Oregon Investor-owned Utilities

Seven-Year Electric Service Reliability Statistics Summary

2003-2009

October 2010

Report available at http://www.puc@state.or.us (Click on "Safety")

Information Contact:
Jerry Murray, Sr. Electrical Engineer
Utility Safety, Reliability and Security Program
Oregon Public Utility Commission
550 Capitol St. NE, PO Box 2148, Salem, Oregon 97308-2148
Telephone: (503) 378-6626
E-mail: jerry murray@state.or.us

Table of Contents

Introduction

Safe and reliable electric power at a reasonable cost is the goal of our industry. How this goal is measured and evaluated for individual customers at the distribution level has changed and improved over the years. The overall robustness and integrity of the distribution systems today are far superior to the systems serving Oregonians 15 or 20 years ago. And yet, the expectations and needs of the average electric customer, whether urban or rural, continue to be higher and higher. Today's wide variety of home and business electronics makes our lives better, but also makes us increasingly dependant on high quality, reliable electric service. The challenge is to find the right balance between low cost and high service quality.

Utility operators need to know how their systems are performing with accurate and up-to-date information. Regular system inspections are important for knowing the general condition of the system. For more immediate information, Oregon's three Investor-Owned Utilities (IOUs) have monitoring and control systems, and each one has chosen a different type of system. PacifiCorp initiated its Computer Aided Distribution Operations System (CADOPS) in Oregon in 2002. Portland General Electric continues to expand Supervisory Control and Data Acquisition (SCADA) systems to additional substations and Idaho Power has added Sentry units downstream of operating devices on their system. Also, some of the new customer meters with real time communication capabilities, promise better system performance analysis tools and prompt utility notification in case of outages. Of course, all of this comes with a price tag.

The Oregon Public Utility Commission has been working with these utilities to bring greater uniformity and accuracy to the data being reported annually. This data is required by OAR 860-023-0080 through 0160. Accurate data allows meaningful comparisons year-to-year and utility-to-utility, even though the systems and the areas served are very different. Accurate data also allows the utility to direct operations and maintenance funds in a more efficient manner, based on solid facts related to what customers on a given circuit are experiencing. Oregon PUC Staff of the Safety Reliability Division is proposing that the OPUC's electric reliability rules (in OAR 860-023-0080 thru 0150) be modified to be in conformance with the nation's industry standard (i.e. ANSI/IEEE Standard 1366-2003). If this standard is adopted in Oregon and nationwide, customers, utilities and regulators will be better able to evaluate electric utility reliability performance with more accuracy and consistency across the nation.

Some of the changes in data collection result in more accurate but higher numbers, which seems to indicate poorer service (even when it has not changed). In general, the multi-year graphs give a good idea of what customers are experiencing in Oregon. The comparisons in performance in this report give a variety of ways of looking at the same general subject. The report does focus on the system failures (outages), but it is important to know that most Oregon customers of these three utilities are receiving safe and reliable service.

Note: IOU means Investor-Owned Utility, which are fully regulated by the Oregon Public Utility Commission. These utilities, Portland General Electric, Pacific Power and Light (PacifiCorp), and Idaho Power, serve almost 74 percent of Oregon's electric customers.

General Information

This report:

A. Compares three utilities whose customer base and service territories are very different in nature:

Portland General Electric (PGE) - has a compact service territory with a fairly urban and suburban character in N.W. Oregon. Average customer per line/trench mile is about 45.4*.

PacifiCorp (PAC) - includes some larger Oregon cities but serves several separate areas and is mostly rural. Average customer per line/trench mile in Oregon is about 26.5*.

Idaho Power (IPC) - covers a very rural part of Eastern Oregon, including some very remote areas. Average customer per line/trench mile in Oregon is about 6.8*.

B. Uses standard industry formulas to calculate data points:

SAIFI - System Average Interruption Frequency Index

The average number of times that an average customer experiences a service interruption during a year. SAIFI is an indicator of utility network performance. (Note: This does not include automatic operations or "blinks." See MAIFIe, below.)

SAIDI - System Average Interruption Duration Index

The average total amount of time that an average customer does not have power during a year. SAIDI generally measures the operating performance of the utility in restoring customer interruptions.

MAIFIe – Momentary Average Interruption Event Frequency Index

The average number of times that an average customer experiences momentary interruption events during a year. This does not include events immediately preceding a sustained interruption.

For further information, see OAR 860-023-0080.

C. Other

In this report, statistics for SAIDI and SAIFI are shown excluding and including major events.

Per OAR 860-023-0080, "Major event" means a catastrophic event that:

a. Exceeds the design limits of the electric power system;

b. Causes extensive damage to the electric power system; and

c. Results in a simultaneous sustained interruption to more than ten percent of the metering points in an operating area.

Note: The definition of "major event" is calculated differently by various electric utilities and other state regulatory commissions across the nation. Oregon PUC staff is looking to adopt into law the "major event" definition and calculation methodology in ANSI/IEEE Standard 1366-2003. If adopted, this should help customers, regulators and utilities in evaluating and comparing electric reliability performance.

---

*These are approximate customer/high voltage line miles and include transmission and distribution, both overhead and underground.

Note: Staff's emphasis on the safety and reliability of electrical utility systems can also be found in the Service Quality Measures for PGE and PacifiCorp, the annual Incident Report, Safety Staff Policies, and National Electrical Safety Code enforcement and administration for Oregon.

Data Collection Methodologies

Each of the three electric utility companies use somewhat different data collection methods for reliability reporting:

Idaho Power Company

Idaho Power Company (IPC) gathers data for the Oregon Annual Electric Service Reliability Report (AESRR) through an Outage Management System (OMS) and dispatch entry process. The OMS receives trouble orders in real time from the Customer Information System (CIS) as they are entered by call center staff. The OMS analyzes the call pattern and predicts the potential extent of each outage. The OMS operators (located in the dispatch center) perform switching real-time on an electronic map in the OMS to reflect all distribution switching performed in the field and any SCADA operations. OMS records are transferred nightly into a permanent historical datamart (PDM). PDM is an Oracle database with a combined Crystal Reports and Excel/Visual Basic reporting system. Transmission events are still entered in the Dispatch Outage Reporting System (DORS). DORS is a SQL (Structured Query Language) database with a Visual Basic/Access reporting system.

Dispatchers also enter any interruption or switching on a Switching Log. OMS records and switching logs are compared and reconciled each evening by dispatch center personnel, to ensure accuracy and consistency. Momentaries are gathered from the Sentry monitoring system and entered manually into the OMS. The use of the OMS and PDM, to report outages, means that single transformer and even single service outages are captured and reported. This level of detail was not available before the implementation of the OMS.

The information from several events, performance data, outage causes, and equipment and statistical reports from PDM are run on IPC's Oregon operating area and each Oregon circuit. The reports are used to create Excel tables and charts and geographic information system (GIS) maps for the AESRR.

Idaho Power's service territory includes one operating area in Eastern Oregon.

PacifiCorp

PacifiCorp operates automated outage management and reporting systems. Customer trouble calls and SCADA events are interfaced with the Company's real-time network connectivity model, its CADOPS system. By overlaying these events onto the network model, the program infers outages at the appropriate devices (such as a transformer, fuse, or other interrupting device) for all customers down line of the interrupting device. The outage is then routed to appropriate field operations' staff for restoration, and the outage event is recorded in the Company's Prosper/US outage repository. In addition to this real-time model of the system's electrical flow, the Company relies heavily upon the SCADA System that it has in place. This includes the Dispatch Log System (an Access database application) which serves to collect all events on SCADA-operable circuits. All data is then analyzed for momentary interruptions to establish state-level momentary interruption indices.

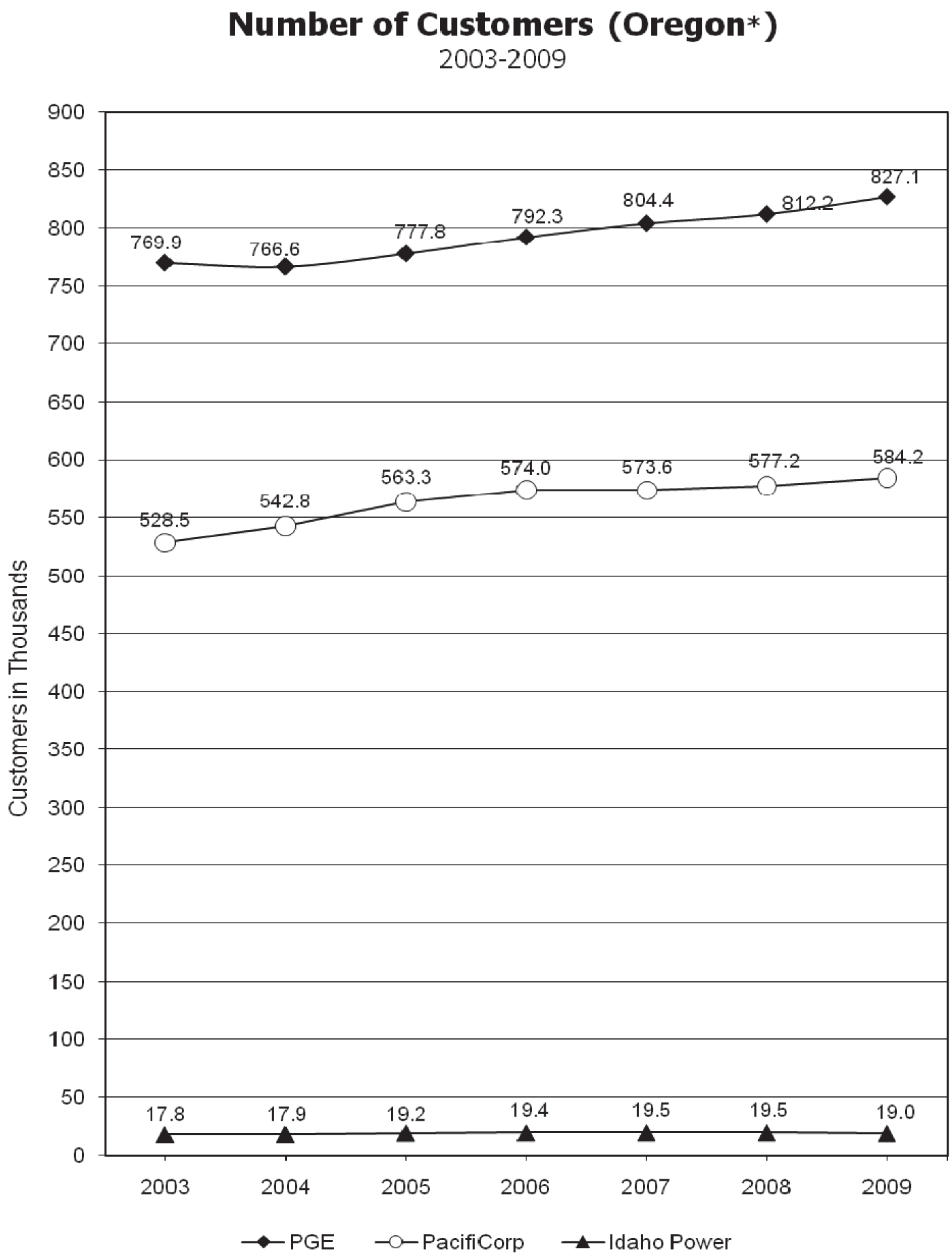
PacifiCorp service territory in Oregon includes 23 operating areas. The operating areas include: Albany, Bend/Redmond, Clatsop (Astoria), Coos Bay/Coquille, Corvallis, Cottage Grove/Junction City, Dallas/Independence, Enterprise, Grants Pass, Hermiston, Hood River, Klamath Falls, Lakeview, Lebanon, Lincoln City, Madras, Medford, Milton-Freewater, Pendleton, Portland, Prineville, Roseburg/Myrtlecreek, and Stayton.

Portland General Electric

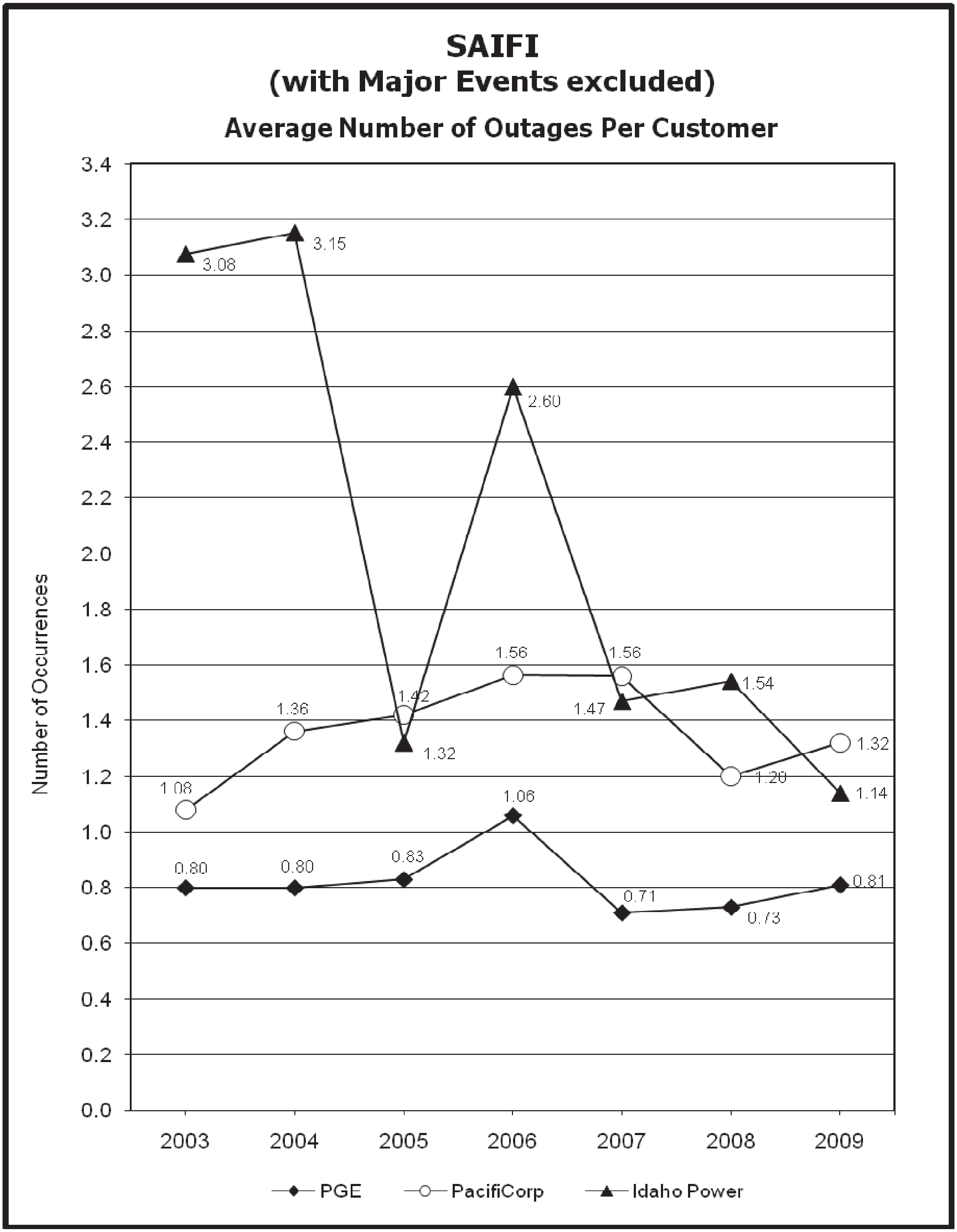
PGE uses a computerized OMS to log and track outages that occur on the system. It interfaces to CIS, GRID (an electronic map-based connectivity system), outage history and IVR (Interactive Voice Response) to generate an outage record once a trouble call comes in. This information is transferred into a new reliability program every month where outages are reviewed and evaluated to ensure that the data is as accurate as possible. The reviewed outages are then used to calculate SAIDI, SAIFI, and data presented in PGE's Annual Reliability Report.

Momentary outages (MAIFIe) are logged and reported for the stations equipped with SCADA and MV90 (a meter-based data collection system). Out of PGE's 146 distribution substations, 87 are equipped with SCADA and 52 are equipped with MV90. The 7 remaining distribution substations, with neither SCADA nor MV90, have recorded reading collected on a monthly basis.

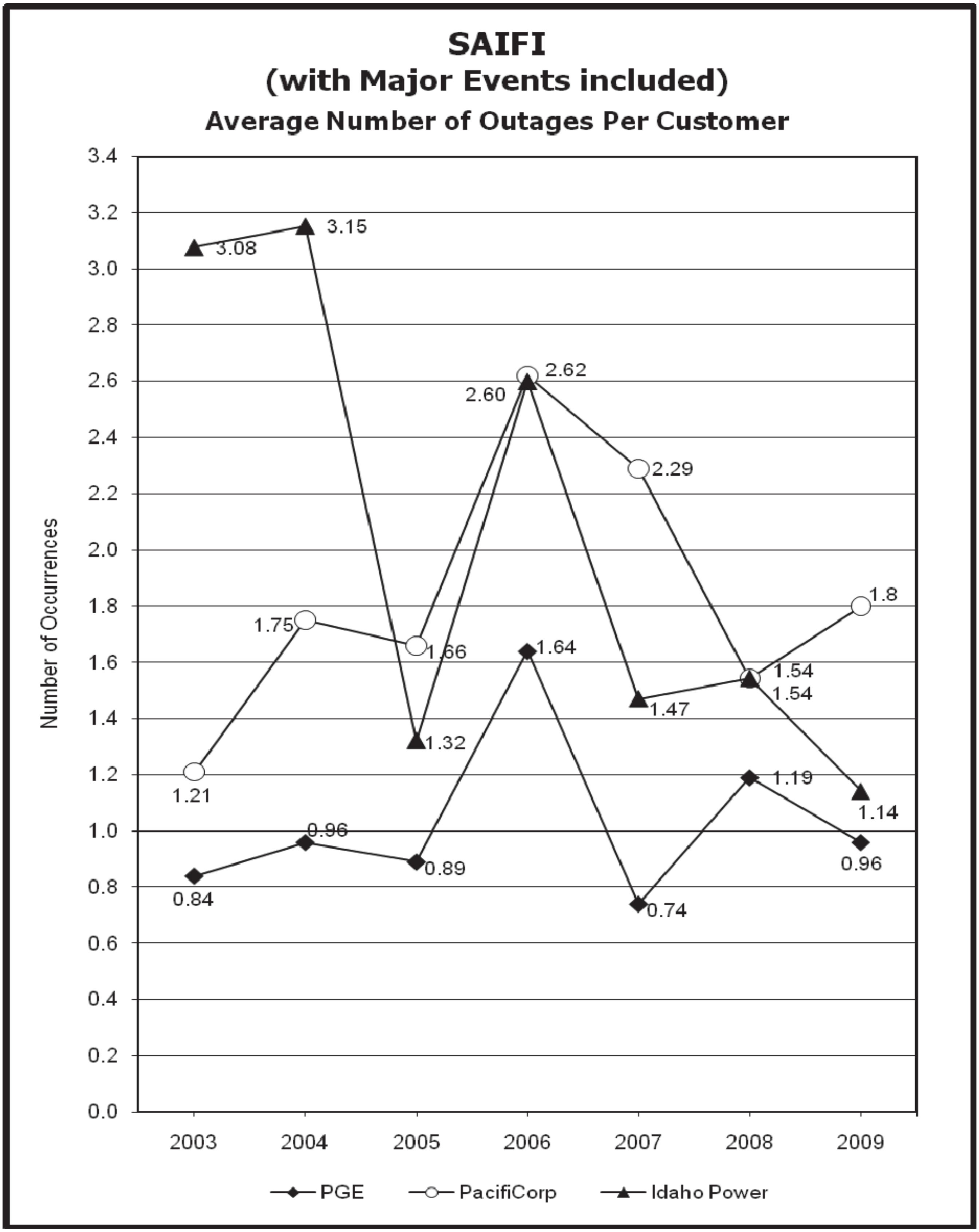
PGE's service territory includes four operating areas in Northwest Oregon. They are the Central Region, Eastern Region, Southern Region, and Western Region.

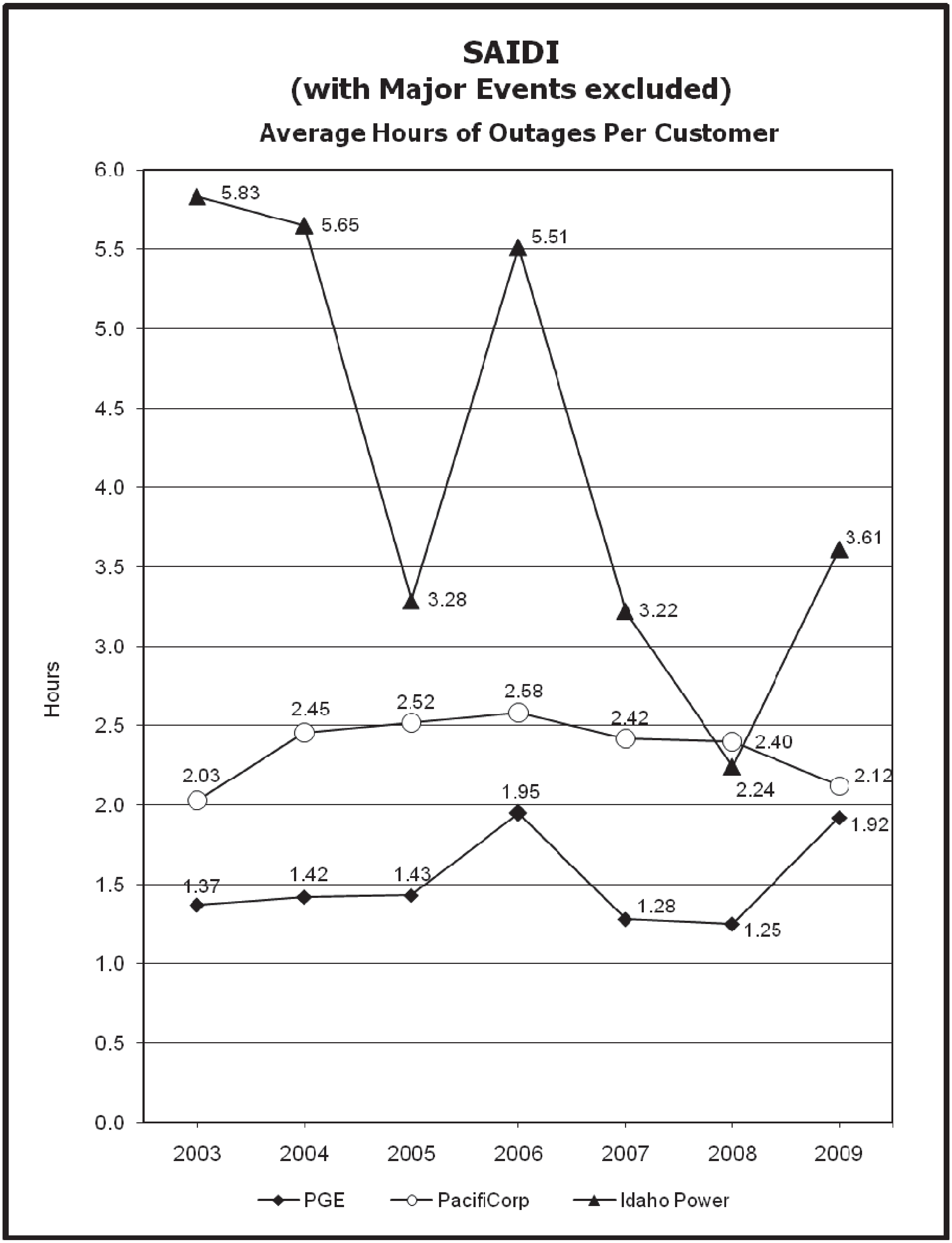


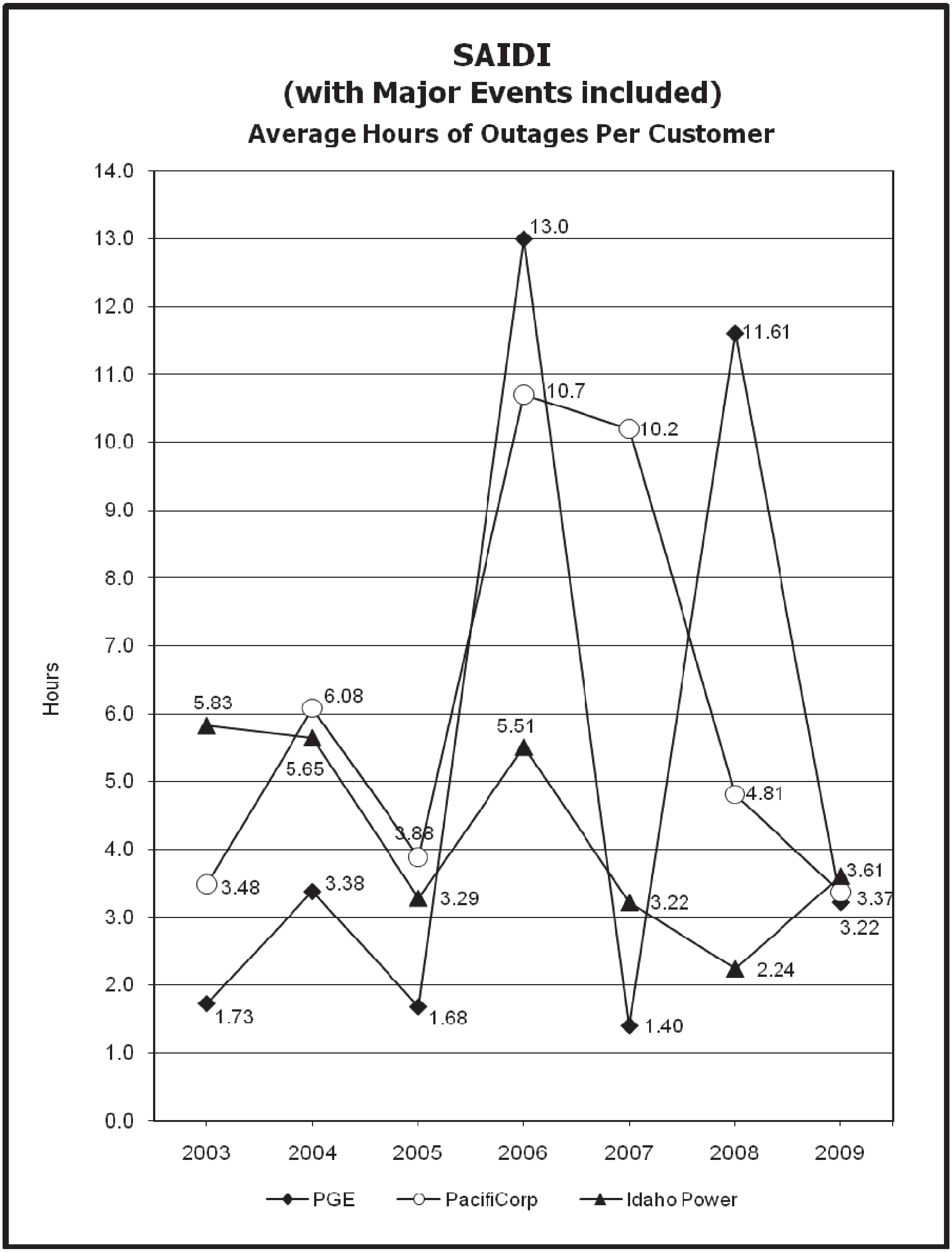
* From number of metering points are defined in OAR 860-023-0080 and as reported in each company's annual reliability report required by OAR 860-023-0150.

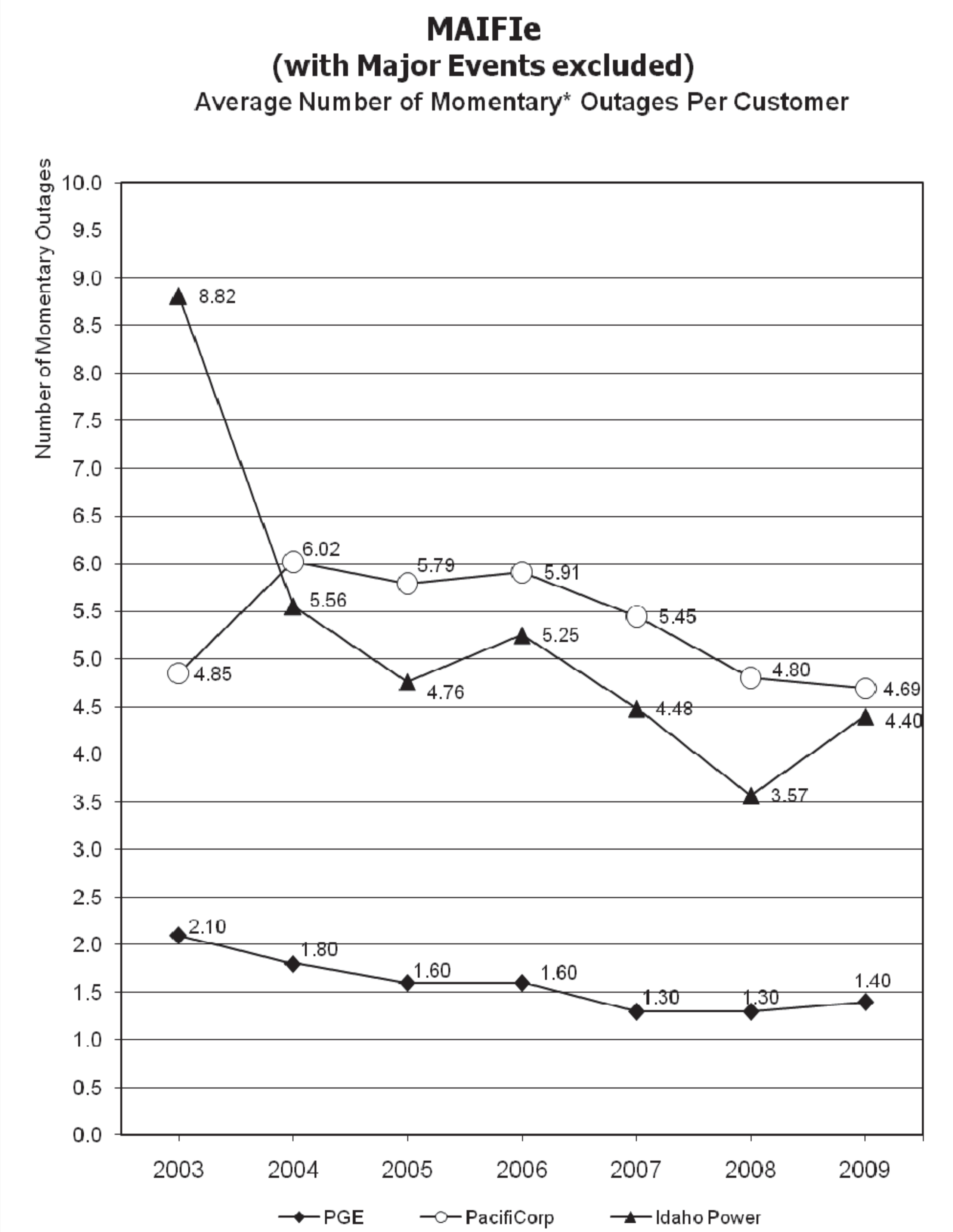


SAIFI
(with Major Events excluded)
Average Number of Outages Per Customer
Number of Occurrences
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
3.08
3.15
2.60
1.56
1.56
1.36
1.42
1.47
1.54
1.32
1.32
1.08
1.20
1.14
1.06
0.80
0.80
0.83
0.71
0.73
0.81
2003
2004
2005
2006
2007
2008
2009
PGE
PacifiCorp
Idaho Power


SAIFI
(with Major Events included)
Average Number of Outages Per Customer
Number of Occurrences
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
3.08
3.15
2.62
2.60
2.29
1.8
1.75
1.66
1.64
1.54
1.54
1.47
1.32
1.21
1.19
1.14
0.96
0.89
0.84
0.74
0.96
2003
2004
2005
2006
2007
2008
2009
PGE
PacifiCorp
Idaho Power


SAIDI
(with Major Events excluded)
Average Hours of Outages Per Customer
Hours
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2003
2004
2005
2006
2007
2008
2009
5.83
5.65
3.28
5.51
3.22
2.24
3.61
2.03
2.45
2.52
2.58
2.42
2.40
2.12
1.37
1.42
1.43
1.95
1.28
1.25
1.92
PGE
PacifiCorp
Idaho Power


SAIDI
(with Major Events included)
Average Hours of Outages Per Customer
14.0
13.0
12.0
11.0
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Hours
13.0
11.61
10.7
10.2
5.83
6.08
5.51
5.65
3.88
4.81
3.48
3.38
3.29
3.22
3.61
3.37
3.22
2.24
1.73
1.68
1.40
2003
2004
2005
2006
2007
2008
2009
PGE
PacifiCorp
Idaho Power



*Interruptions under five minutes.

Potomac Electric Power Company
Maryland Distribution System

2003 Reliability Indices

and

Corrective Action Process

April 30, 2004

2003 Reliability Indices and Corrective Action Process

On July 30, 2001, the Maryland Public Service Commission issued Order No. 77132 in Case No. 8826. On page 26 of the Order, the Commission directed Maryland Utilities to file annually, a report of the previous year's performance statistics and its proposed reliability improvement process. These requirements were set forth in Order No. 77132 and later adopted in COMAR 20.50.07.06. This report is structured to comport with the COMAR format.

COMAR 20.50.07.06

C.1. System-Wide Indices: A utility shall provide SAIDI, SAIFI, and CAIDI for all feeders originating in Maryland. The indices shall be calculated and reported with two sets of input data.
(a) All interruption data:
(b) Major event interruption data excluded.

Pepco Response:

Table 1 - Maryland System Wide for 2003		
	All Sustained Interruptions	Excluding Major Events *
SAIFI	3.68	1.11
SAIDI (hours)	59.61	2.05
CAIDI (hours)	16.19	1.85

Note: * Days Excluded are:
- Aug 26 thru 30 Severe Thunderstorms resulting in multiple locked out feeders.
- Sep 18 thru 28 Hurricane Isabel
- Nov 13 High winds (winds gusting at 51mph)

C.2. Feeders Indices: An investor-owned utility shall provide SAIDI, SAIFI, and CAIDI for 2% of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability. The indices shall be calculated and reported with two sets of input data.
(a) All interruption data,
(b) Major event interruption data excluded.

Pepco Response:

SAIFI, SAIDI and CAIDI indices including and excluding major events for 2% of feeders identified as being the least reliable are shown below in Table 2a and 2b.

Table 2a - Least Reliable Feeders for 2003 *					
		Including Major Events			
Rank	Feeder Number	SAIFI	SAIDI (hrs.)	CAIDI (hrs.)	CPI+
1	14033	9.86	57.18	5.80	0.45
2	14986	12.28	179.71	14.64	0.43
3	14923	7.03	38.93	5.54	0.35
4	14447	13.80	62.08	4.50	0.34
5	14968	13.28	111.14	8.37	0.3
6	15110	10.32	62.82	6.09	0.3
7	15292	9.10	69.37	7.63	0.28
8	15233	3.00	11.76	3.92	0.28
9	14242	3.46	97.65	28.21	0.26
10	15230	8.27	119.55	14.46	0.26
11	14446	9.16	59.26	6.47	0.26
12	14045	11.00	103.06	9.37	0.25
13	14994	2.10	14.90	7.10	0.25

Notes: * Feeder Analysis covers period October 1, 2002 to September 30, 2003
+ CPI = Composite Performance Index (Includes momentary interruptions

Table 2b - Least Reliable Feeders for 2003 *					
		Excluding Major Events			
Rank	Feeder Number	SAIFI	SAIDI (hrs.)	CAIDI (hrs.)	CPI
1	14033	6.78	10.78	1.59	0.45
2	14986	8.58	10.30	1.20	0.43
3	14923	6.70	13.58	2.03	0.35
4	14447	10.40	7.99	0.77	0.34
5	14968	7.22	6.63	0.92	0.3
6	15110	7.17	6.69	0.93	0.3
7	15292	8.07	3.86	0.48	0.28
8	15233	1.98	8.39	4.24	0.28
9	14242	0.63	9.29	14.66	0.26
10	15230	5.19	7.73	1.49	0.26
11	14446	5.50	7.30	1.33	0.26
12	14045	5.22	10.25	1.96	0.25
13	14994	2.04	9.33	4.58	0.25

Note: * Feeder Analysis covers period October 1, 2002 to September 30, 2003

D. <u>Identifications of Feeders with Poorest Reliability.</u>

(1) The method used by a utility to identify the feeders with the poorest reliability shall be approved by the Commission and be included in the report.

(2) Feeders included in the report, which serve customers in Maryland and one or more bordering jurisdictions, shall be identified. The report shall include the percentage of customers located in Maryland and the percentage of customers located in bordering jurisdictions.

Pepco Response:

(1) The CPI model description was previously provided to Mr. J. H. Walter of the Maryland Commission Staff in correspondence of May 15, 2001 from C. H. Knapp of Pepco and as Attachment A to Pepco's 2000 Reliability Indices and Corrective Action Process filing of November 1, 2001. Attachment A was and is considered proprietary and was provided to the Commission on a confidential basis. Pepco has no proposed changes to its filed method for identifying feeders with the poorest reliability.

(2) With the exception of feeder 14033, all feeders included in Table 2 served only Maryland customers. Approximately 2% of the customers on feeder 14033 reside in the District of Columbia.

E. Major Event Interruption Data:

The report shall include the time periods during which major event interruption data was excluded from the indices, along with a brief description of the interruption causes during each time period.

Pepco Response:

There were three major events in Pepco's service territory during the twelve month period ending December 31, 2003.

- August 26 thru 30 -- Severe Thunderstorms resulting in multiple locked out feeders.
- September 18 thru 28 -- Hurricane Isabel.
- November 13 -- High winds (winds gusting at 51mph).

F.1. Actions for Feeders with Poorest Reliability.

An investor-owned utility shall report remedial actions for all feeders identified by the utility as the 2% of feeders having the poorest reliability.

Pepco Response:

Table 3 provides corrective actions Pepco will take on its least reliable Maryland Feeders identified above in Table 2.

Table 3 - Corrective Actions for 2003 Selected Maryland Feeders		
Rank	**Feeder No.**	**Corrective Actions (Includes Tree Trimming if Required)**
1	14033	Upgrade/Install 3 fuses, replace 3 cross-arms, install 1 spacer; install 1 lightning arrestor, and tree trimming
2	14986	Upgrade/Install 29 fuses, replace 3 cross-arms, install 2 spacers, and tree trimming
3	14923	Upgrade/Install 18 fuses, replace 6 cross-arms, install 15 spacers, and tree trimming
4	14447	Upgrade/Install 6 fuses, replace 1 cross-arm, install tree wire in 1 area, install 22 spacers, and tree trimming
5	14968	Upgrade/Install 14 fuses, replace 1 cross-arm, install 20 spacers, and tree trimming
6	15110	Upgrade/Install 5 cross-arms, install 1 animal guard, install 1 spacer, and tree trimming
7	15292	Upgrade/Install 6 fuses, replace 3 cross-arms, install 2 spacers, install 2 lightning arrestors, and tree trimming
8	15233	Install 12 spacers, install ACR, and tree trimming
9	14242	Install 2 lightning arrestors, 3 cross-arms, install 6 spacers, install ACR, and tree trimming
10	15230	Upgrade/Install 21 fuses, replace 5 cross-arms, install 6 lightning arrestors, and tree trimming
11	14446	Upgrade/Install 24 fuses, replace 4 cross-arms, install tree wire 1 area, and tree trimming
12	14045	Upgrade/Install 6 fuses, replace 3 cross-arms, install tree wire 2 areas, and tree trimming
13	14994	Replace/Install 4 cross-arms, install 6 spacers, install tree wire 1 area, install ACR, and tree trimming

G. Evaluation of Remedial Actions. For feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports.

(1) The annual report for the year following the identification of the feeders as having the poorest performance shall provide a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions.

(2) The annual report two years after the identification of the feeders as having the poorest performance shall include the ordinal ranking representing the feeders' reliability during the current reporting period.

Pepco Response:

(1) Table 4 provides corrective actions Pepco has taken on its year 2002 least reliable Maryland Feeders.

Table 4 - Corrective Actions for 2002 Selected Maryland Feeders			
Rank	**Feeder No.**	**Corrective Actions**	**Completion Date**
1	14247	Upgrade/Install 30 fuses, replace 5 cross-arms, install 14 spacers, install 2 lightning arrestors, install 1 down guy, tree trimming	9/20/2003
2	15837	Upgrade/Install 10 fuses, install 1 lighting arrestor; install 3 cross-arms, install 2 down guys, install 16 spacers	9/30/2003
3	14249	Upgrade/Install 1 fuse, install 5 animal guards, replace 6 cross-arms, remove slack in one location	8/01/2003
4	15127	Upgrade/Install 19 fuses, remove slack in 2 locations, install tree wire one area, install 1 animal guard, tree trimming	9/30/2003
5	15134	Upgrade/Install 45 fuses, install 2 animal guards, install 1 lightning arrestor, replace 8 cross-arms, remove slack in 1 location, install 3 spacers	6/20/2003
6	15023	Upgrade/Install 9 fuses, replace 4 cross-arms, install 1 animal guard, install 2 lightning arrestors, tree trimming	9/10/2003
7	15107	Replace/Install 1 cross-arm, install 22 fuses, install 2 spacers, tree trimming	9/30/2003
8	15235	Replace/Install 4 cross-arms, install 2 spacers, tree trimming	9/30/2003
9	15115	Upgrade/Install 3 fuses, install tree wire in 1 area, install 2 lightning arrestors, install 12 cross-arms, replace 3 insulators	9/30/2003
10	15122	Upgrade/Install 16 fuses, install 18 spacers	9/30/2003
11	14163	Upgrade/Install 3 fuses, install 2 lightning arrestors, 1 animal guard, 1 spacer	6/18/2003
12	14181	Upgrade/Install 30 fuses, replace 3 cross-arms, install 4 lightning arrestors, install 8 spacers at 1 location	8/11/2003
13	14970	Upgrade/Install 1 fuse, install tree wire in 1 area, install 1 cross-arm,	4/29/2003

Table 5 - Least Reliable Feeders in 2001						
2001 Rank	2003 Rank	Feeder Number	SAIFI		SAIDI	
			2001	2003	2001	2003
1	112	14476	1.21	0.31	2.71	1.23
2	128	14844	8.21	3.1	3.56	1.38
3	347	14466	1.41	1.02	5.18	0.35
4	320	14823	0.14	0.2	0.47	0.95
5	72	14943	2.16	4.15	3.56	3.73
6	262	15254	2.13	0.2	0.84	0.9
7	240	15274	1.12	0.18	1.23	0.67
8	13	14994	0.07	1.75	0.29	5.1
9	392	14991	0.08	1.09	0.4	0.9
10	352	14824	0.03	0.05	0.15	0.08
11	51	14442	2.09	2.14	1.23	3.43
12	197	14473	1.16	1.05	3.79	2.15
13	376	14294	5.47	0.13	0.33	0.25

(2) Table 5 provides a comparison of the ordinal ranking, as well as the SAIFI and SAIDI values, of the feeders' reliability during 2001 and 2003.

As indicated in Table 5, five (5) feeders (14823, 14943, 14991, 14994, and 14442) did not show improvement in both SAIDI and SAIFI from 2001 levels. However, the ranking on these feeders, with the exception of feeder 14994, are significantly improved in ranking when compared to the rest of the system. The increased indices may be attributed to the extreme amounts of severe weather conditions in 2003 and the implementation of a new outage data collection method (Outage Management System).

The five feeders discussed above are being re-inspected for additional corrective action to improve reliability.

H. Momentary Interruptions. A utility shall maintain information which it collects on momentary interruptions for five years.

Pepco Response:

Pepco collects and maintains information on momentary interruptions for the required period of time.

PAULA M. CARMODY
PEOPLE'S COUNSEL

THERESA V. CZARSKI
DEPUTY PEOPLE'S COUNSEL

STATE OF MARYLAND

OFFICE OF PEOPLE'S COUNSEL

ASSISTANT PEOPLE'S COUNSEL

CYNTHIA GREEN-WARREN
WILLIAM F. FIELDS
PETER SAAR
GARY L. ALEXANDER
RONALD HERZFELD
ANNE JOHNSON
RICHARD S. GRATZ
DONNIECE GOODEN

6 Saint Paul Street, Suite 2102
Baltimore, Maryland 21202
(410) 767-8150 (800) 207-4055
FAX (410) 333-3616
WWW.OPC.STATE.MD.US

May 6, 2011

Terry J. Romine, Executive Secretary
Public Service Commission
Of Maryland
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: Case No. 9240

Dear Ms. Romine:

Enclosed for filing, please find an original and seventeen (17) copies of Direct Testimony of Peter J. Lanzalotta and David J. Effron on behalf of the Office of People's Counsel in the above-referenced case.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

/electronic signature/

Anne L. Johnson
Assistant People's Counsel

ALJ/eom
Enclosure
cc: All Parties of Record

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

IN THE MATTER OF	)	
AN INVESTIGATION INTO THE	)	
RELIABILITY AND QUALITY OF THE	)	Case No. 9240
ELECTRIC DISTRIBUTION SERVICE OF	)	
POTOMAC ELECTRIC POWER COMPANY	)	

DIRECT TESTIMONY OF PETER J. LANZALOTTA

ON BEHALF OF

MARYLAND OFFICE OF PEOPLE'S COUNSEL

MAY 6, 2011

Q. Mr. Lanzalotta, please state your name, position and business address.

A. My name is Peter J. Lanzalotta. I am a Principal with Lanzalotta & Associates LLC, ("Lanzalotta"), 67 Royal Point Drive, Hilton Head Island, SC 29926.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Maryland Office of People's Counsel ("OPC").

Q. Mr. Lanzalotta, please summarize your educational background and recent work experience.

A. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor of Science degree in Electric Power Engineering. In addition, I hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

I am currently a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, I was a partner of Whitfield Russell Associates, with which I had been associated since March 1982. My areas of expertise include electric system planning and operation, economic studies, cost allocation, and reliability analyses. I am a registered professional engineer in the states of Maryland and Connecticut.

In particular, I have been involved with planning, operating, and economic issues related to electric utility systems as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities over a period exceeding thirty years.

I have presented expert testimony before the FERC and before regulatory commissions and other judicial and legislative bodies in 22 states, the District of Columbia, and the Provinces of Alberta and Ontario. My clients have included utilities, state regulatory agencies, state ratepayer advocates, independent power producers, industrial consumers, the United States Government, environmental interest groups, and various city and state government agencies.

A copy of my current resume is included as Exhibit___(PJL-1) and a list of my testimonies is included as Exhibit___(PJL-2).

Q. What is the purpose of your testimony?

A. I was retained to review Potomac Electric Power Company's ("PEPCO" or "Company") electric distribution service reliability performance as part of OPC's participation in Maryland Public Service Commission ("PSC" or "Commission") Case No. 9240 ("Proceeding"). This testimony presents the results of my review.

Q. Please explain how you conducted your analyses.

A. I have reviewed the following information in our investigation:

i. The Evaluation of the Reliability and Quality of the Electric Distribution System of Potomac Electric Power Company Final Report ("Consultants' Report"), dated March 2, 2011, and prepared by First Quartile Consulting and Silverpoint Consulting, LLC ("Consultants") in this Proceeding, as well as interview notes and supporting documents.

ii. The Company's responses to discovery questions submitted by the Commission (in Order No. 83552), OPC, Commission Staff, Montgomery County, and the Maryland Energy Administration, in this Proceeding.

iii. Major Storm Reports for a) all Maryland utilities for the storm on February 5-12, 2010, b) PEPCO for each of the storms on July 25-31, 2010, on August 5-7, 2010, and on August 12-15, 2010, and c) each of PEPCO and for Baltimore Gas and Electric Company ("BGE") for the storm on January 26-31, 2010.

iv) Annual Reliability Index Reports (filed as per Code of Maryland Regulations ("COMAR") §20.50.07.06) a) by PEPCO for the years 2004 – 2010 and b) by BGE for 2010.

Q. Please summarize your conclusions.

A. My testimony concludes that:

i) PEPCO's electric service reliability to its Maryland service area has been getting worse over the past seven years, and was especially poor during major storms in 2010;

ii) serious shortcomings in PEPCO's vegetation management program were the principal causes of this poor storm performance and represents a potential violation of COMAR requirements;

iii) equipment failures and lightning were contributing causes to PEPCO's reliability performance;

iv) PEPCO's failure to periodically inspect its overhead distribution facilities violates COMAR requirements;

v) PEPCO's difficulties in getting accurate ETRs (hereafter defined) from the automated OMS (hereafter defined) during the initial stages of major storms has contributed significantly to customer dissatisfaction.

Based on the foregoing conclusions, I recommend that the Commission require that:

a) PEPCO perform inspections of its distribution facilities at least once every five years;

b) PEPCO institute the practice of inspecting storm-hit areas after service restoration is complete to find and repair storm damage that may have gone undetected during the storm;

c) PEPCO to implement its current vegetation management plan, since it appears to be sufficient to remedy its historical shortcomings, if it is fully implemented and maintained for eight years and thereafter;

d) PEPCO expand the priority feeder portion of PEPCO's Reliability Enhancement Plan ("REP") to at least the 40 feeder level as recommended by the Commission's Consultants;

e) while both the distribution automation and the selective undergrounding portions of the REP can reduce customer interruptions, evaluate the potential cost concerns prior to any decision to implement these proposals;

f) PEPCO improve its OMS and/or its ability to operate the OMS in high volume situations to automatically calculate ETRs.

g) PEPCO use consistent categories of causes in all major storm reports, since its major storm reports frequently change some of the categories of causes into which customer interruptions and customer interruption hours are broken down into from one report to the next.

h) PEPCO report annually to the Commission on PEPCO's progress on implementing these recommendations.

<u>Historical Reliability Performance</u>

Q. Please describe the basis for concerns about PEPCO's electric service reliability which led to the Commission's initiation of this Proceeding.

A. In 2010, PEPCO's Maryland service area experienced a number of storms which resulted in large numbers of lengthy customer service interruptions, poor communications with customers, and many resultant complaints. In addition, the Commission reports receiving complaints of frequent and inexplicable service interruptions even when there are no storms. As a result, the Commission instituted this Proceeding to investigate these issues, including but not limited to the following:

- The number of customers affected by recent power outages;
- The root causes for the scope, frequency and duration of outages - either storm or non-storm related;
- The communications failures that have occurred and continue to occur between Pepco and affected customers; and
- Pepco' s inability to communicate estimated times of restoration to affected customers in a timely manner.[1]

Q. Please describe the basic structure of PEPCO's electric distribution system.

A. Pepco's electric distribution system moves electric power from PEPCO's high voltage[2] transmission system to the ultimate user of that electricity. There are sub-transmission circuits that take power from transmission lines after it has been stepped down to a lower voltage, generally 69,000 volts (69 kV), at a sub-transmission substation. Sub-transmission circuits supply distribution substations, which are located closer to the end users and which lower the voltage further.[3] Typically, each distribution substation supplies a dozen or so primary distribution circuits, frequently called feeders, which extend out from the distribution substation and run to immediate vicinity of the end users.

<u>PEPCO's Electric Service Reliability</u>

[1] Order No. 83526.

[2] High voltage transmission is generally considered to be those facilities operating at 115,000 volts (115 kV) and higher.

[3] The most typical distribution voltages are in the 4 kV to 15 kV range, although some utilities may voltages outside this range for distribution purposes.

Q. How is electric service reliability to electric customers measured on electric utility systems?

A. Electric service reliability to customers is measured using various metrics or reliability indices. Among the most widely-used reliability indices are those published by the IEEE[4], a technical society. In IEEE Standard 1366-2003, a large number of reliability indices are defined, along with related topics. Among the most commonly used of these reliability indices are SAIFI, a measure of the average customer outage frequency, and SAIDI, a measure of the average customer outage duration. SAIDI and SAIFI are defined thusly:

> **System average interruption frequency index (SAIFI):** This index indicates how often the average customer experiences an interruption[5] to their electric service over a predefined period of time, as used in this testimony, a year. Mathematically, SAIFI equals the sum of the total number of interruptions[6] experienced by customers divided by the total number of electric customers. For example, a SAIFI of 2.0 for a period of a year means that the average electric customer experienced two service interruptions in that year. A higher value for SAIFI reflects lower electric service reliability.

---

[4] "IEEE" means and refers to The Institute of Electrical and Electronics Engineers, Inc.

[5] SAIFI and SAIDI both look only at sustained electric service interruptions, but not at momentary electric service interruptions, which are limited in duration to the amount of time it takes to restore service via immediate switching operations, up to much as 5 minutes in duration. If an interruption cannot be classified as momentary, it is considered to be sustained.

[6] If an electric distribution circuit with 1,000 electric customers connected to it suffers a complete outage of all its customers, that is equivalent to 1,000 customer interruptions.

System average interruption duration index (SAIDI): This index indicates the total duration of the electric service interruptions for the average customer during a predefined period of time, as used in this testimony, a year. It is commonly measured in customer minutes (or hours) of service interruption. Mathematically, SAIDI equals the sum of the total number of customer interruption minutes during the year divided by the total number of electric customers. For example, a SAIDI of 120 for a period of a year means that the average electric customer experienced a total of 120 minutes of electric service interruption in that year. A higher value for SAIDI reflects lower electric service reliability.

Q. Are all electric service interruptions included in the calculation of these reliability indices, even if they are the result of a major storm?

A. Weather is a major driver of electric service interruptions. Storms with intense wind, ice, and/or snow conditions can cause greatly increased numbers of customer electric service interruptions and can cause increased duration of those service interruptions as well. Because weather varies from year to year, some weather-related customer outage data may be withheld from the calculation of some of these electric service reliability indices in an attempt to develop electric service reliability indices that reflect the inherent reliability of the electric system as designed and maintained, without any influence from extraordinary weather events. Maryland's COMAR currently defines major storms as weather-related events when 10% or 100,000 of an electric utility's Maryland customers (whichever is less) experience a sustained interruption of electric service, and when service restoration to these customers takes more than 24 hours.[7] This definition is used in the annual reports of reliability indices that Maryland utilities file with the Commission as required by COMAR §20.50.07.06. A different definition for major storms or major events is supported by the IEEE and is used by an increasing number of utilities for reliability analysis. This IEEE definition defines a major event day as occurring anytime the daily SAIDI for a utility, such as PEPCO, reaches a level that exceeds a target level. This target level is calculated based on up to five years of historical daily SAIDI data for that utility and is used for the entire year.[8]

Maryland electric utilities typically use two sets of reliability index data, one set that excludes all customer interruption data from during major storms or major events (using one of the two major event definitions mentioned above[9]), and one set that includes all interruption data. The reliability indices that include all interruption data, regardless of major storms or events, are useful because these indices show what electric customers are actually experiencing in the way of electric service reliability. My testimony looks at both sets of reliability indices.

---

[7] COMAR §20.50.01.03(10). Proposed changes to Maryland regulations are currently pending which would change the term "major storm" to "major event" and, among other things, remove the weather-related requirement. RM 43 -- *Revisions to COMAR 20.50 - Service Supplied by Electric Companies - Proposed Reliability and Service Quality Standards*.

[8] The calculation involves i) taking the natural logarithm for each daily SAIDI in the historical data set, ii) determining the average and the standard deviation of these logarithms, and iii) calculating the major event day threshold from this average and standard deviation. During the following year, any day with a daily SAIDI that exceeds the major event day threshold is considered a major event day.

[9] The PEPCO SAIFI and SAIDI performance discussed herein uses the IEEE definition for major event data.

Q. How has PEPCO's electric service reliability performance been over the period of time leading up to this investigation?

A. PEPCO has exhibited steadily declining electric distribution service reliability over the past seven years in some reliability indices and has experienced significant increases in its storm-related reliability problems. Table 1, below, shows PEPCO's SAIFI performance over the past seven years, first excluding interruption data from major events[10], and then including it.[11]

Table 1

	SAIFI Excluding Major Events				
Year	Pepco	DC	Maryland	PG	MC
2004	1.22	0.73	1.44	1.64	1.30
2005	1.34	0.92	1.53	1.62	1.47
2006	1.44	0.85	1.72	1.88	1.60
2007	1.69	1.04	2.00	2.52	1.62
2008	1.73	1.05	2.03	2.27	1.85
2009	1.74	1.06	2.06	2.06	2.07
2010 (11Mo)	1.88	1.15	2.23	1.92	2.46
	SAIFI Including Major Events				
Year	Pepco	DC	Maryland	PG	MC
2004	1.37	0.78	1.63	1.87	1.45
2005	1.83	1.44	2.01	1.95	2.05

[10] This data uses the IEEE definition for major event days because that was what PEPCO provided in response to discovery requests. This generally results in lower values for SAIFI and SAIDI with major events excluded than if the COMAR definition is used. That is, SAIFI and SAIDI with major events excluded determined using the IEEE definition of major event days will generally reflect better electric distribution reliability than the same indices determined using the COMAR definition.

[11] All of the SAIFI data shown in Table 1 is taken from PEPCO's response to Consultants' Data Request No. 72, Attachment 1, which is attached hereto as Exhibit ___(PJL-6). Please note that data for 2010 is through November only. In addition, calculation of the Maryland SAIFI indices were based on the retail customer data provided by PEPCO in the Attachment to its response to Montgomery County Data Request No. 6-2, which is attached hereto at Exhibit ___ (PJL-7).

2006	2.13	1.08	2.61	3.00	2.33
2007	1.86	1.07	2.23	2.92	1.73
2008	2.33	1.24	2.85	3.15	2.59
2009	1.74	1.06	2.06	2.06	2.07
2010 (11Mo)	3.18	1.58	3.96	3.00	4.65

Table 1 shows SAIFI for (i) PEPCO as a whole, (ii) each of PEPCO's District of Columbia ("DC") and Maryland service areas, and, finally, (iii) PEPCO's service areas in each of Maryland's Prince George's County ("PG") and Montgomery County ("MC") for 2004 through 2010.

Looking first at PEPCO's SAIFI, excluding major events, we see that it has increased every year, from 1.22 interruptions per customer per year in 2004 to 1.88 interruptions in 2010, an increase of about 54% over 7 years. (As stated previously, a higher SAIFI value means more interruptions per customer per year, so a higher SAIFI means lower reliability.) PEPCO's two jurisdictions, DC and Maryland, have substantially different levels of SAIFI performance (excluding major events), with DC's SAIFI ranging from 0.73 interruptions per customer per year in 2004 to 1.15 interruptions in 2010 (an increase of 58%), as compared with Maryland's SAIFI, which ranges from 1.44 interruptions in 2004 to 2.23 interruptions in 2010 (an increase of 55%). Although the percentage increase over the time period is about the same for both jurisdictions, Maryland is starting from a much worse position since its SAIFI in 2004 is nearly twice as high as that of DC for the same year. DC's SAIFI (excluding major events) is also about half or slightly more than half that of Maryland's in most of these years. PEPCO's Maryland SAIFI (excluding major events) increases every year from 2004 to 2010.

Finally, looking at the breakdown of PEPCO's Maryland SAIFI (excluding major events) performance by county, PG's SAIFI (excluding major events) ranges from 1.64 interruptions per customer per year in 2004 to 1.92 interruptions in 2010 (an increase of 17%), while MC's SAIFI (excluding major events) ranges from 1.30 interruptions per customer per year in 2004 to 2.46 interruptions in 2010 (an increase of 89%). PEPCO's MC SAIFI (excluding major events) increases every year from 2004 to 2010.

I mentioned earlier that the reliability indices excluding major events are typically considered to be more representative of the basic reliability inherent in the design, construction, and maintenance of a utility's electric system, while the reliability indices including major events reflects total performance, including during major storms, which can vary substantially from year to year. Using this perspective, we see a consistent increase in PEPCO's SAIFI values, excluding major events, which reflects a consistent decline in PEPCO's reliability for the period 2004 to 2011. In MC, this reliability decline in 2010 was a substantial 19%[12] compared to 2009, as measured by SAIFI excluding major events.

Looking at PEPCO's SAIFI performance including major events on the lower half of Table 1, note that SAIFI is higher when including major events, except for 2009 which reflects the same SAIFI values both with and without major events because no major events occurred that year. PEPCO's total Company SAIFI including major events ranges from 1.37 interruptions per customer per year in 2004 to 3.18 interruptions in 2010. The

[12] 2.46 ÷ 2.07 = 1.1884

2010 value is more than 36% greater than the next highest year, 2008. Consistent with SAIFI excluding major events, PEPCO's DC jurisdiction has consistently better SAIFI performance than Maryland, with a 2010 SAIFI including major events of 1.58 interruptions per customer per year in DC as compared to PEPCO's Maryland jurisdiction at 3.96 interruptions in 2010. This 2010 Maryland value is approximately 39% higher than the next highest year in 2008. PEPCO's MC service area had a SAIFI including major events of 4.65 interruptions per customer per year in 2010, a level that is about 80% higher than the next highest year, 2008.

To provide a point of comparison, BGE's 2010 SAIFI was 1.48 interruptions per customer excluding major events and 1.58 interruptions per customer including major events.[13]

These SAIFI values including major events show how storms decrease electric distribution system reliability. In 2010, this impact was especially severe for SAIFI including major events performance in PEPCO's MC service area.

Q. Please discuss PEPCO's historical SAIDI index performance.

A. PEPCO SAIDI performance is summarized in Table 2 below.

[13] BG&E's 2010 Annual Reliability Indices Report, Mail Log #130867, p. 1 ("BGE 2010 Reliability Report"), a copy of which is attached hereto as Exhibit ___(PJL-8).

Table 2

	SAIDI Excluding Major Events				
Year	Pepco	DC	Maryland	PG	MC
2004	97	78	105	115	98
2005	198	178	207	199	213
2006	247	210	264	284	249
2007	252	215	268	338	218
2008	256	209	276	313	249
2009	184	141	205	207	203
2010 (11Mo)	227	156	261	192	311
	SAIDI Including Major Events				
Year	Pepco	DC	Maryland	PG	MC
2004	115	86	128	144	117
2005	419	398	429	304	520
2006	509	317	597	742	492
2007	317	230	358	503	253
2008	568	273	709	705	708
2009	184	141	205	207	203
2010 (11Mo)	1,553	494	2,065	851	2,947

The SAIDI values in Table 2 reflect the total electric service outage duration, in minutes, of all the electric service outages experienced by the average PEPCO electric customer during each year.[14]

Looking first at the values for PEPCO's SAIDI excluding major events, in the top half of Table 2, the annual SAIDI for the total Company varies from 97 minutes per customer in 2004 to 227 minutes in 2010, with the highest SAIDI values in 2006, 2007, and 2008, ranging from 247 to 256 minutes. When PEPCO's service territory is broken down into

[14] As with Table 1 above, the SAIDI data for Table 2 is taken from Exhibit ___ (PJL-6) and calculation of the Maryland SAIDI indices were based on the retail customer data from Exhibit ___ (PJL-7).

its DC and Maryland jurisdictions, as was the case with the SAIFI analysis discussed above, the SAIDI (excluding major events) values for PEPCO's DC jurisdiction are consistently lower (reflecting higher electric service reliability) than the SAIDI (excluding major events) for PEPCO's Maryland jurisdiction. DC's SAIDI excluding major events is 78 minutes in 2004 and 156 minutes in 2010 with the highest values in 2006, 2007 and 2008, ranging from 209 to 215 minutes. PEPCO's Maryland SAIDI values, excluding major events, are 105 minutes in 2004 and 261 minutes in 2010, with the highest values occurring in 2006, 2007, and 2008 in the range from 264 to 276 minutes. Looking at PG and MC individually, PG's SAIDI excluding major events is 115 minutes in 2004 and 192 minutes[15] in 2010, with the highest SAIDI values occurring in the 2006-2008 time period, peaking at 338 minutes in 2007. MC's SAIDI (excluding major events) ranges from a low of 98 minutes in 2004 to a peak of 311 minutes in 2010, with 2010 showing a 53% increase in SAIDI (excluding major events) over the previous year 2009.

The performance of PEPCO's SAIDI (excluding major events) reliability index over the seven years of historical performance we are looking at (2004 to 2010) is less conclusive than was PEPCO's SAIFI performance because the 2010 performance was not the least reliable year for all jurisdictions identified in Tables. In most cases, however, the 2010 SAIDI performance (excluding major events) was worse than 2009, with MC leading the way with a 53% increase in SAIDI (excluding major events) in 2010 over 2009.

[15] This 2010 SAIDI value (excluding major events) for PG is the second lowest in the last seven years.

PEPCO's SAIDI performance including major events is more conclusive. Looking at the bottom half of Table 2, we see that PEPCO's 2010 SAIDI performance (including major events) suffered a dramatic deterioration. For the entire Company, PEPCO's SAIDI (including major events) for 2010 was 1,553 minutes (25.88 hours) of electric service interruption per customer, compared to its next highest year in 2008 with 569 minutes (9.48 hours).

For PEPCO's DC jurisdiction, SAIDI including major events was 494 minutes (8.23 hours) in 2010, compared to its next highest year in 2005 with 398 minutes (6.63 hours).

By comparison, PEPCO's SAIDI (including major events) performance in Maryland in 2010 was 2,065 minutes (34.41 hours) of electric service interruption per customer, compared to its next highest year in 2006 with 597 minutes (9.95 hours). In 2010, PEPCO's Maryland customers experienced, on average, i) more than four times the electric service outage minutes than DC customers experienced, and ii) almost 3.5 times the previous annual outage minutes peak[16] in 2006.

PEPCO's Maryland SAIDI (including major events) electric service outage performance in 2010 is even more dramatic when MC is examined individually. To be sure, PG's SAIDI of 851 minutes (including major events) (14.18 hours) was at its highest level in at least seven years and more than 70% higher (less reliable) than DC's. But, PEPCO's MC service area experienced much worse reliability performance. PEPCO's MC 2010 SAIDI including major events was 2,947 minutes of outages per customer for the year. That's

[16] Within the seven year period 2004 – 2010.

49.12 hours, or 2.05 days, of electric service interruption per customer on average for the year. This 2010 SAIDI (including major events) performance in MC reflects a total outage duration per customer that is about 6 times longer than that experienced by Pepco's DC customers.

By way of comparison, BG&E reported SAIDI values (excluding major events) for 2010 of 4.52 hours (271 minutes), and of 5.46 hours (328 minutes) including major events.[17] Note that the difference in SAIDI values including major events for 2010 between PEPCO's Maryland service area (2,065 minutes) and BG&E (328 minutes) highlight PEPCO's reliability problems during major events.[18]

Q. What is your evaluation of this reliability performance by PEPCO?

A. PEPCO's overall reliability performance has exhibited a consistent worsening of customer outage frequency in its Maryland service area over the past seven years, as reflected in values for SAIFI excluding major events. When including major events, PEPCO's SAIFI performance in 2010 in Maryland, and particularly in MC, was substantially worse than in any of the other six preceding years.

PEPCO's reliability performance exhibited dramatic increases in average outage duration in 2010, as reflected in values for SAIDI including major events. While an increase in SAIDI due to an increase in major storms is normal, increases of the level experienced by PEPCO reflect more than just variations in weather. As I will discuss later in my

[17] Exhibit ___ (PJL-8) (BG&E 2010 Reliability Report) p. 1.

[18] Exhibit ___ (PJL-8) (BG&E 2010 Reliability Report) , p. 1.

testimony, poor vegetation management practices, lack of system inspections, and other factors helped produce a situation where the effects of the 2010 storms on PEPCO's electric system were greatly increased from what would have been expected in the event of adequate system maintenance.

What is Causing PEPCO's Deteriorating Reliability Performance?

Q. What are the leading causes of customer electric service interruptions on PEPCO's electric system in Maryland?

A. My review shows that tree-related electric service interruptions are the leading cause of such interruptions, and that equipment failure and lightning are significant contributors.

In order to investigate this question, I reviewed PEPCO's major storm reports to the Commission for the four major storms to hit PEPCO's Maryland service area in 2010 (collectively, "PEPCO Major Storm Reports"),[19] as well as information related to the least reliable distribution feeders in PEPCO's Maryland service area as reported to the Commission in PEPCO's annual reliability indices reports for 2009 and 2010.[20] I also

[19] PSC Case No. 9220, *In The Matter Of An Investigation Into The Performance Of Utilities During The Snow Storms Between The Period February 5 Through February 12, 2010,* State of Maryland Major Storm Report February 5-12, 2010: Snow Storm (ML#121772) ("February Storm Report"); State of Maryland Major Storm Report July 25-31, 2010: Severe Thunderstorm (ML#124982) ("July Storm Report"); State of Maryland Major Storm Report August 5-7, 2010: Severe Thunderstorm (ML#125122) ("August 5-7 Storm Report"); and State of Maryland Major Storm Report August 12-15, 2010: Severe Thunderstorm (ML#125269) ("August 12-15 Storm Report," together with the February Storm Report, July Storm Report, and August 5-7 Storm Report, the "PEPCO Major Storm Reports"). Copies of the February Storm Report, July Storm Report, August 5-7 Storm Report and August 12-15 Storm Report are attached hereto as Exhibit ___(PJL-9), Exhibit ___(PJL-10), Exhibit ___(PJL-11), and Exhibit ___(PJL-12), respectively.

[20] 2009 Annual Reliability Indices Reporting, ML#122846 ("PEPCO 2009 Reliability Report"), and 2010 Annual Reliability Indices Reporting, ML#130919 ("PEPCO 2010 Reliability Report," together with the "PEPCO 2009

reviewed the Consultants' Report and underlying support documents such as data responses and interview notes.

My review of the PEPCO Major Storm Reports is summarized in Exhibit___(PJL-3) attached to this testimony. Exhibit___(PJL-3) shows a breakdown of customer-interruptions (shown as "Customers") and customer interruption hours (shown as "Interruption Hours") by the cause for the interruption. Causes included are Tree, Equipment (failure), Lightning, Ice, Wind, Other Weather, and Other Causes.[21] PEPCO has indicated[22] that it considers the interruption causes of Tree and Wind to both be tree-related. The Consultants' Report also made reference to the fact that many of the tree-related outages the Consultants reviewed had "storm" listed as the cause on the system operator logs.[23]

Exhibit___(PJL-3) lists the actual numerical metrics (number of customer interruptions and number of customer interruption hours) for each interruption cause with the percent of the total for each cause listed below the numerical metrics. For example, for the winter storm(s) of February 5-12, 2010, there were 93,071 customer interruptions and

Reliability Report," the "PEPCO Reliability Reports"). Copies of the PEPCO 2009 Reliability Report and the PEPCO 2010 Reliability Report are attached hereto as Exhibit ___(PJL-13), and Exhibit ___(PJL-14), respectively.

[21] Exhibit ___ (PJL-9) (February Storm Report) p. 24; Exhibit ___ (PJL-10) (July Storm Report) p. 24; Exhibit ___ (PJL-11) (August 5-7 Storm Report) p. 16; and Exhibit ___ (PJL-12) (August 12-15 Storm Report) p. 17.

[22] Exhibit ___ (PJL-17) (PEPCO January Storm Report), p. 25.

[23] Consultants' Report, p. 22.

1,822,470 customer interruption hours due to "Tree",[24] which represented 35% of the total customer interruptions and 51% of the total customer interruption hours experienced in PEPCO's Maryland service area during this storm. Below this percentage breakdown is the total percentage of customer interruptions and customer interruption hours due to "Tree" and "Wind", which I am considering for purposes of this testimony as being tree-related. For example, for the February 5-12, 2010 storm, 82% of both customer interruptions and customer interruption hours are tree-related.

Exhibit___(PJL-3) shows the percentage of customer interruptions and customer interruption hours due to each cause for each of the four major storms running across the top of the Exhibit. Line 22 of Exhibit___(PJL-3), shows that a majority of the customer interruptions and customer interruption hours are considered tree-related in the three storms on February 5-12, July 25-31, and August 5-7. In the fourth storm, on August 12-15, only 33% of the customer interruptions and 44% of the customer interruption hours are considered tree-related. In this storm, lightning was the majority cause (51%) of customer interruptions, with no single cause being responsible for a majority of the customer interruption hours.

Below the individual storm information in Exhibit___(PJL-3) are two summary sets of data. The set of data on the left, under the heading "Total 3 Summer Storms," is for the total of the three summer storms (i.e. July 25-31, August 5-7, and August 12-15), and

[24] February Storm Report, p. 24.

shows that 57% of the customer interruptions and 67% of the customer interruption hours are considered tree-related. This set of data also shows that, for these summer storms, lightning was also a major cause of outages with 29% of customer interruptions and 20% of customer interruption hours.

To the right of the total statistics for the three summer storms in Exhibit___(PJL-3) is data which totals up all four 2010 storms. This data, under the column entitled "Total 4 Storms," shows that 64% of customer interruptions and 70% of customer interruption hours for all four 2010 storms are tree-related. This data also shows that, after the causes considered to be tree-related, i.e., Tree and Wind, the next biggest cause of customer interruptions and customer interruption hours is lightning with responsibility for 21% of customer interruptions and 16% of customer interruption hours.

Q. Do you have any other comments on PEPCO's storm outage statistics?

A. Yes. PEPCO changed some of the cause categories it used in the PEPCO Major Storm Reports part of the way through the year. The result of these changes was that the February Storm Report and the August 12-15 Storm Report had "weather – wind" as a cause of outages,[25] while other two reports (for July 25-31 and Aug. 5-7) did not use this cause.[26] Rather, the July Storm Report and August 5-7 Storm Report used the cause of "weather other than lightning," which appears to have combined "weather – wind" and

[25] Exhibit ___ (PJL-9) (February Storm Report) p.24; and Exhibit ___ (PJL-12) (August 12-15 Storm Report) p. 17.

[26] Exhibit ___ (PJL-10) (July Storm Report) p. 24; and Exhibit ___ (PJL-11) (August 5-7 Storm Report) p. 16.

"weather – other".[27] Also, the August 5-7 Storm Report and the August 12-15 Storm Report include "source lost" as a separate category of outage causes[28] while the February and July Storm Reports do not use this cause category, and may possibly include data from this outage cause under another cause category, such as "Other Causes". These changes make it difficult to see how PEPCO's performance during major storms may vary from one storm to the next, or from one year to the next, as well as to discern the extent and underlying vulnerabilities on the system.

Q. You also made reference to your review of information related to the least reliable distribution feeders in PEPCO's Maryland service area as reported to the Commission in the PEPCO Reliability Reports. Please describe.

A. In its recently filed PEPCO 2010 Reliability Report, the Company lists outage cause responsibility percentages for what it calls its 2011 Maryland Priority Feeders.[29] These outage cause percentages are listed in Exhibit___(PJL-4) which shows these outage cause percentages for 14 Maryland feeders with the poorest reliability and calculates the average outage cause percentages for each of the causes. The "Tree" outage cause category had an average value of 52% (out of a possible 100%), while the next highest cause was "Equipment" (failure) with 22%. "Unknown" was third with 11%.

[27] Exhibit ___ (PJL-10) (July Storm Report) p. 24; and Exhibit ___ (PJL-11) (August 5-7 Storm Report) p. 16.

[28] Exhibit ___ (PJL-11) (August 5-7 Storm Report) p. 16; and Exhibit ___ (PJL-12) (August 12-15 Storm Report) p. 17.

[29] Exhibit ___ (PJL-14) (PEPCO 2010 Reliability Report), Table 3, pp. 10-14.

These results attribute the major portion of outages on these 14 poorly performing distribution feeders to tree-related causes.

Q. Please summarize your outage cause findings.

A. My review of customer interruption data from the PEPCO Major Storm Reports and from the PEPCO 2010 Reliability Report shows that tree-related faults were the major cause of reliability problems on PEPCO's Maryland electric distribution system. Data from the PEPCO Major Storm Reports indicated that lightning was the next biggest cause of customer interruptions, while data from the PEPCO 2010 Reliability Report indicated that equipment failure was the next biggest cause of customer interruptions.

Q. Do you have any related comment on data that should be reflected in future filings by PEPCO in its Annual Reliability Indices Report?

A. Yes. The major storm reports in Maryland include a breakdown by cause of customer interruptions and customer interruption hours. I recommend that the Annual Reliability Indices Reports also include a similar breakdown by cause for customer interruptions and customer interruption hours that occur outside of major storms.

Q. How does the fact that tree-related causes were the major cause of customer interruptions explain the fact that customer outage durations during the major storms in 2010 were so lengthy in PEPCO's Maryland service area?

A. By itself, the fact that tree-related causes were the major cause of customer interruptions does not explain PEPCO's Maryland outage durations during major storms in 2010.

However, because PEPCO's vegetation management shortcomings were widespread, when a major storm hit PEPCO's Maryland service area, the storm caused many more customer interruptions per distribution circuit than was the case for other Maryland utility systems. To demonstrate, I will use the twin snowstorms of February, 2010, which hit many areas of Maryland with record snowfall levels. Table 3, below, was filed in March 2010 in comments filed by OPC[30].

Table 3

	Allegheny Power	BGE	Choptank	DPL	PEPCO	SMECO
MD Service Area (Sq Mi)	2,544	2,300	2,742	3,471	575	1,150
OH Distribution (Cir Mi)	5,500	9,384	2,133	3,727	3,482	3,726
Cir Mi per Sq Mi	2.2	4.1	0.8	1.1	6.1	3.2
Cust Interruptions per Cir Mi	2.6	15.2	17.9	23.1	75.9	10.4

Table 3 shows, for each of the major Maryland electric utility systems, (i) the Maryland service area in square miles, (ii) the miles of overhead (OH) distribution circuits, (iii) the circuit miles of overhead distribution per square mile of service area (which reflects service area load density), and (iv) the number of customer interruptions experienced during the February 5-12, 2010 storm per circuit mile of overhead distribution (which reflects customer interruption density). Note that PEPCO's 75.9 customer interruptions per circuit mile of overhead distribution were more than three times that of the next

[30] Actually, Table 3 reflects corrected data filed a few days after the original OPC comments were filed. PSC Case No. 9220, OPC Supplemental Comments, Mail Log#122062, p. 5. A copy of the OPC Supplemental Comments is attached hereto as Exhibit ___ (PJL-15).

hardest hit utility, Delmarva Power & Light Company (DPL), with 23.1 customer interruptions per circuit mile of overhead distribution. Given this volume of customer interruptions, it does not seem surprising that service restoration for PEPCO's customers would take longer than for other Maryland utilities.

