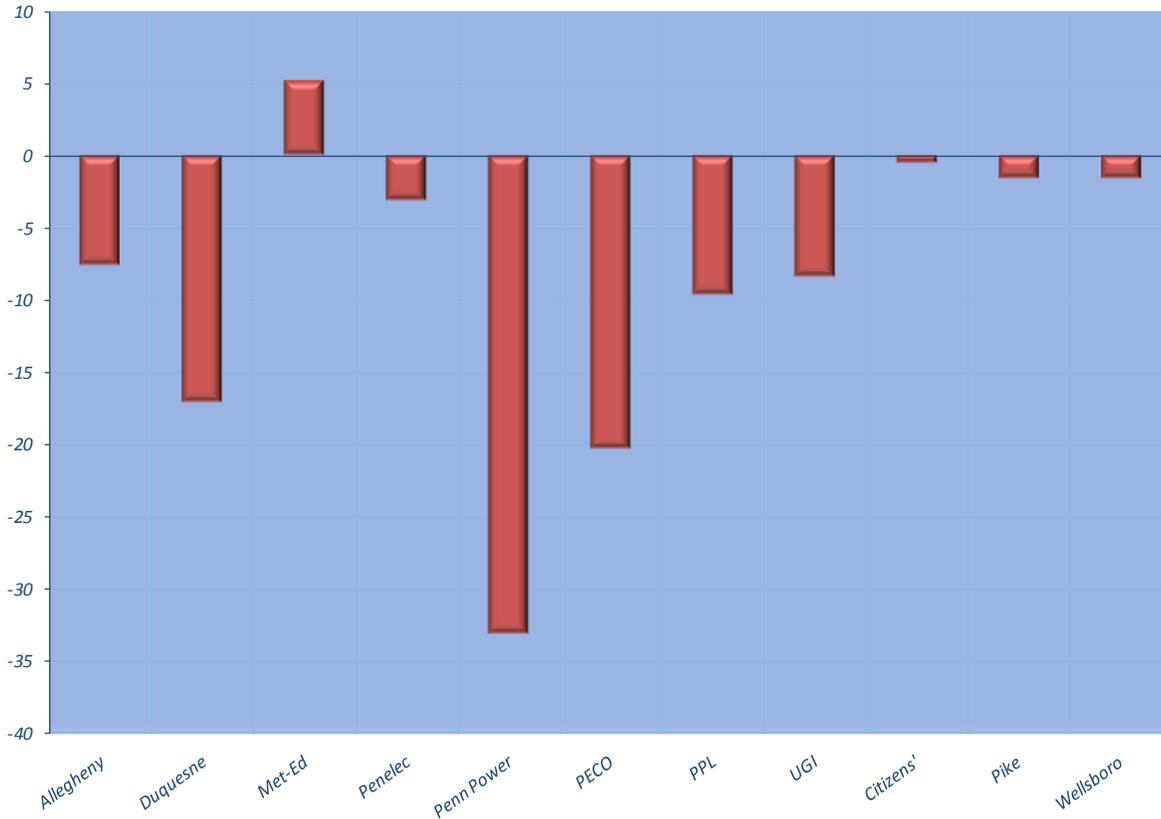
Figures 1 and 2 compare the 2009 CAIDI and SAIFI performance against benchmarks for all EDCs.

Figure 1 CAIDI 2009 comparison (percent above or below benchmark)



Note: In Figures 1 and 2, the bars below the zero line indicate performance better than the benchmarks.

Figure 2 SAIFI 2009 comparison (percent above or below benchmark)



Appendix A provides the actual 2009 reliability performance for each EDC and the benchmarks and standards for each reliability index.

We have also assessed the average reliability performance of EDCs for a three-year period, utilizing data from 2007, 2008 and 2009. One EDC (Penn Power) failed to meet its rolling three-year CAIDI performance standard by seven minutes. Three EDCs (Met-Ed, Penelec and Citizens') failed to meet their rolling three-year SAIFI performance standards. Overall, however, the three-year average performance has greatly improved. Only one EDC (Penelec) exceeded the SAIDI standard (by five minutes), as compared to five EDCs in the previous year's comparison.

The actual 2007, 2008 and 2009 performance for each EDC and the results of the three-year performance analysis are also displayed in Appendix A.

During 2009, 11 requests for exclusion of major events were filed by the EDCs. All of these requests were approved. A major event exclusion request may be denied for a variety of reasons, including such things as the event not meeting the 10 percent threshold of customers interrupted or the failure of equipment without supporting maintenance records. A brief description of each major event is provided in the individual EDC sections.

Utility-Specific Performance Data

The reliability performance data provided herein for each of the indices represent, for the most part, rolling 12-month averages. Benchmarks are based on the averages of index values computed for the 12-month periods ending December 1994 through December 1998. Some benchmarks have been adjusted in subsequent proceedings. The 12-month standard is 120 percent of the benchmark for large EDCs and 135 percent for small EDCs. The three-year standard is 110 percent of the benchmark for all EDCs.

The Commission compares reliability indices on a quarterly basis, using data obtained for the preceding 12 months. This periodic assessment determines the current status of electric service reliability on an ongoing basis and is instrumental in identifying negative trends. The three-year average performance is measured at the end of each calendar year, using the average of the past three end-year indices, as indicated in Appendix A.

Allegheny Power

In 2009, Allegheny experienced 686,453 customer interruptions with a total duration of 113.8 million minutes, which was 17.2 percent lower than last year. Nearly 14,000 incidents were reported in over 9,000 locations. One major event occurred in Allegheny's service territory during 2009. The calculation of the reliability indices excludes outage data relating to this event, which was approved by the Commission.²⁹ Allegheny's service territory also experienced many major weather events, which contributed 65 minutes, or 40 percent, to SAIDI.

- Feb. 11-15, 2009 – The most severe event in its history with strong, steady winds with wind gusts; 136,569 customers were affected; 108.6 million customer minutes were excluded.

Allegheny's CAIDI slightly decreased from 168 minutes in 2008 to 166 minutes in 2009, which was a 1.2 percent decrease in CAIDI minutes and 2.4 percent better than the benchmark of 170 minutes. Since the last quarter of 2008, CAIDI has remained below the benchmark. The CAIDI three-year average was six minutes below the standard of 187 minutes. For the 12-month average ending March 31, 2010, CAIDI was 163 minutes, or 4.1 percent below the benchmark. SAIDI dropped from 195 minutes in 2008 to 161 minutes in 2009. Figure 3 depicts the trend in the duration of customer interruptions for the Allegheny system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

Allegheny's SAIFI decreased from 1.16 in 2008 to 0.97 in 2009, which was a 16.4 percent decrease in outage frequency and 7.6 percent better than the benchmark of 1.05. SAIFI has remained below the benchmark since the first quarter of 2009. The SAIFI three-year average was 0.9 percent below the standard of 1.16. For the 12-month average ending March 31, 2010, SAIFI was 0.92, or 12.4 percent below the benchmark. Figure 4 depicts the trend in the frequency of service interruptions for the Allegheny system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, equipment failure was responsible for 31.7 percent of the outages, 31.5 percent of customers affected and 21.3 percent of customer minutes interrupted. Trees off the right-of-way were the second

²⁹ Docket No. M-2009-2093220.

leading cause of service interruptions, with 22.3 percent of the outages, 23.4 percent of customers affected and 38.1 percent of interruption minutes. Weather accounted for 11.3 percent of total outages, 10.8 percent of customers affected and 15.1 percent of interruption minutes. Figure 5 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top three major causes is shown in Figure 6.

Figure 3 Allegheny Customer Average Interruption Duration Index (minutes)



Figure 4 Allegheny System Average Interruption Frequency Index (interruptions per customer)

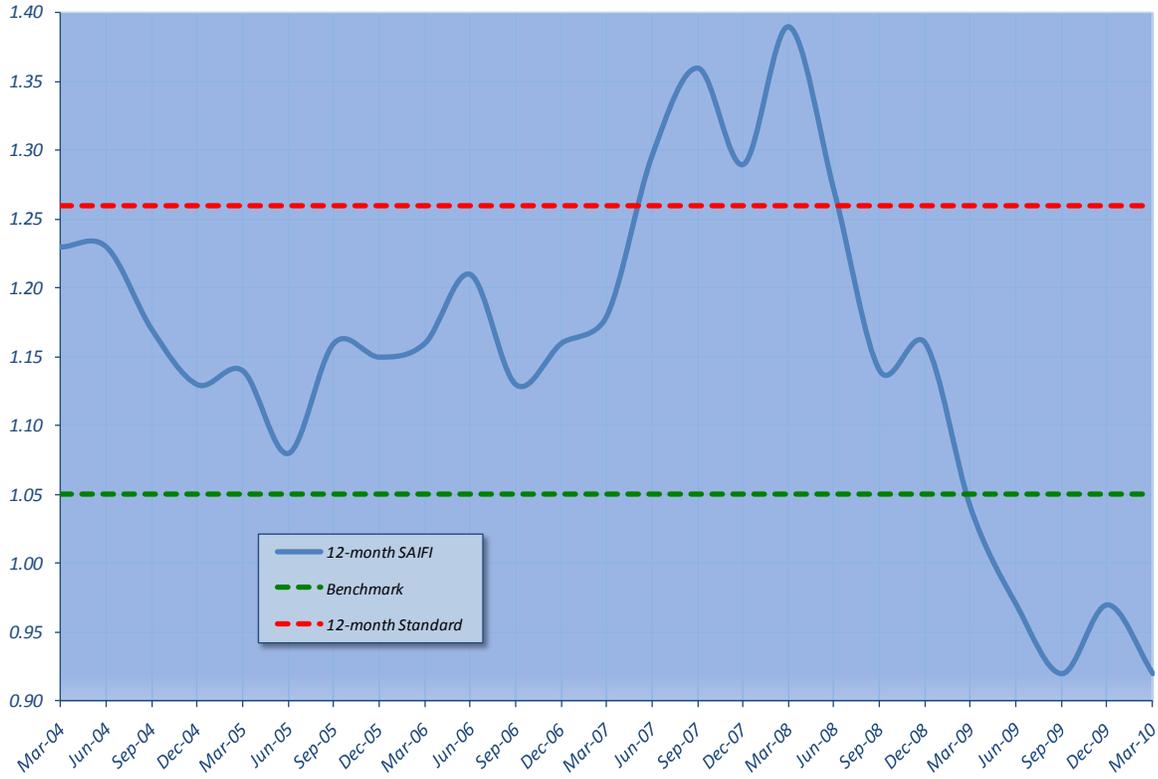


Figure 5 Allegheny outage causes (percent of total outages)

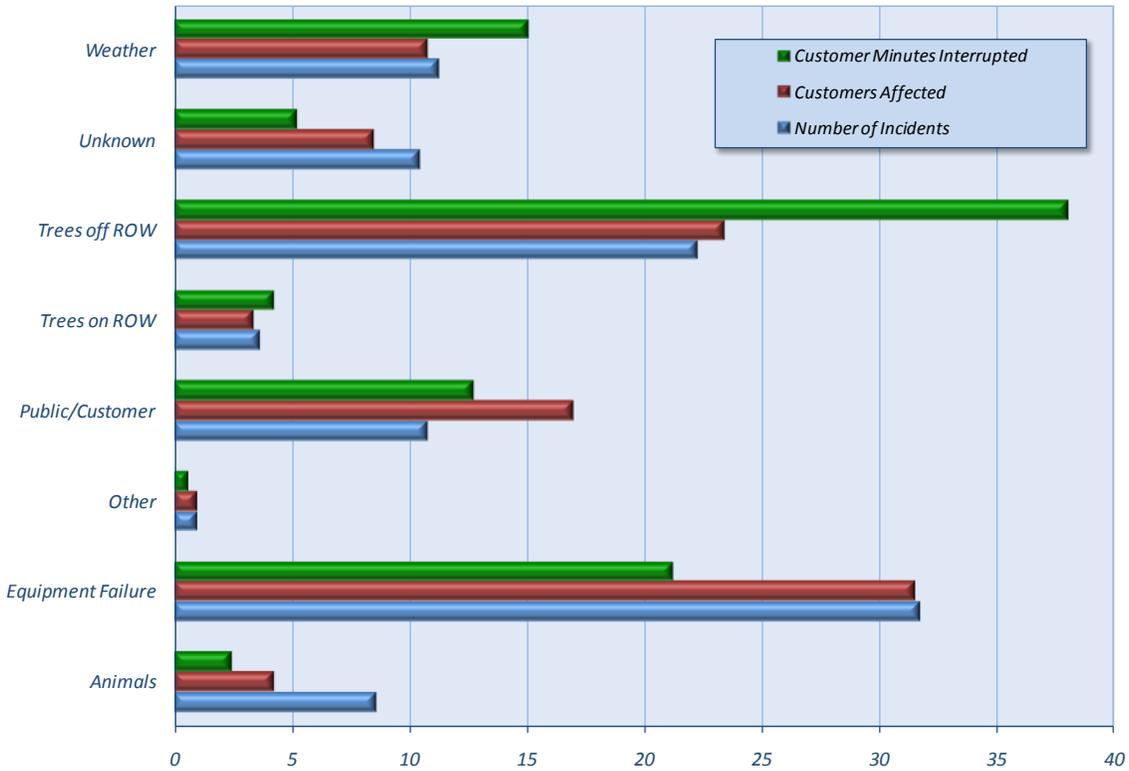


Figure 6 Allegheny outage tracking (number of incidents)



Duquesne Light Company

In 2009, Duquesne experienced a total of 6.8 million kVA interrupted with a total duration of 578.9 million kVA-minutes, which was 15.5 percent lower than that which was reported last year. One major event occurred in Duquesne’s service territory during 2009. The calculation of the reliability indices excludes outage data relating to this event, which was approved by the Commission.³⁰

- Feb. 11-15, 2009 – Strong storms with sustained winds of 30 to 40 miles per hour, gusting to 60 miles per hour; 903,714 kVA were affected (13 percent of system load); 291.2 million kVA-minutes were excluded.

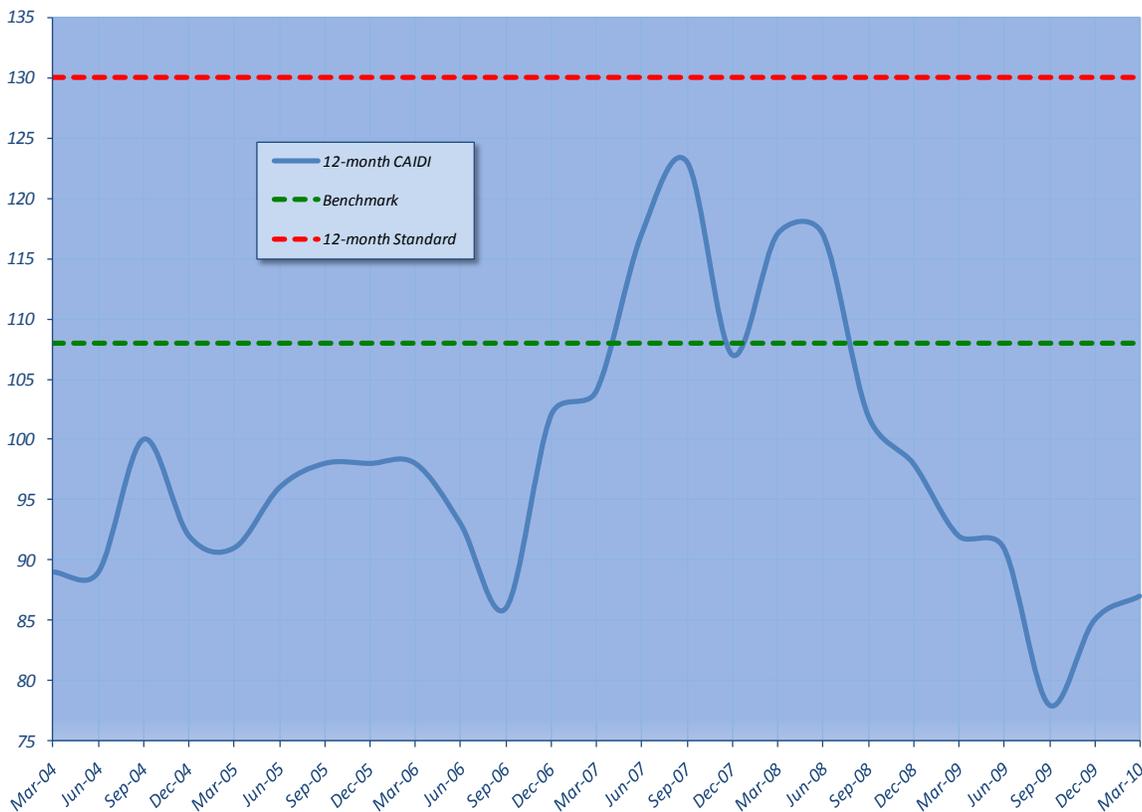
Duquesne’s 2009 CAIDI of 85 minutes was 13 minutes better than last year, a 13.3 percent decrease in CAIDI minutes and 23 minutes lower than the benchmark of 108 minutes. CAIDI has remained below the benchmark since September 2008 and was the lowest at 85 minutes for the 12 months ending December 2009, according to Commission records. The CAIDI three-year average was 22 minutes below the standard of 119 minutes, or five minutes better than last year’s average performance. For the 12-month average ending March 31, 2010, CAIDI was 87 minutes, or 19.4 percent below the benchmark. SAIDI dropped from 97 minutes in 2008 to 82 minutes in 2009, or a 15.5 percent improvement. Figure 7 depicts the trend in the duration of customer interruptions for the Duquesne system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

³⁰ Docket No. M-2009-2096867.

Duquesne’s SAIFI reliability performance continues to fall well within the parameters of acceptability. The 2009 SAIFI was an average of 0.97 outages per customer, compared to last year’s 0.99 and a benchmark of 1.17 outages.³¹ Interruption frequency has remained well below the benchmark since 2004. Since its low of 0.77 in September 2006, SAIFI has risen to just under one outage, still 17 percent better than the historical benchmark. The three-year SAIFI average continues to be well below the standard. For the 12-month average ending March 31, 2010, SAIFI was 0.95, or 18.8 percent below the benchmark. Figure 8 shows the trend in the frequency of service interruptions for the Duquesne service territory from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, equipment failure was responsible for 32.9 percent of the outages, 36.0 percent of interrupted load and 35.1 percent of interruption minutes, up from 28.5 percent in 2008. Fallen trees accounted for 16.0 percent of outages, 19.2 percent of interrupted load and 17.8 percent of interruption minutes. Storms were identified as causing 14.7 percent of the outages, 14.2 percent of interrupted load and 27.7 percent of interruption minutes. Figure 9 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top three major causes is shown in Figure 10.

Figure 7 Duquesne Customer Average Interruption Duration Index (minutes)



³¹ Duquesne’s system does not provide an actual count of customers interrupted. The data available is in regard to interrupted load. The unit used is kVA, or kilovoltampere, which is the basic unit of apparent power.