PEPCO's Vegetation Management Program

Q. Why have PEPCO's reliability problems with trees become such a factor in the Company's electric service reliability performance?

A. The adverse electric service reliability impacts of PEPCO's vegetation management program has resulted from a number of factors. First, perhaps the most important such factor was the inadequate level of funding for maintenance tree-trimming on the distribution system. Exhibit___(PJL-5) compares budgeted versus actual distribution O&M[31] for Maryland annual tree-trimming expenses for the period 2004 through 2010.[32] PEPCO's actual Maryland spending on distribution O&M trimming was $5.4 million in 2004. From 2005 through 2009, PEPCO's actual Maryland distribution tree-trimming expenditures were consistently below this level, sometimes below $4 million per year, and budgeted amounts in some years, particularly 2005 and 2007, were cut even more drastically. Once electric service reliability became more of an issue in early 2010, the tree trimming budget for Maryland distribution O&M increases from $4.3 million in

[31] O&M [Operation and Maintenance] tree-trimming maintains existing facilities, as compared to capital tree-trimming which is to accommodate newly-constructed facilities.

[32] PEPCO's response to Montgomery County Data Request 4-25 Attachment, a copy of which is attached hereto as Exhibit ___ (PJL-16).

2009 to more than $7.3 million in 2010, and actual spending increased from $5 million in 2009 to more than $11 million in 2010. This increase of more than 100% in tree-trimming expenditures in 2010 indicates the extent of the inadequacy of the spending levels of $3.9 million to $5.1 million during the previous five years. PEPCO's tree-related reliability performance in 2010 is another indication of the insufficiency of PEPCO's tree-trimming spending levels during 2004 through 2009.

Second, because of these inadequate tree-trimming budgets and expenditures prior to 2010, PEPCO kept changing its approach to tree trimming multiple times during the preceding years. The Consultants' Report states:

> We discussed with Pepco the details of its vegetation management programs and practices over the last dozen years. We found that Pepco kept revamping its vegetation management program in an attempt to use its available funds in the most efficient manner possible.[33]

While using tree-trimming funds in as efficient a manner as possible has value, changing the tree-trimming program can result in additional costs. Again, as noted by the Consultants in the Consultants' Report :

> At the beginning of 2010, Pepco significantly overhauled its sub-transmission and distribution vegetation management program so that it would now trim trees on a four-year cycle to provide a clearance zone of four years' growth from the wires, which increased the amount of trimming required that year. Since it was trying to transition from a two-year cycle to a four-year cycle, in addition to trimming one-quarter of its system for four years of growth, the Company also had to perform spot trimming on the other three-quarters of its system to prevent further degradation.[34]

[33] Consultants' Report, p.36.

[34] Consultants' Report, p.37.

One way PEPCO tried to increase the effectiveness from its tree-trimming budgets was to use condition based maintenance ("CBM"), in which more distribution feeders were selected for tree-trimming based on each feeder's tree SAIFI[35] and fewer were selected based on a time-based cycle. The Consultants provided the following description of the CBM vegetation management program:

> From 1999 until 2003, Pepco performed its distribution vegetation management program on a plat basis, which means that it inspected and trimmed lines and substations by defined areas. The Company also included its worst performing feeders (2 percent of its feeders or roughly 14 circuits in Maryland) into its yearly schedule as required, regardless of location.
>
> In 2003, Pepco began doing less trimming within each plat in order to stretch its available budget. Pepco introduced "condition-based" maintenance to its plat-based trimming program. It identified those feeders in each plat with a Tree SAIFI of 2.5 (*i.e.*, a circuit with 2.5 or more outages due to trees in a year) and trimmed those feeders to the prescribed requirements. On the remaining feeders, the Company patrolled and lightly trimmed if needed to maintain the two years' growth distance from wires. Even with the reduction in workload, the Company did not complete ten percent of its scheduled work.
>
> From 2004 to 2007, Pepco continued its two-year plat-based vegetation maintenance program with the emphasis on lines with 2.5 Tree SAIFI or higher—but now only within the Washington Beltway. Outside the Beltway (which is most of the Maryland territory), Pepco cut its program back to focus on only the three-phase portion of the distribution lines, relying primarily on "hotspot" trimming for the one-phase portion of those circuits.
>
> In the same four years, Pepco's SAIDI and CAIDI in Maryland essentially tripled.[36]

[35] "Tree SAIFI" is the frequency of outages that are tree-related.

[36] Consultants' Report, pp. 36-37.

The increase in CBM meant that distribution feeders which were experiencing fewer tree-related electric service interruptions were less likely to be trimmed and trees along, around, and above such feeders were allowed to grow with fewer restraints. (In addition, reduced tree-trimming expenditures meant that less tree trimming was being performed, regardless of the trimming program.) Since tree growth is gradual, any reliability impacts from reduced levels of distribution tree trimming under the CBM program may not be noticeable and may take several years to become evident. Eventually, however, increased vegetation in close proximity to distribution wires will negatively impact reliability. Further, these negative reliability impacts will be increased greatly during big storms where high winds, heavy snow, and/or accumulations of ice can cause portions of the untrimmed, and therefore, increased vegetation to make contact with or come down on top of distribution conductors, sometimes taking distribution conductors down in the process.

Q. In your preparation for this Proceeding, did you come across any factors you think may have contributed to Pepco's decisions to reduce or hold down its distribution O&M tree trimming budgets and expenditures in Maryland?

A. Yes, in reviewing certain discovery for this Proceeding, there appears to be a correlation between annual dividends paid to the commons stock shareholders of PEPCO Holdings, Inc. ("PHI") and O&M budgets and expenditures of PEPCO. On the lower portion of Exhibit___(PJL-5), the annual cash dividends paid to holders of the common stock of PHI are calculated for the years 2004 to 2010. Line 11 of the Exhibit shows the annual cash dividend per share of common stock. In 2006, when PHI increased its dividend from $1.00 to $1.04 per share (a 4% increase), PEPCO reduced its expenditures on Maryland distribution tree-trimming to $3.9 million, its lowest level of the entire period from 2004 to 2010 and a 13.8% decrease from 2005. In 2009, PHI increased its common stock dividend again from $1.04 to $1.08. Likewise, in 2009, PEPCO's Maryland O&M distribution tree-trimming expenditures were also reduced from the level of expenditures in 2008. Of course, PHI common stock reflects not only what happens in PEPCO's Maryland service area, but all of PEPCO as well as PHI's other utility subsidiaries. As shown on line 14 of Exhibit___(PJL-5), however, the annual increase in cash dividends that PHI had to fund as a result of the increases in the common stock dividend started at $7.6 million in 2006 and increases every year until, in 2010, when dividends reach $17.9 million.

Equipment Failure and Lightning Impacts

Q. Your prior analyses indicated that, after tree-related faults, lightning-related faults during the major storms and equipment failure during other times were the next most substantial sources of customer interruptions in PEPCO's Maryland service area. Please discuss.

A. Equipment failure can result from age, storm damage, or other causes as well. In their Report, the Consultants state:

> During our circuit inspection, we found a considerable number of items that should have been identified and fixed during systematic inspections, but were not, including:
> • Broken, split, or deteriorated poles and cross arms
> • Blown lightning arrestors

- Dangling live secondaries from transformers
- Broken guy wires and head guys and missing guy insulator sticks
- Bad or loose pole top pins
- Loose or floating insulators
- Tree wire tied to glass insulators without stripping.[37]

PEPCO does not perform regular inspections of its sub-transmission and distribution circuits. This practice does not comply with COMAR §20.50.02.02, which provision refers to the National Electric Safety Code ("NESC"), which has requirements for overhead system inspections in Section 21 General Requirements, Subsection 214 Inspection and Tests of Lines and Equipment, Part A When In Service, Subpart 2. Inspection, states:

> Lines and equipment shall be inspected at such intervals as experience has shown to be necessary.

The Consultants' Report describes some of the damage referenced in the quote above as appearing to be storm-related and states that PEPCO does not perform after-storm inspections or patrols to look for storm damage or other storm impacts that could affect reliability in the future.[38]

The overhead sub-transmission and distribution facilities should undergo a full visual inspection at least once every five years, which, in my experience is fairly typical for the industry. Follow-up testing or inspection, equipment repairs, equipment replacement, remedial tree trimming, or other follow-up actions should be implemented as indicated by

[37] Consultants' Report, p. 51.

[38] Consultants' Report, p. 52.

the results of these inspections. Furthermore, following any storms involving high winds, heavy snow accumulation, or significant ice accumulations, PEPCO should perform a visual inspection of all overhead sub-transmission and distribution facilities in the affected area so as to identify and remedy storm damage or other storm impacts that could adversely affect reliability in the future.

Lightning impacts on electric distribution service reliability are related to some extent on the placement and effectiveness of lightning arrestors on overhead facilities. As shown on Exhibit___(PJL-3) , the total statistics for the three summer storms reflect that lightning caused 29% of the customer interruptions, but only 20% of the customer interruption hours. This means that outages caused by lightning are somewhat shorter than the typical outage during these storms. Lightning arrestors do not have a fixed service life of a certain number of years. Rather, their service life is dependent upon the number and intensity of lightning strikes to which they are subjected. Most utilities tend to deal with placing or replacing lightning arrestors when the utilities have other work to do on a given pole, or if a particular feeder is experiencing high levels of lightning induced outages. In the PEPCO 2009 Reliability Report, the Company replaced or installed about 85 lightning arrestors on its 2008 and 2009 Maryland Priority Feeders.[39] When PEPCO establishes a visual inspection program for its overhead distribution facilities, any damaged lightning arrestors found should be repaired in a reasonable and timely fashion, as would be the case for all other damage as well.

[39] Exhibit ___ (PJL-13) (PEPCO 2009 Reliability Report), pp. 8-9.

Q. Your testimony above refers to a violation of COMAR by PEPCO due to a lack of regular inspections of sub-transmission and distribution overhead facilities. Did you find any other COMAR violations?

A. COMAR §20.50.07.05 A, Endeavor To Avoid Interruptions provides, in part that "(e)ach utility shall make reasonable efforts to avoid interruptions of service…" There is substantial documentation showing that PEPCO's vegetation management program, in the years leading up to 2010, does not represent a reasonable effort to avoid interruptions of service.

<u>Estimating Service Restoration Times</u>

Q. One of the most pervasive complaints involving PEPCO's communications with customers deals with the subject of Estimated Time of Restoration ("ETR"). Please discuss.

A. Other than letting the power company know about outages, many customer calls to the utility during major storms involve finding out how long the customer may expect to be without electricity. While doing a good job estimating and communicating ETRs to customers during a major storm may do little to affect the pace of repairs and the length of outages, there is little doubt that doing a poor job frustrates customers trying to plan how to respond to extended outages. This can result in increased levels of telephone traffic to the utility during a period when the utility's telephone lines are already experiencing a high number of calls.

PEPCO's handling of outage data is heavily involved with a computerized outage management system ("OMS"). The Consultants' Report describes the OMS as follows:

> The OMS is a computerized operating model of Pepco's distribution system. Pepco has a one-way Energy Management System (EMS) interface to the OMS that provides information on those breakers that are monitored. The OMS uses that information to determine the type of outages that need restoration.166 Pepco's OMS predicts which failed device caused specific outages. The algorithm in OMS runs every 15 minutes using updated information on all remaining active outages; it creates a forecast ETR and prioritization for repairs, but does not assign crews.
>
> The OMS calculates a total number of repair-hours for all known outages based on the total number of repairs needed (*i.e.*, the extent of damage), and the standard amount of time it takes to complete them; it then divides this total number of repair-hours by the number of available workers on duty. The result is the length of time it would take to complete all repairs using only the crews on hand. The OMS also produces individual ETRs for each outage, which are different depending on the circuit or nature of the outage. When a customer requests an ETR, Pepco gives the customer the ETR associated with the outage responsible for causing his or her loss of power.[40]

Under normal operating conditions, with only small, localized outages, PEPCO's OMS apparently calculates accurate ETRs. But, in a high volume situation, such as a major storm with a substantial number of customers interrupted during a short time period, the OMS data must be updated to reflect the addition of mutual assistance crews and other resources that are not typically available on a day-to-day basis. Also, having "foreign" crews working repairs on PEPCO's system during major storms resulted in delays in

[40] Consultants' Report, p. 86.

entering repair data into the OMS. For these reasons, the data in the OMS is not always up to date and, hence, the OMS has difficulty producing reasonable ETRs.[41]

When this happens, PEPCO reverts to a manual method to calculate ETRs and prioritize work orders. PEPCO refers to this manual process as "tiering".[42] PEPCO is reported to have used this manual tiering process in the initial stages of the 2010 major storms. In the February and July storms, the Consultants' Report states that there were difficulties in calculating ETRs, while PEPCO manually determined tiers and ETRs in less than six hours in the August storms.[43] Considering the relative outage volumes of these storms, this doesn't necessarily mean the manual method is a reasonable approach to developing ETRs. Referring to Exhibit___(PJL-3) , the February and July 2010 storms had many more customer interruptions, with 97,071 interruptions in February and 138,311 interruptions in July, than the August 5-7 and 12-15 storms, with interruptions of 24,807 and 51,178, respectively.

The use of a manual method for developing ETRs and prioritizing work in a really big storm is counterproductive. One of the purposes of installing a computerized OMS is typically to help manage situations dealing with high outage volumes. Data regarding operation of substation breakers and customer trouble calls is automatically fed into the OMS. Once the PEPCO system is fitted out with smart meters, data from these should also connect with the OMS. Trying to manually accomplish what the OMS is designed to

[41] Consultants' Report, p. 86-87.

[42] Consultants' Report, p. 88.

[43] Consultants' Report, p. 89.

do in high volume outage situations also seems like a misallocation of system operator resources at a time when these resources are in short supply. Indications are that PEPCO understands this and has been working to address the limitations affecting use of the OMS in calculating ETRs. For example, in January 2011, PEPCO experienced a snowstorm that resulted in 380,459 Maryland customer interruptions, a level just shy of three times the biggest storm in 2010.[44] In its major storm report, PEPCO reports that the OMS performed as designed, and that there were no software or hardware issues that impacted service restoration.[45]

Of course, if the very large outage volumes of interruptions that PEPCO has been experiencing during major storms can be reduced down to more reasonable levels as a result of increased tree-trimming and other reliability-related improvements, the process of determining ETRs will be made that much easier to accomplish.

In the meantime, PEPCO needs to develop and/or maintain the ability to fully use the capabilities of the OMS system during high volume outage situations.

[44] Case No. 9256, *In The Matter of an Investigation into The Performance of Potomac Electric Power Company and Baltimore Gas and Electric Company During the January 26-27, 2011 Snow Storm*, State of Maryland Major Storm Report January 26-31, 2011: Snow Storm (Mail Log #128709) ("PEPCO January 2011 Storm Report"), a copy of which is attached hereto as Exhibit ___ (PJL-17).

[45] Exhibit ___ (PJL-17) (PEPCO January 2011 Storm Report), p. 24.

PEPCO's Reliability Enhancement Plan

Q. In 2010, PEPCO proposed a Reliability Enhancement Plan ("REP") that it describes as advancing work on some existing reliability-based programs and as starting some new reliability activities. Do you have any comment?

A. Yes. The REP addresses six different reliability programs:

i) Enhanced Vegetation Management

ii) Priority Feeders

iii) Load Growth

iv) Distribution Automation

v) URD Cable Replacement

vi) Selective Undergrounding

With the exception of the load growth category, all will help address reliability issues, although only one, the enhanced vegetation management, should be expected to have a significant effect on reliability, during storm situations. PEPCO's recent changes to its vegetation management programs, including implementation of a maximum four-year trimming cycle, an aggressive hazard tree removal program, removal (when possible) of all vegetation above both three phase and single phase feeder primaries, and other features should, if maintained through to fruition, remedy much of the negative reliability impact being experienced due to the historical shortcoming in PEPCO's vegetation management program. The Consultants' Report suggests that vegetation on the PEPCO distribution system is overgrown to the point that it will take 8 years, or two full trimming cycles, to bring the vegetation management situation under control and to fully realize the reliability benefits of this program.[46] Since a majority of the major storm service interruptions are tree-related, I expect these benefits to be substantial as long as the program is maintained for the full eight years.

Priority feeders are feeders selected for reliability upgrades or replacements because of poor reliability performance. These upgrades/replacements are tailored to the causes of each feeders' reliability problems. Currently, PEPCO picks 13 or 14 feeders a year, which would be increased by 45%, to 19 or so feeders under the REP. This program element seems beneficial to electric service reliability, as far as it goes. The Consultants' Report suggests that, since PEPCO has some 700 Maryland circuits, a more appropriate annual number of priority circuits would be 40.[47] I agree, although a higher number may well be reasonable since, even at 40 circuits, PEPCO will address upgrades or replacements of less than 6% of PEPCO's priority circuits per year at a time when there is an obvious need for reliability improvements on PEPCO's system.

The load growth program is a regular part of annual distribution system planning to address the loads of new customers or the increased loads of existing customers. It's not clear that PEPCO's existing reliability problems have much to do with there being too

[46] Consultants' Report, p. 39.

[47] Consultants' Report, p. 54.

much load on certain distribution or sub-transmission facilities, so there's no evidence that this program will help remedy PEPCO's existing reliability performance.

The distribution automation program looks at automating the tie switching on distribution feeders to enable potential sustained interruptions to be converted into momentary interruptions, thereby reducing both the frequency and duration of total annual customer sustained interruptions. These systems tend to have more of an impact on reliability during normal conditions or during minor storms. During major storms, there is sometimes so much system damage that the value of automated switching ties between feeders is reduced.

Although distribution automation, when fully integrated into all or most distribution feeders, can be expected to reduce sustained interruptions on the distribution system, distribution automation can also be expected to increase distribution system costs. It is not clear at this point to what extent costs will be increased , or whether such costs will reasonable in light of the actual reliability benefits that may be received.

The URD (underground residential distribution) cable replacement program deals with mostly old cable that is approaching the end of its service life. This program won't have a major reliability impact on a system-wide basis as there is apparently not a large amount of the most problematic vintage of such cable on PEPCO's system.[48] But, although these facilities are old and will need to be replaced for reliability reasons at

[48] Consultants' Report, p. 55.

some point, this reflects routine replacement of facilities that have reached the end of their useful service lives.

The selective undergrounding/substation improvement program is the most expensive single element of the REP. In addition to putting selected portions of distribution feeders underground, this program also addresses the hardening of supply circuits to distribution substations. Placing portions of existing or new distribution feeders underground is relatively expensive to install compared to overhead facilities, but underground facilities tend to experience fewer interruptions and do not require regular vegetation management. While the selective undergrounding element of the REP can improve reliability, care must be exercised in deciding in which instances facilities should be placed underground because of the higher up-front costs. Under these conditions, selective undergrounding can be a valuable reliability improvement program.

Hardening of the circuits feeding distribution substations seems to be a worthwhile system improvement depending, again, on the costs involved. A distribution substation can supply a dozen or more distribution feeders, so eliminating loss of supply to such a substation can have a substantial reliability impact.

Q. Please summarize your direct testimony and conclusions.

A. My testimony concludes that:

i) PEPCO's electric service reliability to its Maryland service area has been getting worse over the past seven years, and was especially poor during major storms in 2010;

ii) serious shortcomings in PEPCO's vegetation management program were the principal causes of this poor storm performance and represents a potential violation of COMAR requirements;

iii) equipment failures and lightning were contributing causes to PEPCO's reliability performance;

iv) PEPCO's failure to periodically inspect its overhead distribution facilities violates COMAR requirements;

v) PEPCO's difficulties in getting accurate ETRs from the automated OMS during the initial stages of major storms has contributed significantly to customer dissatisfaction.

Based on the foregoing conclusions, I recommend that the Commission require that:

a) PEPCO perform inspections of its distribution facilities at least once every five years;

b) PEPCO institute the practice of inspecting storm-hit areas after service restoration is complete to find and repair storm damage that may have gone undetected during the storm;

c) PEPCO to implement its current vegetation management plan, since it appears to be sufficient to remedy its historical shortcomings, if it is fully implemented and maintained for eight years and thereafter;

d) PEPCO expand the priority feeder portion of PEPCO's Reliability Enhancement Plan ("REP") to at least the 40 feeder level as recommended by the Commission's Consultants;

e) while both the distribution automation and the selective undergrounding portions of the REP can reduce customer interruptions, evaluate the potential cost concerns prior to any decision to implement these proposals;

f) PEPCO improve its OMS and/or its ability to operate the OMS in high volume situations to automatically calculate ETRs.

g) PEPCO use consistent categories of causes in all major storm reports, since its major storm reports frequently change some of the categories of causes into which customer interruptions and customer interruption hours are broken down into from one report to the next.

h) PEPCO report annually to the Commission on PEPCO's progress on implementing these recommendations.

Q. Does this conclude your direct testimony?

A. Yes.

Prior Experience Of Peter J. Lanzalotta

Mr. Lanzalotta has more than thirty-five years experience in electric utility system planning, power pool operations, distribution operations, electric service reliability, load and price forecasting, and market analysis and development. Mr. Lanzalotta has appeared as an expert witness on utility reliability, planning, operation, and rate matters in more than 90 proceedings in 22 states, the District of Columbia, the Provinces of Alberta and Ontario, and before the Federal Energy Regulatory Commission. He has developed evaluations of electric utility system cost, value, reliability, and condition. He has participated in negotiations or other interactions between utilities and customers or regulators in more than ten states regarding transmission access, the need for facilities, electric rates, electric service reliability, the value of electric system components, and system operator structure under wholesale competition.

Prior to his forming Lanzalotta & Associates LLC in 2001, he was a Partner at Whitfield Russell Associates for fifteen years and a Senior Associate for approximately four years before that. He holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration with a concentration in Finance from Loyola College of Baltimore.

Prior to joining Whitfield Russell Associates in 1982, Mr. Lanzalotta was employed by the Connecticut Municipal Electric Energy Cooperative ("CMEEC") as a System Engineer. He was responsible for providing operational, financial, and rate expertise to Coop's budgeting, ratemaking and system planning processes. He participated on behalf of CMEEC in the Hydro-Quebec/New England Power Pool Interconnection project and initiated the development of a database to support CMEEC's pool billing and financial data needs.

Prior to his CMEEC employment, he served as Chief Engineer at the South Norwalk (Connecticut) Electric Works, with responsibility for planning, data processing, engineering, rates and tariffs, generation and bulk power sales, and distribution operations. While at South Norwalk, he conceived and implemented, through Northeast Utilities and NEPOOL, a peak-shaving plan for South Norwalk and a neighboring municipal electric utility, which resulted in substantial power supply savings. He programmed and implemented a computer system to perform customer billing and maintain accounts receivable

Proceedings In Which
Peter J. Lanzalotta
Has Testified

accounting. He also helped manage a generating station overhaul and the undergrounding of the distribution system in South Norwalk's downtown.

From 1977 to 1979, Mr. Lanzalotta worked as a public utility consultant for Van Scoyoc & Wiskup and separately for Whitman Requart & Associates in a variety of positions. During this time, he developed cost of service, rate base evaluation, and rate design impact data to support direct testimony and exhibits in a variety of utility proceedings, including utility price squeeze cases, gas pipeline rates, and wholesale electric rate cases.

Prior to that, He worked for approximately 2 years as a Service Tariffs Analyst for the Finance Division of the Baltimore Gas & Electric Company where he developed cost and revenue studies, evaluated alternative rate structures, and studied the rate structures of other utilities for a variety of applications. He was also employed by BG&E in Electric System Operations for approximately 3 years, where his duties included operations analysis, outage reporting, and participation in the development of BG&E's first computerized customer information and service order system.

Mr. Lanzalotta is a member of the Institute of Electrical & Electronic Engineers, the Association of Energy Engineers, the National Fire Protection Association, and the American Solar Energy Society. He is also registered Professional Engineer in the states of Maryland and Connecticut.

**Proceedings In Which
Peter J. Lanzalotta
Has Testified**

1. **In re: Public Service Company of New Mexico**, Docket Nos. ER78-337 and ER78-338 before the Federal Energy Regulatory Commission, concerning the need for access to calculation methodology underlying filing.

2. **In re: Baltimore Gas and Electric Company**, Case No. 7238-V before the Maryland Public Service Commission, concerning outage replacement power costs.

3. **In re: Houston Lighting & Power Company**, Texas Public Utilities Commission Docket No. 4712, concerning modeling methods to determine rates to be paid to cogenerators and small power producers.

4. **In re: Nevada Power Company**, Nevada Public Service Commission, Docket No. 83-707 concerning rate case fuel inventories, rate base items, and O&M expense.

5. **In re: Virginia Electric & Power Company**, Virginia State Corporation Commission, Case No. PUE820091, concerning the operating and reliability-based need for additional transmission facilities.

6. **In re: Public Service Electric & Gas Company**, New Jersey Board of Public Utilities, Docket No. 831-25, concerning outage replacement power costs.

7. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. P-830453, concerning outage replacement power costs.

8. **In re: Cincinnati Gas & Electric Company**, Public Utilities Commission of Ohio, Case No. 83-33-EL-EFC, concerning the results of an operations/fuel-use audit conducted by Mr. Lanzalotta.

9. **In re: Kansas City Power and Light Company**, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

10. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. R-850152, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

11. **In re: ABC Method Proposed for Application to Public Service Company of Colorado**, before the Public Utilities Commission of the State of Colorado, on behalf of the Federal Executive Agencies ("FEA"), concerning a production cost allocation methodology proposed for use in Colorado.

12. **In re: Duquesne Light Company**, Docket No. R-870651, before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning the system reserve margin needed for reliable service.

13. **In re: Pennsylvania Power Company**, Docket No. I-7970318 before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning outage replacement power costs.

14. **In re: Commonwealth Edison Company**, Docket No. 87-0427 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from new base-load generating facilities, needed for reliable system operation.

15. **In re: Central Illinois Public Service Company**, Docket No. 88-0031 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the degree to which existing generating capacity is needed for reliable and/or economic system operation.

16. **In re: Illinois Power Company**, Docket No. 87-0695 before the State of Illinois Commerce Commission, on behalf of Citizens Utility Board of Illinois, Governors Office of Consumer Services, Office of Public Counsel and Small Business Utility Advocate, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

17. **In re: Florida Power Corporation**, Docket No. 860001-EI-G (Phase II), before the Florida Public Service Commission, on behalf of the Federal Executive Agencies of the United States, concerning an investigation into fuel supply relationships of Florida Power Corporation.

18. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Docket No. 877, on behalf of the Public Service Commission Staff, concerning the need for and availability of new generating facilities.

19. **In re: South Carolina Electric & Gas Company**, before the South Carolina Public Service Commission, Docket No. 88-681-E, On Behalf of the State of Carolina Department of Consumer Affairs, concerning the capacity needed for reliable system operation, the capacity available from existing generating units, relative jurisdictional rate of return, reconnection charges, and the provision of supplementary, backup, and maintenance services for QFs.

20. **In re: Commonwealth Edison Company**, Illinois Commerce Commission, Docket Nos. 87-0169, 87-0427, 88-0189, 88-0219, and 88-0253, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation.

21. **In re: Illinois Power Company**, Illinois Commerce Commission, Docket No. 89-0276, on behalf of the Citizen's Utility Board Of Illinois, concerning the determination of capacity available from existing generating units.

22. **In re: Jersey Central Power & Light Company**, New Jersey Board of Public Utilities, Docket No. EE88-121293, on behalf of the State of New Jersey Department of the Public Advocate, concerning evaluation of transmission planning.

23. **In re: Canal Electric Company**, before the Federal Energy Regulatory Commission, Docket No. ER90-245-000, on behalf of the Municipal Light Department of the Town of Belmont, Massachusetts, concerning the reasonableness of Seabrook Unit No. 1 Operating and Maintenance expense.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

24. **In re: New Hampshire Electric Cooperative Rate Plan Proposal**, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation.

25. **In re: Connecticut Light & Power Company**, before the Connecticut Department of Public Utility Control, Docket No. 90-04-14, on behalf of a group of Qualifying Facilities concerning O&M expenses payable by the QFs.

26. **In re: Duke Power Company**, before the South Carolina Public Service Commission, Docket No. 91-216-E, on behalf of the State of South Carolina Department of Consumer Advocate, concerning System Planning, Rate Design and Nuclear Decommissioning Fund issues.

27. **In re: Jersey Central Power & Light Company**, before the Federal Energy Regulatory Commission, Docket No. ER91-480-000, on behalf of the Boroughs of Butler, Madison, Lavallette, Pemberton and Seaside Heights, concerning the appropriateness of a separate rate class for a large wholesale customer.

28. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Formal Case No. 912, on behalf of the Staff of the Public Service Commission of the District of Columbia, concerning the Application of PEPCO for an increase in retail rates for the sale of electric energy.

29. **Commonwealth of Pennsylvania, House of Representatives**, General Assembly House Bill No. 2273. Oral testimony before the Committee on Conservation, concerning proposed Electromagnetic Field Exposure Avoidance Act.

30. **In re: Hearings on the 1990 Ontario Hydro Demand\Supply Plan**, before the Ontario Environmental Assessment Board, concerning Ontario Hydro's System Reliability Planning and Transmission Planning.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

31. **In re: Maui Electric Company**, Docket No. 7000, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning MECO's generation system, fuel and purchased power expense, depreciation, plant additions and retirements, contributions and advances.

32. **In re: Hawaiian Electric Company, Inc.**, Docket No. 7256, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning need for, design of, and routing of proposed transmission facilities.

33. **In re: Commonwealth Edison Company**, Docket No. 94-0065 before the Illinois Commerce Commission on behalf of the City of Chicago, concerning the capacity needed for system reliability.

34. **In re: Commonwealth Edison Company**, Docket No. 93-0216 before the Illinois Commerce Commission on behalf of the Citizens for Responsible Electric Power, concerning the need for proposed 138 kV transmission and substation facilities.

35. **In re: Commonwealth Edison Company**, Docket No. 92-0221 before the Illinois Commerce Commission on behalf of the Friends of Illinois Prairie Path, concerning the need for proposed 138 kV transmission and substation facilities.

36. **In re: Commonwealth Edison Company**, Docket No. 94-0179 before the Illinois Commerce Commission on behalf of the Friends of Sugar Ridge, concerning the need for proposed 138 kV transmission and substation facilities.

37. **In re: Public Service Company of Colorado**, Docket Nos. 95A-531EG and 95I-464E before the Colorado Public Utilities Commission on behalf of the Office of Consumer Counsel, concerning a proposed merger with Southwestern Public Service Company and a proposed performance-based rate-making plan.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

38. **In re: South Carolina Electric & Gas Company, Duke Power Company, and Carolina Power & Light Company**, Docket No. 95-1192-E, before the South Carolina Public Service Commission on behalf of the South Carolina Department of Consumer Advocate, concerning avoided cost rates payable to qualifying facilities.

39. **In re: Lawrence A. Baker v. Truckee Donner Public Utility District**, Case No. 55899, before the Superior Court of the State of California on behalf of Truckee Donner Public Utility District, concerning the reasonableness of electric rates.

40. **In re: Black Hills Power & Light Company**, Docket No. OA96-75-000, before the Federal Energy Regulatory Commission on behalf of the City of Gillette, Wyoming, concerning the Black Hills' proposed open access transmission tariff.

41. **In re: Metropolitan Edison Company and Pennsylvania Electric Company** for Approvals of the Restructuring Plan Under Section 2806, Docket Nos. R-00974008 and R-00974009 before the Pennsylvania PUC on behalf of Operating NUG Group, concerning miscellaneous restructuring issues.

42. **In re: New Jersey State Restructuring Proceeding** for consideration of proposals for retail competition under BPU Docket Nos. EX94120585U; E097070457; E097070460; E097070463; E097070466 before the New Jersey BPU on behalf of the New Jersey Division of Ratepayer Advocate, concerning load balancing, third party settlements, and market power.

43. **In re: Arbitration Proceeding In City of Chicago v. Commonwealth Edison** for consideration of claims that franchise agreement has been breached, Proceeding No. 51Y-114-350-96 before an arbitration panel board on behalf of the City of Chicago concerning electric system reliability.

44. **In re: Transalta Utilities Corporation**, Application No. RE 95081 on behalf of the ACD companies, before the Alberta Energy And Utilities Board in reference to the use and value of interruptible capacity.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

45. **In re: Consolidated Edison Company,** Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for a breach of contract to provide firm transmission service on a non-discriminatory basis.

46. **In re: ESBI Alberta Ltd.,** Application No. 990005 on behalf of the FIRM Customers, before the Alberta Energy And Utilities Board concerning the reasonableness of the cost of service plus management fee proposed for 1999 and 2000 by the transmission administrator.

47. **In re: South Carolina Electric & Gas Company,** Docket No. 2000-0170-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new and repowered generating units at the Urquhart generating station.

48. **In re: BGE,** Case No. 8837 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

49. **In re: PEPCO,** Case No. 8844 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

50. **In re: GenPower Anderson LLC,** Docket No. 2001-78-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the GenPower Anderson LLC generating station.

51. **In re: Pike County Light & Power Company,** Docket No. P-00011872, on behalf of Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Pike County request for a retail rate cap exception.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

52. **In re: Potomac Electric Power Company and Conectiv,** Case No. 8890, on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning the proposed merger of Potomac Electric Power Company and Conectiv.

53. **In re: South Carolina Electric & Gas Company,** Docket No. 2001-420-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the Jasper County generating station.

54. **In re: Connecticut Light & Power Company,** Docket No. 217 on behalf of the Towns of Bethel, Redding, Weston, and Wilton, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between Plumtree Substation, Bethel and Norwalk Substation, Norwalk.

55. **In re: The City of Vernon, California,** Docket No. EL02-103 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting calendar year 2001 transactions.

56. **In re: San Diego Gas & Electric Company et. al.,** Docket No. EL00-95-045 on behalf of the City of Vernon, California before the Federal Energy Regulatory Commission concerning refunds and other monies payable in the California wholesale energy markets.

57. **In re: The City of Vernon, California,** Docket No. EL03-31 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2002 transactions.

58. **In re: Jersey Central Power & Light Company,** Docket Nos. ER02080506, ER02080507, ER02030173, and EO02070417 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in

Proceedings In Which
Peter J. Lanzalotta
Has Testified

base tariff rates.

59. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability rules, standards and indices.

60. **In re: Central Maine Power Company,** Docket No. 2002-665, on behalf of the Maine Public Advocate and the Town of York before the Maine Public Utilities Commission concerning a Request for Commission Investigation into the New CMP Transmission Line Proposal for Eliot, Kittery, and York.

61. **In re: Metropolitan Edison Company,** Docket No. C-20028394, on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission concerning the reliability service complaint of Robert Lawrence.

62. **In re: The California Independent System Operator Corporation,** Docket No. ER00-2019 *et al.* on behalf of the City of Vernon, California, before the Federal Energy Regulatory Commission concerning wholesale transmission tariffs, rates and rate structures proposed by the California ISO.

63. **In re: The Narragansett Electric Company,** Docket No. 3564 on behalf of the Rhode Island Department of Attorney General, before the Rhode Island Public Utilities Commission concerning the proposed relocation of the E-183 transmission line.

64. **In re: The City of Vernon, California,** Docket No. EL04-34 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2003 transactions.

65. **In re: Atlantic City Electric Company,** Docket No. ER03020110 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

66. **In re: Connecticut Light & Power Company and the United Illuminating Company,** Docket No. 272 on behalf of the Towns of Bethany, Cheshire, Durham, Easton, Fairfield, Hamden, Middlefield, Milford, North Haven, Norwalk, Orange, Wallingford, Weston, Westport, Wilton, and Woodbridge, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between the Scoville Rock Switching Station in Middletown and the Norwalk Substation in Norwalk, Connecticut.

67. **In re: Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company,** Docket No. I-00040102, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning electric service reliability performance.

68. **In re: Entergy Louisiana, Inc.,** Docket No. U-20925 RRF-2004 on behalf of Bayou Steel before the Louisiana Public Service Commission concerning a proposed increase in base rates.

69. **In re: Jersey Central Power & Light Company,** Docket No. ER02080506, Phase II, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

70. **In re: Maine Public Service Company,** Docket No. 2004-538, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 138 kV transmission line from Limestone, Maine to the Canadian border near Hamlin, Maine.

71. **In re: Pike County Light and Power Company,** Docket No. M-00991220F0002, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Company's Petition to amend benchmarks for distribution reliability.

72. **In re: Atlantic City Electric Company,** Docket No. EE04111374, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey

Proceedings In Which
Peter J. Lanzalotta
Has Testified

Board of Public Utilities concerning the need for transmission system reinforcement, and related issues.

73. **In re: Bangor Hydro-Electric Company,** Docket No. 2004-771, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 345 kV transmission line from Orrington, Maine to the Canadian border near Baileyville, Maine.

74. **In re: Eastern Maine Electric Cooperatve,** Docket No. 2005-17, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a petition to approve a purchase of transmission capacity on a 345 kV transmission line from Maine to the Canadian province of New Brunswick.

75. **In re: Virginia Electric and Power Company,** Case No. PUE-2005-00018, on behalf of the Town of Leesburg VA and Loudoun County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for transmission and substation facilities in Loudoun County.

76. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability reporting, standards, and indices.

77. **In re: Proposed Merger Involving Constellation Energy Group Inc. and the FPL Group, Inc.**, Case No. 9054, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the proposed merger involving Baltimore Gas & Electric Company and Florida Light & Power Company.

78. **In re: Proposed Sale and Transfer of Electric Franchise of the Town of St. Michaels to Choptank Electric Cooperative, Inc.,** Case No. 9071, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the sale by St. Michaels of their electric franchise and service area to Choptank.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

79. **In re: Petition of Rockland Electric Company for the Approval of Changes in Electric Rates, and Other Relief,** BPU Docket No. ER06060483, on behalf of the Department of the Public Advocate, Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning electric service reliability and reliability-related spending.

80. **In re: The Complaint of the County of Pike v. Pike County Light & Power Company, Inc.,** Docket No. C-20065942, et al., on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, concerning electric service reliability and interconnecting with the PJM ISO.

81. **In re: Application of American Transmission Company to Construct a New Transmission Line,** Docket No. 137-CE-139, on behalf of The Sierra Club of Wisconsin, before the Public Service Commission of Wisconsin, concerning the request to build a new 138 kV transmission line.

82. **In re: The Matter of the Self-Complaint of Columbus Southern Power Company and Ohio Power Company Regarding the Implementation of Programs to Enhance Distribution Service Reliability,** Case No. 06-222-EL-SLF, on behalf of The Office of The Ohio Consumers' Counsel, before the Public Utilities Commission of Ohio, concerning distribution system reliability and related topics.

83. **In re: Central Maine Power Company,** Docket No. 2006-487, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning CMP's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line between Saco and Old Orchard Beach.

84. **In re: Bangor Hydro Electric Company,** Docket No. 2006-686, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning BHE's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line and substation in Hancock County.

85. **In re: Commission Staff's Petition For Designation of Competitive Renewable Energy Zones,** Docket No. 33672, on behalf of the Texas Office

Proceedings In Which
Peter J. Lanzalotta
Has Testified

of Public Utility Counsel, concerning the Staff's Petition and the determination of what areas should be designated as CREZs by the Commission.

86. **In re: Virginia Electric and Power Company,** Case No. PUE-2006-00091, on behalf of the Towering Concerns and Stafford County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Stafford County.

87. **In re: Trans-Allegheny Interstate Line Company,** Docket Nos. A-110172 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Pennsylvania.

88. **In re: Commonwealth Edison Company,** Docket No. 07-0566, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning electric transmission and distribution projects promoted as smart grid projects, and the rider proposed to pay for them.

89. **In re: Commonwealth Edison Company,** Docket No. 07-0491, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning the applicability of electric service interruption provisions.

90. **In re: Hydro One Networks ,** Case No. EB-2007-0050, on behalf of Pollution Probe, before the Ontario Energy Board, concerning a request for leave to construct electric transmission facilities in the Province of Ontario.

91. **In re: PEPCO Holdings, Inc.,** Docket No. ER-08-686-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

92. **In re: PPL Electric Utilities Corporation and Public Service Electric and Gas Company,** Docket No. ER-08-23-000, on behalf of the Joint Consumer Advocates, including the state consumer advocacy offices for the States of

Proceedings In Which
Peter J. Lanzalotta
Has Testified

Maryland, West Virginia, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

93. **In re: PPL Electric Utilities Corporation,** Docket Nos. A-2008-2022941 and P-2008-2038262, on behalf of Springfield Township, Bucks County, PA, before the Pennsylvania Public Utility Commission, concerning the need for and alternatives to proposed electric transmission lines and a proposed electric substation.

94. **In re: PEPCO Holdings, Inc.,** Docket No. ER08-1423-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

95. **In re: Public Service Electric and Gas Company, Inc.,** Docket No. ER09-249-000, on behalf of the New Jersey Division of Rate Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

96. **In re: New York Regional Interconnect Inc.,** Case No. 06-T-0650, on behalf of the Citizens Against Regional Interconnect, before the New York Public Service Commission, concerning the economics of and alternatives to proposed transmission facilities.

97. **In re: Central Maine Power Company and Public Service of New Hampshire,** Docket No. 2008-255, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning CMP's and PSNH's Petition for Finding of Public Convenience & Necessity to build the Maine Power Reliability Project, a series of new and rebuilt electric transmission facilities to operate at 345 kV and 115 kV in Maine and New Hampshire.

98. **In re: PPL Electric Utilities Corporation, Docket No. A-2009-2082652 et al,** on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning the Company's application for approval to site and construct electric transmission facilities in Pennsylvania.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

99. **In re: Bangor Hydro-Electric,** Docket No. 2009-26, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning BHE's Petition for Certificate of Public Convenience & Necessity to build a 115 kV transmission line in Washington and Hancock Counties.

100. **In re: United States, et al. v. Cinergy Corp., et al.** Civil Action No. IP99-1693 C-M/S, on behalf of Plaintiff United States and Plaintiff-Intervenors State of New York, State of New Jersey, State of Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, before the United States District Court for the Southern District of Indiana, concerning the system reliability impacts of the potential retirement of Gallagher Power Station Unit 1 and Unit 3.

101. **In re: Application of Potomac Electric Power Company, et al.** Case No. 9179, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the application for a determination of need under a certificate of public convenience and necessity for the Maryland portion of the MAPP transmission line, and related facilities.

102. **In re: Potomac Electric Power Company v. Perini/Tompkins Joint Venture,** Case No. 9210, on behalf of Perini Tompkins before the Maryland Public Service Commission concerning a review of PEPCO's estimates of electric consumption by Perini Tompkins Joint Venture's temporary electric service at National Harbor during a 29 month period for which no metered consumption data is available.

103. **In re: Duke Energy Ohio, Inc.,** Case No. 10-503-EL-FOR, on behalf of the Natural Resources Defense Council and Sierra Club before the Public Utilities Commission Of Ohio concerning a review of the reliability impacts that would result from closure of selected generating units as part of a review of Duke's 2010 Electric Long-Term Forecast Report and Resources Plan.

104. **In re: Detroit Edison Company,** Case Nos. U-16472 and 16489, on behalf of the Michigan Environmental Council and the Natural Resources Defense Council, concerning a review looking for studies of the reliability impacts that would result from closure of selected generating units as part of a electric rate increase case.

Ehibit__(PJL-3)

	A	B	C	D	E	F	G	H	I	J	K	L
1	Storm	Feb 5-12, 2010			Jul 25-31, 2010			Aug 5-7, 2010			Aug 12-15, 2010	
2		Customers	Interruption Hours		Customers	Interruption Hours		Customers	Interruption Hours		Customers	Interruption Hours
3	Tree	93,071	1,822,470		138,311	4,045,366		24,807	212,519		51,178	615,021
4	Equipment	3,585	52,412		5,903	245,802		1,527	9,198		9,850	128,494
5	Lightning	0	0		105,816	1,914,734		15,587	85,918		89,742	543,322
6	Ice	13,742	237,600		0	0		0	0		0	0
7	Wind	123,207	1,121,290		153,802	3,176,281		45,781	283,020		6,530	70,202
8	Other Weather	1,766	14,285		0	0		0	0		1,390	13,086
9	Other Causes	29,063	343,099		33,609	896,584		31,216	95,086		18,783	183,238
10	Total	264,434	3,591,156		437,441	10,278,767		118,918	685,741		177,473	1,553,363
11												
12		Customers	Interruption Hours		Customers	Interruption Hours		Customers	Interruption Hours		Customers	Interruption Hours
13	Tree	35%	51%		32%	39%		21%	31%		29%	40%
14	Equipment	1%	1%		1%	2%		1%	1%		6%	8%
15	Lightning	0%	0%		24%	19%		13%	13%		51%	35%
16	Ice	5%	7%		0%	0%		0%	0%		0%	0%
17	Wind	47%	31%		35%	31%		38%	41%		4%	5%
18	Other Weather	1%	0%		0%	0%		0%	0%		1%	1%
19	Other Causes	11%	10%		8%	9%		26%	14%		11%	12%
20	Total	100%	100%		100%	100%		100%	100%		100%	100%
21												
22	Total Tree & Wind	82%	82%	#	67%	70%	#	59%	72%	#	33%	44%
23												
24	Storm	Total 3 Summer Storms			Total 4 Storms							
25		Customers	Interruption Hours		Customers	Interruption Hours						
26	Tree	214,296	4,872,906		307,367	6,695,376						
27	Equipment	17,280	383,494		20,865	435,906						
28	Lightning	211,145	2,543,974		211,145	2,543,974						
29	Ice	0	0		13,742	237,600						
30	Wind	206,113	3,529,503		329,320	4,650,793						
31	Other Weather	1,390	13,086		3,156	27,371						
32	Other Causes	83,608	1,174,908		112,671	1,518,007						
33	Total	733,832	12,517,871		998,266	16,109,027						
34												
35		Customers	Interruption Hours		Customers	Interruption Hours						
36	Tree	29%	39%		31%	42%						
37	Equipment	2%	3%		2%	3%						
38	Lightning	29%	20%		21%	16%						
39	Ice	0%	0%		1%	1%						
40	Wind	28%	28%		33%	29%						
41	Other Weather	0%	0%		0%	0%						
42	Other Causes	11%	9%		11%	9%						
43	Total	100%	100%		100%	100%						
44												
45	Total Tree & Wind	57%	67%	#	64%	70%						

	A	B	C	D	E	F	G
1							
2		Outage Causes For 2011 Maryland Priority Feeders In PEPCO's Maryland Service Area					
3	Rank	Tree	Equipment	Weather	Animal	Unknown	Other
4	1	57%	22%			21%	
5	2	64%	2%	8%	13%	13%	
6	3	70%	3%	14%		13%	
7	4	13%	37%				50%
8	5	63%	2%		3%	32%	
9	6	72%	9%	10%		9%	
10	7		99%				1%
11	8	53%	32%			15%	
12	9	80%	3%			9%	8%
13	10	64%	21%	13%			2%
14	11	83%	15%	1%			1%
15	12	37%	4%	9%		28%	22%
16	13	55%	32%				13%
17	14	13%	32%	33%	3%	14%	5%
18	Average	52%	22%	6%	1%	11%	7%
19							
20	As portrayed in PEPCO's 2010 Annual Reliability Indices Reporting dated April 29, 2011, pages 10-14.						
21							

Exhibit___(PJL-5)

Data Regarding Budgeted and Actual Tree-Trimming O&M Maryland for Pepco & PHI Cash Dividends to Common Stockholders

	2004	2005	2006	2007	2008	2009	2010
Actual Tree-Trimming O&M Maryland ($)	5,430,930	4,524,564	3,901,462	3,960,829	5,131,719	5,024,721	11,025,398
Budget Tree-Trimming O&M Maryland	5,853,631	3,326,751	4,056,039	3,380,947	4,303,120	4,324,033	7,387,562
Cash Dividends/Share Common Stock ($)	1.00	1.00	1.04	1.04	1.04	1.08	1.08
Wtd Ave Shares Outstanding (Millions)	177	189	191	194	204	221	224
Cash Dividends ($000)	177,000,000	189,000,000	198,640,000	201,760,000	212,160,000	238,680,000	241,920,000
Incr Cash Dividends Relative To $1 ($000)			7,640,000	7,760,000	8,160,000	17,680,000	17,920,000

Source of Cash Dividends and Shares of Stock 2010 and 2008 Pepco Holdings 10-K*

Source of Tree Trimming Expenditures MD 9240 MC DR 4-25

*For Pepco Holdings, Inc. 2010 cash dividends and shares of stock see 10-K, Annual Report pursuant to section 13 and 15(d), filed on 2/26/10 at http://phx.corporate-ir.net/phoenix.zhtml?c=62854&p=irol-sec, Item 6, p. 38.

For Pepco Holdings, Inc. 2008 cash dividends and shares of stock see 10-K, Annual Report pursuant to section 13 and 15(d), filed on 2/29/08 at http://phx.corporate-ir.net/phoenix.zhtml?c=62854&p=irol-sec, Item 6, pp. 36-37.

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9240
RESPONSE TO FIRST QUARTILE SILVERPOINT QUESTION NO. 72

QUESTION NO. 72

Q. PLEASE SUPPLY SAIFI AND SAIDI ANNUAL VALUES FROM 2004 THROUGH 2010 TO DATE AS REQUESTED: (A) TOTAL PEPCO SAIDI AND SAIFI WITH AND WITHOUT MAXIMUM EVENT DATE (MED) BY YEAR; (B) PLEASE BREAK DOWN THE RESULTS IN (A) BY SEPARATE TRANSMISSION AND DISTRIBUTION METRICS; (C) BREAK DOWN THE RESULTS IN (B) BY DC, MONTGOMERY COUNTY, AND PRINCE GEORGE COUNTY; (D) PLEASE BREAK DOWN THE RESULTS IN (C) EXCLUDING STORMS IN WHICH WIND GUSTS EXCEEDED: (I) 50 MPH, (II) 35 MPH, AND (III) 25 MPH.

RESPONSE:

A. Refer to Attachment 1 which provides for the requested SAIFI and SAIDI data that is available.

The following data is included:

A) Total Pepco SAIDI and SAIFI with and without maximum (major) event date (MED) by year as defined by IEEE 1366-2003.
B) Results in (a) by separate transmission, substation and distribution metrics are provided for 2005 through November 2010.
C) Results in (b) by DC, Montgomery County, and Prince George County are provided for 2008 through November 2010.
D) Results in (c) are not available based on excluding storms in which wind gusts exceeded: (i) 50 mph, (ii) 35 mph, and (iii) 25 mph. Pepco has not historically archived this information.

MED Inclusive (System - Distribution, Substation, Transmission)														
Region or District	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	0.78	86	1.44	398	1.08	317	1.07	230	1.24	273	1.06	141	1.58	494
MC	1.45	117	2.05	520	2.33	492	1.73	253	2.59	708	2.07	203	4.65	2,947
PG	1.87	144	1.95	304	3.00	742	2.92	503	3.15	705	2.06	207	3.00	851
Pepco	1.37	115	1.83	419	2.13	509	1.86	317	2.33	568	1.74	184	3.18	1,553

MED Exclusive (System - Distribution, Substation, Transmission)														
Region or District	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	0.73	78	0.92	178	0.85	210	1.04	215	1.05	209	1.06	141	1.15	156
MC	1.30	98	1.47	213	1.60	249	1.62	218	1.85	249	2.07	203	2.46	311
PG	1.64	115	1.62	199	1.88	284	2.52	338	2.27	313	2.06	207	1.92	192
Pepco	1.22	97	1.34	198	1.44	247	1.69	252	1.73	256	1.74	184	1.88	227

MED Inclusive (Distribution)														
Region or District	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	-	-	-	-	-	-	-	-	0.99	243	0.88	133	1.18	440
MC	-	-	-	-	-	-	-	-	2.16	601	1.59	178	3.01	2,155
PG	-	-	-	-	-	-	-	-	2.55	596	1.57	186	2.07	712
Pepco	-	-	1.69	407	2.04	503	1.77	301	1.90	484	1.35	166	2.15	1,187

MED Exclusive (Distribution)														
Region or District	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	-	-	-	-	-	-	-	-	0.85	189	0.88	133	0.84	138
MC	-	-	-	-	-	-	-	-	1.55	237	1.59	178	1.75	265
PG	-	-	-	-	-	-	-	-	1.99	299	1.57	186	1.39	163
Pepco	-	-	1.28	194	1.36	241	1.60	236	1.45	239	1.35	166	1.36	195

9240
First Quartile Silverpoint
Question No.72
Attachment 1

MED Inclusive (Substation)														
Region or	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
District	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	-	-	-	-	-	-	-	-	0.25	30	0.18	9	0.40	54
MC	-	-	-	-	-	-	-	-	0.43	107	0.48	24	1.63	790
PG	-	-	-	-	-	-	-	-	0.55	69	0.49	20	0.94	140
Pepco	-	-	0.05	4	0.08	5	0.09	16	0.40	71	0.38	18	1.03	366

MED Exclusive (Substation)														
Region or	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
District	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	-	-	-	-	-	-	-	-	0.20	20	0.18	9	0.31	18
MC	-	-	-	-	-	-	-	-	0.29	12	0.48	24	0.70	45
PG	-	-	-	-	-	-	-	-	0.28	14	0.49	20	0.53	29
Pepco	-	-	0.04	4	0.07	5	0.09	16	0.26	15	0.38	18	0.53	32

MED Inclusive (Transmission)														
Region or District	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	-	-	-	-	-	-	-	-	0.00	0	0.00	0	0.00	0
MC	-	-	-	-	-	-	-	-	0.01	1	0.00	0	0.01	2
PG	-	-	-	-	-	-	-	-	0.06	41	0.01	0	0.00	0
Pepco	-	-	0.09	8	0.01	1	0.00	0	0.02	12	0.00	0	0.00	1

MED Exclusive (Transmission)														
Region or District	2004		2005		2006		2007		2008		2009		2010 YTD (Nov.)	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
DC	-	-	-	-	-	-	-	-	0.00	0	0.00	0	0.00	0
MC	-	-	-	-	-	-	-	-	0.01	1	0.00	0	0.01	1
PG	-	-	-	-	-	-	-	-	0.00	0	0.01	0	0.00	0
Pepco	-	-	0.02	1	0.01	1	0.00	0	0.00	0	0.00	0	0.00	0

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9240
RESPONSE TO MC OCP DATA REQUEST NO. 6

QUESTION NO. 2

Q. PLEASE PROVIDE THE NUMBER OF PEPCO CUSTOMERS AT YEARS END FOR EACH YEAR FROM 2004-2010 SPECIFICALLY PROVIDE THE NUMBER OF BOTH RESIDENTIAL AND NON-RESIDENTIAL CUSTOMERS:

A. SYSTEM-WIDE
B. IN MARYLAND
C. IN MONTGOMERY COUNTY

RESPONSE:

A. See the attached.

SPONSOR:

MD 9240
MC DR 6-2
Attachment

POTOMAC ELECTRIC POWER COMPANY

Retail Customers at Year-End

2004 - 2010

	2010	2009	2008	2007	2006	2005	2004
System							
1. Residential	713,148	704,575	692,987	686,636	680,358	674,046	664,994
2. Commercial	73,782	73,630	73,446	73,331	73,436	72,989	71,802
3. Other	133	132	134	134	143	138	141
Retail Customers	787,063	778,337	766,567	760,101	753,937	747,173	736,937

	2010	2009	2008	2007	2006	2005	2004
Montgomery County							
1. Residential	280,945	278,686	275,947	274,652	272,927	270,595	267,919
2. Commercial	26,660	26,562	26,389	26,367	26,300	26,091	25,527
3. Other	61	61	61	60	63	64	65
Retail Customers	307,666	305,309	302,397	301,079	299,290	296,750	293,511

	2010	2009	2008	2007	2006	2005	2004
Maryland							
1. Residential	483,906	478,545	472,874	471,466	469,138	465,722	461,458
2. Commercial	47,348	47,231	46,767	46,701	46,699	46,300	45,411
3. Other	100	100	102	101	112	107	109
Retail Customers	531,354	525,876	519,743	518,268	515,949	512,129	506,978

Beverly A. Sikora
Senior Counsel

BGE

2 Center Plaza
110 W. Fayette Street
Baltimore, Maryland 21201
410.470.1410
443.213.3206 Fax
beverly.a.sikora@bge.com

April 29, 2011

Via Electronic Filing

Terry J. Romine, Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

RE: Annual Reliability Indices Reporting

Dear Ms. Romine:

Pursuant to COMAR 20.50.07.06, please find attached Baltimore Gas and Electric Company's annual reporting of reliability indices for the year ended December 31, 2010.

The Company will hand deliver an original and 17 copies of this filing by noon on the next business day in accordance with Commission guidelines for electronic filing. The Maillog number assigned to this filing will be indicated above for your reference.

Respectfully submitted,

Beverly A. Sikora

Beverly A. Sikora

BAS:meg

Attachment

Baltimore Gas and Electric Company
COMAR 20.50.07.06 Reporting of Reliability Indices – CY 2010

(1) System-Wide Indices. A utility shall report SAIDI, SAIFI, and CAIDI for its system consisting of all feeders originating in Maryland. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

SAIFI – 1.58
SAIDI – 5.46
CAIDI – 3.45

Note: SAIFI, SAIDI and CAIDI are calculated using COMAR 20.50.01.03 Definitions.

(b) All interruption data minus major event interruption data.

SAIFI – 1.48
SAIDI – 4.52
CAIDI – 3.05

Data in (b) above exclude customer interruptions from one Major Event experienced during July 2010, further detailed in Section 6.

All interruption data minus July 2010 major event interruption data and interruption data from the February 2010 snow storms.[1]

SAIFI – 1.37
SAIDI – 3.60
CAIDI – 2.63

All interruption data minus interruption data for all weather events.

SAIFI – 0.77
SAIDI – 1.56
CAIDI – 2.04

Note: The data sets showing SAIFI, SAIDI and CAIDI excluding July 2010 major event interruption data and interruption data from the February 2010 snow storms as well as excluding interruption data for all weather events are provided to demonstrate the impact of weather events on system-wide reliability.

[1] While the two snow storms in February 2010 were separate events and neither met the Major Storm definition in COMAR 20.50.01.03, the Commission directed BGE to file a Major Storm report in Case No. 9220 providing the information set forth in COMAR 20.50.07.07 for both storms.

(2) District Indices. A cooperatively-owned utility shall provide SAIDI, SAIFI, and CAIDI for each operating district and identify the operating district with the poorest reliability. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

(b) Major event interruption data excluded.

Requirements (a) & (b) are not applicable to BGE since BGE is an Investor Owned Utility.

(3) Feeder Indices. An investor-owned utility shall provide SAIDI, SAIFI, and CAIDI for 2% of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability. The indices shall be calculated and reported with 2 sets of input data.

(a) All interruption data

13.8 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
7583	RIVERSIDE	6.52	8.33	13.70	1.64
8445	BESTGATE	6.02	7.20	20.66	2.87
7497	CEDAR PARK	5.29	6.23	32.77	5.26
8144	EAST TOWSON	5.00	5.73	13.95	2.43
7407	CEDAR PARK	4.99	6.48	33.11	5.11
8010	COLDSPRING	4.91	6.45	16.10	2.50
7483	HUNT CLUB	4.88	5.96	37.59	6.31
8475	CROWNSVILLE	4.74	5.60	24.42	4.36
8411	BEVERLY BEACH	4.60	5.73	13.53	2.36
8004	COLDSPRING	4.53	5.26	7.68	1.46
8152	TEXAS	4.46	5.05	27.48	5.44
7105	MOUNT WASHINGTON	4.41	5.58	11.28	2.02
8474	CROWNSVILLE	4.40	4.66	34.59	7.42
7423	TRACEYS LANDING	4.34	5.73	30.21	5.27
7656	COLUMBIA	4.32	5.29	6.31	1.19
8158	TEXAS	4.23	4.17	4.55	1.09
8556	WAUGH CHAPEL	4.11	4.55	23.73	5.21
8072	GLENARM	4.05	4.00	19.26	4.82
7481	HUNT CLUB	3.97	4.36	28.42	6.52
8387	RIVA ROAD	3.93	4.81	13.40	2.78
7111	MOUNT WASHINGTON	3.90	5.06	12.44	2.46

13000 Series Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
13991	*MIDDLE RIVER*	*3.75*	*5.00*	*9.50*	*1.90*
13947	*WESTPORT BROOM FACTORY*	*3.33*	*3.33*	*32.67*	*9.80*
13330	*HIGHLANDTOWN*	*2.35*	*2.08*	*10.16*	*4.88*

4.4 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
4067	*PHILADELPHIA ROAD*	*6.79*	*9.05*	*22.27*	*2.46*
4816	*CALVERTON*	*4.28*	*5.10*	*52.89*	*10.37*
4068	*PHILADELPHIA ROAD*	*4.07*	*5.40*	*36.79*	*6.82*

(b) All interruption data minus major event interruption data:

BGE's "Worst Feeder Program" consists of the Company's plans to improve reliability performance for the top 2% of the 13.8 kV distribution feeders (21 out of 1048 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 133 total 13000 series distribution feeders) and 2% of the 4.4 kV distribution feeders (3 out of 107 total 4.4 kV distribution feeders) based on all interruption data minus major event interruption data. There was one major event experienced during July 2010.

13.8 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
7583	RIVERSIDE	6.34	8.09	13.10	1.62
8445	BESTGATE	5.77	6.87	14.90	2.17
7497	CEDAR PARK	5.29	6.22	32.59	5.24
8144	EAST TOWSON	5.00	5.73	13.95	2.43
8010	COLDSPRING	4.91	6.45	16.10	2.50
8004	COLDSPRING	4.53	5.26	7.68	1.46
7105	MOUNT WASHINGTON	4.41	5.58	11.28	2.02
8411	BEVERLY BEACH	4.32	5.37	12.32	2.30
7656	COLUMBIA	4.32	5.29	6.31	1.19
8475	CROWNSVILLE	4.28	4.99	11.33	2.27
8158	TEXAS	4.21	4.14	4.50	1.09
8474	CROWNSVILLE	4.12	4.28	24.00	5.61
8072	GLENARM	3.94	3.86	18.51	4.79
8387	RIVA ROAD	3.91	4.80	12.61	2.63
7111	MOUNT WASHINGTON	3.90	5.06	12.44	2.46
7972	HONEYGO	3.84	3.84	3.56	0.93
8425	BAY RIDGE	3.81	4.88	15.59	3.20
8074	GLENARM	3.78	4.07	21.79	5.35
8121	KAUFFMAN	3.76	3.81	12.28	3.22
8073	GLENARM	3.75	5.00	13.00	2.60
7483	HUNT CLUB	3.71	4.40	20.94	4.76

13000 Series Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
13991	MIDDLE RIVER	3.75	5.00	9.50	1.90
13947	WESTPORT BROOM FACTORY	3.33	3.33	32.67	9.80
13330	HIGHLANDTOWN	2.35	2.08	10.16	4.88

4.4 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
4067	PHILADELPHIA ROAD	6.79	9.05	22.27	2.46
4816	CALVERTON	4.28	5.10	52.89	10.37
4262	CENTER	3.54	4.72	44.84	9.50

(c) Feeders shall not be included as having the poorest reliability in two consecutive reports.

Feeders listed in the CY 2009 report as having poor reliability are not included in this report, which allows time for reliability data to reflect corrective actions performed in 2009 and 2010.

(4) The method used by a utility to identify the district and feeders with poorest reliability shall be approved by the Commission and be included in the report.

In order to determine which distribution feeders and areas have the poorest performance, BGE utilizes a Composite Reliability Index (CRI). In the event that two feeders have identical composite reliability indices, the feeders are then ranked based on the most recent year's feeder SAIFI. The formula for the index is:

$$CRI = 0.75 \times SAIFI_{2010} + 0.25 \times SAIFI_{2009}$$

(5) Feeders included in the report, which serve customers in Maryland and one or more bordering jurisdiction shall be identified. The report shall include the percentage of customers located in Maryland and the percentage of customers located in bordering jurisdictions.

Not applicable to BGE. BGE has no feeders outside Maryland.

(6) Major Event Interruption Data. The report shall include the time periods during which major event interruption data was excluded from the indices, along with a brief description of the interruption causes during each time period.

BGE experienced one Major Event in 2010.

On Sunday, July 25, 2010, beginning approximately 3:30 PM, portions of the BGE territory were impacted by lightning, wind and rain. Localized heavy rains, wind gusts and lightning experienced were due to a few strong thunderstorms that moved through Anne Arundel, Prince George's, Baltimore, Howard, Montgomery, Howard, Harford, Carroll and Calvert Counties as well as Baltimore City. A major storm was declared on the BGE system at 1:45 PM on July 25 with a peak of 78,534 sustained customer interruptions occurring at 6:42 PM. Cumulatively, BGE experienced 122,234 customer interruptions. A total of 1,313 BGE personnel and BGE contractors along with 185 external contractors were involved in the restoration effort. The storm was declared over and the Storm Center closed at 6:00 PM on Tuesday, July 27, 2010.

While not a Major Event on BGE's system, BGE prepared and filed a Major Storm Report for the dual blizzards of February 2010 at the request of the Commission. Between February 5 and February 12, 2010, the BGE service territory was impacted by two significant snow storms. Between them, these storms dumped nearly four feet of snow on Central Maryland. Nearly 97,000 customers lost service during the first storm that began on Friday, February 5 and intensified rapidly in the early morning hours of Saturday, February 6. At 4:00 PM on Friday, February 5, a minor storm was declared on the BGE electric distribution system in anticipation of the impending blizzard. The peak number of sustained customer interruptions was 45,158 and occurred on February 6, 2010 at 11:11AM. By the late evening on Monday, February 8, all but 800 customers had been restored. The second storm started Tuesday, February 9 and caused *approximately 45,000 additional service interruptions. Most were restored by Thursday, February 11, with a very small number of customer outages extending into Friday, February 12. The storm was declared over and the Storm Center closed at 3:00 PM on Friday, February 12, 2010.Between the two storms, BGE experienced a total of 142,001 customer interruptions.*

(7) Actions for Operating District and Feeders with Poorest Reliability.

(a) An investor-owned utility shall report remedial actions taken or planned to improve reliability for all feeders reported under C.(3) of this regulation.

BGE will review the design for each feeder reported under this section to identify potential improvements. BGE will also trim the trees on feeders as needed, conduct a thorough equipment inspection on each feeder and correct any deficiencies found during the inspections. These inspections will permit the identification of potential outage causes and will, as a result, reduce the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process and have since been repaired or replaced. In some cases, underground cable replacement will be performed if the underground conductor experiences an excessive number of failures.

Feeder 7583

Feeder 7583 supplies approximately 1,403 customers in the Dundalk area on the Baltimore City/County line. During 2010, 37% of the customer interruptions were caused by weather (32% due to wind/rain, 5% due to lightning), 37% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 15% were caused by overhead conductor failures, 5% were caused by miscellaneous events, 4% were caused by overhead equipment failures, and 2% were caused by wildlife. Tree trimming on this feeder was most recently completed in May 2007 and the feeder is due for routine cycle trimming in May 2011. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE renewed poles and modified the design of a pole to improve overhead conductor tension and sag in December 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2011. The design of this feeder has been studied, and Distribution Automation reclosers will be installed in 2011.

Feeder 8445

Feeder 8445 supplies approximately 1,236 customers in the Heritage Harbour area of Anne Arundel County. During 2010, 35% of the customer interruptions were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 32% were caused by trees, 29% were caused by underground equipment failures, 3% were caused by underground cable failures, and 1% were caused by weather (wind/rain and ice/snow). Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. A project to reduce the length and exposure of this feeder and add Distribution Automation reclosers will be completed in 2013 in conjunction with expected load increases.

Feeder 7497

Feeder 7497 supplies approximately 1,103 customers in the Annapolis area of Anne Arundel County. During 2010, 61% of the customer interruptions were caused by weather (36% due to ice/snow, 25% due to wind/rain), 36% were caused by trees, 2% were caused by underground equipment failures, and 1% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified). Tree trimming on this feeder was most recently completed in December 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8144

Feeder 8144 supplies approximately 96 customers in the Towson area of Baltimore County. During 2010, 53% of the customer interruptions were caused by underground equipment failures, 40% were caused by underground cable splice failures, and 7% were caused by trees. Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the cable splices and each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8010

Feeder 8010 supplies approximately 892 customers in the Roland Park area of Baltimore City. During 2010, 56% of the customer interruptions were caused by trees, 18% were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 17% were caused by weather (wind/rain), 6% were caused by wildlife, and 3% were caused by overhead equipment failures. Tree trimming on this feeder was most recently completed in January 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8004

Feeder 8004 supplies approximately 2,116 customers in the Roland Park area of Baltimore City. During 2010, 33% of the customer interruptions were caused by weather (wind/rain), 23% were caused by trees, 22% were caused by unknown reasons (consisted mainly of a feeder lockout where no system damage was identified), 20% were caused by a splice failure, and 2% were caused by wildlife. Tree trimming on this feeder was most recently completed in May 2009. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 7105

Feeder 7105 supplies approximately 1,484 customers in the Stevenson area of Baltimore County. During 2010, 32% of the customer interruptions were caused by trees, 27% were caused by *weather (wind/rain), 18% were caused by unknown reasons (consisted mainly of a feeder lockout where no system damage was identified), 14% were caused by underground cable failures, 7% were caused by public interference (vehicle-hits), and 2% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in February 2011. BGE completed one cable replacement job in October 2010 and one in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.*

Feeder 8411

Feeder 8411 supplies approximately 1,457 customers in the Mayo area of Anne Arundel County. During 2010, 61% of the customer interruptions were caused by weather (38% due to wind/rain, 20% due to lightning, and 3% due to ice/snow), 27% were caused by trees, 9% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 1% were caused by wildlife, 1% were caused by overhead conductor failures, and 1% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in June 2008. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. A project to reduce the length and exposure of this feeder and add Distribution Automation reclosers will be completed by the end of the second quarter of 2011.

Feeder 7656

Feeder 7656 supplies approximately 742 customers in the Columbia area of Howard County. During 2010, 88% of the customer interruptions were caused by underground cable failures, 9% were caused by a partial feeder lockout as a result of an overload, 2% were caused by underground equipment failures, and 1% were caused by a dig-in. BGE identified one cable replacement opportunity. The construction work is complete and an outage is pending for cut-in. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8475

Feeder 8475 supplies approximately 731 customers in the Crownsville area of Anne Arundel County. During 2010, 45% of the customer interruptions were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 30% were caused by trees, 21% were caused by weather (19% due to ice/snow and 2% due to wind/rain), 3% were caused by overhead equipment failures, and 1% were caused by underground cable failures. Tree trimming on this feeder was most recently completed in October 2007 and is due for routine cycle trimming in 2011. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2011. BGE identified one cable replacement opportunity that was completed in March 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8158

Feeder 8158 supplies approximately 872 customers in the Timonium area of Baltimore County. During 2010, 23% of the customer interruptions were caused by a defective splice, 20% were caused by equipment failures, 15% were caused by overhead conductor failures, 14% were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 15% were caused by trees, 10% were caused by a defective underground cable, 1% were caused by a dig-in, 1% were caused by weather (wind/rain), and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in October 2008. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. BGE identified three cable replacement opportunities. One was completed in February 2011. Construction work on the remaining two is complete and outages are pending for cut-in. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8474

Feeder 8474 supplies approximately 634 customers in the Sherwood Forest area of Anne Arundel County. During 2010, 63% of the customer interruptions were caused by trees, 23% were caused by weather (wind/rain), 10% were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 2% were caused by wildlife, 1% were caused by a dig-in, and 1% were caused by overhead equipment failures. Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8072

Feeder 8072 supplies approximately 1,530 customers in the Baldwin area of Baltimore County. During 2010, 58% of the customer interruptions were caused by weather (28% due to lightning, 19% due to wind/rain and 11% due to ice/snow), 36% were caused by trees, 2% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 2% were caused by overhead equipment failures, 1% were caused by foreign objects blown by wind, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in April 2010. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. BGE identified two cable replacement opportunities. One was completed in February 2011. The other is currently in design and is scheduled for completion by the end of the fourth quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. The design of this feeder has been studied, and Distribution Automation reclosers will be installed and a portion of the feeder will be reconductored in 2011.

Feeder 8387

Feeder 8387 supplies approximately 664 customers in the Riva area of Anne Arundel County. During 2010, 64% of the customer interruptions were caused by trees, 28% were caused by weather (wind/rain), 7% were caused by underground equipment failures, and 1% were caused *by underground cable failures. Tree trimming on this feeder was most recently completed in December 2009. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. BGE identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the fourth quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.*

Feeder 7111

Feeder 7111 supplies approximately 2,074 customers in the Mt. Washington area on the Baltimore City/County line. During 2010, 21% of the customer interruptions were caused by underground cable failures, 21% were caused by public interference (vehicle-hits), 20% were caused by overhead equipment failures, 16% were caused by weather (lightning), 15% were caused by overhead conductor failures, 5% were caused by trees, 1% were caused by wildlife, and 1% were caused by unknown reasons (consisted mainly of a blown fuse where no system damage was identified). Tree trimming on this feeder was most recently completed in January 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 7972

Feeder 7972 supplies approximately 81 customers in the White Marsh area of Baltimore County. During 2010, 51% of the customer interruptions were caused by underground cable failures and 49% were caused by underground equipment failures. BGE identified one cable replacement opportunity that was completed in March 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8425

Feeder 8425 supplies approximately 928 customers in the Highland Beach area of Anne Arundel County. During 2010, 34% of the customer interruptions were caused by unknown reasons (consisted mainly of a feeder lockout where no system damage was identified), 26% were caused by trees, 23% were caused by weather (ice/snow), 14% were caused by an overhead conductor failure, 2% were caused by overhead equipment failures, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8074

Feeder 8074 supplies approximately 1,178 customers in the Carney area of Baltimore County. During 2010, 69% of the customer interruptions were caused by trees, 17% were caused by weather (14% due to wind/rain and 3% due to lightning), 6% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 5% were caused by *public interference (vehicle-hit), 2% were caused by overhead conductor failures, and 1% were caused by overhead equipment failures. Tree trimming on this feeder was most recently completed in January 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed, a portion of the feeder will be reconductored, and an overhead portion will be relocated underground in 2011.*

Feeder 8121

Feeder 8121 supplies approximately 1,140 customers in the Freeland area of Baltimore County. During 2010, 37% of the customer interruptions were caused by weather (22% due to wind/rain and 15% due to lightning), 32% were caused by trees, 26% were caused by overhead equipment failures, 3% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 1% were caused by foreign objects blown by wind, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in August 2007 and the feeder is due for routine cycle trimming in August 2011. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2011. BGE identified three cable replacement opportunities based on performance in 2009. One was completed in January 2011. The remaining two are currently in construction and are scheduled for completion by the end of the second quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8073

Feeder 8073 supplies 2 customers in the Glen Arm area of Baltimore County. During 2010, 60% of the customer interruptions were caused by underground equipment failures and 40% were caused by underground cable failures. Tree trimming on this feeder was most recently completed in January 2011. BGE identified one cable replacement opportunity that is currently in construction and is scheduled for completion by the end of the third quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 7483

Feeder 7483 supplies approximately 1,148 customers in the Cape Saint Claire area of Anne Arundel County. During 2010, 72% of the customer interruptions were caused by trees, 18% were caused by unknown reasons (consisted mainly of blown fuses and a feeder lockout where no system damage was identified), 5% were caused by weather (3% due to ice/snow and 2% due to wind/rain), 3% were caused by overhead conductor failures, 1% were caused by underground cable failures, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in January 2011. BGE identified one cable replacement opportunity that is currently in scheduling and is planned for completion by the end of the fourth quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase *pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.*

Feeder 13991

Feeder 13991 supplies 2 customers in the Middle River area of Baltimore County. During 2010, 40% of the customer interruptions were caused by wildlife in the substation, 40% were caused by unknown reasons (a feeder lockout where no system damage was identified), and 20% were caused by an underground cable failure. Each of the pieces of equipment and the underground cable segment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 13947

Feeder 13947 supplies 6 customers in the Westport area of Baltimore City. During 2010, 70% of the customer interruptions were caused by equipment failures and 30% were caused by weather (ice/snow). Each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies have been corrected except one correction that will be completed in May 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. Station relays were reset in March 2011 to coordinate with a commercial customer on the feeder.

Feeder 13330

Feeder 13330 supplies approximately 25 customers in the Highlandtown area of Baltimore City. During 2010, 48% of the customer interruptions were caused by wildlife in a customer substation, 48% were caused by an underground cable failure in duct, and 4% were caused by public interference (vandalism). Each of the pieces of equipment and the underground cable segment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 4067

Feeder 4067 supplies approximately 743 customers in the Highlandtown area of Baltimore City. During 2010, 88% of the customer interruptions were caused by an underground cable splice failure, 11% were caused by an unknown reason (consisted of a blown fuse where no system damage was identified), and 1% were caused by overhead conductor failures. Tree trimming on this feeder was most recently completed in November 2010. In addition, each splice and each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. A project to transfer all customers on feeder 4067 to 13 kV feeders was completed in March 2011. Customers previously supplied by #6 copper 4 kV cable and sections of 4/0 and 350 copper paper-lead 4 kV feeder main cable are now supplied by new sections of overhead or underground 13 kV cable. This project will improve the reliability of the feeder as well as increase the emergency load capacity.

Feeder 4816

Feeder 4816 supplies approximately 90 customers in the Shipley Hill area of Baltimore City. During 2010, 39% of the customer interruptions were caused by underground equipment failures, 20% were caused by unknown reasons (consisted mainly of a blown fuse where no system damage was identified), 20% were caused by weather (ice/snow), 20% were caused by an underground cable failure, and 1% were caused by overhead conductor failures. Each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 4262

Feeder 4262 supplies approximately 451 customers in the Station North area of Baltimore City. During 2010, 40% of the customer interruptions were caused by underground equipment failures, 37% were caused by weather (lightning), and 23% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified). Tree trimming on this feeder was most recently completed in August 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in December 2010 and the identified deficiencies are scheduled to be corrected in May 2011.

(b) Each utility shall briefly describe the actions taken or planned to improve reliability. When the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

BGE plans include remedial actions for all feeders identified as worst performers.

(8) Evaluation of Remedial Actions. For the operating district and feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports.

(a) The annual report for the year following the identification of the operating district and feeders as having the poorest performance shall provide a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions.

BGE reviewed the design for each feeder reported under this section to identify potential improvements. BGE also trimmed the trees on each feeder as needed, conducted a thorough equipment and conductor inspection on each feeder and corrected any deficiencies found during the inspections. Those inspections permitted the identification of potential outage causes and, as a result, reduced the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process and have since been repaired or replaced. In some cases, underground cable replacement was performed if the underground conductor experienced an excessive number of failures.

Feeder 8783
Feeder 8783 supplies approximately 1,109 customers in the Woodwardville area of Anne Arundel County. During 2009, 91% of the customer interruptions were caused by trees, 7% were caused by overhead conductor failures, and 2% were caused by weather (wind/rain). Tree trimming on this feeder was most recently completed in July 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 8734
Feeder 8734 supplies approximately 529 customers in the Ashton area of Montgomery County. During 2009, 93% of the customer interruptions were caused by weather (47% were caused by wind/rain and 46% were caused by ice/snow), 5% were caused by trees, 1% were caused by overhead conductor failures, and 1% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in July 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. The design of this feeder was studied, and Distribution Automation reclosers were installed on a portion of the feeder in February 2010. Station relays were reset in April 2010 to coordinate with the Distribution Automation reclosers. In addition, a project completed in 2009 created a new feeder that reduced the length and exposure of this feeder.

Feeder 8472
Feeder 8472 supplies approximately 1,183 customers in the Severn Run area of Anne Arundel County. During 2009, 81% of the customer interruptions were caused by trees, 16% were caused by a vehicle-hit, 2% were caused by wildlife, and 1% were caused by weather (lightning). The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2010. The design of this feeder was studied and Distribution Automation reclosers were installed in April 2010.

Feeder 7903
Feeder 7903 supplies approximately 670 customers in the Dickinson area of Howard County. During 2009, 56% of the customer interruptions were caused by underground cable failures, 20% were caused by underground equipment failures, 20% were caused by trees, and 4% were caused by a dig-in. Tree trimming on this feeder was most recently completed in May 2007. An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in 2010 and trimming beyond BGE's routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in March 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found. The design of this feeder was studied and Distribution Automation reclosers were installed in May 2010.

Feeder 7236
Feeder 7236 supplies approximately 1,352 customers in Union Mills in Carroll County. During 2009, 36% of the customer interruptions were caused by trees, 22% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 21% were caused by weather (wind/rain), 9% were caused by public interference (vehicle-hits), 8% were caused by overhead equipment failures, and 4% were caused by underground cable failures. The feeder was trimmed during the routine maintenance schedule in December 2010 and trimming beyond

routine trimming standards was performed. BGE identified three cable replacement opportunities. One was completed in June 2010, one was completed in October 2010, and the third is currently in construction and is scheduled for completion by the end of the second quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found. The design of this feeder was studied and Distribution Automation reclosers were installed in May 2010.

Feeder 7351

Feeder 7351 supplies approximately 1,013 customers in Severna Park in Anne Arundel County. During 2009, 42% of the customer interruptions were due to unknown causes (consisted mainly of feeder lockouts where no system damage was identified), 35% were caused by overhead equipment failures, 18% were caused by trees, and 5% were caused by overhead conductor failures. The feeder was trimmed during the routine maintenance schedule in July 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in April 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in November 2009 and January 2010.

Feeder 7696

Feeder 7696 supplies approximately 1,077 customers in the Glenwood area of Howard County. During 2009, 81% of the customer interruptions were caused by trees, 10% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 7% were caused by public interference (vehicle-hits), 1% were caused by underground cable failures, and 1% were caused by weather (lightning). The feeder was trimmed during the routine maintenance schedule in October 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in December 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 7593

Feeder 7593 supplies approximately 1,921 customers in Fullerton in Baltimore County. During 2009, 37% of the customer interruptions were caused by underground equipment failures, 35% were caused by weather (lightning), 17% were from an unknown cause (a feeder lockout where no system damage was identified), and 11% were caused by underground cable failures. The feeder was trimmed during the routine maintenance schedule in October 2010 and trimming beyond routine trimming standards was performed. BGE identified two cable replacement opportunities. One was completed in April 2010 and the second is currently in construction and is scheduled for completion by the end of the second quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 7849

Feeder 7849 supplies approximately 1,231 customers in the Franklin Square area of Baltimore City. During 2009, 52% of the customer interruptions were caused by underground cable *failures, 25% were caused by underground equipment failures, 21% were from an unknown cause (a feeder lockout where no system damage was identified), 1% were caused by trees, and 1% were caused by public interference (foreign objects blown by wind). The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. Each failed cable was repaired or replaced during 2009 as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2010 and corrected the deficiencies identified.*

Feeder 7446

Feeder 7446 supplies approximately 1,048 customers in the Pointer Ridge area of Prince George's County. During 2009, 28% of the customer interruptions were caused by trees, 21% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 20% were caused by weather (wind/rain), 20% were caused by overhead conductor failures, 9% were caused by public interference (vehicle-hit), 1% were caused by overhead equipment failures, and 1% were due to other causes. Tree trimming on this feeder was most recently completed in April 2007. An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in 2010 and trimming beyond BGE's routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in October 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010.

Feeder 7534

Feeder 7534 supplies approximately 473 customers in the Cromwood area of Baltimore County. During 2009, 45% of the customer interruptions were caused by trees, 34% were caused by overhead equipment failures, and 21% were caused by weather (lightning). The feeder was trimmed during the routine maintenance schedule in January 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. The design of this feeder was studied and Distribution Automation reclosers were installed in November 2010.

Feeder 8463

Feeder 8463 supplies approximately 551 customers in Bowie in Prince George's County. During 2009, 42% of the customer interruptions were caused by underground cable failures, 32% were from underground equipment failures, and 26% were caused by weather (wind/rain). An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in April 2010 and trimming beyond BGE's routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in April 2010. This job included the replacement of a switchgear. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. A project to reconfigure the feeder and create additional feeder tie capabilities was completed in March 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 7844

Feeder 7844 supplies approximately 1,137 customers in the Lexington Terrace area of Baltimore City. During 2009, 80% of the customer interruptions were caused by underground cable failures, 15% were caused by wildlife, 3% were caused by trees, 1% were caused by weather (wind/rain), and 1% were due to other causes. Each failed cable was repaired or replaced during 2009 as part of the service restoration and repair process. The feeder was trimmed during the routine maintenance schedule in June 2010 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and the identified deficiencies are being corrected.

Feeder 7070

Feeder 7070 supplies approximately 1,727 customers in Edgewood in Harford County. During 2009, 55% of the customer interruptions were caused by trees, 31% were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 6% were caused by public interference (vehicle-hit), 5% were caused by underground cable failures, and 3% were caused by weather. Tree trimming on this feeder was most recently completed in December 2007. An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in April 2010 and trimming beyond BGE's routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 7555

Feeder 7555 supplies approximately 3,012 customers in Middle River in Baltimore County. During 2009, 28% of the customer interruptions were caused by underground cable failures, 24% were caused by weather (wind/rain), 24% were caused by underground equipment failures, 23% were caused by a vehicle-hit, and 1% were caused by dig-ins. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE identified one cable replacement opportunity that was completed in July 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found. The design of this feeder has been studied, and Distribution Automation reclosers will be installed and overhead reconductoring will be completed by the end of the second quarter of 2011.

Feeder 8521

Feeder 8521 supplies approximately 2,399 customers in Bowleys Quarters in Baltimore County. During 2009, 26% of the customer interruptions were caused by company interference (new pole was undermined and leaned into the feeder), 17% were due to miscellaneous causes (consisted mainly of an outage due to a crossarm fire), 15% were caused by trees, 15% were caused by overhead conductor failures, 13% were caused by public interference (vehicle-hit), 8% were caused by weather (lightning), 4% were caused by overhead equipment failures, and 2% were caused by wildlife. The feeder was trimmed during the routine maintenance schedule in April 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 7141

Feeder 7141 supplies approximately 1,056 customers in the Jacksonville area of Baltimore County. During 2009, 68% of the customer interruptions were caused by trees, 15% were caused by overhead equipment failures, 6% were due to unknown causes, 5% were caused by weather (lightning), 3% were caused by overhead conductor failures, 1% were caused by wildlife, 1% were caused by underground cable failures, and 1% were due to other causes. Tree trimming on this feeder was most recently completed in October 2009. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 8451

Feeder 8451 supplies approximately 1,285 customers in the Severn Run area of Anne Arundel County. During 2009, 71% of the customer interruptions were caused by public interference (vehicle-hit), 22% were caused by trees, 5% were caused by weather (lightning), and 2% were caused by underground cable failures. The feeder was trimmed during the routine maintenance schedule in September 2010 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 7352

Feeder 7352 supplies approximately 803 customers in the Arnold area of Anne Arundel County. During 2009, 68% of the customer interruptions were caused by trees, 22% were caused by a dig-in, 6% were caused by overhead equipment failures, and 4% were caused by overhead conductor failures. The feeder was trimmed during the routine maintenance schedule in March 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity which was completed in April 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in December 2009 and February 2010. The design of this feeder was studied and Distribution Automation reclosers were installed in June 2010.

Feeder 8799

Feeder 8799 supplies approximately 1,134 customers in Glyndon in Baltimore County. During 2009, 33% of the customer interruptions were due to unknown causes (consisted mainly of a feeder lockout and a recloser lockout where no system damage was identified), 31% were caused by trees, 26% were caused by vehicle-hits, 5% were caused by weather (4% was caused by lightning and 1% were caused by wind/rain), 2% were caused by underground cable failures, 1% were caused by wildlife, 1% were caused by dig-ins, and 1% were due to other causes. The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. BGE identified two cable replacement opportunities. One was completed in February 2010. The second was completed in November 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 7693
Feeder 7693 supplies approximately 1,163 customers in the Woodbine area on the border between Carroll and Howard Counties. During 2009, 30% of the customer interruptions were caused by trees, 27% were caused by a vehicle-hit, 26% were caused by overhead conductor failure, 8% were caused by dig-ins, 6% were caused by weather (wind/rain), 2% were caused by underground cable failure, and 1% were due to miscellaneous causes. The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in February 2011. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in June 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 13758
Feeder 13758 supplies approximately 21 customers in the Brooklyn area of South Baltimore City. During 2009, 49% of the customer interruptions were caused by overhead cable failures, 43% were caused by wildlife, 7% were caused by weather (6% were caused by lightning, and 1% were caused by wind/rain) and 1% were caused by overhead equipment failures. Poles and equipment were replaced in February 2010 to improve customer reliability. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 13946
Feeder 13946 supplies approximately 3 customers in the Carroll Park area of Baltimore City. During 2009, 50% of the customer interruptions were caused by overhead conductor failures, 40% were caused by public interference (vehicle-hit), and 10% were due to unknown causes (consisted mainly of a blown fuse where no system damage was identified). Tree trimming on this feeder was most recently completed in July 2009. Failed overhead conductors were repaired or replaced during 2009 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 13913
Feeder 13913 supplies approximately 10 customers in Mount Vernon in Baltimore City. During 2009, 100% of the customer interruptions were caused by underground cable failures in duct. Each failed cable was replaced during 2009 as part of the service restoration and repair process.

Feeder 4823
Feeder 4823 supplies approximately 546 customers in Broadway East in Baltimore City. During 2009, 50% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 13% were caused by weather (lightning), 13% were caused by wildlife, 12% were caused by underground cable failures, and 12% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in July 2009. Each failed cable was replaced during 2009 as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in May 2010 with no reliability deficiencies being found. Thermovision and visual

inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 4416

Feeder 4416 supplies approximately 865 customers in the Druid Heights area of Baltimore City. During 2009, 60% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 24% were caused by underground cable failures, and 16% were caused by overhead equipment failures. The feeder was trimmed during the routine maintenance schedule in December 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in July 2010 with no reliability deficiencies being found. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 4403

Feeder 4403 supplies approximately 672 customers in the Penn North area of Baltimore City. During 2009, 83% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), and 17% were caused by underground equipment failures. The feeder was trimmed during the routine maintenance schedule in December 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in September 2010 with no reliability deficiencies being found. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

(b) The annual report two years after the identification of the operating district or feeders as having the poorest performance shall include the ordinal ranking representing the feeder's reliability during the current reporting period.

BGE's poorest performing 2% of the 13.8 kV distribution feeders (20 out of 993 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 126 total 13000 series distribution feeders and 2% of the 4.4 kV distribution feeders (3 out of 124 total 4.4 kV distribution feeders) in 2008 had the following ordinal rankings in 2010. Ordinals for 2010 range from 1 (worst) to 107 (best) for 4.4 kV feeder, from 1 (worst) to 133 (best) for 13000 series feeders and from 1 (worst) to 1048 (best) for 13.8 kV feeders, ranked by Composite Reliability Index. Ranking excludes major event data.

13.8 kV Feeder	*Substation*	*2010 Ordinal Ranking*
8102	*MOUNT WASHINGTON*	*151*
7633	*LONG REACH*	*126*
7348	*LIPINS CORNER*	*299*
8420	*WAYSONS CORNER*	*483*
7130	*HEREFORD*	*69*
7257	*FREDERICK ROAD*	*181*
7616	*WILDE LAKE*	*127*
7658	*COLUMBIA*	*835*
7382	*SOUTH BALTIMORE*	*166*
8052	*ROCK RIDGE*	*275*
8604	*CONCORD STREET*	*428*
8682	*TEN OAKS*	*624*
7381	*SOUTH BALTIMORE*	*742*
7617	*WILDE LAKE*	*157*
8101	*MOUNT WASHINGTON*	*270*
7710	*MEADOWS*	*399*
8103	*MOUNT WASHINGTON*	*31*
8272	*HOLLOFIELD*	*560*
8556	*WAUGH CHAPEL*	*68*
8141	*EAST TOWSON*	*32*

13000 Series Feeder	*Substation*	*2010 Ordinal Ranking*
13602	*COLDSPRING*	*68*
13302	*ERDMAN*	*57*
13936	*MONUMENT STREET OUTDOOR*	*50*

4.4 kV Feeder	*Substation*	*2010 Ordinal Ranking*
4430	*FOREST PARK*	*25*
4812	*CALVERTON*	*27*
4828	*CLIFTON PARK*	*56*

(9) Momentary Interruptions. A utility shall maintain information which it collects on momentary interruptions for five years.

BGE collects momentary outage information on devices that are monitored by SCADA (e.g., Distribution Automation reclosers, substation breakers, etc.). However, BGE does not routinely collect counter readings from hydraulic reclosers.

Pepco Holdings, Inc

Marc K. Battle
Assistant General Counsel

EP1132
701 Ninth Street, NW
Suite 1100
Washington, DC 20068

(202) 372-3360
(202) 331-6767 Fax
mkbattle@pepcoholdings.com

March 5, 2010

Terry J. Romine, Esquire
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 19th Floor
Baltimore, Maryland 21202

Re: <u>State of Maryland Major Storm Report February 5 - 12, 2010: Snow Storm</u>

Dear Ms. Romine:

Enclosed for filing are the original and seventeen (17) copies of the State of Maryland Major Storm Report February 5 - 12, 2010: Snow Storm for Potomac Electric Power Company.

Very truly yours,

Marc K Battle

MKB/sar

Enclosures

cc: Paula M. Carmody, Esq.

Respectfully submitted,

Potomac Electric Power Company

By ______________________
Marc K Battle
Assistant General Counsel

Kirk J. Emge, Senior Vice President & General Counsel
Marc K. Battle, Assistant General Counsel
701 Ninth Street, N.W., Suite 1100
Washington, D.C. 20068
(202) 872-2890

Of Counsel for Potomac Electric Power Company

Washington, D.C.
March 5, 2010

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing State of Maryland Major Storm Report February 5 – 12, 2010: Snow Storm of the Potomac Electric Power Company was served, this 5th day of March 2010, by first class mail, postage prepaid.

____
Marc K. Battle

pepco

A PHI Company

State of Maryland
Major Storm Report
February 5 – 12, 2010: Snow Storm

Prepared By: **Potomac Electric Power Company**

701 Ninth St. NW

Washington, DC 20068-0001

March 5, 2010

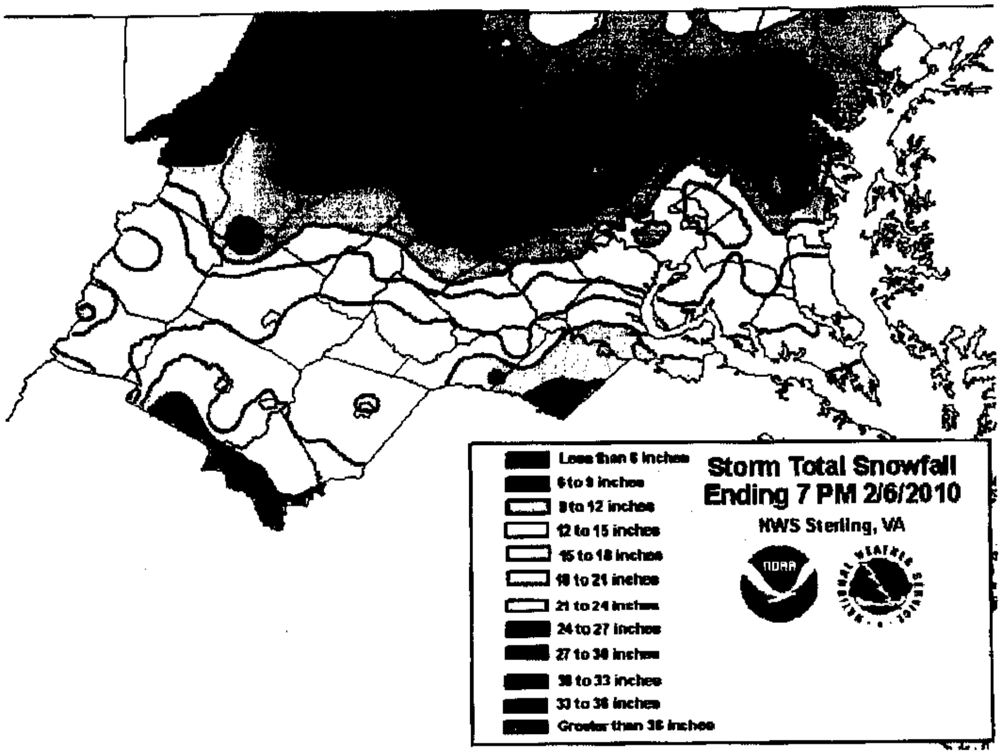
Foreword

A major service outage occurred in Pepco's service territory on February 5, 2010, following a severe snow storm which interrupted power to nearly 100,000 customers, including 90,858 Maryland customers. Full service was restored to customers in Maryland on February 12, 2010. Pursuant to COMAR 20.50.07.07, Pepco is required to file with the Maryland Public Service Commission (Commission), a written report within three weeks following the end of a major storm detailing the event's impact on Pepco's electric system and the associated system restoration efforts. Pepco's report on the effects of the February 5 storm and Pepco's restoration efforts are provided herein.

Table of Contents

Executive Summary

On February 4, 2010, Pepco began preparing for the second major snowstorm of the winter season which was forecasted to have strong winds and significant snow accumulations. Snow began falling in Pepco's service territory on February 5 during the late morning hours. On February 5 and 6, the Washington, DC Metropolitan area encountered its worst snowstorm in 90 years. Over 17 inches of snowfall was recorded at Reagan National Airport and 26 inches at BWI Thurgood Marshall Airport. As shown below, the heaviest snowfall impacted the northernmost portions of Pepco's service territory. The weight of the snow along with heavy winds caused power outages across the region. The record snow storm impacted Pepco's service territory beginning at 7:00 PM on February 5.



At the height of the storm, approximately 97,651 customers system-wide were affected by power outages at 12:00 PM on February 6, 2010. Pepco's Maryland service territory experienced peak of 90,858 customers interrupted at 12:00 PM the same day. A total of 120 distribution and 26 transmission feeders tripped and locked out system-wide. Service was interrupted to three substations in Maryland. Pepco patrols of the affected feeders indicated significant damage due to downed trees and tree limbs. In addition, Pepco received over a total of 1,000 reports of "wires down" throughout its service area. This event resulted in significant damage to the electric distribution system in Maryland.

Pepco activated its Storm Restoration Plan and after initial assessment, a Level "4" Storm was declared on the Pepco system at approximately 8:30 AM. Pepco defines a Level "4" storm as a major event with over 100,000 customers system wide affected and the estimated time of full restoration is in excess of 48 hours. In addition, arrangements were made for a conference call the afternoon of February 4 to obtain mutual assistance crews to assist in restoration efforts. Crews began arriving on the afternoon of February 6.

A second snow storm occurred on February 10 which impacted Pepco's restoration efforts. Since Pepco's restoration efforts were on-going at the time of the second storm, the affects of the second storm are captured in this report.

Approximately 90% of Maryland customers affected by outages were restored within the first 72 hours of the restoration effort. All remaining Maryland customers affected by the storm were restored by 3:46 PM on February 12.

Note that, except where otherwise noted, data presented in this report reflects system-wide information.

Customers Affected

1. Event

The weather event occurred on February 5 and 6 and was attributed to heavy snow and extremely high winds and caused a large number of power outages in the Pepco service territory.

On February 5 at 7:00 PM, Pepco declared a storm event in its service territory. On February 6 at 11:59 PM, the storm event declaration was terminated. Pepco's service restoration efforts began at the onset of the storm and lasted until 3:46 PM on February 12.

Storm on system: 7:00 PM, February 5, 2010

Storm off system: 11:59 PM, February 12, 2010

A second snow storm occurred in Pepco's service territory on February 10. At 6:25 AM on February 10, Pepco again declared a storm event in its service territory. At 11:15 PM that same day, the storm event declaration was terminated. Pepco's service restoration efforts lasted until 2:54 PM on February 12.

Storm on system: 6:25 AM, February 10, 2010

Storm off system: 11:15 PM, February 10, 2010

2. Major Storm Restoration

3:46 PM on February 12, 2010

3. Number of Customers Affected

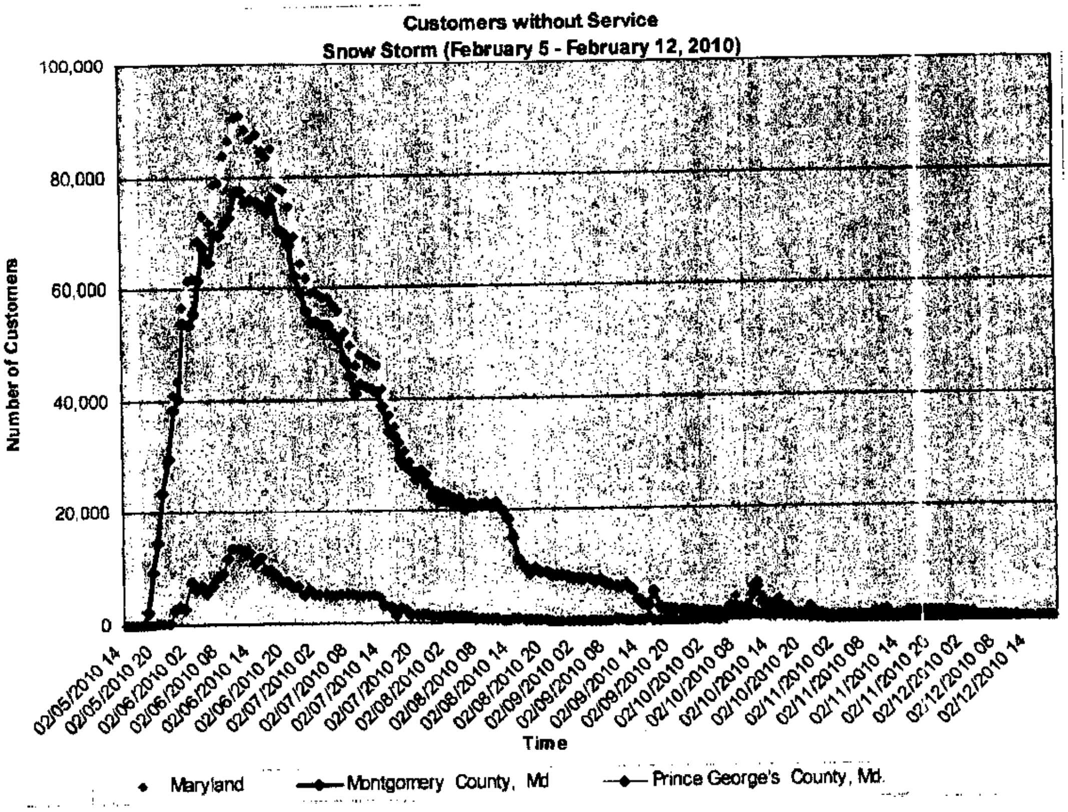
Peak System wide

97,651 outages at 12:00 hours on February 6, 2010

Peak State of Maryland

90,858 at 1200 hours on February 6, 2010

4. Sustained Interruptions



Customers Experiencing a Sustained Interruption Recorded At Six Hour Intervals

	Total Customers Out at Peak (at end of hour, not minute based)			
Time	Pepco System	Maryland	Montgomery County, Md	Prince George's County, Md.
02/05/2010 18	2,515	2,502	2,501	1
02/06/2010 00	44,835	43,780	40,470	3,310
02/06/2010 06	77,018	72,015	64,930	7,085
02/06/2010 12	97,651	90,858	77,574	13,284
02/06/2010 18	85,970	84,813	75,928	8,885
02/07/2010 00	62,441	61,865	55,784	6,081
02/07/2010 06	56,497	56,018	50,804	5,214
02/07/2010 12	47,350	46,883	41,986	4,897
02/07/2010 18	31,029	30,767	28,273	2,494
02/08/2010 00	23,412	23,256	21,965	1,291
02/08/2010 06	21,895	21,739	20,761	978
02/08/2010 12	20,306	20,155	19,715	440
02/08/2010 18	9,791	9,636	9,429	207
02/09/2010 00	8,258	8,162	8,048	114
02/09/2010 06	7,478	7,391	7,275	116
02/09/2010 12	7,706	5,801	5,657	144
02/09/2010 18	4,130	2,253	2,171	82
02/10/2010 00	1,671	1,629	1,561	68
02/10/2010 06	2,797	2,764	899	1,865
02/10/2010 12	4,882	4,204	3,328	876
02/10/2010 18	2,425	1,298	809	489
02/11/2010 00	1,089	675	612	63
02/11/2010 06	1,127	581	526	55
02/11/2010 12	1,243	610	540	70
02/11/2010 18	1,328	1,084	1,053	31
02/12/2010 00	1,127	988	977	11
02/12/2010 06	179	173	150	23
02/12/2010 12	133	128	122	6
02/12/2010 18	94	86	53	33

Last customer restored as the result of the event occurred at 3:46 PM on February 12.

5. Customer Interruption Hours

Customer Interruption Hours - System	3,735,072
Customer Interruption Hours - Maryland	3,591,156
Customer Interruption Hours - Montgomery County	3,249,368
Customer Interruption Hours - Prince George's County	341,788

Outside Assistance Resources

6. Outside Assistance Contacts

Mutual Assistance personnel were contacted beginning at 3:30 PM on February 4. A total of 200 personnel were requested. Also, Pepco requested augmentation of its sustaining contractor workforce. Below is a listing of the dates, times and organizations communicated with regarding Mutual Assistance.

DATE	TIME	GROUP	
2/04/2010	1530	Mid-Atlantic Mutual Assistance Call [MAMA]	
2/04/2010	1600	Southeast Electric Exchange Mutual Assistance Call [SEE]	
2/05/2010	0730	MAMA Call	
2/05/2010	1330	SEE Call	
2/05/2010	1800	SEE Call	
2/06/2010	0830	SEE Call	- 200 FTE's for PHI Requested
2/06/2010	1000	MAMA Call	- 200 FTE's for PHI Requested. No MAMA

resources available. All companies holding on call. After call MAMA members JCP&L/FE, PSE&G and O&R released resources to ACE.

2/07/2010	0830	SEE Call	
2/08/2010	1600	MAMA Call	- 200 FTE's for PHI Requested to ACE/DPL
2/08/2010	1700	SEE Call	- 200 FTE's for PHI Requested to ACE/DPL
2/09/2010	1300	MAMA Call	
2/09/2010	1400	SEE Call	
2/10/2010	1330	MAMA Call	
2/10/2010	1500	SEE Call	
2/11/2010	0730	MAMA Call	
2/11/2010	1000	SMECO Service Crews [4] Offered to Pepco	

7. Outside Assistance Resources

Resources

7. a) Organization(s) Providing Crews

- Progress Energy (North Division)
- Progress Energy (South Division)
- Progress Energy (East Division)
- Area Electric
- Tri-M Construction
- Southern Maryland Electric Cooperative (SMECO)

- Frye Electric
- Gregory Electric
- Riggs Distler

7. b) Date and Time of Crew Arrivals and Departures

Organization Providing Crews	Arrived	Number of Personnel	Departed
Progress Energy (North Division)	February 7 15:00 hours	56 People	February 13 07:00 hours
Progress Energy (East Division)	February 7 10:00 hours	51 People	February 13 07:00 hours
Progress Energy (South Division)	February 7 10:00 hours	42 People	February 13 07:00 hours
Area Electric	February 7 06:30 hours	15 People	February 12 07:00 hours
Tri-M Construction	February 7 06:30 hours	7 People	February 12 07:00 hours
Southern Maryland Electric Cooperative (SMECO)	February 11 14:00 hours	8 People	February 14 07:00 hours
Frye Electric	February 6 17:00 hours	24 People	February 11 16:00 hours
Gregory Electric	February 9 14:00 hours	36 People	February 14 07:00 hours
Riggs Distler	February 7 09:00 hours	4 People	February 14 07:00 hours

7. c) Number and Type of Vehicles - 149

- 63 Bucket Trucks
- 21 Digger Derricks
- 65 Miscellaneous Vehicles [Pick-ups, other trucks, etc]

7. d) Total Number of Personnel

- 243 Personnel

Deployment

7. e) Primary Overhead Line Personnel

- 243 Personnel

7. f) Secondary Overhead Line Personnel

- 0

7..g) Tree Trimming Personnel / Other Support Personnel

- 0

7. h) Primary Underground Line Crews

- N/A

7. i) Secondary Underground Line Crews

- N/A

7.j) Substation Crews

- N/A

Electric Utility Resources

8. Electric Utility Crews

Resources

8. a) Number and Type of Vehicles - 242

- 119 Bucket Trucks
- 14 Digger Derricks
- 109 Miscellaneous Vehicles [Pick-ups, other trucks, etc.]

8. b) Total Number of Personnel - 900

- 900 Personnel

Deployment

8. c) Primary Overhead Line Personnel

- 388 Personnel

8. d) Secondary Overhead Line Personnel

- 31 Personnel

8. e) Damage Assessment Personnel

- 83 Personnel performed field damage assessments

8. f) Tree Trimming Personnel

- 75 Contractor personnel worked tree complaints.
- 5 Foresters (employees) and 3 contract Forester/Planners

8. g) Primary Underground Line Crews

- 3

8. h) Secondary Underground Line Crews

- 2

8. i) Substation Crews

- 7

8. j) Other Personnel

- 315 Other Support Personnel

Communications

General

Pepco maintains positive relationships with State, County and/or Local Emergency Management Agencies (EMA) through the PHI Emergency Management Department.

Emergency Management is responsible for providing State, County and/or Local EMA personnel with "one point of contact" for addressing operational and community support requests. During major events, a Pepco EMA Liaison may be assigned to the jurisdiction upon consultation.

All 911 Centers and EMA in Pepco's service territory have a direct dial line communications radio that is supplied courtesy of the utility and can be used to communicate with each utility in the event of a communications emergency. Utility and EMA activation and coordination were based on how each area was affected by the storm.

MONTGOMERY COUNTY EMA

- **Pepco Relationship Manager** – Manager-Emergency Management was supported by two assigned Pepco EMA Liaisons tied to Pepco Incident Management Team (IMT) Liaison at Pepco's Control Center. Participated in preparatory conference calls and briefings and briefings and situation report development during the event.
- **Challenge** – Pepco provided customer counts and information via e-mail and telephone calls. Pepco EMA Liaison provided information on site to the County Emergency Operations Center (EOC). County snow removal challenges were overwhelming with many roads impassable. Main roads were passable by Monday, February 8 but secondary roads presented challenges. County did attempt to assist with plowing on a case by case basis. WSSC Potomac Plant and City of Rockville water plants were down during the storm. One supply restored to each on Sunday, February 7 which allowed them to fully operate. Second supply required extensive work and was restored on February 8. Snow clearance on privately maintained roads in sub-divisions presented challenges.
- **Coordination** – Pepco was represented in the EOC. County provided plows, on a case by case basis, early Sunday morning, February 7, to support transmission restoration to substation supplies. Coordination on snow clearance in sub-divisions and secondary roads in areas with power outages. Improved. Maps were provided electronically periodically to assist Department of Public Works in their planning. Priorities for critical restoration were adjudicated by the EOC and forwarded to Pepco for information or consideration in restoration planning.

STATE OF MARYLAND EMA

- **Pepco Relationship Manager** – Manager-Emergency Management or Pepco IMT Liaison Officer participated in preparatory conference calls with all Maryland utilities in advance and situational updates after the event. E-mail updates and press releases were provided.
- **Challenge** – Differentiation between County and State protocol for snow removal on roads hampered effective coordination.

- **Coordination** – Pepco requested assistance form Maryland State Highway Administration (MD SHA) through the Maryland Emergency Management Agency (MEMA) for plowing assistance to our Burtonsville Substation. MD SHA provided a plow o assist us in accessing this critical substation.

PRINCE GEORGES COUNTY EMERGENCY MGMT AGENCY

- **Pepco Relationship Manager** – Manager-Emergency Management or Pepco IMT Liaison Officer conducted direct contact with the County EMA Director. E-mail updates and press releases provided.

- **Challenge** – Plowing and access was problematic. County assisted on a case by case basis on plowing requests. Problems with private subdivisions and the inability of their contractors to maintain open roads and access

- **Coordination** – Pepco provided response to specific inquiries to assist Prince George's Government. County did provide plowing assistance on a case by case basis.

DISTRICT OF COLUMBIA HOMELAND SECURITY & EMERGENCY MANAGEMENT AGENCY

- **Pepco Relationship Manager** – Manager-Emergency Management or Pepco Liaison Officer participated in all preparatory conference calls with District agencies and ongoing status update calls. E-mail updates and press releases provided.

- **Challenge** – Several District facilities did not have or had non-working backup power supplies including one Police Station and one 800 MHz radio tower. Wires down were problematic as the District looks to Pepco to be the only responder for wires down while over 40% are owned by other entities.

- **Coordination** – Pepco provided response to specific inquiries to assist District Government in contingency planning.

GOVERNMENT AFFAIRS AND PUBLIC POLICY

In addition to communications between State and County EMA, Pepco conducted three conference calls with participants from County and Local Governments, elected officials, members from both the District of Columbia and Maryland Public Service Commissions, Hospital Associations and Homeowner Associations.

OTHER COMMUNICATIONS

The President of Pepco conducted briefing sessions with the Montgomery County Council and the EMA. In addition, throughout the course of the snow storm, Pepco reached out and provided information to both the Maryland and District of Columbia Public Service Commission's Commissioners, Senior Staff members and Technical Advisors to the Commissioners, as well as the Director of the Office of External Relations from the Maryland Commission. Further, Pepco issued ten Press Releases and 53 television and 31 radio interviews were aired respectively. Also, Pepco's website received over 72,000 visits on the peak day of the snow storm, February 6 which represents over six times the number of visits received during the average of the first five days of February 2010. Social media was also utilized including PepcoConnect's Blog, Twitter, and Facebook.

9. Customer Operations Statistics

Severe Weather 2.5.10
February 5, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
7PM-8PM	414	478	1876	2768	2768	23	0
8PM-9PM	163	267	1398	1836	1828	8	0
9PM-10PM	132	245	1768	2145	2145	6	0
10PM-11PM	86	206	1550	1842	1842	5	0
11PM-12AM	101	165	1398	1664	1664	5	0
	896	**1361**	**7990**	**10255**	**10247**		

TSF @ 60 Seconds: 96.1%

Rep Ans – Representative Answered,
Inhse VRU – In house Voice Response Unit,
HVCA – High Volume Call Answering System

Severe Weather 2.5.10
February 6, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	112	161	1381	1654	1654	5	0
1AM - 2AM	83	115	1724	1923	1922	5	0
2AM - 3AM	84	166	1679	1929	1929	5	0
3AM - 4AM	85	147	1381	1614	1613	5	0
4AM - 5AM	59	204	1681	1944	1944	5	0
5AM-6AM	56	258	2104	2418	2418	5	0
6AM - 7AM	80	376	3345	3801	3801	5	0
7AM - 8AM	290	763	6147	7253	7200	17	0
8AM - 9AM	387	1039	7444	8969	8870	17	0
9AM - 10AM	322	1050	7429	8945	8801	17	0
10AM - 11AM	330	1127	7641	9267	9098	17	0
11AM - 12PM	178	1102	6639	8096	7919	12	0
12PM - 1PM	187	1108	6334	7815	7629	12	0
1PM - 2PM	183	710	6519	7574	7412	50	0
2PM - 3PM	142	519	5908	6717	6569	50	0
3PM - 4PM	143	547	6367	7184	7057	51	0
4PM - 5PM	142	505	5323	6141	5970	50	0
5PM - 6PM	196	426	5206	5929	5828	38	0
6PM-7PM	272	588	5594	6500	6454	30	0
7PM-8PM	244	301	4203	4767	4748	23	0
8PM-9PM	287	353	3266	3920	3906	8	0
9PM-10PM	232	192	2172	2597	2596	6	0
10PM-11PM	139	128	1204	1471	1471	5	0
11PM-12AM	91	82	701	874	874	5	0
	4324	**11967**	**101392**	**119302**	**117683**		

TSF @ 60 Seconds: 95.7%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather 2.5.10
February 7, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	62	37	458	557	557	12	0
1AM - 2AM	43	29	295	367	367	14	0
2AM - 3AM	33	26	382	441	441	14	0
3AM - 4AM	43	16	375	434	434	11	0
4AM - 5AM	56	25	338	419	419	11	0
5AM-6AM	44	22	470	537	536	10	0
6AM - 7AM	66	85	1199	1350	1350	7	0
7AM - 8AM	237	258	3042	3545	3537	19	0
8AM - 9AM	215	535	4795	5554	5545	19	0
9AM - 10AM	201	473	3586	4266	4260	21	0
10AM - 11AM	240	383	2843	3481	3466	22	0
11AM - 12PM	243	312	2096	2656	2651	20	0
12PM - 1PM	214	272	1971	2462	2457	20	0
1PM - 2PM	264	273	2901	3439	3438	20	0
2PM - 3PM	257	297	2690	3248	3244	23	0
3PM - 4PM	287	260	2079	2636	2626	23	12
4PM - 5PM	294	216	1951	2462	2461	22	21
5PM - 6PM	295	235	1594	2129	2124	20	16
6PM-7PM	252	165	1491	1910	1908	16	0
7PM-8PM	145	132	1314	1591	1591	12	0
8PM-9PM	126	95	920	1141	1141	15	0
9PM-10PM	125	229	612	966	966	16	0
10PM-11PM	101	252	520	873	873	8	0
11PM-12AM	58	133	265	456	456	8	0
	3901	**4760**	**38187**	**46920**	**46848**		

TSF @ 60 Seconds: 94.9%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather 2.5.10
February 8, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	37	106	209	352	352	7	0
1AM - 2AM	6	29	52	87	87	7	0
2AM - 3AM	13	27	36	76	76	7	0
3AM - 4AM	9	20	49	78	78	7	0
4AM - 5AM	12	26	50	88	88	7	0
5AM-6AM	17	43	119	179	179	7	0
6AM - 7AM	84	227	329	640	640	7	0
7AM - 8AM	350	390	738	1488	1478	21	0
8AM - 9AM	460	700	881	2088	2041	35	0
9AM - 10AM	692	887	978	2653	2557	68	0
10AM - 11AM	973	784	775	2552	2532	84	0
11AM - 12PM	813	934	1087	2834	2834	97	0
12PM - 1PM	752	572	811	2137	2135	110	0
1PM - 2PM	725	548	859	2133	2132	115	0
2PM - 3PM	801	337	1131	2271	2269	115	0
3PM - 4PM	986	158	443	1597	1587	115	0
4PM - 5PM	1097	311	513	1937	1921	110	0
5PM - 6PM	1034	227	114	1401	1375	102	0
6PM-7PM	938	173	92	1217	1203	86	0
7PM-8PM	627	119	44	799	790	51	7
8PM-9PM	451	85	30	578	566	20	15
9PM-10PM	253	83	35	373	371	10	15
10PM-11PM	178	61	10	252	249	10	7
11PM-12AM	118	42	0	160	160	10	0
	11426	**6889**	**9385**	**27970**	**27700**		

TSF @ 60 Seconds: 95.1%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather 2.5.10
February 9, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	76	34	0	110	110	9	0
1AM - 2AM	24	9	0	33	33	9	0
2AM - 3AM	19	7	0	27	26	9	0
3AM - 4AM	14	13	0	20	27	8	0
4AM - 5AM	30	6	0	32	36	8	0
5AM-6AM	110	11	8	129	129	8	0
6AM - 7AM	150	37	178	365	365	8	0
7AM - 8AM	403	99	356	865	858	28	0
8AM - 9AM	740	231	534	1510	1505	65	0
9AM - 10AM	916	322	424	1667	1662	90	0
10AM - 11AM	1057	309	274	1652	1640	99	0
11AM - 12PM	1482	287	84	1860	1853	105	0
12PM - 1PM	1354	296	11	1671	1661	108	0
1PM - 2PM	1129	268	0	1404	1397	110	0
2PM - 3PM	971	261	0	1240	1232	109	0
3PM - 4PM	1139	282	0	1424	1421	106	0
4PM - 5PM	1228	243	72	1550	1543	104	0
5PM - 6PM	990	206	29	1234	1225	92	0
6PM-7PM	453	163	0	619	616	84	0
7PM-8PM	239	101	0	343	340	40	0
8PM-9PM	166	81	0	254	247	23	0
9PM-10PM	84	62	0	150	146	18	0
10PM-11PM	71	57	0	128	128	13	0
11PM-12AM	35	14	0	49	49	10	0
	12880	**3399**	**1970**	**18336**	**18249**		

TSF @ 60 Seconds: 98.5%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather 2.5.10
February 10, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	0	4	0	4	4	9	0
1AM - 2AM	22	12	0	34	34	9	0
2AM - 3AM	19	8	0	27	27	9	0
3AM - 4AM	9	8	0	17	17	9	0
4AM - 5AM	10	9	0	19	19	9	0
5AM-6AM	15	12	0	27	27	9	0
6AM - 7AM	214	41	0	255	255	9	0
7AM - 8AM	715	71	0	787	786	14	0
8AM - 9AM	493	133	0	634	626	18	0
9AM - 10AM	978	188	64	1239	1230	34	0
10AM - 11AM	1164	243	0	1411	1407	38	0
11AM - 12PM	1140	256	98	1510	1494	42	0
12PM - 1PM	955	208	0	1179	1163	46	0
1PM - 2PM	620	184	0	815	804	47	0
2PM - 3PM	520	194	0	719	714	46	0
3PM - 4PM	1059	198	100	1371	1357	46	0
4PM - 5PM	1011	204	0	1221	1215	41	0
5PM - 6PM	452	140	25	623	617	34	20
6PM-7PM	739	130	33	911	902	30	20
7PM-8PM	193	102	13	312	308	22	20
8PM-9PM	156	61	9	228	226	17	20
9PM-10PM	89	36	42	167	167	12	20
10PM-11PM	107	47	8	163	162	11	0
11PM-12AM	58	41	0	99	99	9	0
	10738	**2530**	**392**	**13772**	**13660**		

TSF @ 60 Seconds: 98.2%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather 2.5.10
February 11, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	25	25	0	50	50	6	0
1AM - 2AM	11	8	0	19	19	6	0
2AM - 3AM	7	10	0	17	17	6	0
3AM - 4AM	11	12	0	23	23	6	0
4AM - 5AM	9	5	0	14	14	6	0
5AM-6AM	26	10	0	37	36	6	0
6AM - 7AM	30	13	0	43	43	7	0
7AM - 8AM	197	79	0	281	276	18	0
8AM - 9AM	484	149	0	635	633	28	0
9AM - 10AM	949	265	0	1218	1214	44	0
10AM - 11AM	886	301	0	1210	1187	48	0
11AM - 12PM	1203	301	12	1537	1516	51	0
12PM - 1PM	703	306	0	1041	1009	53	0
1PM - 2PM	684	284	0	1018	968	54	0
2PM - 3PM	571	253	0	897	824	51	0
3PM - 4PM	549	285	0	958	834	52	0
4PM - 5PM	535	249	0	908	784	45	0
5PM - 6PM	580	192	0	830	772	40	0
6PM-7PM	345	143	0	491	488	38	0
7PM-8PM	227	125	0	355	352	25	0
8PM-9PM	75	84	0	159	159	13	0
9PM-10PM	76	79	0	155	155	11	0
10PM-11PM	62	64	0	126	126	10	0
11PM-12AM	22	54	2	78	78	10	0
	8267	**3296**	**14**	**12100**	**11577**		

TSF @ 60 Seconds: 80.6%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather 2.5.10
February 12, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	10	29	2	41	41	9	0
1AM - 2AM	9	19	1	29	29	9	0
2AM - 3AM	2	12	1	15	15	9	0
3AM - 4AM	5	12	18	35	35	9	0
4AM - 5AM	3	22	22	47	47	9	0
5AM-6AM	3	21	2	26	26	9	0
6AM - 7AM	10	48	7	65	65	9	0
7AM - 8AM	195	151	30	377	376	17	0
8AM - 9AM	415	304	33	796	752	28	0
9AM - 10AM	544	438	50	1164	1032	42	0
10AM - 11AM	556	481	34	1240	1071	45	0
11AM - 12PM	526	483	43	1256	1052	45	0
12PM - 1PM	451	459	42	1185	952	47	0
1PM - 2PM	420	494	30	1214	944	49	0
2PM - 3PM	416	425	47	1179	888	49	0
3PM - 4PM	493	414	24	1233	931	48	0
	4058	**3812**	**386**	**9902**	**8256**		

TSF @ 60 Seconds: 67.4%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit,
HVCA – High Volume Call Answering System

Storm Damage Information

10. System Damage

a) Poles Replaced 21

b) Distribution Transformers Replaced 20

c) Fuses Replaced 1,624

d) Downed Wires Reported 1,147*

e) Substation with Equipment Damage 3

* Of the 1,147 downed wires reported, 265 were Pepco wires.

11. Materials

There were no unusual issues concerning the availability of materials for service restoration. Material inventories were closely monitored to ensure the availability of necessary equipment and materials for restoration activities.

12. Self Assessment

Each major storm impacting the Pepco service territory is different, bringing unique system restoration challenges. The snow and wind event of February 5-12 was no exception. The biggest challenge faced by restoration crews was impaired access to substations, rights-of-way, neighborhoods and equipment as a result of the large amount of accumulated snow along with downed trees and tree branches. Nevertheless, despite these impediments, crews were able to restore power to approximately 90% of Pepco customers within the first 72 hours of the restoration effort while braving knee to waist high snow and, at times, blizzard conditions.

Pepco's response processes included logistics, damage assessment, wires down response, call center operations, mutual assistance procurement and coordination, planning and analysis, EMA liaison efforts and field restoration. All notifications to internal resources prior to the onset of the event went as planned according to Pepco's Incident Response Plan. Lessons-learned sessions were conducted following the event, and the following was noted:

<u>System Restoration Issues</u>
There was good communication with, and support from, State and local Emergency Management Agencies, Maryland State Highway Administration, and county Public Works Departments with respect to outages at critical infrastructure facilities and for snow plowing assistance. The embedded Pepco Liaison at the Montgomery County Emergency Operations Center provided an important communication conduit on an around the clock basis. The movement of PHI crews and contractors between regions worked well. PHI company crews worked especially well because of the common Advantex computerized dispatch system across all PHI regions, and through the use of global positioning systems in vehicles. The dispatch of resources from other PHI regions supporting the Pepco Incident Management Team was transparent to System Operations and Dispatchers. Material delivery and staging efforts were very well coordinated.

Mobility was a significant challenge. At one point during the height of the storm, more than twelve heavy duty dual -wheeled bucket trucks with chains were stuck in the deep snow. In addition, snow piles on roadsides challenged Pepco personnel and increased the time required to access switches and buried pad mounted and sub-surface electrical equipment. Additional portable Advantex units would have helped restoration, as would additional 4x4 rental vehicles. Wires down response continues to be a challenge due to the large number of telephone and cable wire failures that coincidentally occur with damage to overhead electrical wires. Over 75% of reported wires down were found to be non-Pepco; but Pepco must respond to all wires down reports.

<u>Computer Systems Issues</u>
Information Technology (IT) infrastructure performed well. High numbers of users were able to work via remote access during the event; this was particularly advantageous as many key support personnel were snow bound at home and could not report for their assigned storm roles. On February 10, IT recorded 898 concurrent users. The system approached but did not exceed its capacity on one of the access points. PHI will review current capacity/constraints for various remote access/WEBmail options and develop user guidelines for efficient use of these resources.

The Outage Management System (OMS) experienced no hardware issues during the February 5-12 event. The OMS did experience two software issues, however.

- Users had difficulty accessing the OMS and the interface between the OMS and the Mobile Data System (MDS) automatically restarted. Upon investigation it was determined that users were accessing the OMS database to run storm statistical information for later reporting. This was impacting the ability of the OMS system to access the same data. Access to the OMS database was removed and the users were directed to use a copy of the OMS database on a reporting server. During this period users were able to access the OMS using web based tools. Once the reporting user access was removed, problem was eliminated.

- One of the programs within the OMS started using all the available resources on the server, causing the entire system to restart. An automated process was put in place to mitigate this process including a monitor to check the program for excessive use and force it to stop when excessive use is detected. This will cause a restart for one user, instead of the entire system restarting for all users. With this process in place, the problem will not recur.

<u>Communications</u>

As described on pages 12 and 13, Pepco ensured that it communicated with its customers, government officials and staff, regulators, State and County agencies, hospital and homeowners associations using a variety of mediums throughout the course of the storm event. Briefing sessions were conducted by the President-Pepco Region for the Montgomery County Council and the Montgomery County EMA. Pepco will continue to seek ways to enhance its messaging during major service interruption events.

<u>Customer Service Issues</u>

Pepco, for the first time, activated mutual assistance for call center support, obtaining support from Tampa Electric, Alabama Power and Georgia Power. Pepco is aware of concerns raised by customers such as call wait times and estimated time of restoration issues, and is continuing its assessment to determine what improvements can be made in this area.

Interruption Causes

13. Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	93,071	1,822,470
b) Equipment Failures	3,585	52,412
c) Lightning Damage	0	0
d) Weather - Ice	13,742	237,600
e) Weather - Wind	123,207	1,121,290
f) Weather - Other	1,766	14,285
g) Other Major Causes*	29,063	343,099

*Includes source lost = 15,581, unknown = 11,347, load = 2,026; animal, employee, foreign contact and motor vehicle = 109

pepco

A PHI Company

William F. O'Brien
Assistant General Counsel

89KS42
800 King Street
Wilmington, DE 19801

PO Box 231
Wilmington, DE 19899-0231
302-429-3143
302-429-3801 Fax
bill.obrien@pepcoholdings.com

August 23, 2010

Terry J. Romine, Esq.
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: Case No. 9240

Dear Ms. Romine:

In accordance with COMAR 20.50.07.07, and for filing in Case No. 9240, please find enclosed an original and seventeen copies of Potomac Electric Power Company's major storm report, which relates to the July 25, 2010 storm event.

Please contact me if you should have any questions.

Sincerely,

William F. O'Brien

pepco

A PHI Company

State of Maryland
Major Storm Report
July 25 - 31, 2010: Severe Thunderstorm

Prepared By: Potomac Electric Power Company

701 Ninth St. NW

Washington, DC 20068-0001

August 23, 2010

Foreword

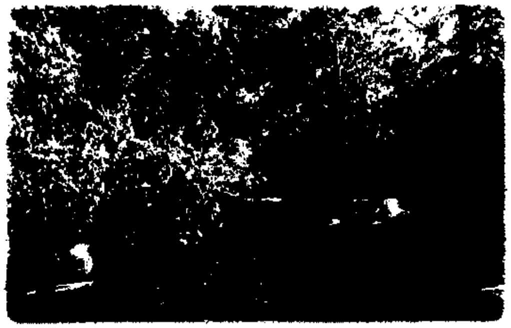
A major service outage occurred in Pepco's service territory on July 25, 2010, following a severe, fast moving storm which interrupted power to over 323,000 customers, including 290,872 Maryland customers at peak. Full service was restored to customers in Maryland on July 31, 2010. Pursuant to COMAR 20.50.07.07, Pepco is required to file with the Maryland Public Service Commission (Commission), a written report within three weeks following the end of a major storm detailing the event's impact on Pepco's electric system and the associated system restoration efforts. Pepco's report on the effects of the July 25 storm and Pepco's restoration efforts are provided herein.

Table of Contents

Executive Summary

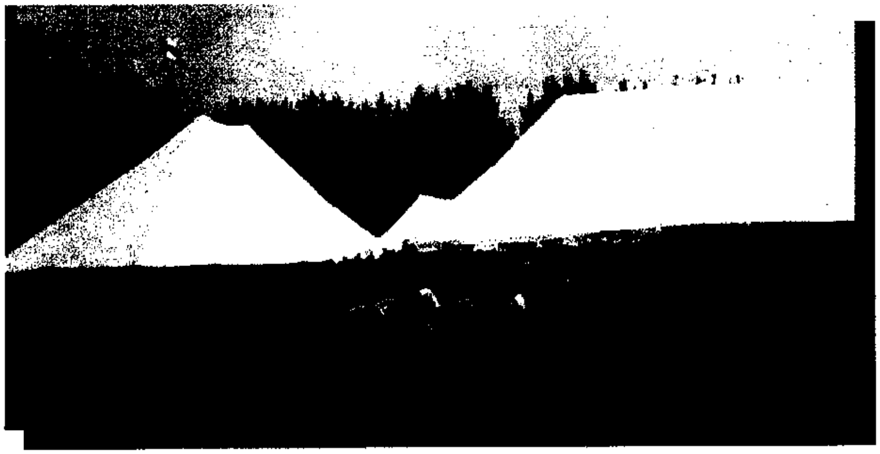
On July 25, 2010, a fast-moving thunderstorm with wind gusts in excess of 70 miles per hour moved through the Pepco service territory, causing outages to 323,662 customers at peak. Of these, 238,977 were in Montgomery County, 49,316 were in Prince George's County and 35,369 were in the District of Columbia. Up to 1.46 inches of rain fell in one hour and 34,696 lightning strikes occurred in Montgomery County, Prince George's County and the District of Columbia. An average peak power output of a single lightning strike is approximately one trillion watts.

At the height of the storm, approximately 323,662 customers system-wide were affected by power outages at 08:00 PM on July 25, 2010. Pepco's Maryland service territory experienced peak of 290,872 customers interrupted at 9:00 PM the same day. On a system-wide basis, a total of 214 distribution circuit lock-outs were experienced, ten substations experienced a sustained outage and more than 1,900 reports of "wires down" were received. Pepco patrols of affected feeders indicated significant damage due to downed trees and tree limbs. The vast majority (almost 92%) of outages were caused by trees and limbs falling onto conductors. This event resulted in significant damage to Pepco's electric distribution system.

Pepco activated its Storm Restoration Plan and after initial assessment, a Level "4" Storm was declared on the Pepco system at approximately 3:07 PM. Pepco defines a Level "4" storm as a major event with over 100,000 customers system wide affected and the estimated time of full restoration is in excess of 48 hours.

The greatest impediment faced by Pepco in responding to the event was the fact that the thunderstorm struck the service territory less than an hour after the weather service issued a warning, effectively depriving Pepco of the opportunity to engage in advanced planning to bring large numbers of outside resources to the Pepco service territory. Notwithstanding this lack of advance notice, however, Pepco mobilized quickly: additional company and contract crews were on duty within three hours; outside mutual assistance resources began arriving within 16 hours; and a remote staging area was operational within 21 hours.



Staging Area

Approximately 90% of Pepco's customers (system-wide) were restored within 72 hours of the event. All remaining Maryland customers affected by the storm were restored by 12:56 AM on July 31, 2010.

Customers Affected

1. Event

The weather event occurred on July 25 and was attributed to sever thunderstorms and extremely high winds and caused a large number of power outages in the Pepco service territory.

On July 25 at 3:07 PM, Pepco declared a storm event in its service territory. On July 25 at 5:30 PM, the storm event declaration was terminated. Pepco's service restoration efforts began at the onset of the storm and lasted until 12:56 AM on July 31.

Storm on system: 3:07 PM, July 25, 2010

Storm off system: 5:30 PM, July 25, 2010

2. Major Storm Restoration

12:56 AM on July 31, 2010

3. Number of Customers Affected

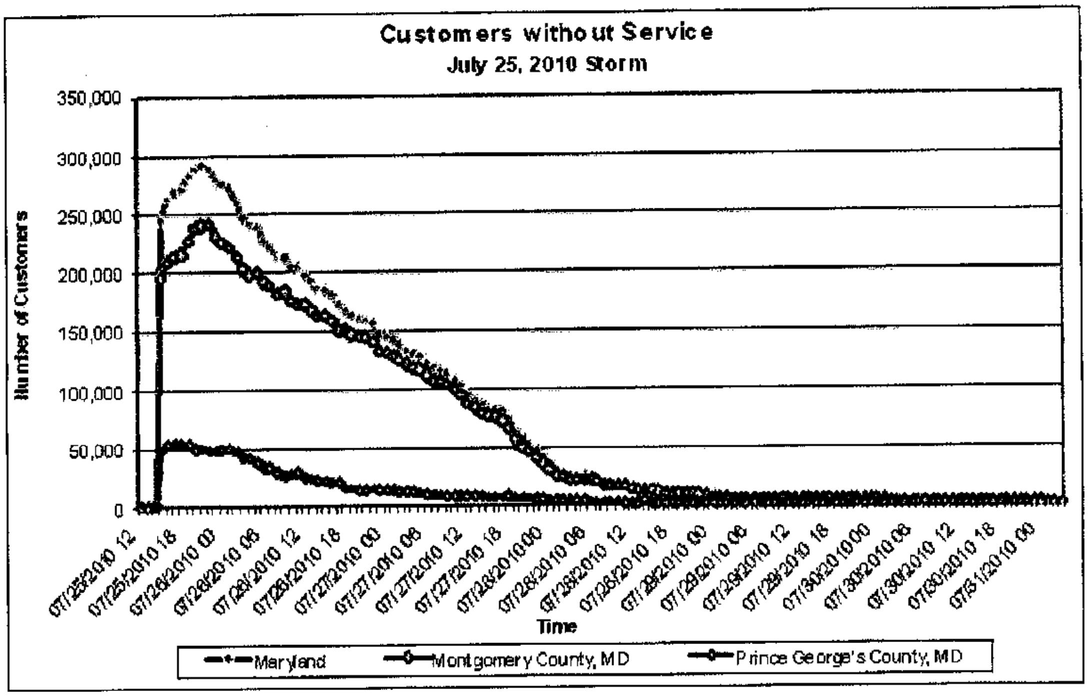
Peak System wide

323,662 outages at 2000 hours on July 25, 2010

Peak State of Maryland

290,872 at 2100 hours on July 25, 2010

4. Sustained Interruptions



Customers Experiencing a Sustained Interruption Recorded At Six Hour Intervals

Time	Pepco System	Maryland	Montgomery County, MD	Prince George's County, MD
07/25/2010 08	521	174	153	21
07/25/2010 14	2,426	2,128	2,056	72
07/25/2010 20	323,662	288,293	238,977	49,316
07/26/2010 02	289,184	260,586	212,901	47,685
07/26/2010 08	239,543	213,674	183,583	30,091
07/26/2010 14	207,899	185,990	163,246	22,744
07/26/2010 20	176,013	161,535	146,650	14,885
07/27/2010 02	148,685	138,421	125,467	12,954
07/27/2010 08	124,253	116,392	106,816	9,576
07/27/2010 14	95,012	87,591	80,045	7,546
07/27/2010 20	60,265	56,750	49,881	6,869
07/28/2010 02	30,579	28,572	25,007	3,565
07/28/2010 08	20,101	18,890	16,361	2,529
07/28/2010 14	16,264	15,289	11,920	3,369
07/28/2010 20	11,560	10,923	9,646	1,277
07/29/2010 02	6,841	6,549	5,655	894
07/29/2010 08	3,946	3,752	3,501	251
07/29/2010 14	4,725	4,549	4,190	359
07/29/2010 20	3,354	3,250	2,900	350
07/30/2010 02	2,396	2,379	1,996	383
07/30/2010 08	2,448	1,875	1,562	313
07/30/2010 14	1,922	1,090	723	367
07/30/2010 20	621	614	321	293
07/31/2010 01	-	-	-	-

Total Customers Out at Peak (at end of hour, not minute based)

Last customer restored as the result of the event occurred at 12:56 AM on July 31.

5. Customer Interruption Hours

Customer Interruption Hours - System	11,342,644
Customer Interruption Hours - Maryland	10,278,767
Customer Interruption Hours - Montgomery County	8,853,568
Customer Interruption Hours - Prince George's County	1,425,199

Outside Assistance Resources

EXTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

6. Outside Assistance Contacts

Mutual Assistance communications commenced at 5:34 PM on July 25. A total of 250 – 300 personnel were requested at 7:30 PM on July 25. Also, Pepco requested augmentation of its external contractor workforce. Below is a listing of the dates, times and organizations communicated with regarding Mutual Assistance.

DATE	TIME	GROUP
7/25/2010	1734	Mid-Atlantic Mutual Assistance Communication [MAMA]
7/25/2010	1900	Requested Delmarva Power and Atlantic City Electric Resources
7/25/2010	1930	Requested for 250 – 300 MAMA Crews
7/25/2010	2030	Additional Delmarva Power and Atlantic City Electric crews requested following passage and assessment of storm damage throughout their respective service territories.

7. Outside Assistance Resources

Resources

7. a) Organization(s) Providing Crews

- East Coast UG
- Area Utilities
- Utility Lines - Delaware
- Tri-M Construction
- Southern Maryland Electric Cooperative (SMECO)
- Duquesne Light
- Didado Construction
- Thompson Electric
- Main Lite Electric
- First Energy
- Davis H Elliott
- American Lighting and Signalization
- CW Wright
- Rockingham
- WA Chester
- Utility Lines
- Asplundh (Tree Trimming)

7. b) Date and Time of Crew Arrivals and Departures

Mutual Assistance

Organization Providing Crews	Arrived	Number of Personnel	Departed
East Coast	July 26 1000 hours	17 People	July 31 1600 hours
Area Utilities	July 26 1000 hours	13 People	July 31 1600 hours
Utility Lines (Delaware)	July 26 0700 hours	11 People	July 31 2100 hours
Tri-M Construction	July 26 1000 hours	10 People	July 31 1600 hours
Southern Maryland Electric Cooperative (SMECO)	July 29 1000 hours	6 People	July 31 1200 hours
Duquesne Light	July 26 2000 hours	15 People	July 31 0930 hours
Didado Construction	July 26 1800 hours	76 People	July 30 1030 hours
Thompson Electric	July 26 1800 hours	38 People	July 30 1130 hours
Main Lite Electric	July 26 1800 hours	16 People	July 30 1600 hours
First Energy[1]	July 26 1800 hours	142 People	July 31 0800 hours
First Energy[2]	July 27 1000 hours	42 People	July 31 0800 hours
Davis H Elliott	July 29 1000 hours	28 People	July 31 1400 hours
American Lighting and Signalization	July 29 1000 hours	25 People	July 31 0700 hours

[1]Includes Cleveland Electric Illuminating Company, Pennsylvania Electric Company, Pennsylvania Power Company and Cleveland Edison Company
[2]Includes Metropolitan Edison Company and Jersey Central Power Company

Pepco Contractors

Organization Providing Crews	Number of Personnel
CW Wright	36 People
Rockingham	40 People
WA Chester	17 People
Utility Lines	4 People
Asplundh (Tree Trimming)	180 People

Other Pepco Holdings, Inc. (PHI) Utility Personnel

Organization Providing Crews	Number of Personnel
Delmarva Power and Atlantic City Electric	114 People

7. c) Number and Type of Vehicles - 257

- 166 Bucket Trucks
- 32 Digger Derricks
- 59 Miscellaneous Vehicles [Pick-ups, other trucks, etc]

7. d) Total Number of External Personnel - 830

- 830 Personnel

Deployment

7. e) Primary Overhead Line Personnel

- 585 Personnel

7. f) Secondary Overhead Line Personnel

- Not Applicable (NA)

7. g) Tree Trimming Personnel / Other Support Personnel

- 183

7. h) Primary Underground Line Crews

- NA

7. i) Secondary Underground Line Crews

- NA

7. j) Substation Crews

- NA

7. k) Other Personnel

- 62 Other Support Personnel

Electric Utility Resources

INTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

8. Electric Utility Crews

Resources

8. a) Number and Type of Vehicles - 229

- 121 Bucket Trucks
- 8 Digger Derricks
- 100 Miscellaneous Vehicles [Pick-ups, other trucks, etc.]

8. b) Total Number of Internal Personnel - 469

- 469 Personnel

Deployment

8. c) Primary Overhead Line Personnel

- 105 Personnel

8. d) Secondary Overhead Line Personnel

- NA

8. e) Damage Assessment Personnel

- 33 Personnel performed field damage assessments

8. f) Tree Trimming Personnel

- 4 Personnel

8. g) Primary Underground Line Crews

- NA

8. h) Secondary Underground Line Crews

- NA

8. i) Substation Personnel

- 70

8. j) Other Personnel

- 257 Other Support Personnel

Communications

General

Pepco maintains positive relationships with state, county and/or local Emergency Management Agencies (EMA) through the PHI Emergency Management Department.

Emergency Management is responsible for providing state, county and/or local EMA personnel with "one point of contact" for addressing operational and community support requests. During major events, a Pepco EMA Liaison was assigned to the Montgomery County EMA.

All 911 Centers and EMA in Pepco's service territory have a direct dial line communications radio that is supplied courtesy of the utility and can be used to communicate with each utility in the event of a communications emergency.

MONTGOMERY COUNTY EMA

- ➢ **Pepco Relationship Manager** – Manager-Emergency Management was supported by two assigned Pepco EMA Liaisons tied to Pepco Incident Management Team (IMT) Liaison at Pepco's Control Center. Participated in preparatory conference calls and briefings and situation report development during the event.

- ➢ **Coordination** – Pepco provided a 24 hour presence in the Emergency Operations Center (EOC). Priorities for critical restoration were adjudicated by the EOC and forwarded to Pepco through its representative for information or consideration in restoration planning.

GOVERNMENT AFFAIRS CONTACTS

Pepco conducted daily conference calls with participants from county and local governments, elected officials, members from both the District of Columbia and Maryland Public Service Commissions and their Staffs and several homeowner associations.

Also, over the course of the storm, the President of Pepco Region

- conducted five press conferences;
- held numerous television and radio interviews;
- briefed the Montgomery County Council in Chambers, Maryland Governor, Prince George's County Executive and other government officials on numerous occasions; and
- conducted daily conference calls with government officials that included over 30 different external participants over five days.

Further, Pepco

- distributed all press releases via email to government officials, community leaders and business leaders;
- processed inquiries from elected officials regarding outage issues called to their attention by constituents; and
- worked closely with government officials to identify restoration priorities.

REGULATORY CONTACTS

Pepco provided storm statistics daily to Maryland Public Service Commission and their Staffs.

MEDIA COMMUNICATIONS

During the restoration period for the July 25 storm, Pepco issued six news releases and four media advisories and conducted over 175 media interviews. Social media was also utilized including PepcoConnect's Blog, Twitter and Facebook.

9. Customer Operations Statistics

Severe Weather
July 25, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
3PM - 4PM	102	552	18787	19493	19441	8	0
4PM - 5PM	126	544	27122	27973	27792	10	0
5PM - 6PM	155	551	23037	23956	23743	11	0
6PM-7PM	209	574	18093	19090	18876	13	0
7PM-8PM	257	664	17104	18244	18025	14	0
8PM-9PM	325	750	16734	17869	17809	19	2
9PM-10PM	366	1202	13521	15092	15089	19	6
10PM-11PM	380	529	8365	9277	9274	19	8
11PM-12AM	362	261	4593	5218	5216	18	10
	2282	**5627**	**147356**	**156212**	**155265**		

TSF @ 60 Seconds: 98.2%

Rep Ans – Representative Answered,
Inhse VRU – In house Voice Response Unit,
HVCA – High Volume Call Answering System

Severe Weather July 26, 2010 Telephone Interval Report							
Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	225	130	2351	2708	2706	15	11
1AM - 2AM	139	70	1373	1582	1582	15	11
2AM - 3AM	90	72	1067	1229	1229	15	11
3AM - 4AM	90	42	945	1077	1077	15	11
4AM - 5AM	82	53	1044	1179	1179	15	12
5AM-6AM	134	115	2231	2480	2480	14	12
6AM - 7AM	297	470	5115	5884	5882	14	12
7AM - 8AM	755	1345	5223	7681	7323	20	22
8AM - 9AM	1976	1666	4374	8100	8016	46	48
9AM - 10AM	2032	778	3647	6518	6457	63	76
10AM - 11AM	2554	2653	2979	3033	2880	66	88
11AM - 12PM	3597	2042	2587	4279	4142	68	95
12PM - 1PM	2597	901	2320	5938	5818	63	92
1PM - 2PM	2057	947	2733	5884	5737	67	83
2PM - 3PM	2410	939	2769	6242	6118	67	94
3PM - 4PM	2661	980	2676	6412	6317	67	100
4PM - 5PM	2724	884	2582	6280	6190	65	103
5PM - 6PM	2555	680	2494	5815	5729	62	111
6PM-7PM	2446	536	1630	4667	4612	57	111
7PM-8PM	1593	396	1700	3725	3689	43	29
8PM-9PM	718	267	1880	2870	2865	13	25
9PM-10PM	514	188	2025	2728	2727	3	23
10PM-11PM	462	131	1197	1798	1790	2	16
11PM-12AM	328	100	429	860	857	2	16
	33036	**6995**	**57371**	**98969**	**97402**		
			TSF @ 60 Seconds: 90.5%				

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather
July 27, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	136	31	216	392	383	5	14
1AM - 2AM	94	12	142	251	248	5	15
2AM - 3AM	74	15	98	188	187	5	15
3AM - 4AM	69	6	108	190	183	5	16
4AM - 5AM	87	23	133	245	243	5	16
5AM-6AM	183	30	322	540	535	5	16
6AM - 7AM	426	115	779	1322	1320	5	18
7AM - 8AM	995	331	1163	2581	2489	16	50
8AM - 9AM	2069	633	812	3540	3514	42	84
9AM - 10AM	2617	776	291	3747	3684	61	101
10AM - 11AM	1846	811	903	3633	3560	63	112
11AM - 12PM	2468	769	120	3481	3357	67	111
12PM - 1PM	2362	848	31	3333	3241	73	105
1PM - 2PM	2028	725	71	2890	2824	73	100
2PM - 3PM	2351	663	1049	4147	4063	74	112
3PM - 4PM	1928	805	9063	12059	11796	74	114
4PM - 5PM	1737	794	5271	7851	7802	71	115
5PM - 6PM	2512	516	2712	5778	5740	66	117
6PM-7PM	2657	417	1791	4931	4865	62	118
7PM-8PM	1687	318	674	2697	2679	47	28
8PM-9PM	997	164	610	1773	1771	16	27
9PM-10PM	618	153	979	1750	1750	6	21
10PM-11PM	550	111	729	1393	1390	5	20
11PM-12AM	528	80	950	1561	1558	5	19
	31019	**9146**	**29017**	**70273**	**69182**		

TSF @ 60 Seconds: 90.9%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather
July 28, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	291	31	148	478	470	5	18
1AM - 2AM	93	12	70	183	175	5	20
2AM - 3AM	79	11	29	125	119	5	19
3AM - 4AM	67	14	36	122	117	5	21
4AM - 5AM	65	20	49	142	134	5	22
5AM-6AM	183	30	110	326	323	5	20
6AM - 7AM	488	89	397	980	974	5	22
7AM - 8AM	836	238	515	1611	1589	17	49
8AM - 9AM	1577	541	578	2716	2696	42	87
9AM - 10AM	1602	712	480	2814	2794	61	98
10AM - 11AM	1438	682	384	2528	2504	60	110
11AM - 12PM	1230	603	313	2188	2146	70	102
12PM - 1PM	1315	600	147	2118	2062	71	94
1PM - 2PM	1221	568	75	1924	1864	72	87
2PM - 3PM	1475	600	0	2103	2075	74	103
3PM - 4PM	1626	579	0	2227	2205	73	108
4PM - 5PM	1618	591	1	2226	2210	72	108
5PM - 6PM	1155	420	0	1591	1575	65	109
6PM-7PM	956	302	0	1285	1258	62	101
7PM-8PM	745	243	0	993	988	46	15
8PM-9PM	628	138	0	774	766	17	16
9PM-10PM	448	134	0	588	582	5	16
10PM-11PM	341	71	0	417	412	5	16
11PM-12AM	315	75	0	393	390	5	17
	19792	**7304**	**3332**	**30852**	**30428**		

TSF @ 60 Seconds: 94.4%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather
July 29, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	110	46	0	162	156	4	16
1AM - 2AM	104	18	0	126	122	4	17
2AM - 3AM	24	8	0	35	32	4	18
3AM - 4AM	38	12	0	58	50	4	18
4AM - 5AM	42	11	0	55	53	4	19
5AM-6AM	96	22	0	123	118	4	18
6AM - 7AM	363	62	0	430	425	4	18
7AM - 8AM	820	236	0	1070	1056	18	59
8AM - 9AM	908	424	0	1339	1332	47	90
9AM - 10AM	1026	567	0	1601	1593	62	99
10AM - 11AM	997	641	0	1653	1638	64	104
11AM - 12PM	1333	631	0	1971	1964	75	97
12PM - 1PM	1233	594	0	1851	1827	78	89
1PM - 2PM	1460	537	1084	3146	3081	79	90
2PM - 3PM	1559	542	839	2961	2940	80	94
3PM - 4PM	1920	731	349	3033	3000	80	97
4PM - 5PM	1642	728	13	2409	2383	75	108
5PM - 6PM	1277	562	0	1859	1839	67	106
6PM-7PM	1148	452	0	1616	1600	63	98
7PM-8PM	1328	368	0	1710	1696	49	24
8PM-9PM	837	149	0	989	986	17	17
9PM-10PM	467	99	0	567	566	7	16
10PM-11PM	302	118	0	422	420	6	16
11PM-12AM	184	81	0	270	265	5	15
	19218	**7639**	**2285**	**29456**	**29142**		

TSF @ 60 Seconds: 87.8%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather
July 30, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	316	67	0	386	383	4	15
1AM - 2AM	44	24	0	71	68	4	16
2AM - 3AM	27	13	0	41	40	4	17
3AM - 4AM	12	12	0	25	24	4	16
4AM - 5AM	26	14	0	40	40	4	18
5AM-6AM	26	40	0	66	66	4	18
6AM - 7AM	131	112	0	246	243	4	18
7AM - 8AM	311	310	0	731	621	13	43
8AM - 9AM	685	638	0	1490	1323	42	76
9AM - 10AM	998	933	0	2060	1931	60	86
10AM - 11AM	924	818	0	1836	1742	61	89
11AM - 12PM	897	1000	0	2106	1897	70	39
12PM - 1PM	587	907	0	1743	1494	72	1
1PM - 2PM	505	840	0	1605	1345	73	0
2PM - 3PM	515	876	0	1674	1391	74	0
3PM - 4PM	948	912	0	2084	1860	46	0
4PM - 5PM	1030	717	0	1811	1747	74	0
5PM - 6PM	493	650	119	1605	1262	68	0
6PM-7PM	481	611	71	1355	1163	64	0
7PM-8PM	353	443	72	1001	868	47	0
8PM-9PM	140	234	13	408	387	16	0
9PM-10PM	46	76	0	122	122	6	0
10PM-11PM	32	72	0	104	104	6	0
11PM-12AM	33	43	0	76	76	5	0
	9560	**10362**	**275**	**22686**	**20197**		

TSF @ 60 Seconds: 71.0%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather July 31, 2010 Telephone Interval Report							
Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming , Calls	Total Ans Calls	Staff	Mutual Assist Staff
12AM - 1AM	14	42	0	56	56	2	0
	14	**42**	**0**	**56**	**56**		
			TSF @ 60 Seconds: 100.0%				

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Storm Damage Information

10. System Damage

a) Poles Replaced 90

b) Distribution Transformers Replaced 135

c) Fuses Replaced 5,874

d) Downed Wires Reported 1,953

e) Substation with Equipment Damage 10

11. Materials

Material inventories were closely monitored to ensure the availability of necessary equipment and materials for restoration activities across the Pepco service territory. Necessary equipment was available for restoration efforts.

12. Self Assessment

Each major storm impacting the Pepco service territory is different, bringing unique system restoration challenges. The severe thunderstorm and wind event of July 25 was no exception. The greatest impediment faced by Pepco in responding to the event was the fact that the thunderstorm struck the service territory less than an hour after the weather service issued a warning, effectively depriving Pepco of the opportunity to engage in advanced planning to bring large numbers of outside resources to the Pepco service territory. Notwithstanding this lack of advance notice, however, Pepco mobilized quickly: additional company and contract crews were on duty within three hours; outside mutual assistance resources began arriving within 16 hours; and a remote staging area was operational within 21 hours. Additional areas of improvement identified by Pepco include: vegetation management practices; communications technology (including outage map access, dissemination of estimated times of restoration information, and automated call back capability); wires down process; and damage assessment process. Nevertheless, in spite of the improvement areas noted above, Pepco was able to restore power to approximately 90% of its customers (system-wide) within 72 hours of the event.

Pepco's response processes included damage assessment, requests for mutual assistance within two and a half hours of the storm entering Pepco's service territory, a staging site established within 21 hours, logistics, call center operations, planning and analysis, prioritization, safety, coordination with Emergency Operations Centers in two jurisdictions and implementation of customer communications processes, including the establishment of the Joint Information Center.