Figure 8 Duquesne System Average Interruption Frequency Index (interruptions per customer)



Figure 9 Duquesne outage causes (percent of total outages)

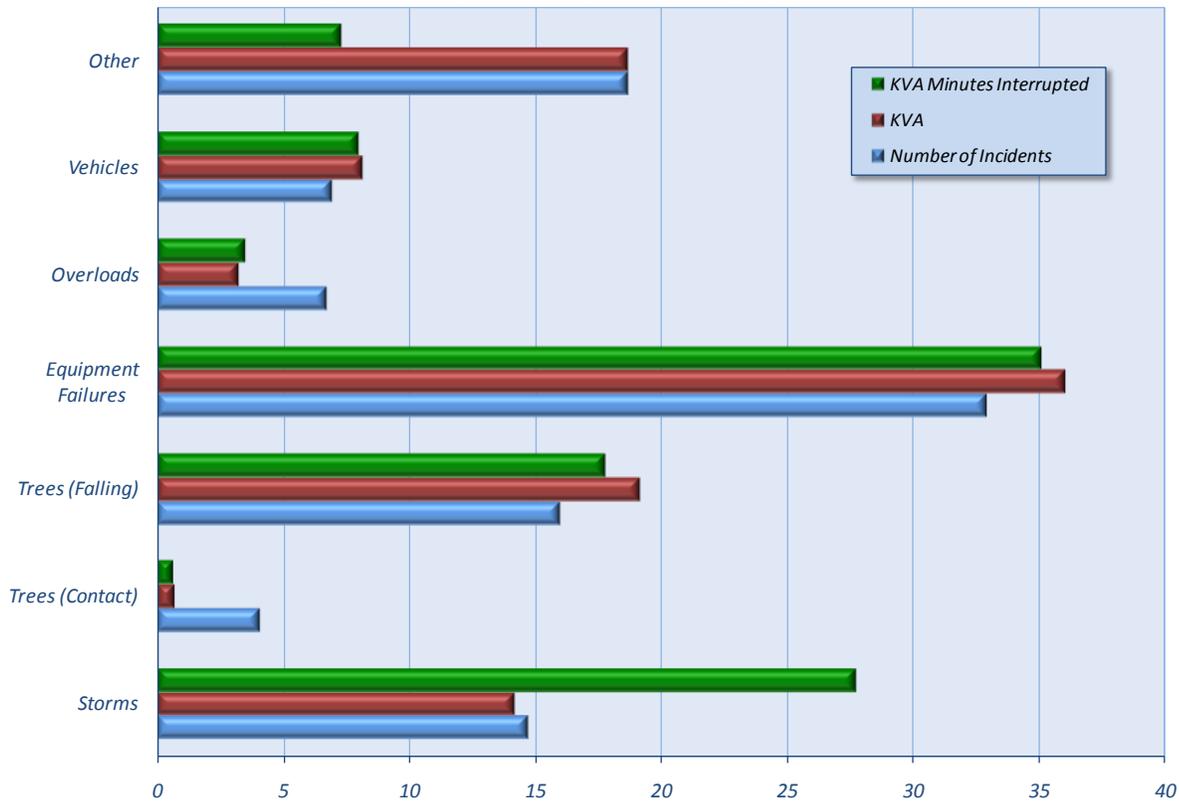
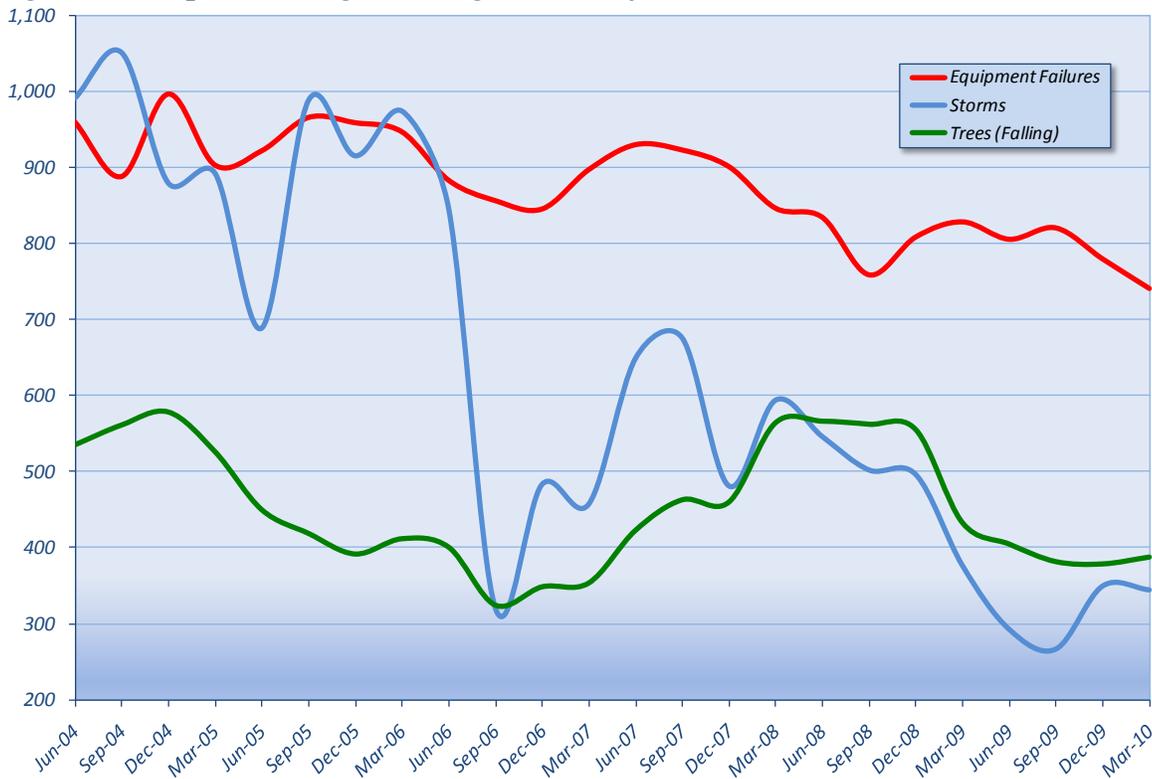


Figure 10 Duquesne outage tracking (number of incidents)



Metropolitan Edison Company

Met-Ed’s reliability performance summary was filed as a joint report submitted on behalf of the three Pennsylvania operating companies of FirstEnergy: Met-Ed, Penelec and Penn Power.

In 2009, Met-Ed experienced 660,319 customer interruptions with a total duration of 73 million customer minutes, or 3.1 percent lower than 2008. Nearly 9,000 incidents were reported. No major events occurred in Met-Ed’s service territory during 2009.

Met-Ed’s CAIDI for 2009 was 111 minutes, an increase from 104 minutes in 2008, and six minutes lower than the benchmark. This is the first time Met-Ed’s annual CAIDI has shown an increased value since 2004. CAIDI has been below the benchmark for every quarter since December 2007. The CAIDI three-year average was 20 minutes below the standard of 129 minutes. For the 12-month average ending March 31, 2010, CAIDI was 117 minutes, equal to the benchmark. SAIDI dropped from 139 minutes in 2008 to 134 minutes in 2009, which is one minute better than the Commission-established benchmark. Figure 11 shows the trend in the duration of customer interruptions for the Met-Ed system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

Met-Ed’s SAIFI decreased from 1.35 in 2008 interruptions per customer to 1.21 in 2009, a 10.4 percent improvement and 12.3 percent below the standard. SAIFI has been trending downward since completion of Met-Ed’s reliability audit and has met the SAIFI standard since September 2008. For the three-year average performance, Met-Ed was above the SAIFI three-year standard by 10 percent, but is

trending downward. For the 12-month average ending March 31, 2010, SAIFI was 1.2, or 4.4 percent above the benchmark. Figure 12 shows the trend in the frequency of customer interruptions for the Met-Ed system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

Equipment failure was responsible for 28.2 percent of incidents, 29.6 percent of customers affected and 25.6 percent of interruption minutes. Non-preventable tree-related incidents caused 20.4 percent of the incidents, 25.2 percent of customers affected and 36.2 percent of interruption minutes. Animals caused 12.7 percent of the outages, 2.7 percent of customers affected and 1.8 percent of interruption minutes. Of the total number of incidents, 12.1 percent were assigned to Met-Ed’s “unknown” category. This category ranked as the No. 4 cause for outages. Figure 13 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top four major causes is shown in Figure 14.

In 2009, Met-Ed implemented a series of reliability improvement initiatives, including aggressive tree-trimming and detailed circuit-condition assessments. To limit the scope of an outage, additional protective equipment, such as fuses and remote controlled switches were systematically added. Future reliability improvements include the application of distribution automation to operate the system.

Figure 11 Met-Ed Customer Average Interruption Duration Index (minutes)

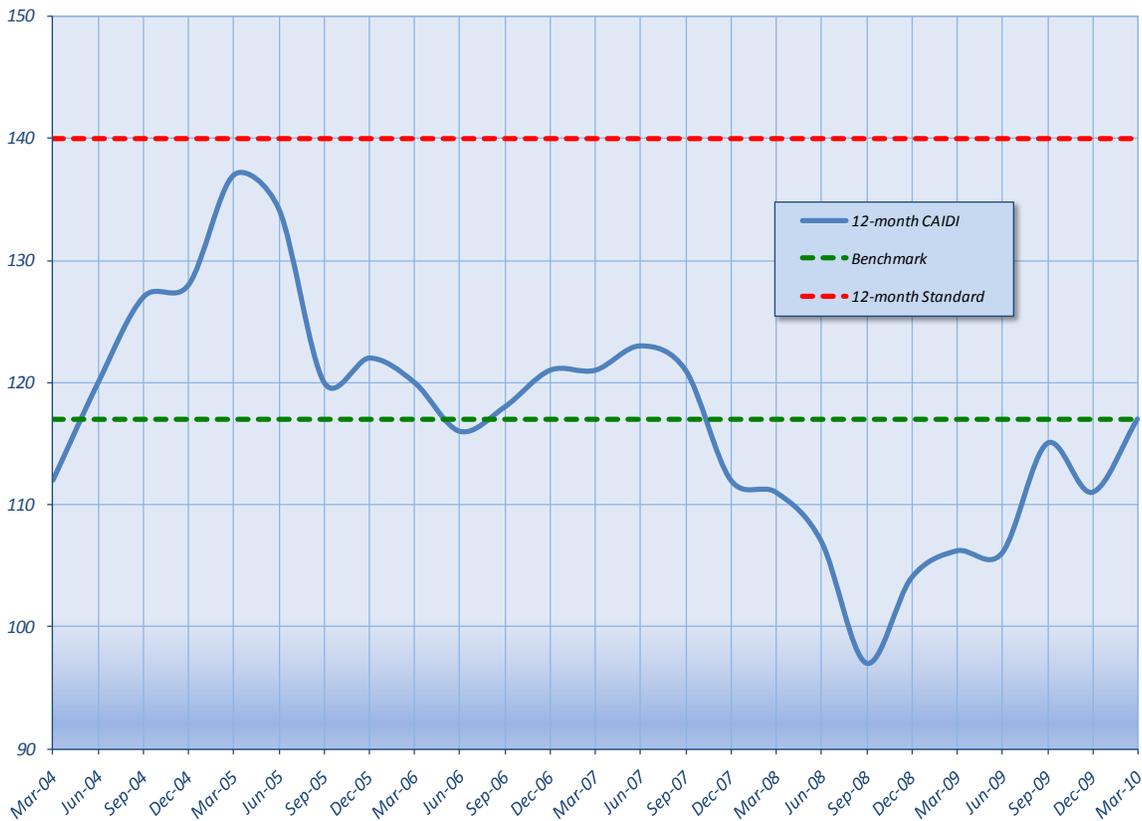


Figure 12 Met-Ed System Average Interruption Frequency Index (interruptions per customer)

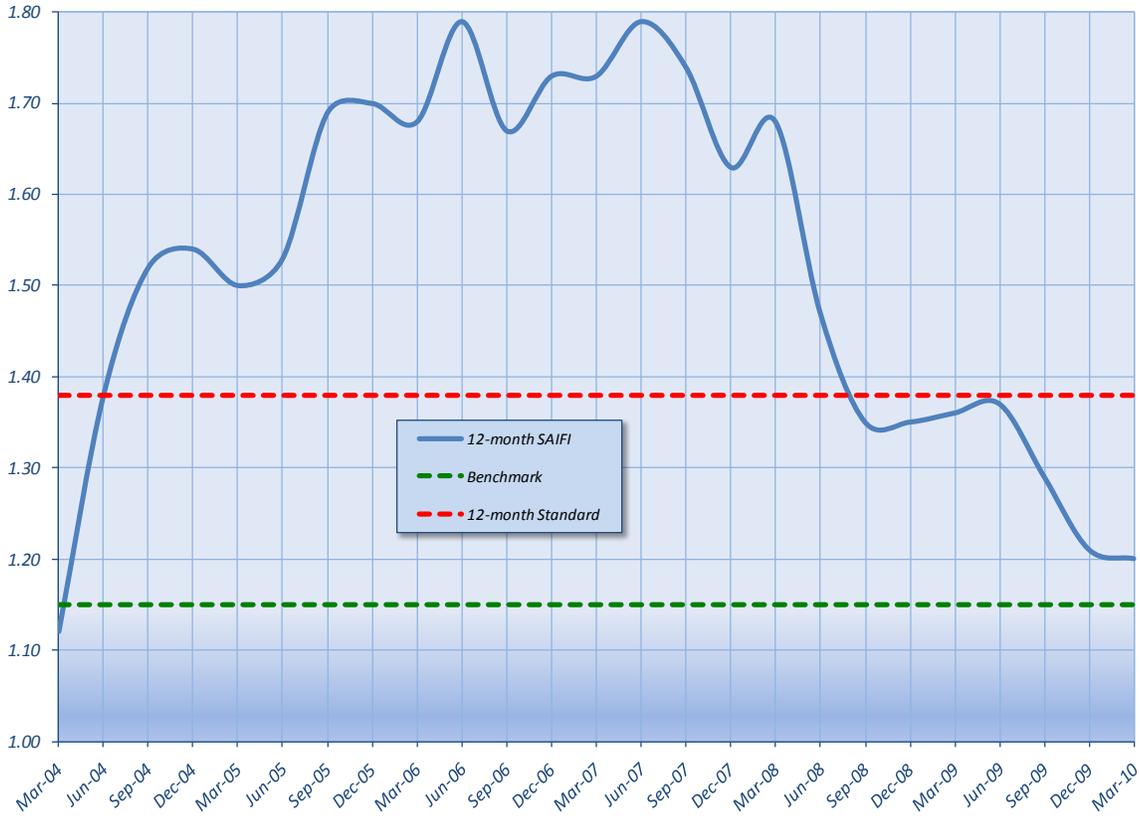


Figure 13 Met-Ed outage causes (percent of total outages)

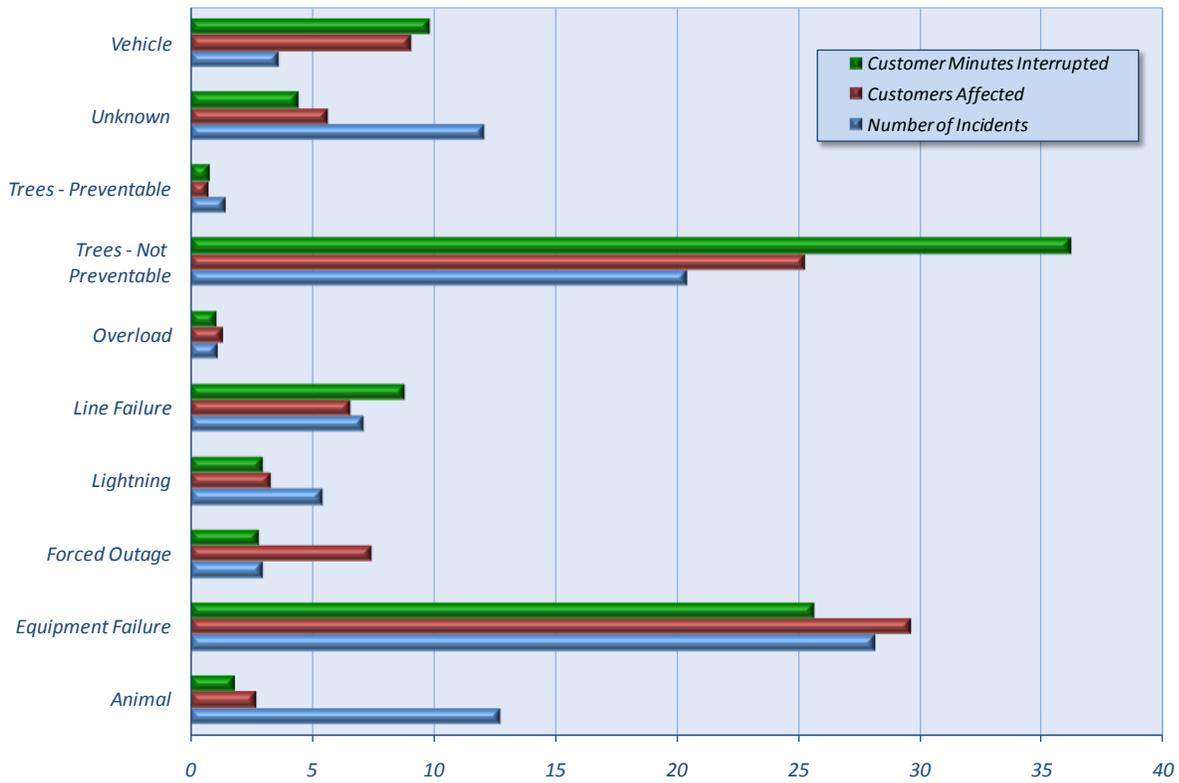
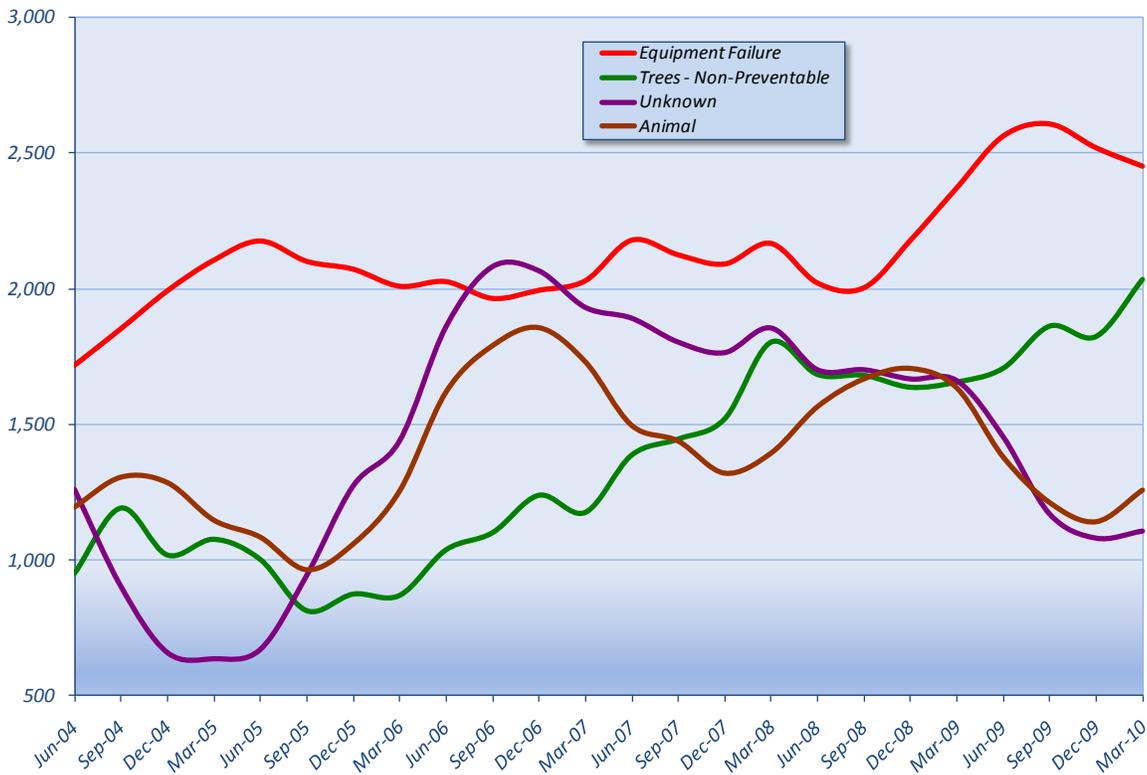


Figure 14 Met-Ed outage tracking (number of incidents)



Pennsylvania Electric Company

Penelec’s reliability performance summary was filed as a joint report submitted on behalf of the three Pennsylvania operating companies of FirstEnergy: Met-Ed, Penelec and Penn Power.

In 2009, Penelec experienced 711,565 customer interruptions with a total duration of 83.2 million customer minutes, or 34.8 percent lower than last year. One major event occurred in Penelec’s service territory during 2009. The calculation of the reliability indices excludes outage data relating to this event, which was approved by the Commission.³²

- Feb. 11-15, 2009 – Wind storm with gusts of over 60 miles per hour; 131,643 customers were affected; 57.5 million minutes were excluded.

Penelec’s overall reliability indices in 2009 were much lower than last year’s. CAIDI decreased from 142 minutes in 2008 to 116.9 minutes in 2009, which was a 17.7 percent decrease in CAIDI minutes and 0.1 percent better than the benchmark of 117 minutes. This the first time CAIDI has met the benchmark since December 2007. The CAIDI three-year average was six minutes below the standard of 129. For the 12-month average ending March 31, 2010, CAIDI was 120 minutes, or 2.6 percent above the benchmark. SAIDI dropped from 220 minutes in 2008 to 143 minutes in 2009, or 3.4 percent below the benchmark. Figure 15 depicts the trend in the duration of customer interruptions for the Penelec system

³² Docket No. M-2009-2095886.

from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

Penelec’s SAIFI decreased from 1.56 service interruptions per customer in 2008 to 1.22 in 2009, which was a 21.8 percent improvement and 3.2 percent below the benchmark of 1.26. SAIFI was better than the benchmark for three of the four quarters of 2009. The SAIFI three-year average was 1.50, or 7.7 percent above the standard of 1.39, but is trending downward. For the 12-month average ending March 31, 2010, SAIFI was 1.24, or 1.6 percent below the benchmark. Figure 16 shows the trend in the frequency of service interruptions for the Penelec system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, equipment failure was responsible for 30.7 percent of incidents, 31.0 percent of customers affected and 26.7 percent of interruption minutes. Penelec has identified porcelain cutout failures to be a large contributor to equipment failure outages and has been replacing them with polymer cutouts as a preventative measure. Non-preventable tree-related incidents accounted for 15.8 percent of total incidents, 19.1 percent of customers affected and 35.1 percent of interruption minutes. Animals contributed to 11.4 percent of total incidents, 4.9 percent of customers affected and 2.8 percent of interruption minutes. Outages in the “unknown” category represented 13.7 percent of incidents, 10.1 percent of customers affected and 7.2 percent of interruption minutes. Figure 17 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top four major causes is shown in Figure 18.