The following lessons learned and opportunities for improvement have been noted:

Vegetation Management Issues

Washington, DC is the fourth highest ranked major metropolitan city in tree cover density percentage behind Charlotte, NC, Portland, OR and Atlanta, GA (see Appendix). In addition, the Pepco service territory features areas with some of the highest percentage of land mass with vegetation coverage in the region. During this event, the majority of outages occurred in areas with significant tree cover and wind speeds of over 60 mph and were caused by entire trees and limbs falling on infrastructure. Under these extreme circumstances, maintenance tree trimming would not have mitigated this issue. Pepco will continue to collaborate with local governments and leaders to seek ways to address vegetation management challenges in all service territories.

Wires Down Process Issues

Pepco takes customer calls reporting wire down cases seriously and follows a pre-defined process to protect public safety and ensure that electric wires that have fallen on the ground are secure. In the aftermath of July 25 event, Pepco had 1,953 wire-down locations, forcing the company to prioritize deployment of its resources to inspect the lines in the field and secure them. Another challenge in addressing wire down reports is that a large portion of reported wires down do not involve electric lines but telecommunication or other utility wires. Because of the serious threat to public safety that downed wires provide, Pepco has to send crews to all reported locations, which may include telecommunications or cable lines, increasing the workload during the restoration effort. Pepco had identified this issue following the February snow storms, and the issue is being examined in ongoing Commission Docket PC-21.

Communication and Technology

Website/Outage Maps Issues

During the event, customers had issues accessing and obtaining accurate outage maps through the Pepco website. These issues were caused by a larger than anticipated number of customers attempting to access the outage maps via the internet, which caused them to be unresponsive. Pepco Information Technology staff are currently working with Customer Care personnel to estimate future web site volumes and upgrade systems and software as appropriate.

Estimated Time of Restoration Issues

During the event, customers experienced several communications issues that caused customer consternation and frustration. More specifically, when customers initially reported outages, some received estimated times of restoration (ETR) that extended to mid-September. These preliminary automated ETRs reflected an unusually high number of outages in a very short time span, matched against a limited number of restoration personnel who were actually on the system at that time. They did not reflect the large numbers of restoration personnel who would be working on the system in the coming hours and days. Therefore, the preliminary ETRs were not useful to customers and were subsequently suppressed until the additional resources were reflected on the system.

In addition, ETRs did not appear in a timely manner to 21st Century and Customer Service Representatives. This backlog was due to the simultaneous occurrence of a large number of outage events. Pepco has now implemented a process that will provide for a sufficient time gap between ETR population and announcing ETR availability to customers.

Details

1. External outage maps were not responsive to external requests due to the volume of people attempting to access.

   Capacity of the outage maps infrastructure to handle the demand was not adequate. In the interim, moved another application to a separate firewall to relieve congestion. For the long term, an evaluation is underway on future volume and process.

2. Estimated Time of Restorations (ETRs) for all outage events not automatically populating correctly.

   A program to populate customer ETRs by tiers was not automatically populating correctly. In the interim, the ETRs were manually adjusted. For the long term, a fix was delivered from the vendor, tested and installed on August 5, 2010.

3. Populated ETRs not available to customers in at timely manner (i.e. instantaneous).

   It took time to process the ETR data from the OMS through a gateway to customer facing systems because of the volume of data to be pushed through in a short time frame. In the interim, data was available to specific customers as their specific ETR was processed in the queue. For the long term, an evaluation is underway on future volume and process.

Interruption Causes

13. Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	138,311	4,045,366
b) Equipment Failures	5,903	245,802
c) Lightning Damage	105,816	1,914,734
d) Weather - Ice	0	0
e) Weather Related Damage (Other than Lightning)	153,802	3,176,281
f) Other Major Causes*	33,609	896,584
	437,441	10,278,767

*Includes Source Lost, Foreign Contact, Unknown, etc.

APPENDIX

APPENDIX

MAJOR CITY TREE COVER

Research as of 8 Aug 2010 (Latest study was Charlotte, NC - April 2010) City	Tree Cover	Population
Charlotte	46.00%	709,441
Portland	42.00%	550,396
Atlanta	32.90%	519,145
Washington	**31.10%**	**588,292**
Detroit	31.00%	925,051
Houston	28.40%	2,208,180
Dallas	28.00%	1,240,499
Minneapolis	26.40%	377,392
Denver	26.00%	588,349
Seattle	22.90%	563,374
Milwaukee	21.60%	590,895
Baltimore	21.50%	637,455
Boston	21.20%	599,351
Oakland	21.00%	401,489
Milwaukee	19.10%	602,191
New York	16.60%	8,274,527
Philadelphia	15.70%	1,449,634
Tucson	13.70%	525,529
San Francisco	11.90%	764,976
Chicago	11.00%	2,836,658
Tampa	9.60%	336,823
San Diego	8.60%	1,266,731

References

Nowak, David J.; Hoehn, Robert E. III; Crane, Daniel E.; Stevens, Jack C.; Walton, Jeffrey T. 2006. Assessing urban forest effects and values, Washington, D.C.'s urban forest. Assessing urban forest effects and values, Washington, D.C.'s urban forest. Resour. Bull. NRS-1. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northern Research Station. 24 p.

Nowak, David J.; Crane, Daniel E.; Stevens, Jack C. 2006. Air pollution removal by urban trees and shrubs in the United States. Urban Forestry and Urban Greening 4:115-123

Nowak, David J.; Hoehn, Robert E., III; Crane, Daniel E.; Stevens, Jack C.; Walton, Jeffrey T. 2007. Assessing urban forest effects and values, New York City's urban forest

Nowak, David J.; Hoehn, Robert E., III; Crane, Daniel E.; Stevens, Jack C.; Walton, Jeffrey T. 2007. Assessing urban forest effects and values, Philadelphia's urban forest

Nowak, David J.; Hoehn, Robert E., III; Crane, Daniel E.; Stevens, Jack C.; Walton, Jeffrey T. 2007. Assessing urban forest effects and values, San Francisco's urban forest

Urban Ecosystem Analysis SE Michigan and City of Detroit, May 2006 (http://www.americanforests.org/downloads/rea/AF_Detroit.pdf)

i-Tree Ecosystem Analysis Milwaukee Urban Forest Effects and Values September 2008 (http://www.itreetools.org/resources/reports/Milwaukee%20Ecosystem%20Analysis.pdf)

pepco

A PHI Company

William F. O'Brien
Assistant General Counsel

89KS42
800 King Street
Wilmington, DE 19801

PO Box 231
Wilmington, DE 19899-0231
302-429-3143
302-429-3801 Fax
bill.obrien@pepcoholdings.com

August 30, 2010

Terry J. Romine, Esq.
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: Case No. 9240

Dear Ms. Romine:

In accordance with COMAR 20.50.07.07, and for filing in Case No. 9240, please find enclosed an original and seventeen copies of Potomac Electric Power Company's Major Storm Report, which relates to the August 5, 2010 storm event.

Please contact me if you should have any questions.

Sincerely,

William F. O'Brien

pepco

A PHI Company

State of Maryland
Major Storm Report
August 5 - 7, 2010: Severe Thunderstorm

Prepared By: **Potomac Electric Power Company**

701 Ninth St. NW

Washington, DC 20068-0001

August 30, 2010

Foreword

A major service outage occurred in Pepco's service territory on August 5, 2010, following a severe, fast moving storm which interrupted power to over 76,000 customers, including 73,193 Maryland customers at peak. Full service was restored to customers in Maryland on August 7, 2010. Pursuant to COMAR 20.50.07.07, Pepco is required to file with the Maryland Public Service Commission (Commission), a written report within three weeks following the end of a major storm detailing the event's impact on Pepco's electric system and the associated system restoration efforts. Pepco's report on the effects of the August 5 storm and Pepco's restoration efforts are provided herein.

Table of Contents

Executive Summary

On August 5, 2010, a cluster of severe thunderstorms moved through the Pepco system during the start of the afternoon rush hour commute of August 5, 2010. According to the National Weather Service (NWS), the first severe thunderstorm warning for the Pepco territory was issued at 3:28 PM. The storm entered Pepco territory about 3:30 PM. A Tornado Warning was issued at 4:18 PM for Prince George's County, just southeast of Upper Marlboro, Maryland. Winds were reported in excess 60 mph. The severe thunderstorms caused outages to 76,729 customers at peak system-wide. Of these, 71,116 were in Prince George's County, 2,077 were in Montgomery County and 3,536 were in the District of Columbia.

At the height of the storm, approximately 76,729 customers system-wide were affected by power outages at 4:00 PM on August 5, 2010. Pepco's Maryland service territory experienced peak of 73,193 customers interrupted at 4:00 PM the same day as well. On a system-wide basis, a total of 78 distribution circuit lock-outs were experienced, four substations experienced a sustained outage and more than 270 reports of "wires down" were received. This event resulted in damage to Pepco's electric distribution system, primarily in Prince George's County.

Approximately 90% of Pepco's customers (system-wide) were restored within 24 hours of the event. All remaining Maryland customers affected by the storm were restored by 5:07 PM on August 7, 2010.

Customers Affected

1. Event

The weather event occurred on August 5 and was attributed to severe thunderstorms which caused a large number of power outages in the Pepco service territory.

On August 5 at 3:30 PM, Pepco declared a storm event in its service territory. On August 5 at 10:00 PM, the storm event declaration was terminated. Pepco's service restoration efforts began at the onset of the storm and lasted until 5:07 PM on August 7.

Storm on system:	3:30 PM, August 5, 2010
Storm off system:	10:00 PM, August 5, 2010

2. Major Storm Restoration

5:07 PM on August 7, 2010

3. Number of Customers Affected

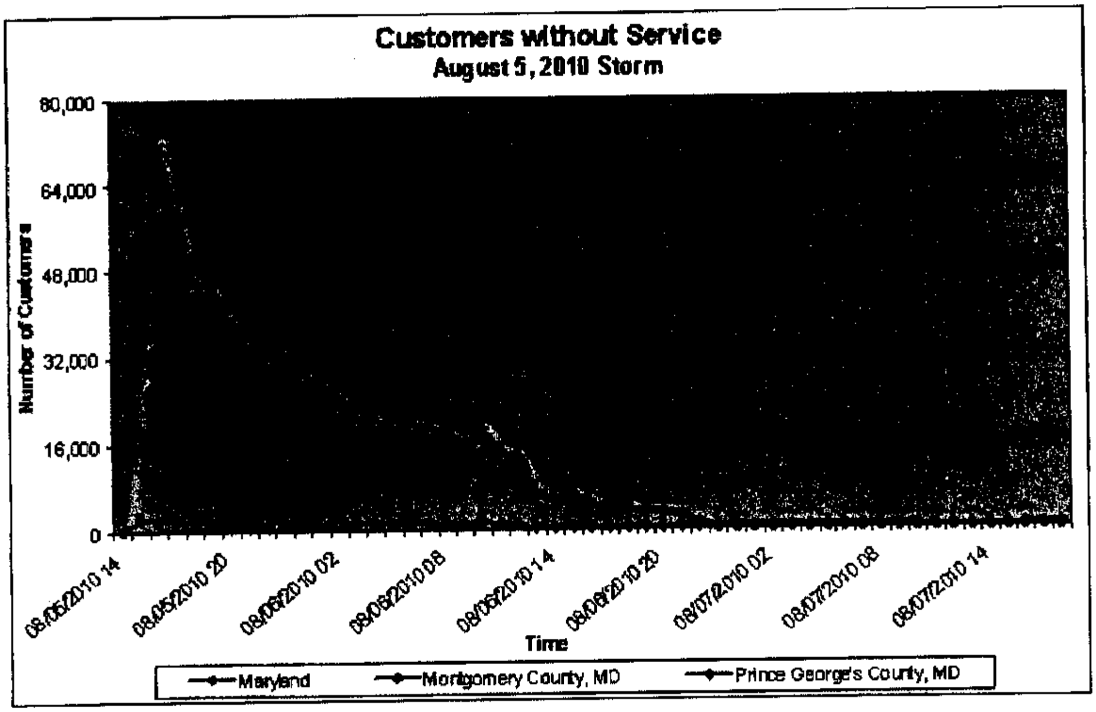
Peak System wide

76,729 at 1600 hours on August 5, 2010

Peak State of Maryland

73,193 at 1600 hours on August 5, 2010

4. Sustained Interruptions



Customers Experiencing a Sustained Interruption Recorded at Six-Hour Intervals from Storm's Onset

Time	Pepco System	Maryland	Montgomery County, MD	Prince George's County, MD
08/05/2010 14	522	520	519	1
08/05/2010 16	76,729	73,193	2,077	71,116
08/05/2010 22	35,573	31,830	879	30,951
08/06/2010 04	22,567	20,314	1,162	19,152
08/06/2010 10	19,021	18,571	1,621	16,950
08/06/2010 16	5,336	4,900	546	4,354
08/06/2010 22	1,253	1,150	574	576
08/07/2010 04	632	618	532	86
08/07/2010 10	603	589	504	85
08/07/2010 16	675	569	503	66
08/07/2010 18	-	-	-	-

Total Customers Out at Peak (at end of hour, not minute based)
Last customer restored as the result of the event occurred at 5:07 PM on August 7.

5. Customer Interruption Hours

Customer Interruption Hours - System	738,582
Customer Interruption Hours - Maryland	685,741
Customer Interruption Hours - Montgomery County	26,888
Customer Interruption Hours - Prince George's County	658,853

EXTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

6. Outside Assistance Contacts

Mutual Assistance communications commenced at 5:53 PM on August 5. A total of 70 personnel were requested by 7:30 PM on August 5. Also, Pepco requested augmentation of its sustaining contractor workforce. Below is a listing of the dates, times and organizations communicated with regarding Mutual Assistance.

DATE	TIME	GROUP
8/5/2010	1753	Mid-Atlantic Mutual Assistance Communication [MAMA]
8/5/2010	1753	Maryland Mutual Assistance Group Communication [MMAG]
8/5/2010	2100	Requested for 50 line Full Time Equivalents (FTEs) MAMA
8/5/2010	2130	Requested for 20 service FTEs MMAG

7. Outside Assistance Resources

Resources

7. a) Organization(s) Providing Crews

- East Coast UG
- Area Utilities
- Utility Lines – Delaware
- Utility Lines – Baltimore Gas & Electric (BG&E)
- Tri-M Construction
- Southern Maryland Electric Cooperative (SMECO)
- Davis H Elliott
- Pike Electric
- CW Wright (SMECO)
- CW Wright
- Rockingham
- Utility Lines
- Asplundh (Tree Trimming)

7. b) Date and Time of Crew Arrivals and Departures

Mutual Assistance

Organization Providing Crews	Arrived	Number of Personnel	Departed
East Coast	August 5 2100 hours	20 People	August 7 0800 hours
Area Utilities	August 5 2100 hours	13 People	August 7 0800 hours
Utility Lines (Delaware)	August 5 2100 hours	14 People	August 7 0800 hours
Utility Lines (BG&E)	August 5 2100 hours	17 People	August 7 0800 hours
Tri-M Construction	August 5 2100 hours	10 People	August 7 0800 hours
Southern Maryland Electric Cooperative (SMECO)	August 7 0900 hours	14 People	August 7 2000 hours
Davis H Elliott	August 5 2100 hours	32 People	August 7 0800 hours
Pike Electric	August 5 2100 hours	17 People	August 7 0800 hours
CW Wright (SMECO)	August 7 0900 hours	9 People	August 7 2000 hours

Pepco Contractors

Organization Providing Crews	Number of Personnel
CW Wright	17 People
Rockingham	27 People
Utility Lines	16 People
Asplundh (Tree Trimming)	99 People

Other Pepco Holdings, Inc. (PHI) Utility Personnel

Organization Providing Crews	Number of Personnel
Delmarva Power and Atlantic City Electric	12 People

7. c) Number and Type of Vehicles - 97

- 56 Bucket Trucks
- 13 Digger Derricks
- 28 Miscellaneous Vehicles [Pick-ups, other trucks, etc]

7. d) Total Number of External Personnel – 317

- 317 Personnel

Deployment

7. e) Primary Overhead Line Personnel

- 210 Personnel

7. f) Secondary Overhead Line Personnel

- 8 Personnel

7. g) Tree Trimming Personnel / Other Support Personnel

- 99 Personnel

7. h) Primary Underground Line Crews

- Not Applicable (NA)

7. i) Secondary Underground Line Crews

- NA

7. j) Substation Crews

- NA

7. k) Other Personnel

- NA

Electric Utility Resources

INTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

8. Electric Utility Crews

Resources

8. a) Number and Type of Vehicles - 214

- 94 Bucket Trucks
- 13 Digger Derricks

- 107 Miscellaneous Vehicles [Pick-ups, other trucks, etc.]

8. b) Total Number of Internal Personnel - 218

- 218 Personnel

Deployment

8. c) Primary Overhead Line Personnel

- 107 Personnel

8. d) Secondary Overhead Line Personnel

- NA

8. e) Damage Assessment Personnel

- 5 Personnel performed field damage assessments

8. f) Tree Trimming Personnel

- 4 Personnel coordinating and supervising tree trimming crews

8. g) Primary Underground Line Crews

- NA

8. h) Secondary Underground Line Crews

- NA

8. i) Substation Personnel

- 20 Personnel

8. j) Other Personnel

- 82 Other Support Personnel

Communications

General

Pepco maintains positive relationships with state, county and/or local Emergency Management Agencies (EMA) through the PHI Emergency Management Department.

Emergency Management is responsible for providing state, county and/or local EMA personnel with "one point of contact" for addressing operational and community support requests. During major events, a Pepco EMA Liaison is assigned to the Montgomery County EMA. However, since the EMA was not activated, no Pepco personnel were assigned.

All 911 Centers and EMA in Pepco's service territory have a direct dial line communications radio that is supplied courtesy of the utility and can be used to communicate with each utility in the event of a communications emergency.

GOVERNMENT AFFAIRS CONTACTS

Over the course of the storm, the President of Pepco Region held several television interviews. In addition, Pepco

- distributed news release via email to government officials, community leaders and business leaders;
- processed inquiries from elected officials regarding outage issues called to their attention by constituents;
- worked closely with government officials to identify restoration priorities; and

REGULATORY COMMUNICATIONS

- provided storm statistics to Maryland Public Service Commission Staff.

MEDIA COMMUNICATIONS

During the restoration period for the August 5 storm, Pepco issued one news release and conducted over 30 media interviews/updates. Social media was also utilized including PepcoConnect's Blog, Twitter and Facebook.

9. Customer Operations Statistics

Severe Weather
August 5, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	AUX Staff
330PM - 4PM	292	223	402	979	917	60	0
4PM - 5PM	1086	1291	6235	8860	8612	59	4
5PM - 6PM	1258	985	4525	6771	6768	59	8
6PM-7PM	940	748	3639	5336	5327	35	8
7PM-8PM	770	673	3322	4777	4765	18	7
8PM-9PM	427	444	3335	4209	4206	12	2
9PM-10PM	283	294	2551	3128	3128	12	1
10PM-11PM	241	192	1387	1820	1820	12	0
11PM-12AM	228	122	888	1238	1238	12	0
	5525	**4972**	**26284**	**37118**	**36781**		

TSF @ 60 Seconds: 95.6%

Rep Ans – Representative Answered,
Inhse VRU – In house Voice Response Unit,
HVCA – High Volume Call Answering System

Severe Weather
August 6, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	AUX Staff
12AM - 1AM	148	92	797	1038	1037	6	0
1AM - 2AM	86	48	408	542	542	6	0
2AM - 3AM	38	24	267	329	329	6	0
3AM - 4AM	44	19	174	237	237	6	0
4AM - 5AM	45	17	264	326	326	6	0
5AM-6AM	78	45	457	580	580	6	0
6AM - 7AM	125	165	899	1189	1189	6	0
7AM - 8AM	199	389	995	1653	1583	13	0
8AM - 9AM	651	578	895	2172	2124	41	0
9AM - 10AM	725	761	772	2262	2258	54	0
10AM - 11AM	636	655	873	2253	2164	56	0
11AM - 12PM	706	662	704	2161	2072	67	0
12PM - 1PM	612	558	508	1735	1678	69	0
1PM - 2PM	473	532	462	1613	1467	68	0
2PM - 3PM	559	564	393	1630	1516	68	0
3PM - 4PM	570	479	494	1704	1543	68	0
4PM - 5PM	554	463	418	1821	1435	60	2
5PM - 6PM	374	387	314	1237	1075	35	4
6PM-7PM	259	308	262	910	829	21	4
7PM-8PM	181	207	209	647	597	16	2
8PM-9PM	60	93	216	372	369	7	0
9PM-10PM	17	129	400	546	546	6	0
10PM-11PM	22	68	234	324	324	6	0
11PM-12AM	9	39	95	143	143	6	0
	7171	**7282**	**11510**	**27424**	**25963**		

TSF @ 60 Seconds: 77.8%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather
August 7, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	AUX Staff
12AM - 1AM	8	25	28	61	61	4	0
1AM - 2AM	2	16	13	31	31	4	0
2AM - 3AM	0	6	12	18	18	4	0
3AM - 4AM	1	6	3	10	10	4	0
4AM - 5AM	0	5	8	13	13	4	0
5AM-6AM	1	4	10	15	15	4	0
6AM - 7AM	5	28	24	57	57	4	0
7AM - 8AM	34	76	24	138	134	3	0
8AM - 9AM	56	122	42	229	220	3	0
9AM - 10AM	56	124	18	221	198	3	0
10AM - 11AM	92	156	19	286	267	3	0
11AM - 12PM	56	154	20	273	230	3	0
12PM - 1PM	92	160	26	288	278	5	0
1PM - 2PM	91	134	11	237	236	6	0
2PM - 3PM	64	145	11	222	220	6	0
3PM - 4PM	61	106	12	182	179	6	0
4PM - 5PM	47	80	22	152	149	3	0
5PM - 6PM	29	39	16	86	84	3	0
	695	**1386**	**319**	**2519**	**2400**		

TSF @ 60 Seconds: 90.0%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Storm Damage Information

10. System Damage

a) Poles Replaced 5

b) Distribution Transformers Replaced 13

c) Fuses Replaced 879

d) Downed Wires Reported 272

e) Substation with Equipment Damage 4

11. Materials

Material inventories were closely monitored to ensure the availability of necessary equipment and materials for restoration activities across the Pepco service territory. Necessary equipment was available for restoration efforts.

Self Assessment

12. Self Assessment

Each major storm impacting the Pepco service territory is different, bringing unique system restoration challenges. The severe thunderstorms of August 5 were no exception. Pepco was able to restore power to approximately 90% of its customers (system-wide) within 24 hours of the event. Pepco's response processes included damage assessment, requests for mutual assistance within three and a half hours of the storm entering Pepco's service territory, call center operations, prioritization, safety and implementation of customer communications processes.

In addition, the Information Technology (IT) restoration systems such as the Outage Management (OMS) and Mobile Dispatch System (MDS) performed as designed and there were no software or hardware issues. Hence, the IT restoration systems performed as designed.

The following lessons learned and opportunities for improvement have been noted:

<u>Wires Down Process Issues</u>

Pepco takes customer calls reporting wire down cases seriously and follows a pre-defined process to protect public safety and ensure that electric wires that have fallen on the ground are secure. In the aftermath of August 5 event, Pepco had 272 wire-down locations, forcing the company to prioritize deployment of its resources to inspect the lines in the field and secure them. Another challenge in addressing wire down reports is that a large portion of reported wires down do not involve electric lines but telecommunication or other utility wires. Because of the serious threat to public safety that downed wires provide, Pepco has to send crews to all reported locations, which may include telecommunications or cable lines, increasing the workload during the restoration effort. Pepco had identified this issue following the February snow storms, and the issue is being examined in ongoing Commission Docket PC-21.

Damage Assessment

Enhance our training for our Damage Assessment Patrollers to include the use of Mobile Data Terminal so damage information can be entered directly into the Outage Management System.

Interruption Causes

13. Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	24,807	212,519
b) Equipment Failures	1,527	9,198
c) Lightning Damage	15,587	85,918
d) Weather - Ice	0	0
e) Weather Related Damage (Other than Lightning)	45,781	283,020
f) Source Lost	22,271	46,876
g) Other Major Causes*	8,945	48,210
	118,918	685,741

*Includes Foreign Contact, Unknown, etc.

Exhibit__(PJL-12)

pepco

A PHI Company

William F. O'Brien
Assistant General Counsel

89KS42
800 King Street
Wilmington, DE 19801

PO Box 231
Wilmington, DE 19899-0231
302-429-3143
302-429-3801 Fax
bill.obrien@pepcoholdings.com

September 7, 2010

Terry J. Romine, Esq.
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: <u>Case No. 9240</u>

Dear Ms. Romine:

In accordance with COMAR 20.50.07.07, and for filing in Case No. 9240, please find enclosed an original and seventeen copies of Potomac Electric Power Company's Major Storm Report, which relates to the August 12, 2010 storm event.

Please contact me if you should have any questions.

Sincerely,

William F. O'Brien

pepco

A PHI Company

State of Maryland
Major Storm Report
August 12 - 15, 2010: Severe Thunderstorm

Prepared By: **Potomac Electric Power Company**

701 Ninth St. NW

Washington, DC 20068-0001

September 7, 2010

Foreword

A major service outage occurred in Pepco's service territory on August 12, 2010, following a severe thunderstorm which interrupted power to over 101,000 customers, including 87,219 Maryland customers at peak. Full service was restored to customers in Maryland on August 15, 2010. Pursuant to COMAR 20.50.07.07, Pepco is required to file with the Maryland Public Service Commission (Commission), a written report within three weeks following the end of a major storm detailing the event's impact on Pepco's electric system and the associated system restoration efforts. Pepco's report on the effects of the August 12 storm and Pepco's restoration efforts are provided herein.

Table of Contents

Executive Summary

On August 12, 2010, a severe thunderstorm moved through the Pepco system during the morning rush hour commute of August 12, 2010. According to the National Weather Service, the first severe thunderstorm warning for the Pepco territory was issued at 0628 hours. The storm entered Pepco territory at approximately 0645 hours. Winds were reported in excess of 60 mph. In addition, a Flash Flood Warning was issued at 0645 hours and up to four inches of rain fell in locations within Pepco's service territory. The severe thunderstorm caused outages to 101,003 customers at peak system-wide, which occurred at 0800 hours. Of these, 77,445 were in Montgomery County, 9,774 were in Prince George's County and 13,784 were in the District of Columbia. Pepco's Maryland service territory experienced peak of 87,219 customers interrupted at 0800 hours the same day as well.

This event resulted in significant damage to Pepco's electric distribution system. On a system-wide basis, a total of 282 distribution circuit lock-outs were experienced, four substations experienced a sustained outage and more than 930 reports of "wires down" were received.

Approximately 90% of Pepco's customers (system-wide) were restored within 36 hours of the event. All remaining Maryland customers affected by the storm were restored by 1600 hours on August 15, 2010.

Customers Affected

1. Event

The weather event occurred on August 12 and was attributed to severe thunderstorms which caused a large number of power outages in the Pepco service territory.

On August 12 at 0645 hours, Pepco declared a storm event in its service territory. On August 12 at 2100 hours, the storm event declaration was terminated. Pepco's service restoration efforts began at the onset of the storm and lasted until 1600 hours on August 15.

Storm on system: 0645 hours, August 12, 2010

Storm off system: 2100 hours, August 12, 2010

2. Major Storm Restoration

1600 hours on August 15, 2010

3. Number of Customers Affected

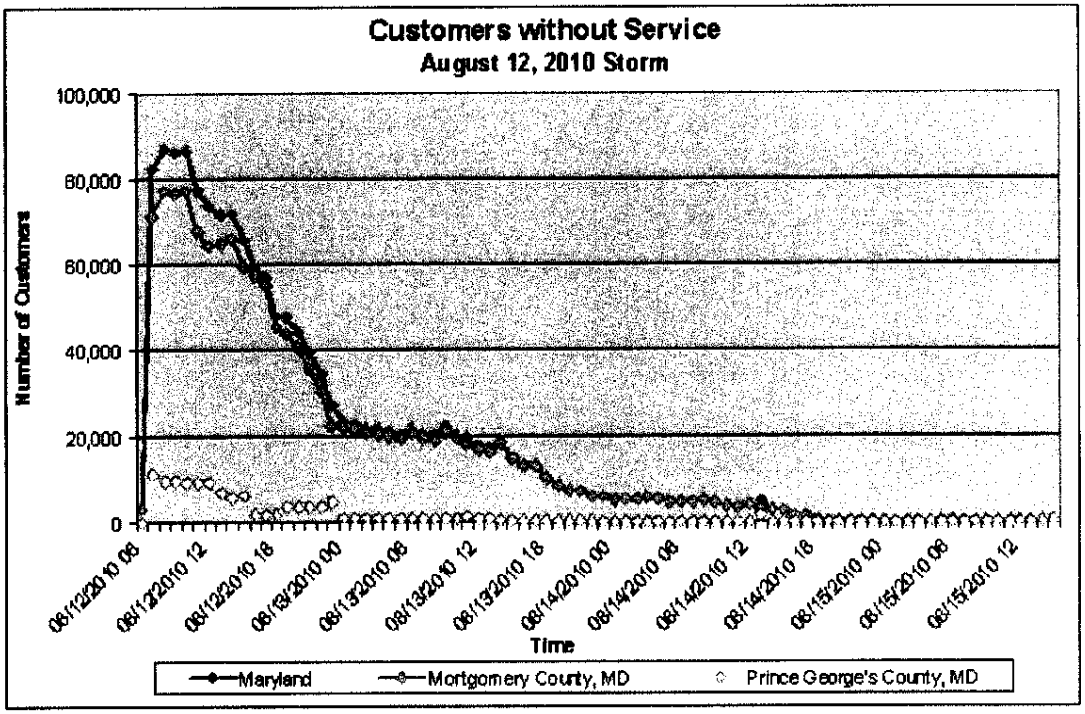
Peak System wide

101,003 at 0800 hours on August 12, 2010

Peak State of Maryland

87,219 at 0800 hours on August 12, 2010

4. Sustained Interruptions



Customers Experiencing a Sustained Interruption Recorded at Six-Hour Intervals from Storm's Onset

Time	Pepco System	Maryland	Montgomery County, MD	Prince George's County, MD
08/12/2010 04	775	662	661	1
08/12/2010 10	99,509	86,846	77,426	9,420
08/12/2010 16	68,076	59,232	57,324	1,908
08/12/2010 22	40,293	34,159	30,676	3,483
08/13/2010 04	23,942	21,293	20,479	814
08/13/2010 10	23,358	20,590	19,725	865
08/13/2010 16	14,884	13,511	13,282	229
08/13/2010 22	7,396	6,483	6,381	102
08/14/2010 04	5,912	5,770	5,726	44
08/14/2010 10	4,322	4,187	4,163	24
08/14/2010 16	1,795	1,746	1,725	21
08/14/2010 22	367	358	354	4
08/15/2010 04	101	95	94	1
08/15/2010 10	121	118	116	2
08/15/2010 16	-	-	-	-

Total Customers Out at Peak (at end of hour, not minute based)

Last customer restored as the result of the event occurred at 1600 hours on August 15.

5. Customer Interruption Hours

Customer Interruption Hours - System	1,788,683
Customer Interruption Hours - Maryland	1,553,363
Customer Interruption Hours - Montgomery County	1,437,293
Customer Interruption Hours - Prince George's County	116,070

Outside Assistance Resources

EXTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

6. Outside Assistance Contacts

Mutual Assistance communications commenced at 0832 hours on August 12. A total of 250 personnel were requested by 1000 hours on August 12. Also, Pepco requested augmentation of its sustaining contractor workforce. Below is a listing of the dates, times and organizations communicated with regarding Mutual Assistance.

DATE	TIME	GROUP
8/12/2010	0832	Mid-Atlantic Mutual Assistance Communication [MAMA]
8/12/2010	1000	Requested for 250 line Full Time Equivalents (FTEs) MAMA
8/12/2010	1500	MAMA Conference Call

7. Outside Assistance Resources

Resources

7. a) Organization(s) Providing Crews

- East Coast UG
- Area Utilities
- Utility Lines – Delaware
- Utility Lines – Baltimore Gas and Electric (BGE)
- Tri-M Construction
- J. W. Foley
- Consolidated Edison Inc. (CEI)
- Consolidated Edison Inc. (Orange and Rockland Utilities)
- First Energy
- Pike Electric
- Henkels and McCoy
- Baltimore Gas and Electric (BGE)
- CW Wright
- Rockingham
- WA Chester
- Utility Lines
- Asplundh (Tree Trimming)

7. b) Date and Time of Crew Arrivals and Departures

Mutual Assistance

Organization Providing Crews	Arrived	Number of Personnel	Departed
East Coast	August 12 1400 hours	20 People	August 16 0700 hours
Area Utilities	August 12 1400 hours	12 People	August 16 0700 hours
Utility Lines (Delaware)	August 12 1400 hours	17 People	August 16 0700 hours
Utility Lines (BGE)	August 13 0800 hours	10 People	August 15 0700 hours
Tri-M Construction	August 12 1400 hours	8 People	August 16 0700 hours
J. W. Foley	August 12 2200 hours	23 People	August 15 0700 hours
Consolidated Edison Inc. (CEI)	August 12 2200 hours	52 People	August 15 0700 hours
Consolidated Edison Inc. (Orange and Rockland Utilities)	August 12 2200 hours	21 People	August 15 0700 hours
First Energy[1]	August 12 2000 hours	105 People	August 15 0700 hours
First Energy[2]	August 13 1000 hours	45 People	August 15 0700 hours
Pike Electric	August 13 0800 hours	16 People	August 15 0700 hours
Henkels & McCoy	August 12 2300 hours	19 People	August 15 0700 hours
Baltimore Gas and Electric (BGE)	August 13 0800 hours	56 People	August 15 1700 hours

[1]Includes Pennsylvania Power Company, Pennsylvania Electric Company, and Ohio Edison
[2]Includes Toledo Edison and Jersey Central Power Company

Pepco Contractors

Organization Providing Crews	Number of Personnel
CW Wright	40 People
Rockingham	48 People
Utility Lines	15 People
WA Chester	7 People
Asplundh (Tree Trimming)	183 People

Other Pepco Holdings, Inc. (PHI) Utility Personnel

Organization Providing Crews	Number of Personnel
Delmarva Power and Atlantic City Electric	48 People

7. c) Number and Type of Vehicles - 245

- 145 Bucket Trucks
- 31 Digger Derricks
- 69 Miscellaneous Vehicles [Pick-ups, other trucks, etc]

7. d) Total Number of External Personnel – 745

- 745 Personnel

Deployment

7. e) Primary Overhead Line Personnel

- 461 Personnel

7. f) Secondary Overhead Line Personnel

- 53 Personnel

7. g) Tree Trimming Personnel / Other Support Personnel

- 183 Personnel

7. h) Primary Underground Line Crews

- Not Applicable (NA)

7. i) Secondary Underground Line Crews

- NA

7. j) Substation Crews

- NA

7. k) Other Personnel

- 48 Other Support Personnel

Electric Utility Resources

INTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

8. Electric Utility Crews

Resources

8. a) Number and Type of Vehicles - 275

- 103 Bucket Trucks
- 13 Digger Derricks
- 159 Miscellaneous Vehicles [Pick-ups, other trucks, etc.]

8. b) Total Number of Internal Personnel - 482

- 482 Personnel

Deployment

8. c) Primary Overhead Line Personnel

- 119 Personnel

8. d) Secondary Overhead Line Personnel

- NA

8. e) Damage Assessment Personnel

- 69 Personnel performed field damage assessments

8. f) Tree Trimming Personnel

- 4 Personnel coordinating and supervising tree trimming crews

8. g) Primary Underground Line Crews

- NA

8. h) Secondary Underground Line Crews

- NA

8. i) Substation Personnel

- 76 Personnel

8. j) Other Personnel

- 214 Other Support Personnel

Communications

General

Pepco maintains positive relationships with state, county and/or local Emergency Management Agencies (EMA) through the PHI Emergency Management Department.

Emergency Management is responsible for providing state, county and/or local EMA personnel with "one point of contact" for addressing operational and community support requests. During major events, a Pepco EMA Liaison is assigned to the Montgomery County EMA. For the August 12 storm, Pepco EMA Liaisons were assigned to the Montgomery County EMA.

All 911 Centers and EMA in Pepco's service territory have a direct dial line communications radio that is supplied courtesy of the utility and can be used to communicate with each utility in the event of a communications emergency.

GOVERNMENT AFFAIRS CONTACTS

Over the course of the storm, Pepco conducted daily conference calls with participants from County and Local Governments, elected officials and members from both the District of Columbia and Maryland Public Service Commissions.

In addition, the President of Pepco Region held two news conferences and conducted several interviews. Further, Pepco

- distributed news release via email to government officials, community leaders and business leaders;
- processed inquiries from elected officials regarding outage issues called to their attention by constituents; and
- worked closely with government officials to identify restoration priorities.

REGULATORY CONTACTS

Pepco provided storm statistics daily to the Maryland Public Service Commission (MDPSC) Commissioners and their Staffs.

MEDIA COMMUNICATIONS

During the restoration period for the August 12 storm, Pepco issued two news releases, two media advisories and conducted over 90 media interviews/updates. Social media was also utilized including PepcoConnect's Blog, Twitter and Facebook.

9. Customer Operations Statistics

Severe Weather
August 12, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	AUX Staff
630AM - 7AM	1	22	75	98	98	0	
7AM - 8AM	535	654	7461	8701	8650	22	
8AM - 9AM	1487	693	7124	9327	9304	53	
9AM - 10AM	1375	672	5174	7225	7221	60	
10AM - 11AM	1423	911	4517	6946	6851	65	
11AM - 12PM	949	912	4016	6175	5877	73	
12PM - 1PM	540	757	3730	5270	5027	73	
1PM - 2PM	434	799	3392	5042	4625	60	
2PM - 3PM	1180	845	3322	5449	5347	59	15
3PM - 4PM	1336	851	3478	5688	5665	60	42
4PM - 5PM	1168	796	2956	4941	4920	61	49
5PM - 6PM	915	600	2534	4063	4049	61	48
6PM-7PM	729	421	2230	3395	3380	53	45
7PM-8PM	673	348	2307	3333	3328	37	12
8PM-9PM	381	236	1836	2456	2453	14	7
9PM-10PM	278	183	1728	2189	2189	15	1
10PM-11PM	181	137	801	1119	1119	14	2
11PM-12AM	100	67	400	568	567	14	5
	13685	**9904**	**57081**	**81985**	**80670**		

TSF @ 60 Seconds: 95.3%

Rep Ans – Representative Answered,
Inhse VRU – In house Voice Response Unit,
HVCA – High Volume Call Answering System

Severe Weather
August 13, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	AUX Staff
12AM - 1AM	65	42	185	292	292	14	5
1AM - 2AM	26	23	178	227	227	14	5
2AM - 3AM	28	11	132	172	171	14	5
3AM - 4AM	30	15	99	144	144	14	5
4AM - 5AM	20	11	110	142	141	14	5
5AM-6AM	41	26	238	305	305	14	5
6AM - 7AM	84	100	445	629	629	14	5
7AM - 8AM	358	233	725	1316	1316	18	31
8AM - 9AM	569	444	906	1923	1919	45	45
9AM - 10AM	804	558	1142	2510	2504	40	50
10AM - 11AM	797	637	814	2255	2248	39	52
11AM - 12PM	796	632	651	2113	2079	49	53
12PM - 1PM	673	676	437	1953	1786	53	43
1PM - 2PM	697	730	241	1868	1668	54	50
2PM - 3PM	1032	794	294	2285	2120	55	58
3PM - 4PM	1082	826	299	2372	2207	55	59
4PM - 5PM	1138	699	255	2355	2092	57	64
5PM - 6PM	1163	689	122	2225	1974	56	67
6PM-7PM	1181	470	0	1669	1651	56	60
7PM-8PM	655	282	0	944	937	40	6
8PM-9PM	258	188	0	446	446	8	6
9PM-10PM	321	104	0	428	425	15	5
10PM-11PM	247	69	0	316	316	14	5
11PM-12AM	291	53	0	344	344	14	5
	12356	**8312**	**7273**	**29233**	**27941**		

TSF @ 60 Seconds: 87.8%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather
August 14, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	AUX Staff
12AM - 1AM	106	23	0	132	129	14	5
1AM - 2AM	47	11	0	59	58	14	5
2AM - 3AM	25	14	0	39	39	14	5
3AM - 4AM	30	8	0	38	38	14	5
4AM - 5AM	44	7	0	52	51	14	5
5AM-6AM	31	10	0	45	41	14	5
6AM - 7AM	97	16	0	113	113	13	5
7AM - 8AM	218	72	0	291	290	18	5
8AM - 9AM	308	133	0	441	441	19	6
9AM - 10AM	244	190	0	454	434	7	6
10AM - 11AM	275	241	0	532	516	7	6
11AM - 12PM	243	236	0	496	479	8	6
12PM - 1PM	195	239	0	466	434	9	5
1PM - 2PM	191	207	0	440	398	9	5
2PM - 3PM	360	194	152	752	706	9	5
3PM - 4PM	275	125	49	458	449	9	5
4PM - 5PM	156	130	0	289	286	9	5
5PM - 6PM	182	95	0	278	277	9	5
6PM-7PM	114	84	0	199	198	8	5
7PM-8PM	94	69	0	163	163	10	5
8PM-9PM	109	44	0	154	153	8	6
9PM-10PM	58	38	0	97	96	15	6
10PM-11PM	28	40	0	69	68	14	6
11PM-12AM	31	29	0	60	60	14	7
	3461	**2255**	**201**	**6117**	**5917**		

TSF @ 60 Seconds: 77.9%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Severe Weather
August 15, 2010 Telephone Interval Report

Interval	Rep Ans	Inhse VRU	HVCA	Total Incoming Calls	Total Ans Calls	Staff	AUX Staff
12AM - 1AM	11	34	0	45	45	8	7
1AM - 2AM	8	18	0	26	26	8	7
2AM - 3AM	10	5	0	15	15	8	7
3AM - 4AM	36	7	0	43	43	8	7
4AM - 5AM	4	2	0	6	6	8	7
5AM-6AM	15	4	0	19	19	8	7
6AM - 7AM	25	8	0	33	33	8	7
7AM - 8AM	50	20	0	70	70	9	4
8AM - 9AM	84	29	0	113	113	9	3
9AM - 10AM	84	65	0	149	149	9	3
10AM - 11AM	108	83	0	193	191	9	3
11AM - 12PM	126	98	0	226	224	10	3
12PM - 1PM	212	136	81	434	429	11	3
1PM - 2PM	61	137	49	247	247	7	3
2PM - 3PM	80	176	38	294	294	7	4
3PM - 4PM	154	433	12	622	599	7	4
	1068	**1255**	**180**	**2535**	**2503**		

TSF @ 60 Seconds: 90.8%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System

Note Major Storm event remained in effect for Pepco's Maryland service territory through August 15 at 1600 hours.

"Total Calls Answered" and "Total Calls Received" represent all storm and non-storm related calls received at the Pepco Call Center and handled by a Customer Service Representative, Voice Response Unit [VRU] or High Volume Call Answering System [HVCA].

Storm Damage Information

10. System Damage

a) Poles Replaced 56

b) Distribution Transformers Replaced 106

c) Fuses Replaced 3,561

d) Downed Wires Reported 937

e) Substation with Equipment Damage 4

11. Materials

Material inventories were closely monitored to ensure the availability of necessary equipment and materials for restoration activities across the Pepco service territory. Necessary equipment was available for restoration efforts.

Self Assessment

12. Self Assessment

Each major storm impacting the Pepco service territory is different, bringing unique system restoration challenges. The severe thunderstorm of August 12 was no exception. Pepco was able to restore power to approximately 90% of its customers (system-wide) within 36 hours of the event. Pepco's response processes included damage assessment, requests for mutual assistance in slightly more than three hours of the storm entering Pepco's service territory, call center operations, prioritization, safety and implementation of customer communications processes.

In addition, the Information Technology (IT) restoration systems such as the Outage Management (OMS) and Mobile Dispatch System (MDS) performed as designed and there were no software or hardware issues.

The following lessons learned and opportunities for improvement have been noted:

Wires Down Process Issues

Pepco takes customer calls reporting wire down cases seriously and follows a pre-defined process to protect public safety and ensure that electric wires that have fallen on the ground are secure. In the aftermath of August 12 event, Pepco had 937 wire-down locations, forcing the company to prioritize deployment of its resources. Another challenge in addressing wire down reports is that a large portion of reported wires down do not involve electric lines but telecommunication or other utility wires. Because of the serious threat to public safety that downed wires provide, Pepco has to send crews to all reported locations, which may include telecommunications or cable lines, increasing the workload during the restoration effort. Pepco had identified this issue following the February snow storms, and the issue is being examined in ongoing Commission Docket PC-21.

Damage Assessment

Enhance training for Damage Assessment Patrollers to include the use of Mobile Data Terminal so damage information can be entered directly into the Outage Management System.

Interruption Causes

13. Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	51,178	615,021
b) Equipment Failures	9,850	128,494
c) Lightning Damage	89,742	543,322
d) Weather - Ice	0	0
e) Weather - Wind	6,530	70,202
f) Weather Related Damage (Other)	1,390	13,086
g) Source Lost	8,675	42,702
h) Other Major Causes*	10,108	140,536
	177,473	1,553,363

*Includes Foreign Contact, Unknown, Load, etc.

Exhibit__(PJL-13)

Pepco Holdings, Inc

EP1132
701 Ninth Street, NW
Suite 1100
Washington, DC 20068

202 872-3360
202 331-6767 Fax
mkbattle@pepcoholdings.com

Marc K. Battle
Assistant General Counsel

April 30, 2010

Terry J. Romine, Esq.
Executive Secretary
Public Service Commission of Maryland
William Donald Schaeffer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: <u>2009 Annual Reliabilities Indices Reporting</u>

Dear Ms. Romine,

Enclosed please find an original and twenty two (22) copies of Potomac Electric Power Company's ("Pepco") Maryland Distribution System's 2009 Annual Reliability Indices Reporting in accordance with COMAR 20.50.07.06 (B)(1).

Please feel free to contact me if you have any questions.

Very truly yours,

M-Battle

Marc K. Battle

MKB/mlp

Enclosure

Potomac Electric Power Company
Maryland Distribution System

2009 Annual Reliability Indices Reporting

April 30, 2010

pepco
A PHI Company

2009 Reliability Indices and Corrective Action Process

On July 30, 2001, the Maryland Public Service Commission issued Order No. 77132 in Case No. 8826. On page 26 of the Order, the Commission directed Maryland Utilities to file annually, a report of the previous year's performance statistics and its proposed reliability improvement process. These requirements were set forth in Order No. 77132 and later adopted in COMAR 20.50.07.06. This report is structured to comport with the COMAR format.

COMAR 20.50.07.06

C. (1) System-Wide Indices:

(a) A utility shall provide SAIDI, SAIFI, and CAIDI for its system consisting of all feeders originating in Maryland.

(b) Each index shall be calculated and reported using the following two sets of input data.

(i) All interruption data; and

(ii) All interruption data minus major event interruption data.

Response:

Table 1 - Maryland System for 2009		
Indices	All Interruption Data	All Interruption Data Minus Major Event Interruption Data
SAIFI	2.06	2.06
SAIDI (minutes)	205	205
CAIDI (minutes)	99	99
Note: * Major event interruption data is defined per COMAR 20.50.01.03B: There were no major events during 2009.		

C. (2) District Indices:

(a) A cooperatively owned utility shall report SAIDI, SAIFI, and CAIDI for each operating district and identify the operating district with the poorest reliability.

(b) Each index shall be calculated and reported using the following two sets of input data:

(i) All interruption data; and

(ii) All interruption data minus major event interruption data.

Response: N/A

C. (3) Feeders Indices:

(a) An investor-owned utility shall report SAIDI, SAIFI, and CAIDI for 2 percent of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability.

(b) Each index shall be calculated and reported using the following two sets of input data:
(i) All interruption data; and
(ii) All interruption data minus major event interruption data.

(c) The feeder indices report may not include the same feeder in two consecutive annual reports.

Response:

SAIFI, SAIDI and CAIDI for the 2% least reliable feeders (Priority Feeders) are shown below. Major event interruption data is defined pursuant to COMAR 20.50.01.03B. There were no major events during 2009.

(a) & (b-i) All interruption data:

Table 2A – 2010 Priority Feeders - All Interruption Data*

Rank	Feeder Number	SAIFI	SAIDI (Mins)	CAIDI (Mins)	CPI+
1	15127	10.77	1044	97	2.6009
2	15133	10.34	910	88	2.3998
3	15126	5.81	1307	225	2.3993
4	14298	12.33	486	39	2.2933
5	15834	8.08	977	121	2.2303
6	14452	8.02	993	124	2.1970
7	15030	9.30	759	82	2.0846
8	14951	5.78	1090	189	2.0696
9	15120	10.08	589	58	2.0387
10	14992	6.65	844	127	1.8417
11	15090	7.37	705	96	1.7721
12	14994	6.16	704	114	1.6170
13	15129	9.03	180	20	1.5822
14	15273	6.96	508	73	1.5036

Notes: * Feeder Analysis covers period October 1, 2008 to September 30, 2009
+ CPI = Composite Performance Index (Excludes momentary interruptions)

(a) & (b-ii) All interruption data minus major event interruption data:

Table 2B - 2010 Priority Feeders+ - Excluding Major Event Interruptions (COMAR 20.50.07.06C(3)(b)(ii))				
Count	**Feeder Number**	**SAIFI**	**SAIDI (Mins)**	**CAIDI (Mins)**
1	15127	8.73	747	86
2	15133	10.13	891	88
3	15126	4.80	746	156
4	14298	13.07	457	35
5	15834	6.50	816	126
6	14452	11.90	1202	101
7	15030	8.28	600	73
8	14951	7.77	1220	157
9	15120	10.01	668	67
10	14992	6.61	935	142
11	15090	7.36	689	94
12	14994	5.39	638	118
13	15129	4.27	108	25
14	15273	2.93	265	91

Pepco Feeder Ranking – Based on CPI and IEEE-1366 (2003) Methodologies

Table 2C – 2010 Priority Feeders* - Excluding Major Event Days (MEDs)**					
Rank	**Feeder Number**	**SAIFI**	**SAIDI (Mins)**	**CAIDI (Mins)**	**CPI++**
1	15127	10.77	1044	97	2.6009
2	15133	10.34	910	88	2.3998
3	15126	5.81	1307	225	2.3993
4	14298	12.33	486	39	2.2933
5	15834	8.08	977	121	2.2303
6	14452	8.02	993	124	2.1970
7	15030	9.30	759	82	2.0846
8	14951	5.78	1090	189	2.0696
9	15120	10.08	589	58	2.0387
10	14992	6.65	844	127	1.8417
11	15090	7.37	705	96	1.7721
12	14994	6.16	704	114	1.6170
13	15129	9.03	180	20	1.5822
14	15273	6.962	508	73	1.5036

Notes: * Feeder Analysis covers period October 1, 2008 to September 30, 2009
+ Feeder Analysis covers period January 1, 2009 to December 31, 2009
++ CPI = Composite Performance Index (Excludes momentary interruptions)
** MED's based on IEEE Std. 1366 (2003)

C. (4) Poorest Reliability Method:

The method used by a utility to identify the district and feeders with poorest reliability shall be included in the report.

Response:

The evaluation of the least reliable feeders (Priority Feeders) in Potomac Electric Power Company (Pepco)'s Maryland service territory, used the Composite Performance Index (CPI) feeder evaluation model devised by Pepco. A description of that model was provided to the Commission in 2001 and has been in use by Pepco since 2001. In addition, Pepco applies IEEE-1366 (2003) methodology to identify major event days for the purpose of ranking feeders.

C. (5) Investor-Owned Report:

Investor-owned utilities shall specifically identify within the report:

(a) Feeders included in the report that serve customers in Maryland and one or more bordering jurisdictions; and
(b) For each feeder included in §C(5)(a) of this regulation, the percentage of customers located in Maryland and the percentage of customers located in a bordering jurisdiction.

Response:

(a) All feeders included in Table 2A and 2B serve only Maryland customers.
(b) N/A

C. (6) Major Event Time Periods:

The report shall include the time periods during which major event interruption data was excluded from the indices and a brief description of the interruption causes during each time period.

Response:

There were no major events during 2009 as defined by COMAR 20.50.01.03B.

C. (7) Operating District and Feeders with Poorest Reliability:

(a) A cooperatively owned utility shall report remedial actions taken or planned to improve reliability for the operating district reported under §C(2) of this regulation. If the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

(b) An investor-owned utility shall report remedial actions taken or planned to improve reliability for all feeders reported under §C(3) of this regulation. If the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

Response:

(a) Response: N/A

(b) Table 3 provides corrective actions Pepco is taking during 2010 on its Priority Feeders identified in Table 2A.

Table 3 – Corrective Actions for 2009 Maryland Priority Feeders		
Rank	**Feeder No.**	**Corrective Actions (Includes Tree Trimming if Required)***
1	15127	Replace 33 animal guards. Replace 3,200 feet of bare wire with tree wire.
2	15133	Replace nine animal guards.
3	15126	Replace five animal guards. Install one Automatic Circuit Recloser (ACR) and one remotely operated switch.
4	14298	Replace two animal guards. Replace one fuse cut-out. Upgrade 1 fuse. Install one new fuse..
5	15834	Replace two animal guards. Replace one down guy.
6	14452	Install two fuses. Replace 350 feet of bare wire with tree wire.
7	15030	Install two new fuses. Install 1 remotely operated switch.
8	14951	Install four animal guards. Replace 350 feet of bare wire with tree wire.
9	15120	Install one new fuse. Replace 1,800 feet of bare wire with tree wire.
10	14992	Replace six lightning arresters. Replace down guy. Upgrade 3 phase primary at one location. Replace one transformer.
11	15090	Replace one pole. Replace one down guy. Replace one transformer. Install one Automatic Circuit Recloser (ACR) and one remotely operated switch.
12	14994	Replace one pole.
13	15129	Install 10,000 feet of tree wire.
14	15273	Replace two animal guards. Replace one transformer. Replace one pole. Install one Automatic Circuit Recloser (ACR) and one remotely operated switch.

* All identified corrective actions are scheduled for completion by December 31, 2010

C. (8) <u>Evaluation of Remedial Actions:</u>

For the operating district and feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports:

(a) In the annual report for the year following the identification of the operating district and feeders as having the poorest performance, a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions; and

(b) In the annual report 2 years after the identification of the operating district or feeders as having the poorest performance, the ordinal ranking representing the feeder's reliability during the current reporting period.

Response:

Table 4 provides corrective actions Pepco has taken on its year 2008 Maryland Priority Feeders.

Table 4 – Corrective Actions for 2008 Maryland Priority Feeders			
Rank	**Feeder No.**	**Corrective Actions**	**Completion Date**
1	14110	Installed two sectionalizing switches, one animal guard and six lightning arrestors. Replaced one pole, one dead-blade fuse with gang operated switch and seven cross arms. Performed tree trimming as required.	6/30/09
2	15238	Installed one sectionalizing switch, one Automatic Circuit Recloser (ACR), eight lighting arrestors and one animal guard. Performed tree trimming as required.	9/8/09
3	15084	Installed one sectionalizing switch, ten animal guards, two lightning arrestors and approximately 3,300 feet of tree wire. Replaced one cross arm. Performed tree trimming as required. One animal guard and two lightning arresters were found to exist.	8/20/09
4	14206	Installed one Automatic Circuit Recloser (ACR), six animal guards and twelve lightning arrestors. Replaced two cross arms. Performed tree trimming as required.	10/26/09
5	14490	Installed two sectionalizing switches, eight animal guards, four lightning arrestors, one wire spacer and one fuse. Replaced seven cross arms. Performed tree trimming as required. One lightning arrester was found to exist.	6/15/09
6	14989	Installed 14 lightning arrestors. Performed tree trimming as required. Installation of one Automatic Circuit Recloser (ACR) and one remotely operated switch was deferred to coordinate with proposed distribution automation scheme.	7/10/09
7	14922	Installed 16 animal guards, five lightning arrestors and approximately 1,200 feet of tree wire. Replaced six cross arms. Performed tree trimming as required.	10/12/09
8	14245	Installed two sectionalizing switches, one Automatic Circuit Recloser (ACR), five lighting arrestors, five animal guards and removed wire slack at one location. Replaced two cross arms. Performed tree trimming as required.	8/5/09
9	14918	Installed one sectionalizing switch, one automatic circuit recloser, four lighting arrestors and three animal guards. Performed tree trimming as required. One lighting arrester and one animal guard were found to exist.	8/11/09

Table 4 – Corrective Actions for 2008 Maryland Priority Feeders (continued)			
10	14184	Installed one sectionalizing switch, one Automatic Circuit Recloser (ACR), eight animal guards and three lightning arrestors. Performed tree trimming as required. One lightning arrester was found to exist.	4/21/09
11	15230	Installed two animal guards and three lightning arrestors, and resized fuses at 12 locations. Replaced two cross arms and removed wire slack at two locations. Rebuild Automatic Circuit Recloser (ACR) loop recloser scheme. Note: the ACRs have been installed and are waiting new communication infrastructure. Performed tree trimming as required.	4/10/09
12	14385	Installed three animal guards and seven lightning arrestors. Performed tree trimming as required.	8/26/09
13	14270	Installed six lightning arrestors, seven animal guards, removed slack at one location and reattached wire insulator at one location. Performed tree trimming as required. One lightning arrester was found to exist.	7/29/09

(a) Table 5 provides a comparison of the ordinal ranking, as well as the SAIFI and SAIDI values, of the feeders' reliability during 2007 and 2009.

Table 5 - Priority Feeders in 2007

2007 Rank	2009 Rank	Feeder Number	SAIFI		SAIDI (Mins)	
			2007	2009	2007	2009
1	21	14240	13.59	4.44	3,269	421
2	330	14247	10.87	0.84	2,257	116
3	382	14161	9.90	0.55	1,703	86
4	338	14982	7.14	1.10	1,617	96
5	1	15127	4.97	10.77	1,527	1,044
6	33	14162	9.93	5.73	1,276	448
7	159	14258	13.35	2.91	948	155
8	30	15256	5.11	5.69	1,189	465
9	138	14793	7.99	3.41	977	167
10	294	15075	7.72	1.38	1,058	136
11	21	14242	3.22	4.65	1,008	684
12	93	15159	4.80	3.26	902	328
13	124	14031	4.31	3.18	899	251

* Rolling calendar used for both 2007 and 2009 (October 1 to September 30).

While SAIDI improved for all of the feeders, SAIFI increased for Feeders 15127 and 14242.

Feeder 15127
In 2009, the substantial increase in SAIFI was primarily due to auto reclose failures at Norbeck Substation. In June 2009, repairs were completed to the substation auto reclose device and the device was restored to service.

Feeder 15256
In 2009, the increase in SAIFI was due primarily to Underground Residential Distribution (URD) cable failures in the Goshen Estates development. Cable replacement work was completed in January 2009.

Feeder 14242
In 2009, the increase in SAIFI was due primarily to trees. The feeder was re-inspected and projects to install tree wire along Mattaponi Road, Croom Road., Molly Berry Road, Van Brady Road and Windsor Manor Road are anticipated to be completed by end of Third Quarter 2010.

pepco

A PHI Company

Marc K. Battle
Assistant General Counsel

EP1132
701 Ninth Street, NW
Suite 1100, 10th Floor
Washington, DC 20068

202 872-3360
202 331-6767 Fax
mkbattle@pepcoholdings.com

May 2, 2011

Terry J. Romine, Esq.
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: Case No. 8826

Dear Ms. Romine:

Enclosed please find an original and seventeen (17) copies of Potomac Electric Power Company's Annual Reliability Indices Reporting.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Marc K. Battle

MKB/mda

Enclosure

cc: All Parties of Record

pepco

A PHI Company

Potomac Electric Power Company
Maryland Distribution System

2010 Annual Reliability Indices Reporting

April 29, 2011

pepco

A PHI Company

2010 Reliability Indices and Corrective Action Process

On July 30, 2001, the Maryland Public Service Commission issued Order No. 77132 in Case No. 8826. On page 26 of the Order, the Commission directed Maryland Utilities to file annually, a report of the previous year's performance statistics and its proposed reliability improvement process. These requirements were set forth in Order No. 77132 and later adopted in COMAR 20.50.07.06. This report is structured to comport with the COMAR format.

In an aggressive effort to improve reliability in Maryland, Pepco developed a six-point reliability plan that advances work on existing programs by augmenting needed corrective action plans as well as initiates new activities. These programs are intended to increase substantially the reliability of the distribution system across Maryland by reducing both the frequency and duration of outages for our customers. Improving the reliability of the electric system is critically important to everyone at Pepco. Pepco will continue to improve its performance and work with its customers to address their concerns.

COMAR 20.50.07.06

C. (1) System-Wide Indices:

(a) A utility shall provide SAIDI, SAIFI, and CAIDI for its system consisting of all feeders originating in Maryland.

(b) Each index shall be calculated and reported using the following two sets of input data.

(i) All interruption data; and

(ii) All interruption data minus major event interruption data.

Response:

Table 1 - Maryland System for 2010		
Indices	All Interruption Data	All Interruption Data Minus Major Event Interruption Data
SAIFI	4.10	2.21
SAIDI (minutes)	2,073	265
CAIDI (minutes)	505	120
Note: * Major event interruption data is defined per COMAR 20.50.01.03B: Major Event 2/5/10 - 2/12/10, 7/25/10 - 7/31/10, 8/5/10 - 8/7/10, 8/12/10 - 8/15/10		

C. (2) District Indices:

(a) A cooperatively owned utility shall report SAIDI, SAIFI, and CAIDI for each operating district and identify the operating district with the poorest reliability.

(b) Each index shall be calculated and reported using the following two sets of input data:

(i) All interruption data; and

(ii) All interruption data minus major event interruption data.

pepco

A PHI Company

Response: N/A

C. (3) Feeders Indices:

(a) An investor-owned utility shall report SAIDI, SAIFI, and CAIDI for 2 percent of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability.

(b) Each index shall be calculated and reported using the following two sets of input data:
(i) All interruption data; and
(ii) All interruption data minus major event interruption data.

(c) The feeder indices report may not include the same feeder in two consecutive annual reports.

Response:

SAIFI, SAIDI and CAIDI for the 2% least reliable feeders (Priority Feeders) are shown below. Major event interruption data is defined pursuant to COMAR 20.50.01.03B. There were four major events during 2010.

(a) & (b-i) All interruption data:

Table 2A – 2011 Priority Feeders - All Interruption Data*					
Rank	**Feeder Number**	**SAIFI**	**SAIDI (Mins)**	**CAIDI (Mins)**	**CPI+**
1	15235	13.80	8,640	626	1.3453
2	14950	12.05	1,238	103	1.3133
3	14264	11.32	5,081	449	1.2706
4	14045	3.62	1,988	549	1.2561
5	14943	10.95	5,274	482	1.2150
6	14988	13.12	1,846	141	1.1885
7	14066	16.35	17,493	1,070	1.1803
8	14214	4.95	1,397	282	1.1704
9	15237	15.42	3,272	212	1.1662
10	15162	9.73	2,037	209	1.1506
11	14247	11.40	1,330	117	1.0771
12	14271	8.97	5,778	644	1.0755
13	15153	13.20	6,101	462	1.0648
14	15793	9.08	1,381	152	1.0516

Notes: * Feeder Analysis covers period October 1, 2009 to September 30, 2010
+ CPI = Composite Performance Index (Excludes momentary interruptions)

pepco
A PHI Company

(a) & (b-ii) All interruption data minus major event interruption data:

Table 2B - 2011 Priority Feeders+ - Excluding Major Event Interruptions (COMAR 20.50.07.06C(3)(b)(ii))				
Count	**Feeder Number**	**SAIFI**	**SAIDI (Mins)**	**CAIDI (Mins)**
1	15235	7.39	1,342	182
2	14950	11.77	1,133	96
3	14264	9.45	1,116	118
4	14045	0.19	42	220
5	14943	5.27	483	92
6	14988	12.13	1,014	84
7	14066	8.58	1,017	119
8	14214	1.94	765	394
9	15237	7.05	659	94
10	15162	5.18	619	120
11	14247	10.07	1,005	100
12	14271	5.93	1,120	189
13	15153	7.58	1,015	134
14	15793	7.38	937	127

Pepco Feeder Ranking – Based on CPI and IEEE-1366 (2003) Methodologies

Table 2C – 2011 Priority Feeders* - Excluding Major Event Days (MEDs)**					
Rank	**Feeder Number**	**SAIFI**	**SAIDI (Mins)**	**CAIDI (Mins)**	**CPI++**
1	15235	9.41	1,507	160	1.3453
2	14950	12.02	1,199	100	1.3133
3	14264	7.79	1,205	155	1.2706
4	14045	3.46	1,370	396	1.2561
5	14943	6.32	1,211	192	1.2150
6	14988	11.91	1,069	90	1.1885
7	14066	10.42	1,264	121	1.1803
8	14214	4.93	1,302	264	1.1704
9	15237	12.54	1,057	84	1.1662
10	15162	7.11	1,228	173	1.1506
11	14247	10.40	1,037	100	1.0771
12	14271	4.49	1,088	242	1.0755

13	15153	7.83	1,124	143	1.0648
14	15793	7.88	1,010	128	1.0516

Notes: * Feeder Analysis covers period October 1, 2009 to September 30, 2010
+ Feeder Analysis covers period January 1, 2010 to December 31, 2010
++ CPI = Composite Performance Index (Excludes momentary interruptions)
** MED's based on IEEE Std. 1366 (2003)

C. (4) Poorest Reliability Method:

The method used by a utility to identify the district and feeders with poorest reliability shall be included in the report.

Response:

The evaluation of the least reliable feeders (Priority Feeders) in Potomac Electric Power Company (Pepco)'s Maryland service territory, used the Composite Performance Index (CPI) feeder evaluation model devised by Pepco. A description of that model was provided to the Commission in 2001 and has been in use by Pepco since 2001. In addition, Pepco applies IEEE-1366 (2003) methodology to identify major event days for the purpose of ranking feeders.

C. (5) Investor-Owned Report:

Investor-owned utilities shall specifically identify within the report:

(a) Feeders included in the report that serve customers in Maryland and one or more bordering jurisdictions; and
(b) For each feeder included in §C(5)(a) of this regulation, the percentage of customers located in Maryland and the percentage of customers located in a bordering jurisdiction.

Response:

(a) All feeders included in Table 2A and 2B serve only Maryland customers.
(b) N/A

C. (6) Major Event Time Periods:

The report shall include the time periods during which major event interruption data was excluded from the indices and a brief description of the interruption causes during each time period.

Response:

pepco
A PHI Company

There were four major events during the twelve month period ending September 30, 2010.

- February 5 – 12, 2010 Snow Storm
  - Period Excluded: February 5 at 1900 hours through February 12 at 1546 hours

Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	93,071	1,822,470
b) Fallen or Broken Pole	0	0
c) Equipment Failures	3,585	52,412
d) Lightning Damage	0	0
e) Ice Accumulation on Conductors	13,742	237,600
f) Weather - Wind	123,207	1,121,290
g) Weather - Other	1,766	14,285
h) Other Major Causes*	29,063	343,099

*Customer count includes source lost = 15,581, unknown = 11,347, load = 2,026; animal, employee, foreign contact and motor vehicle = 109.

Note when a pole falls due to pole decay, soil erosion, etc. and causes an outage, the "interruption cause" is categorized as "fallen pole." However, when a pole is broken or damaged due to tree-related damage, vehicular or third party accidents, the cause is not categorized as "fallen or broken pole" but rather "fallen tree" or "accident." During the February 5-12 storm, there were no reports of "fallen or broken poles" that caused outages in Pepco's Maryland service territory.

- July 25 – 31, 2010 Severe Thunderstorm
  - Period Excluded: July 25 at 1507 hours through July 31 at 0056 hours

Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	138,311	4,045,366
b) Fallen or Broken Pole	0	0
c) Equipment Failures	5,903	245,802

d) Lightning Damage	105,816	1,914,734
e) Ice Accumulation on Conductors	0	0
f) Weather Related Damage (Other than Lightning)	153,802	3,176,281
g) Other Major Causes*	33,609	896,584
	437,441	10,278,767

*Includes Source Lost, Foreign Contact, Unknown, etc.

Note when a pole falls due to pole decay, soil erosion, etc. and causes an outage, the "interruption cause" is categorized as "fallen pole." However, when a pole is broken or damaged due to tree-related damage, vehicular or third party accidents, the cause is not categorized as "fallen or broken pole" but rather "fallen tree" or "accident." During the July 25-31 storm, there were no reports of "fallen or broken poles" that caused outages in Pepco's Maryland service territory.

- August 5 – 7, 2010 Severe Thunderstorm
    - Period Excluded: August 5 at 1530 hours through August 7 at 1707 hours

Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	24,807	212,519
b) Fallen or Broken Pole	0	0
c) Equipment Failures	1,527	9,198
d) Lightning Damage	15,587	85,918
e) Ice Accumulation on Conductors	0	0
f) Weather Related Damage (Other than Lightning)	45,781	283,020
g) Source Lost	22,271	46,876
h) Other Major Causes*	8,945	48,210
	118,918	685,741

*Includes Foreign Contact, Unknown, etc.

Note when a pole falls due to pole decay, soil erosion, etc. and causes an outage, the "interruption cause" is categorized as "fallen pole." However, when a pole is broken or damaged due to tree-related damage, vehicular or third party accidents, the cause is not categorized as "fallen or broken pole" but rather "fallen tree" or "accident." During the August 5-7 storm, there were no reports of "fallen or broken poles" that caused outages in Pepco's Maryland service territory.

pepco

A PHI Company

- August 12 – 15, 2010 Severe Thunderstorm
  - Period Excluded: August 12 at 0645 hours through August 15 at 1600 hours

Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	51,178	615,021
b) Fallen or Broken Pole	0	0
c) Equipment Failures	9,850	128,494
d) Lightning Damage	89,742	543,322
e) Ice Accumulation on Conductors	0	0
f) Weather - Wind	6,530	70,202
g) Weather Related Damage (Other)	1,390	13,086
h) Source Lost	8,675	42,702
i) Other Major Causes*	10,108	140,536
	177,473	1,553,363

*Includes Foreign Contact, Unknown, Load, etc.

Note when a pole falls due to pole decay, soil erosion, etc. and causes an outage, the "interruption cause" is categorized as "fallen pole." However, when a pole is broken or damaged due to tree-related damage, vehicular or third party accidents, the cause is not categorized as "fallen or broken pole" but rather "fallen tree" or "accident." During the August 12-15 storm, there were no reports of "fallen or broken poles" that caused outages in Pepco's Maryland service territory.

C. (7) Operating District and Feeders with Poorest Reliability:

(a) A cooperatively owned utility shall report remedial actions taken or planned to improve reliability for the operating district reported under §C(2) of this regulation. If the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

(b) An investor-owned utility shall report remedial actions taken or planned to improve reliability for all feeders reported under §C(3) of this regulation. If the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

Response:

(a) Response: N/A

(b) Table 3 provides corrective actions Pepco is taking during 2010 on its Priority Feeders identified in Table 2A.

All identified corrective actions are scheduled for completion by December 31, 2011. Enhanced Integrated Vegetation Management (EIVM) is included in the corrective actions.

Table 3 - Corrective Actions for 2011 Maryland Priority Feeders

Rank	Feeder No.	Feeder Description	Outage Causes	Corrective Actions (Includes infrared scan of all feeders and EIVM for all feeders)
1	15235	Feeder 15235 serves approximately 292 customers in Montgomery County. It extends 38.2 miles and is 70% overhead and 30% underground.	Tree = 57% Equip Failure = 22% Unknown = 21% 96% of the total numbers of customers affected were associated with six mainline feeder events, caused by four tree/tree limbs, one wire down and one wherein the cause was unknown 2% of the total numbers of customers affected were associated with four localized fused lateral events, caused by two trees, one outside the right of way and one wire down. 2% of the total numbers of customers affected were associated with 23 localized transformer events affecting less than ten customers each	Replace approximately 8,500 feet of 3 phase wire along Berryville Road Replace approximately 4,500 feet of single phase wire along Berryville Road Upgrade approximately 13,000 feet of bare neutral associated with above work Upgrade approximately 50 poles and crossarms along Berryville Road Install approximately 46 fuses along Darnestown Road, Black Rock Road, Whites Ferry Road and Sugarland Rd Upgrade approximately two transformers along Sugarland Lane and Morrow Road Perform thermal vision inspection of overhead facilities to identify necessary upgrades
2	14950	Feeder 14950 serves approximately 1353 customers in Montgomery County. It extends 12.5 miles and is 91% overhead and 9% underground	Tree = 64% Unknown = 13% Animal = 13% Weather = 8% Equip Failure - 2% 98% of the total numbers of customers affected were associated with ten mainline feeder related events, caused by seven trees/tree limbs, one animal, one weather and one wherein the cause was unknown 1% of the total numbers of customer affected were associated with five localized fused lateral events, caused by three trees, one equipment failure and one wherein the cause was unknown 1% of the total numbers of customers affected were associated with 31 localized transformer events affecting less than 16 customers each	Replace approximately 19,000 feet of bare mainline primary with tree wire along Goldsboro Road, Millwood Road, Bradley Boulevard, Fairfax Road, Clarendon Road, Hillendale Road, Pembroke Road, Fairfax Road, Chevy Chase Boulevard and Wisconsin Avenue Replace approximately 100 feet of open wire secondary with triplex or quadruplex along Goldsboro Road, Millwood Lane, River Road, Wisconsin Avenue, Fairfax Road and Hillandale Road Replace transformer on Langdrum Lane Replace approximately five poles along Chevy Chase Boulevard & Millwood Road and Wisconsin Avenue and Goldsboro Road, associated with above work Replace manually operated switch on Bradley Boulevard Perform thermal vision inspection of overhead facilities to identify necessary upgrades
3	14264	Feeder 14264 serves approximately 1741 customers in Montgomery County. It extends 10.1 miles and is 90% overhead and 10% underground	Tree = 70% Weather - 14% Unknown - 13% Equip Failure = 3% 96 % of the total numbers of customers affected were associated with 16 mainline feeder events, causes by seven tree/tree limb, six tree limbs outside the right of way, one unplanned switching event following repairs, one weather/high winds and one wherein the cause was unknown. 3% of the total numbers of customers affected were associated with six fused lateral events, caused by one motor vehicle accident, three tree/tree limbs from outside the right of way, one weather/lightning related and one cable related equipment failure 1% of the total numbers of customers affected were associated with localized 26 localized transformer events, one affecting 30 customers, 25 affecting less than 20 customers each	Replace approximately 11,000 feet of bare primary mainline with tree wire and approximately 7500 feet of secondary mainline with triplex wire along Montgomery Avenue, Kenilworth Driveway, Stewart Driveway, Manor Road, Jones Mill Road, East West Highway, Terrace Drive and Brookville Road Replace approximately 500 feet of secondary service wire with #2 triplex service wire along Montgomery Avenue, Kenilworth Driveway, Stewart Driveway and Terrace Drive Replace approximately 33 poles along Montgomery Avenue, Kenilworth Driveway, Stewart Driveway, Manor Road Jones Mill Road, East West Highway, Terrace Drive and Brookville Road Perform thermal vision inspection of overhead facilities to identify necessary upgrades
4	14045	Feeder 14045 serves approximately 1312 customers in Montgomery County. It extends 10.9 miles and is 88% overhead and 12% underground	Equip Failure = 37% Other* = 31% Overload - 19% Tree 13% 80% of the total numbers of customers affected were associated with three mainline feeder related events, caused by one equipment failure, one overload and one source lost 16% of the total numbers of customers affected were associated with three localized fused lateral events affecting less than 280 customers each, caused by two tree related events and one equipment failure 4% of the total numbers of customers affected were associated with one event affecting 91 customers and 21 localized transformer events affecting less than 13 customers each	Replace approximately 50 poles along Stickley Road, Gaynor Road, Leahy Drive, Vandegrift Avenue, Ardennes Avenue, Lewis Avenue, Galena Road, Furman, Road, Otis Drive, Mori Drive, Veirs Mill Road, Hunters Lane, Atlantic Avenue, Wainwright Avenue and Halpine Road Replace transformers on Lewis Avenue at pole number 764449-140640 and install additional transformer to split the existing load Replace transformers on Stickley Road at pole number 772445-130480 and install additional transformer to split the existing load Replace lighting arrester on Veirs Mill Road Replace down guy on Veirs Mill Road Replace crossarms on pole number located on Veirs Mill Road Replace crossarm on 3008 Atlantic Avenue Replace down guys with fiber glass inserts along Ardennes Avenue Replace fuse cutout on Rockland Avenue Replace existing anchors on pole at Lewis Avenue Replace crossarms, cutouts and guy wires on a pole on Stanley Road Upgrade fusing along Halpine Road, Valley Stream Drive, Alsace Lane, Ridgeway Avenue, Leahy Drive, Stillwell Road, Ardennes Avenue and Wainwright Avenue Perform thermal vision inspection of overhead facilities to identify necessary upgrades

A PHI Company

Table 3 - Corrective Actions for 2011 Maryland Priority Feeders				
Rank	Feeder No.	Feeder Description	Outage Causes	Corrective Actions (Includes infrared scan of all feeders and EIVM for all feeders)
5	14943	Feeder 14943 serves approximately 1474 customers in Montgomery County. It extends 21.3 miles and is 67% overhead and 33% underground	Tree - 63% Unknown = 32% Animal = 3% Equip. Failure - 2% 94% of the total numbers of customers affected were associated with eight mainline feeder events, caused by six tree/tree limbs, one equipment related cable fault and one wherein the cause was unknown 4% of the total numbers of customers affected were associated with seven localized fuse related events, caused by two tree limbs, four animals and one wherein the cause was unknown during wind/weather event 2% of the total numbers of customers affected were associated with 32 localized transformer related events affecting less than 35 customers each	Replace approximately 24,000 feet of bare primary mainline with tree wire along East Halbert Road, Bannock Burn Road, Bent Branch Road, Wyoming Road, 76th Street, MacArthur Boulevard, and Goldsboro Road Replace approximately 20,000 feet of open wire secondary with triplex along East Halbert Road, Bannock Burn Road, Bent Branch Road, Wyoming Road and 76th Street Upgrade one pole and one transformer at Tulip Hill Terrace Upgrade one pole and one transformer at 76th Street Perform thermal vision inspection of overhead facilities to identify necessary upgrades
6	14988	Feeder 14988 serves approximately 1362 customers in Prince George's County. It extends 14 miles and is 45% overhead and 55% underground	Trees - 72% Weather - 10% Equip. Hit - 9% Unknown - 9% 98% of the total numbers of customers affected by outages were associated with 15 mainline feeder related events, caused by ten trees/tree limbs within the right of way, one motor vehicle accident, one weather/lightning and three wherein the cause was unknown 1% of the total numbers of customers affected by outages were associated with three localized fused lateral events, caused by one tree outside the right of way, one failed primary tap and one animal 1% of the total numbers of customers affected by outages were associated with 18 localized transformer related events affecting less than ten customers each	Replace 13,000 feet of open wire secondary with triplex or quadruplex along Adams Drive, Parker Lane, Chalfont Avenue, Taylor Circle, Taylor Court, Tioga Road, Cleveland Lane, Pine Road, Harrison Avenue and Colwyn Road Upgrade 19,000 feet of bare wire primary wire with tree wire along Jefferson Road, Cleveland Lane, Warburton Road, Taylor Avenue and Gallahan Road Upgrade eight transformers along Pine Road, Jefferson Road, Harrison Avenue and Adams Drive Replace approximately 24 poles in association with the above work Perform thermal vision inspection of overhead facilities to identify necessary upgrades
7	14066	Feeder 14066 serves approximately 184 Customers in Montgomery County. It extends 12.1 miles and is 23% OH, 77% UG	Equip. Failure = 99% Other* - 1% 77% of the total numbers of customers affected by outages were associated with five mainline feeder related events, caused by four equipment failures and one lightning related 15% of the total numbers of customers affected by outages were associated with tow localized cable failures 8% of the total numbers of customers affected by outages were associated with five localized transformer events. One event affected 60, the remaining events affected less than 40 customers each	Perform underground residential distribution (URD) cable replacement in the Deer Park subdivision and reconfigure subdivision to balance load Replace 13 transformers Replace approximately 800 feet of single phase mainline primary with tree wire Replace approximately 13 transformers along West Side Drive, one transformer along Conservation Drive Replace 800 feet bare wire with tree wire along Conservation Drive Upgrade fusing serving 707 Conservation Road Perform a transformer load study on the transformer located at 504 Philmont Drive and replace or upgrade as necessary Perform thermal vision inspection of overhead facilities to identify necessary upgrades.
8	14214	Feeder 14214 serves approximately 989 customers in Prince George's County. It extends 8.2 miles and is 58% overhead and 42% underground	Tree = 53% Equip. Failures - 32% Unknown - 15% 20% of the total numbers of customers affected were associated with one mainline feeder event which was caused by a failed lightning arrester 78% of the total numbers of customers affected were associated with eight localized fused lateral events, caused by five tree/tree limbs, two of which were trees outside the right of way, one equipment failure and two wherein the cause was unknown 2% of the total numbers of customers affected were associated with eight localized transformer events. One event affecting 43 customers, one affecting 65 customers and the remaining affecting less than ten customers each	Replace approximately 3,300 feet of mainline primary with triplex wire and 1700 feet of bare neutral along East West Highway, Kenilworth Avenue, 62nd Place, 61st Street, and 64th Avenue Reconfigure feeder to remove rear lot construction along 64th Avenue Replace approximately 6,000 feet of secondary mainline with triplex wire along 61st Street and 62nd Avenue Replace approximately 700 feet of secondary with quadruplex along 61st Street. Install approximately 12 crossarms along East West Highway, Kenilworth Avenue, 62nd Place, 61st Street and 64th Avenue Install approximately 20 poles along East West Highway, Kenilworth Avenue, 62nd Place, 61st Street and 64th Avenue Replace approximately 19 transformers along East West Highway, Kenilworth Avenue, 62nd Place, 61st Street and 64th Avenue Install approximately 60 animal guards along East West Highway, Kenilworth Avenue, 62nd Place, 61st Street, and 64th Avenue Install approximately 20 Fuses along East West Highway, Kenilworth Avenue, 62nd Place, 61st Street, and 64th Avenue Install four manually operated switches along East West Hwy and one on Kenilworth Avenue Perform thermal vision inspection of overhead facilities to identify necessary upgrades

pepco
A PHI Company

Table 3 - Corrective Actions for 2011 Maryland Priority Feeders				
Rank	**Feeder No.**	**Feeder Description**	**Outage Causes**	**Corrective Actions (Includes infrared scan of all feeders and EIVM for all feeders)**
9	15237	Feeder 15237 serves approximately 909 customers in Montgomery County. It extends 39.6 miles and is 27% overhead and 73% underground	Tree - 80% Unknown - 9% Other* - 8% Equip. Failure = 3% 96% of the total numbers of customers affected were associated with 13 mainline feeder related events, caused by ten trees/tree limbs, two wherein the cause was unknown and one source lost 4% of the total numbers of customers affected by outages were associated with 12 localized fused lateral events, caused by nine equipment failures, two tree related and one cable cut Less than 1% of the total numbers of customers were affected by single transformer events affecting less that 30 customers each.	Replace approximately 42,000 feet of mainline primary with tree wire, 800 feet of bare neutral and approximately 800 feet of secondary mainline with triplex wire along Ancient Oak Drive, Darnestown Road, Chestnut Oak Drive and Turkey Foot Road. Install three poles and two eight foot crossarms along Turkey Foot Road Install 79 fuses and six lightning arrestors along Darnestown Road, Chestnut Oak Drive, Wye Oak Drive, Ancient Oak Road, Meadow View Drive, and White Oak Drive Install one automatic circuit recloser (ACR), location to be determined. Replace 35 transformers along Scarlet Oak Drive, Darnestown Road, Bondy Lane, Chestnut Oak Drive, Ancient Oak Drive, and Turkey Foot Road Install three manually operated switches along Darnestown Road Perform thermal vision inspection of overhead facilities to identify necessary upgrades.
10	15162	Feeder 15162 serves approximately 904 customers in Montgomery County. It extends 23.1 miles and is 20% overhead and 80% underground	Tree - 64% Equip. Failure - 21% Weather = 13% Equip. Hit - 2% 91% of the total numbers of customers affected were associated with six mainline feeder related events, caused by four tree related, one weather and one equipment failure 8% of the total numbers of customers affected were associated with seven localized fused lateral events, caused by six cable failures and one cable cut 1% of the total numbers of customers affected by outages were associated with 16 single localized transformer events affecting less than 26 customers each	Install one ACR along the main trunk line to be determined Upgrade fusing at two laterals along Seven Locks Road, Seven Locks Road serving Monroe Street area, Potomac Valley Road & Marcus Court, Monument Street & Monument Court, Monument St & Falls Road, Falls Road & Rose Petal Way, Falls Road & Winding Rose Drive lateral tap off Falls Road, Potomac Valley Road & Maryland Avenue, two fuses serving lateral tap to nursing home off Potomac Valley Road, Potomac Valley Road east of tap to nursing home and Potomac Valley Road at Leonard Court
11	14247	Feeder 14247 serves approximately 535 customers in Prince George's County. It extends 48.2 miles and is 58% overhead and 42% underground	Tree = 83% Equip. Failure - 15% Weather = 1% Unknown = 1% 96% of the total numbers of customers affected by outages were associated with ten mainline feeder related events, caused by two equipment failures and eight tree related 3% of the total numbers of customers affected by outages were associated with seven localized fused lateral events affecting less than 53 customers each, caused by two equipment failures, three tree related events, one unknown and one lightning 1% of the total numbers of customers affected were associated with 39 single transformer events affecting less than seven customers each	Replace approximately 1,240 feet of bare primary wire with 477 Aluminum Conductor Steel Reinforced (ACSR) tree wire and bare neutral Replace three poles along Crain Highway Install approximately 900 feet of mainline wire along Crain Highway Install one manually operated switch Performing thermal vision inspection of overhead facilities to identify necessary upgrades
12	14271	Feeder 14271 serves approximately 1365 customers in Montgomery County. It extends 13 miles and is 80% overhead and 20% underground	Tree - 37% Unknown = 28% Other* - 22% Weather - 9% Equip. Failure - 4% 73% of the total numbers of customers affected were associated with three mainline feeder related events, caused by one manual load shed event, one tree outside the right of way and one wherein the cause was unknown 20% of the total numbers of customers affected were associated with five localized lateral fused events, caused by three tree/tree limbs, (2 outside the right of way), one wherein the cause was unknown during weather/wind and one equipment related fuse holder 7% of the total numbers of customers affected were associated with 47 localized transformer related events. One event affecting 70 customers while the rest affected less than 20 customers each	Replace 500 feet open wire secondary on lateral located on Blaine Drive Replace 400 feet open wire secondary on lateral located on Jonquil Street NW Install single phase arm and head guy to pole on Parkside Drive to clear tree Install fuses at Yorktown Road and Sudbury Road, Parkside Lane and Parkside Drive, Plymouth Street and West Beach Drive, Juniper Street and alley, Juniper Street and 17th Street, Portal Drive and Poplar Lane, Orchid Street and Poplar Lane, Portal Drive and Roxanna Road, Redbud Lane and Tulip Street, Tamarack Street and Redwood Terrace Replace transformer on Primrose Road, pole number 788420-340790 Upgrade poles along the following locations West Beach Terrace, West Beach Drive and West Beach Terrace, Sudbury Road, Yorktown Road, Parkside Drive, West Beach Drive, Juniper Street, Primrose Road and Orchid Street, Roxanna Road, Redwood Terrace, Redwood Terrace, Tulip Street and Spruce Drive Replace damaged crossarm and cut on Ashboro Drive Replace damaged crossarms along Ashboro Drive, Sudbury Road, Yorktown Road, Plymouth Street, Kalmia Road and Juniper Street

Table 3 - Corrective Actions for 2011 Maryland Priority Feeders				
Rank	Feeder No.	Feeder Description	Outage Causes	Corrective Actions (Includes infrared scan of all feeders and EIVM for all feeders)
13	15153	Feeder 15153 serves approximately 658 customers in Montgomery County. It extends 19.3 miles and is 35% overhead and 65% underground.	Tree = 55% Equip. Failure = 32% Other* = 13% 96% of the total numbers of customers affected by outages were associated with eight mainline feeder related events, caused by five tree related events, two equipment failures and one cable cut 3% of the total numbers of customers affected by outages were associated with four localized fused lateral events, caused by three equipment failures and one tree related event 1% of the total numbers of customers were associated with 25 localized transformer events with less than five customers each	Install two remote controlled ACRs at locations to be determined Replace approximately five poles on Glen Mill Road. Repair approximately eight poles (including replacement of taps, lightning arresters and crossarms) along Red Barn Lane and Rolling Road, Coppello Drive, Lloyd Road, Glen Mill Road. Install fuses along Mistwood Drive, Glen Mill Road, Red Barn Road, Lloyd Road, St James Road, Betteker Lane, Tulip Lane, and Rolling Road. Replace approximately four animal guards and approximately five lightning arresters along Copula Drive Install or upgrade fusing at approximately 32 locations along St James Road, Betteker Lane, Lloyd Road, Glen Mill Road, Red Barn Lane, Tower Oaks Road, Tulip Lane, Firstfield Road, Rolling Road and Clopper Road Replace approximately 6,500 feet of mainline primary with tree wire and approximately 6,500 feet of bare neutral along Red Barn Lane, Tulip Lane, and Unity Lane Perform thermal vision inspection of overhead facilities to identify necessary upgrades.
14	15793	Feeder 15793 serves approximately 1319 customers in Montgomery County. It extends 9.8 miles and is 66% overhead and 34% underground.	Weather = 33% Equip Failure = 32% Unknown = 14% Tree = 13% Other* = 5% Animal = 3% 98% of the total numbers of customers affected were associated with 11 mainline feeder related events, caused by one animal, two tree/tree limbs, two weather wind/ice events, two wherein the cause was unknown and four equipment (two preassembled aerial cable failures, one spacer cable failure and one cable fault) 1% of the total numbers of customers affected were associated with two localized fuse events caused by one cable failure and one tree related event 1% of the total numbers of customers affected were associated with 23 localized transformer events affecting less than 20 customers each.	Replace approximately 5,200 feet of mainline primary with tree wire along Beech Avenue, Old Georgetown Road and Linden Lane Replace 2,400 feet of open wire secondary mainline with triplex along Johnson Avenue, Ewing Avenue and Old Georgetown Road Perform thermal vision inspection of overhead facilities to identify necessary upgrades

C. (8) <u>Evaluation of Remedial Actions:</u>

For the operating district and feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports:

(a) In the annual report for the year following the identification of the operating district and feeders as having the poorest performance, a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions; and

(b) In the annual report 2 years after the identification of the operating district or feeders as having the poorest performance, the ordinal ranking representing the feeder's reliability during the current reporting period.

Response:

Table 4 provides corrective actions Pepco has taken on its year 2008 Maryland Priority Feeders.

All corrective actions were completed by October 31, 2009.

pepco
A PHI Company

Table 4 – Corrective Actions for 2009 Maryland Priority Feeders			
Rank	**Feeder No.**	**Outage Causes**	**Corrective Actions (Includes tree trimming all feeders as required)**
1	14110	Equipment Failure- 4% Other - 36% Tree- 34% Unknown- 8% Weather-19%	Installed two sectionalizing switches, one animal guard and six lightning arrestors. Replaced one pole, one dead blade fuse with gang operated switch and seven cross arms.
2	15238	Animal-7% Equipment Fail- 17% Equipment Hit- 3% Other - 38% Overload- 3% Tree- 7% Unknown- 21% Weather - 3%	Installed one sectionalizing switch, one automatic circuit recloser, eight lighting arrestors and one animal guard.
3	15084	Animal-4% Equipment Fail- 9% Equipment Hit- 4% Other - 6% Tree- 59% Unknown- 13% Weather- 6%	Installed one sectionalizing switch, ten animal guards, two lightning arrestors and approximately 3,300 feet of tree wire. Replaced one crossarm. One animal guard and two lightning arresters were found to exist.
4	14206	Animal- 21% Equipment Failure- 14% Other- 36% Unknown- 29%	Installed one automatic circuit recloser, six animal guards and 12 lightning arrestors. Replaced two crossarms.
5	14490	Animal-5% Equipment Fail- 16% Equipment Hit- 8% Other - 18% Tree- 5% Unknown- 47%	Installed two sectionalizing switches, eight animal guards, four lightning arrestors, one wire spacer and one fuse. Replaced seven crossarms. One lightning arrester was found to exist.

pepco

A PHI Company

Table 4 – Corrective Actions for 2009 Maryland Priority Feeders			
Rank	**Feeder No.**	**Outage Causes**	**Corrective Actions (Includes tree trimming all feeders as required)**
6	14989	Animal-6% Equipment Fail- 26% Equipment Hit- 2% Other - 26% Tree- 24% Unknown- 9% Weather - 7%	Installed 14 lightning arrestors. Installation of one automatic circuit recloser (ACR) and one remotely operated switch was deferred to coordinate with proposed distribution automation scheme.
7	14922	Animal-2% Equipment Fail- 5% Equipment Hit- 7% Other - 16% Tree- 20% Unknown- 24% Weather - 25%	Installed 16 animal guards, five lightning arrestors and approximately 1,200 feet of tree wire. Replaced six crossarms.
8	14245	Animal- 4% Equipment Failure- 10% Equipment Hit-4% Other- 22% Tree-13% Unknown- 13% Weather - 30% Overload- 4%	Installed two sectionalizing switches, one automatic circuit recloser, five lighting arrestors, five animal guards and removed wire slack at one location. Replaced two crossarms.
9	14918	Animal-1% Equipment Fail- 9% Equipment Hit- 7% Other - 7% Tree- 40% Unknown- 24% Weather- 11%	Installed one sectionalizing switch, one automatic circuit recloser, four lighting arrestors and three animal guards. One lighting arrester was found to exist.
10	14184	Animal- 3% Equipment Failure- 5% Equipment Hit-3% Other- 21% Tree-36% Unknown- 15% Weather - 18%	Installed one sectionalizing switch, one automatic circuit recloser, eight animal guards and three lightning arrestors. One lightning arrester was found to exist.

Table 4 – Corrective Actions for 2009 Maryland Priority Feeders			
Rank	**Feeder No.**	**Outage Causes**	**Corrective Actions (Includes tree trimming all feeders as required)**
11	15230	Animal-2% Equipment Fail- 9% Equipment Hit- 1% Other - 16% Tree- 38% Unknown- 23% Weather- 11%	Installed two animal guards, three lightning arrestors, and resized fuses at 12 locations. Replaced two crossarms and removed wire slack at two locations. Rebuilt ACR loop recloser scheme.
12	14385	Equipment Failure- 8% Other - 16% Overload - 5% Tree- 3% Unknown- 54% Weather-14%	Installed three animal guards and seven lightning arrestors.
13	14270	Animal- 23% Equipment Failure- 12% Equipment Hit-15% Other- 12% Unknown- 23% Weather - 12% Overload- 4%	Installed six lightning arrestors, seven animal guards, removed slack at one location and reattached wire insulator at one location. Performed tree trimming as required. One lightning arrester was found to exist.

(a) Table 5 provides a comparison of the ordinal ranking, as well as the SAIFI and SAIDI values, of the feeders' reliability during 2008 and 2010.

As of December 31, 2010, there were 689 feeders in Pepco's Maryland service territory.

Table 5 - Priority Feeders in 2008						
2008 Rank	2010 Rank	Feeder Number	SAIFI		SAIDI (Mins)	
			2008	2010	2008	2010
1	170	14110	8.92	3.87	2,551	290
2	51	15238	5.50	9.48	2,138	536
3	509	15084	4.51	0.05	1,605	16
4	419	14206	4.75	0.05	1,608	42
5	78	14490	4.25	3.11	1,518	550
6	59	14989	7.71	6.02	1,235	573
7	183	14922	6.00	2.37	1,227	300
8	139	14245	10.97	4.46	951	350
9	253	14918	5.00	2.31	1,110	118
10	329	14184	8.11	1.68	953	142
11	175	15230	9.48	2.25	894	274
12	234	14385	10.78	0.63	720	297
13	94	14270	5.96	3.68	1,062	519

Note the ordinal ranking shown in Table 5 may differ from the rankings shown in Table 2C, 2011 Priority Feeders Excluding Major Event Days (MEDs) which reflect the CPI and IEEE methodologies.
Rolling calendar used for both 2008 and 2010 (October 1 to September 30).

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Potomac Electric Power Company's 2010 Annual Reliability Indices Reporting was sent by first-class mail, postage prepaid, on this 2nd day of May 2011 to all parties in Case No. 8826.

Terry J. Romine, Esq.
Executive Secretary
Public Service Commission Of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202-6806

Mr. Dru Sedwick, President
Armstrong Telephone Company
122 South Queen Street
Rising Sun, Maryland 21911

Phillip J. Bray, Esq.
Allegheny Power
10435 Downsville Pike
Hagerstown, MD 21740

George D. Billinson, Esq.
Baltimore Gas and Electric Company
39 W. Lexington Street, 20th Floor
Baltimore, MD 21202

Ms. Sherry F. Bellamy, President
Verizon Maryland, Inc.
Constellation Place
One East Pratt Street, 8E
Baltimore, MD 21202

Peter F. Clark, Esq.
General Counsel
Conectiv
500 N. Wakefield Drive
Newark, DE 19899

Mr. Frederick L. Hubbard
Executive Vice President
Choptank Electric Cooperative
P.O. Box 430
Denton, MD 21629

Mr. I. Wayne Swann, President
Southern Maryland Electric Cooperative, Inc.
P.O. Box 1937
(Route 231 West)
Hughesville, MD 20637-1937

Ronald A. Decker, Esq.
Chief Staff Counsel
Office of Staff Counsel
Maryland Public Service Commission
6 St. Paul Street, 17th Floor
Baltimore, MD 21202

Jeral A. Milton, Esq.
111 South Calvert Street, Suite 2700
Baltimore, MD 21202-3200

M. Brent Hare, Esq.
Assistant Attorney General
Maryland Energy Administration
60 West Street, Suite 300
Annapolis, MD 21401

James L. Hunter
Business Manager, President
International Brotherhood of Electrical Workers,
Local Union 1900
5121 Henderson Road, Suites 300 and 103
Camp Springs, MD 20748

Mr. Robert D. Gardner
President
North Shore Association, Inc.
477 Edgewater Road
Pasadena, MD 21122

Guy Rendell
4064 Arjay Circle
Ellicott City, MD 21042-5608

Paula M. Carmody, Esq.
People's Counsel
Office of People's Counsel
6 St. Paul Street, 21st Floor
Baltimore, MD 21202

Stephanie A. Baldanzi, Esq.
Regulatory Attorney
AT&T Communications
3033 Chain Bridge Road, Room D316
Oakton, VA 22185-0001

Paul S. Buckley, Esq.
Washington Gas Light Company
1100 H Street, N.W.
Washington, DC 20080

Marc K. Battle

PAULA M. CARMODY
PEOPLE'S COUNSEL

THERESA V. CZARSKI
DEPUTY PEOPLE'S COUNSEL

STATE OF MARYLAND

ASSISTANT PEOPLE'S COUNSEL
CYNTHIA GREEN-WARREN
WILLIAM F. FIELDS
PETER SAAR
GARY L. ALEXANDER
ANNE JOHNSON
RON HERZFELD
FRANCIS D. HARTNETT
RICHARD S. GRATZ

OFFICE OF PEOPLE'S COUNSEL

6 Saint Paul Street, Suite 2102
Baltimore, Maryland 21202
(410) 767-8150 (800) 207-4055
FAX (410) 333-3616
WWW.OPC.STATE.MD.US

March 23, 2010

Terry Romine, Executive Secretary
Public Service Commission
Of Maryland
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: Case No. 9220

Dear Ms. Romine:

Subsequent to the filing, on March 18, 2010, by the Office of People's Counsel (OPC) of its Comments in connection with the above-referenced matter, Potomac Edison Company d/b/a Allegheny Power filed a Supplement to its original Storm Report. In addition, Choptank Electric Cooperative advised OPC that Choptank had inadvertently provided OPC with incorrect information in response to certain data requests of OPC.

The new information provided by Allegheny Power and Choptank is relevant to Tables 1, 2 and 3 of our Comments, and results in minor revisions to these Tables. The revised Tables are shown on Exhibit 1 attached to this letter. For ease of comparison, each Table is shown both "as filed" originally in the Comments and "after changes;" the changes are shown in boxes and in bold italics typeface. By way of this letter, OPC hereby substitutes each of revised Tables 1, 2 and 3 for the respective "as filed" Tables in the Comments.

The new information received from Allegheny Power and Choptank does not change the conclusions or recommendations contained in OPC's Comments.

Enclosed please find an original and seventeen (17) copies of Comments of the Office of People's Counsel in the above-referenced case.

A copy has been provided to all parties of record. If you have any questions, please do not hesitate to contact me.

Sincerely,

<u>/electronic signature/</u>

Anne L. Johnson
Assistant People's Counsel

ALJ/eom
Enclosure
cc: All Parties of Record

Changes in boxes.

TABLE 1 - as filed

	Allegheny Power	BGE	Choptank	DPL	PEPCO	SMECO
Cust Interruptions	14,192	142,228	38,240	86,024	264,434	38,724
Cust Interruption Hours	110,002	1,145,347	223,146	581,785	3,591,156	286,540
Hours per Cust Interruption	7.8	8.1	5.8	6.8	13.6	7.4

TABLE 1 - after changes

	Allegheny Power	BGE	Choptank	DPL	PEPCO	SMECO
Cust Interruptions	***14,321***	142,228	38,240	86,024	264,434	38,724
Cust Interruption Hours	***112,405***	1,145,347	223,146	581,785	3,591,156	286,540
Hours per Cust Interruption	7.8	8.1	5.8	6.8	13.6	7.4

TABLE 2 - as filed

	Allegheny Power	BGE	Choptank	DPL	PEPCO	SMECO
MD Service Area (Sq Mi)	2,544	2,300	9,500	3,471	575	1,150
OH Distribution (Cir Mi)	5,500	9,384	2,133	3,727	3,482	3,726
Cir Mi per Sq Mi	2.2	4.1	0.2	1.1	6.1	3.2
Cust Interruptions per Cir Mi	2.6	15.2	17.9	23.1	75.9	10.4

TABLE 2 - after changes

	Allegheny Power	BGE	Choptank	DPL	PEPCO	SMECO
MD Service Area (Sq Mi)	2,544	2,300	***2,742***	3,471	575	1,150
OH Distribution (Cir Mi)	5,500	9,384	2,133	3,727	3,482	3,726
Cir Mi per Sq Mi	2.2	4.1	***0.8***	1.1	6.1	3.2
Cust Interruptions per Cir Mi	2.6	15.2	17.9	23.1	75.9	10.4

	TABLE 3 - as filed			TABLE 3 - after changes	
	All Companies*			All Companies	
	Customer Interruptions	Customer Hours Interrupted		Customer Interruptions	Customer Hours Interrupted
Outage Cause					
Fallen Tree or Tree Limb	43%	55%		43%	55%
Fallen or Broken Pole	1%	1%		1%	1%
Lightning Damage	0%	0%		0%	0%
Ice accumulation or snow	10%	9%		10%	9%
Other	10%	7%		***11%***	7%
Power Supplier Outages	8%	5%		8%	5%
Substation Equipment	1%	0%		1%	0%
Wind	26%	22%		***25%***	22%
Weather--Other	0%	0%		0%	0%
Equipment Failures	1%	1%		1%	1%
Total	100%	100%		100%	100%

* except Allegheny Power

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9240
RESPONSE TO MC OCP DATA REQUEST NO. 4

QUESTION NO. 25

Q. PROVIDE A SUMMARY OF THE VEGETATION MANAGEMENT BUDGETS AND ACTUAL COSTS FOR 2003 TO 2009 AND THE VOLUME OF TRIMMING EXECUTED WITHIN PEPCO MARYLAND REGION, AND IF AVAILABLE, IN MONTGOMERY COUNTY. SPECIFICALLY, FOR EACH YEAR BETWEEN 2005 AND 2010:

A. REQUESTED VEGETATION MANAGEMENT BUDGET FOR PEPCO REGION, AND IF AVAILABLE, MONTGOMERY COUNTY.
B. MARYLAND PUBLIC SERVICE COMMISSION APPROVED VEGETATION MANAGEMENT BUDGET FOR PEPCO REGION, AND ANY SURPLUS OR SHORTFALL FROM THE REQUESTED BUDGET.
C. ACTUAL EXPENDITURES FOR TRIMMING FOR THE SAME AREA AS FOR THE BUDGET DATA ABOVE.
D. NUMBER OF MILES OF LINE THAT WERE TRIMMED
E. AVERAGE HOURLY COST AND NUMBER OF HOURS SPENT ON TREE TRIMMING OPERATIONS
F. ANTICIPATED CHANGES TO BUDGET REQUESTS FOR THE NEXT FIVE YEARS.

PEPCO'S RESPONSE February 15, 2011

A. A. See the attached. The requested information for Montgomery County is not available.

IBUTION TREE TRIMMING - Pepco MD	2003	2004	2005	2006	2007	2008	2009	2010
ACTUAL TREE TRIMMING O & M-MARYLAND	$3,999,858	$5,430,930	$4,524,564	$3,901,462	$3,960,829	$5,131,719	$5,024,721	$11,025,398
ACTUAL TREE TRIMMING CAPITAL-MARYLAND	NA	$4,344,107	$1,236,767	$858,758	$443,325	$619,793	$1,020,525	$471,690
ACTUAL TREE TRIMMING TOTAL-MARYLAND	$3,999,858	$9,775,037	$5,761,331	$4,760,220	$4,404,154	$5,751,512	$6,045,246	$11,497,088
BUDGET TREE TRIMMING O & M-MARYLAND	NA	$5,853,631	$3,326,751	$4,056,039	$3,380,947	$4,303,120	$4,324,033	$7,387,562
BUDGET TREE TRIMMING CAPITAL-MARYLAND	NA	$4,344,107	$1,236,767	$858,758	$443,325	$619,793	$1,020,525	$471,690
BUDGET TREE TRIMMING TOTAL-MARYLAND	NA	$10,197,738	$4,563,518	$4,914,797	$3,824,272	$4,922,913	$5,344,558	$7,859,252

Notes:
1. Available data for 2003 are included
2. Capital budgets for tree trimming are not available. In the table above, Capital actuals are shown as the Capital Budgets
3. 2010 Annual budget reflects $3 million supplemental provision for 2010.
4. Accruals for Pepco MD in the amount of $1,286,000 are included in the actual costs for 2010.

pepco

A PHI Company

Marc K. Battle
Assistant General Counsel

EP1132
701 Ninth Street, NW
Suite 1100, 10th Floor
Washington, DC 20068

202 872-3360
202 331-6767 Fax
mkbattle@pepcoholdings.com

February 18, 2011

Terry J. Romine, Esq.
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: Case No. 9256

Dear Ms. Romine:

Enclosed please find an original and seventeen (17) copies of Potomac Electric Power Company's (Pepco) State of Maryland Major Storm Report in the above-referenced proceeding.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Marc K. Battle

MKB/mda

Enclosure

cc: Paula M. Carmody, People's Counsel
Ronald A. Decker, Chief Staff Counsel

pepco

A PHI Company

State of Maryland
Major Storm Report
January 26 – 31, 2011: Snow Storm

Prepared By: **Potomac Electric Power Company**

701 Ninth St. NW

Washington, DC 20068-0001

February 18, 2011

Foreword

A major service outage occurred in Pepco's service territory on January 26, 2011, following a snow storm which interrupted power to over 221,000 customers, including 189,589 Maryland customers at peak. The last customer to be restored as a result of this storm was on January 31, 2011. Pursuant to COMAR 20.50.07.07, Pepco is required to file with the Maryland Public Service Commission (Commission), a written report within three weeks following the end of a major storm detailing the event's impact on Pepco's electric system and the associated system restoration efforts. Pepco's report on the effects of the January 26 storm and Pepco's restoration efforts are provided herein.

Table of Contents

Executive Summary

On January 26, 2011, a snow storm moved through the Pepco system during the afternoon rush hour commute. According to the National Weather Service, the first winter storm warning for the Pepco territory was issued at 1142 hours on January 26. The weather for the Pepco Region included a mixture of fog, rain and sleet during the morning hours, followed by period of icing, heavy wet snow and thunder which occurred during the late afternoon and evening rush hours in the Washington Metropolitan area. Due to the build up of ice followed by wet snow, there was a significant build up of snow on all exposed surfaces including trees, wires and poles. The snow fall totals for the Pepco region ranged from four to six inches in Central Montgomery County, areas such as Takoma Park and Silver Spring to Northern Montgomery County where isolated areas of Germantown and Damascus picked up over nine inches of snow. The storm began impacting the Pepco service territory at approximately 1700 hours. The snow storm caused outages to 221,632 customers at peak system-wide, which occurred at 2300 hours on January 26. Of these, 136,695 were in Montgomery County, 52,894 were in Prince George's County and 32,043 were in the District of Columbia. Pepco's Maryland service territory experienced peak of 189,589 customers interrupted at 2300 hours the same day as well.

On a system-wide basis, a total of 185 distribution circuit lock-outs were experienced; a total of 20 subtransmission line lock-outs occurred (14 – 69 kV circuits, 6 – 34 kV circuits) and 4,866 reports of "wires down" were responded to by Pepco. Of the 4,866 reports of wires down responded to by the Company, only 1,458 or 30% were actual Pepco electric wires down that Pepco found when the Company responded to wires down. No substations were out of service due to tree related issues.

From the peak of the storm, 90% of customers impacted system-wide, were restored by 0700 hours Saturday, January 29 which is 56 hours from the peak that occurred at 2300 hours on January 26. Further, from the start of the storm, which occurred at 1700 hours on January 26, 90% of the customers impacted system-wide were restored in 62 hours. In addition, from the peak of the storm, 90% of Maryland customers were restored in 59 hours or 65 hours from the start of the storm (1000 hours Saturday, January 29). The last Maryland customer affected by the storm was restored at 1609 hours on January 31, 2011.

Customers Affected

1. Event

The weather event occurred on January 26 and was attributed to a snow storm that followed a period of rain and icing which caused a large number of power outages in the Pepco service territory. The snow fall totals for the Pepco region ranged from four to six inches in Central Montgomery County, areas such as Takoma Park and Silver Spring to Northern Montgomery County where isolated areas of Germantown and Damascus picked up over nine inches of snow. The heavy wet snow/ice combination caused the failure of many trees and tree branches resulting in bringing down both electric and communication wires in many locations. On January 26 at 1700 hours, Pepco declared a storm event in its service territory.

2. Major Storm Restoration

Last customer restored as a result of the storm was at 1609 hours on January 31, 2011.

3. Number of Customers Affected

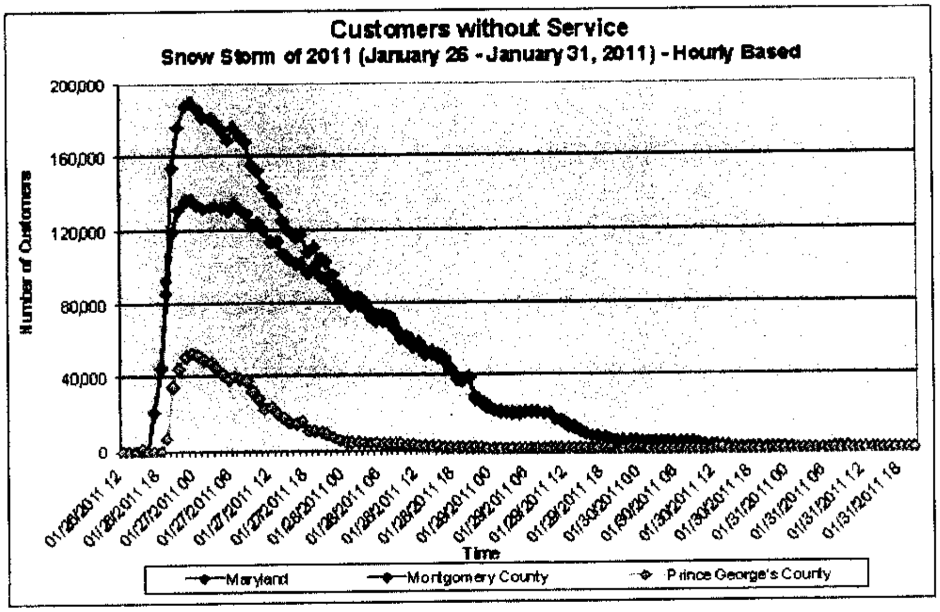
Peak System wide

The total number of customers experiencing outages, at the peak of the storm, across Pepco's Maryland and District of Columbia service territories was 221,632 at 2300 hours on January 26, 2011.

Peak State of Maryland

The total number of customers experiencing outages, at the peak of the storm, across Pepco's Maryland service territories was 189,589 at 2300 hours on January 26, 2011.

4. Sustained Interruptions



Number of Customers that were Experiencing a Sustained Interruption at Hourly Intervals During the Storm

Date: 01/26/2011

TIME	Pepco System	State of Maryland	Montgomery County, MD	Prince George's County, MD
01/26/2011 12	130	-	-	-
01/26/2011 13	151	15	15	-
01/26/2011 14	151	15	15	-
01/26/2011 15	4,374	1,062	5	1,057
01/26/2011 16	3,522	7	7	-
01/26/2011 17	24,911	21,303	21,302	1
01/26/2011 18	53,705	44,907	44,786	121
01/26/2011 19	109,378	93,029	85,785	7,244
01/26/2011 20	181,116	153,833	118,987	34,846
01/26/2011 21	207,236	175,264	130,933	44,331
01/26/2011 22	219,666	187,283	136,266	50,997
01/26/2011 23	221,632	189,589	136,695	52,894

Total Customers Out at Peak (at end of hour, not minute based)
Last customer restored as the result of the event occurred at 1609 hours on January 31.

Date: 01/27/2011

TIME	Pepco System	State of Maryland	Montgomery County, MD	Prince George's County, MD
01/27/2011 00	217,324	185,581	133,841	51,740
01/27/2011 01	207,640	181,299	131,963	49,336
01/27/2011 02	204,462	180,137	132,379	47,758
01/27/2011 03	200,827	178,453	133,210	45,243
01/27/2011 04	194,643	173,616	132,325	41,291
01/27/2011 05	189,835	168,506	130,137	38,369
01/27/2011 06	193,293	175,277	135,028	40,249
01/27/2011 07	190,532	171,088	132,188	38,900
01/27/2011 08	186,930	167,339	129,245	38,094
01/27/2011 09	174,920	155,328	122,496	32,832
01/27/2011 10	168,913	152,380	123,914	28,466
01/27/2011 11	159,787	143,162	119,902	23,260
01/27/2011 12	153,191	137,832	113,804	24,028
01/27/2011 13	149,467	134,223	113,630	20,593
01/27/2011 14	139,228	125,085	107,048	18,037
01/27/2011 15	131,324	119,662	104,322	15,340
01/27/2011 16	126,160	116,490	101,909	14,581
01/27/2011 17	129,074	117,580	101,554	16,026
01/27/2011 18	119,245	107,735	96,738	10,997
01/27/2011 19	120,817	110,634	99,584	11,050
01/27/2011 20	114,763	104,607	94,706	9,901
01/27/2011 21	112,716	102,856	93,776	9,080
01/27/2011 22	105,712	96,047	88,746	7,301
01/27/2011 23	98,889	89,554	83,913	5,641

Date: 01/28/2011

TIME	Pepco System	State of Maryland	Montgomery County, MD	Prince George's County, MD
01/28/2011 00	94,270	86,645	82,114	4,531
01/28/2011 01	91,092	83,503	79,000	4,503
01/28/2011 02	91,762	84,181	79,678	4,503
01/28/2011 03	87,802	81,416	77,082	4,334
01/28/2011 04	82,761	76,583	72,274	4,309
01/28/2011 05	80,945	74,400	70,217	4,183
01/28/2011 06	79,770	73,796	69,928	3,868
01/28/2011 07	78,526	72,829	69,064	3,765
01/28/2011 08	74,530	68,816	65,262	3,554
01/28/2011 09	69,274	63,707	60,101	3,606
01/28/2011 10	67,525	61,959	58,961	2,998
01/28/2011 11	63,515	58,251	55,742	2,509
01/28/2011 12	63,444	57,903	55,433	2,470
01/28/2011 13	58,963	53,870	51,655	2,215
01/28/2011 14	58,262	53,221	51,095	2,126
01/28/2011 15	57,011	52,180	50,139	2,041
01/28/2011 16	54,809	50,084	48,468	1,616
01/28/2011 17	49,265	44,600	43,185	1,415
01/28/2011 18	43,182	38,791	37,629	1,162
01/28/2011 19	42,853	38,461	37,329	1,132
01/28/2011 20	43,909	39,512	38,470	1,042
01/28/2011 21	31,704	28,879	27,838	1,041
01/28/2011 22	29,505	26,690	25,719	971
01/28/2011 23	26,977	24,104	23,262	842

Date: 01/29/2011

TIME	Pepco System	State of Maryland	Montgomery County, MD	Prince George's County, MD
01/29/2011 00	24,245	21,400	20,649	751
01/29/2011 01	23,594	21,081	20,551	530
01/29/2011 02	23,331	20,827	20,312	515
01/29/2011 03	22,870	20,324	19,819	505
01/29/2011 04	22,729	20,238	19,756	482
01/29/2011 05	23,224	20,763	20,269	494
01/29/2011 06	22,795	20,665	20,172	493
01/29/2011 07	21,525	20,771	20,279	492
01/29/2011 08	20,790	20,072	19,577	495
01/29/2011 09	20,363	19,622	19,165	457
01/29/2011 10	17,539	16,742	16,330	412
01/29/2011 11	16,856	16,207	15,790	417
01/29/2011 12	13,698	13,146	12,734	412
01/29/2011 13	12,745	12,209	11,459	750
01/29/2011 14	10,860	10,395	9,756	639
01/29/2011 15	9,370	8,899	8,270	629
01/29/2011 16	7,974	7,468	7,229	239
01/29/2011 17	7,644	7,155	6,951	204
01/29/2011 18	6,961	6,540	6,342	198
01/29/2011 19	5,482	5,089	4,893	196
01/29/2011 20	5,159	4,771	4,582	189
01/29/2011 21	5,087	4,696	4,509	187
01/29/2011 22	5,110	4,728	4,474	254
01/29/2011 23	4,972	4,600	4,384	216

Date: 01/30/2011

TIME	Pepco System	State of Maryland	Montgomery County, MD	Prince George's County, MD
01/30/2011 00	4,742	4,372	4,166	206
01/30/2011 01	4,611	4,240	4,056	184
01/30/2011 02	4,610	4,241	4,058	183
01/30/2011 03	4,509	4,163	4,021	142
01/30/2011 04	4,256	3,937	3,813	124
01/30/2011 05	3,755	3,435	3,313	122
01/30/2011 06	3,821	3,505	3,400	105
01/30/2011 07	3,631	3,331	3,228	103
01/30/2011 08	3,685	3,401	3,300	101
01/30/2011 09	3,129	2,936	2,835	101
01/30/2011 10	2,568	2,459	2,355	104
01/30/2011 11	2,265	2,170	2,091	79
01/30/2011 12	1,883	1,808	1,612	196
01/30/2011 13	1,387	1,310	1,117	193
01/30/2011 14	1,250	1,051	983	68
01/30/2011 15	1,046	833	769	64
01/30/2011 16	905	722	593	129
01/30/2011 17	805	630	507	123
01/30/2011 18	694	524	404	120
01/30/2011 19	688	369	257	112
01/30/2011 20	606	292	244	48
01/30/2011 21	599	287	240	47
01/30/2011 22	584	273	237	36
01/30/2011 23	551	245	210	35

Date: 01/31/2011

TIME	Pepco System	State of Maryland	Montgomery County, MD	Prince George's County, MD
01/31/2011 00	500	197	189	8
01/31/2011 01	492	191	185	6
01/31/2011 02	301	175	170	5
01/31/2011 03	279	153	150	3
01/31/2011 04	262	136	136	-
01/31/2011 05	261	135	134	1
01/31/2011 06	262	131	130	1
01/31/2011 07	267	260	258	2
01/31/2011 08	303	296	284	12
01/31/2011 09	385	280	267	13
01/31/2011 10	252	145	132	13
01/31/2011 11	210	106	100	6
01/31/2011 12	191	74	69	5
01/31/2011 13	162	61	54	7
01/31/2011 14	51	49	41	8
01/31/2011 15	29	26	19	7
01/31/2011 16	21	18	14	4
01/31/2011 17	-	-	-	-

5. Customer Interruption Hours

Customer Interruption Hours - Pepco System	6,721,141
Customer Interruption Hours - State of Maryland	6,021,515
Customer Interruption Hours - Montgomery County	5,115,802
Customer Interruption Hours - Prince George's County	905,713

Outside Assistance Resources

EXTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

6. Outside Assistance Contacts

On January 25, Pepco contacted existing Company contractors to inform them of the pending storm and requested identification of additional crews. On January 26, additional Company and Pepco contract crews were scheduled for extended work hours. At 1830 hours on January 26, and additional 57 contract crews were obtained from outside of the Pepco Holdings Inc. (PHI) system by companies currently on the Pepco system. These crews began reporting at 1000 hours January 27 (Utility Lines, Henkels and Fry Electric). In addition, 43 additional Delmarva Power contract crews were obtained at 18:30 and reported to Pepco at 1000 hours on January 27 and 48 Atlantic City Electric contract crews were released and reported to Pepco on January 27 at 1630 hours.

In addition to obtaining assistance from contractors and Pepco utility affiliates as described above, the Company also obtained Mutual Assistance. Mutual Assistance, as Pepco uses that term, refers to the sharing of line crew resources between utilities during an emergency, and is secured through formal Mutual Assistance coordination structures, such as the Mid-Atlantic Mutual Assistance organization and the Southeastern Electric Exchange. Mutual Assistance is in addition to the support that Pepco musters through its own Company-wide and contractor resources.

Mutual Assistance communications commenced at 2030 hours on January 26. A total of 615 personnel were requested by 1600 hours January 31. Also, Pepco requested augmentation of its sustaining contractor workforce. Below is a listing of the dates, times and organizations communicated with regarding Mutual Assistance.

DATE	TIME	GROUP
1/25/2011		Communication with Company contractors
1/26/2011		Secured additional Company contract crews
1/26/2011	2030 hrs.	Mid-Atlantic Mutual Assistance (MAMA) communication
1/26/2011	2130 hrs.	Requested Southeastern Electrical Exchange (SEE) mutual call
1/27/2011	0730 hrs.	Mid-Atlantic Mutual Assistance (MAMA) communication
1/27/2011	0830 hrs.	Southeastern Electrical Exchange (SEE) communication
1/27/2011	1000 hrs.	Maryland Utility Group Mutual Assistance (MUGMA) communication
1/31/2011	1439 hrs.	Mid-Atlantic Mutual Assistance (MAMA) communication
1/31/2011	1600 hrs.	Southeastern Electrical Exchange (SEE) communication

Crews travelled from Pennsylvania, Ohio, New Jersey, North Carolina, Virginia and Delaware. In addition, Pepco built two staging sites and secured lodging to accommodate all out-of-town resources.

In addition, Pepco's Call Center reached out to the Mutual Assistance Routing System (MARS) to obtain additional resources to process customer calls during the storm. A call was made at 2115 hours on January 26 to inform MARS responding companies that activation was required for January 27 and January 28. Georgia Power responded back at 0015 hours on January 27 to advise that Southern Company could assist. On January 27, Tampa and NSTAR also responded with support. At 1130 hours, a meeting with responding companies and Twenty First Century was convened to discuss staffing needs, training update, logistics, etc. At 1400 hours, a conference bridge was opened and MARS was activated.

7. Outside Assistance Resources

Resources

7. a) Organization(s) Providing Crews

- Area Utilities
- Utility Lines – Off Property
- MainLite
- Thompson Electric
- Duquesne Light
- First Energy
- MasTec
- J. W. Foley
- East Coast UG
- Tri-M Electric
- Henkels
- Fry Electric
- J. W. Didado
- Delaware Electric Co-op
- MJ Electric – Duquesne
- MJ Electric – PPL
- Asplundh Construction
- Hawkeye
- Riggs Distler
- Progress Energy – Northern
- Progress Energy – Eastern
- Sumter Utilities
- Pike Electric
- E&R
- First Energy – JCP&L
- CW Wright
- Rockingham
- Utility Lines
- WA Chester
- Asplundh (Tree Trimming)

7. b) Date and Time of Crew Arrivals and Departures

Mutual Assistance

Organization Providing Crews	Arrived	Number of Personnel	Departed
Area Utilities	January 27 1000 hours	12 People	February 1 1800 hours
Utility Lines	January 27 1000 hours	16 People	February 2 0800 hours
MainLite	January 27 1800 hours	32 People	February 2 0700 hours
Thompson Electric	January 27 1715 hours	51 People	February 2 0930 hours
Duquesne Light	January 27 1800 hours	18 People	January 31 1100 hours
First Energy	January 27 1830 hours	29 People	January 31 1200 hours
MasTec	January 28 0230 hours	48 People	February 2 0800 hours
East Coast UG	January 27 1000 hours	27 People	February 2 0800 hours
Tri-M Electric	January 27 0945 hours	16 People	February 2 0800 hours
Henkels	January 27 1530 hours	8 People	February 2 0800 hours
Fry Electric	January 27 1045 hours	33 People	February 2 0800 hours

Organization Providing Crews	Arrived	Number of Personnel	Departed
J. W. Didado	January 27 1715 hours	87 People	February 2 0800 hours
Delaware Electric Co-op	January 27 1330 hours	16 People	January 31 0700 hours
MJ Electric – Duquesne	January 27 1630 hours	12 People	January 31 1200 hours
MJ Electric – PPL	January 27 1630 hours	9 People	February 2 0830 hours
Asplundh Construction	January 27 1630 hours	33 People	January 31 1300 hours
Progress Energy – Northern	January 28 0900 hours	35 People	February 2 0830 hours
Progress Energy – Eastern	January 28 1000 hours	40 People	February 2 0830 hours
Sumter Utilities	January 27 2230 hours	22 People	February 2 0845 hours
Pike Electric	January 27 2200 hours	32 People	February 2 0930 hours
E&R	January 27 2400 hours	21 People	February 2 0900 hours
First Energy – JCP&L	January 30 0800 hours	35 People	January 31 1300 hours

Pepco Contractors on the Pepco system on January 26

Organization Providing Crews	Number of Personnel
CW Wright	59 People
Rockingham	29 People
Utility Lines	21 People
WA Chester	14 People
Asplundh (Tree Trimming)	250 People

Other Pepco Holdings, Inc. (PHI) Contractors on the Pepco System

Organization Providing Crews	Arrived	Number of Personnel	Departed
Asplundh (Tree Trimming) - Delmarva Power	January 28 1000 hours	63 People	February 1 1300 hours
J. W. Foley – Atlantic City Electric	January 28 1300 hours	30 People	January 31 1300 hours
Hawkeye– Atlantic City Electric	January 27 1630 hours	8 People	February 2 0830 hours
Riggs Distler– Atlantic City Electric	January 27 1615 hours	10 People	February 2 0915 hours
Delmarva Power	January 28 1000 hours	45 People	January 31 1300 hours

Other Pepco Holdings, Inc. (PHI) Utility Personnel – 45 Support Personnel

7. c) Number and Type of Vehicles – 594

- 337 Bucket Trucks
- 84 Digger Derricks
- 173 Miscellaneous Vehicles [Pick-ups, other trucks, etc]

7. d) Total Number of External Personnel – 1,206

- 1,206 Personnel

Deployment

7. e) Primary Overhead Line Personnel

- 739 Personnel

7. f) Secondary Overhead Line Personnel

- 109 Personnel

7. g) Tree Trimming Personnel / Other Support Personnel

- 313 Personnel

7. h) Primary Underground Line Crews

- Not Applicable (NA)

7. i) Secondary Underground Line Crews

- NA

7. j) Substation Crews

- NA

7. k) Other Personnel

- 45 Other Support Personnel (PHI) – Includes crew guides, logistics, Incident Management Team personnel and other support personnel

INTERNAL RESOURCES – DEPLOYED PEPCO SYSTEM-WIDE

8. Electric Utility Crews

Resources

8. a) Number and Type of Vehicles – 247

- 49 Bucket Trucks
- 4 Digger Derricks
- 194 Miscellaneous Vehicles [Pick-ups, other trucks, etc.]

8. b) Total Number of Internal Pepco Personnel - 964

- 964 Personnel

Deployment

8. c) Primary Overhead Line Personnel

- 143 Personnel

8. d) Secondary Overhead Line Personnel

- 11 Personnel

8. e) Damage Assessment Personnel

- 122 Personnel performed field damage assessments

8. f) Tree Trimming Personnel

- 6 Personnel coordinating and supervising tree trimming crews

8. g) Primary Underground Line Crews

- NA

8. h) Secondary Underground Line Crews

- NA

8. i) Substation Personnel

- 76 Personnel

8. j) Other Personnel

- 606 Other Support Personnel – Includes crew guides, wires down patrollers, dispatchers, logistics and other support personnel

Communications

General

Pepco works to maintain positive relationships with county and/or local Emergency Management Agencies (EMA). PHI's Emergency Management Manager is responsible for providing county and/or local EMA personnel with "one point of contact" for addressing operational and community support requests. For the January 26 storm, Pepco EMA Liaisons were assigned to the Montgomery County EMA. Prince George's County did not request EMA Liaison support.

All 911 Centers and EMA in Pepco's service territory have a direct dial line communications radio that is supplied courtesy of the utility and can be used to communicate with each utility in the event of a communications emergency.

GOVERNMENT AFFAIRS AND REGULATORY AFFAIRS CONTACTS

Over the course of the storm, Pepco conducted daily conference calls with participants from County and Local Governments, elected officials, the Office of the People's Counsel (District and Maryland) and members from both the District of Columbia and Maryland Public Service Commissions.

In addition, the President of Pepco Region held news conferences and conducted several interviews. Further, Pepco:

- Conducted daily conference calls with government officials from January 27 – January 30 that included on average, 49 participants with maximum participation of 88;
- distributed news release via email to government stakeholders;
- responded to inquiries from elected officials; and
- worked closely with government officials to identify restoration priorities.

REGULATORY CONTACTS

Pepco provided storm updates to the Maryland Public Service Commission (MDPSC) Commissioners and their Staffs as well as to other key stakeholders.

MEDIA COMMUNICATIONS

During the restoration period for the January 26 storm, Pepco held 33 media interviews the first day following the storm (January 27) and issued six news releases detailing restoration efforts and estimated times of restoration. Social media was also utilized including Twitter and Facebook.

9. Customer Operations Statistics

Severe Weather
January 26, 2011 Telephone Interval Report

Time	Rep Ans	Inhse VRU	HVCA	Total Inc	Total Ans	Internal Staff	AUX Staff	MARS Staff
5PM - 6PM	523	485	1918	3096	2926	41	0	0
6PM-7PM	645	842	6225	7839	7712	34	0	0
7PM-8PM	565	1049	15373	17110	16987	30	0	0
8PM-9PM	368	1074	16331	17836	17773	29	0	0
9PM-10PM	387	894	11245	12555	12526	29	0	0
10PM-11PM	355	991	6797	8172	8143	26	1	0
11PM-12AM	349	626	3451	4426	4426	28	1	0
	3192	**5961**	**61340**	**71034**	**70493**			

TSF @ 60 Seconds: 95.08%

Rep Ans – Representative Answered,
Inhse VRU – In house Voice Response Unit,
HVCA – High Volume Call Answering System
AUX Staff – Auxiliary Staff (internal)
MARS Staff – Mutual Assistance Routing System (external)

Severe Weather
January 27, 2011 Telephone Interval Report

Time	Rep Ans	Inhse VRU	HVCA	Total Inc	Total Ans	Internal Staff	AUX Staff	MARS Staff
12AM - 1AM	223	279	1784	2287	2286	14	1	0
1AM - 2AM	160	164	1206	1532	1530	13	1	0
2AM - 3AM	136	147	1242	1527	1525	13	1	0
3AM - 4AM	119	154	1187	1461	1460	12	1	0
4AM - 5AM	111	161	1484	1756	1756	10	1	0
5AM-6AM	84	284	2160	2528	2528	9	1	0
6AM - 7AM	189	379	3291	3860	3859	10	9	0
7AM - 8AM	487	787	7975	9375	9249	21	23	0
8AM - 9AM	836	1497	9359	11992	11692	42	47	0
9AM - 10AM	920	1324	6603	9198	8847	48	64	0
10AM - 11AM	1381	1279	5463	8249	8123	51	78	0
11AM - 12PM	1290	1227	4855	7375	7372	57	81	0
12PM - 1PM	1508	1492	4552	7559	7552	61	80	0
1PM - 2PM	1714	1154	4004	7015	6872	63	79	0
2PM - 3PM	1827	996	3599	6774	6422	63	82	17
3PM - 4PM	2364	1780	2557	6993	6701	63	86	40
4PM - 5PM	2383	1874	2280	6754	6537	55	82	43
5PM - 6PM	2022	1539	1814	5615	5375	50	74	78
6PM-7PM	1930	1456	915	4457	4301	47	67	90
7PM-8PM	1133	1163	744	3368	3040	43	21	95
8PM-9PM	904	1030	496	2489	2430	27	16	86
9PM-10PM	742	889	389	2030	2020	14	15	76
10PM-11PM	540	596	251	1390	1387	12	14	33
11PM-12AM	291	289	153	734	733	13	13	18
	23294	**21940**	**68363**	**116318**	**113597**			

TSF @ 60 Seconds: 91.04%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System
AUX Staff – Auxiliary Staff (internal)
MARS Staff – Mutual Assistance Routing System (external)

Severe Weather
January 28, 2011 Telephone Interval Report

Time	Rep Ans	Inhse VRU	HVCA	Total Inc	Total Ans	Internal Staff	AUX Staff	MARS Staff
12AM - 1AM	59	52	147	258	258	8	18	0
1AM - 2AM	27	23	112	162	162	8	20	0
2AM - 3AM	20	27	124	171	171	8	19	0
3AM - 4AM	35	41	118	194	194	8	17	0
4AM - 5AM	42	43	187	272	272	8	17	0
5AM-6AM	55	89	320	464	464	8	17	0
6AM - 7AM	96	153	575	824	824	10	20	0
7AM - 8AM	600	418	1396	2421	2414	30	95	0
8AM - 9AM	1295	1138	1632	4073	4065	47	68	0
9AM - 10AM	2378	305	255	2988	2938	52	85	11
10AM - 11AM	2560	339	257	3223	3156	52	94	18
11AM - 12PM	2558	328	397	3323	3283	58	96	17
12PM - 1PM	2411	315	340	3099	3066	61	90	16
1PM - 2PM	2092	284	369	2814	2745	61	85	14
2PM - 3PM	1997	261	645	2981	2903	68	82	17
3PM - 4PM	2514	326	473	3345	3313	70	97	18
4PM - 5PM	2559	328	211	3125	3098	69	95	25
5PM - 6PM	2364	258	77	2760	2699	65	96	69
6PM-7PM	2017	193	43	2301	2253	63	90	74
7PM-8PM	1605	156	47	1835	1808	49	21	65
8PM-9PM	1370	93	470	1991	1933	31	18	69
9PM-10PM	1072	78	183	1381	1333	24	18	71
10PM-11PM	731	48	442	1277	1221	24	17	30
11PM-12AM	442	50	1005	1567	1497	23	15	8
	30899	**5346**	**9825**	**46849**	**46070**			

TSF @ 60 Seconds: 69.29%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System
AUX Staff – Auxiliary Staff (internal)
MARS Staff – Mutual Assistance Routing System (external)

Severe Weather
January 29, 2011 Telephone Interval Report

Time	Rep Ans	Inhse VRU	HVCA	Total Inc	Total Ans	Internal Staff	AUX Staff	MARS Staff
12AM - 1AM	270	20	489	795	779	15	14	0
1AM - 2AM	72	13	250	335	335	8	14	0
2AM - 3AM	47	9	150	206	206	7	14	0
3AM - 4AM	38	11	146	195	195	7	14	0
4AM - 5AM	39	16	156	211	211	7	14	0
5AM-6AM	49	7	181	237	237	7	14	0
6AM - 7AM	91	28	451	572	570	12	15	0
7AM - 8AM	423	49	1366	1839	1838	26	62	0
8AM - 9AM	1170	126	1284	2586	2580	42	102	0
9AM - 10AM	2276	103	263	2717	2642	50	97	48
10AM - 11AM	1667	140	180	2068	1987	53	99	51
11AM - 12PM	1541	138	130	1881	1809	54	101	50
12PM - 1PM	1398	163	118	1762	1679	52	97	54
1PM - 2PM	1316	128	108	1621	1552	53	98	53
2PM - 3PM	1163	129	89	1408	1381	55	100	53
3PM - 4PM	1343	124	88	1604	1555	55	100	55
4PM - 5PM	1436	101	28	1640	1565	51	97	50
5PM - 6PM	856	81	26	1008	963	50	98	35
6PM-7PM	613	81	20	776	714	50	92	31
7PM-8PM	442	60	14	541	516	39	16	28
8PM-9PM	307	49	7	384	363	29	9	28
9PM-10PM	266	40	60	368	366	25	9	12
10PM-11PM	244	21	59	328	324	25	9	0
11PM-12AM	261	23	41	329	325	24	9	0
	17328	**1660**	**5704**	**25411**	**24692**			

TSF @ 60 Seconds: 96.55%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System
AUX Staff – Auxiliary Staff (internal)
MARS Staff – Mutual Assistance Routing System (external)

Severe Weather
January 30, 2011 Telephone Interval Report

Time	Rep Ans	Inhse VRU	HVCA	Total Inc	Total Ans	Internal Staff	AUX Staff	MARS Staff
12AM - 1AM	55	9	86	150	150	7	13	0
1AM - 2AM	17	10	34	61	61	7	14	0
2AM - 3AM	11	8	18	37	37	7	14	0
3AM - 4AM	13	3	20	37	36	7	14	0
4AM - 5AM	19	1	18	38	38	7	14	0
5AM-6AM	7	2	12	21	21	7	14	0
6AM - 7AM	27	6	63	96	96	18	16	0
7AM - 8AM	138	22	131	294	291	32	76	0
8AM - 9AM	176	43	315	535	534	47	102	0
9AM - 10AM	379	71	30	491	480	54	104	29
10AM - 11AM	386	66	7	471	459	54	104	26
11AM - 12PM	345	65	9	427	419	56	104	29
12PM - 1PM	299	66	7	374	372	54	100	26
1PM - 2PM	240	66	1	312	307	53	98	28
2PM - 3PM	238	78	2	321	318	52	99	27
3PM - 4PM	190	52	2	246	244	48	100	25
4PM - 5PM	277	87	1	372	365	49	98	15
5PM - 6PM	200	77	4	286	281	46	96	14
6PM-7PM	111	72	2	186	185	46	94	14
7PM-8PM	151	59	7	222	217	37	16	13
8PM-9PM	84	53	4	143	141	24	14	14
9PM-10PM	52	60	1	116	113	17	11	0
10PM-11PM	190	46	33	271	269	17	11	0
11PM-12AM	49	20	2	72	71	17	10	0
	3654	**1042**	**809**	**5579**	**5505**			

TSF @ 60 Seconds: 97.94%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System
AUX Staff – Auxiliary Staff (internal)
MARS Staff – Mutual Assistance Routing System (external)

Severe Weather
January 31, 2011 Telephone Interval Report

Time	Rep Ans	Inhse VRU	HVCA	Total Inc	Total Ans	Internal Staff	AUX Staff	MARS Staff
12AM - 1AM	2	27	9	38	38	7	15	0
1AM - 2AM	10	18	5	33	33	7	16	0
2AM - 3AM	2	6	6	14	14	7	16	0
3AM - 4AM	7	16	5	28	28	7	16	0
4AM - 5AM	2	3	7	12	12	7	16	0
5AM-6AM	14	22	5	41	41	7	15	0
6AM - 7AM	17	27	14	61	58	7	14	0
7AM - 8AM	349	144	37	540	530	22	37	0
8AM - 9AM	557	256	56	1011	869	44	38	0
9AM - 10AM	670	310	54	1338	1034	54	38	0
10AM - 11AM	696	352	46	1400	1094	60	37	0
11AM - 12PM	706	307	31	1361	1044	65	37	0
12PM - 1PM	648	312	34	1336	994	65	29	0
1PM - 2PM	665	305	34	1276	1004	66	29	0
2PM - 3PM	522	213	19	1147	754	68	24	0
3PM - 4PM	683	225	30	1289	938	66	21	0
	5550	**2543**	**392**	**10925**	**8485**			

TSF @ 60 Seconds: 60.09%

Rep Ans – Representative Answered
Inhse VRU – In house Voice Response Unit
HVCA – High Volume Call Answering System
AUX Staff – Auxiliary Staff (internal)
MARS Staff – Mutual Assistance Routing System (external)

"Total Calls Answered" and "Total Calls Received" represent all storm and non-storm related calls received at the Pepco Call Center and handled by a Customer Service Representative, Voice Response Unit [VRU] or High Volume Call Answering System [HVCA].

Storm Damage Information

10. System Damage

a) Poles Replaced..50

b) Distribution Transformers Replaced..41

c) Fuses Replaced..7,917

d) Downed Wires Reported..4,866

e) Substation with Equipment Damage...................................... 1*

*No substations were out of service due to tree related issues similar to the last storm of August 12, 2010. Note Kensington Substation was not affected as a result of the loss of its supply feeders. An equipment failure within the building occurred that resulted in the collapse of a portion of the roof, damage to the building structure and equipment and to some of the power lines exiting the station. There were other storm-related outages in this neighborhood that were unrelated to the substation issue. Power from all distribution feeders out of Kensington Substation, were routed through ties to seven other substations surrounding the Kensington/Wheaton area. Kensington Substation serves approximately 12,000 customers.

11. Materials

Material inventories were closely monitored to ensure the availability of necessary equipment and materials for restoration activities across the Pepco service territory. Necessary materials were available for restoration efforts.

Self Assessment

12. Self Assessment

Wire Down Process Issues

Pepco takes customer calls reporting wire down cases seriously and follows a pre-defined process to protect public safety and ensure that electric wires that have fallen on the ground are secure. In the aftermath of the January 26 event, Pepco responded to 4,866 reports of wire down, forcing the Company to prioritize deployment of its resources to inspect lines in the field and secure them. Note of the 4,866 reports of wires down responded to by the Company, only 1,458 or 30% were actual Pepco electric wires down that Pepco found when it responded to wires down. Another challenge in addressing wire down reports is that a large portion of reported wires down do not involve electric lines but telecommunication of other utility wires. Because of the potential threat to public safety that downed wires pose, Pepco has to send crews to all reported locations, which may include telecommunications or cable lines as well as calls of wires down when no wires are found by the crews, increasing the workload during the restoration effort.

Pepco has identified this issue following all the storms in 2010, and the issue is being examined in ongoing Commission Docket PC-21.

Damage Assessment, Crew Allocation, and Decentralized Resource Dispatch

Within the past year, Pepco has made several changes to its process for allocating internal and mutual assistance crews responding to major storms. Specifically, Pepco has increased the number of employees qualified to perform damage assessment, crew leader, and crew guide functions. During this event, it provided Pepco the greater flexibility to perform more damage assessment and enabled the dispatch of smaller crew compliments. This was particular critical for this event where we experienced many single customer outages and reports of individual house and secondary wires down.

Furthermore, for this event Pepco was able to implement a decentralization process of the crew dispatch functions. By dispatching work from de-centralized locations, more effective crew management was realized. Due to its success in this event, Pepco plans to further refine this process in the coming months.

Technology Issues

The Information Technology (IT) restoration systems such as the Outage Management (OMS) and Mobile Dispatch System (MDS) performed as designed and there were no software or hardware issues that impacted the restoration. There was one issue with the OMS that did not affect the restoration effort in any known way but did result in an over-count of 11,279 customers on the external web site. Pepco personnel have identified the specific nature of the underlying issue and are working with the OMS vendor to remedy this reporting error in the future.

There was a second and unrelated issue related to the outage maps portion of the Pepco public web site (www.pepco.com). This site is intended for general information for the public. As such, this site does not allow close zoom-in on specific outages in order to protect customer privacy and ensure that this site is not used by others for inappropriate purposes. The closest level of zoom is one mile and provides grouped outages and a single ETR (Estimated Time of Restoration) that is the longest in the group. However, during the storm restoration, a number of customers compared this to the ETR they received when they reported their outage on the phone and noted that there was a mismatch. Based on customer concerns, the public site was taken down late on the evening of January 27 to ensure that there were no underlying technical issues (there were none) and to install a message as follows:

"Estimated restoration times reflected in a stacked blue triangle are the most conservative for the outages below the zoom level. The outage maps only zoom to a 1 mile level to ensure customer privacy. For customer specific estimated restoration time, please call 877-737-2662."

This site was brought back up again on the morning of January 28. It should be noted that Pepco has surveyed other utilities regarding their practice on outage maps. Pepco discovered that many utilities do not provide outage maps. Utilities that do provide outage maps have encountered similar issues of balancing the need for public information, against the need for customer privacy and preventing inappropriate use.

Call Center Voice Mailbox Issues

During the January 26 storm, when customers attempted to a leave a message in Pepco's Call Center voice mailbox, some customers received a voice mailbox is full message. A customer could have received the message if they were trying to input information into the system that was not unique to a premise that Pepco has on record. For example, if a customer wanted to report a wires down and the customer provided address information not unique to a premise on record (corner of Oxon Hill Road and Livingston Road), that information would have gone into the voice mailbox. When the number of people leaving messages ramped up at a faster rate than Pepco representatives could retrieve the messages, the mailbox would have gotten full and customers would have received a voice mailbox is full message. Pepco recognized the need to deploy more resources to retrieve the messages and did so accordingly.

EMA Coordination

Pepco representation was unable to report immediately to the Montgomery County EMA location due to the harsh weather and severe traffic congestion experienced the day of the storm and missed a conference call. Pepco acknowledges that better coordination is necessary in order to address the needs of the Montgomery County EMA. Since the January 26 storm, Pepco has obtained direct contact numbers for the director of the Montgomery County EMA in order to communicate and participate on calls even if Liaison representation is not physically at the convening location.

Logistics

In Montgomery County, there were concerns regarding the location of the staging area in Gaithersburg, Maryland as opposed to having a staging area located closer to the Beltway. Pepco currently has several alternative areas that can be used for staging in the future. Pepco will investigate using alternative locations for future events.

Interruption Causes

13. Interruption Causes and Interruption Hours

	Customers	Hours of Interruption
a) Fallen Tree or Tree Limb	116,065	2,642,435
b) Equipment Failures	2,344	76,610
c) Lightning Damage	1,418	21,985
d) Weather	226,872	2,474,853
e) Weather Related Damage (Other)	690	17,514
f) Source Lost	1,465	21,295
g) Other Major Causes*	31,605	776,823
	380,459	6,021,515

*Includes Unknown, Fire, Load, etc.

Note approximately 90% of the outages during the storm were tree-related (Percentage is derived from taking the sum of fallen trees or tree limb and weather categories and dividing by the total number customers).

CASE NO. 9240

**IN THE MATTER OF AN INVESTIGATION INTO
THE RELIABILITY AND QUALITY OF THE
ELECTRIC DISTRIBUTION SERVICE OF
POTOMAC ELECTRIC POWER COMPANY**

BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION

**DIRECT TESTIMONY OF DAVID J. EFFRON
ON BEHALF OF THE
MARYLAND OFFICE OF PEOPLE'S COUNSEL**

MAY 6, 2011

CASE NO. 9240
DIRECT TESTIMONY OF DAVID J. EFFRON
TABLE OF CONTENTS

EXHIBITS AND ATTACHMENTS

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My business address is 12 Pond Path, North Hampton, New Hampshire, 03862

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. I have analyzed numerous electric, telephone, gas and water rate filings in different jurisdictions. Pursuant to those analyses, I have prepared testimony, assisted attorneys in rate case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over two hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

My other professional experience and educational background are summarized in Appendix 1 accompanying this testimony.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Maryland Office of People's Counsel (or "OPC").

Q. What is the purpose of your testimony?

A. In this case, the Commission is conducting an investigation into the reliability of the Potomac Electric Power Company ("Pepco" or "the Company") electric distribution system and the quality of electric distribution service Pepco is providing its customers. Mr. Lanzalotta addresses the Company's declining electric service reliability in recent years and the causes of the deteriorating reliability performance. It is my understanding that the OPC may recommend that the Commission impose sanctions or penalties on Pepco based on Mr. Lanzalotta's findings and other evidence in the instant proceeding. The purpose of my testimony is to present options for penalties or sanctions if it is determined that such are warranted and to discuss the accounting implications of those options.

III. FORMS OF SANCTIONS OR PENALTIES

Q. What alternative forms of sanctions or penalties do you address, in the event that the Commission determines that such sanctions or penalties should be imposed?

A. I am presenting three alternatives: 1) a penalty in the form of fines to be paid by Pepco; 2) a reduction to the Company's authorized return on common equity; and 3) direct bill credits to affected customers.

Q. What would a penalty in the form of a fine entail?

A. The Company would be required to pay cash fines based on the extent and severity of the deterioration of service quality. The cash disbursements for the fines would be charged to Account 426.3 – Penalties. This is a "below the line" account, and charges to Account 426.3 are not included in utility operating expenses or in the cost of service in the context of a rate case. For example, assuming the Commission determined i) that Pepco had failed to "make reasonable efforts to avoid interruptions of service,"[1] for the period February 5, 2010 through May 6, 2011, and ii) to impose a civil penalty of $10,000 per day against the Company, Pepco would then be liable for an amount equal to $4,550,000.00.[2] As I stated above, since fines are charged to a "below the line" account, Pepco would be precluded from passing any portion of this amount on to its ratepayers.

Q. What would a reduction to the Company's authorized return on common equity entail?

A. The authorized return on equity included in the determination of the overall rate of return applied to the Company's rate base in the calculation of the return requirement component of the Company's revenue requirement would be reduced. Again, the amount of the adjustment would be based on the extent and severity of the deterioration of service quality. By the way of illustration, a reduction of 0.10% to the authorized return on equity would reduce the Company's annual revenue requirement by approximately $750,000 based on the capital structure and rate base

[1] See Direct Testimony of Mr. Lanzalotta, p. 32, lines 1-8.
[2] $10,000 times 455 days

in the last rate case. No special accounting treatment would be necessary; the penalty would result in lower rates being paid by all customers, based on the substandard quality of service.

Q. What would direct bill credits to affected customers entail?

A. Customers experiencing frequent or extended outages would get credits to the amounts they owe for service in a given period. The customers' bills would already be reduced for energy not used during an outage. Therefore, the imposition of a penalty would entail an additional credit that could be based on elimination or proration of the customer charge and/or a bill credit for a fixed dollar amount. As a practical matter, a penalty in the form of bill credits to affected customers could probably be imposed only prospectively, if the reliability problems continue in the future. In the context of a rate case, the effect of such bill credits must be excluded from the calculation of the revenue deficiency, either by imputing the amount of the bill credits to test year revenues or by calculating pro forma test year revenue by applying the relevant rates to the test year billing determinants without reference to the bill credits.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX 1

RESUME OF DAVID J. EFFRON

UTILITY REGULATION EXPERIENCE

Assistance to offices representing customer interests in Rhode Island, Maryland, Massachusetts, Illinois, and Texas regarding electric utility restructuring matters.

Presentation of testimony on various utility regulation matters involving electric, gas, telephone, and water utilities in the following jurisdictions: Alabama, Arizona, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, Washington, and FERC.

Assistance to attorneys in preparing discovery, cross-examination, post-hearing briefs, and analysis of orders; provision of technical assistance during settlement negotiations.

OTHER BUSINESS EXPERIENCE

Supervision of capital project analysis, capital budgets, spending reports, leasing program, and special studies; feasibility studies, accounting systems, statistical surveys; audits of publicly held companies in various industries.

EMPLOYMENT HISTORY

Dates	Company
March 1982 - Present	Berkshire Consulting Services (Self employed)
January 1977 - February 1982	Georgetown Consulting Group
April 1975 - January 1977	Gulf & Western Industries
February 1973 - March 1975	Touche Ross & Company

EDUCATION

Columbia University, MBA, 1973
Dartmouth College, BA Economics, 1968

HONORS AND AWARDS

Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 Certified Public Accounting Examination in New York State.
Graduated from Dartmouth College with distinction in the field of Economics.

Reliability Report Data 2002-2012
Investor-Owned Utilities

This report summarizes the reliability indices reports filed by each of the investor-owned utilities, in compliance with 170 IAC 4-1-23(e). Reliability data is shown for the time period 2002 through 2012.

Each utility reported its indices with and without major events. Major events are storms or weather events that are more destructive than normal storm patterns. The utilities do not all define a "major event" exactly the same; therefore some utilities will capture more of their service interruptions in the "without" category than other utilities. This is one reason why one should avoid making direct comparisons among the utilities based on the indices. Service territory geography and size and customer mix are also factors that make direct comparison of the indices among the utilities difficult.

Three separate reliability indices were reported by each of the utilities:

- System Average Interruption Frequency Index (SAIFI): the total number of customer interruptions divided by the total number of customers (average interruptions per customer).
- System Average Interruption Duration Index (SAIDI): the sum of all customer interruption durations (in minutes) divided by the total number of customers (average minutes of interruption per customer).
- Customer Average Interruption Duration Index (CAIDI): SAIDI divided by SAIFI (average minutes per interruption).

"Major Events" (Weather) Summary

The following table summarizes the number of major event days each utility reported having in 2012. In addition to the major events below, NIPSCO stated it experienced an additional 76 weather events it considered severe. It should be noted that one storm system can potentially cause multiple major event days.

Utility	Major Event Days
NIPSCO	17
IPL	6
I&M	9
Duke Energy Indiana	4
Vectren	4

Electric Reliability: Including Major Events*

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NIPSCO											
SAIFI	1.41	1.65	1.38	1.24	1.40	2.23	1.80	0.88	1.36	1.38	1.44
SAIDI	542	498	317	258	317	1,073	882	140	505	371	428
CAIDI	385	302	229	208	227	480	490	158	372	269	297
PSI/Duke											
SAIFI	1.57	1.58	1.66	1.59	1.63	1.41	2.48	1.76	1.58	2.07	1.52
SAIDI	170	201	255	282	203	178	689	293	195	630	216
CAIDI	109	128	153	177	125	126	278	166	124	304	143
IPL											
SAIFI	1.17	0.90	0.81	0.90	1.07	0.76	1.54	1.1	1.04	0.86	1.04
SAIDI	133	98	77	67	105	47	359	158	71	75	125
CAIDI	113	108	94	74	98	62	233	145	68	88	120
Vectren											
SAIFI	1.46	1.27	2.36	2.05	1.87	1.23	2.33	2.56	1.02	2.16	1.24
SAIDI	164	111	932	376	241	89	859	2,889	90	711	117
CAIDI	107	87	395	185	128	72	369	1,126	88	330	95
I&M											
SAIFI	1.68	1.56	1.42	1.31	1.24	1.24	1.63	0.91	0.98	1.12	1.39
SAIDI	931	594	291	1,132	222	199	1,164	122	392	258	1,071
CAIDI	554	380	205	863	179	161	713	133	400	230	773

Notes

SAIFI: System Average Interruption Frequency Index; (total # of customer interruptions) / (total # of customers)

SAIDI: System Average Interruption Duration Index; (duration or time of service interruptions) / (total # of customers)

CAIDI: Customer Average Interruption Duration Index; (SAIDI) / (SAIFI)

*Major events are storms or weather events that are more destructive than normal storm patterns. The same definition of "major event" is not used by all utilities.

**NIPSCO's 2007 report updated values for 2004-2006 based on accepted industry standard IEEE Std 1366 - the values above reflect these revisions.