Figure 15 Penelec Customer Average Interruption Duration Index (minutes)

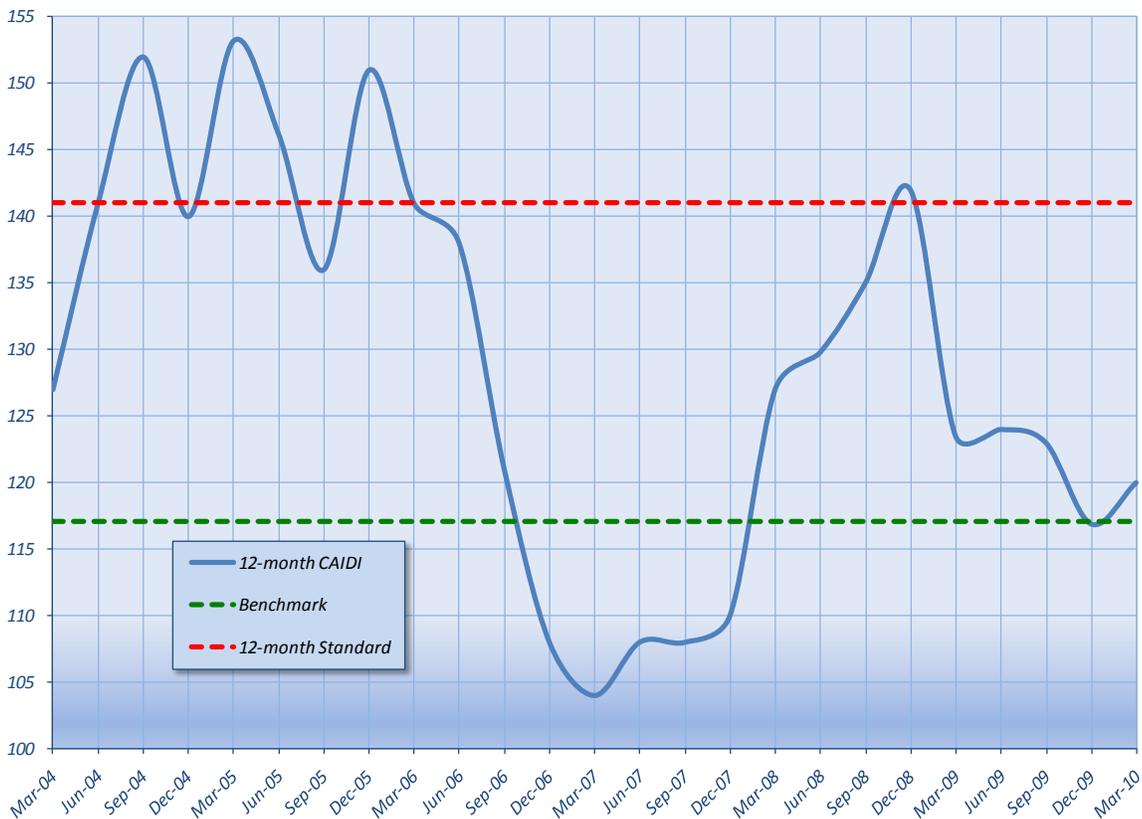


Figure 16 Penelec System Average Interruption Frequency Index (interruptions per customer)

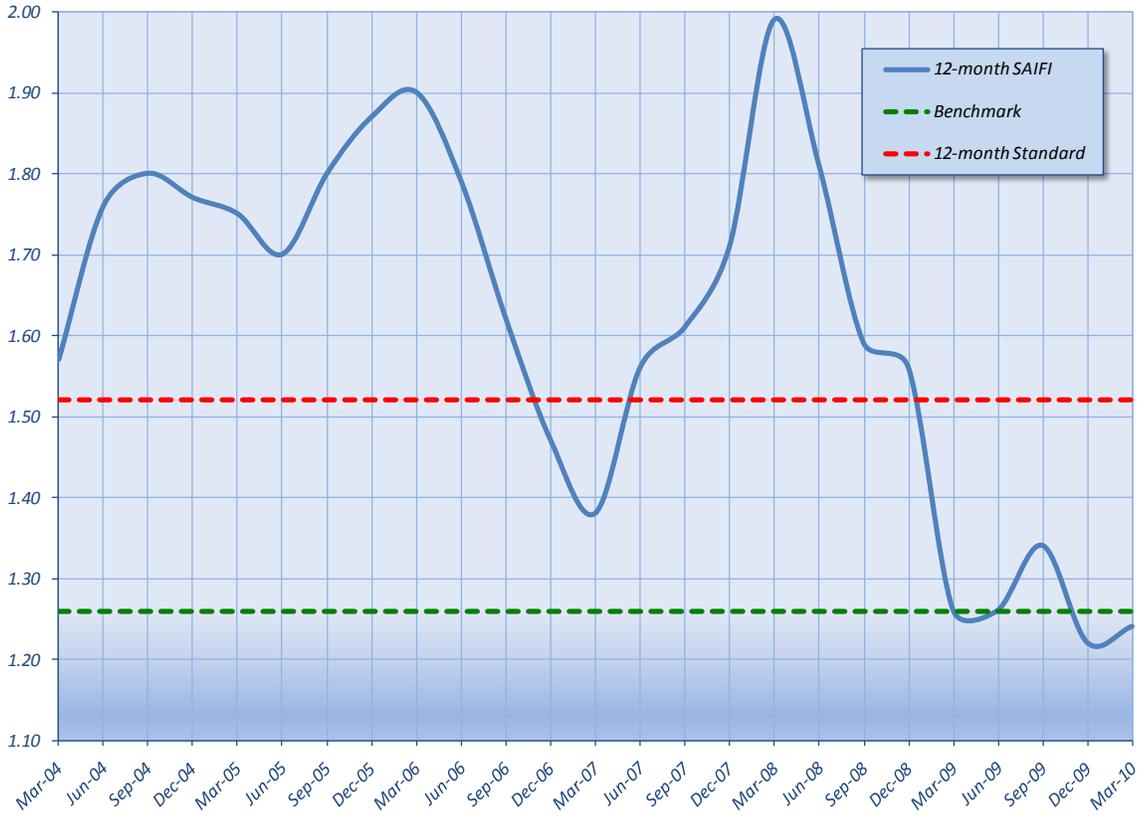


Figure 17 Penelec outage causes (percent of total outages)

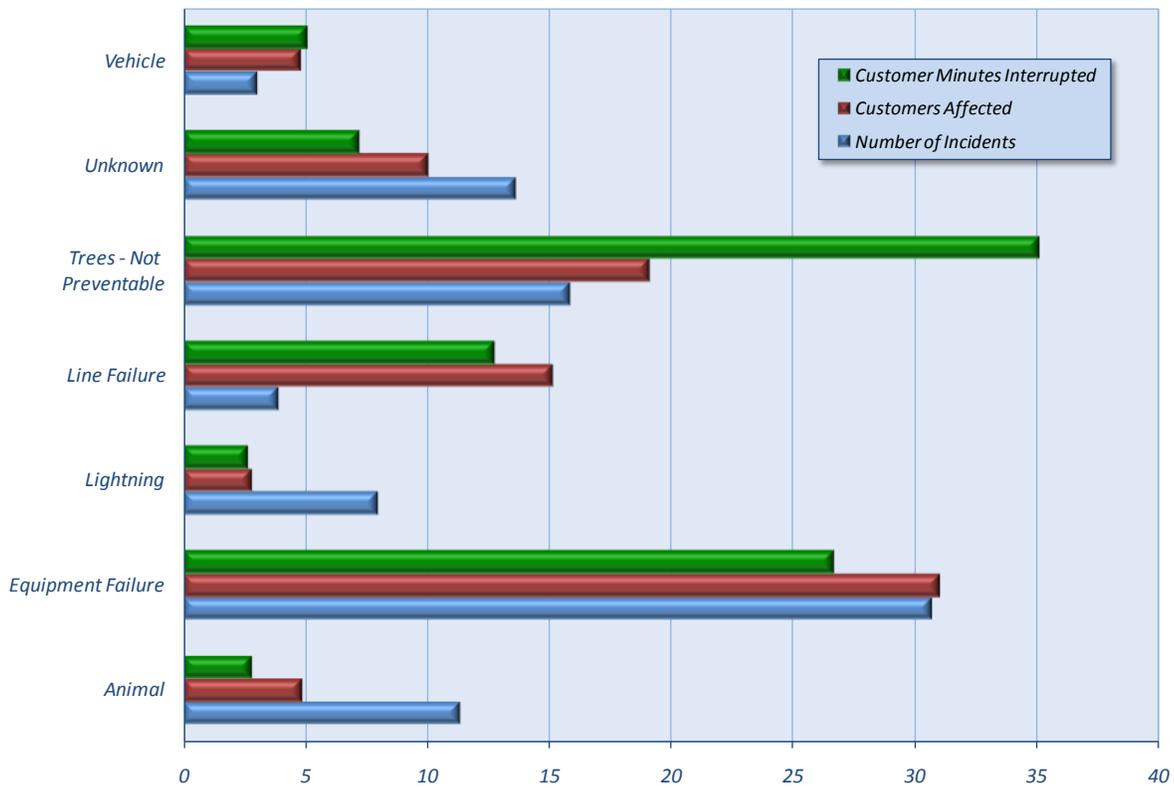
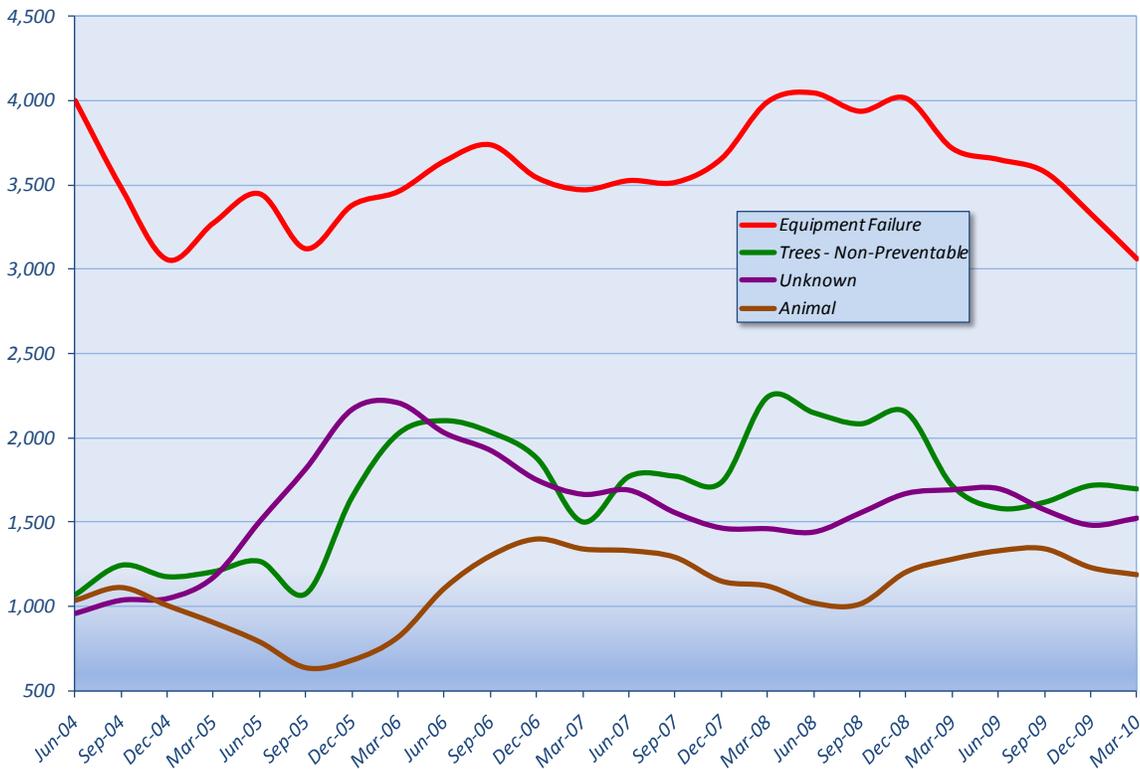


Figure 18 Penelec outage tracking (number of incidents)



Pennsylvania Power Company

Penn Power’s reliability performance summary was filed as a joint report submitted on behalf of the three Pennsylvania operating companies of FirstEnergy: Met-Ed, Penelec and Penn Power.

In 2009, Penn Power experienced 118,277 customer interruptions with a total duration of 13.7 million minutes, or 30.8 percent lower than 2008. Penn Power’s customers experienced one major event. The outage data relating to this event has been excluded from the calculation of the reliability indices.³³

- Feb. 11-14, 2009 – Wind storm with gusts up to 51 miles per hour; 33,796 customers were affected; 12.3 million minutes were excluded.

Penn Power’s CAIDI increased from 111 minutes in 2008 to 116 minutes in 2009, which was a 4.5 percent increase in CAIDI minutes, 15 minutes above the benchmark and 4.1 percent below the standard. Penn Power has consistently met the CAIDI standard since June 2008. The CAIDI three-year average was seven minutes above the standard of 111 minutes, but has been trending downward. For the 12-month average ending March 31, 2010, CAIDI was 109 minutes, or 7.9 percent above the benchmark. SAIDI dropped from 125 minutes in 2008 to 87 minutes in 2009. Figure 19 depicts the trend in the duration of customer interruptions for the Penn Power system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

³³ Docket No. M-2009-2095946.

Penn Power’s SAIFI was 33.6 percent lower than last year’s, dropping from 1.13 service interruptions per customer in 2008 to 0.75 in 2009, which is 33.0 percent below the benchmark of 1.12. SAIFI was better than the benchmark for all four quarters of 2009. The SAIFI three-year average was 1.02, or 16.8 percent below the standard of 1.23, and continues to trend downward. For the 12-month average ending March 31, 2010, SAIFI was 0.88, or 21.4 percent better than the benchmark. Figure 20 shows the trend in the frequency of service interruptions for the Penn Power system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, non-preventable tree-related outages represented 21.5 percent of the incidents, 16.6 percent of customers affected and 31.7 percent of interruption minutes. Equipment failure accounted for 13.7 percent of the incidents, 16.8 percent of customers affected and 16.5 percent of interruption minutes. Porcelain cutouts were found to be the major cause for cutout-related outages, resulting in the discontinued use of porcelain cutouts for new installations, and older porcelain cutouts are being replaced with new polymer cutouts when they fail. Line failure resulted in 11.1 percent of incidents, 14.2 percent of customers affected and 12.2 percent of interruption minutes. Lightning caused 9.3 percent of outages, 14.2 percent of customers affected and 12.2 percent of interruption minutes. Figure 21 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top four major causes is shown in Figure 22.

Figure 19 Penn Power Customer Average Interruption Duration Index (minutes)

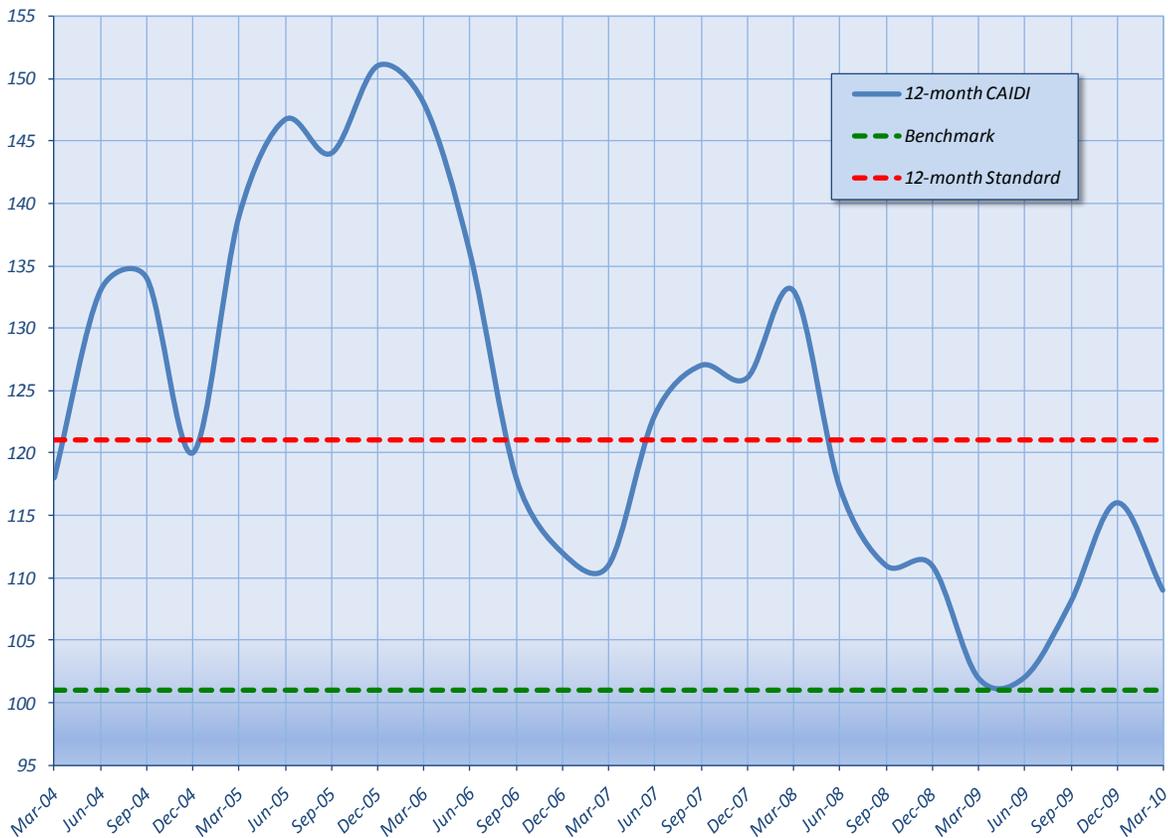


Figure 20 Penn Power System Average Interruption Frequency Index (interruptions per customer)

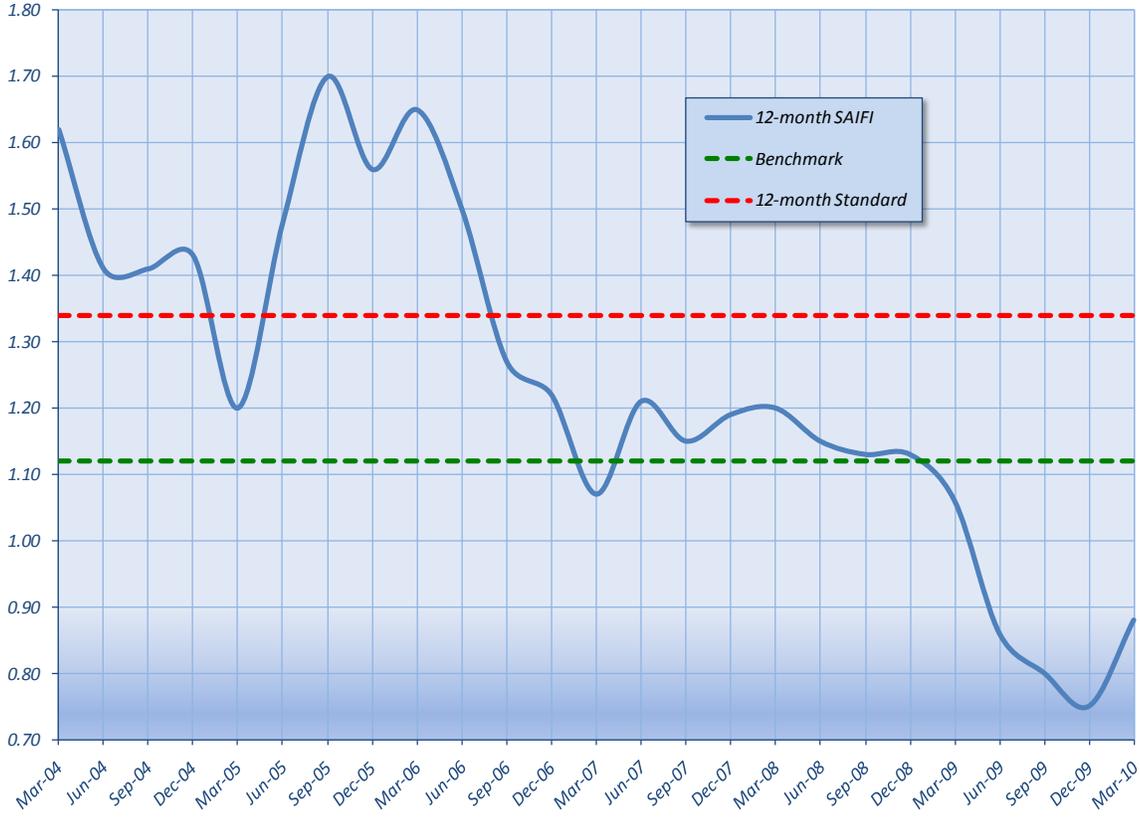


Figure 21 Penn Power outage causes (percent of total outages)