Electric Reliability: NOT Including Major Events*

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NIPSCO											
SAIFI	1.15	1.45	1.22	1.09	1.21	1.06	1.11	0.88	0.94	0.92	0.83
SAIDI	196	350	213	181	196	180	199	140	122	126	102
CAIDI	171	242	175	166	163	169	179	158	130	137	123
PSI/Duke											
SAIFI	1.36	1.22	1.21	1.27	1.32	1.23	1.26	1.3	1.32	1.27	1.29
SAIDI	134	127	124	138	136	133	146	133	138	146	149
CAIDI	98	103	102	109	103	109	116	102	104	115	115
IPL											
SAIFI	1.03	0.79	0.71	0.90	1.07	0.76	1.04	0.94	1.04	0.86	0.82
SAIDI	74	66	53	67	105	47	81	81	71	75	57
CAIDI	72	83	75	74	98	62	78	86	68	88	70
Vectren											
SAIFI	1.46	1.27	1.12	1.68	1.51	1.23	1.42	1.2	1.02	1.43	1.07
SAIDI	164	111	107	137	151	89	133	110	90	137	83
CAIDI	107	87	95	82	100	72	94	92	88	96	78
I&M											
SAIFI	1.12	0.95	1.25	1.00	1.12	1.11	1.12	0.83	0.74	0.99	0.91
SAIDI	179	129	194	171	147	139	144	90	111	154	137
CAIDI	159	135	156	171	131	126	129	109	151	156	151

Notes

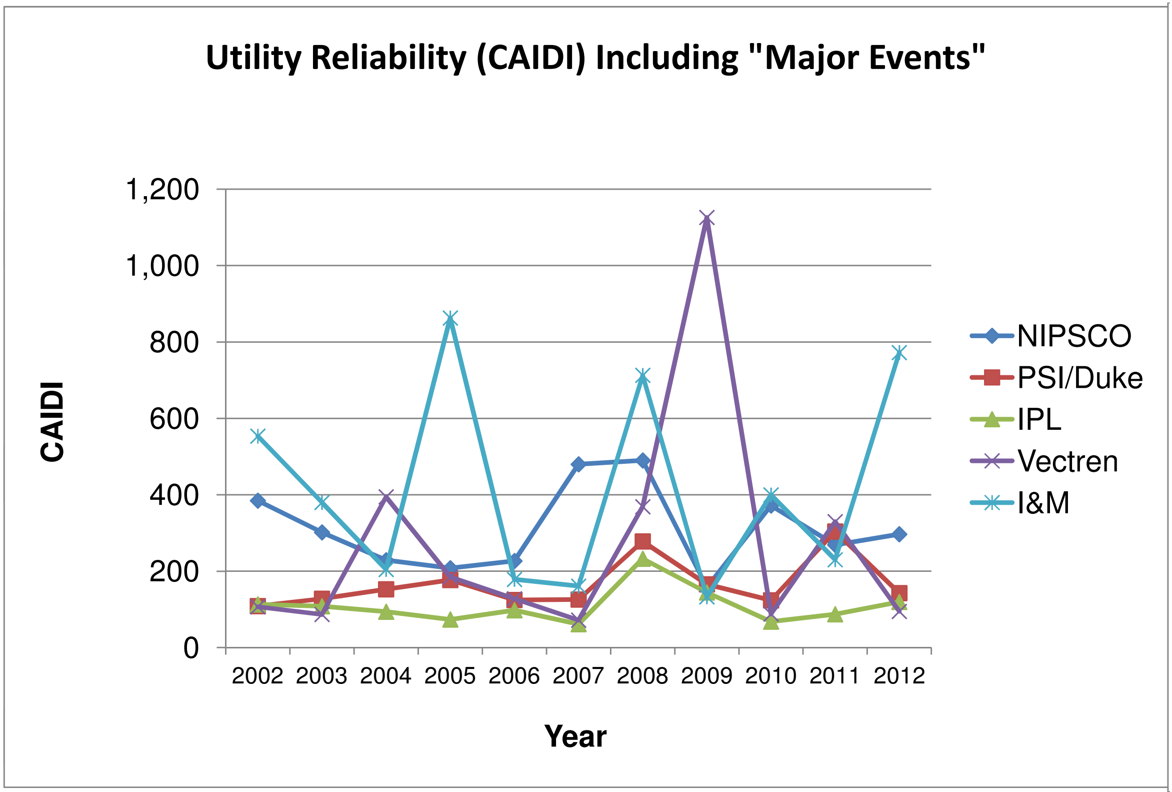
SAIFI: System Average Interruption Frequency Index; (total # of customer interruptions) / (total # of customers)

SAIDI: System Average Interruption Duration Index; (duration or time of service interruptions) / (total # of customers)

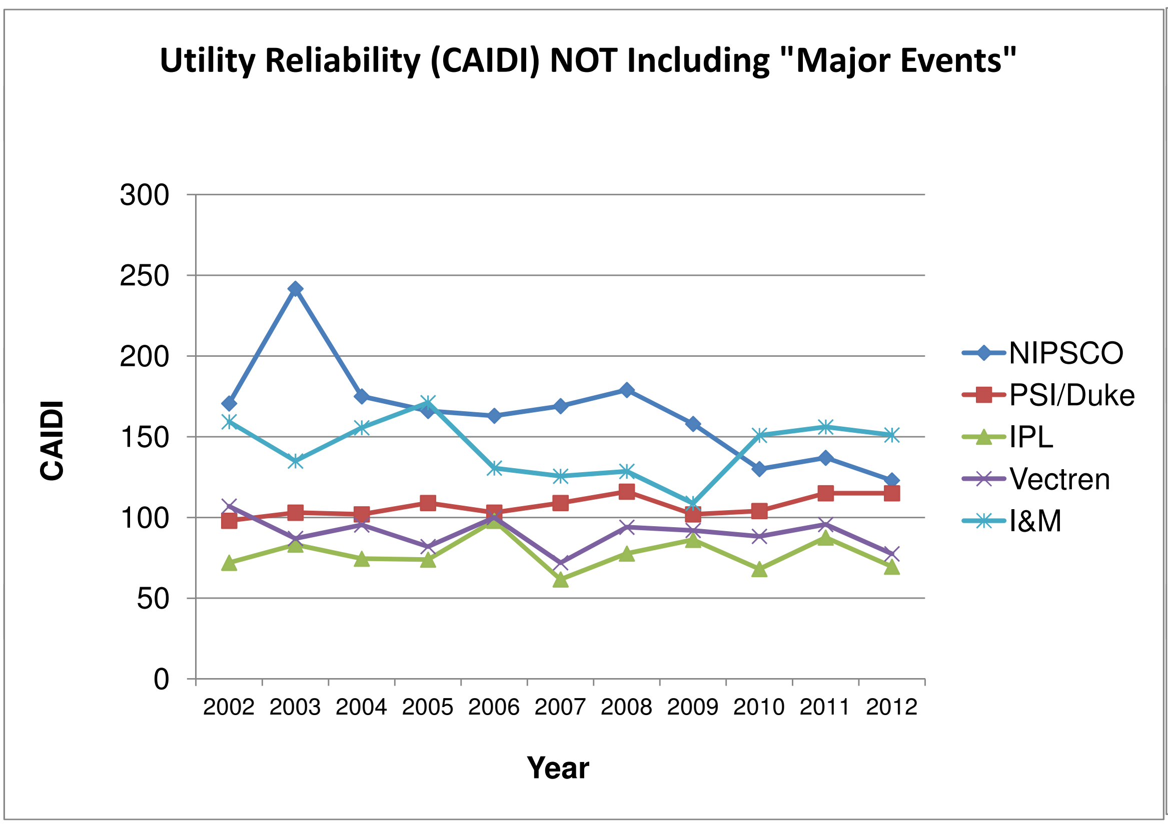
CAIDI: Customer Average Interruption Duration Index; (SAIDI) / (SAIFI)

*Major events are storms or weather events that are more destructive than normal storm patterns. The same definition of "major event" is not used by all utilities.

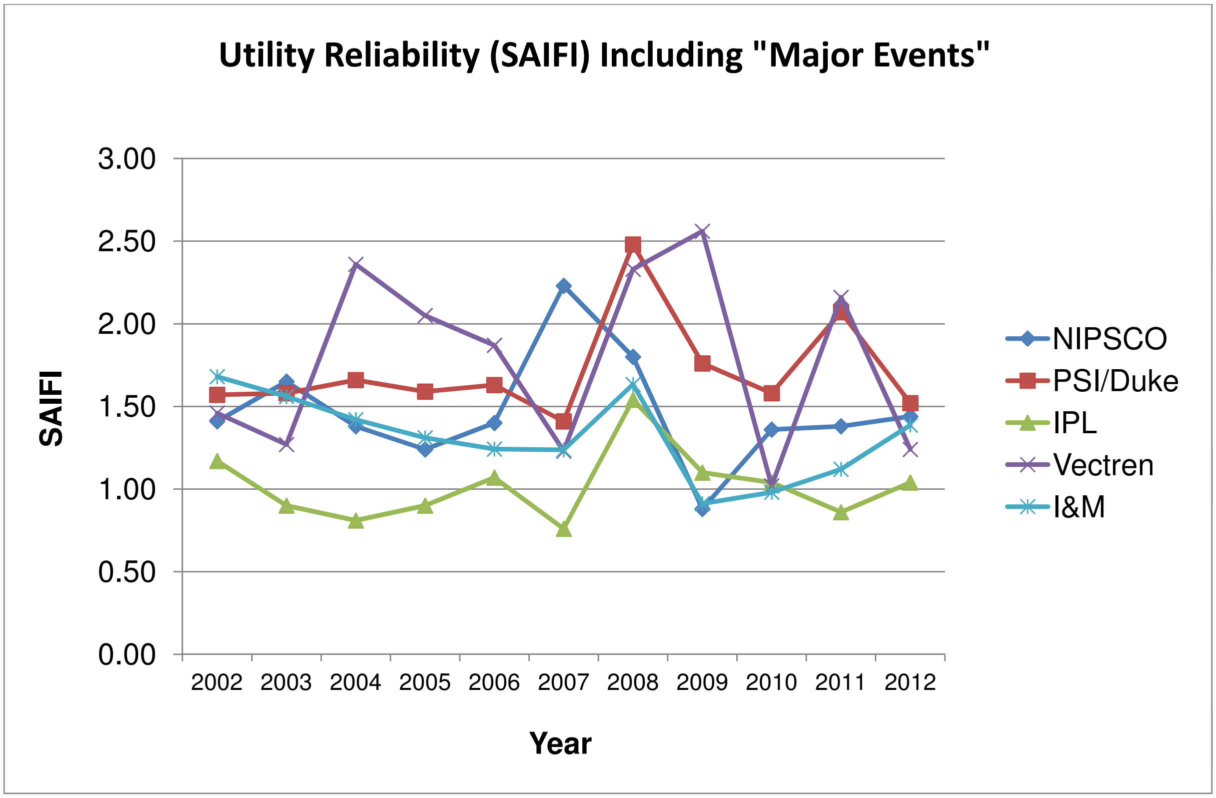
**NIPSCO's 2007 report updated values for 2004-2006 based on accepted industry standard IEEE Std 1366 - the values above reflect these revisions.

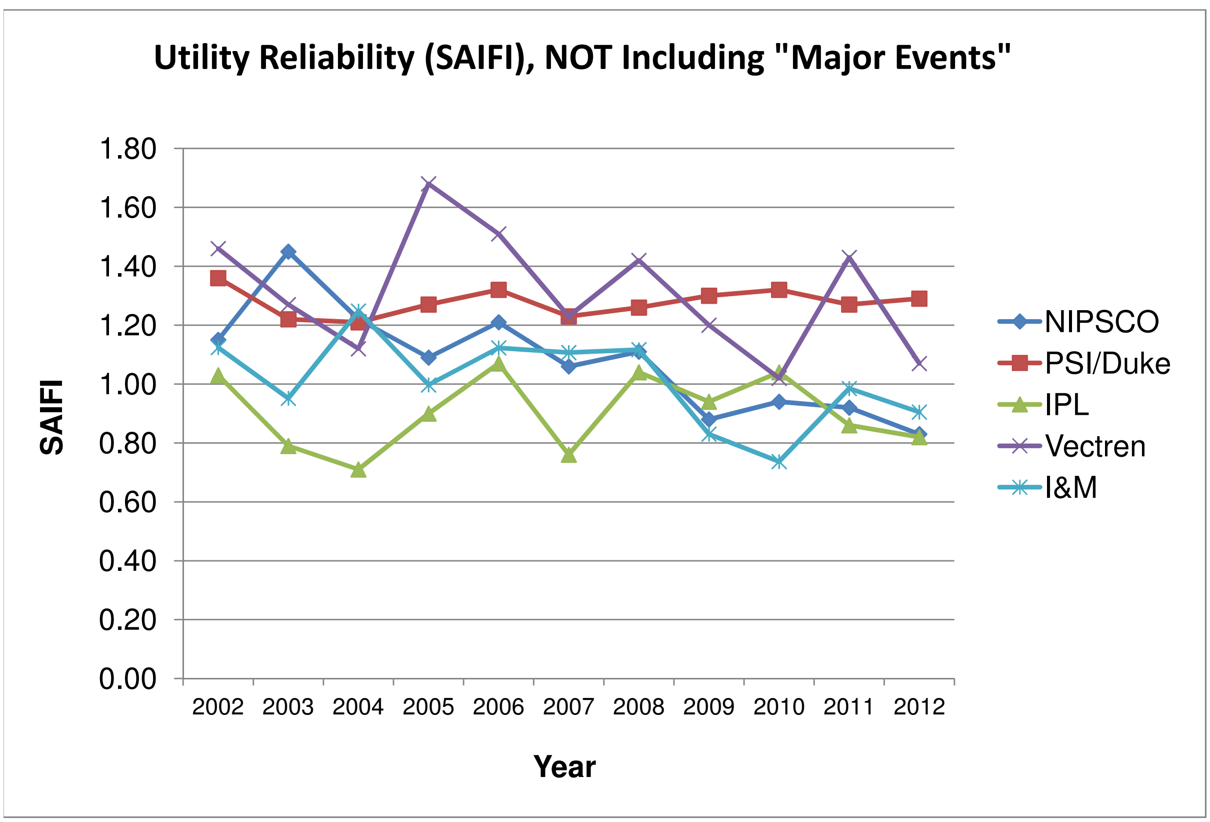


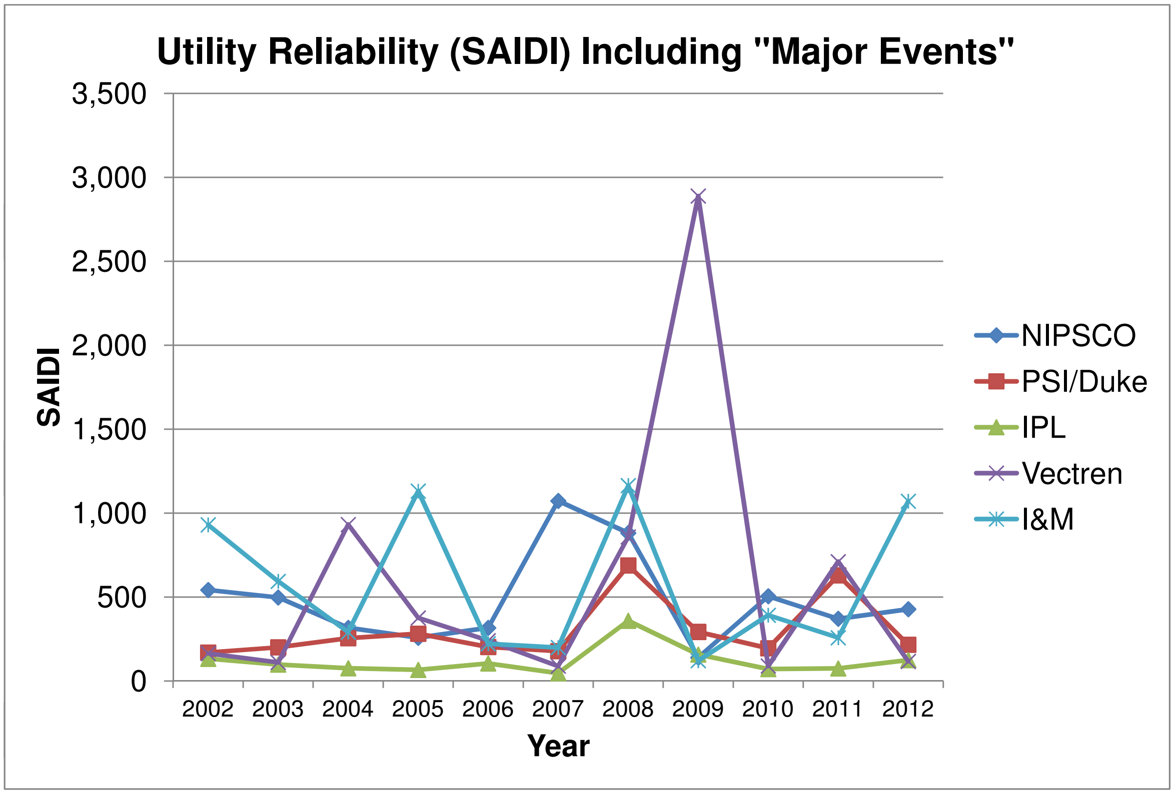
Utility Reliability (CAIDI) Including "Major Events"
CAIDI
1,200
1,000
800
600
400
200
0
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012
Year
NIPSCO
PSI/Duke
IPL
Vectren
I&M

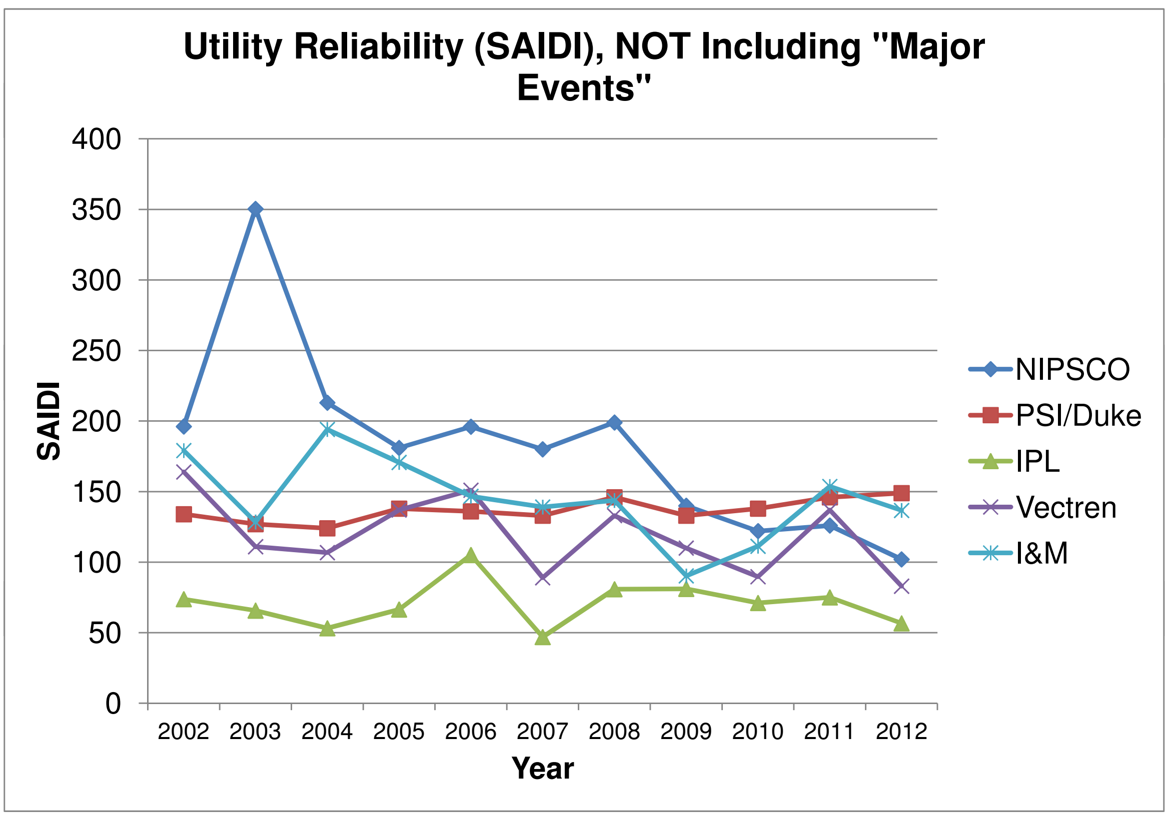


Utility Reliability (CAIDI) NOT Including "Major Events"
CAIDI
300
250
200
150
100
50
0
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012
Year
NIPSCO
PSI/Duke
IPL
Vectren
I&M


Utility Reliability (SAIFI) Including "Major Events"
3.00
2.50
2.00
1.50
1.00
0.50
0.00
SAIFI
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012
Year
NIPSCO
PSI/Duke
IPL
Vectren
I&M


Utility Reliability (SAIFI), NOT Including "Major Events"
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
SAIFI
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012
Year
NIPSCO
PSI/Duke
IPL
Vectren
I&M


Utility Reliability (SAIDI) Including "Major Events"
SAIDI
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
NIPSCO
PSI/Duke
IPL
Vectren
I&M


Utility Reliability (SAIDI), NOT Including "Major Events"
SAIDI
400
350
300
250
200
150
100
50
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
NIPSCO
PSI/Duke
IPL
Vectren
I&M

Comparison of 2012 Indices with 2002-2011 Average Indices (Without Major Events)				
	2012	***2002-2011 Avg.***	**2012 Diff Vs Avg**	**2012 % Diff Vs Avg**
NIPSCO*				
SAIFI	0.83	1.10	-0.27	-25%
SAIDI	102	190	-88	-46%
CAIDI	123	169	-46	-27%
PSI/Duke				
SAIFI	1.29	1.28	0.01	1%
SAIDI	149	136	14	10%
CAIDI	115	106	9	8%
IPL				
SAIFI	0.82	0.91	-0.09	-10%
SAIDI	57	72	-15	-21%
CAIDI	70	78	-9	-11%
Vectren				
SAIFI	1.07	1.33	-0.26	-20%
SAIDI	83	123	-40	-32%
CAIDI	78	91	-14	-15%
I&M				
SAIFI	0.91	1.02	-0.12	-11%
SAIDI	137	146	-9	-6%
CAIDI	151	142	9	6%

*NIPSCO's 2007 report updated values for 2004-2006 based on accepted industry standard IEEE Std 1366.
The averages above reflect these revisions.

STATE OF NEW YORK

DEPARTMENT OF PUBLIC SERVICE

EXCELSIOR

2008 ELECTRIC RELIABILITY PERFORMANCE REPORT

Electric Distribution Systems

Office of Electric, Gas, and Water

June 2009

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report presents Department of Public Service Staff's (Staff) assessment of electric reliability performance in New York State. As a means of monitoring the levels of service, utilities are required to submit detailed interruption data to the Public Service Commission (Commission). Staff relies on two primary metrics to measure reliability performance: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration).[1] By compiling the results of individual utilities, the average frequency and duration of interruptions can be reviewed to assess the overall reliability of electric service in New York State.

The statewide interruption frequency for 2008, excluding major storms, was considerably better than that recorded in 2007, where all companies except Orange and Rockland Utilities, Inc. (Orange and Rockland) showed improvement. The statewide duration in 2008 was slightly worse than in 2007. The year 2008 was the second-most affected by storms in five years and had 35 more storms than in 2007. Staff attributes some of the 2008 improvement in frequency to the high number of major storms (excludable events). Typical weather patterns result in less severe weather that lead to minor storms, which are included in the measures and thereby increase performance measures. Similar overall patterns exist for frequency and duration when analyzing the reliability data excluding Consolidated Edison Company of New York, Inc (Con Edison) performances.[2]

With respect to individual utilities' performances in 2008, Central Hudson Gas and Electric Corporation (Central Hudson), Niagara Mohawk Power Corporation d/b/a National Grid's (National Grid) and Rochester Gas and Electric Corporation (RG&E) performed at, or better than, their historic levels. Infrastructure improvements

---

[1] SAIFI is the average number of times that a customer is interrupted during a year. CAIDI is the average interruption duration time for those customers that experience an interruption during the year.

[2] Con Edison's system includes many large, highly concentrated distribution networks. As a result, its interruption frequency is extremely low as compared to other utilities' interruption frequency and typically skews aggregated data measurements. Therefore, Staff examines statewide statistics both including and excluding Con Edison's data.

associated with National Grid's commitment to invest $1.47 billion over a five year period appears to positively affect its reliability performance.[3] Additionally, Central Hudson's revised tree trimming program seems to be helping in reducing tree caused interruptions. In 2008, Orange and Rockland was not as good as its 2007 performance for both frequency (slight change) and duration. Orange and Rockland attributes its change in duration to the installation of distribution automation; Staff is currently investigating the relationship between distribution automation and duration.

Con Edison performed satisfactorily on its radial system for both frequency and duration, and better than previous year with respect to its network frequency. The Company's performance in 2008 for network duration, however, was significantly worse than its historic performance. Based on a self-assessment conducted in response to Staff's report for 2007Con Edison identified strategies to improve its performance and is implementing several pilot programs this summer. It also formed a task force to continue to identify means to improve performances, especially on it network system. The programs involve predictive outage modeling, improvements to assist in crew allocation and deployment in order to improve both network and radial outage durations. In order to evaluate the effectiveness of Con Edison's actions, Staff is recommending that the Company file a report of the task force findings and results from its pilot programs by September 15, 2009. Staff is also recommending Con Edison perform a self-assessment to identify actions to improve its network duration performance and file the self-assessment with Staff by September 15, 2009.

Although NYSEG's overall reliability statistics improved compared with 2007, its performance with respect to tree related outages continues to decline. In last year's reliability report, Staff recommended NYSEG perform a self-assessment of its existing distribution tree trimming program based on its declining performance and reduced expenditures on tree trimming. The continued decline in performance with respect to tree related interruptions is not surprising because the Company's self-

[3] Case 06-M-0878, Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and other Regulatory Authorizations.

assessment showed approximately half the circuit miles have been trimmed in 2007 and 2008 when compared to 2002 through 2005 levels. NYSEG's decision to reduce its tree trimming activities and expenditures despite declining performance in this area needs to be examined in detail and will be the focus of a newly established Case 09-E-0472.[4]

Electric utilities have reliability performance mechanisms (RPMs) in place as part of their rate plans. The reliability performance mechanisms are designed such that companies are subject to negative revenue adjustments for failing to meet electric reliability targets.[5] In 2008, Con Edison failed to achieve the duration target in its reliability performance mechanism for the network component of its distribution system and Orange and Rockland failed to achieve the duration target in its reliability performance mechanism for 2008. Combined, these failures resulted in about $5.4 million in negative revenue adjustments.

This report will be transmitted to an executive level operating officer of each electric utility with a letter from the Director of the Office of Electric, Gas, and Water. Con Edison is expected to comply with the recommendations and submit documentation by the dates indicated in the report.

---

[4] Case 09-E-0472, In the Matter of Investigation of New York State Electric and Gas Corporation Expenditures Related to its Line Clearance Programs.

[5] NYSEG was the only utility not under an RPM in 2007 and 2008 because its mechanism expired in 2006. A new RPM is in place for the Company's 2009 performance.

INTRODUCTION

The following report is an overview of the electric reliability performance in New York State. As a means of monitoring the levels of service quality, the Commission's Rules and Regulations require utilities delivering electricity in New York State to collect and submit information to the Commission about electric service interruptions on a monthly basis.[6] Using the data, Staff calculates two primary performance metrics: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration). The information provided is also subdivided into 10 categories that reflect the nature of the cause of interruption (cause code).[7] By doing so, analysis of the cause code data can be used to highlight areas where increased capital investment or maintenance is needed. As an example, if a circuit were shown to be prone to lightning-caused interruptions, devices could be installed on that circuit to try to minimize the problem. In general, most of a utility's interruptions are a result of major storms, tree contacts, equipment failures, and accidents.[8] Staff maintains the interruption information in a database that dates back to 1989, which allows it to observe trends.

In addition, the Commission adopted standards addressing the reliability of electric service by establishing minimum acceptable levels for both the frequency and duration of service interruptions for each major electric utility's operating divisions. The utilities are required to submit a formal reliability report by March 31st of every year containing detailed assessments of performance, including outage trends in a utility's various geographic regions, reliability improvement projects, and analyses of worst-performing

---

[6] 16 NYCRR Part 97, Notification of Interruption of Service requires utilities to keep detailed back-up data for six years.

[7] 16 NYCRR Part 97, Notification of Interruption of Service specifies and defines the following ten cause codes that reflect the nature of the interruptions: major storms, tree contacts, overloads, operating errors, equipment failures, accidents, prearranged interruptions, customers equipment, lightning, and unknown. There are an additional seven cause codes used exclusively for Con Edison's underground network system.

[8] The accident cause codes cover events not typically in the utilities' control including vehicular accidents, sabotage, and animal contacts. Lightning is reported under a separate cause code.

feeders. There are no revenue adjustments for failure to meet a minimum level under the service standards; utilities are, however, required to include a corrective action plan as part of the annual report.[9] The service standards were last revised in 2004.

Interruption data is presented in two ways in this report – with major storms excluded and with major storms included. A major storm is defined by the Commission's regulations as any storm which causes service interruptions of at least 10 percent of customers in an operating area, and/or interruptions with duration of 24 hours or more.[10] Major storm interruptions are excluded from the data when calculating performance levels for service standards and reliability performance mechanisms. The purpose of this policy is to achieve a balance between service interruptions under a utility's control, such as equipment failures and line maintenance, and those over which a utility's control is more limited, such as severe ice storm or a heavy wet snowstorm. Performance inclusive of major storms shows the actual customer experience during a year.

---

[9] Revenue adjustments for inferior performances are implemented through individual Reliability Performance Mechanisms established in rate orders.

[10] Major storms do not include heat-related service interruptions.

2008 RELIABILITY PERFORMANCE

The following sections provide a summary discussion of the reliability performance statewide and for each of the major utilities. Each year, Staff also prepares an Interruption Report summarizing the monthly interruption data submitted by the utilities. The 2008 Interruption Report contains detailed interruption data for each utility and statewide statistics for the past five years. The Interruption Report for 2008 is attached as an Appendix. Individual company discussions identify issues or actions within each company that influenced performance levels for 2008 and indicates company-specific trends where applicable.

In addition, performances are compared to utilities' reliability performance mechanisms (RPMs) placed into effect as part of their rate orders. The reliability performance mechanisms are designed such that companies are subjected to negative revenue adjustments for failing to meet electric reliability targets. The targets are based on the indices used by the Commission's electric service standards.

Con Edison and Orange and Rockland each failed to achieve a target in their reliability performance mechanisms for 2008. Con Edison failed to achieve the duration target for its network system, resulting in a potential negative rate adjustment of $5 million.[11] Orange and Rockland failed to achieve its duration target, which results in a negative revenue adjustment of approximately $400,000.

STATEWIDE

For many years, Staff has been combining the individual utility performances into overall statewide statistics. By doing so, we evaluate the level of reliability provided and identify statewide trends. Because Con Edison's system includes many large, highly concentrated distribution networks, its interruption frequency is

[11] This rate adjustment is a preliminary assessment based on Con Edison's March 31, 2009 filing that detailed the Company's compliance with its RPM. Con Edison's rate adjustment has not been presented to the Commission for final action.

extremely low as compared with other utilities. This, combined with the fact that it serves the largest number of customers in the state, typically results in a skewing of the performance measures. As a result, we examine and present aggregated data including and excluding Con Edison's data.

Statewide, the frequency of interruptions when excluding major storms was 0.56 in 2008, which is considerably better than the five-year average of 0.63 and better than 2007's performance level of 0.65. All companies, except Orange and Rockland, had fewer customers affected by power outages, again when major storms are excluded, as shown in Figure 1. This improvement is amplified when Con Edison is excluded with the frequency performance for 2008 at 0.88, which is considerably better than the five-year average of 0.98.

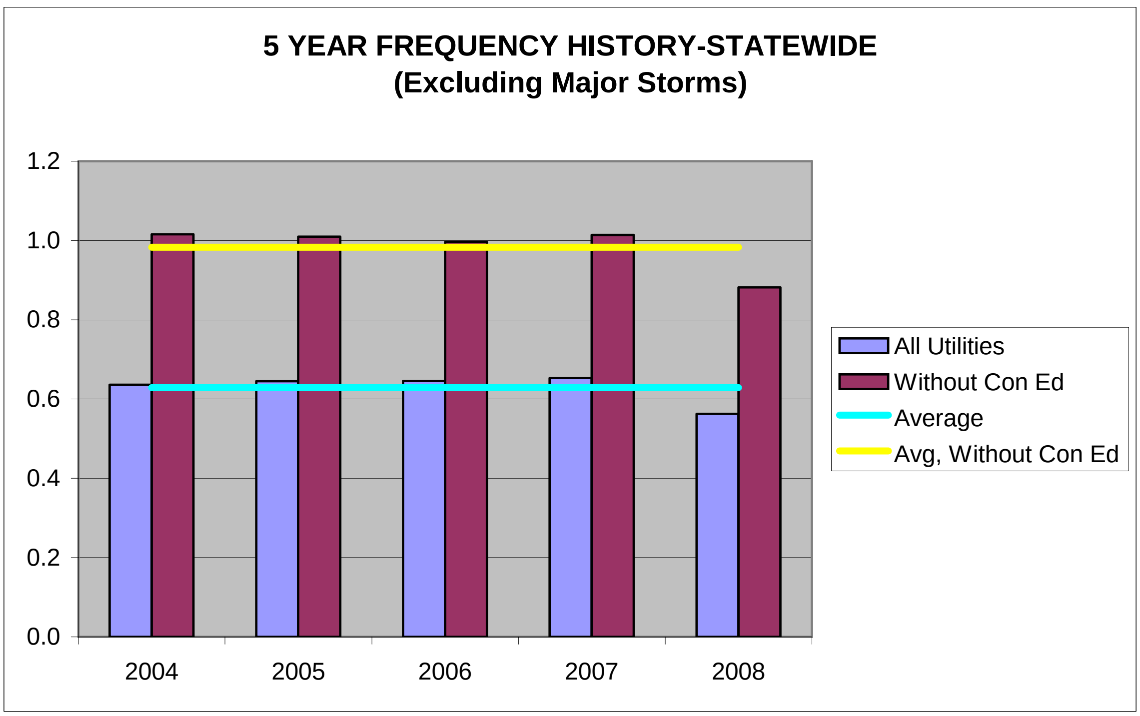


Figure 1: Statewide Frequency Performance

Figure 2 shows the statewide duration index for 2008, excluding major storms. The overall statewide duration index continues to be at a more normal level of 1.93 hours, as compared with 1.95 hours and 1.89 hours in 2005 and 2007, respectively. Con Edison's Long Island City network outages greatly affected the statewide duration in 2006. The statewide duration index, excluding Con Edison, was 1.89 hours in 2008, which is slightly better than 2007 and equal to the five-year average.

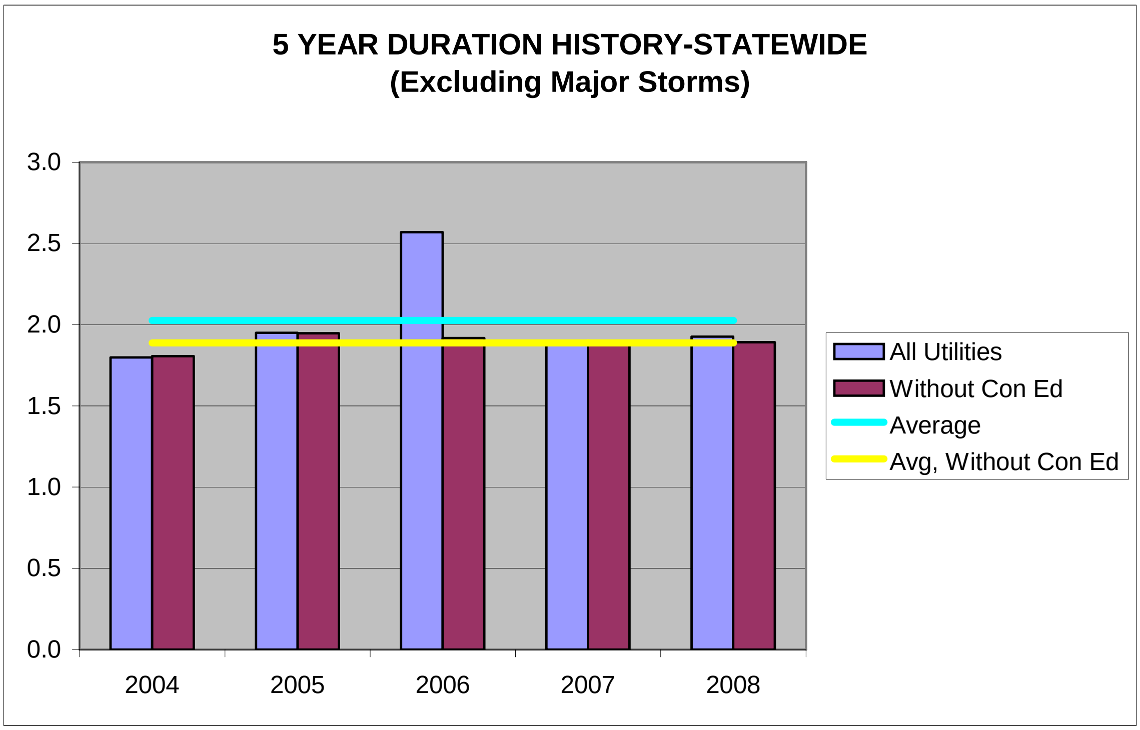


Figure 2: Statewide Duration Performance

In 2008, the weather during the winter and summer months was relatively severe, while there was a moderate amount of adverse weather activities in the spring. This pattern was apparent as numerous winter storms occurred during the early part of the year, culminating in a severe ice storm which significantly affected the Capital Region and Mid-Hudson in December 2008. Several fronts that traversed the State in June and July brought severe storms and/or damaging winds. In general, wind speeds and gusts were higher in 2008 than in prior years; National Grid reported the number of days with winds exceeding 30 miles per hour was 20% higher than the annual norm, and nearly twice the norm in two of its service areas. As a result, the total number of major storms experienced by utilities increased by 35 storms over last year (Table 1, below). National Grid and NYSEG each experienced more than 20 major storms in 2008.

Table 1: Major Storms in 2008

Company	2007	2008	Change in Major Storms
Con Edison	4	4	0
National Grid	10	24	+14
NYSEG	17	25	+8
RG&E	10	12	+2
Central Hudson	5	9	+4
Orange and Rockland	1	8	+7
Total	**47**	**82**	**+35**

The year 2008 was the second-worst year for severe weather effects in the last five years (Figure 3, below).[12] When including major storms, the 2008 statewide frequency and duration performances were 0.93 and 4.50, respectively. When excluding Con Edison, the 2008 statewide frequency and duration performances including major storms were 1.51 and 4.62, respectively. All four of these measures were worse than the five-year averages. Major storms in 2008 accounted for 71% of the overall customer-hours of interruptions and 39% of the overall number of customers affected.

[12] The Buffalo area experienced a massive ice storm in 2006.

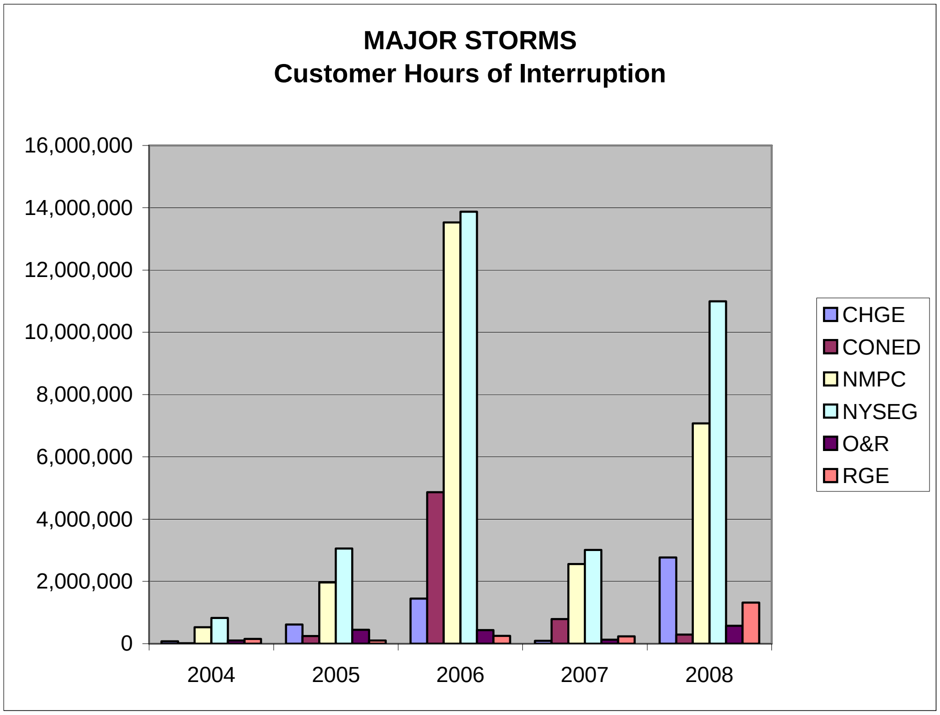


Figure 3: Major Storm Customer Hours

New York State investor-owned electric utilities must submit a report to the Commission addressing all facets of their restoration effort if the restoration period associated with significant storms lasts more than three days.[13] Overall, the utilities responded well to the major storms in 2008, restoring most customers affected within 24-72 hours from the end of a storm. In 2008, there were four reports submitted on major storms as listed in Table 2, below. These storms, especially the December ice storm, as well as the numerous other major storms mentioned earlier, had a greater than historic effect on the total number of hours that customers were without service.

Table 2: Storm reports filed in 2008

Date	Company	Areas Affected	Reason for Interruptions
October	NYSEG	Oneonta, Liberty	Wind and Snow Storm
December	Central Hudson, NYSEG, GRID	Capital District & Troy area	Ice Storm

CON EDISON

[13] 16 NYCRR Part 97, Part 105.4

Table 3: Con Edison's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Network Systems						
Frequency (SAIFI)	0.005	0.006	**0.021**	**0.075**	0.017	0.025
Duration (CAIDI)	3.64	**4.44**	**60.81**	1.79	**6.28**	15.39
Radial System						
Frequency (SAIFI)	0.39	0.51	**0.54**	0.38	0.42	0.45
Duration (CAIDI)	1.64	**1.91**	**2.66**	**2.07**	1.83	2.02

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Con Edison serves approximately 3.2 million customers in New York City and Westchester County. Electricity is supplied to 2.4 million customers using network systems. The remaining 900,000 customers are supplied by radial systems.

In 2008, the network frequency performances were significantly lower than its historical performances in 2006 and 2007. The Company radial frequency was slightly higher than in 2007 but lower than the five year average. In 2008, the Con Edison spent $562 million to improve the reliability on its electric system including $352 million on relief programs, $122 million on reliability programs, and $88 million on maintenance programs. In 2007 and 2008, the Company expanded its tree trimming budget and has seen a reduction in the number of interruption caused by trees as compared with previous years.

To minimize the frequency of customer outages, Con Edison's networks are designed with redundant supply paths. Individual service lines to customer premises, however, lack any supplemental supply. Given these design criteria and underground settings, the majority of interruptions (85%) are associated with the service portion of the network system, as shown in Figure 4. Equipment failures are the second highest (7%) cause for interruptions in 2008. Failures on parts of the network grid itself (secondary feeders or mains) are the third highest cause for interruptions at 6%.

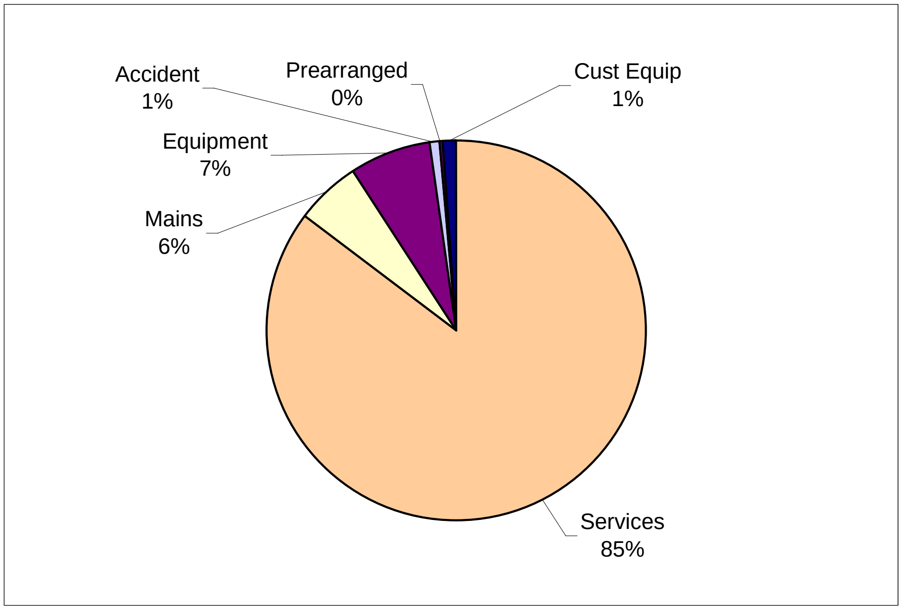


Figure 4: Con Edison's 2008 Network Interruptions by Cause

On its radial system, Con Edison's performance in 2008 was better than the five year average for both frequency and duration. Equipment failures are responsible for 71% of the interruptions on the radial system, followed by trees and accidents at 14% and 8%, respectively, as shown in Figure 5.

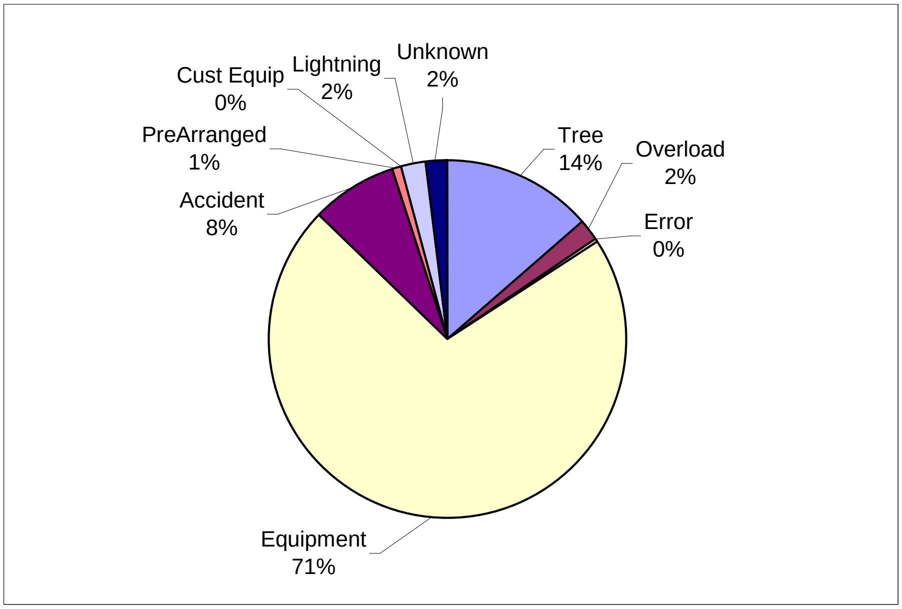


Figure 5: Con Edison's 2008 Radial Interruptions by Cause

Con Edison had one of its worst years for network duration in 2008. In recent years, Con Edison has missed its duration targets for both network and non-network.[14] As part of last year's report, Staff recommended that the Company conduct a detailed self assessment into why its duration performance associated with its radial systems had deteriorated. Con Edison responded by noting that nearly 40% of it longer duration outages are associated with weather events that typically occur in the late afternoon and early evening. As a result, the Company has initiated a study to correlate weather patterns to high duration events. Based on the results of the study, the Company expects to be able to better predict events and ensure sufficient staffing levels are on duty. For 2009, the Con Edison has established a program to experiment with length of shifts (8-hr vs. 12-hr) to determine which provides better coverage, and will be implementing an automated call system to improve crew response times. The Company is also considering dedicated crews to respond to specific outages and using electricians as first responders. In 2008, Con Edison established a new workplace in Westchester County to reduce travel time in that area.

Finally, Con Edison has recently assembled a task force to identify strategies to help improve its network and radial duration performances. Staff will be meeting with the task force in June to review new proposed actions. We are encouraged by the pilot programs and would like to see successful programs applied on a company-wide basis. Therefore, Staff recommends that Con Edison file a report by September 15, 2009 detailing information learned by the task force and during pilot programs. The report should include information on how Con Edison will implement successful programs on a permanent basis. Additionally, Staff recommends that Con Edison perform a self-assessment to identify strategies to improve its network performance and identify corrective actions that are unique to its network system. The self assessment should also be filed by September 15, 2009.

[14] In 2007, a short duration incident affecting a large number of customers resulted in a network duration

NATIONAL GRID

Table 4: National Grid's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	**1.02**	**0.98**	**1.01**	**0.96**	0.75	0.94
Duration (CAIDI)	2.04	**2.32**	2.05	2.01	1.96	2.08

Note: Data presented in red represents a failure to meet the RPM target for a given year.

National Grid serves approximately 1.59 million customers across upstate New York. The Company's territories include metropolitan areas such as the cities of Buffalo, Albany, and Syracuse. National Grid also serves many rural areas in northern New York and the Adirondacks.

Overall, National Grid improved in 2008 and achieved all of its reliability targets. Previously, National Grid missed the frequency target level of 0.93 for each year from 2004 until 2007. Results this year, however, significantly improved and the Company met the target with an end result of 0.75. Duration results were better in 2008 as well; the Company has performed better than the duration target for three consecutive years now. In general, the utility had improved service on a region by region basis.

The overall reliability improvements are partially due to the installation of 432 reclosers, of which most were identified and installed through the Engineering Reliability Review (ERR) process since 2006. The Company installed 234 out of the 432 reclosers during the calendar year of 2008. Results for both the frequency and duration categories were unusually low, due in part to the numerous interruptions resulting from major storms in 2008. Although the Company exhibited a significant reliability improvement through various efforts, it is not likely that results of this magnitude will continue in the future. Staff will encourage the utility to continue with efforts in order to sustain a reasonable level of reliability.

As a result of past reliability results, the Commission placed additional emphasis on National Grid's reliability performance in association with its acquisition of Keyspan, which provides electric distribution services to the Long Island Power

that was well below historic performances.

Authority. Because of this acquisition, the Commission created an Order requiring the utility to file details of its capital expenditure spending. Staff actively reviews listed projects within this filing. Additionally, Staff provides input and recommendations on the justification and progress of the projects.

As seen in Figure 6, equipment failures are the leading cause of interruptions for National Grid, however, this has been improving over the past five years. The five year average number of interruptions in this category is approximately 4,000; yet this year, the utility reported around 3,500 such occurrences. Furthermore, results showed that the utility reduced the number of customers affected and customer hours for this cause code by almost one half compared to 2007. As evident in the equipment failure cause code results from 2008, the above noted programs appear to be useful methods for improving National Grid's reliability performance in association with equipment failures.

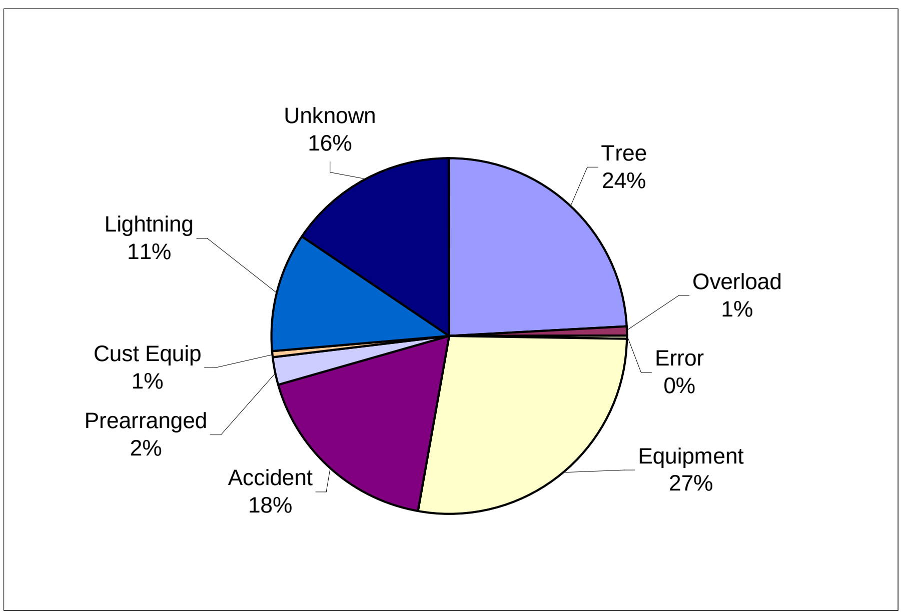


Figure 6: National Grid's 2008 Interruptions by Cause

National Grid made a commitment to spend $1.47 billion on capital improvements to its transmission and distribution system over a five year period from 2007 until 2011. The five-year investment plan contains proposed projects and strategies to upgrade and replace components on its electric system. In particular, the utility developed a Reliability Enhancement Plan (REP) to improve its performance by focused maintenance work on poor performing circuits and replacement of aging assets. This plan specifically includes a targeted program to enhance the performance of feeders, asset replacement, an improved inspection and maintenance program, and a tree trimming program. The REP also provides for the installation of sectionalizing equipment and animal guards that will help to minimize the number of customers affected when an outage occurs, or to avoid interruptions in general. In conjunction with other programs, National Grid has replaced 665 transformers which were deteriorated or overloaded. As noted above, the Company identified and installed 432 reclosers since 2006. Many of the deteriorated assets addressed by the REP were identified as a result of the utility's inspection program.

The second highest contributor to National Grid's interruption performance for 2008 was tree-related outages; however, the Company showed signs of improvement as compared with last year's results in this area as well. Although the number of interruptions in 2008 for this cause code was fairly close to results of 2007, the number of customers affected and customer hours were reduced from last year by approximately 15%. Prior performance had prompted the utility to shorten its trimming cycle from six years to a more traditional five year period in urban areas. National Grid has also expanded its program to remove "danger" trees outside of the standard clearance zone. With these amplified activities, the utility has gradually increased its spending on distribution tree trimming in recent years. National Grid spent approximately $33 million for distribution trimming during fiscal year 2008. The drop in tree-related interruptions in 2008 was mainly due to a reduced number of interruptions related to fallen trees. Outages caused by broken limbs and tree growth actually increased as compared with last years results. Furthermore, the majority of improvements within this cause code occurred in the Syracuse and Buffalo areas. Tree-related frequency results were actually up in five of National Grid's eight operating divisions.

The number of accident caused interruptions in 2008 as compared with 2007decreased by approximately 20% and yielded a reduction of approximate 25% for both customers affected and customer duration. The number of unknown causes of interruptions in 2008 was fairly equivalent to those of 2007, however, the number of customer affected and customer duration were higher than the 2007 results. The number of 2008 lightning caused interruptions was also close to those of 2007, but the customer affected and customer duration decreased by approximately one half compared to the previous results.

National Grid's capital investment program is having a positive affect. National Grid should continue to pursue infrastructure investments that relate reliability. As part of Case 06-M-0878, Staff will continue to closely monitor the Company's capital improvements.

NEW YORK STATE ELECTRIC AND GAS

Table 5: NYSEG's Historic Performance Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	1.13	1.12	1.12	1.20	1.11	1.13
Duration (CAIDI)	1.96	1.96	2.01	2.22	2.08	2.05

Approximately 840,000 customers are served by NYSEG. The Company is primarily located in the Binghamton and Finger Lakes regions, but does have localized service regions, including areas near Plattsburgh, Brewster, Mechanicville, and Lancaster.

The year 2008 showed improvement over last year's poor reliability performance by the Company. NYSEG's 2008 frequency performance of 1.11 was better than both the previous year's performance and its five year average performance level. The 2008 duration performance of 2.08 was also better than both the previous year's performance, however, still slightly higher than the five year average. The two major contributors to NYSEG's interruptions were tree contacts (41%) and equipment failures (21%), as shown in Figure 7.

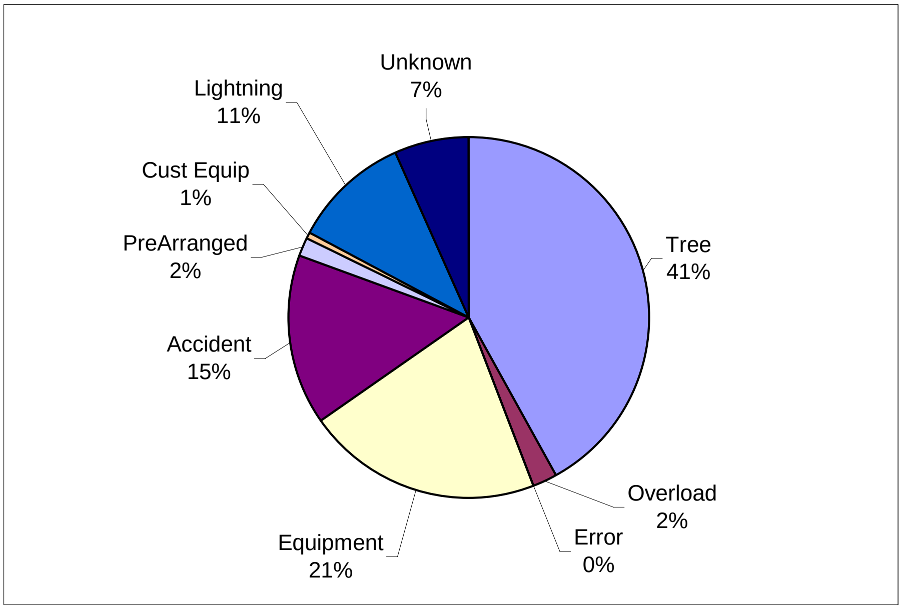


Figure 7: NYSEG's 2008 Interruptions by Cause

Tree related interruptions have consistently had the greatest impact on NYSEG's interruption performance. As shown in Table 6 below, NYSEG's performance has continuously declined with respect to tree caused interruptions. In last year's reliability report, Staff recommended that NYSEG perform a self-assessment of its existing distribution tree trimming program based on its declining performance and reduced expenditures on tree trimming. On January 7, 2009, NYSEG responded to Staff's recommendation stating that increased costs for tree trimming efforts per mile have reduced the number of overall miles completed each year. The report showed

Table 6: NYSEG's Reliability Performance with respect to Tree Caused Interruptions

Year	Customers Affected by Tree Interruptions	Customer Hours for Tree Interruptions	Number of Interruptions due to Trees
2004	205,245	477,623	3,002
2005	288,347	666,940	4,090
2006	297,893	735,250	3,779
2007	333,469	865,694	3,997
2008	349,065	886,543	4,215

approximately half the circuit miles have been trimmed in 2007 and 2008 when compared to 2002 through 2005 levels. The number of customers affected by tree events has increased by 32% compared to the average for the years 2002 through 2005.

In Case 05-E-1222, NYSEG was allowed $17.7 million in rates for tree trimming on an annual basis effective in 2007. The Company indicated, however, that it has spent less in tree trimming on its distribution system than what was allowed in rates.

NYSEG's existing tree trimming program requires cycle trimming on all of the 35 kV circuits, but only the three phase sections of its 12 kV and 5 kV circuits, and single phase sections of these circuits on an ad hoc basis. The Company recommended in its self-assessment that in order to reduce tree caused interruptions, the existing tree trimming program should be expanded to perform cycle trimming on all single phase portions of its circuits. Given that NYSEG has not completed its planned trimming in recent years, Staff has concerns about NYSEG's tree trimming program.

Even though both frequency and duration improved in 2008 as compared with 2007, Staff continues to be concerned with NYSEG's overall approach to managing its tree caused interruptions. NYSEG's decision to reduce its tree trimming activities despite declining performance in this area needs to be examined. As a result, Staff will be seeking detailed information and explanations of trimming activities performed, spending variances, and quality assurance as part of the newly established Case 09-E-0472.

Equipment failures are the second highest cause of interruptions. In the Iberdrola merger (Case 07-M-0906), NYSEG was required to submit a condition assessment report. This report was received by Staff on December 8, 2008, and provided information on all of the electrical equipment and assets within its service territory and identified how age is a continued concern on the entire electrical system. The report concluded that NYSEG's electrical system is in "sound" condition. Over the past five years, however, NYSEG's reliability data show a steady increase in the number of interruptions caused by the failure or poor performance of the system equipment.

To proactively address the Company's aging infrastructure and equipment failure issues, NYSEG started a Transmission and Distribution Infrastructure Replacement Program (TDIRP). This program has been in place since 2005 and is the principal funding source for projects that address overall system condition issues. Overall Staff views this program as beneficial; however, funding for the program has been on the decline, and Staff is concerned whether NYSEG is committing appropriate funding resources to making the necessary infrastructure investments through TDIRP.

Another concern noted in Staff's reliability report last year was a declining trend in field staffing/personnel levels. As required, NYSEG provided its self-assessment that stated cost pressures have diminished its ability to increase or even maintain the field personnel levels once held in previous years. The Company goes on to say that while it continues to maintain sufficient numbers of workers to achieve the established reliability performance targets, increasing the number of qualified field personnel by approximately 10% may support improved duration numbers. As shown in Table 7 below, NYSEG has increased in total field personnel number for 2008. The increases, however, are for apprentice workers and not the qualified workers the Company is seeking.[15]

Table 7: NYSEG's Field Personnel Information

	2004	2005	2006	2007	2008
Total Number of Field Personnel	646	651	619	608	662
Percent Change from Previous Year	----	+0.8%	-4.9%	-1.8%	+8.2%

ROCHESTER GAS AND ELECTRIC

Table 8: RG&E's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	0.86	0.79	0.79	0.83	0.78	0.81
Duration (CAIDI)	1.84	1.87	1.78	1.73	1.85	1.81

[15] It takes approximately 3 years for an apprentice to be considered a qualified worker.

RG&E serves approximately 360,000 customers. Although the Company is comprised of four service areas, its Rochester division accounts for approximately 80% of its customer base. As a result, its overall reliability statistics mirror that of the Rochester division.

With regard to service reliability, RG&E continues to be one of the better performing utilities within the state. The Company has not failed its RPM targets of 0.90 for frequency and 1.90 for duration as established in its rate orders. As shown in Table 8, above, RG&E's performance for frequency and duration continue to be fairly consistent with its five year average. In 2008, the Company's frequency performance of 0.78 is the lowest since 2004. RG&E's duration performance of 1.85 in 2008 was slightly higher than both the previous year's performance. Figure 8 shows that the two major contributors to interruptions continue to be equipment failures (31%) and tree contacts (21%). The levels are slightly higher than the five year averages of both equipment failures and tree contacts.

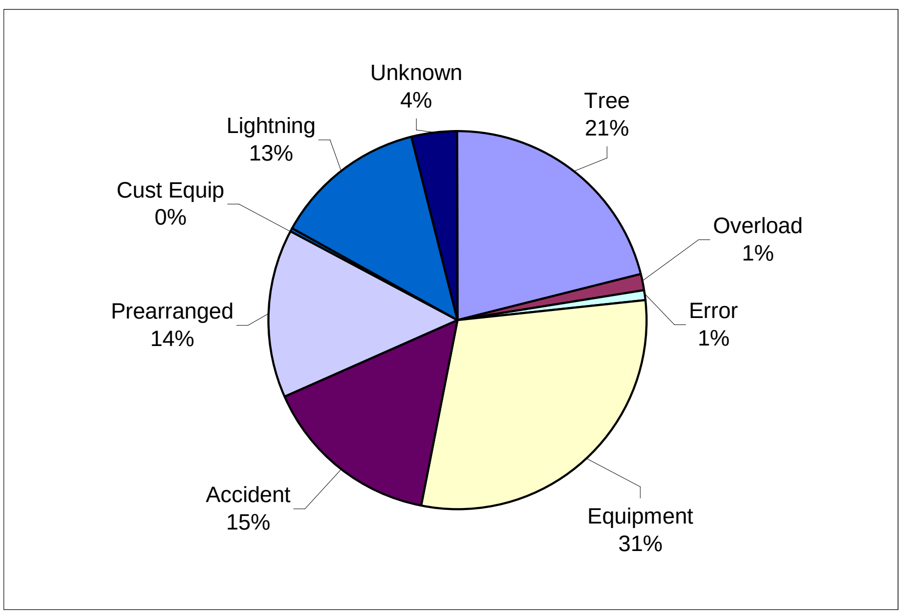


Figure 8: RG&E's 2008 Interruptions by Cause

Like NYSEG, RG&E was required to submit a conditions assessment report as part of the Iberdrola merger agreement. This report was received by Staff on December 8, 2008, and concluded that RGE's electrical system is in "sound" condition. Equipment failures, however, continues to be RG&E's highest contributor to its interruption performance. In 2007, RG&E implemented its own Transmission and Distribution Infrastructure Replacement Program (TDIRP), similar to that used by NYSEG, to address the Company's aging infrastructure and equipment failure issues. Staff encourages RG&E to make necessary infrastructure investments through TDIRP to ensure safe and reliable service to its customers.

CENTRAL HUDSON GAS AND ELECTRIC

Table 9: Central Hudson's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	**1.36**	1.44	**1.59**	1.42	1.27	1.42
Duration (CAIDI)	**2.35**	2.70	**2.58**	2.43	2.47	2.51

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Central Hudson serves approximately 298,000 customers in the Mid-Hudson Valley region. The Company's territory is mainly suburban and rural. Central Hudson does serve some urban regions, such as the cities of Poughkeepsie and Newburgh. Central Hudson's RPM targets were reestablished at 1.45 for frequency and 2.50 for duration in its most recent rate order, effective in 2007.[16]

Central Hudson' frequency performance of 1.27 in 2008 was its best in five years, considerably better than its five-year average (Table 9, above). The 2008 duration performance of 2.47 was better than the five-year average, but still close to the RPM target of 2.50, however. Figure 9 shows that 37% of customer interruptions are due to tree related issues, followed by accidents at 22%.

[16] As part of the joint agreement adopted in the last rate order, Central Hudson was not assessed revenue adjustments for 2005 performances.

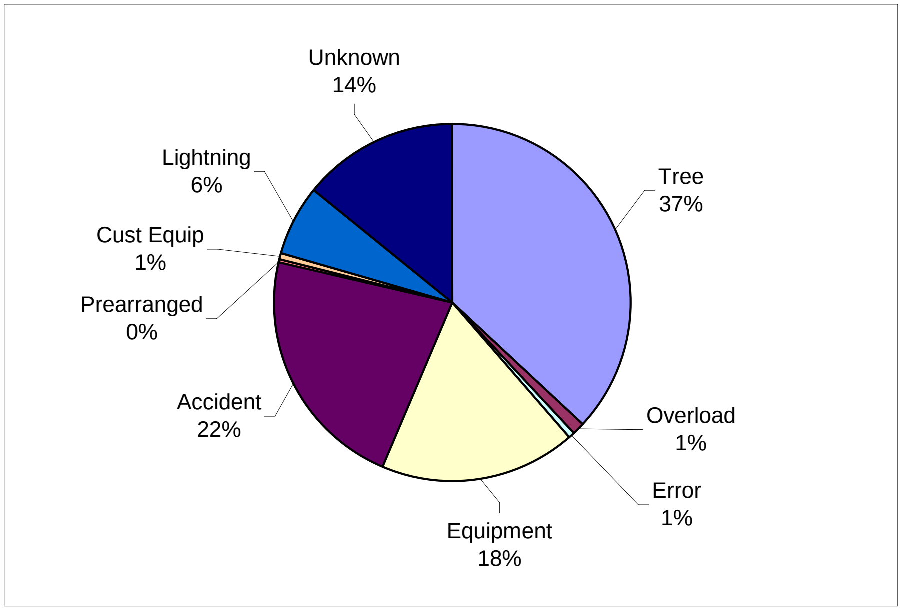


Figure 9: Central Hudson's 2008 Interruptions by Cause

Central Hudson has had a reduction in equipment failures resulting in customer outages since 2005 (see Table 10 below); in 2008, equipment failures were responsible for only 18% of the interruptions.

Table 10: Customers Affected by Service Interruptions

Year	Tree	Equipment
2004	136,933	89,177
2005	155,504	109,190
2006	172,850	104,263
2007	156,053	99,290
2008	137,170	86,115

In last year's report Staff directed that Central Hudson perform a self assessment of its line clearance program. Staff reviewed Central Hudson's report and found it satisfactory. It does appear that Central Hudson has been addressing tree caused interruptions in a logical way, expanding lessons learned in its enhanced clearance program to the rest of the system and positive results might have begun to be seen (see Table 10, above). In its current rate case proceeding, based on the recommendation of its consultant and actual experience, Central Hudson proposed (and Staff supported) expanding its enhanced tree trimming program of critical three-phase lines as well as the implementation of the modified enhanced program for the rest of the system, both single and multi-phase. A possible encouraging trend in reduced tree outages may also be seen in Table 9 (above) and will be something we will monitor.

Central Hudson's annual reliability report indicates one driver of outage duration is overloaded distribution transformers. Several districts noted they are replacing transformers before they fail using a combination of Transformer Load Management database and field checks with line foremen. This approach appears to have merit especially as preparation for warmer summers, such as was experienced in 2008.

ORANGE AND ROCKLAND

Table 11: O&R's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	1.30	1.36	1.23	1.03	1.19	1.22
Duration (CAIDI)	**1.61**	**1.71**	1.51	1.60	**1.83**	1.65

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Orange and Rockland is the smallest of the major investor-owned electric utilities. It serves approximately 217,000 customers in three New York counties along the New Jersey and Pennsylvania border. In 2008, the Company met its reliability performance mechanism target for frequency. The 2008 frequency performance, although higher than 2007, was still below the Company's five year average performance level. Orange and Rockland, however, failed its reliability performance mechanism for duration in 2008 with a performance of 1.83.

As shown in Figure 10 (below), equipment failures (34%) and trees (31%) caused the majority of interruptions in 2008. Orange and Rockland is addressing reliability issues due to equipment failures through capital improvement programs such as the Distribution Automation Program, the Underground Cable Maintenance and

Rebuild Program, and a number of service reliability improvement projects directed by the circuit priority-rating methodology.

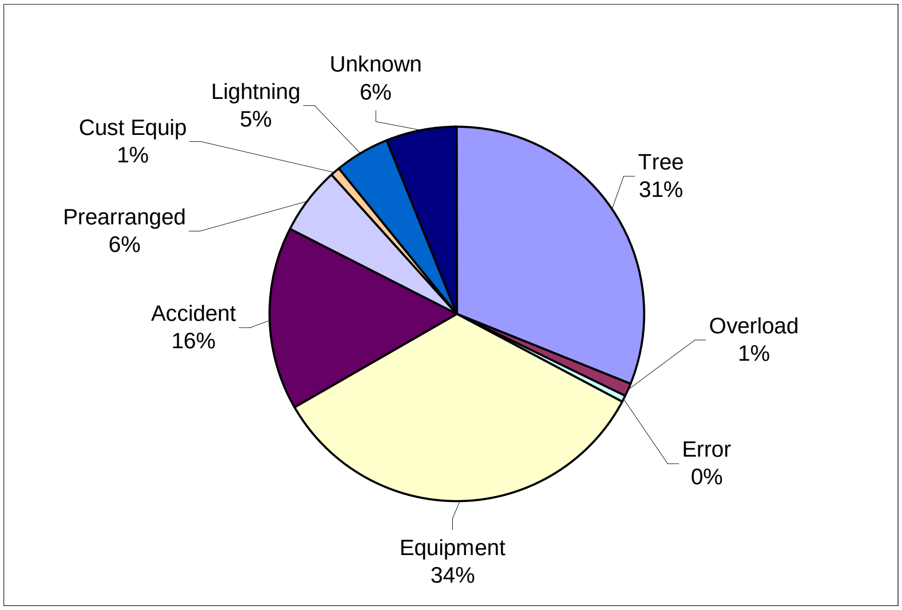


Figure 10: Orange and Rockland's 2008 Interruptions by Cause

The Company is addressing the tree concerns through increased efforts on its trimming programs. In addition to the four-year cycle based tree trimming program, the Company has continued to identify additional efforts to address key areas with recurring outages such as a recurring outage identification program and a "cycle buster" trimming program. These programs should help reduce the impact of tree contacts on the Company's electrical system through the coming years.

Orange and Rockland's duration performance in 2008 was slightly above its RPM target of 1.70. The Company had performed better than this target in both 2006 and 2007. Since its last rate filing (Case 07-0949), Orange and Rockland has been expressing concern that distribution automation equipment is negatively impacting its duration performance and recently made a presentation to Staff on the issue. As a result, Staff is working closely with the Company to determine the identifiable affects distribution automation has on the duration measure.

Staff believes that Orange and Rockland is appropriately installing more distribution automation equipment, increasing tree trimming efforts, and performing needed capital improvement projects to improve overall reliability. Equipment Failures and Tree Contacts continue to be the major causes of interruptions throughout the past five-years and this performance trend remains consistent throughout each operating division as well. Orange and Rockland's has been striving to control tree and equipment related interruptions for several years now. Even though immediate drastic changes are not anticipated due to the nature of the causes, small and steady improvements are expected in the years to come with the finalization of additional reliability projects.

RECOMMENDATIONS

The following is a summary of Staff recommendations based on our analysis of reliability performances in 2008. Additionally, NYSEG will have to respond to actions taken as part of Case 04-E-0472.

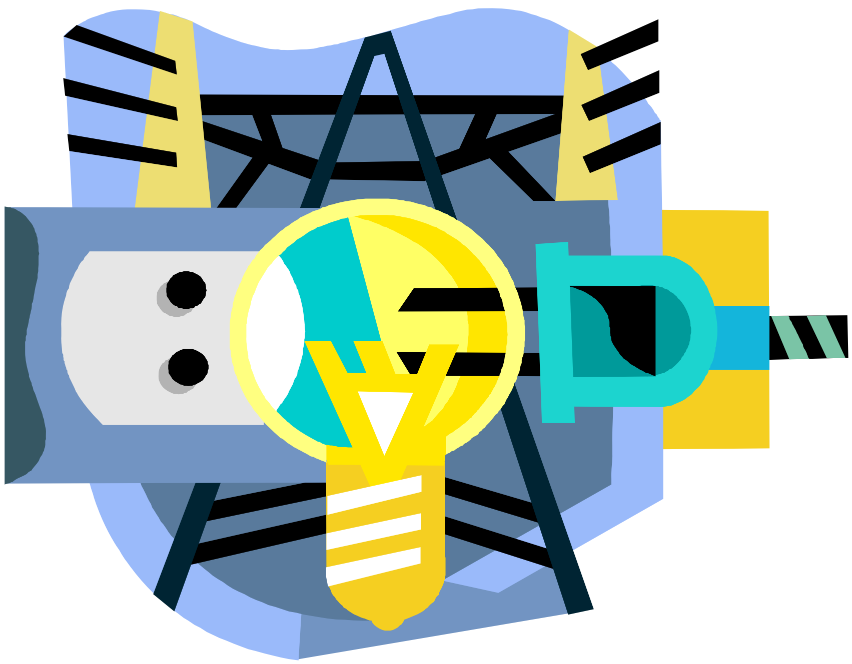
1. Con Edison should file a report no later than September 15, 2009 detailing information learned during pilot programs related to improving its duration performance and explaining how successful programs from the pilot programs would be implemented on a permanent basis.

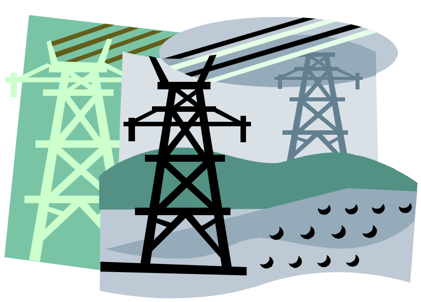
2. Con Edison should perform a self-assessment to identify strategies to improve its network duration performance and identify corrective actions that are unique to its network system. The self assessment should be filed no later than September 15, 2009.

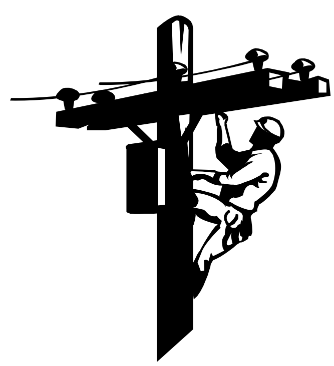
APPENDIX

2008 INTERRUPTON REPORT

The 2008 Interruption Report







Office of Electricity Gas and Water

June, 2009

ATTACHMENT
Definitions and Explanations of Terms Used in the 2008 Statewide Electric Service Interruption Report

Interruption is the loss of service for five minutes or more.

Customer hours is the time a customer is without electric service.

Customers affected is the number of customers without electric service.

Customers served is the number of customers as of the last day of the **current year.** For example, for the calendar year of **2008**, customers served is the number of customers as of 12/31/2008. For indices using customers served, the **previous** year is used.

Frequency (**SAIFI)** measures the average number of interruptions experienced by customers served by the utility. It is the customers affected divided by the customers served at the end of the **previous** year, i.e., 12/31/2007.

Duration (CAIDI) measures the average time that an affected customer is out of electric service. It is the customer hours divided by the customers affected.

Availability (SAIDI) is the average amount of time a customer is out-of-service during a year. It is the customer hours divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2007. Mathematically, it also is **SAIFI** multiplied by **CAIDI**.

Interruptions Per 1000 Customers Served is the number of interruptions divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2007, divided by 1,000.

Major Storm is defined as any storm which causes service interruptions of at least ten percent of customers in an operating area, or if the interruptions last for 24 hours or more.

Operating Area is a geographical subdivision of each electric utility's franchise territory. These areas are also called regions, divisions, or districts.

Most of the data is presented two ways, with major storms included and major storms excluded. Major storms tend to distort a utility's performance trend. Tables and graphs that exclude major storms illustrate interruptions that are more under the utility's control. It portrays a utility's system facilities under normal conditions, although this can be misleading because interruptions during "normal" bad weather are included and it is difficult to analyze from year to year.

The first two tables show frequency and duration indices for the last five years for each utility and Statewide with and without Con Edison data. Con Edison has by far the lowest frequency numbers and tends to distort the Statewide data. Much of Con Edison's distribution system consists of a secondary network. In a secondary network, a customer is fed from multiple supplies, making the probability of an interruption relatively rare.