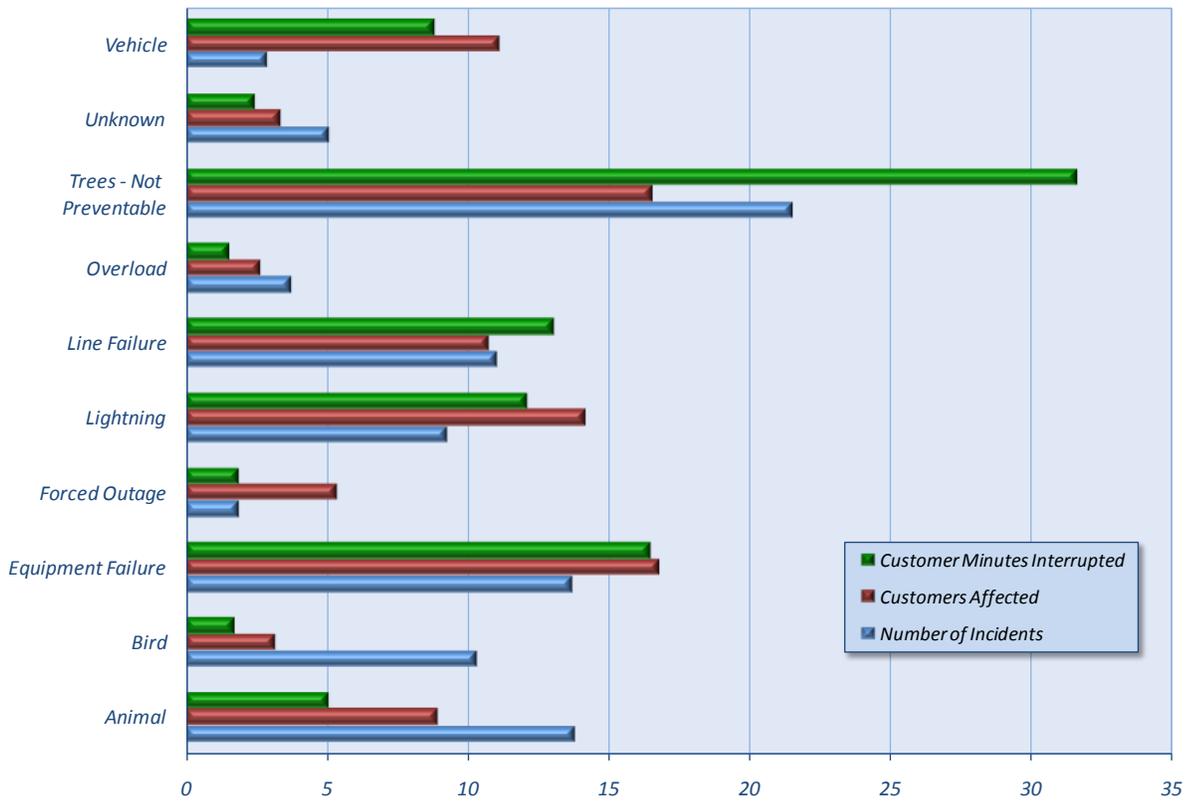
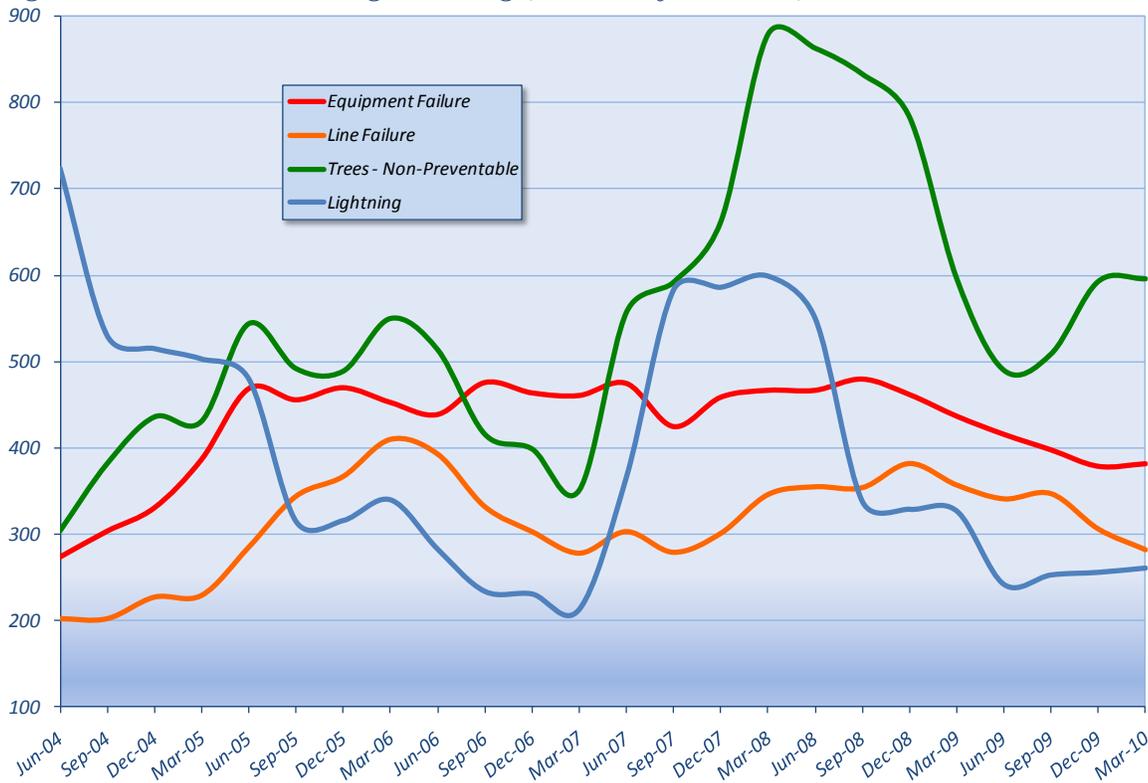


Figure 22 Penn Power outage tracking (number of incidents)



PECO Energy Company

In 2009, PECO’s customers experienced 1,633,916 service interruptions with a total duration of 214.9 million minutes, which was 19.6 percent lower than the 2008 outage minutes. No major events occurred in PECO’s service territory during 2009.

PECO’s CAIDI decreased from 124 minutes in 2008 to 106 minutes in 2009, which was a 14.5 percent improvement and 5.4 percent better than the benchmark of 112 minutes. CAIDI was below the benchmark for three of the past four quarters. The CAIDI three-year average was 9.2 percent below the standard of 123 minutes. For the 12-month average ending March 31, 2010, CAIDI was 130 minutes, or 3.0 percent below the standard, the increase being attributable to a March storm that was not a major event. SAIDI dropped from 129 minutes in 2008 to 103 minutes in 2009. Figure 23 depicts the trend in the duration of customer interruptions for the PECO system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

PECO’s SAIFI decreased from 1.04 interruptions in 2008 to 0.98 in 2009, which was a 5.8 percent improvement on outage frequency and 20.3 percent better than the benchmark of 1.23. SAIFI has remained below the benchmark for most of the past 10 years. The SAIFI three-year average was 25.7 percent below the standard of 1.35. For the 12-month average ending March 31, 2010, SAIFI was 1.07, or 13.0 percent below the benchmark. Figure 24 depicts the trend in the frequency of service interruptions for the PECO system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, equipment failure was responsible for 35.6 percent of the incidents, 34.7 percent of customers affected and 32.7 percent of interruption minutes. Tree-related outages involving broken branches and tree trunks or uprooted trees caused 17.1 percent of the incidents, 24.2 percent of customers affected and 26.5 percent of interruption minutes. Vegetation in-growth caused 10.7 percent of outages, 6.3 percent of customers affected and 9.8 percent of interruption minutes. Of the total number of incidents, 13.8 percent were categorized as “other.” Figure 25 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top four major causes is shown in Figure 26.

PECO completed installation of a new mobile dispatch system in 2009. This new technology provides the capability to transfer outage information directly from centrally located computers to computers in the vehicles of workers in the field for more efficient operations in outage restoration.

Figure 23 PECO Customer Average Interruption Duration Index (minutes)

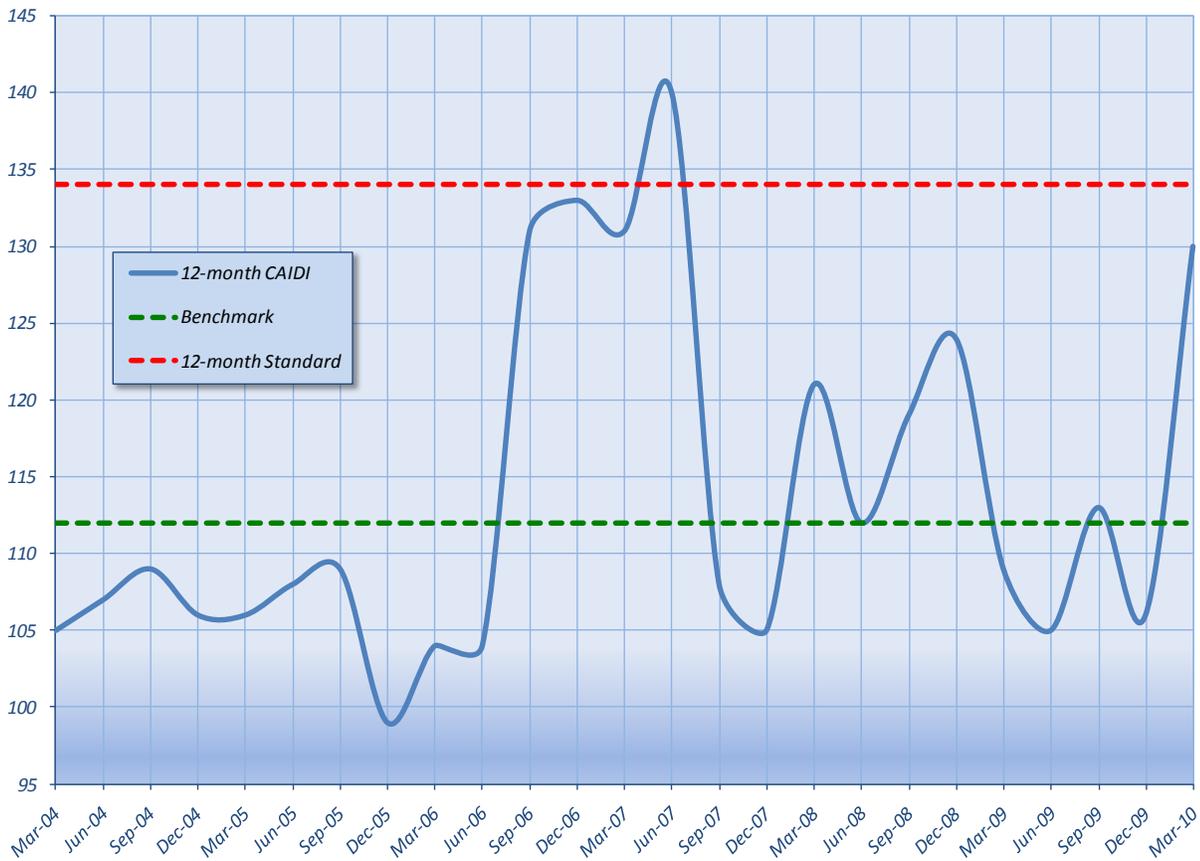


Figure 24 PECO System Average Interruption Frequency Index (interruptions per customer)

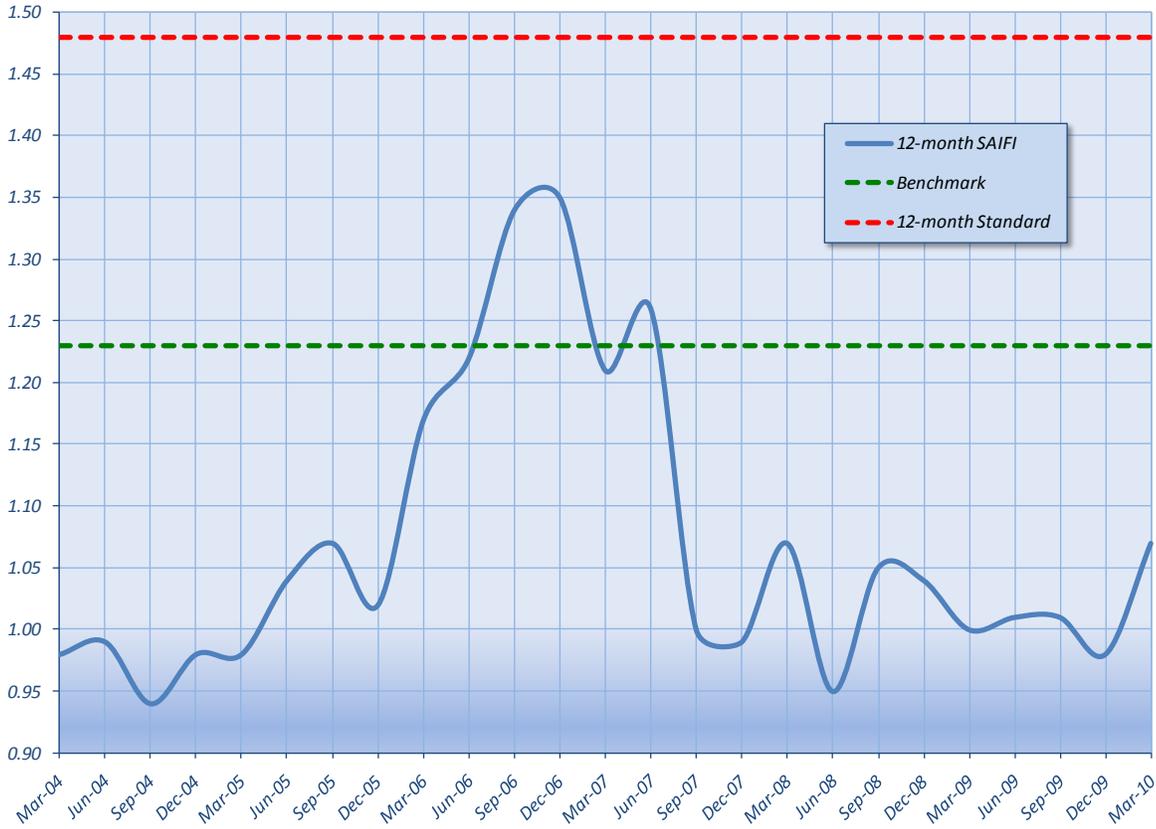


Figure 25 PECO outage causes (percent of total outages)

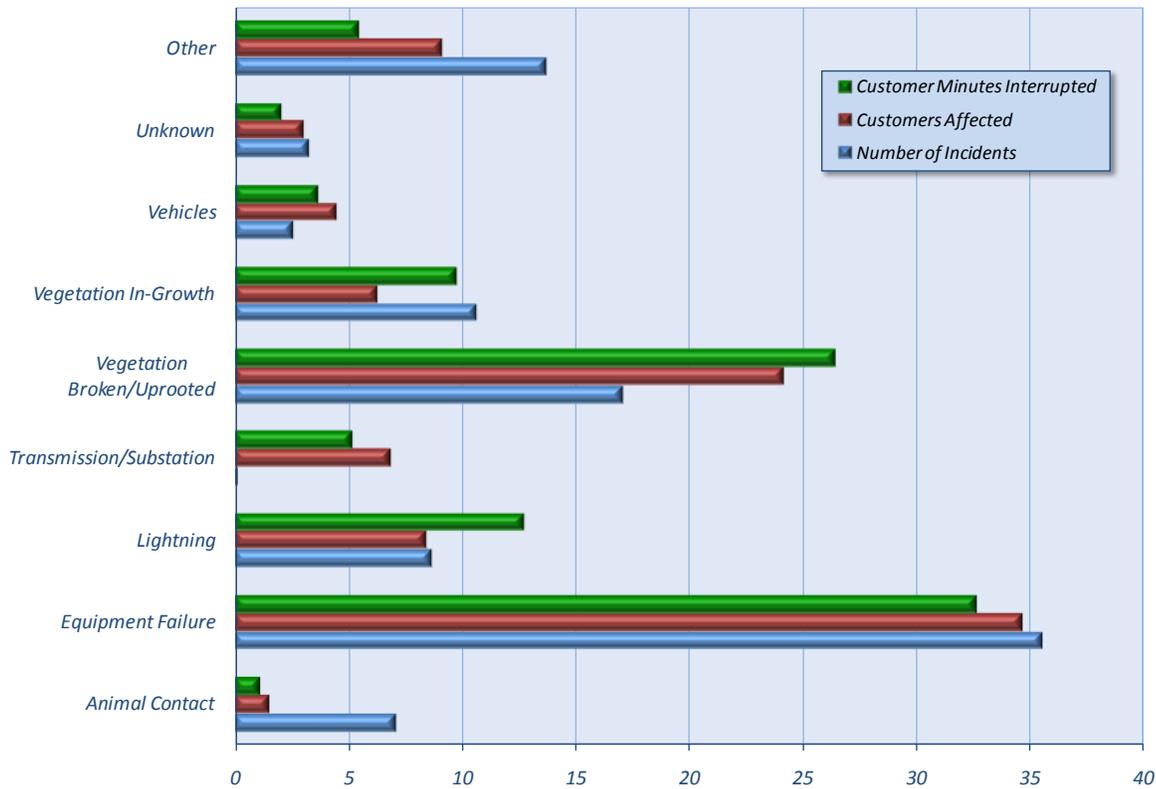
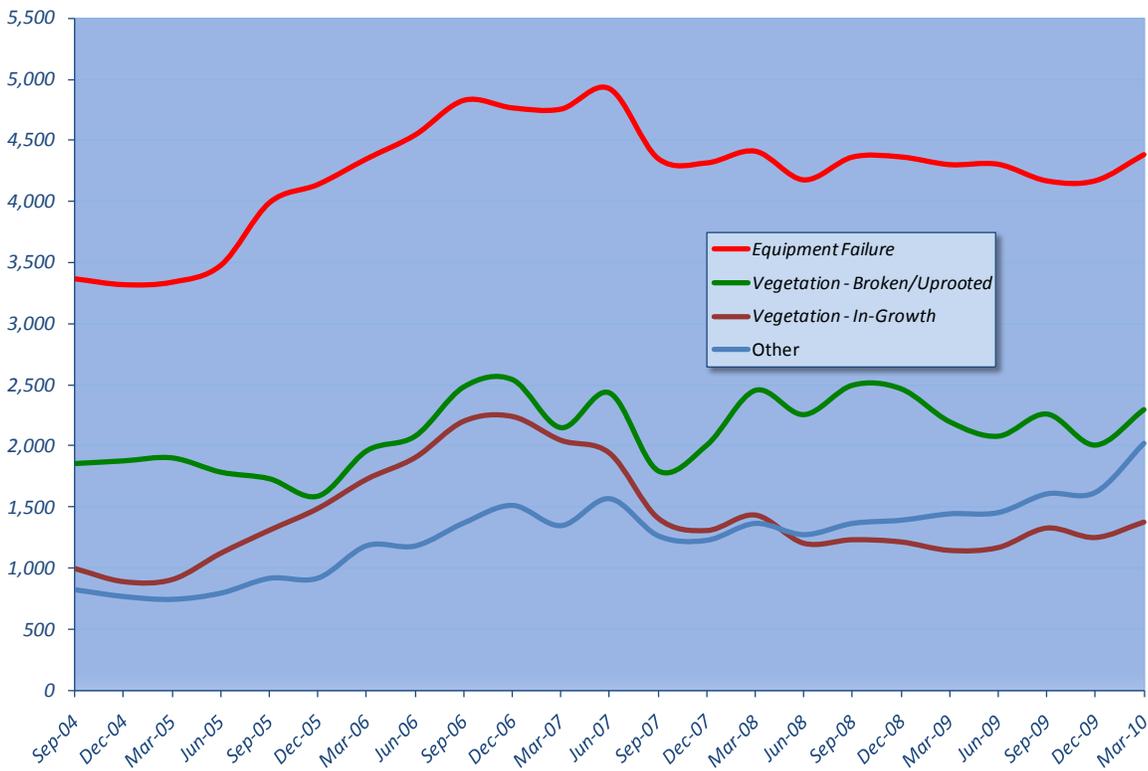


Figure 26 PECO outage tracking (number of incidents)



PPL Electric Utilities Corporation

PPL’s customers experienced 1,225,421 service interruptions in 2009 with a total duration of 143.4 million minutes, or 41.5 percent lower than last year’s figure. No major events occurred in PPL’s service territory during 2009. There were, however, four PUC-reportable storms, other than major events, which is comparable to the average of 4.2 storms per year during the benchmark years, 1994-1998. There were also 16 storms that were not reportable, compared to an average of 10.7 storms per year recorded from 2000 to 2005. The company’s overall performance was attributable to these storms, which required opening one or more area emergency centers to manage restoration efforts.

PPL’s CAIDI was much improved from last year, dropping from 169 minutes in 2008 to 117 minutes in 2009, which was a 30.8 percent decline and 19.3 percent below the benchmark of 145 minutes. This is the first time PPL’s CAIDI was better than the benchmark since December 2007. The CAIDI three-year average was 11.3 percent below the standard of 160 minutes. For the 12-month average ending March 31, 2010, CAIDI was 126 minutes, or 13.1 percent below the benchmark. SAIDI dropped from 178 minutes in 2008 to 104 minutes in 2009. Figure 27 depicts the trend in the duration of customer interruptions for the PPL system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

PPL’s SAIFI decreased from 1.05 in 2008 to 0.89 in 2009, which was a 15.2 percent decline in outage frequency and 9.7 percent better than the benchmark of 0.98. SAIFI has remained below the benchmark for the last three quarters of 2009. The SAIFI three-year average was 1.02, or 5.9 percent below the

standard of 1.08. For the 12-month average ending March 31, 2010, SAIFI was 0.92, or 6.3 percent below the benchmark. Figure 28 depicts the trend in the frequency of service interruptions for the PPL system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, equipment failure represented 30.3 percent of the interruptions, 34.5 percent of customers affected and 30.3 percent of interruptions minutes. PPL reported that 46 percent of trouble cases, 50 percent of customer interruptions and 58 percent of interruption minutes attributed to equipment failure were weather-related and are not considered to be indicators of equipment condition or performance. Non-trimming tree-related outages, generally caused by trees falling from outside of PPL’s rights-of-way, were the second largest cause of customer outages representing 24.2 percent of incidents, 28.9 percent of customers affected and 42.7 percent of interruption minutes. Animal-related outages accounted for 22.4 percent of incidents, 8.1 percent of customers affected and 4.4 percent of interruption minutes. Most of these trouble cases are associated with individual distribution transformers. In 2009, PPL initiated distribution and substation animal guarding programs to systematically focus on protecting facilities most at risk of incurring animal-caused interruptions. Figure 29 shows the distribution of causes of service outages occurring during 2008 as a percentage of total outages. The trend in the number of outages by the top three major causes is shown in Figure 30.

Figure 27 PPL Customer Average Interruption Duration Index (minutes)

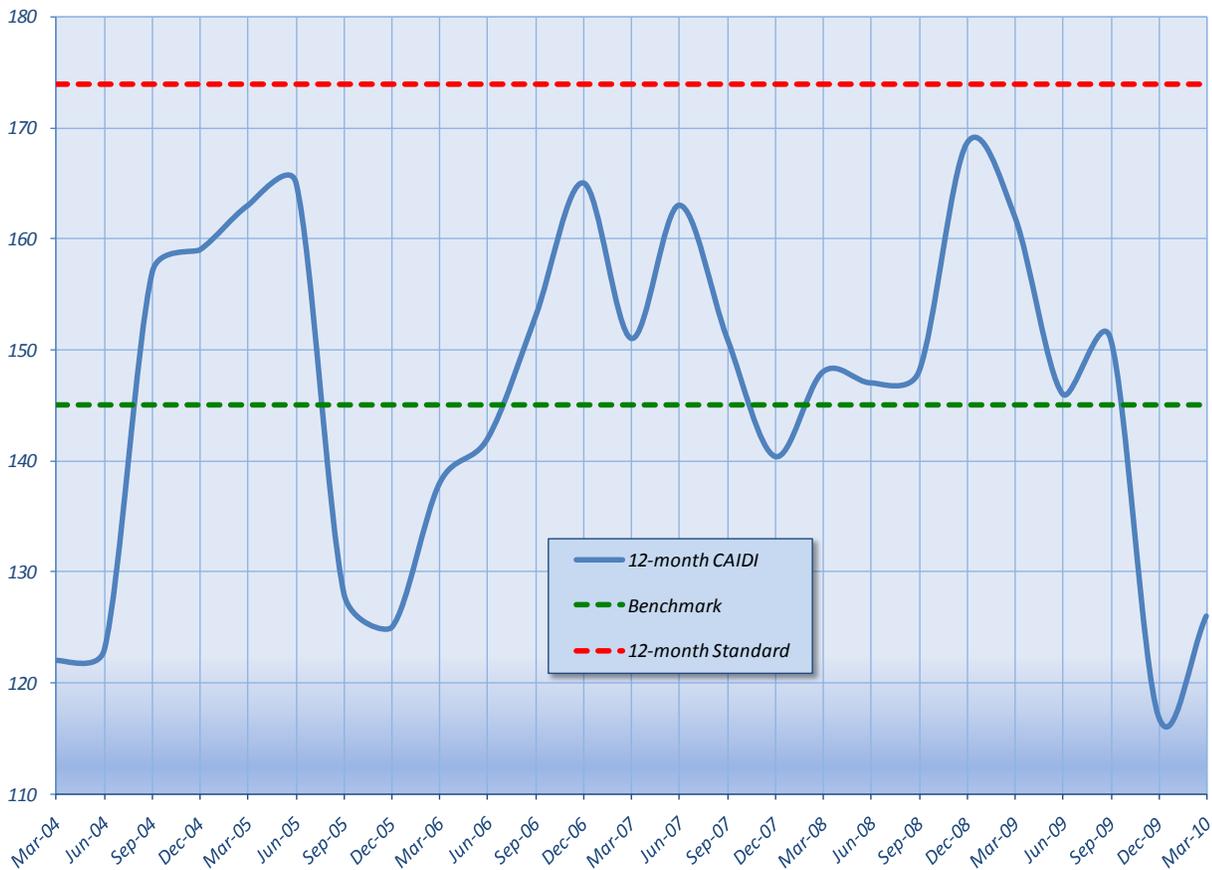


Figure 28 PPL System Average Interruption Frequency Index (interruptions per customer)

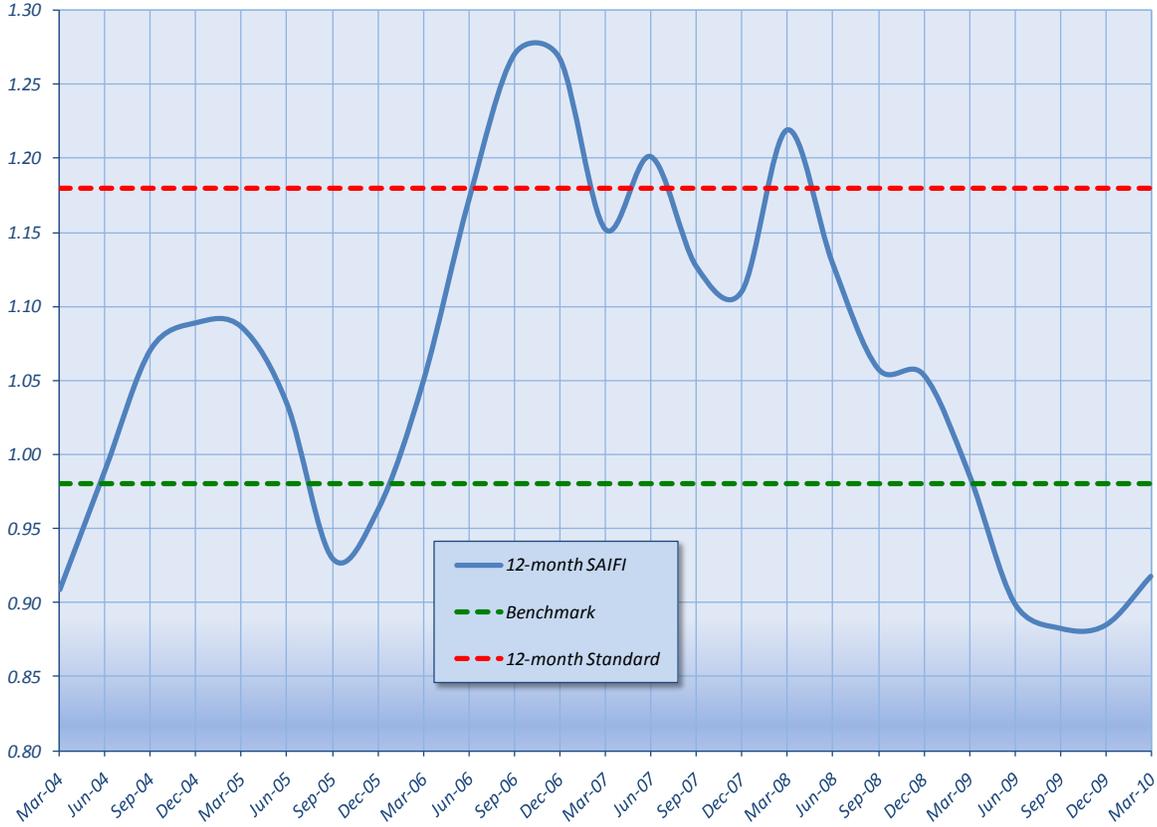


Figure 29 PPL outage causes (percent of total outages)

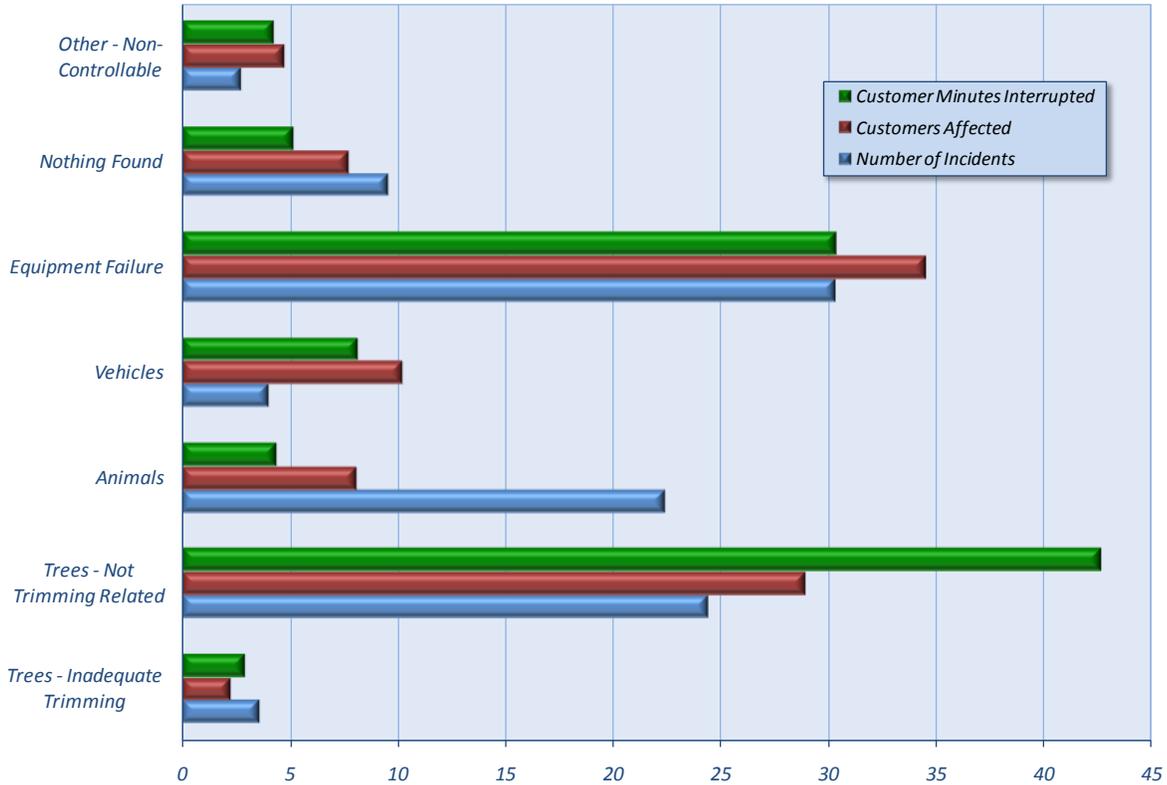
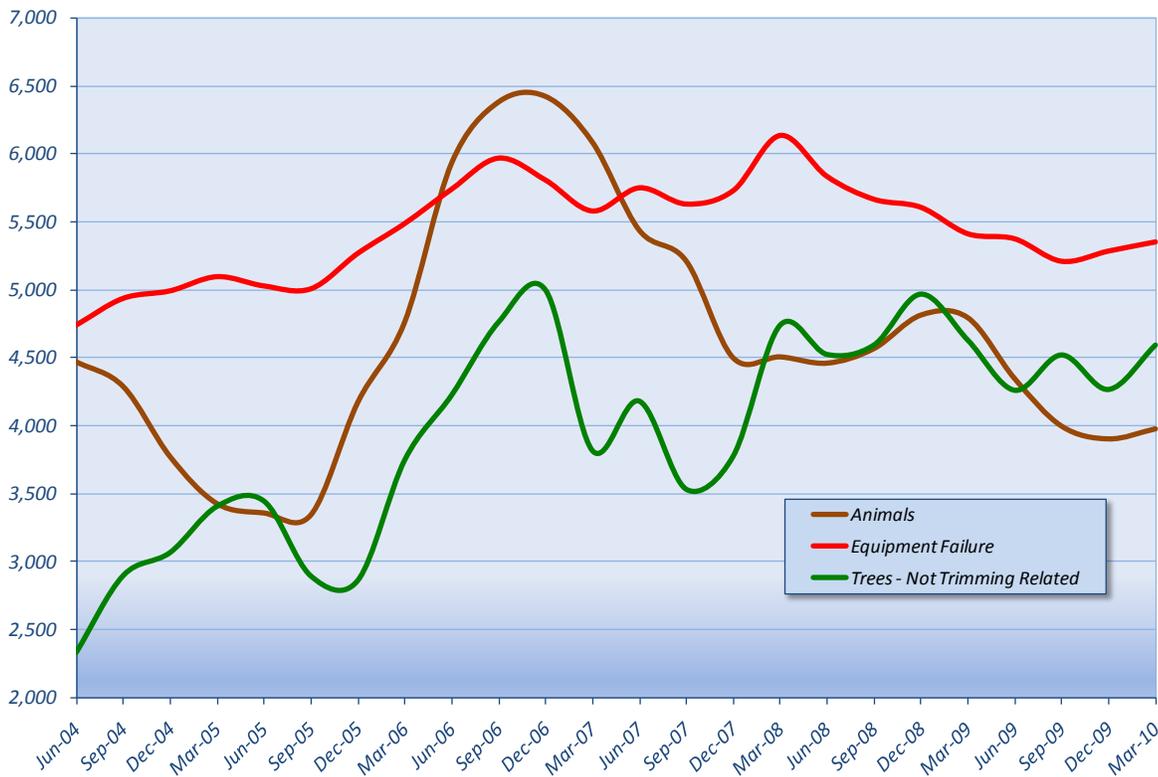


Figure 30 PPL outage tracking (number of incidents)



UGI Utilities, Inc.

In 2009, UGI’s customers experienced 47,235 service interruptions with a total duration of five million minutes, which was 11.4 percent lower than last year. No major events occurred in UGI’s service territory in 2009.

UGI’s CAIDI substantially declined from 135 minutes in 2008 to 105 minutes in 2009, which was a 22.2 percent decrease in CAIDI minutes and 37.9 percent better than the benchmark of 169 minutes. CAIDI has remained below the benchmark ever since the Commission began monitoring reliability performance. A declining CAIDI has been the general trend since December 2008. The CAIDI three-year average of 136 minutes was 27.1 percent better than the standard of 186 minutes. For the 12-month average ending March 31, 2010, CAIDI was 116 minutes, or 31.4 percent below the benchmark. SAIDI dropped from 90 minutes in 2008 to 80 minutes in 2009. Figure 31 depicts the trend in the duration of customer interruptions for the UGI system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

UGI’s SAIFI increased from 0.67 in 2008 to 0.76 in 2009, which was a 13.4 percent increase in outage frequency and 8.4 percent better than the benchmark. Except for two quarters in 2009, SAIFI has remained under the benchmark for several years. The SAIFI three-year average was 22.7 percent below the standard of 0.91. For the 12-month average ending March 31, 2010, SAIFI was 0.67, or 19.3 percent better than the benchmark. Figure 32 depicts the trend in the frequency of service interruptions for the

UGI system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, equipment failure was attributed to 36.6 percent of the incidents, 40.4 percent of customers affected and 28.2 percent of interruption minutes. Tree-related outages represented 18.4 percent of incidents, 21.0 percent of customers affected and 31.6 percent of interruption minutes. Lightning was responsible for 8.4 percent of the outages, 5.8 percent of customers affected and 3.7 percent of interruption minutes. Animals were responsible for 17.6 percent of the outages, 1.0 percent of customers affected and 0.9 percent of interruption minutes. Figure 33 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top four major causes is shown in Figure 34.

A portion of the equipment failures are attributed to a problem with the A. B. Chance fuse cutouts utilized on the UGI system. UGI implemented an aggressive replacement program to actively identify and replace these defective parts. By the end of 2009, all of the identified cutouts were replaced; however, UGI believes there are still some unidentified Chance cutouts on its system as well as other porcelain style cutouts that may be subject to similar failures. As UGI finds these cutouts on its system, they will be replaced. Also, Most of the four-kilovolt distribution lines have been rebuilt and converted to thirteen-kilovolt operation.

Figure 31 UGI Customer Average Interruption Duration Index (minutes)

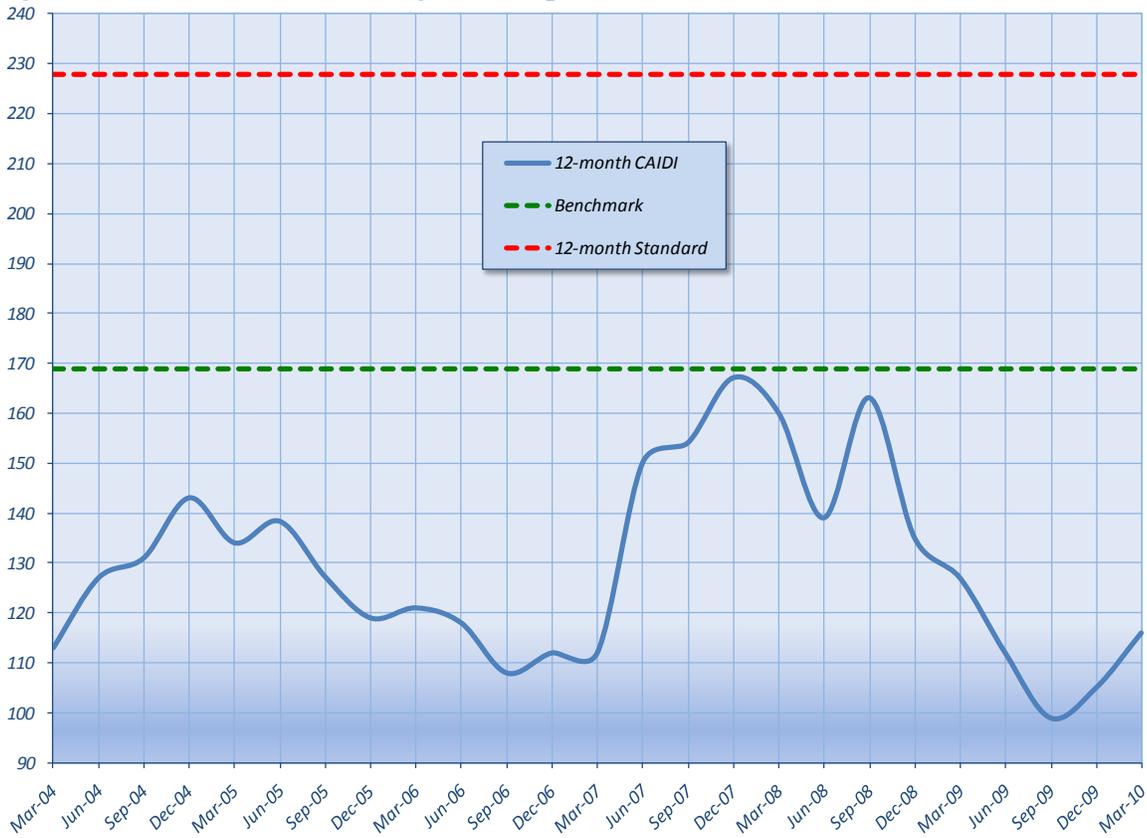


Figure 32 UGI System Average Interruption Frequency Index (interruptions per customer)

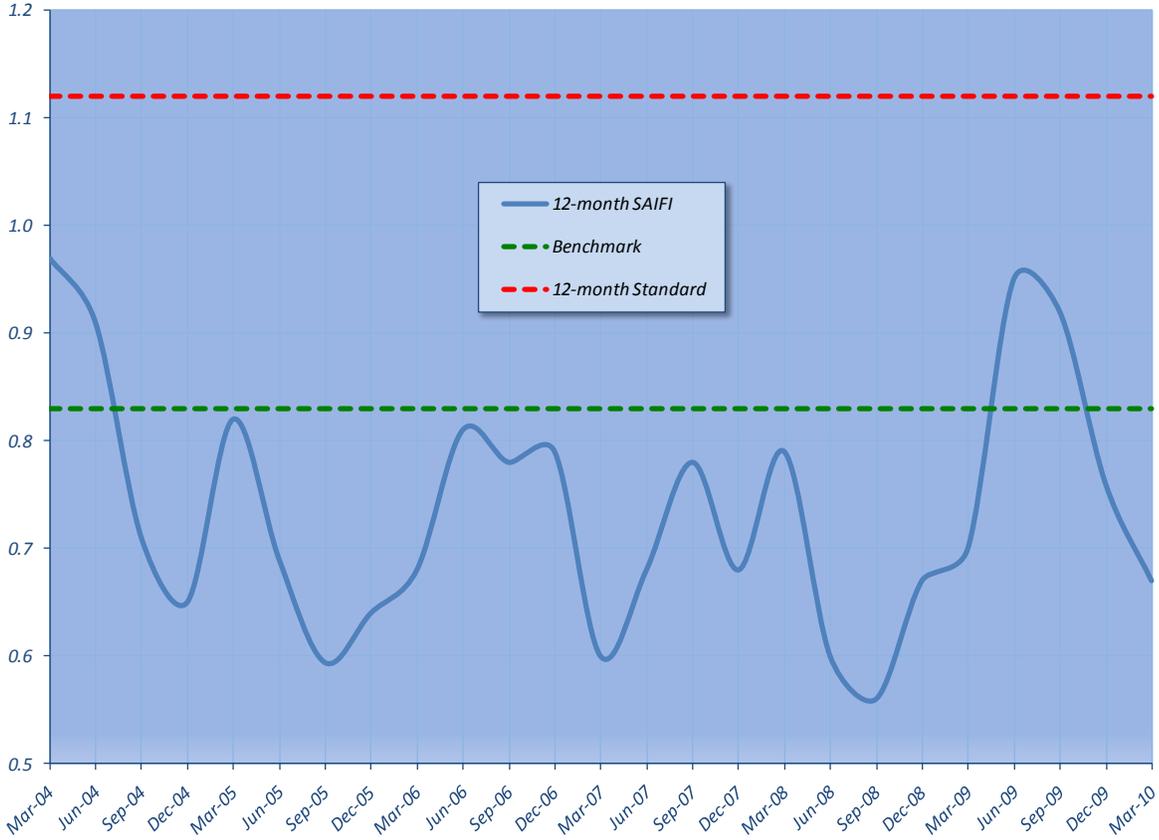


Figure 33 UGI outage causes (percent of total outages)