COMPARISON OF SERVICE RELIABILITY INDICES
(EXCLUDING MAJOR STORMS)

	2004	2005	2006	2007	2008	5 YR AVG
CHGE						
FREQUENCY	1.36	1.44	1.59	1.42	1.27	1.42
DURATION	2.35	2.70	2.58	2.43	2.47	2.51
CONED						
FREQUENCY	0.11	0.14	0.16	0.16	0.13	0.14
DURATION	1.71	1.99	8.23	1.97	2.27	3.23
LIPA *						
FREQUENCY	0.83	0.85	0.75	0.90	0.77	0.82
DURATION	1.04	1.07	1.37	1.20	1.36	1.21
NAT GRID						
FREQUENCY	1.02	0.98	1.01	0.96	0.75	0.94
DURATION	2.04	2.32	2.05	2.01	1.96	2.08
NYSEG						
FREQUENCY	1.13	1.12	1.12	1.20	1.11	1.13
DURATION	1.96	1.96	2.01	2.22	2.08	2.05
O&R						
FREQUENCY	1.30	1.36	1.23	1.03	1.19	1.22
DURATION	1.61	1.71	1.51	1.60	1.83	1.65
RG&E						
FREQUENCY	0.86	0.79	0.79	0.83	0.78	0.81
DURATION	1.84	1.87	1.78	1.73	1.85	1.81
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.02	1.01	1.00	1.01	0.88	0.98
DURATION	1.81	1.95	1.92	1.88	1.89	1.89
STATEWIDE (WITH CONED)						
FREQUENCY	0.64	0.65	0.65	0.65	0.56	0.63
DURATION	1.80	1.95	2.57	1.89	1.93	2.03

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

June, 2009

COMPARISON OF SERVICE RELIABILITY INDICES
(INCLUDING MAJOR STORMS)

	2004	2005	2006	2007	2008	5 YR AVG
CHGE						
FREQUENCY	1.42	1.83	2.20	1.51	2.15	1.82
DURATION	2.45	3.27	4.12	2.51	5.76	3.62
CONED						
FREQUENCY	0.11	0.15	0.23	0.18	0.14	0.16
DURATION	1.74	2.32	12.31	3.12	2.71	4.44
LIPA *						
FREQUENCY	0.91	1.07	1.17	1.03	1.09	1.05
DURATION	1.12	1.42	1.99	1.37	1.65	1.51
NAT GRID						
FREQUENCY	1.12	1.28	1.48	1.31	1.37	1.31
DURATION	2.15	2.76	7.18	2.70	4.32	3.82
NYSEG						
FREQUENCY	1.41	1.77	1.79	1.71	2.14	1.76
DURATION	2.26	3.27	10.32	3.62	7.07	5.31
O&R						
FREQUENCY	1.46	1.83	1.81	1.17	1.64	1.58
DURATION	1.77	2.42	2.15	1.92	2.94	2.24
RG&E						
FREQUENCY	0.98	0.93	0.98	1.16	1.36	1.08
DURATION	2.04	1.90	2.14	1.80	3.77	2.33
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.15	1.36	1.48	1.31	1.51	1.36
DURATION	1.97	2.60	6.02	2.56	4.62	3.55
STATEWIDE (WITH CONED)						
FREQUENCY	0.71	0.85	0.96	0.83	0.93	0.86
DURATION	1.95	2.58	6.65	2.61	4.50	3.66

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

June, 2009

STATEWIDE (WITHOUT CON ED)
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	50,242	54,434	55,211	55,425	53,758	53,814
Number of Customer-Hours	8,015,041	8,631,869	8,439,916	8,439,464	7,399,179	8,185,094
Number of Customers Affected	4,439,677	4,433,386	4,400,072	4,495,428	3,910,426	4,335,798
Number of Customers Served	4,392,363	4,415,079	4,434,324	4,436,307	4,429,635	4,421,542
Average Duration Per Customer Affected (CAIDI)	1.81	1.95	1.92	1.88	1.89	1.89
Average Duration Per Customers Served	1.83	1.97	1.91	1.90	1.67	1.86
Interruptions Per 1000 Customers Served	11.49	12.39	12.51	12.50	12.12	12.20
Number of Customers Affected Per Customer Served (SAIFI)	1.02	1.01	1.00	1.01	0.88	0.98

STATEWIDE (WITH CON ED)
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	59,458	65,019	65,752	66,746	65,403	64,476
Number of Customer-Hours	8,596,012	9,506,355	12,603,322	9,429,452	8,326,562	9,692,341
Number of Customers Affected	4,779,817	4,873,534	4,905,844	4,996,967	4,319,550	4,775,142
Number of Customers Served	7,553,747	7,602,291	7,652,745	7,681,104	7,701,361	7,638,250
Average Duration Per Customer Affected (CAIDI)	1.80	1.95	2.57	1.89	1.93	2.03
Average Duration Per Customers Served	1.14	1.26	1.66	1.23	1.08	1.28
Interruptions Per 1000 Customers Served	7.91	8.61	8.65	8.72	8.51	8.48
Number of Customers Affected Per Customer Served (SAIFI)	0.64	0.65	0.65	0.65	0.56	0.63

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

STATEWIDE (WITHOUT CON ED)
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	53,535	66,767	70,872	61,753	73,150	65,215
Number of Customer-Hours	9,852,887	15,493,419	39,413,242	14,848,512	30,962,269	22,114,066
Number of Customers Affected	5,009,438	5,960,730	6,548,910	5,808,516	6,705,414	6,006,602
Number of Customers Served	4,392,363	4,415,079	4,434,324	4,436,307	4,429,635	4,421,542
Average Duration Per Customer Affected (CAIDI)	1.97	2.60	6.02	2.56	4.62	3.55
Average Duration Per Customers Served	2.25	3.53	8.93	3.35	6.98	5.01
Interruptions Per 1000 Customers Served	12.24	15.20	16.05	13.93	16.49	14.78
Number of Customers Affected Per Customer Served (SAIFI)	1.15	1.36	1.48	1.31	1.51	1.36

STATEWIDE (WITH CON ED)
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	62,806	77,937	86,734	74,261	85,548	77,457
Number of Customer-Hours	10,454,054	16,612,929	48,437,221	16,630,252	32,188,186	24,864,528
Number of Customers Affected	5,355,101	6,442,863	7,282,114	6,379,276	7,158,329	6,523,537
Number of Customers Served	7,553,747	7,602,291	7,652,745	7,681,104	7,701,361	7,638,250
Average Duration Per Customer Affected (CAIDI)	1.95	2.58	6.65	2.61	4.50	3.66
Average Duration Per Customers Served	1.39	2.20	6.37	2.17	4.19	3.27
Interruptions Per 1000 Customers Served	8.36	10.32	11.41	9.70	11.14	10.18
Number of Customers Affected Per Customer Served (SAIFI)	0.71	0.85	0.96	0.83	0.93	0.86

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CENTRAL HUDSON
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	6,514	6,911	7,538	6,386	6,857	6,841
Number of Customer-Hours	917,136	1,125,389	1,201,109	1,021,859	933,993	1,039,897
Number of Customers Affected	389,969	416,547	464,765	420,769	377,564	413,923
Number of Customers Served	289,080	292,816	295,368	298,386	300,621	295,254
Average Duration Per Customer Affected (CAIDI)	2.35	2.70	2.58	2.43	2.47	2.51
Average Duration Per Customers Served	3.21	3.89	4.10	3.46	3.13	3.56
Interruptions Per 1000 Customers Served	22.77	23.91	25.74	21.62	22.98	23.40
Number of Customers Affected Per Customer Served (SAIFI)	1.36	1.44	1.59	1.42	1.27	1.42

CENTRAL HUDSON
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	6,756	8,309	10,066	6,681	9,887	8,340
Number of Customer-Hours	994,057	1,735,705	2,649,690	1,117,802	3,705,277	2,040,506
Number of Customers Affected	405,534	530,319	643,778	444,813	642,949	533,479
Number of Customers Served	289,080	292,816	295,368	298,386	300,621	295,254
Average Duration Per Customer Affected (CAIDI)	2.45	3.27	4.12	2.51	5.76	3.62
Average Duration Per Customers Served	3.47	6.00	9.05	3.78	12.42	6.95
Interruptions Per 1000 Customers Served	23.62	28.74	34.38	22.62	33.13	28.50
Number of Customers Affected Per Customer Served (SAIFI)	1.42	1.83	2.20	1.51	2.15	1.82

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (SYSTEM)

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	9,216	10,585	10,541	11,321	11,645	10,662
Number of Customer-Hours	580,971	874,487	4,163,407	989,988	927,383	1,507,247
Number of Customers Affected	340,140	440,148	505,772	501,539	409,124	439,345
Number of Customers Served	3,161,384	3,187,212	3,218,421	3,244,797	3,271,726	3,216,708
Average Duration Per Customer Affected (CAIDI)	1.71	1.99	8.23	1.97	2.27	3.23
Average Duration Per Customers Served	0.18	0.28	1.31	0.31	0.29	0.47
Interruptions Per 1000 Customers Served	2.93	3.35	3.31	3.52	3.59	3.34
Number of Customers Affected Per Customer Served (SAIFI)	0.11	0.14	0.16	0.16	0.13	0.14

CON ED (SYSTEM)

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	9,271	11,170	15,862	12,508	12,398	12,242
Number of Customer-Hours	601,167	1,119,510	9,023,979	1,781,740	1,225,917	2,750,463
Number of Customers Affected	345,663	482,133	733,204	570,760	452,915	516,935
Number of Customers Served	3,161,384	3,187,212	3,218,421	3,244,797	3,271,726	3,216,708
Average Duration Per Customer Affected (CAIDI)	1.74	2.32	12.31	3.12	2.71	4.44
Average Duration Per Customers Served	0.19	0.35	2.83	0.55	0.38	0.86
Interruptions Per 1000 Customers Served	2.95	3.53	4.98	3.89	3.82	3.83
Number of Customers Affected Per Customer Served (SAIFI)	0.11	0.15	0.23	0.18	0.14	0.16

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (NETWORK)

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	4,360	4,967	4,274	5,571	5,485	4,931
Number of Customer-Hours	44,195	59,566	2,947,306	316,477	252,964	724,101
Number of Customers Affected	12,138	13,406	48,467	176,430	40,301	58,148
Number of Customers Served	2,319,321	2,339,622	2,363,897	2,361,145	2,385,760	2,353,949
Average Duration Per Customer Affected (CAIDI)	3.64	4.44	60.81	1.79	6.28	15.39
Average Duration Per Customers Served	0.02	0.03	1.26	0.13	0.11	0.31
Interruptions Per 1000 Customers Served	1.89	2.14	1.83	2.36	2.32	2.11
Number of Customers Affected Per Customer Served (SAIFI)	0.005	0.006	0.021	0.075	0.017	0.025

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (RADIAL)

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	4,856	5,618	6,267	5,750	6,160	5,730
Number of Customer-Hours	536,776	814,921	1,216,101	673,511	674,419	783,146
Number of Customers Affected	328,002	426,742	457,305	325,109	368,823	381,196
Number of Customers Served	842,063	847,590	854,524	883,652	885,966	862,759
Average Duration Per Customer Affected (CAIDI)	1.64	1.91	2.66	2.07	1.83	2.02
Average Duration Per Customers Served	0.64	0.97	1.43	0.79	0.76	0.92
Interruptions Per 1000 Customers Served	5.81	6.67	7.39	6.73	6.97	6.72
Number of Customers Affected Per Customer Served (SAIFI)	0.39	0.51	0.54	0.38	0.42	0.45

CON ED (RADIAL)

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	4,911	6,203	11,588	6,937	6,913	7,310
Number of Customer-Hours	556,972	1,059,944	6,076,673	1,465,264	972,954	2,026,361
Number of Customers Affected	333,525	468,727	684,737	394,330	412,614	458,787
Number of Customers Served	842,063	847,590	854,524	883,652	885,966	862,759
Average Duration Per Customer Affected (CAIDI)	1.67	2.26	8.87	3.72	2.36	3.78
Average Duration Per Customers Served	0.67	1.26	7.17	1.71	1.10	2.38
Interruptions Per 1000 Customers Served	5.88	7.37	13.67	8.12	7.82	8.57
Number of Customers Affected Per Customer Served (SAIFI)	0.40	0.56	0.81	0.46	0.47	0.54

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

LIPA
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	15,423	17,728	18,634	18,736	18,135	17,731
Number of Customer-Hours	942,669	999,412	1,129,275	1,190,411	1,166,613	1,085,676
Number of Customers Affected	908,253	931,276	823,396	995,077	856,405	902,881
Number of Customers Served	1,096,472	1,103,162	1,108,540	1,110,853	1,114,716	1,106,749
Average Duration Per Customer Affected (CAIDI)	1.04	1.07	1.37	1.20	1.36	1.21
Average Duration Per Customers Served	0.87	0.91	1.02	1.07	1.05	0.98
Interruptions Per 1000 Customers Served	14.16	16.17	16.89	16.90	16.33	16.09
Number of Customers Affected Per Customer Served (SAIFI)	0.83	0.85	0.75	0.90	0.77	0.82

LIPA
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	15,956	21,317	24,905	20,077	20,471	20,545
Number of Customer-Hours	1,105,002	1,675,011	2,564,134	1,564,559	1,998,270	1,781,395
Number of Customers Affected	986,170	1,177,059	1,289,698	1,142,365	1,208,292	1,160,717
Number of Customers Served	1,096,472	1,103,162	1,108,540	1,110,853	1,114,716	1,106,749
Average Duration Per Customer Affected (CAIDI)	1.12	1.42	1.99	1.37	1.65	1.51
Average Duration Per Customers Served	1.01	1.53	2.32	1.41	1.80	1.62
Interruptions Per 1000 Customers Served	14.65	19.44	22.58	18.11	18.43	18.64
Number of Customers Affected Per Customer Served (SAIFI)	0.91	1.07	1.17	1.03	1.09	1.05

* LIPA is not regulated by the NYS PSC.
* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

NATIONAL GRID

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	13,917	13,680	13,665	14,606	12,939	13,761
Number of Customer-Hours	3,274,229	3,598,884	3,289,340	3,045,363	2,334,754	3,108,514
Number of Customers Affected	1,602,708	1,551,448	1,607,461	1,518,634	1,188,585	1,493,767
Number of Customers Served	1,580,131	1,585,383	1,589,949	1,594,179	1,583,311	1,586,591
Average Duration Per Customer Affected (CAIDI)	2.04	2.32	2.05	2.01	1.96	2.08
Average Duration Per Customers Served	2.08	2.28	2.07	1.92	1.46	1.96
Interruptions Per 1000 Customers Served	8.82	8.66	8.62	9.19	8.12	8.68
Number of Customers Affected Per Customer Served (SAIFI)	1.02	0.98	1.01	0.96	0.75	0.94

NATIONAL GRID

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	14,760	16,211	16,279	16,222	18,301	16,355
Number of Customer-Hours	3,800,127	5,568,127	16,813,162	5,605,931	9,410,833	8,239,636
Number of Customers Affected	1,766,092	2,020,066	2,341,235	2,075,480	2,177,786	2,076,132
Number of Customers Served	1,580,131	1,585,383	1,589,949	1,594,179	1,583,311	1,586,591
Average Duration Per Customer Affected (CAIDI)	2.15	2.76	7.18	2.70	4.32	3.82
Average Duration Per Customers Served	2.41	3.52	10.61	3.53	5.90	5.19
Interruptions Per 1000 Customers Served	9.35	10.26	10.27	10.20	11.48	10.31
Number of Customers Affected Per Customer Served (SAIFI)	1.12	1.28	1.48	1.31	1.37	1.31

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

NYSEG

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	8,946	10,190	9,682	10,317	10,027	9,832
Number of Customer-Hours	1,866,112	1,872,868	1,913,315	2,299,142	1,980,213	1,986,330
Number of Customers Affected	952,258	955,009	953,941	1,034,113	953,105	969,685
Number of Customers Served	849,335	854,508	859,440	859,963	857,517	856,153
Average Duration Per Customer Affected (CAIDI)	1.96	1.96	2.01	2.22	2.08	2.05
Average Duration Per Customers Served	2.21	2.21	2.24	2.68	2.30	2.32
Interruptions Per 1000 Customers Served	10.59	12.00	11.33	12.00	11.66	11.48
Number of Customers Affected Per Customer Served (SAIFI)	1.13	1.12	1.12	1.20	1.11	1.13

NYSEG

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	10,269	14,364	12,835	12,928	17,008	13,481
Number of Customer-Hours	2,687,162	4,926,508	15,787,602	5,314,914	12,974,501	8,338,137
Number of Customers Affected	1,188,998	1,504,612	1,529,247	1,469,825	1,836,251	1,505,787
Number of Customers Served	849,335	854,508	859,440	859,963	857,517	856,153
Average Duration Per Customer Affected (CAIDI)	2.26	3.27	10.32	3.62	7.07	5.31
Average Duration Per Customers Served	3.18	5.80	18.48	6.18	15.09	9.75
Interruptions Per 1000 Customers Served	12.15	16.91	15.02	15.04	19.78	15.78
Number of Customers Affected Per Customer Served (SAIFI)	1.41	1.77	1.79	1.71	2.14	1.76

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

O&R

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	2,546	2,718	2,688	2,596	2,993	2,708
Number of Customer-Hours	440,617	493,591	397,977	356,514	470,431	431,826
Number of Customers Affected	274,124	289,022	264,121	222,895	256,943	261,421
Number of Customers Served	212,352	214,546	216,268	215,694	217,373	215,247
Average Duration Per Customer Affected (CAIDI)	1.61	1.71	1.51	1.60	1.83	1.65
Average Duration Per Customers Served	2.09	2.32	1.85	1.65	2.18	2.02
Interruptions Per 1000 Customers Served	12.10	12.80	12.53	12.00	13.88	12.66
Number of Customers Affected Per Customer Served (SAIFI)	1.30	1.36	1.23	1.03	1.19	1.22

O&R

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	2,729	3,123	3,546	2,738	3,655	3,158
Number of Customer-Hours	542,652	942,127	836,046	483,938	1,043,235	769,600
Number of Customers Affected	307,396	388,553	388,164	252,650	354,315	338,216
Number of Customers Served	212,352	214,546	216,268	215,694	217,373	215,247
Average Duration Per Customer Affected (CAIDI)	1.77	2.42	2.15	1.92	2.94	2.24
Average Duration Per Customers Served	2.58	4.44	3.90	2.24	4.84	3.60
Interruptions Per 1000 Customers Served	12.97	14.71	16.53	12.66	16.95	14.76
Number of Customers Affected Per Customer Served (SAIFI)	1.46	1.83	1.81	1.17	1.64	1.58

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

RG&E
Excluding Major Storms

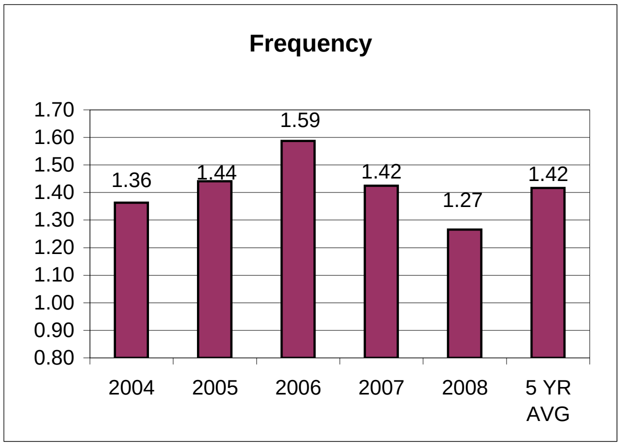
	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	2,896	3,207	3,004	2,784	2,807	2,940
Number of Customer-Hours	574,278	541,725	508,899	526,175	513,175	532,850
Number of Customers Affected	312,365	290,084	286,388	303,940	277,824	294,120
Number of Customers Served	364,993	364,664	364,759	357,232	356,097	361,549
Average Duration Per Customer Affected (CAIDI)	1.84	1.87	1.78	1.73	1.85	1.81
Average Duration Per Customers Served	1.58	1.48	1.40	1.44	1.44	1.47
Interruptions Per 1000 Customers Served	7.96	8.79	8.24	7.63	7.86	8.10
Number of Customers Affected Per Customer Served (SAIFI)	0.86	0.79	0.79	0.83	0.78	0.81

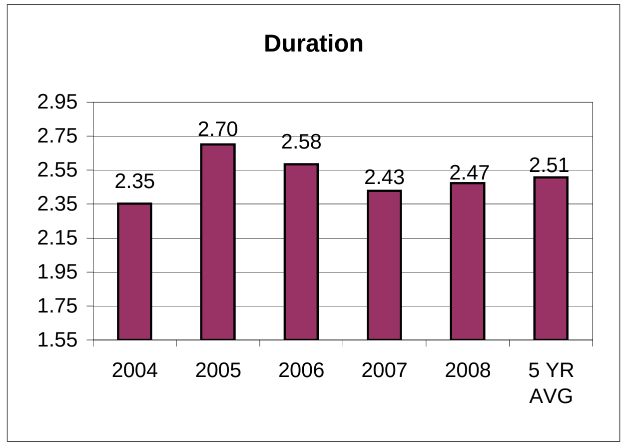
RG&E
Including Major Storms

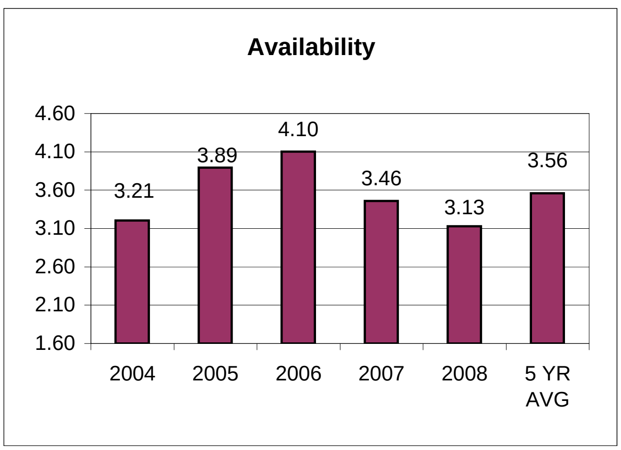
	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	3,065	3,443	3,241	3,107	3,828	3,337
Number of Customer-Hours	723,887	645,940	762,609	761,368	1,830,153	944,791
Number of Customers Affected	355,248	340,121	356,788	423,383	485,821	392,272
Number of Customers Served	364,993	364,664	364,759	357,232	356,097	361,549
Average Duration Per Customer Affected (CAIDI)	2.04	1.90	2.14	1.80	3.77	2.33
Average Duration Per Customers Served	1.99	1.77	2.09	2.09	5.12	2.61
Interruptions Per 1000 Customers Served	8.43	9.43	8.89	8.52	10.72	9.20
Number of Customers Affected Per Customer Served (SAIFI)	0.98	0.93	0.98	1.16	1.36	1.08

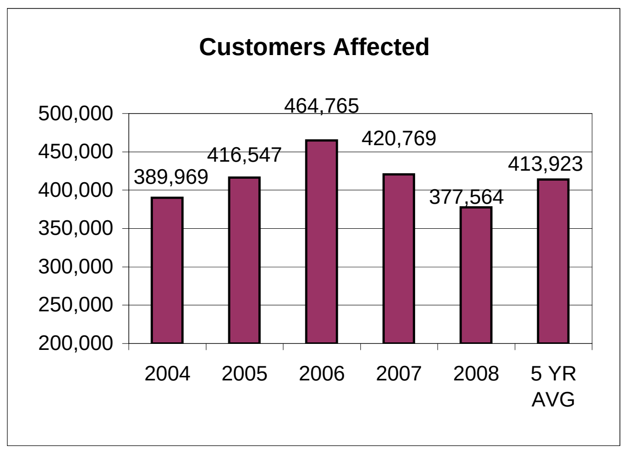
* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

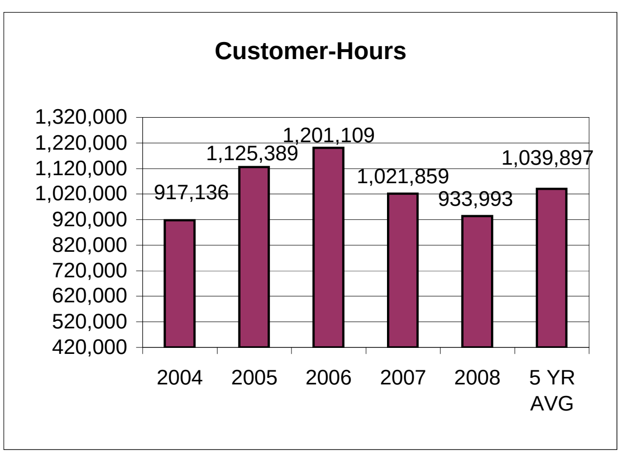
Central Hudson Gas and Electric
(Excluding Major Storms)

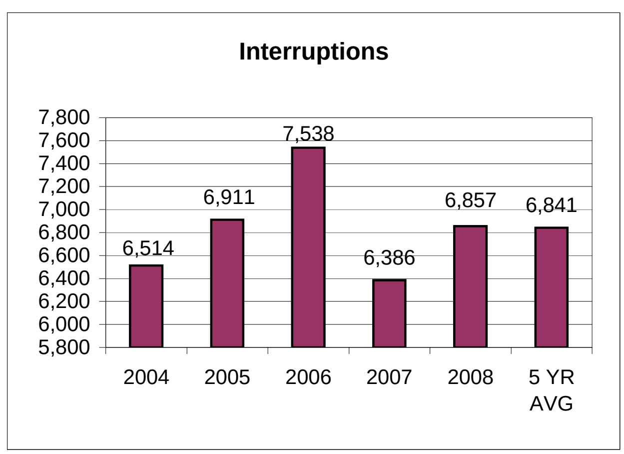




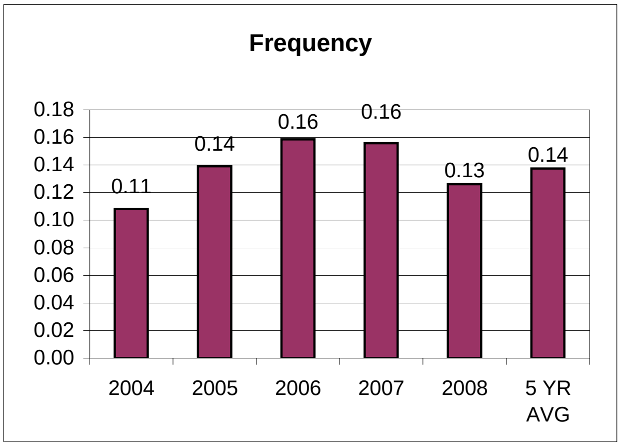


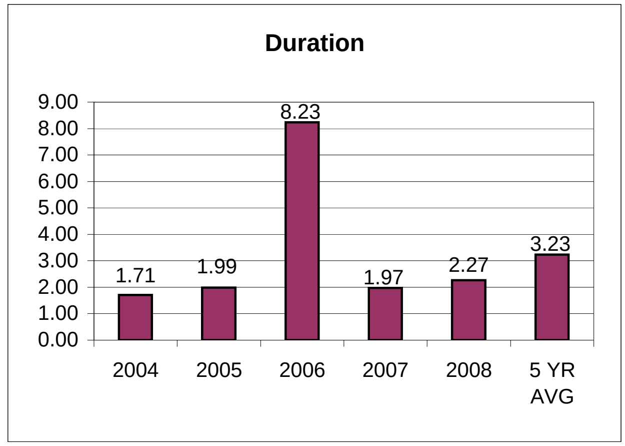


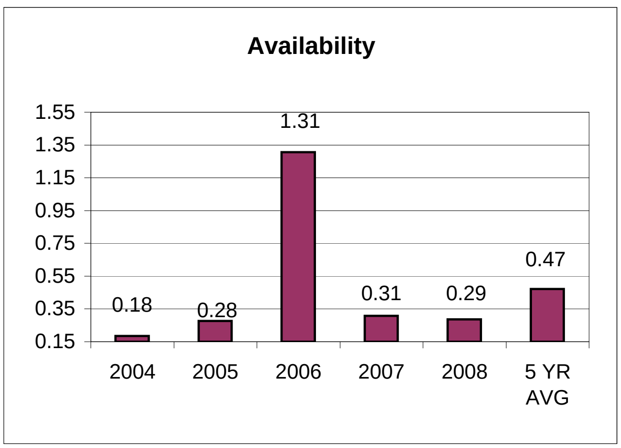


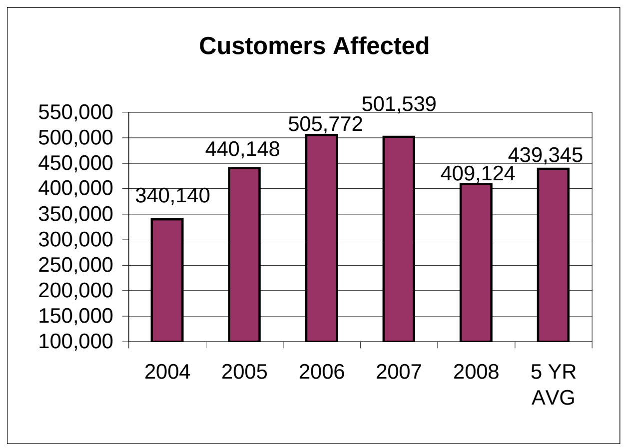


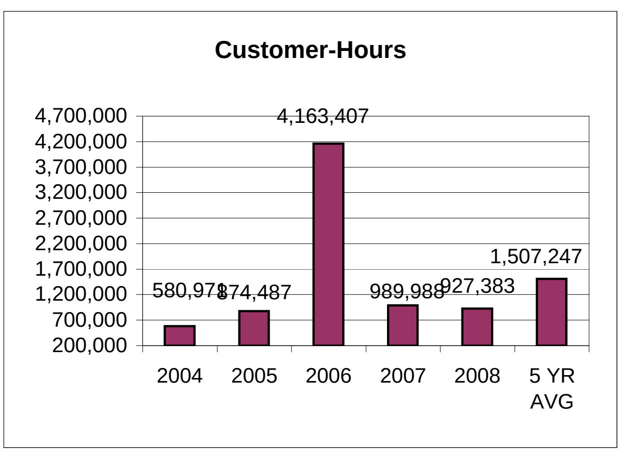
Consolidated Edison - System
(Excluding Major Storms)

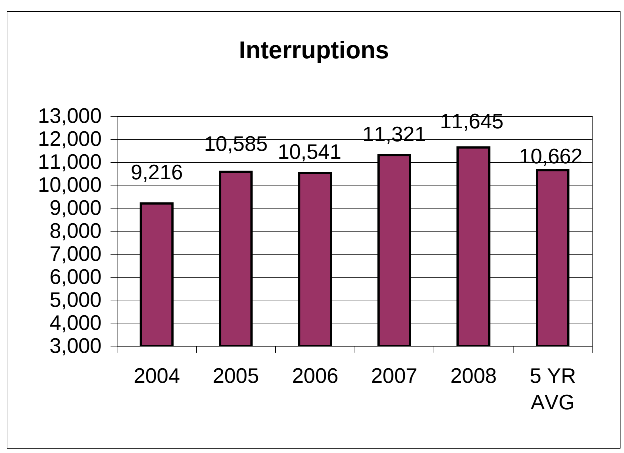






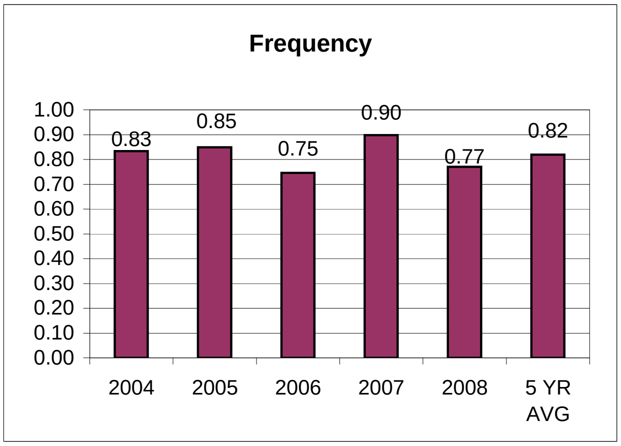


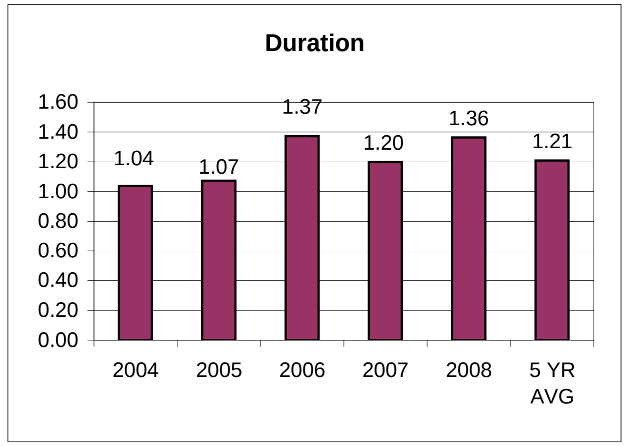


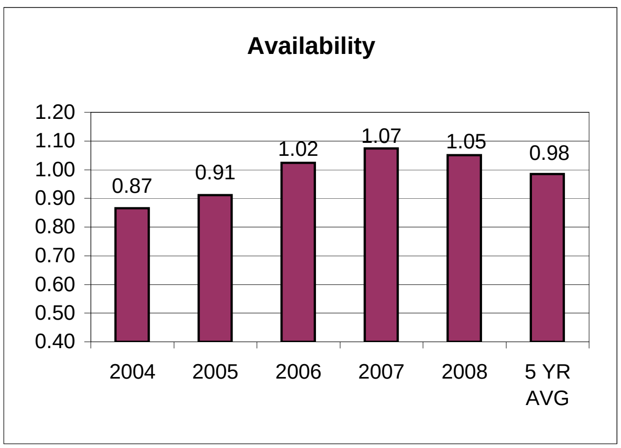


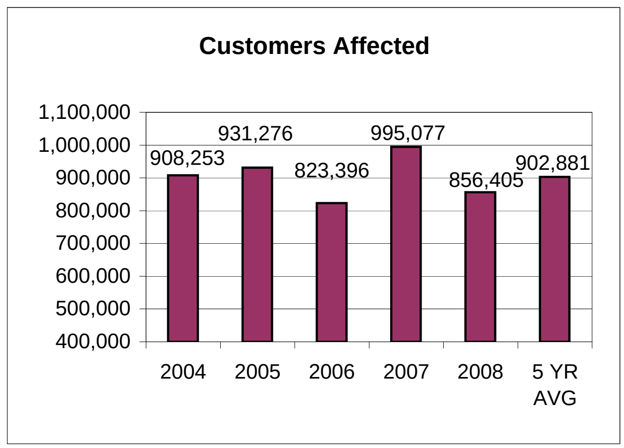
June, 2009

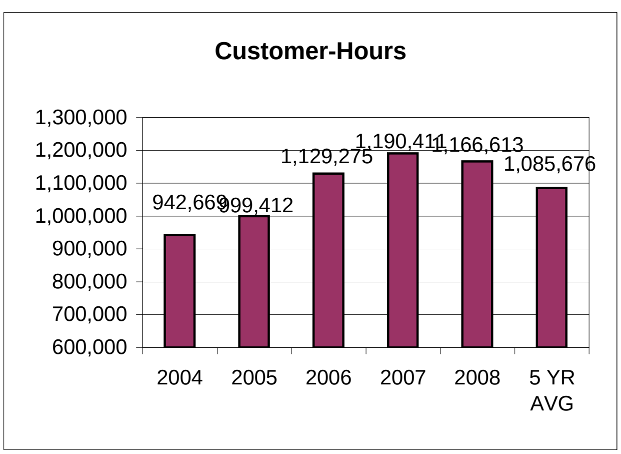
Long Island Power Authority
(Excluding Major Storms)

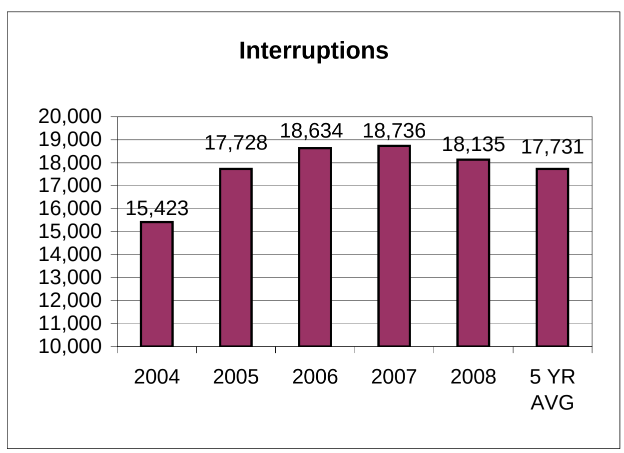






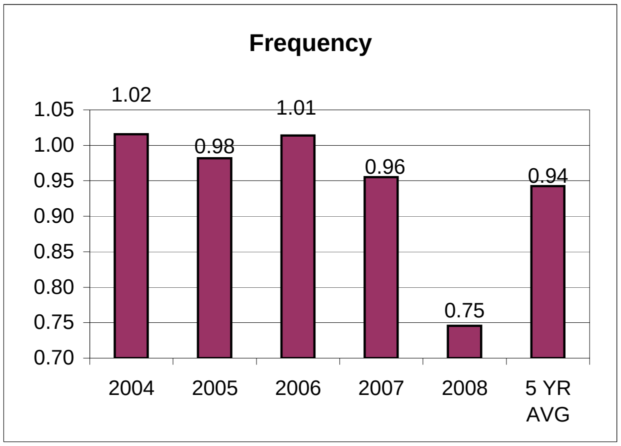


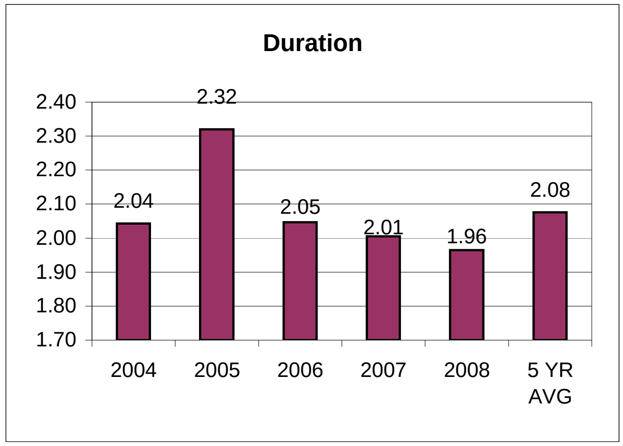


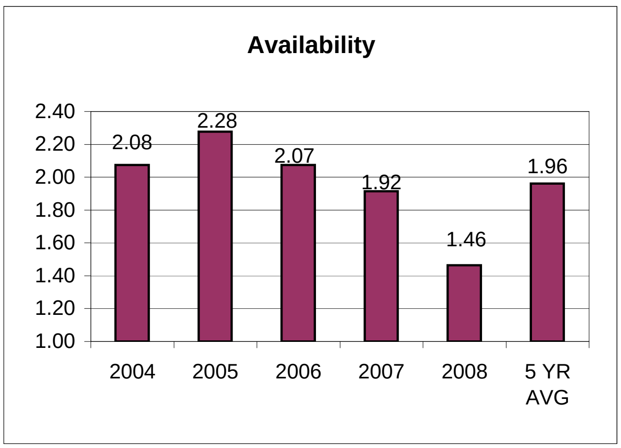


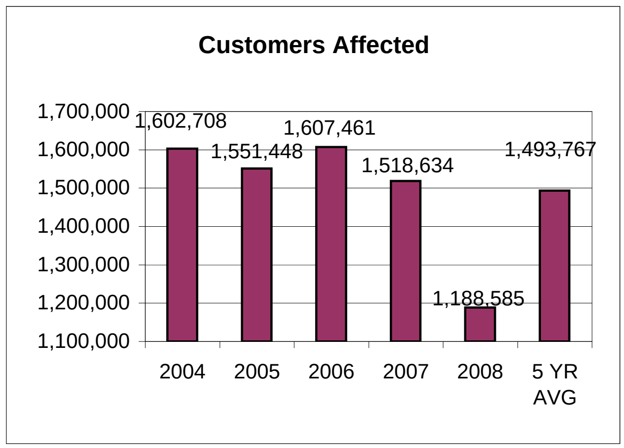
* LIPA is not regulated by the NYS PSC.

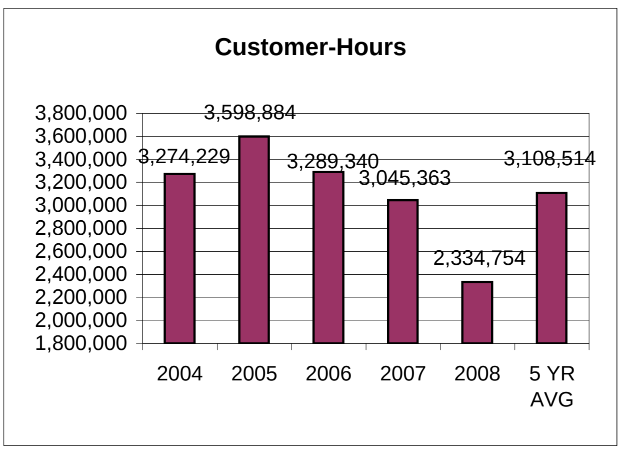
National Grid
(Excluding Major Storms)

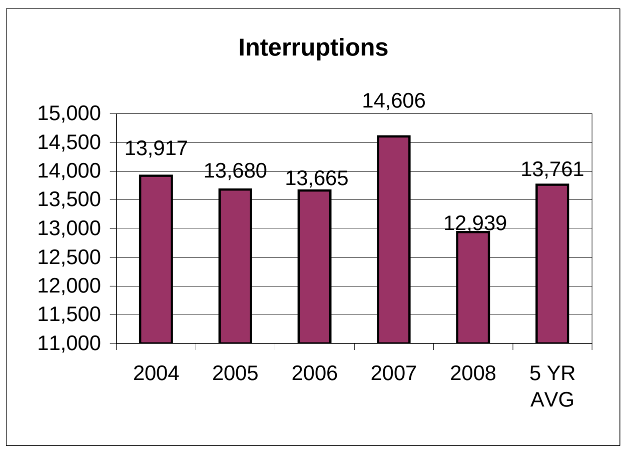




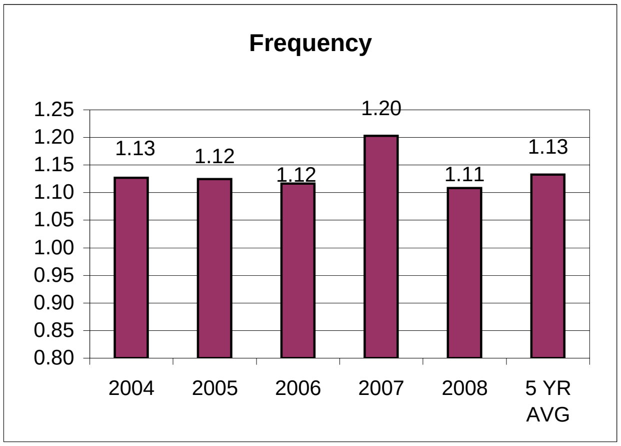


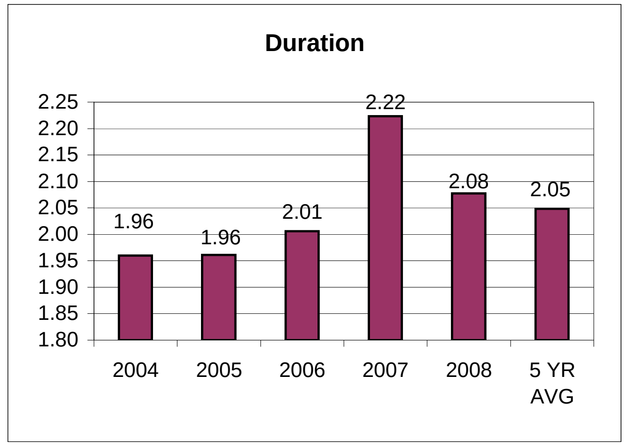


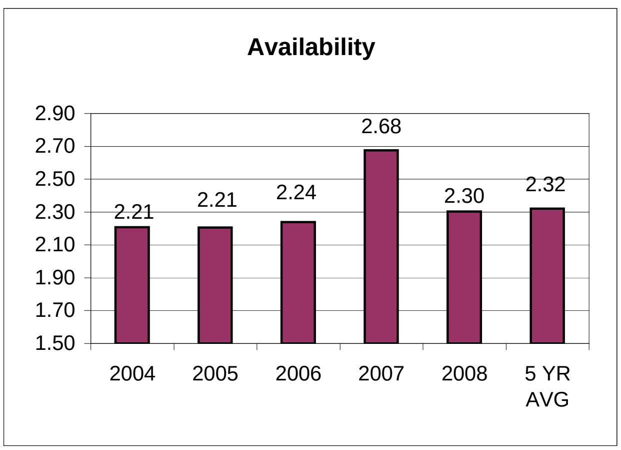


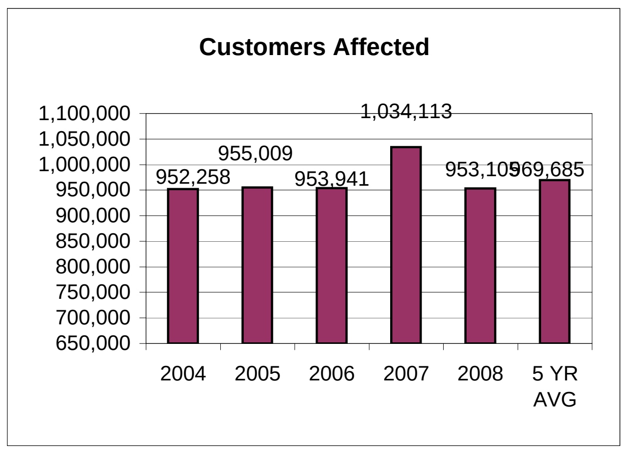


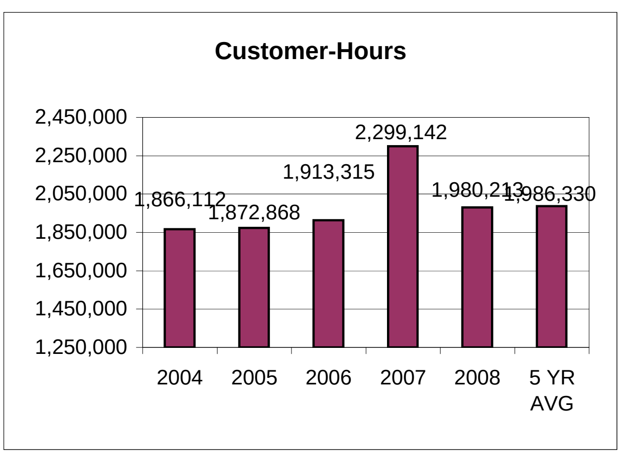
New York State Electric and Gas
(Excluding Major Storms)

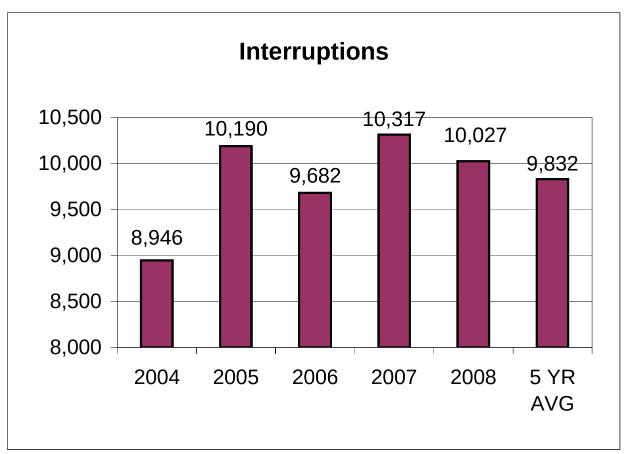




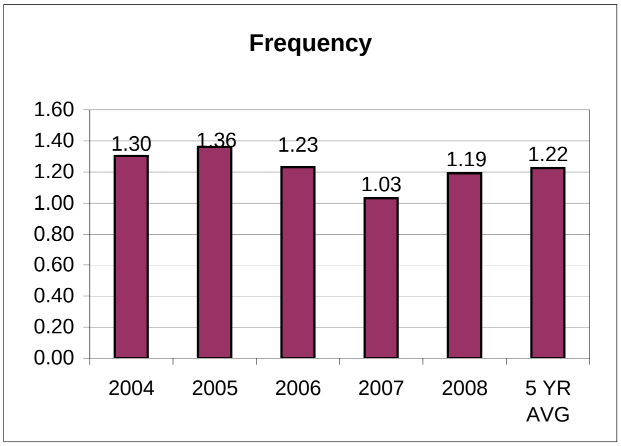


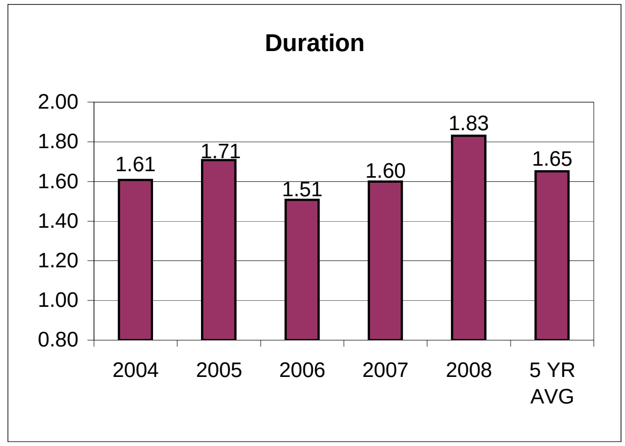


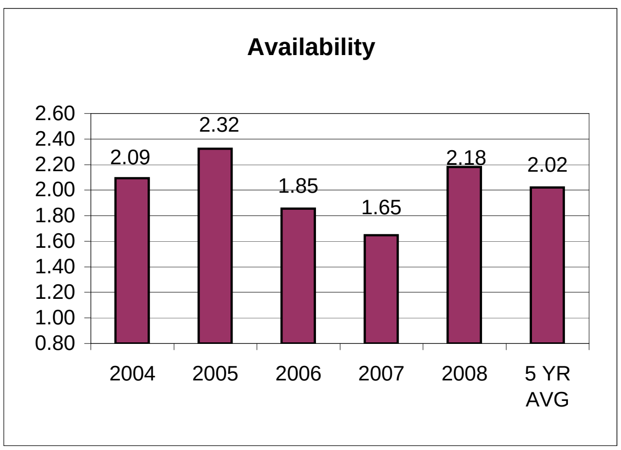


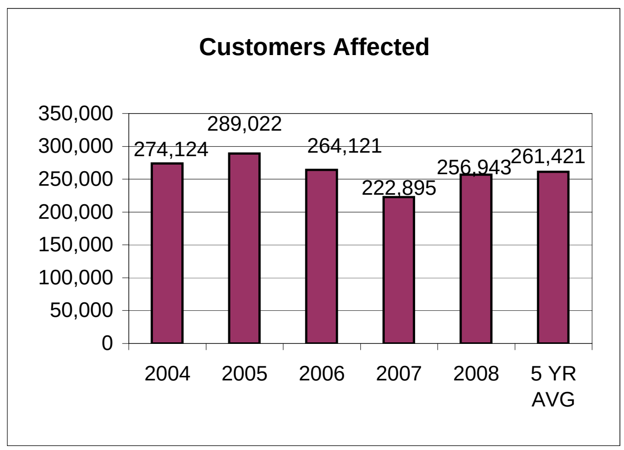


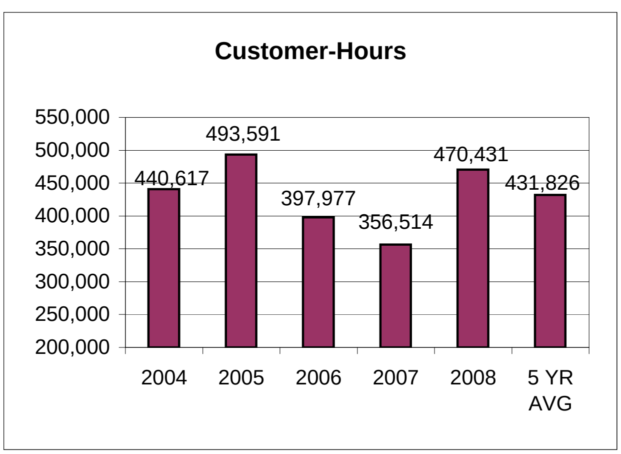
Orange and Rockland Utilities
(Excluding Major Storms)

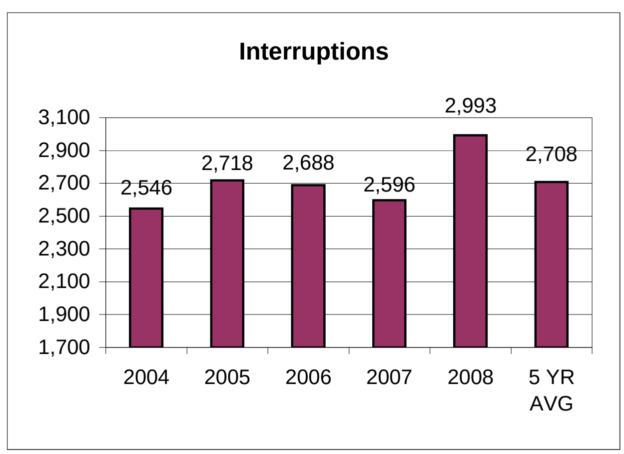




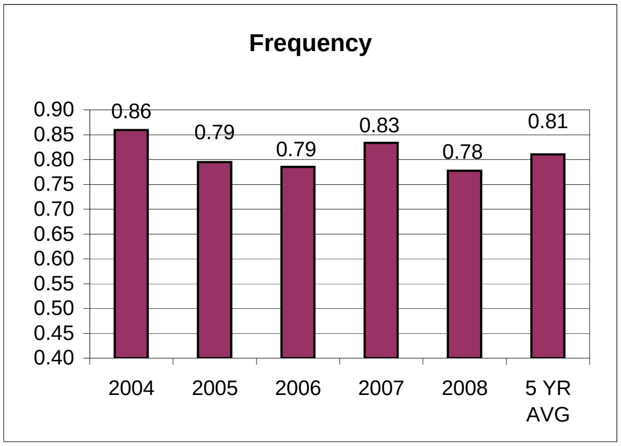


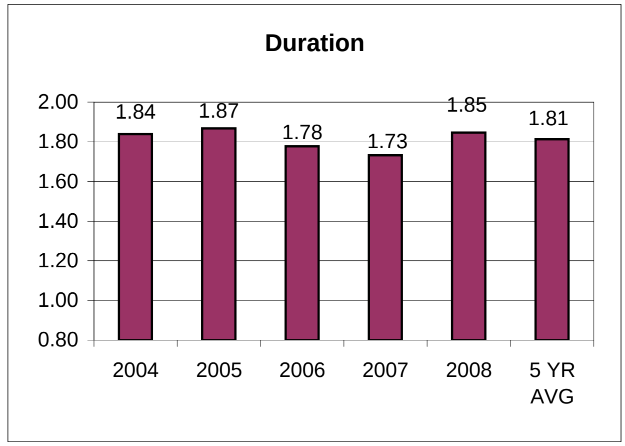


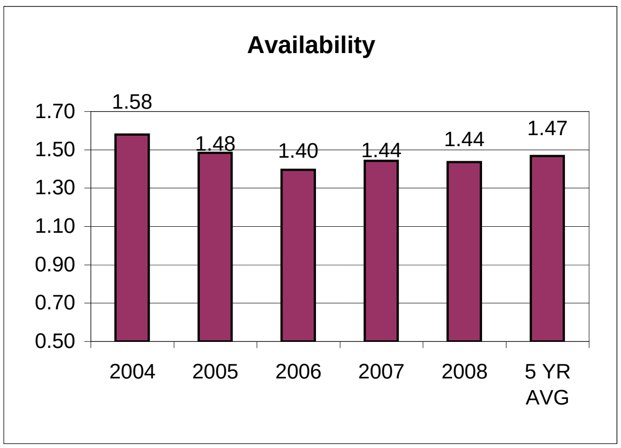


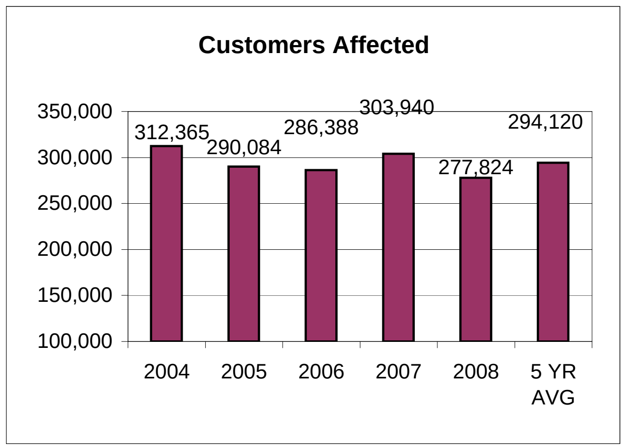


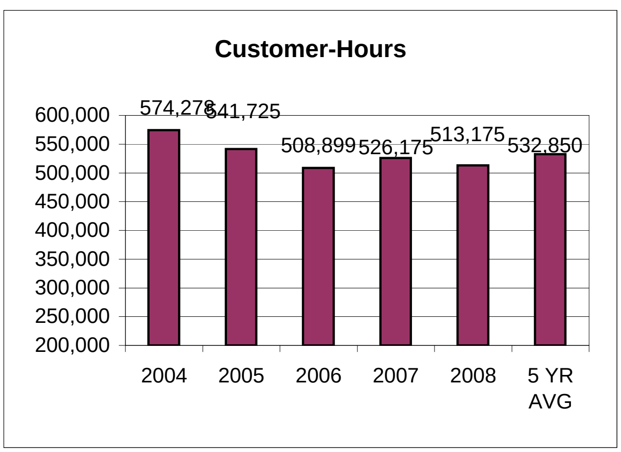
Rochester Gas and Electric
(Excluding Major Storms)

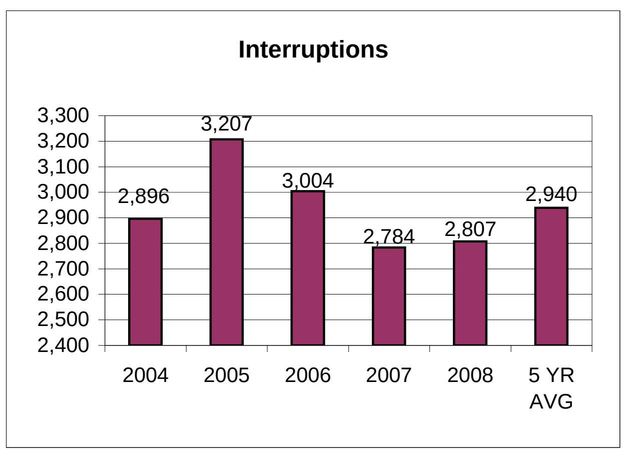












Filed Session of June 16, 2011

STATE OF NEW YORK

DEPARTMENT OF PUBLIC SERVICE

2010 ELECTRIC RELIABILITY PERFORMANCE REPORT

Electric Distribution Systems

Office of Electric, Gas, and Water

June 2011

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report presents Department of Public Service Staff's (Staff) assessment of electric reliability performance in New York State for 2010. As a means of monitoring the levels of service, utilities are required to submit detailed monthly interruption data to the Public Service Commission (Commission). Staff primarily relies on two metrics commonly used in the industry to measure reliability performance: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration).[1] Frequency is influenced by factors such as system design, capital investment, maintenance, and weather.[2] Decisions made by utilities today on capital expenditures and maintenance policies, however, can take several years before being fully reflected in the frequency measure. Duration, on the other hand, is affected by work force levels, management of the workforce, and geography. By compiling the interruption data provided by the individual utilities, the average frequency and duration of interruptions can be reviewed to assess the overall reliability of electric service in New York State. Recent data is also compared with historic performances to identify positive or negative trends. Finally, Staff reviews several other specific metrics that vary by utility to gauge electric reliability.

The statewide interruption frequency for 2010, excluding major storms, has been nearly identical for the past three years, and better than the five year average. Central Hudson Gas and Electric Corporation (Central Hudson) and Niagara Mohawk Power Corporation d/b/a National Grid's (National Grid) improved when compared with 2009. While the performances of the remaining four of the major electric companies were not as good as 2009 levels, they still performed satisfactorily and met the criteria in the performance mechanisms to which they were subject. For these companies, calendar year 2009 was also one of their best performing years in recent history.

---

[1] SAIFI is the average number of times that a customer is interrupted during a year. CAIDI is the average interruption duration time for those customers that experience an interruption during the year.

[2] To help achieve a balance between service interruptions under a utility's control, such as equipment failures, and those which a utility's control is more limited, such as an ice storm, we review reliability data both including and excluding severe weather events.

For the most part, duration performances were acceptable. Although, the statewide duration in 2010 was slightly worse than 2009, it was better than the five year average. In 2010, New York State Electric and Gas (NYSEG)'s and Rochester Gas and Electric (RG&E)'s duration was its best performance in the past five years.

Calendar year 2010 was historically one of the worst with respect to major storm effects. Three significant storms in the Hudson Valley and Downstate contributed to the entire State having the fifth-most hours of customer electric service interruption (including major storms) in the past twenty years.

With respect to individual utility performance in 2010, Consolidated Edison Company of New York's (Con Edison) generally performed satisfactorily. Due to concerns regarding the accuracy of the number of customers that were affected by an interruption in a network, we are now measuring network performance using two alternate measures: the number of interruptions per 1000 customers[3] and the average interruption duration. In 2010, Con Edison's network interruption performance was better than its 2009 performance, however, the Company's network interruption duration was worse in 2010 when compared to its 2009 performance. With regard to its radial system, Con Edison's radial system interruption frequency was nearly the same as its five year average. The radial system interruption duration performance declined compared to prior years, but was better than the five year average.

While NYSEG and RG&E had worse frequency performances in 2010 as compared with 2009, they are still much better than the Companies' respective performance targets. Outages associated with tree contacts and equipment failures continue to be a concern relative to NYSEG. In 2010, the companies have resumed investing in and maintaining their systems at more appropriate levels after low spending levels in 2009. As previously stated, the companies achieved their best duration performances of the past five years in 2010.

[3] An interruption is the loss of service for five minutes or more, for one or more customers. For example, a blown fuse that affects twelve customers is one interruption.

National Grid continues to perform well. The Company's recent infrastructure improvement and reliability focused programs are having a positive impact. Central Hudson's performance was better or consistent with its five year averages. Because of continuing tree issues, Central Hudson implemented a more rigorous tree trimming specification several years ago. Staff will perform field reviews of electric lines that are at or near the end of the first four-year trimming cycle. Orange and Rockland Utilities, Inc. (Orange and Rockland) performed satisfactorily with regard to interruption frequency, but not with respect to interruption duration. The Company has lacked consistency in its performances and Staff will be working with the Company to help reduce this variability.

All investor-owned electric utilities have reliability performance mechanisms (RPMs) in place as part of their rate plans. The RPMs are designed such that companies are subject to negative revenue adjustments for failing to meet electric reliability targets. In 2010, Con Edison achieved the network outage duration metric and the remote monitoring system metric in its RPM only if the exclusions it is asserting are accepted by the Commission. Failure to achieve the performance levels set forth in these metrics may result in negative revenue adjustments of $5 million and $10 million, respectively. Con Edison is seeking exclusion of storm related outages and extraordinary circumstances in its Long Island City network, as permitted under certain circumstances in its RPM. If the exclusion is allowed, this would result in the Company meeting all RPM targets.[4] Orange and Rockland failed to achieve its interruption duration target in 2010, which would result in a negative revenue adjustment of $800,000. On March 16, 2011, Orange and Rockland filed a request for exemption for outages experienced during a storm on July 19, 2010. The request, if granted, improves the duration performance such that the Company would meet its target and not be subject to any negative revenue adjustments.[5] All of the other companies met their RPM targets.

---

[4] Con Edison filed a request for exemption on March 31, 2010 which has yet to be presented to the Commission for final action.

[5] Orange and Rockland's request for exemption has yet to be presented to the Commission for final action.

Overall, we are generally pleased with the steady electric reliability performance across the State. There are, however, individual concerns that are being addressed through various Staff efforts. This report will be transmitted to an executive level operating officer of each electric utility with a letter from the Director of the Office of Electric, Gas, and Water.

INTRODUCTION

This report provides an overview of the electric reliability performance in New York State. As a means of monitoring the levels of service reliability, the Commission's Rules and Regulations require utilities delivering electricity in New York State to collect and submit information to the Commission regarding electric service interruptions on a monthly basis.[6] The utilities provide interruption data that enables Staff to calculate two primary performance metrics: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration). The information is grouped into 10 categories that delineate the nature of the cause of interruption (cause code).[7] Analysis of the cause code data enables the utilities and Staff to identify areas where increased capital investment or maintenance is needed. As an example, if a circuit were shown to be prone to lightning-caused interruptions, arrestors could be installed on that circuit to try to minimize the effect of future lightning strikes. In general, most of a utility's interruptions are a result of major storms, tree contacts, equipment failures, and accidents.[8] Staff maintains the interruption information in a database that dates back to 1989, which enables it to observe trends.

The Commission also adopted electric service standards addressing the reliability of electric service. The standards contain minimum acceptable performance levels for both the frequency and duration of service interruptions for each major electric utility's operating divisions. The utilities are required to submit a formal reliability report by March 31 of each year containing detailed assessments of performance, including outage trends in a utility's various geographic regions, reliability improvement projects, and analyses of worst-performing feeders. There are no revenue adjustments for failure

---

[6] 16 NYCRR Part 97, Notification of Interruption of Service requires utilities to keep detailed back-up data for six years.

[7] 16 NYCRR Part 97, Notification of Interruption of Service specifies and defines the following ten cause codes that reflect the nature of the interruptions: major storms, tree contacts, overloads, operating errors, equipment failures, accidents, prearranged interruptions, customers equipment, lightning, and unknown. There are an additional seven cause codes used exclusively for Con Edison's underground network system.

[8] The accident cause code covers events not entirely within in the utilities' control including vehicular accidents, sabotage, and animal contacts. Lightning is reported under a separate cause code.

to meet a minimum level under the service standards; utilities are, however, required to include a corrective action plan as part of the annual report. The service standards were last revised in 2004.

In addition, utility performance is compared with utilities' RPMs established as part of the utilities' rate orders. RPMs are designed such that companies are subjected to negative revenue adjustments for failing to meet electric reliability targets. The RPMs typically include targets for frequency and duration; some RPMs have additional measures to address specific concerns within an individual company.

2010 RELIABILITY PERFORMANCE

The following sections provide a summary discussion of the reliability performance statewide and for each of the major utilities.[9] Interruption data is presented in two ways in this report – with major storms excluded and with major storms included. A major storm is defined by the Commission's regulations as any storm which causes service interruptions of at least 10 percent of customers in an operating area, and/or interruptions with duration of 24 hours or more. Major storm interruptions are excluded from the data used in calculating performance levels for service standards and reliability performance mechanisms. The purpose of this policy is to achieve a balance between service interruptions under a utility's control, such as equipment failures and line maintenance, and those over which a utility's control is more limited, such as severe ice storm or a heavy wet snowstorm. Reliability performance data inclusive of major storms reflects the actual customer experience during a year.

Each year, Staff prepares an Interruption Report summarizing the monthly interruption data submitted by utilities. The 2010 Interruption Report contains detailed interruption data for each utility and statewide statistics for the past five years. The Interruption Report for 2010 is attached as an Appendix. Individual company discussions identify issues or actions within each company that influenced performance levels for 2010 and indicate company-specific trends where applicable.

Revenue adjustments for inadequate performance are implemented through individual RPMs which have been established in the utilities' rate orders.[10] Con Edison and Orange and Rockland failed to achieve targets in their reliability performance mechanisms for 2010. Con Edison failed to achieve the average interruption duration target for its network system and also failed its Remote Monitoring System target, resulting in a negative rate adjustment of $15 million. Orange and Rockland failed to achieve its interruption duration target, which results in a negative revenue adjustment of $800,000. The rate adjustments are preliminary assessments because both companies are

---

[9] Although LIPA is not regulated by the Commission, it supplies interruption data that is used to calculate statewide performance in this report.

[10] Revenue adjustments for inferior performances are implemented through individual Reliability Performance Mechanisms established in rate orders.

requesting exemptions, which are permitted under certain circumstances, and with which the companies would meet their targets and avoid any negative revenue adjustments.[11]

STATEWIDE

For many years, Staff has been combining individual utility performance statistics into overall statewide statistics. By doing so Staff is able to evaluate the level of reliability provided statewide and identify statewide trends. Because Con Edison's system includes many large, highly concentrated distribution networks that are generally less prone to interruptions than overhead systems, its interruption frequency is extremely low (i.e., better) as compared with other utilities. This, combined with the fact that it serves the largest number of customers in the state, typically results in a skewing of the performance measures. As a result, Staff examines and presents aggregated data both including and excluding Con Edison's data.

Statewide, as may be seen in Figure 1, the frequency of interruptions excluding major storms was 0.57 in 2010; this is generally equivalent to the previous two years' performances and better than the five-year average. National Grid and Central Hudson had fewer customers affected by power outages in 2010 when major storms are excluded, while NYSEG, Con Edison, RG&E, and O&R had more customers affected. The frequency performance in 2010 for utilities other than Con Edison is 0.89, which is substantially the same as their frequency performance of 0.88 in 2008 and .090 in 2009, and better than the five-year average of 0.94.

[11] The requests have not been presented to the Commission for final action.

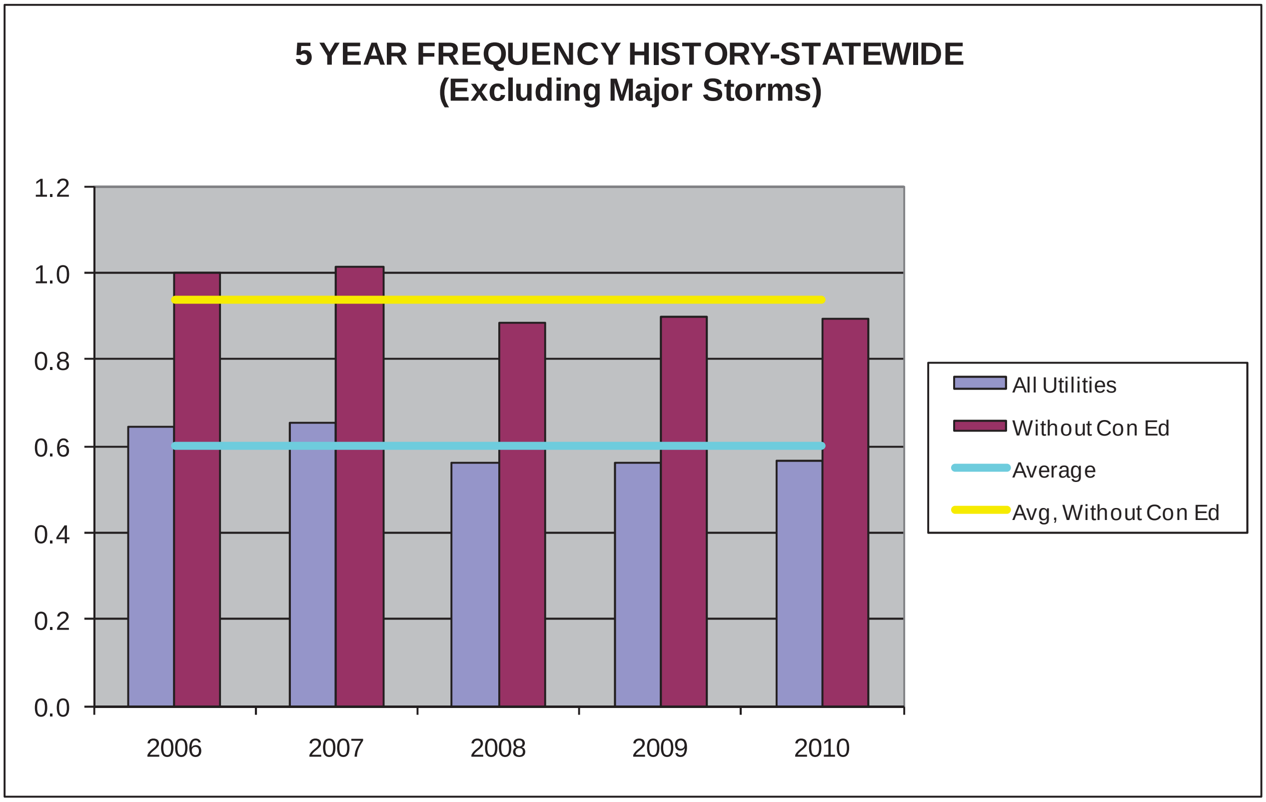


Figure 1: Statewide Frequency Performance

Figure 2 shows the historical statewide interruption duration index, excluding major storms. The 2010 overall statewide interruption duration index of 1.89 is slightly worse than 2009's 1.83, but is still consistent with the history of the past four years. When examining the chart, it should be kept in mind that Con Edison's Long Island City network outages in 2006 are still in the five year average. The statewide interruption duration index, excluding Con Edison, was 1.82 hours in 2010, which is the second best of the past five years.

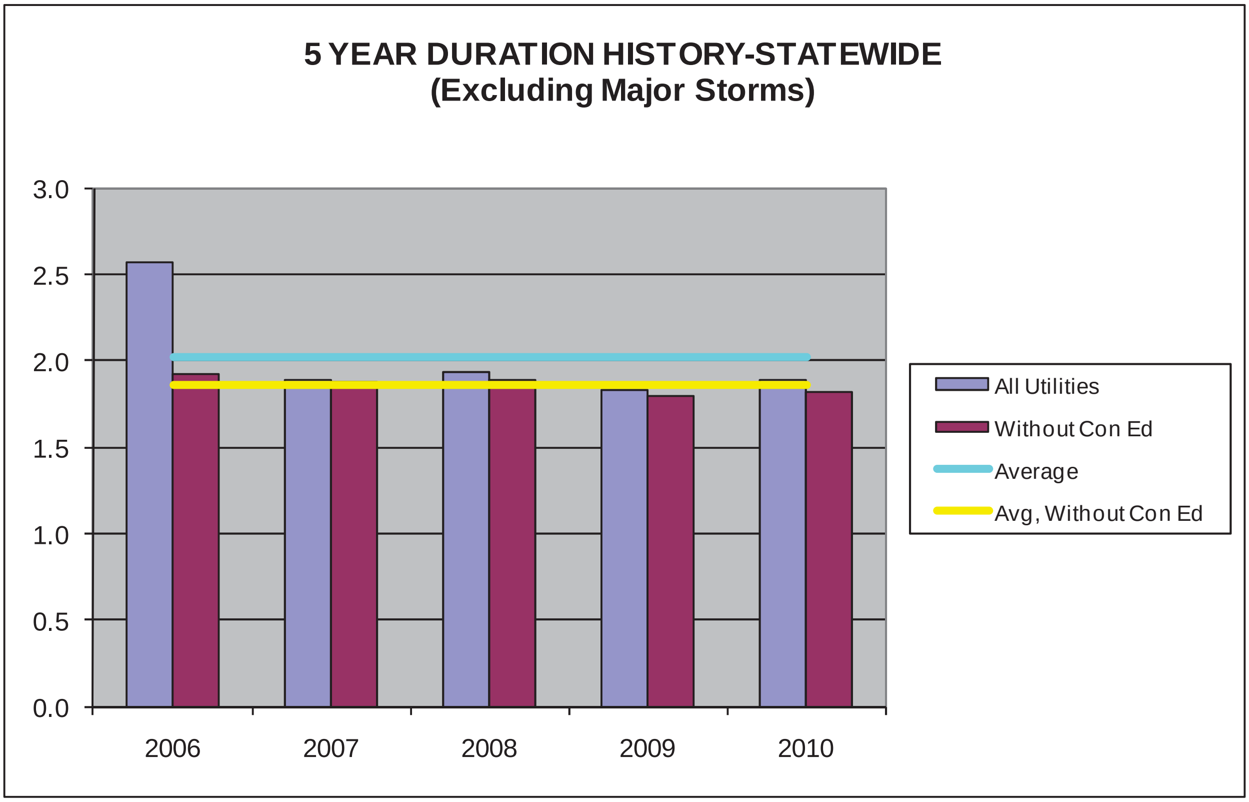


Figure 2: Statewide Duration Performance

While the overall number of major storms in 2010 was not atypical, three significant storms occurred in the Hudson Valley and Downstate. The three storms, summarized below, contributed to 2010 having the fifth-most hours of customer electric service interruption (including major storms) in the past twenty years (Figures 3 and 4, below). Because of the extended restoration times associated with these storms, the Commission requires the companies to file storm reports detailing restoration activities. [12] These reports were reviewed during the course of the year and determined that, in general, the utilities responded well.

- On February 23rd and 25th, heavy wet snow hit the Hudson Valley causing 300,000 customers to lose power. Central Hudson, Con Edison, NYSEG, and O&R were affected with overall restoration time exceeding a week. For Central Hudson, it was the worst storm in Company history since 1991, causing twice as much hours of customer interruption as Hurricane Floyd in 1999.

[12] 16 NYCRR Part 97, Part 105.4, requires utilities to file storm reports for outages lasting longer than three days.

- A March nor'easter swept the downstate area on March 3rd and affected 475,000 customers. Companies primarily affected were Con Edison, O&R, and LIPA. For Con Edison, it was the largest storm with respect to customer hours of interruption in Company history, with more than three times the amount experienced in Tropical Storm Ernesto in 2006.

- On September 16th, Tornados/Macrobursts hit downstate and affected Con Edison, O&R and LIPA, causing Con Edison 31,000 customers, mostly in Staten Island, Brooklyn and Queens, to lose power, some for extended times. The storms, while narrow in this geography, were notable in the magnitude of their destructiveness.