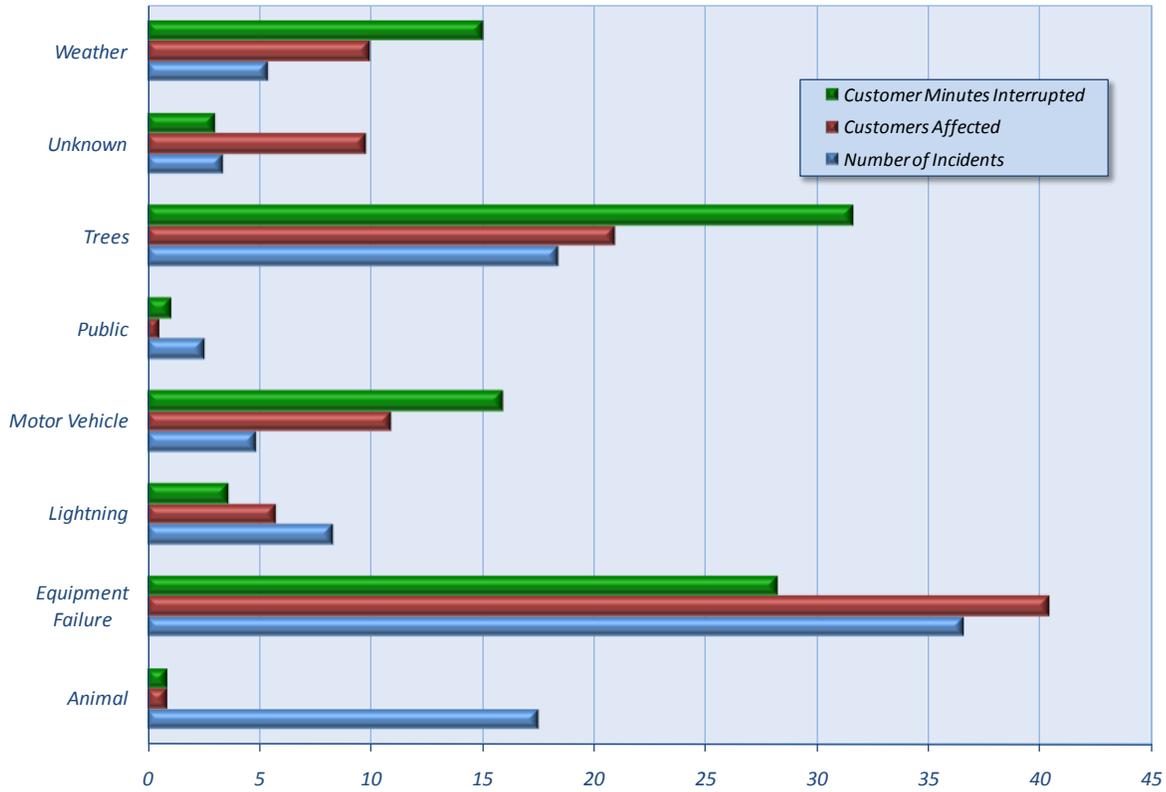
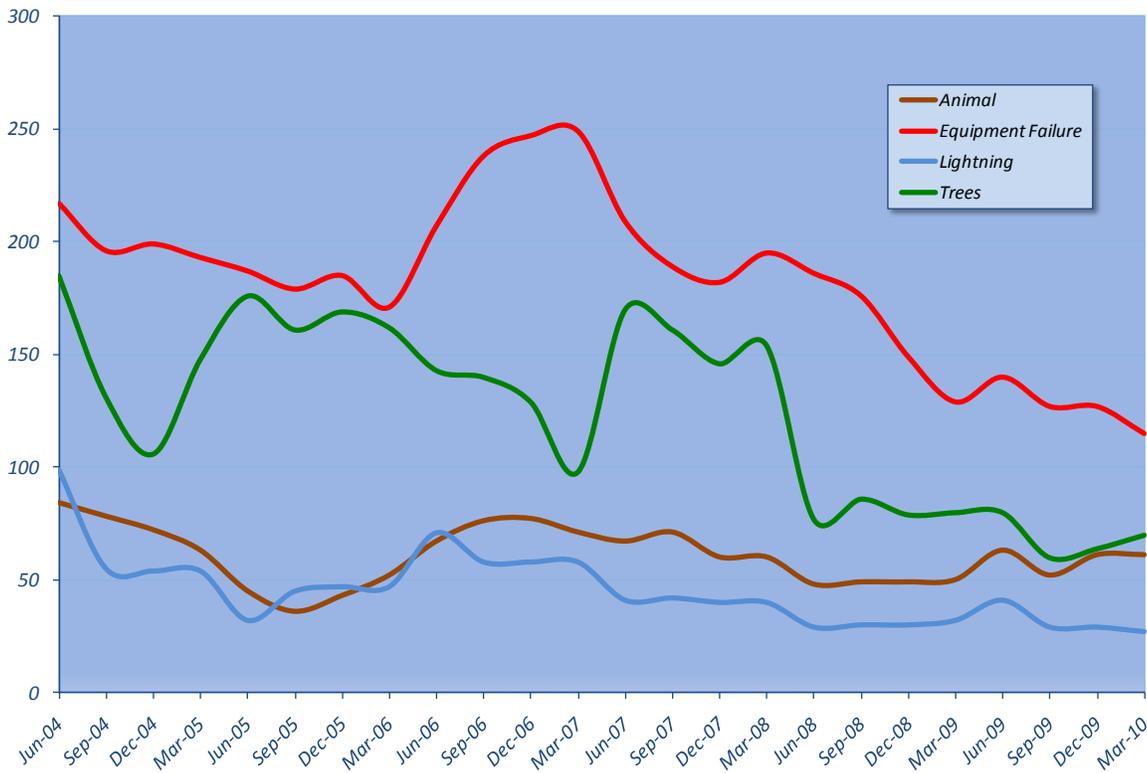


Figure 34 UGI outage tracking (number of incidents)



Citizens’ Electric Company

Citizens’ has a relatively small operating area with an electric system consisting of one distribution substation and nine distribution feeder lines.

In 2009, Citizens’ experienced a total of 1,358 customer interruptions, with a total duration of 102,265 minutes, excluding major events, which was 9.7 percent lower than that which was reported last year. The calculation of the 2009 reliability indices excludes outage data relating to two major events, which were approved by the Commission.³⁴

- Jan. 25, 2009 – A post insulator failed allowing the overhead line to contact the neutral conductor, causing the interruption of the entire circuit at the substation; 1,214 customers were affected; 169,506 interruption minutes were excluded.
- Aug. 9-10, 2009 – A severe thunderstorm with high winds, gusting to 53 miles per hour, blew numerous off right-of-way trees onto overhead lines; 2,323 customers were affected; 405,243 interruption minutes were excluded.

Citizens’ CAIDI increased from 64 minutes in 2008 to 75 minutes in 2009, which was a 17.2 percent increase in CAIDI minutes and still 28.6 percent better than the benchmark of 105 minutes. Except for 2005, Citizens’ CAIDI has been below the benchmark since 2000. The CAIDI three-year average was

³⁴ Docket Nos. M-2009-2087943; M-2009-2125369.

48 minutes or 41.7 percent below the standard of 115 minutes. For the 12-month average ending March 31, 2010, CAIDI was 92 minutes, or 12.4 percent below the benchmark. SAIDI dropped from 17 to 15 minutes. Figure 35 depicts the trend in the duration of customer interruptions for the Citizens' system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

Citizens' SAIFI decreased from 0.26 in 2008 to 0.20 in 2009, which was a 23.5 percent improvement in outage frequency and 0.5 percent better than the benchmark of 0.20. Except for the years 2003 and 2004, SAIFI has been better than the standard of 0.27 since 2000. The SAIFI three-year average was 7.6 percent above the standard of 0.22. For the 12-month average ending March 31, 2010, SAIFI was 0.24, or 11.1 below the standard. Figure 36 depicts the trend in the frequency of service interruptions for the Citizens' system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

Although the outage frequency values shown on these graphs are much smaller than the SAIFI values of larger companies, valid comparisons are not made with other companies' reliability performance, but with the historical performance of Citizens'. Smaller systems tend to experience more variability in service outage data, which is captured in the development of historical benchmarks.

In 2009, the most frequent outage cause was animal related, representing 37.3 percent of the outages, 12.6 percent of customers affected and 8.6 percent of customer minutes interrupted. Equipment failure caused 23.5 percent of the service interruptions, 23.9 percent of customers affected and 29.7 percent of interruption minutes. Trees off the right-of-way represented 13.7 percent of outages, 40.8 percent customers affected and 39.6 percent of interruption minutes. Weather was identified as being responsible for 13.7 percent of total outages, 19.4 percent of customers affected and 19.5 percent of interruption minutes. Figure 37 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top four major causes is shown in Figure 38.

During 2009, Citizens' completed validation of data generated by its new Outage Management System (OMS) by conducting a parallel analysis of the old and new systems for the entire year. Statistics generated from both systems were found to be consistent and accurate. Citizens' will deactivate its old system in 2010. Citizens' also integrated its OMS with its Automatic Meter Reading system during 2009, which allows the system to automatically verify customer outages by attempting to communicate with the customer's meter immediately upon receipt of an outage call. If an outage is verified, the system will begin testing meters up-line from the customer to determine the extent of the outage. As a result, dispatchers will quickly know how many customers are affected and the likely location of affected fault sectionalizing equipment. This information helps speed outage analysis and restoration time. Once an outage is restored, the system again tests affected meters to ensure that all customers are back in service.

Figure 35 Citizens' Customer Average Interruption Duration Index (minutes)

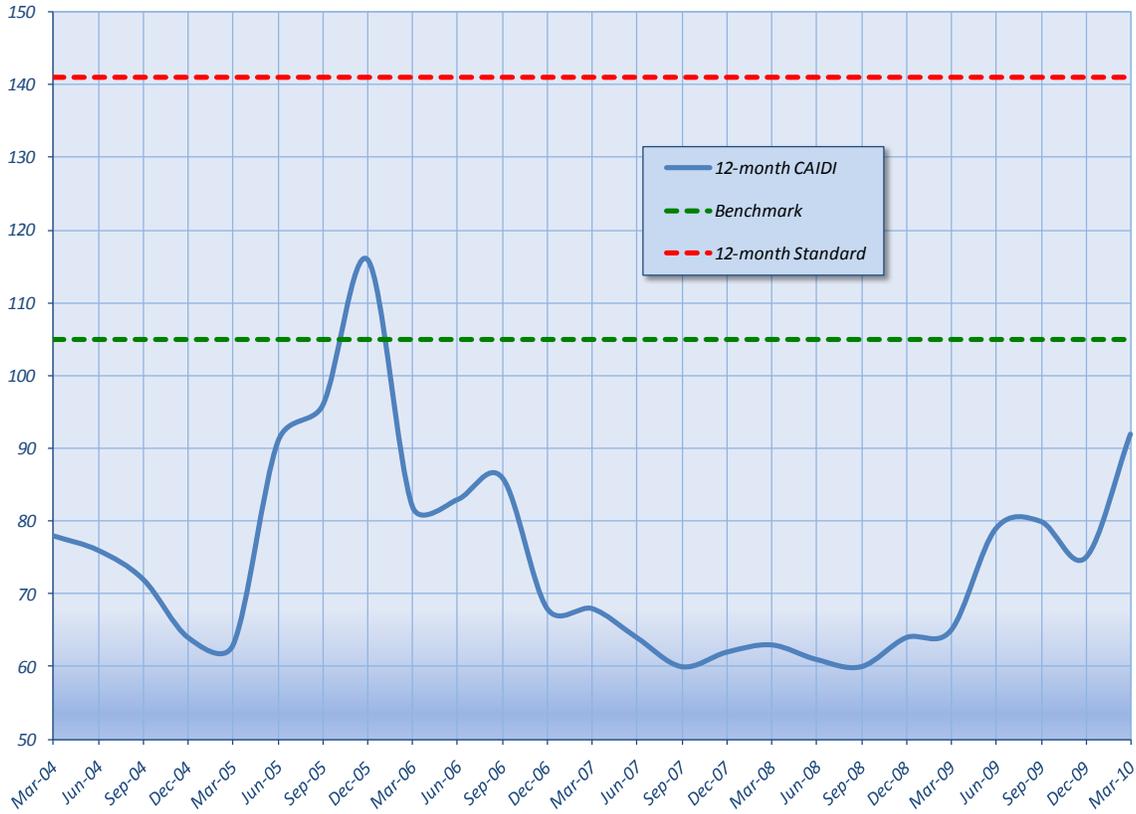


Figure 36 Citizens' System Average Interruption Frequency Index (interruptions per customer)

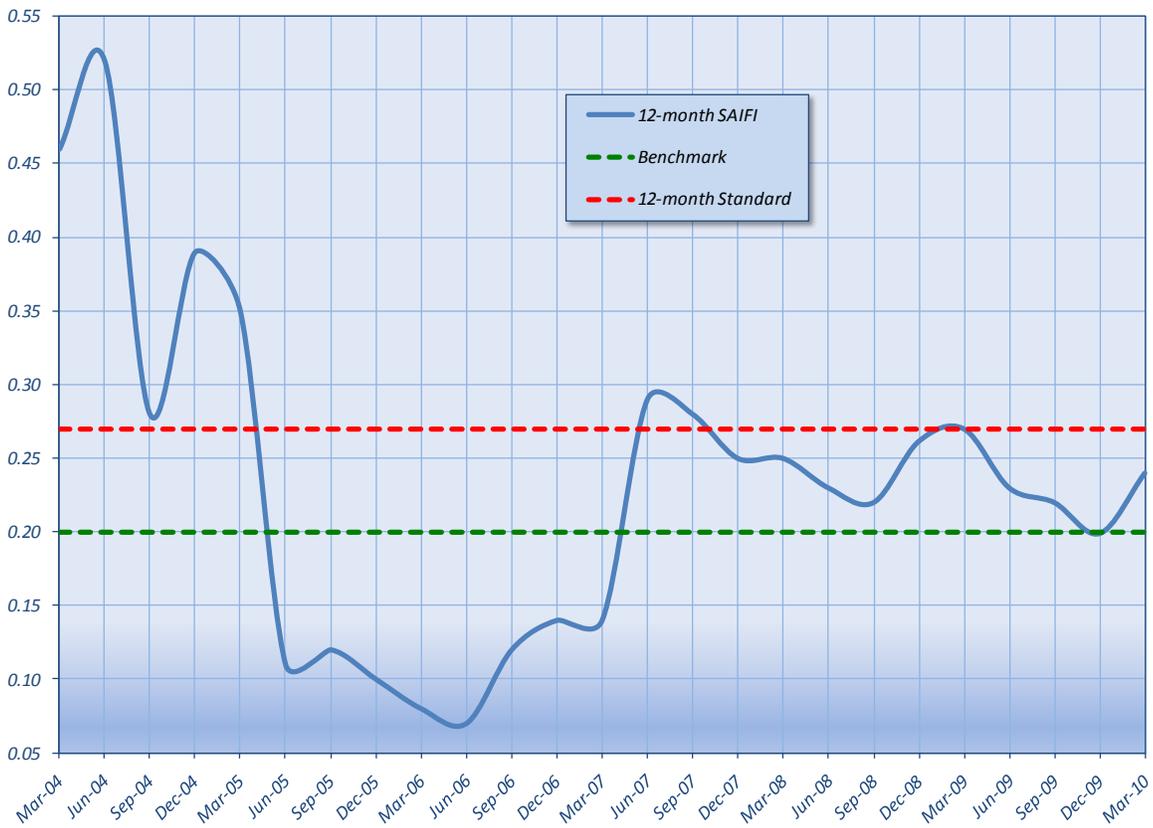


Figure 37 Citizens' outage causes (percent of total outages)

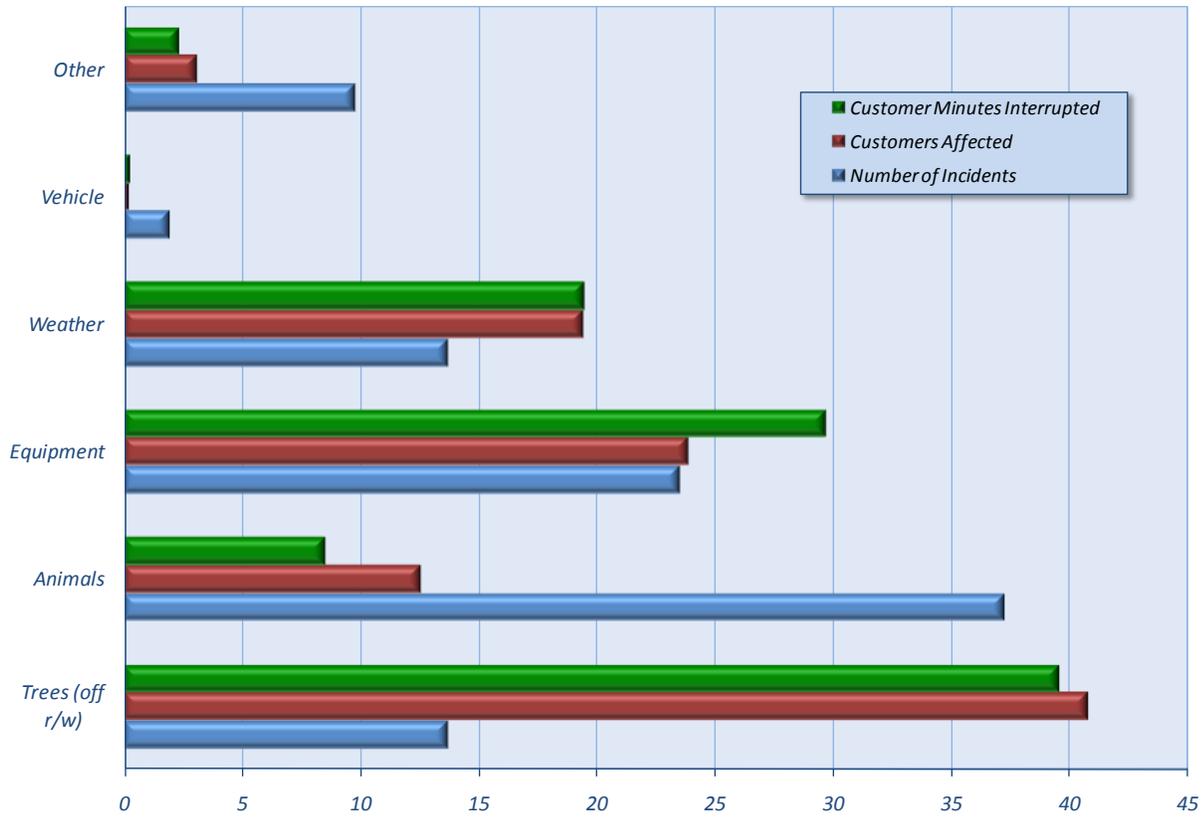
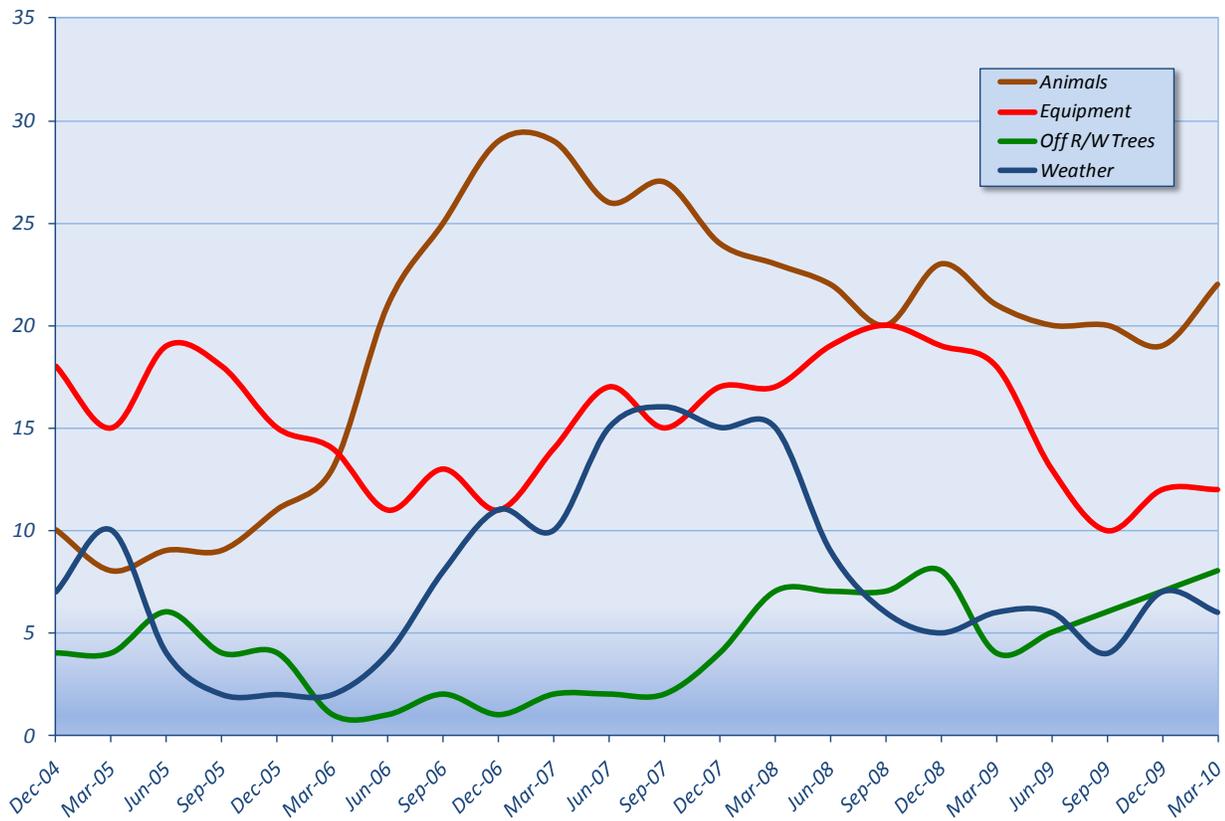


Figure 38 Citizens' outage tracking (number of incidents)



Pike County Light & Power Company

Pike County is the westernmost portion of Orange & Rockland's Northern Operating Division. This area is primarily fed from two 34.5 kV feeders that emanate from New York substations. Thus, sustained interruptions are usually smaller, affecting fewer customers, and will take a longer amount of time per customer to restore service.

In 2009, Pike County experienced 2,666 customer interruptions with a total duration of 475,501 minutes, which was 1.6 percent lower than that which was reported last year. The calculation of the 2009 reliability indices excludes outage data relating to one major event, which was approved by the Commission.³⁵

- June 26-28, 2009 – Severe thunderstorms and strong lightning; 4,368 customers were affected; 4,738,108 interruption minutes were excluded.

Pike County's CAIDI improved substantially, dropping from 236 minutes in 2008 to 178 minutes in 2009, which was a 24.6 percent decrease in CAIDI minutes and 2.3 percent above the benchmark of 174 minutes. CAIDI has not been under the benchmark since March 2008. The CAIDI three-year average, however, was 12 minutes (6.4 percent) below the standard of 192 minutes, but is trending upward. For the 12-month average ending March 31, 2010, CAIDI was 208 minutes, or 19.5 percent above the benchmark.³⁶ SAIDI dropped from 109 minutes in 2008 to 106 minutes in 2009. Figure 39 depicts the trend in the duration of customer interruptions for the Pike County system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

Pike County's SAIFI increased from 0.46 in 2008 to 0.60 in 2009, which was a 30.4 percent incline in outage frequency and 1.6 percent better than the benchmark of 0.61. SAIFI has remained below the benchmark since September 2007. The SAIFI three-year average was 24.9 percent below the standard of 0.67, and is trending downward. For the 12-month average ending March 31, 2010, SAIFI was 0.53, or 13.1 percent below the benchmark. Figure 40 depicts the trend in the frequency of service interruptions for the Pike County system from March 2004 through March 2010, compared to the established benchmark and standards for SAIFI.

In 2009, the major cause of service outages was tree contact with 55.4 percent of interruptions affecting 57.0 percent of customers for 59.2 percent of interruption minutes. The change to a more frequent (3-year) tree trimming cycle is expected to help to contain the number of these types of interruptions. Equipment failure accounted for 25.0 percent of the outages, 30.1 percent of customers affected and 20.6 percent of interruption minutes. Lightning was responsible for 7.1 percent of total outages, 8.6 percent of customers affected and 18.2 percent of interruption minutes. Figure 41 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top three major causes is shown in Figure 42.

³⁵ Docket No. M-2009-2118007.

³⁶ A denial of Pike County's request for an exemption of a major event, occurring in the 1st quarter of 2010, has been appealed. If the denial is upheld, a CAIDI of 282 minutes, 20 percent above the standard, will result.

Figure 39 Pike County Customer Average Interruption Duration Index (minutes)

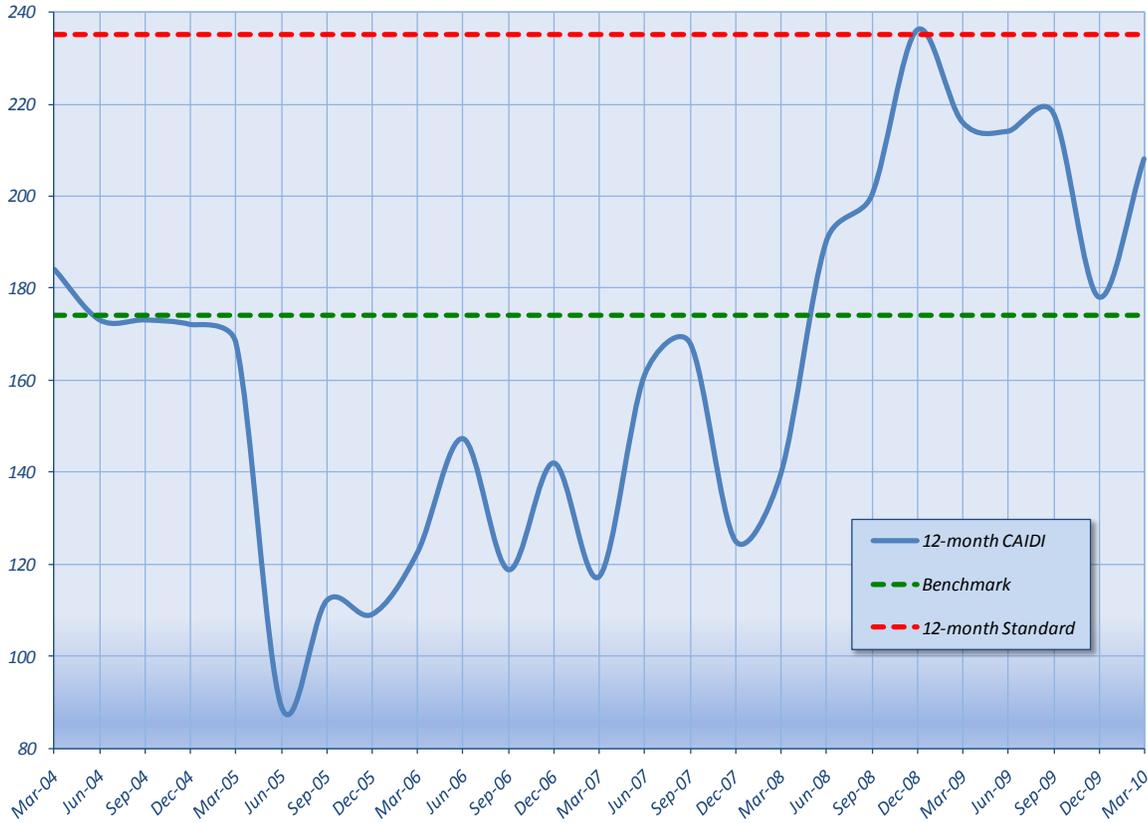


Figure 40 Pike County System Average Interruption Frequency Index (interruptions per customer)

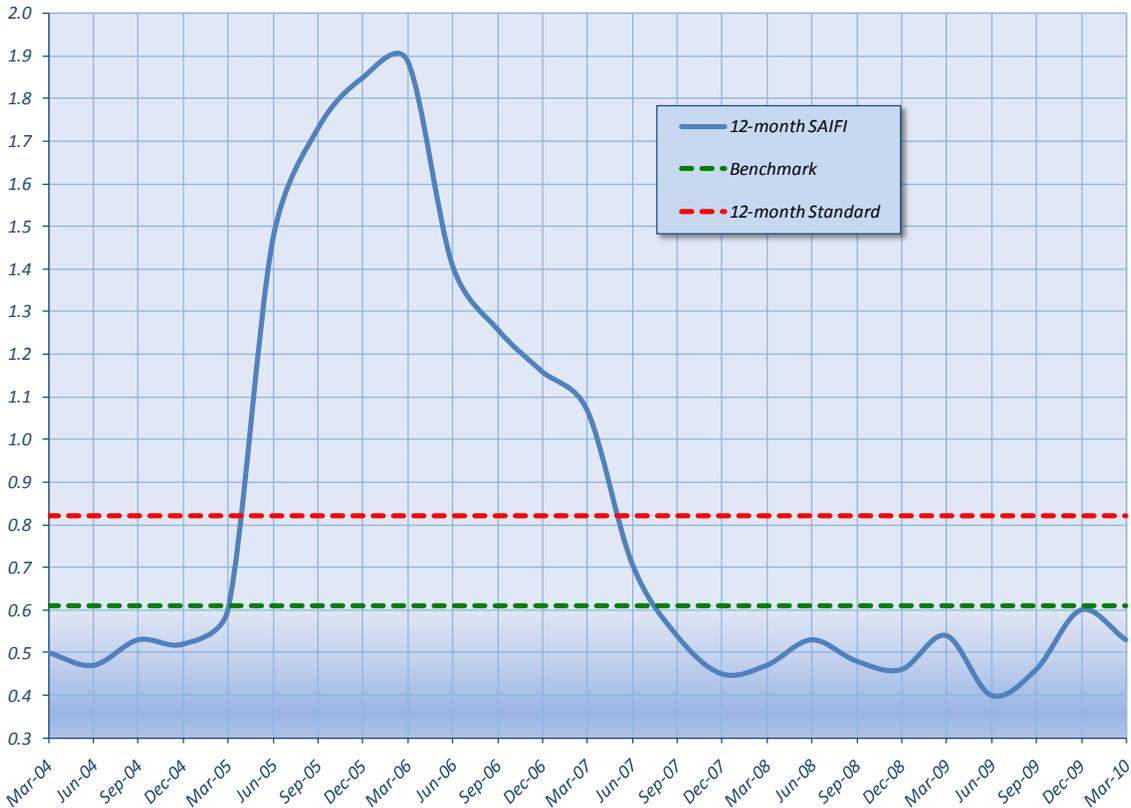


Figure 41 Pike County outage causes (percent of total outages)

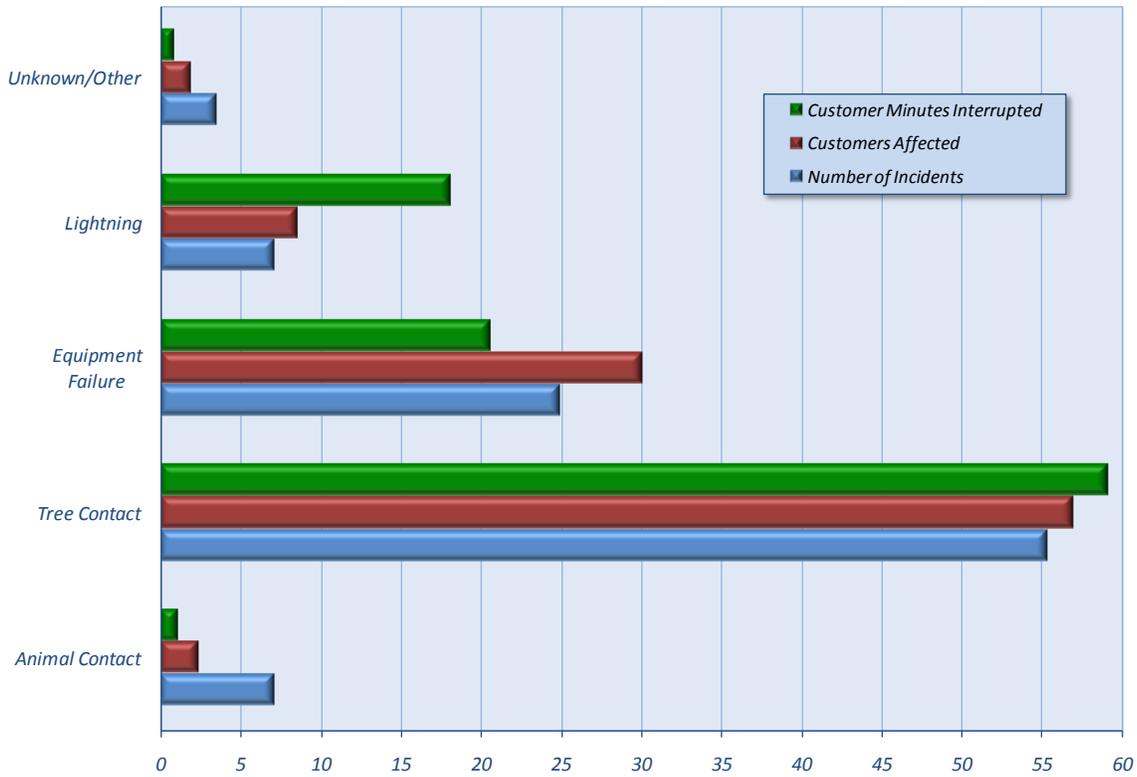
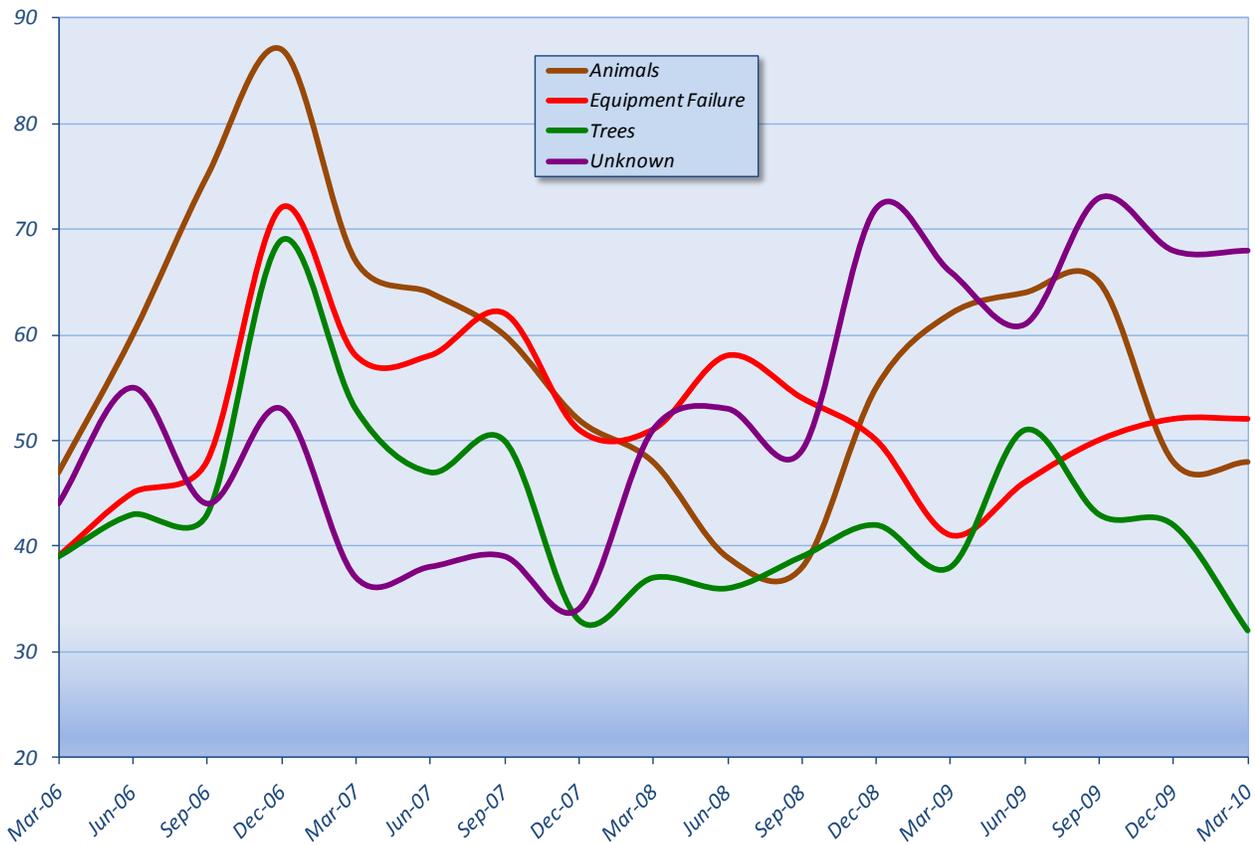


Figure 42 Pike County outage tracking (number of incidents)



Wellsboro Electric Company

In 2009, Wellsboro experienced 7,521 customer interruptions with a total duration of 725,505 customer minutes, which was 23.7 percent higher than last year. Five major events occurred in Wellsboro's service territory during 2009. The calculation of the reliability indices excludes outage data related to these events, which were approved by the Commission.³⁷

- Feb. 11-12, 2009 – Storm with rain, snow and high winds; 848 customers were affected; 1.1 million interruption minutes were excluded.
- June 11-12, 2009 – Loss of power supply due to insulator failure in Penelec substation; 6,085 customers were affected; 3.1 million interruption minutes were excluded.
- June 26, 2009 – Transformer and substation breaker lockout; 1,674 customers were affected; 56,916 interruption minutes were excluded.
- June 26, 2009 – Severe thunderstorm; 1,047 customers were affected; 62,820 interruption minutes were excluded.
- Aug. 9-11, 2009 – Severe thunderstorm; 6,379 customers were affected; 19.7 million interruption minutes were excluded.

Wellsboro's CAIDI slightly increased from 91 minutes in 2008 to 96 minutes in 2009, which was a 5.5 percent increase in CAIDI minutes and 22.3 percent better than the benchmark of 124 minutes. Since June 2004, CAIDI has remained below the benchmark. The CAIDI three-year average was 24.2 percent below the standard of 136 minutes. For the 12-month average ending March 31, 2010, CAIDI was 91 minutes, or 27.0 percent below the benchmark. SAIDI increased from 98 minutes in 2008 to 117 minutes in 2009, or 23.5 percent below the benchmark. Figure 43 depicts the trend in the duration of customer interruptions for the Wellsboro system from March 2004 through March 2010, compared to the established benchmark and standards for CAIDI.

Wellsboro's SAIFI increased from 1.07 in 2008 to 1.21 in 2009, which was a 13.1 percent increase in outage frequency and 1.6 percent better than the benchmark of 1.23. SAIFI has remained below the benchmark since September 2008. The SAIFI three-year average was 1.5 percent below the standard of 1.35. For the 12-month average ending March 31, 2010, SAIFI was 1.07, or 13.0 percent below the benchmark. Figure 44 depicts the trend in the frequency of service interruptions for the Wellsboro system from March 2004 through March 2010, compared to the established benchmarks and standards for SAIFI.

In 2009, tree-related incidents were responsible for 17.1 percent of the outages, 15.3 percent of customers affected and 15.7 percent of interruption minutes. Equipment failure caused 21.2 percent of incidents, 38.4 percent of customers affected and 43.2 percent of interruption minutes. Animals were responsible for 19.6 percent of incidents, 14.8 percent of customers affected and 10.8 percent of interruption minutes. Outages with unknown causes represented 27.8 percent of outage incidents, 21.1 percent of customers affected and 10.8 percent of interruption minutes. Figure 45 shows the distribution of causes of service outages occurring during 2009 as a percentage of total outages. The trend in the number of outages by the top four major causes is shown in Figure 46.

Wellsboro's Outage Management System tracks causes of outages and is used to identify circuits or individual customers that are experiencing multiple outages due to animal contact, trees, etc. This data

³⁷ Docket Nos. M-2009-2090862; M-2009-2115062; M-2009-2119618; M-2009-2119622; and M-2009-2126924.

assists Wellsboro in preventing future outages from occurring. Wellsboro is working with Penelec to replace equipment in the Penelec substation that, in the event of insulator failure, only half of the station load will be affected. Wellsboro is also installing a new distribution substation, and there are plans to convert the existing 4 kV distribution system to 12 kV.

Wellsboro has been awarded a DOE grant for the installation of smart metering over the next two years on 50 percent of residential customers and 100 percent of commercial/industrial customers.

Figure 43 Wellsboro Customer Average Interruption Duration Index (minutes)

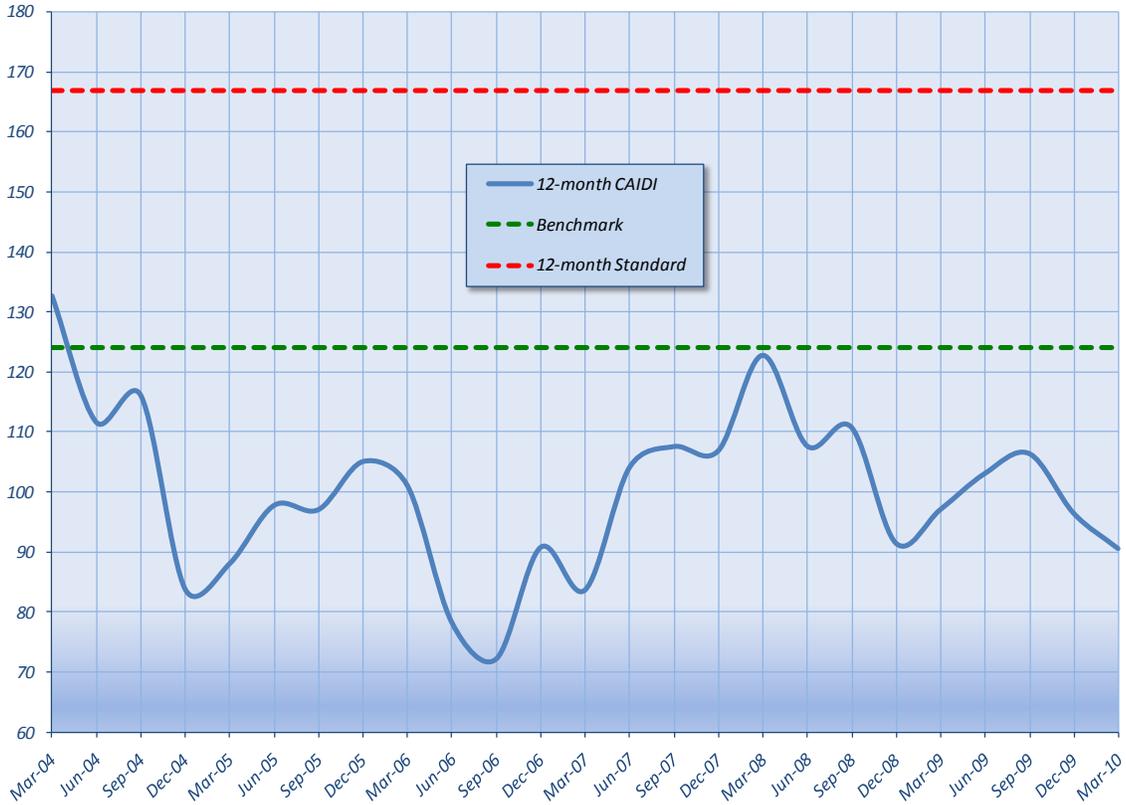


Figure 44 Wellsboro System Average Interruption Frequency Index (interruptions per customer)

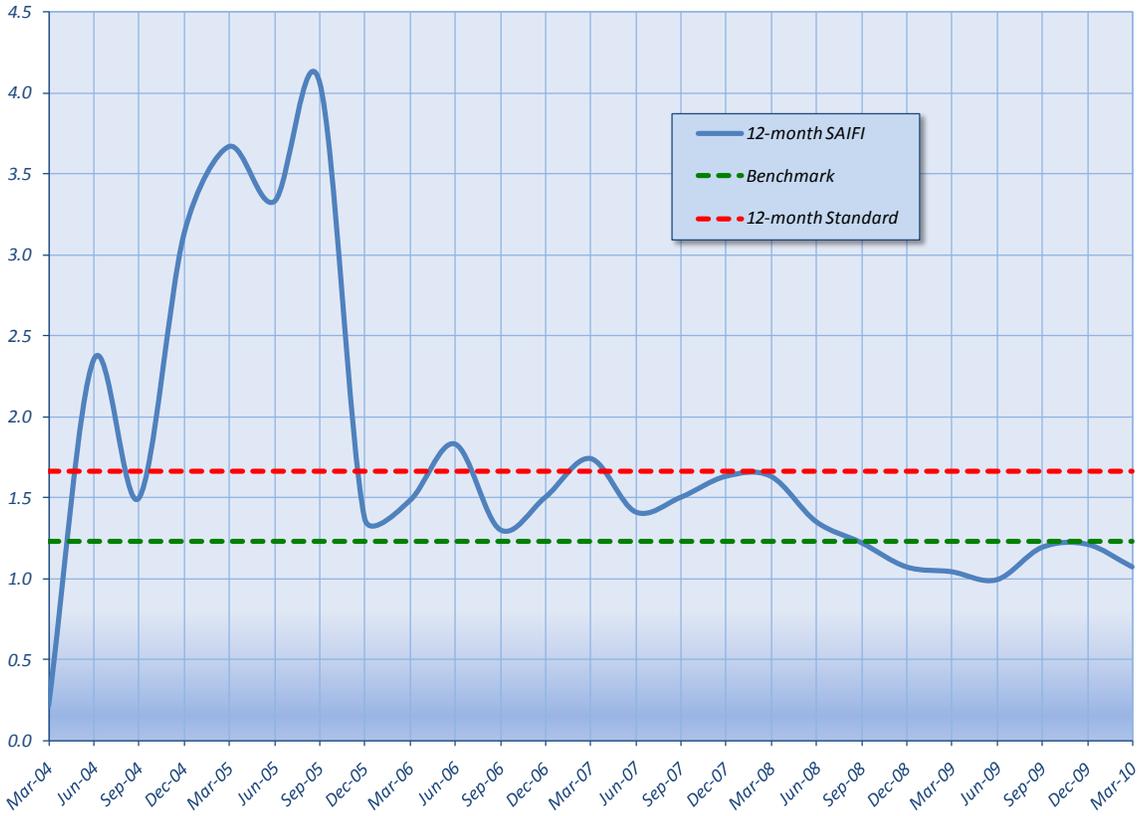


Figure 45 Wellsboro outage causes (percent of total outages)

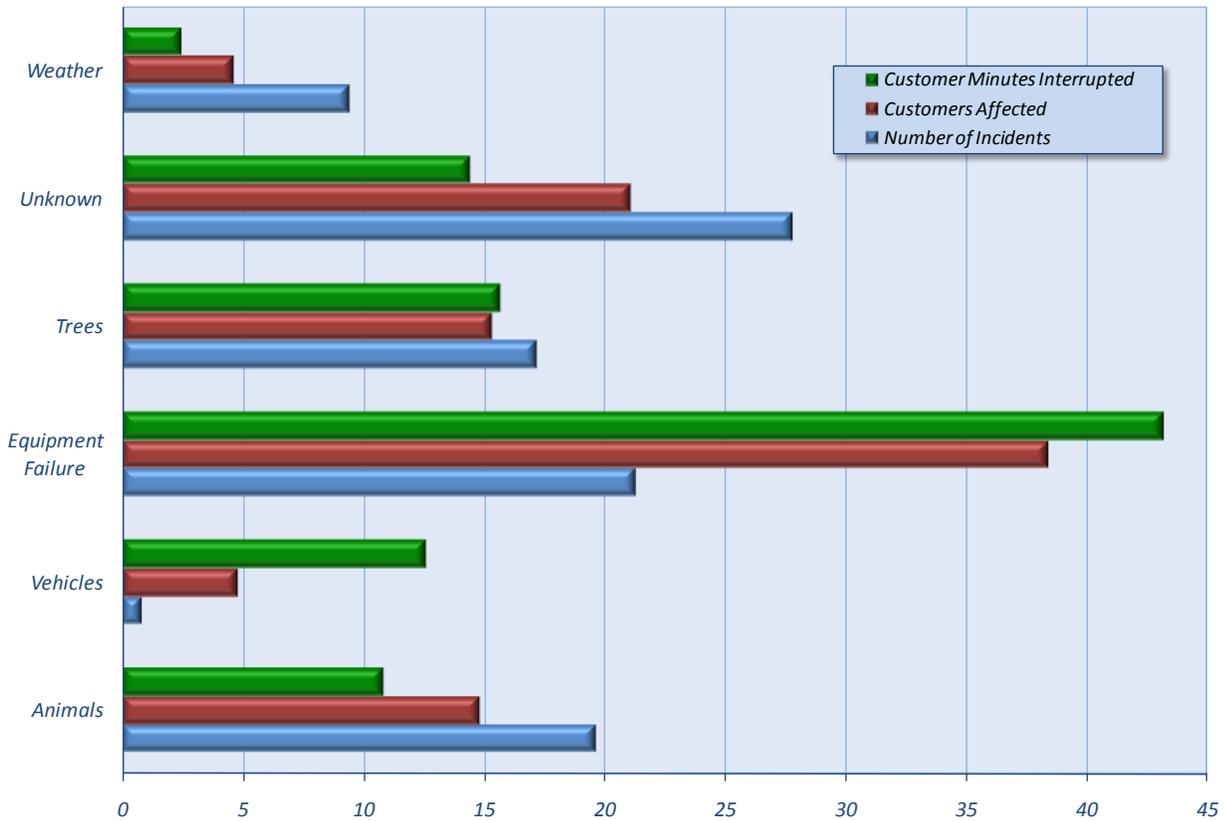
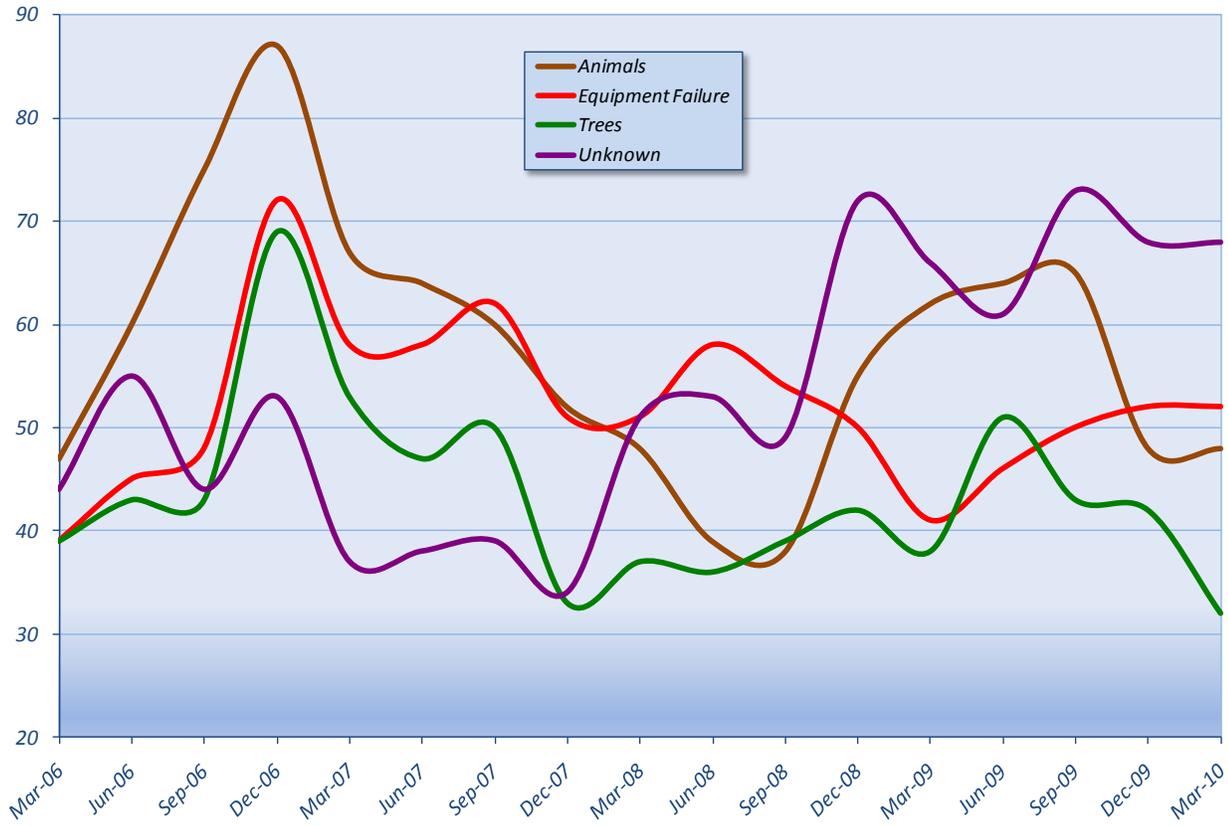


Figure 46 Wellsboro outage tracking (number of incidents)



Section 4 – Conclusion

The Electricity Generation Customer Choice and Competition Act of 1996 mandates that the Commission ensure that levels of reliability that existed prior to the restructuring of the electric utility industry continue in the new competitive markets. In response to this mandate, the Commission adopted reporting requirements designed to ensure the continuing safety, adequacy and reliability of the generation, transmission and distribution of electricity in the Commonwealth. The Commission also established reliability benchmarks and standards with which to measure the performance of each EDC, and standards for the inspection and maintenance of electric distribution facilities.

Given the uncertainty of weather and other events that can affect reliability performance, the Commission has stated that EDCs should set goals to achieve benchmark performance or better to allow for those times when unforeseen circumstances push the indices above the benchmark. In recognition of these unforeseen circumstances, the Commission set the performance standard as the minimum level of EDC reliability performance. The standard is the level of performance beyond which the company must either justify its poor performance or provide information on the corrective measures it will take to improve performance. Performance that does not meet the standard for any reliability measure may be the threshold for triggering additional scrutiny and potential compliance enforcement actions.

In 2009, for the first time since the Commission has been monitoring electric reliability performance, all 11 EDCs met their established performance standards for the three indices. In fact, most EDCs performed better than their benchmarks, which has been the Commission goal at the onset. Although there are obviously external factors which can affect such performance, it is the dedication of utility employees, adequate funding, and proper management practices and planning that must be recognized as the internal deciding factors.

Positive trends can be seen in a comparison of the reliability indices between 2008 and 2009. Looking at SAIDI alone, all EDCs have achieved benchmark performance or better, whereas only five did so the previous year. The three-year average performance ending in 2009 has also significantly improved, with all but one EDC meeting their standards, compared to only six in 2008.

Through ongoing oversight of utility performance and enforcement of newly established inspection and maintenance standards, the Commission will continue to ensure that the reliability of electric service in Pennsylvania is maintained.

Appendix A – Electric Reliability Indices

Twelve-month average electric reliability indices for 2009

Customer Average Interruption Duration Index (CAIDI)				% Above (+) or Below (-) Benchmark	% Above (+) or Below (-) Standard
EDC	2009	Benchmark	Standard		
Allegheny Power	166	170	204	-2.4	-18.6
Duquesne Light	85	108	130	-21.3	-34.6
Met-Ed (FE)	111	117	140	-5.1	-20.7
Penelec (FE)	117	117	141	-0.1	-17.1
Penn Power (FE)	116	101	121	14.9	-4.1
PECO	106	112	134	-5.4	-20.9
PPL	117	145	174	-19.3	-32.8
UGI	105	169	228	-37.9	-53.9
Citizens	75	105	141	-28.6	-46.8
Pike County	178	174	235	2.3	-24.3
Wellsboro	96	124	167	-22.3	-42.3

System Average Interruption Frequency Index (SAIFI)				% Above (+) or Below (-) Benchmark	% Above (+) or Below (-) Standard
EDC	2009	Benchmark	Standard		
Allegheny Power	0.97	1.05	1.26	-7.6	-23.0
Duquesne Light	0.97	1.17	1.40	-17.1	-30.7
Met-Ed (FE)	1.21	1.15	1.38	5.2	-12.3
Penelec (FE)	1.22	1.26	1.52	-3.2	-19.7
Penn Power (FE)	0.75	1.12	1.34	-33.0	-44.0
PECO	0.98	1.23	1.48	-20.3	-33.8
PPL	0.89	0.98	1.18	-9.7	-25.0
UGI	0.76	0.83	1.12	-8.4	-32.1
Citizens	0.20	0.20	0.27	-0.5	-26.3
Pike County	0.60	0.61	0.82	-1.6	-26.8
Wellsboro	1.21	1.23	1.66	-1.6	-27.1

System Average Interruption Duration Index (SAIDI)				% Above (+) or Below (-) Benchmark	% Above (+) or Below (-) Standard
EDC	2009	Benchmark	Standard		
Allegheny Power	161	179	257	-10.1	-37.4
Duquesne Light	82	126	182	-34.9	-54.9
Met-Ed (FE)	134	135	194	-0.7	-30.9
Penelec (FE)	143	148	213	-3.4	-32.9
Penn Power (FE)	87	113	162	-23.0	-46.3
PECO	103	138	198	-25.4	-48.0
PPL	104	142	205	-27.1	-49.5
UGI	80	140	256	-42.9	-68.8
Citizens	15	21	38	-28.6	-60.5
Pike County	106	106	194	0.4	-45.2
Wellsboro	117	153	278	-23.5	-57.9

Note: GREEN = better than benchmark; RED = worse than standard; BLACK = between benchmark and standard.

Performance Benchmark. An EDC's "performance benchmark" is calculated by averaging the EDC's annual, system-wide reliability performance indices over the five-year period directly prior to the implementation of electric restructuring (1994 to 1998). The benchmark is the level of performance that the EDC should strive to achieve and maintain.

Performance Standard. An EDC's "performance standard" is a numerical value that represents the minimal performance allowed for each reliability index for a given EDC. Performance standards are based on a percentage of each EDC's historical performance benchmarks.

Three-year average electric reliability indices for 2007-09

Customer Average Interruption Duration Index (CAIDI)				3-Year Average	3-Year Standard	% Above (+) or Below (-) Standard
EDC	2007	2008	2009			
Allegheny Power	208	168	166	181	187	-3.4
Duquesne Light	107	98	85	97	119	-18.8
Met-Ed (FE)	112	104	111	109	129	-15.5
Penelec (FE)	110	142	117	123	129	-4.7
Penn Power (FE)	126	111	116	118	111	6.0
PECO	105	124	106	112	123	-9.2
PPL	140	169	117	142	160	-11.3
UGI	167	135	105	136	186	-27.1
Citizens	62	64	75	67	115	-41.7
Pike County	125	236	178	180	192	-6.4
Wellsboro	107	91	96	98	136	-27.7

System Average Interruption Frequency Index (SAIFI)				3-Year Average	3-Year Standard	% Above (+) or Below (-) Standard
EDC	2007	2008	2009			
Allegheny Power	1.29	1.16	0.97	1.15	1.16	-0.9
Duquesne Light	0.79	0.99	0.97	0.92	1.29	-28.9
Met-Ed (FE)	1.63	1.35	1.21	1.40	1.27	10.0
Penelec (FE)	1.71	1.56	1.22	1.50	1.39	7.7
Penn Power (FE)	1.19	1.13	0.75	1.02	1.23	-16.8
PECO	0.99	1.04	0.98	1.00	1.35	-25.7
PPL	1.11	1.05	0.89	1.02	1.08	-5.9
UGI	0.68	0.67	0.76	0.70	0.91	-22.7
Citizens	0.25	0.26	0.20	0.24	0.22	7.4
Pike County	0.45	0.46	0.60	0.50	0.67	-24.9
Wellsboro	1.63	1.07	1.21	1.30	1.35	-3.5

System Average Interruption Duration Index (SAIDI)				3-Year Average	3-Year Standard	% Above (+) or Below (-) Standard
EDC	2007	2008	2009			
Allegheny Power	268	195	161	208	217	-4.1
Duquesne Light	84	97	82	88	153	-42.7
Met-Ed (FE)	182	139	134	152	163	-7.0
Penelec (FE)	188	220	143	184	179	2.6
Penn Power (FE)	150	125	87	121	136	-11.3
PECO	104	129	103	112	167	-32.9
PPL	156	178	104	146	172	-15.2
UGI	114	90	80	95	170	-44.3
Citizens	16	17	15	16	25	-36.0
Pike County	57	109	106	91	129	-29.6
Wellsboro	169	98	117	128	185	-30.8

Note: GREEN = better than standard; RED = worse than standard.

Appendix B – Modifications to Inspection and Maintenance Intervals

The Commission's regulations provide the following relating to inspection and maintenance time frames:

(c) *Time frames.* The plan must comply with the inspection and maintenance standards in subsection (n). A justification for the inspection and maintenance time frames selected shall be provided, even if the time frame falls within the intervals prescribed in subsection (n). However, an EDC may propose a plan that, for a given standard, uses intervals outside the Commission standard, provided that the deviation can be justified by the EDC's unique circumstances or a cost/benefit analysis to support an alternative approach that will still support the level of reliability required by law.

52. Pa. Code § 57.198(c).

On Oct. 1, 2009, each Compliance Group 1 EDC filed its Biennial Inspection, Maintenance, Repair and Replacement Plan, pursuant to 52 Pa. Code § 57.198(a), to become effective on Jan. 1, 2011. Four of the five EDCs proposed modifications to the standards for some programs or parts of programs. The exemptions requested involved pole loading calculations and the intervals for overhead line and transformer inspections and substations inspections.

On Dec. 1, 2009, the Bureau of CEEP accepted four of the five EDCs' I&M plans, as submitted. West Penn's I&M plan was accepted, in part, and rejected with regard to its substation inspection intervals. A Petition for Appeal from Action of Staff was filed, pursuant to 52 Pa. Code § 5.44, and subsequently denied by the Commission.³⁸

The following table describes the exemptions which were requested and provides a summary of the justification for said exemptions.

³⁸ Docket No. M-2009-2094773.

Modifications to Inspection and Maintenance Intervals

Company	Exemption Requested	Justification
FirstEnergy	Pole loading calculations	Line designs are based on NESC Heavy Loading guidelines. An assessment of the pole's ability to accommodate new pole attachments is performed at the time a request is made. Additional load calculations make cost of pole inspections three times higher and do not make economical or technical sense.
FirstEnergy	Distribution overhead line inspections	A periodicity of five years between inspections has been proven to be successful in addressing emergent problems in a timely manner. This experience does not justify the expense of an increased cycle.
FirstEnergy	Overhead transformer inspections	A five-year cycle is based on accepted electric utility practices and company experience and has proven to be successful in addressing emergent problems in a timely manner.
West Penn	Pole loading calculations	Pole failure rates are under 50 per year and do not warrant the additional \$1.2 million per year. Also, pole attachment companies are required to perform pole load calculations on all poles prior to attaching their equipment.
West Penn	Distribution overhead line inspections	Inspection intervals less than the current six-year cycle would provide minimal, if any, safety or reliability benefit. Failure rates for various components were less than one percent in 2008. An increase in the frequency of inspections to 1-2 years would cost an additional \$1 million per year.
West Penn	Overhead transformer inspections	The 2008 failure rate for overhead transformers was 0.337 percent. Additional costs are included in the \$1 million figure, above.
West Penn	Substation inspections	Performing inspections on a cycle less than six months would provide minimal, if any, safety or reliability benefit. The number of customer minutes interrupted as a result of equipment issues in substations averaged 1.96 percent from 2003 to 2008. In 2008, with a six-month inspection period, 75 percent of its substations were visited six or more times. Increasing the frequency to monthly would require 17,000 additional man-hours at a cost of \$0.78 million per year.
UGI	None	n/a

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