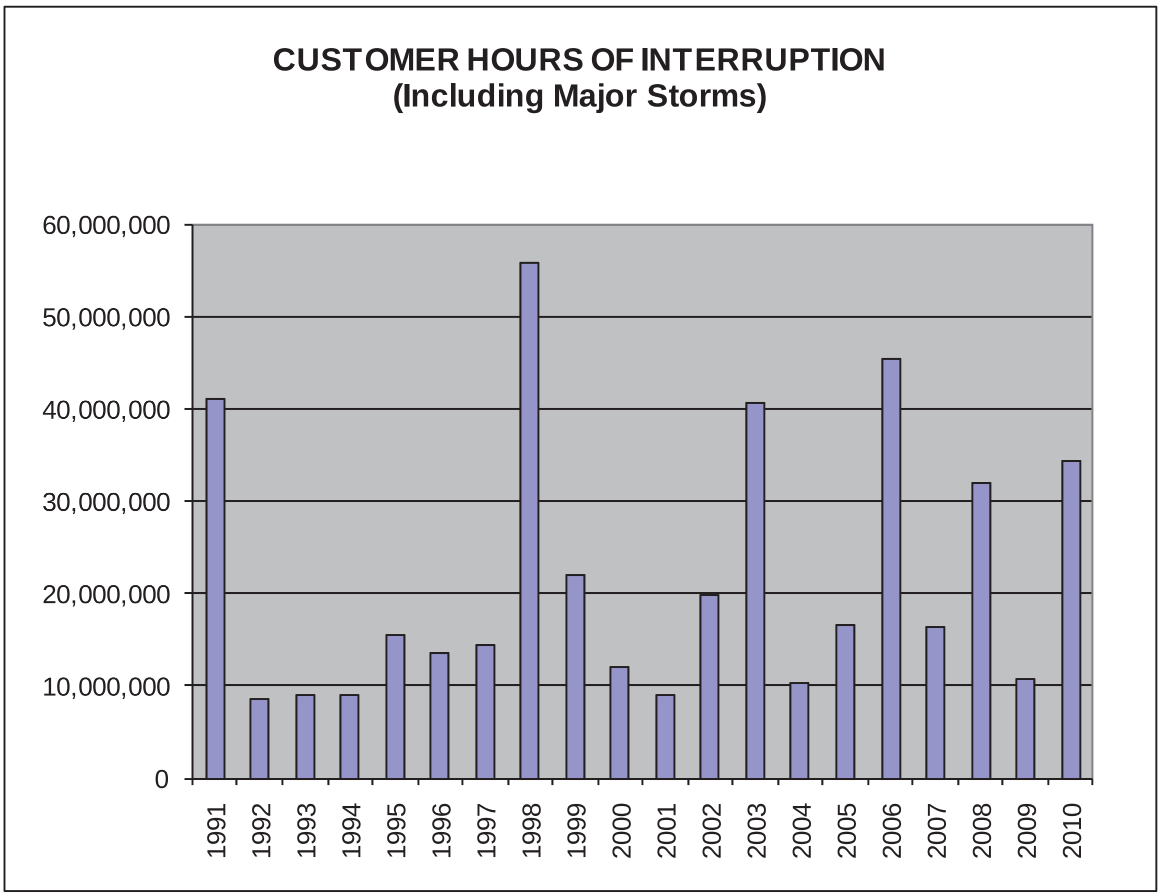


Figure 3: Customer Hours of Interruption (Including Major Storms)

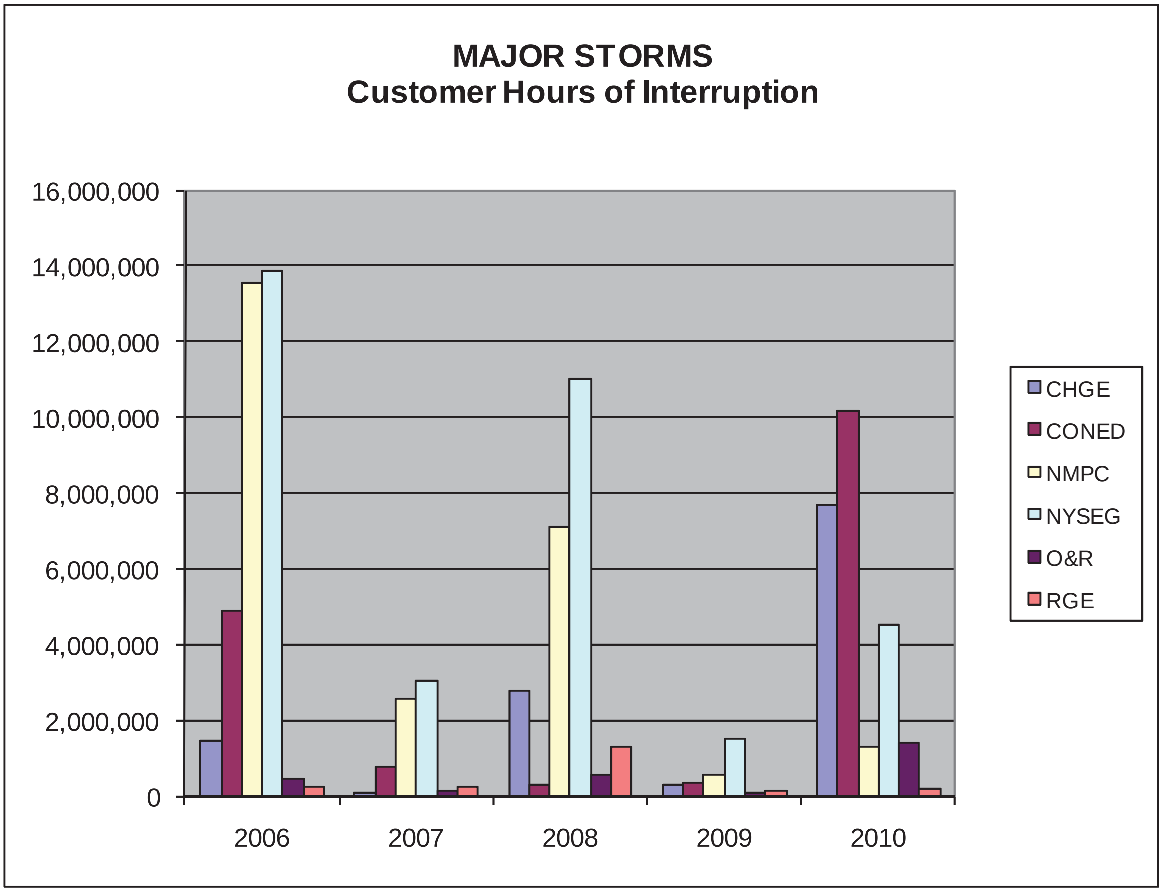


Figure 4: Major Storm Customer Hours

CON EDISON

Table 1: Con Edison's Historic Performance Excluding Major Storms

Metric	**2006**	**2007**	**2008**	**2009**	**2010**	**5-Year Average**
Network Systems[13]						
Frequency				3.63	3.09	---
Duration				4.63	5.89	---
Radial System						
Frequency (SAIFI)	**0.54**	0.38	0.42	0.32	0.41	0.42
Duration (CAIDI)	**2.66**	**2.07**	1.83	1.74	1.95	2.05

Note: Data presented in red represents a failure to meet the RPM target for a given year.

[13] The duration and frequency metrics to measure network performance were replaced for 2009 with other measures.

Con Edison serves approximately 3.3 million customers in New York City and Westchester County. Electricity is supplied to 2.4 million customers using network systems. The remaining 900,000 customers are supplied by radial systems.

To minimize the frequency of customer outages, Con Edison's networks are designed with redundant supply paths. Individual service lines to customer premises, however, lack any supplemental supply. Given these design characteristics and underground settings, the majority of interruptions (78%) are associated with the service portion of the network system, as shown in Figure 5. Equipment failures (8%) are the next highest causes for interruptions in 2010 followed by Mains (7%).

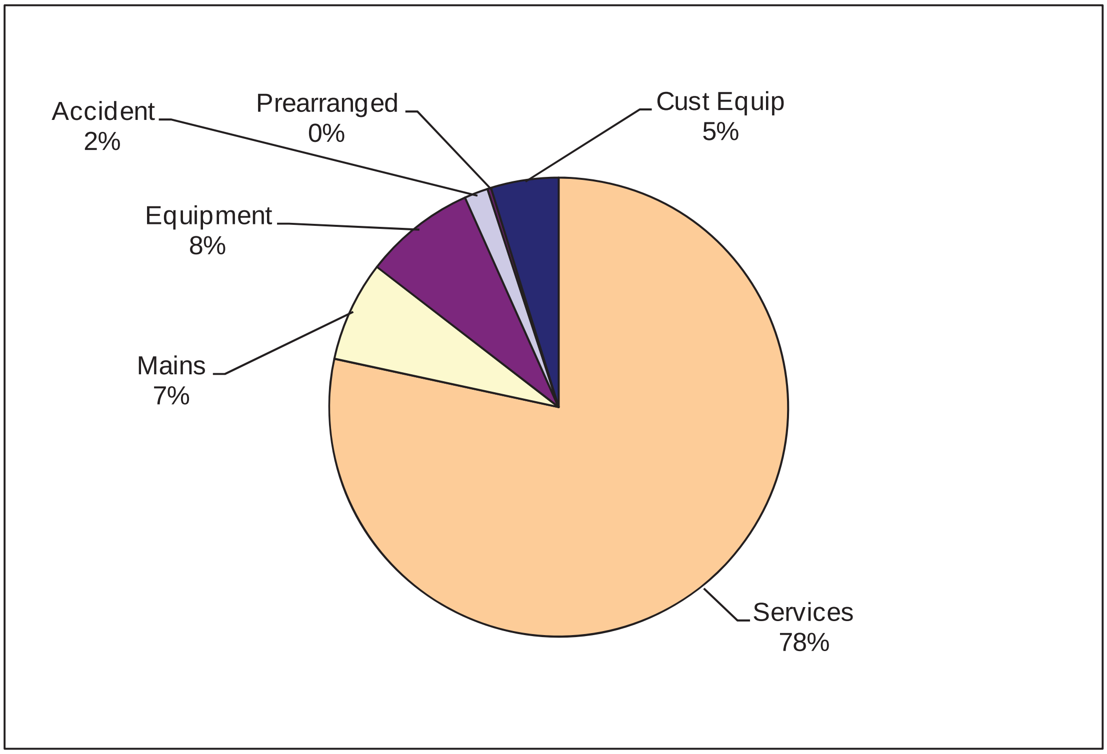


Figure 5: Con Edison's 2010 Network Interruptions by Cause

Due to concerns regarding the accuracy of the number of customers affected by an interruption in a network, we are now measuring network performance using two measures: the number of interruptions per 1000 customers and the average interruption duration. By using measures that are not based on the number of customers affected, we are able to monitor and trend network reliability performances without questioning the validity of the measures. In 2010, Con Edison's network interruptions metric was better than its 2009 performance. The Company also achieved its RPM network interruption target for the past two years. With regard to duration, Con Edison performed worse in 2010 when compared to its 2009 performance. The Company did not meet its RPM target for average interruption duration in 2010. Con Edison is seeking exclusion of storm related outages from its interruption performance levels. It also failed to achieve the remote monitoring system metric in its RPM, but is seeking an exclusion due to extraordinary circumstances with regard to the Remote Monitoring System (RMS) criteria for its Long Island City network. If these exclusions are granted, the Company would meet the targets and not incur any negative revenue adjustment.[14]

On its radial system, Con Edison's frequency in 2010 of 0.41 was worse than 2009's performances and nearly equal to its five year average. The Company met its RPM frequency target of 0.495 for 2010. Equipment failures are responsible for 75% of the interruptions on the radial system, followed by trees and accidents at 9% and 8%, respectively, as shown in Figure 6.

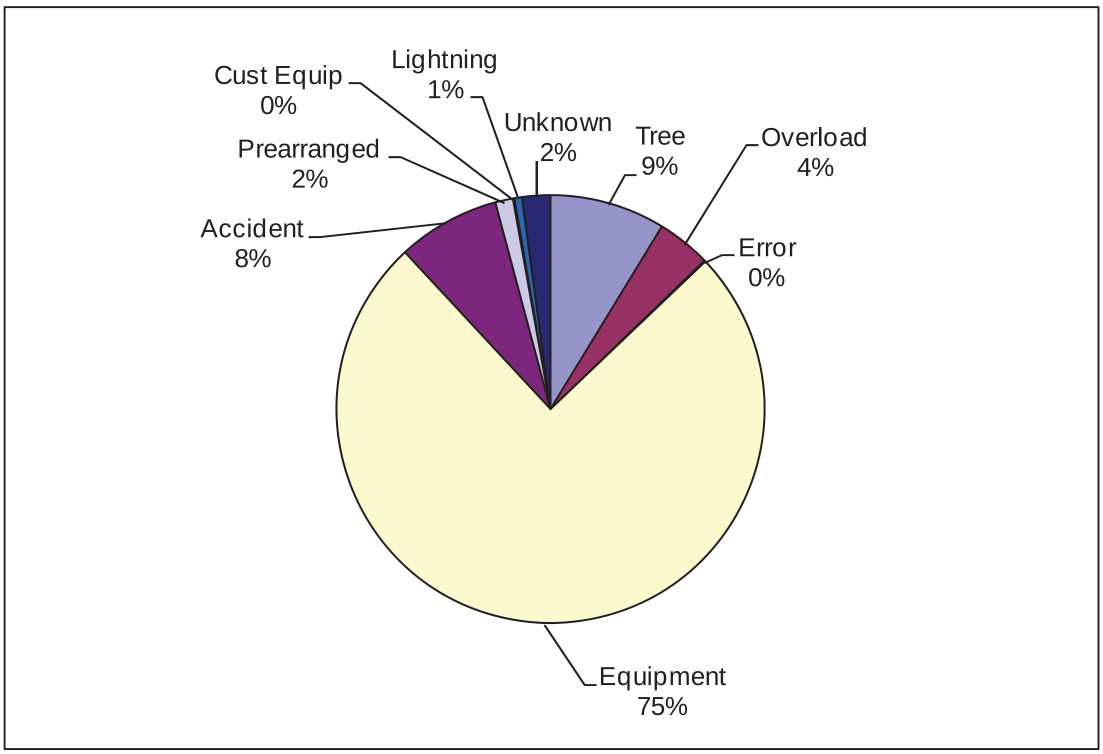


Figure 6: Con Edison's 2010 Radial Interruptions by Cause

[14] Con Edison filed a request for exemption on March 31, 2010 which has yet to be presented to the Commission for final action.

With respect to duration, Con Edison's radial performance in 2010 was worse than the previous two years. While the Company passed its RPM target of 2.04, duration performance is something we and the Company are monitoring closely. In response to a self-assessment recommended by Staff, Con Edison developed and implemented duration improvement strategies for both its radial and network system. To improve crewing efficiency and reduce outage duration, the Company has increased use of first responder staffing, increased the ability to mobile dispatch work to crews, and improve training resources. Con Edison stated that enhancements have been made to the process utilized for its outage management system to flag large outage jobs, and it now employs an automatic call out process for additional crews. The Company also continues to improve the reliability of its system by installing switches and other rapid restoration technologies. Given the focus and efforts Con Edison has put into place regarding duration, we believe 2010's performance is acceptable.

NATIONAL GRID

Table 2: National Grid's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	**1.01**	**0.96**	0.75	0.88	0.80	0.88
Duration (CAIDI)	2.05	2.01	1.96	1.91	1.98	1.98

Note: Data presented in red represents a failure to meet the RPM target for a given year.

National Grid serves approximately 1.59 million customers across upstate New York. The Company's 25,000 square mile territory includes metropolitan areas, such as the cities of Buffalo, Albany, and Syracuse, as well as many rural areas in northern New York and the Adirondacks.

In 2010, National Grid achieved both its reliability targets, comprising three consecutive years of positive performance. The Company's frequency level of 0.80 in 2010 improved as compared with 0.88 in 2009, and is well below its frequency target level of 0.93. The duration performance for 2010 was worse than 2009, but equal to its historic five-year average, and better than its duration target of 2.07 for five consecutive years. National Grid also provided consistent service on a region by region basis. In 2010, the Company's Northeast division failed to achieve its duration expectation and the Capital Region barely missed its frequency expectation. As previously discussed, the divisional expectations are defined by our Electric Service Standards.

Historically, equipment failures were National Grid's leading cause of interruptions. Aged equipment, leading to poor frequency performances in mid 2000 necessitated the Company's significant investment in capital improvement projects aimed at improving reliability. As a result of the upgrades and modifications to its distribution system, the percentage of interruptions caused by equipment failures is now less than tree related electric service interruptions for 2010 (see Figure 7, below). It should be noted, however, that tree-related outages were worse in 2009 and 2010 when compared to historic interruption rates. Analysis of the data indicates that the increase in tree related interruptions is attributable to increased broken limb conditions. Interruptions caused by re-growth and danger trees, however, were both lower in 2010 than in 2009. As a result, National Grid is not recommending changes to its five year trimming cycle or hazard tree removal program. To help reduce it tree-related outages, National Grid is doing additional off-cycle trimming and trimming on worst performing circuits in 2011.

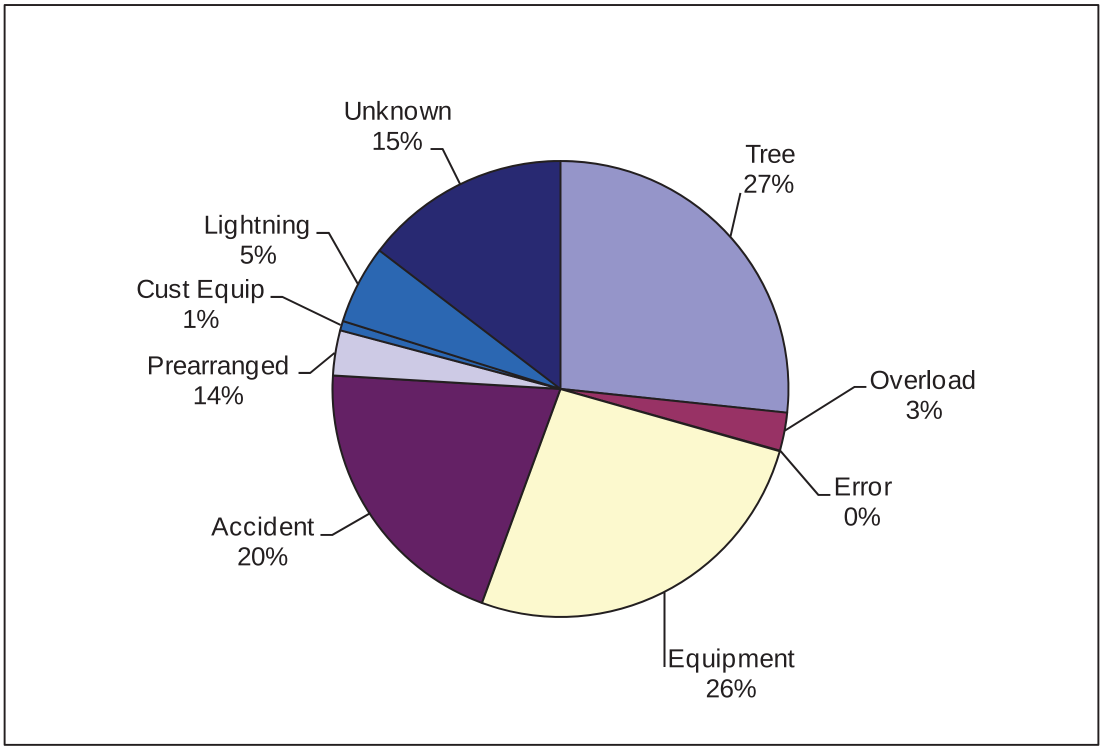


Figure 7: National Grid's 2010 Interruptions by Cause

In addition to improved performance on equipment failures, National Grid has decreased the number of customers affected when a failure occurs (see Table 3). The average number of customers affected by an interruption has been reduced from over 100 customers per interruption to approximately 90 customers per interruption in each of the last three years. National Grid credits the reduction to its effort to sectionalize lines via recloser and side tap fuse installations. National Grid's Line Recloser Program installs 100 additional reclosers per year and is expected to continue to limit the number of customers affected by a single interruption.

Table 3: National Grid's Historic Customers Affected per Interruption

	2006	2007	2008	2009	2010
Average number of customers affected per interruption	118	104	92	87	92

National Grid now uses a system that establishes repair work orders in direct response to inspection findings. Based on its success in repairing deteriorated items under its inspection and maintenance, National Grid will be discontinuing focused programs, such as the Pole Replacement Program and Feeder Hardening Program in 2011. While these programs were helpful in reducing National Grid's frequency performance over the past years, it is appropriate for the Company to consolidate its efforts in the interest of prioritizing and scheduling efficiencies. We expect that National Grid will continue to address reliability concerns on worst performing feeders, either through engineering reliability reviews or alternate methods, and maintain at least the current level of performance in future years.

NEW YORK STATE ELECTRIC AND GAS

Table 4: NYSEG's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	1.12	1.20	1.11	1.08	1.14	1.13
Duration (CAIDI)	2.01	2.22	2.08	2.00	1.98	2.06

Approximately 858,269 customers are served by NYSEG. The Company is primarily located in the Binghamton and Finger Lakes regions, but does have localized service regions, including areas near Plattsburgh, Brewster, Mechanicville, and Lancaster.

NYSEG's frequency performance of 1.14 was worse when compared with 2009's performance of 1.08, but nearly the same as the five year average. The 2010 duration performance of 1.98 was the best in the past five years. Overall, NYSEG's performance is satisfactory and the Company was able to meet its RPM reliability targets of 1.20 for frequency and 2.08 for duration.

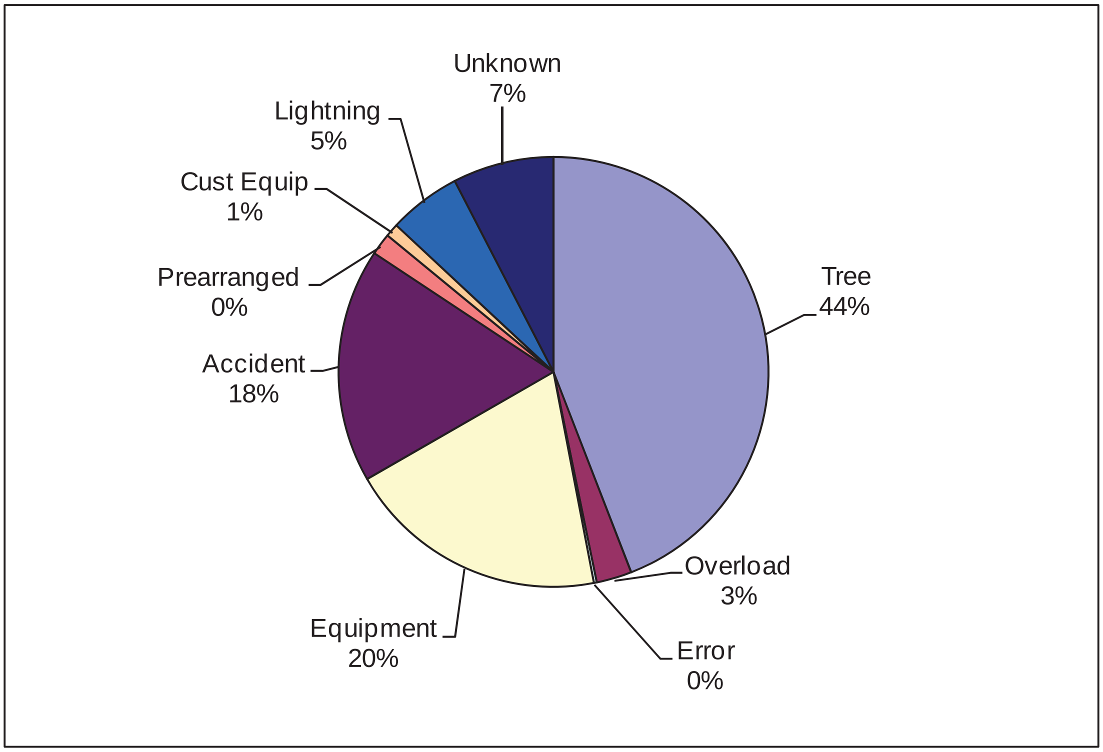


Figure 8: NYSEG's 2010 Interruptions by Cause

As shown in Figure 8, tree contacts (44%), equipment failures (20%), and accidents (18%) remain the predominant causes of interruption throughout NYSEG's twelve operating divisions in 2010. NYSEG has one of the worst frequency rates which is caused primarily by customers affected by tree interruptions. As a result, NYSEG needs to continue to focus on improving its distribution vegetation management program and reducing tree related outages. The Commission approved increased funding for distribution vegetation management activities as part of its last 2010 rate case agreement to help move NYSEG towards full cycle trimming activities. Therefore, Staff expects NYSEG to address the issue of tree trimming more aggressively and undertake measures to identify and perform trimming in areas where tree related outages are more frequent.

Equipment failures are NYSEG's second major cause for interruption. For the past two years, it accounted for 20% of the total number of interruptions. NYSEG has been addressing equipment failures under its Transmission and Distribution Infrastructure Replacement Program (TDIRP) program. The TDIRP program replaces electrical T&D equipment based on the condition, age, and failure characteristics of the specific item based on the Company's experience and knowledge. Funding for the

TDIRP program was reduced significantly in 2009 to approximately $6.0 million from historical levels of approximately $23 million annually.[15] In 2010, NYSEG began to invest in its system at close to or higher than historic levels. The most recent rate case supported $25 million in expenditures for the TDIRP efforts annually, to bring the Company back up to pre 2009 spending levels. The reinvestment into this program is expected to help reduce outages related to equipment failures and improve the system reliability on a going forward and proactive basis. Staff will continue to monitor the Company's performance on these issues.

ROCHESTER GAS AND ELECTRIC

Table 5: RG&E's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	0.79	0.83	0.78	0.59	0.71	0.74
Duration (CAIDI)	1.78	1.73	1.85	1.80	1.71	1.77

RG&E serves approximately 358,109 customers. Although the Company is comprised of four service areas, its Rochester division accounts for approximately 80% of its customer base. As a result, its overall reliability statistics mirror that of the Rochester division.

With regard to service reliability, RG&E continues to be one of the better utilities in the state by continually performing better than its RPM targets of 0.90 for frequency and 1.90 for duration, as established in its rate orders. As shown in Table 5, RG&E's performance for frequency and duration is fairly consistent with its five year average. The Company's frequency performance of 0.71 in 2010 was an increase from 0.59 in 2009; however, the 2009 performance was the best in the past five years. RG&E's duration performance of 1.71 in 2010 was better than in 2009 and better than the five-year average.

[15] In 2009, the Company reduced all expenditures to essential needs only while stating financial issues within the Company as the reasoning behind the reduced spending.

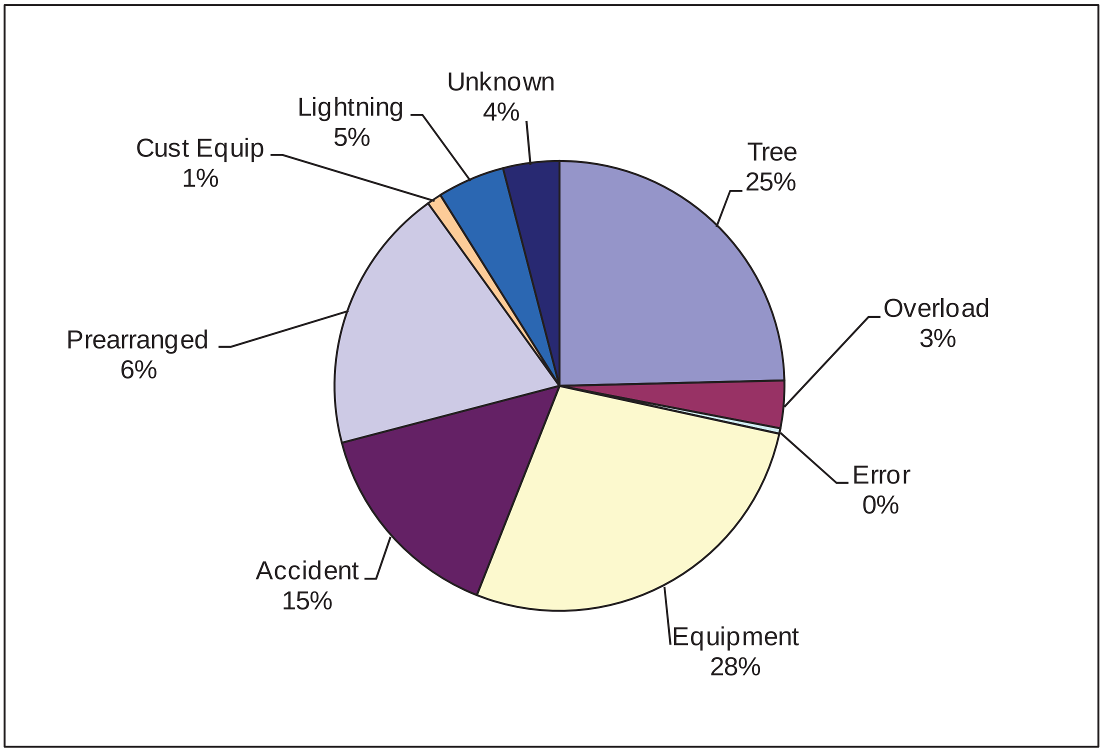


Figure 9: RG&E's 2010 Interruptions by Cause

Figure 9 shows that the two major contributors to interruptions in 2010 continue to be equipment failures (28%) and tree contacts (25%). Similar to NYSEG, funding for RG&E's Transmission and Distribution Infrastructure Replacement Program (TDIRP) was reduced due to Company financial issues in 2009 and the beginning of 2010. In the last rate case, the Commission supported expenditures for the TDIRP efforts, in the amount of $15 million annually, to bring the Company back up to pre 2009 spending levels. Likewise, the Commission also supported increased expenditures for vegetation management, in the amount of $6.6 million annually, allowing the Company to implement a full system vegetation management (tree trimming) cycle program. Staff believes that these two programs and associated expenditures will help reduce outages and improve the system reliability going forward on proactive basis.

CENTRAL HUDSON GAS AND ELECTRIC

Table 6: Central Hudson's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	**1.59**	1.42	1.27	1.37	1.27	1.38
Duration (CAIDI)	**2.58**	2.43	2.47	2.22	2.42	2.43

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Central Hudson serves approximately 298,000 customers in the Mid-Hudson Valley region. The Company's territory is mainly suburban and rural. Central Hudson does serve some urban regions, such as the cities of Poughkeepsie and Newburgh.

Central Hudson's frequency performance of 1.27 in 2010 was better than 2009 and ties its five-year best. The Company's duration performance of 2.42 in 2010, on the other hand, was slightly better than average. Figure 10 shows that 38% of customer interruptions were due to tree related issues, followed by accidents which comprised 25%. In 2010, the Company achieved its RPM targets of 1.45 for frequency and 2.50 for duration.

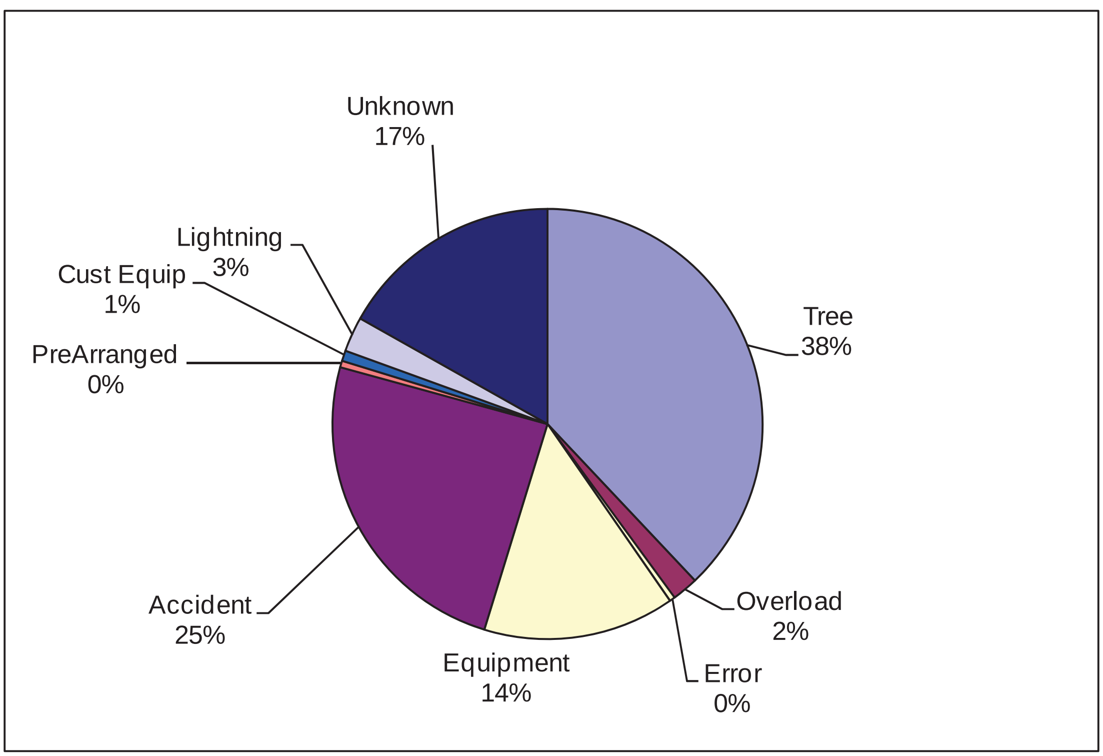


Figure 10: Central Hudson's 2010 Interruptions by Cause

As is the case with most overhead distribution utilities, trees are a primary cause of outages (Figure 10, above). The Company as a whole suffers more tree interruptions per customer served than any other major New York electric utility. Since 2007 Central Hudson has done vegetation line clearance in accordance with a new, improved specification. Using greater level of detail available to it, the Company reports a trend of decreasing interruptions resulting from trees falling inside its trimming zone. Staff will follow-up this summer with the Company and perform field reviews of electric lines that are at or near the end of the four-year trimming cycle.

The Unknown and Accident categories historically make up large portions of electric interruptions for all New York utilities, and this is the case for Central Hudson as well. Staff will be looking more closely with the Company at these classifications of outages to see if the Company's performance can be improved.

Equipment failures cause a large number of electric interruptions as is the case with most electric utility companies. Central Hudson is continuing several programs to decrease the number of these interruptions, including programs for substation breaker replacement, porcelain cutout replacement, 14kV paper and lead cable replacement, automatic load transfer switch installation, and aging recloser replacement (including remote communication). In addition, the Company has a program to upgrade individual circuits.

ORANGE AND ROCKLAND

Table 7: O&R's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	1.23	1.03	1.19	0.96	1.21	1.13
Duration (CAIDI)	1.51	1.60	**1.83**	1.66	**1.79**	1.68

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Orange and Rockland serves approximately 218,000 customers in three New York counties along the New Jersey and Pennsylvania border. In 2010, the

Company met its reliability performance mechanism target of 1.36 for frequency with a frequency of 1.21; however, it failed to achieve the duration target of 1.70 with a 1.79 performance.[16] As the table above shows, the 2010 frequency and duration performance levels were both much worse than last years and continue ORU's sporadic performance trend from year to year. The 2010 results were worse than the 5 year averages and are similar to those in 2008 when the Company again failed to achieve its duration target. Staff will continue to work with the Company to help reduce the variability in performances.

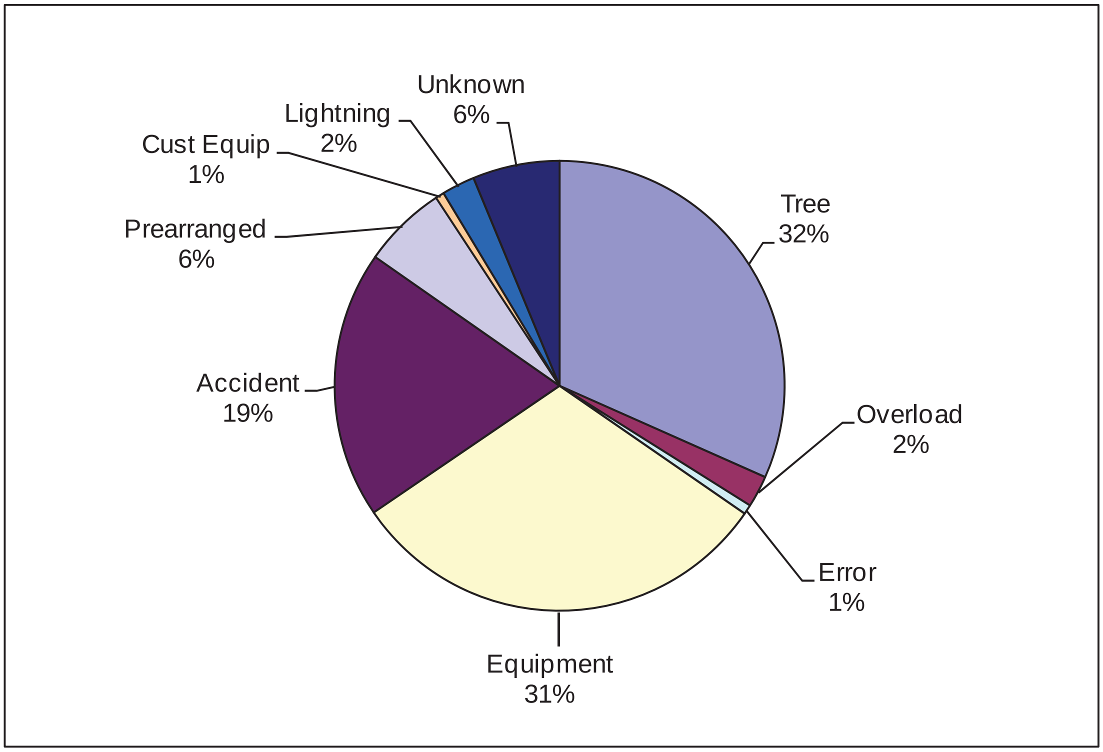


Figure 11: Orange and Rockland's 2010 Interruptions by Cause

As shown in Figure 11, tree contacts (32%) and equipment failures (31%) caused the majority of interruptions in 2010. Orange and Rockland is addressing reliability issues resulting from equipment failures through capital improvement programs such as the Distribution Automation Program, the Underground Cable

[16] The Company has filed a petition to the Commission for exemption from the RPM revenue adjustment, related to a storm that affected its Eastern Division on July 19, 2010. This petition has not been acted on by the Commission.

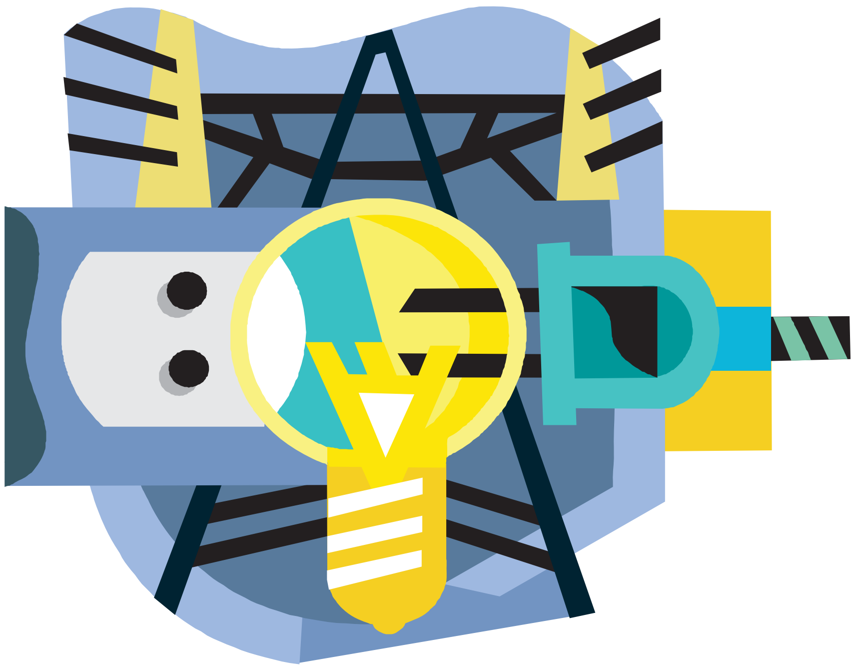
Maintenance and Rebuild Program, and a number of service reliability improvement projects directed by the circuit priority-rating methodology.

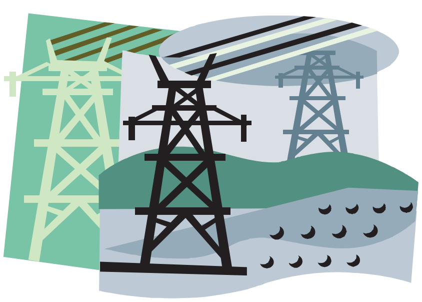
The Company continues to address concerns regarding tree-related outages through increased efforts on its line clearance programs. In addition to the four-year cycle based tree trimming program, the Company has continued to identify and perform supplemental trimming to address areas with recurring tree related outages. These programs are expected to reduce the impact of tree contacts on the Company’s electrical system through the coming years.

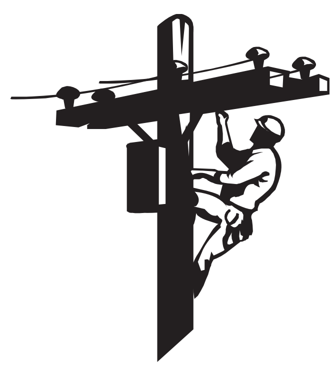
APPENDIX

2010 INTERRUPTON REPORT

The 2010 Interruption Report







Office of Electricity, Gas, and Water

June 2011

June 2011

ATTACHMENT
Definitions and Explanations of Terms Used in the 2010 Statewide Electric Service Interruption Report

Interruption is the loss of service for five minutes or more.

Customer hours is the time a customer is without electric service.

Customers affected is the number of customers without electric service.

Customers served is the number of customers as of the last day of the **current year.** For example, for the calendar year of **2010**, customers served is the number of customers as of 12/31/2010. For indices using customers served, the **previous** year is used.

Frequency (**SAIFI)** measures the average number of interruptions experienced by customers served by the utility. It is the customers affected divided by the customers served at the end of the **previous** year, i.e., 12/31/2009.

Duration (CAIDI) measures the average time that an affected customer is out of electric service. It is the customer hours divided by the customers affected.

Availability (SAIDI) is the average amount of time a customer is out-of-service during a year. It is the customer hours divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2009. Mathematically, it also is **SAIFI** multiplied by **CAIDI**.

Interruptions Per 1000 Customers Served is the number of interruptions divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2009, divided by 1,000.

Major Storm is defined as any storm which causes service interruptions of at least ten percent of customers in an operating area, or if the interruptions last for 24 hours or more.

Operating Area is a geographical subdivision of each electric utility's franchise territory. These areas are also called regions, divisions, or districts.

Most of the data is presented two ways, with major storms included and major storms excluded. Major storms tend to distort a utility's performance trend. Tables and graphs that exclude major storms illustrate interruptions that are more under the utility's control. It portrays a utility's system facilities under normal conditions, although this can be misleading because interruptions during "normal" bad weather are included and it is difficult to analyze from year to year.

The first two tables show frequency and duration indices for the last five years for each utility and Statewide with and without Con Edison data. Con Edison has by far the lowest frequency numbers and tends to distort the Statewide data. Much of Con Edison's distribution system consists of a secondary network. In a secondary network, a customer is fed from multiple supplies, making the probability of an interruption relatively rare.

COMPARISON OF SERVICE RELIABILITY INDICES
(EXCLUDING MAJOR STORMS)

	2006	2007	2008	2009	2010	5 YR AVG
CHGE						
FREQUENCY	1.59	1.42	1.27	1.37	1.27	1.38
DURATION	2.58	2.43	2.47	2.22	2.42	2.43
CONED						
FREQUENCY	0.16	0.16	0.13	0.10	0.13	0.13
DURATION	8.23	1.97	2.27	2.27	2.57	3.46
LIPA *						
FREQUENCY	0.75	0.90	0.77	0.74	0.73	0.78
DURATION	1.37	1.20	1.36	1.17	1.11	1.24
NAT GRID						
FREQUENCY	1.01	0.96	0.75	0.88	0.80	0.88
DURATION	2.05	2.01	1.96	1.91	1.98	1.98
NYSEG						
FREQUENCY	1.12	1.20	1.11	1.08	1.14	1.13
DURATION	2.01	2.22	2.08	2.00	1.98	2.06
O&R						
FREQUENCY	1.23	1.03	1.19	1.03	1.21	1.14
DURATION	1.51	1.60	1.83	1.67	1.79	1.68
RG&E						
FREQUENCY	0.79	0.83	0.78	0.59	0.71	0.74
DURATION	1.78	1.73	1.85	1.80	1.71	1.77
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.00	1.02	0.88	0.90	0.89	0.94
DURATION	1.92	1.88	1.89	1.79	1.82	1.86
STATEWIDE (WITH CONED)						
FREQUENCY	0.65	0.65	0.56	0.56	0.57	0.60
DURATION	2.57	1.89	1.93	1.83	1.89	2.02

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

COMPARISON OF SERVICE RELIABILITY INDICES
(INCLUDING MAJOR STORMS)

	2006	2007	2008	2009	2010	5 YR AVG
CHGE						
FREQUENCY	2.20	1.51	2.15	1.63	2.62	2.02
DURATION	4.12	2.51	5.76	2.48	10.94	5.16
CONED						
FREQUENCY	0.23	0.18	0.14	0.11	0.23	0.18
DURATION	12.31	3.12	2.71	3.06	15.05	7.25
LIPA *						
FREQUENCY	1.18	1.04	1.09	0.81	1.04	1.03
DURATION	1.99	1.37	1.65	1.25	1.84	1.62
NAT GRID						
FREQUENCY	1.48	1.31	1.37	1.01	0.98	1.23
DURATION	7.18	2.70	4.32	2.01	2.46	3.74
NYSEG						
FREQUENCY	1.79	1.71	2.14	1.47	1.84	1.79
DURATION	10.32	3.62	7.07	2.68	4.09	5.55
O&R						
FREQUENCY	1.81	1.17	1.64	1.15	1.79	1.51
DURATION	2.15	1.92	2.94	1.89	4.76	2.73
RG&E						
FREQUENCY	0.98	1.16	1.36	0.74	0.79	1.01
DURATION	2.14	1.80	3.77	2.03	2.18	2.38
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.49	1.31	1.51	1.07	1.29	1.34
DURATION	6.02	2.56	4.62	2.09	4.09	3.87
STATEWIDE (WITH CONED)						
FREQUENCY	0.96	0.83	0.93	0.67	0.84	0.85
DURATION	6.65	2.61	4.50	2.16	5.35	4.25

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

STATEWIDE (WITHOUT CON ED)

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	55,211	55,425	53,758	55,995	54,310	54,940
Number of Customer-Hours	8,439,916	8,439,464	7,399,179	7,116,848	7,197,156	7,718,512
Number of Customers Affected	4,400,072	4,495,428	3,910,426	3,976,492	3,962,829	4,149,049
Number of Customers Served	4,428,946	4,433,994	4,425,772	4,437,856	4,446,105	4,434,535
Average Duration Per Customer Affected (CAIDI)	1.92	1.88	1.89	1.79	1.82	1.86
Average Duration Per Customers Served	1.91	1.91	1.67	1.61	1.62	1.74
Interruptions Per 1000 Customers Served	12.52	12.51	12.12	12.65	12.24	12.41
Number of Customers Affected Per Customer Served (SAIFI)	1.00	1.02	0.88	0.90	0.89	0.94

STATEWIDE (WITH CON ED)

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	65,752	66,746	65,403	70,930	68,221	67,410
Number of Customer-Hours	12,603,322	9,429,452	8,326,562	7,891,155	8,284,480	9,306,994
Number of Customers Affected	4,905,844	4,996,967	4,319,550	4,316,932	4,385,672	4,584,993
Number of Customers Served	7,647,367	7,678,791	7,697,498	7,729,599	7,766,918	7,704,035
Average Duration Per Customer Affected (CAIDI)	2.57	1.89	1.93	1.83	1.89	2.02
Average Duration Per Customers Served	1.66	1.23	1.08	1.03	1.07	1.21
Interruptions Per 1000 Customers Served	8.66	8.73	8.52	9.21	8.83	8.79
Number of Customers Affected Per Customer Served (SAIFI)	0.65	0.65	0.56	0.56	0.57	0.60

* LIPA is not regulated by the NYS PSC.

** For those indices that use Customers Served, Customers Served is the December

STATEWIDE (WITHOUT CON ED)
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	70,872	61,753	73,150	61,841	72,135	67,950
Number of Customer-Hours	39,413,242	14,848,512	30,962,269	9,923,723	23,466,391	23,722,827
Number of Customers Affected	6,548,910	5,808,516	6,705,414	4,752,148	5,741,806	5,911,359
Number of Customers Served	4,428,946	4,433,994	4,425,772	4,437,856	4,446,105	4,434,535
Average Duration Per Customer Affected (CAIDI)	6.02	2.56	4.62	2.09	4.09	3.87
Average Duration Per Customers Served	8.94	3.35	6.98	2.24	5.29	5.36
Interruptions Per 1000 Customers Served	16.08	13.94	16.50	13.97	16.25	15.35
Number of Customers Affected Per Customer Served (SAIFI)	1.49	1.31	1.51	1.07	1.29	1.34

STATEWIDE (WITH CON ED)
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	86,734	74,261	85,548	77,181	91,471	83,039
Number of Customer-Hours	48,437,221	16,630,252	32,188,186	11,046,399	34,693,862	28,599,184
Number of Customers Affected	7,282,114	6,379,276	7,158,329	5,118,841	6,487,588	6,485,230
Number of Customers Served	7,647,367	7,678,791	7,697,498	7,729,599	7,766,918	7,704,035
Average Duration Per Customer Affected (CAIDI)	6.65	2.61	4.50	2.16	5.35	4.25
Average Duration Per Customers Served	6.38	2.17	4.19	1.44	4.49	3.73
Interruptions Per 1000 Customers Served	11.42	9.71	11.14	10.03	11.83	10.83
Number of Customers Affected Per Customer Served (SAIFI)	0.96	0.83	0.93	0.67	0.84	0.85

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December

CENTRAL HUDSON
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	7,538	6,386	6,857	6,705	7,762	7,050
Number of Customer-Hours	1,201,109	1,021,859	933,993	910,250	922,392	997,921
Number of Customers Affected	464,765	420,769	377,564	410,516	380,489	410,821
Number of Customers Served	295,368	298,386	300,621	299,557	299,971	298,781
Average Duration Per Customer Affected (CAIDI)	2.58	2.43	2.47	2.22	2.42	2.43
Average Duration Per Customers Served	4.10	3.46	3.13	3.03	3.08	3.36
Interruptions Per 1000 Customers Served	25.74	21.62	22.98	22.30	25.91	23.71
Number of Customers Affected Per Customer Served (SAIFI)	1.59	1.42	1.27	1.37	1.27	1.38

CENTRAL HUDSON
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	10,066	6,681	9,887	7,609	11,994	9,247
Number of Customer-Hours	2,649,690	1,117,802	3,705,277	1,211,827	8,597,567	3,456,433
Number of Customers Affected	643,778	444,813	642,949	488,732	785,806	601,216
Number of Customers Served	295,368	298,386	300,621	299,557	299,971	298,781
Average Duration Per Customer Affected (CAIDI)	4.12	2.51	5.76	2.48	10.94	5.16
Average Duration Per Customers Served	9.05	3.78	12.42	4.03	28.70	11.60
Interruptions Per 1000 Customers Served	34.38	22.62	33.13	25.31	40.04	31.10
Number of Customers Affected Per Customer Served (SAIFI)	2.20	1.51	2.15	1.63	2.62	2.02

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (SYSTEM)

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	10,541	11,321	11,645	14,935	13,911	12,471
Number of Customer-Hours	4,163,407	989,988	927,383	774,307	1,087,325	1,588,482
Number of Customers Affected	505,772	501,539	409,124	340,440	422,843	435,944
Number of Customers Served	3,218,421	3,244,797	3,271,726	3,291,743	3,320,813	3,269,500
Average Duration Per Customer Affected (CAIDI)	8.23	1.97	2.27	2.27	2.57	3.46
Average Duration Per Customers Served	1.31	0.31	0.29	0.24	0.33	0.49
Interruptions Per 1000 Customers Served	3.31	3.52	3.59	4.56	4.23	3.84
Number of Customers Affected Per Customer Served (SAIFI)	0.16	0.16	0.13	0.10	0.13	0.13

CON ED (SYSTEM)

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	15,862	12,508	12,398	15,340	19,336	15,089
Number of Customer-Hours	9,023,979	1,781,740	1,225,917	1,122,677	11,227,471	4,876,357
Number of Customers Affected	733,204	570,760	452,915	366,693	745,782	573,871
Number of Customers Served	3,218,421	3,244,797	3,271,726	3,291,743	3,320,813	3,269,500
Average Duration Per Customer Affected (CAIDI)	12.31	3.12	2.71	3.06	15.05	7.25
Average Duration Per Customers Served	2.83	0.55	0.38	0.34	3.41	1.50
Interruptions Per 1000 Customers Served	4.98	3.89	3.82	4.69	5.87	4.65
Number of Customers Affected Per Customer Served (SAIFI)	0.23	0.18	0.14	0.11	0.23	0.18

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (NETWORK)

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	4,274	5,571	5,485	8,650	7,434	6,283
Number of Customer-Hours	2,947,306	316,477	252,964	273,705	370,405	832,171
Number of Customers Affected	48,467	176,430	40,301	52,994	54,555	74,549
Number of Customers Served	2,363,897	2,361,145	2,385,760	2,403,818	2,439,565	2,390,837
Average Duration Per Customer Affected (CAIDI)	60.81	1.79	6.28	5.16	6.79	16.17
Average Duration Per Customers Served	1.26	0.13	0.11	0.11	0.15	0.35
Interruptions Per 1000 Customers Served	1.83	2.36	2.32	3.63	3.09	2.64
Number of Customers Affected Per Customer Served (SAIFI)	0.021	0.075	0.017	0.022	0.023	0.031

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (RADIAL)

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	6,267	5,750	6,160	6,285	6,477	6,188
Number of Customer-Hours	1,216,101	673,511	674,419	500,602	716,920	756,310
Number of Customers Affected	457,305	325,109	368,823	287,446	368,288	361,394
Number of Customers Served	854,524	883,652	885,966	887,925	881,248	878,663
Average Duration Per Customer Affected (CAIDI)	2.66	2.07	1.83	1.74	1.95	2.05
Average Duration Per Customers Served	1.43	0.79	0.76	0.57	0.81	0.87
Interruptions Per 1000 Customers Served	7.39	6.73	6.97	7.09	7.29	7.10
Number of Customers Affected Per Customer Served (SAIFI)	0.54	0.38	0.42	0.32	0.41	0.42

CON ED (RADIAL)

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	11,588	6,937	6,913	6,690	11,902	8,806
Number of Customer-Hours	6,076,673	1,465,264	972,954	848,971	10,857,066	4,044,185
Number of Customers Affected	684,737	394,330	412,614	313,699	691,227	499,321
Number of Customers Served	854,524	883,652	885,966	887,925	881,248	878,663
Average Duration Per Customer Affected (CAIDI)	8.87	3.72	2.36	2.71	15.71	6.67
Average Duration Per Customers Served	7.17	1.71	1.10	0.96	12.23	4.63
Interruptions Per 1000 Customers Served	13.67	8.12	7.82	7.55	13.40	10.11
Number of Customers Affected Per Customer Served (SAIFI)	0.81	0.46	0.47	0.35	0.78	0.57

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

LIPA
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	18,634	18,736	18,135	17,795	17,180	18,096
Number of Customer-Hours	1,129,275	1,190,411	1,166,613	958,679	905,031	1,070,002
Number of Customers Affected	823,396	995,077	856,405	821,723	811,969	861,714
Number of Customers Served	1,103,162	1,108,540	1,110,853	1,114,716	1,117,281	1,110,910
Average Duration Per Customer Affected (CAIDI)	1.37	1.20	1.36	1.17	1.11	1.24
Average Duration Per Customers Served	1.03	1.08	1.05	0.86	0.81	0.97
Interruptions Per 1000 Customers Served	16.99	16.98	16.36	16.02	15.41	16.35
Number of Customers Affected Per Customer Served (SAIFI)	0.75	0.90	0.77	0.74	0.73	0.78

LIPA
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	24,905	20,077	20,471	19,003	22,867	21,465
Number of Customer-Hours	2,564,134	1,564,559	1,998,270	1,121,723	2,125,507	1,874,839
Number of Customers Affected	1,289,698	1,142,365	1,208,292	894,595	1,153,884	1,137,767
Number of Customers Served	1,103,162	1,108,540	1,110,853	1,114,716	1,117,281	1,110,910
Average Duration Per Customer Affected (CAIDI)	1.99	1.37	1.65	1.25	1.84	1.62
Average Duration Per Customers Served	2.34	1.42	1.80	1.01	1.91	1.70
Interruptions Per 1000 Customers Served	22.71	18.20	18.47	17.11	20.51	19.40
Number of Customers Affected Per Customer Served (SAIFI)	1.18	1.04	1.09	0.81	1.04	1.03

* LIPA is not regulated by the NYS PSC.
* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

NATIONAL GRID

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	13,665	14,606	12,939	15,915	13,822	14,189
Number of Customer-Hours	3,289,340	3,045,363	2,334,754	2,645,775	2,529,126	2,768,872
Number of Customers Affected	1,607,461	1,518,634	1,188,585	1,387,131	1,277,727	1,395,908
Number of Customers Served	1,589,949	1,594,179	1,583,311	1,589,810	1,593,830	1,590,216
Average Duration Per Customer Affected (CAIDI)	2.05	2.01	1.96	1.91	1.98	1.98
Average Duration Per Customers Served	2.07	1.92	1.46	1.67	1.59	1.74
Interruptions Per 1000 Customers Served	8.62	9.19	8.12	10.05	8.69	8.93
Number of Customers Affected Per Customer Served (SAIFI)	1.01	0.96	0.75	0.88	0.80	0.88

NATIONAL GRID

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	16,279	16,222	18,301	17,060	15,571	16,687
Number of Customer-Hours	16,813,162	5,605,931	9,410,833	3,214,148	3,824,438	7,773,703
Number of Customers Affected	2,341,235	2,075,480	2,177,786	1,599,090	1,553,727	1,949,464
Number of Customers Served	1,589,949	1,594,179	1,583,311	1,589,810	1,593,830	1,590,216
Average Duration Per Customer Affected (CAIDI)	7.18	2.70	4.32	2.01	2.46	3.74
Average Duration Per Customers Served	10.61	3.53	5.90	2.03	2.41	4.89
Interruptions Per 1000 Customers Served	10.27	10.20	11.48	10.77	9.79	10.50
Number of Customers Affected Per Customer Served (SAIFI)	1.48	1.31	1.37	1.01	0.98	1.23

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

NYSEG

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	9,682	10,317	10,027	9,643	9,777	9,889
Number of Customer-Hours	1,913,315	2,299,142	1,980,213	1,848,599	1,934,747	1,995,203
Number of Customers Affected	953,941	1,034,113	953,105	922,448	975,375	967,796
Number of Customers Served	859,440	859,963	857,517	858,712	856,474	858,421
Average Duration Per Customer Affected (CAIDI)	2.01	2.22	2.08	2.00	1.98	2.06
Average Duration Per Customers Served	2.24	2.68	2.30	2.16	2.25	2.32
Interruptions Per 1000 Customers Served	11.33	12.00	11.66	11.25	11.39	11.52
Number of Customers Affected Per Customer Served (SAIFI)	1.12	1.20	1.11	1.08	1.14	1.13

NYSEG

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	12,835	12,928	17,008	11,948	14,976	13,939
Number of Customer-Hours	15,787,602	5,314,914	12,974,501	3,369,824	6,445,599	8,778,488
Number of Customers Affected	1,529,247	1,469,825	1,836,251	1,257,464	1,576,105	1,533,778
Number of Customers Served	859,440	859,963	857,517	858,712	856,474	858,421
Average Duration Per Customer Affected (CAIDI)	10.32	3.62	7.07	2.68	4.09	5.55
Average Duration Per Customers Served	18.48	6.18	15.09	3.93	7.51	10.24
Interruptions Per 1000 Customers Served	15.02	15.04	19.78	13.93	17.44	16.24
Number of Customers Affected Per Customer Served (SAIFI)	1.79	1.71	2.14	1.47	1.84	1.79

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

O&R

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	2,688	2,596	2,993	2,987	2,897	2,832
Number of Customer-Hours	397,977	356,514	470,431	375,064	472,939	414,585
Number of Customers Affected	264,121	222,895	256,943	223,976	263,752	246,337
Number of Customers Served	216,268	215,694	217,373	217,884	218,393	217,122
Average Duration Per Customer Affected (CAIDI)	1.51	1.60	1.83	1.67	1.79	1.68
Average Duration Per Customers Served	1.85	1.65	2.18	1.73	2.17	1.92
Interruptions Per 1000 Customers Served	12.53	12.00	13.88	13.74	13.30	13.09
Number of Customers Affected Per Customer Served (SAIFI)	1.23	1.03	1.19	1.03	1.21	1.14

O&R

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	3,546	2,738	3,655	3,111	3,646	3,339
Number of Customer-Hours	836,046	483,938	1,043,235	471,941	1,857,491	938,530
Number of Customers Affected	388,164	252,650	354,315	249,064	389,937	326,826
Number of Customers Served	216,268	215,694	217,373	217,884	218,393	217,122
Average Duration Per Customer Affected (CAIDI)	2.15	1.92	2.94	1.89	4.76	2.73
Average Duration Per Customers Served	3.90	2.24	4.84	2.17	8.53	4.33
Interruptions Per 1000 Customers Served	16.53	12.66	16.95	14.31	16.73	15.44
Number of Customers Affected Per Customer Served (SAIFI)	1.81	1.17	1.64	1.15	1.79	1.51

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

RG&E

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	3,004	2,784	2,807	2,950	2,872	2,883
Number of Customer-Hours	508,899	526,175	513,175	378,481	432,921	471,930
Number of Customers Affected	286,388	303,940	277,824	210,698	253,517	266,473
Number of Customers Served	364,759	357,232	356,097	357,177	360,156	359,084
Average Duration Per Customer Affected (CAIDI)	1.78	1.73	1.85	1.80	1.71	1.77
Average Duration Per Customers Served	1.40	1.44	1.44	1.06	1.21	1.31
Interruptions Per 1000 Customers Served	8.24	7.63	7.86	8.28	8.04	8.01
Number of Customers Affected Per Customer Served (SAIFI)	0.79	0.83	0.78	0.59	0.71	0.74

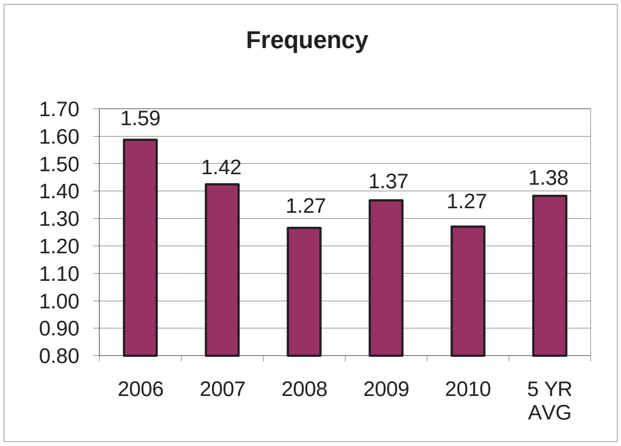
RG&E

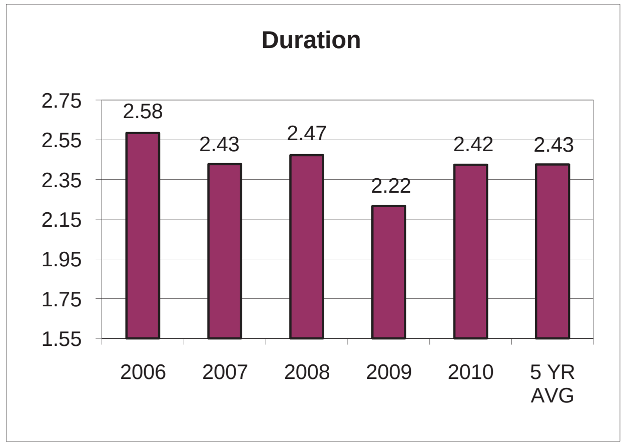
Including Major Storms

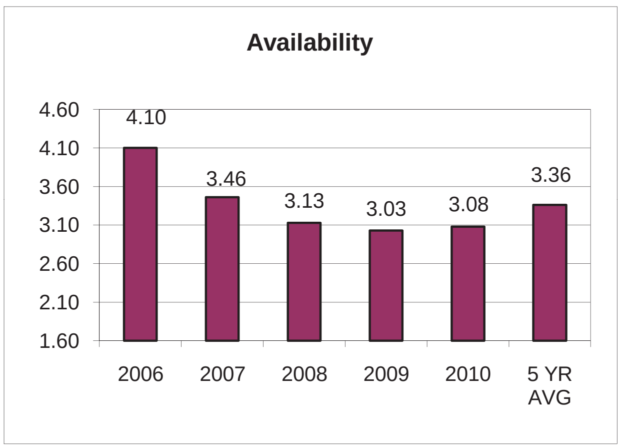
	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	3,241	3,107	3,828	3,110	3,081	3,273
Number of Customer-Hours	762,609	761,368	1,830,153	534,259	615,789	900,835
Number of Customers Affected	356,788	423,383	485,821	263,203	282,347	362,308
Number of Customers Served	364,759	357,232	356,097	357,177	360,156	359,084
Average Duration Per Customer Affected (CAIDI)	2.14	1.80	3.77	2.03	2.18	2.38
Average Duration Per Customers Served	2.09	2.09	5.12	1.50	1.72	2.51
Interruptions Per 1000 Customers Served	8.89	8.52	10.72	8.73	8.63	9.10
Number of Customers Affected Per Customer Served (SAIFI)	0.98	1.16	1.36	0.74	0.79	1.01

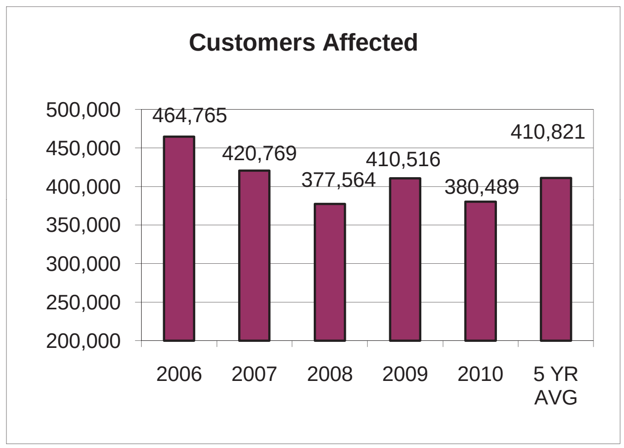
* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

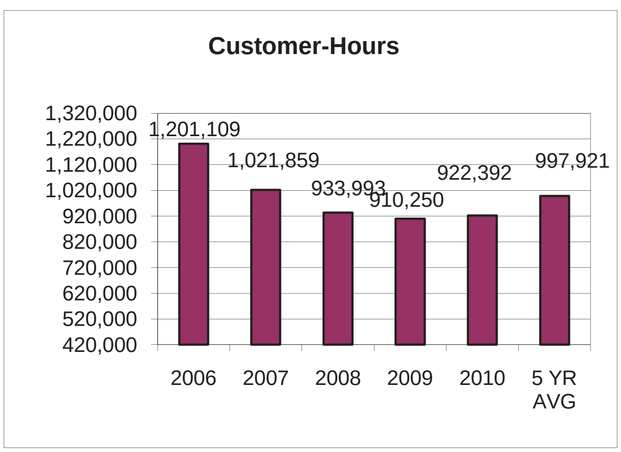
Central Hudson Gas and Electric
(Excluding Major Storms)

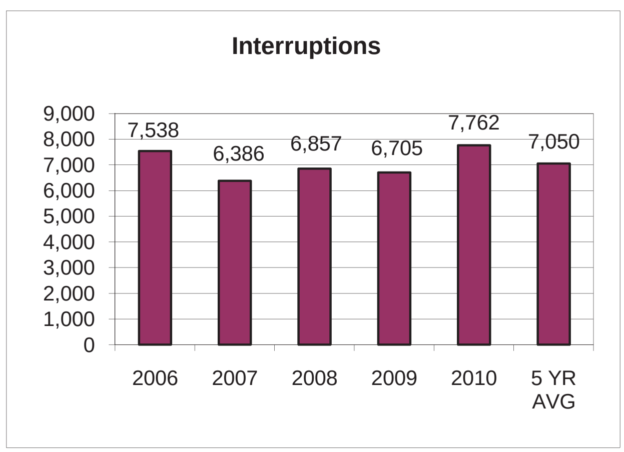




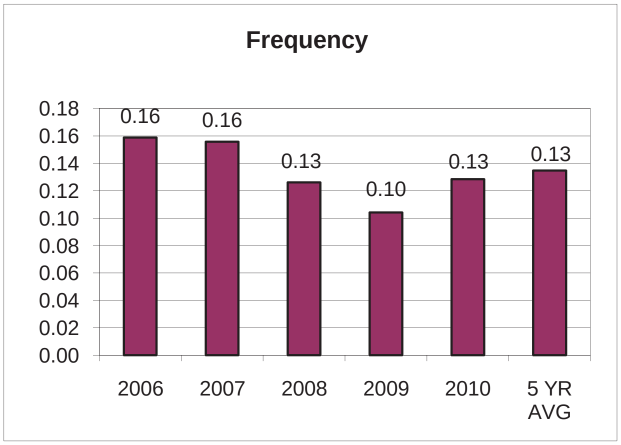


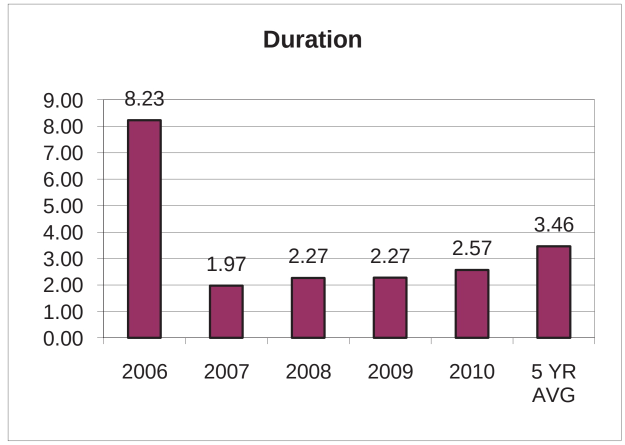


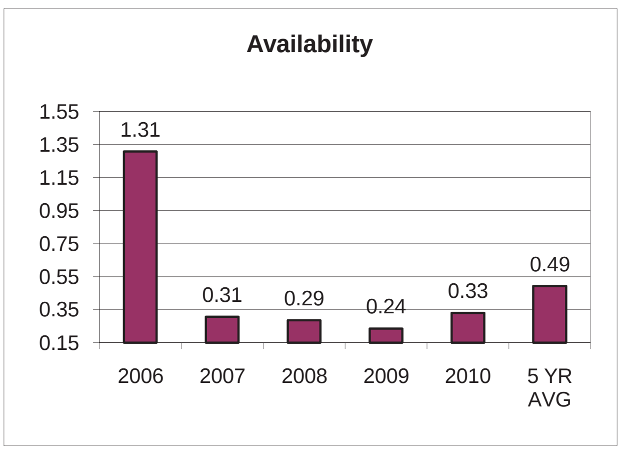


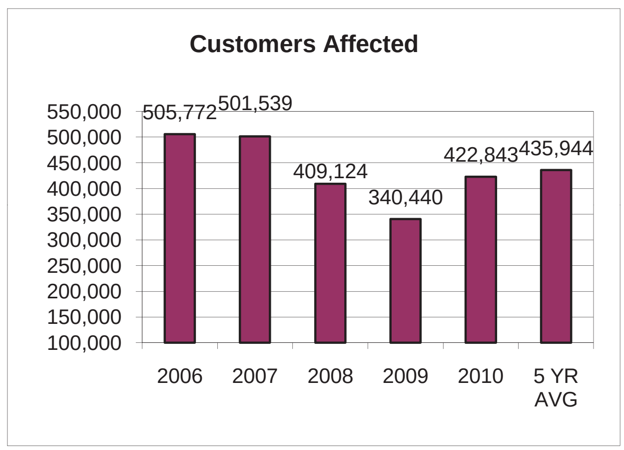


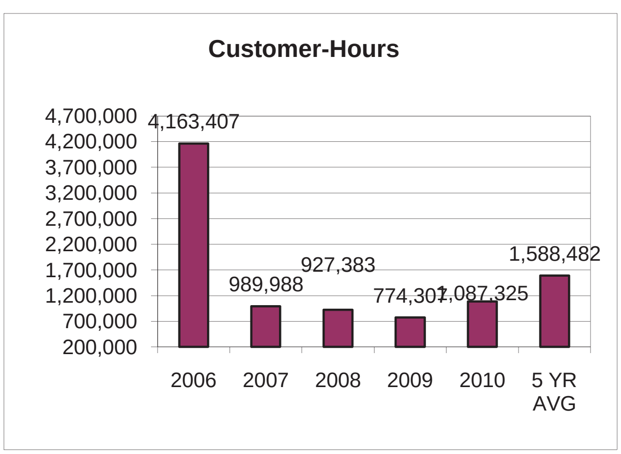
Consolidated Edison - System
(Excluding Major Storms)

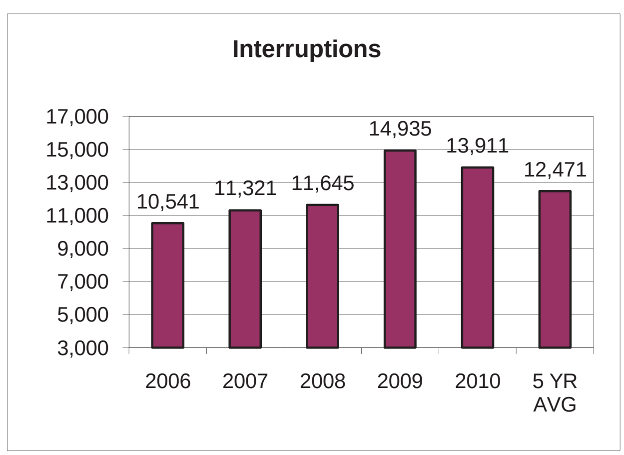




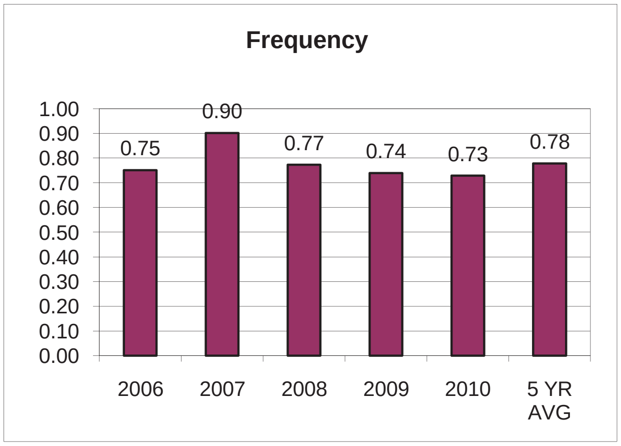


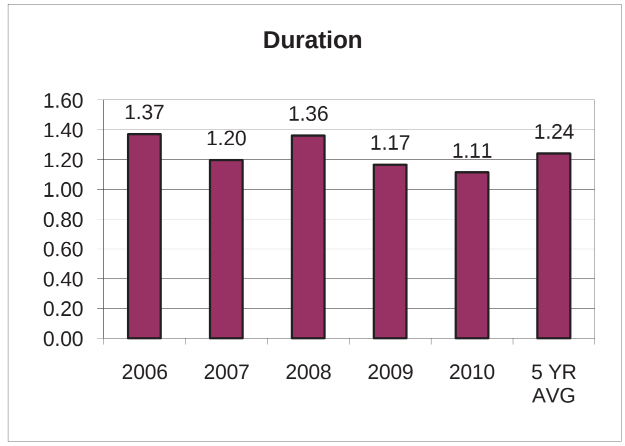


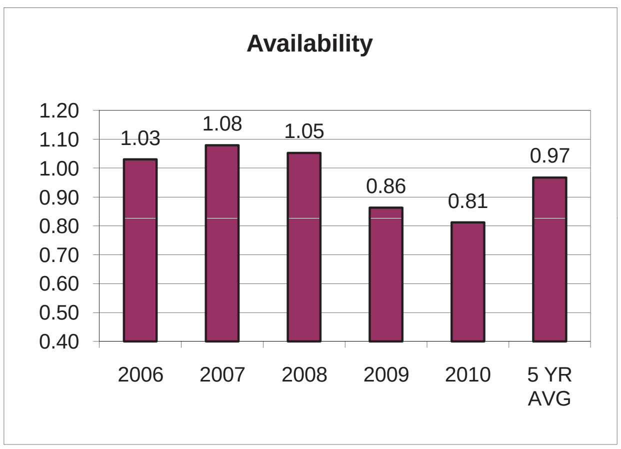


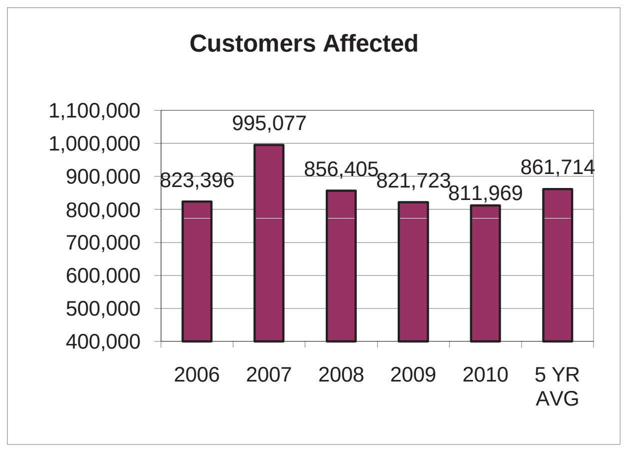


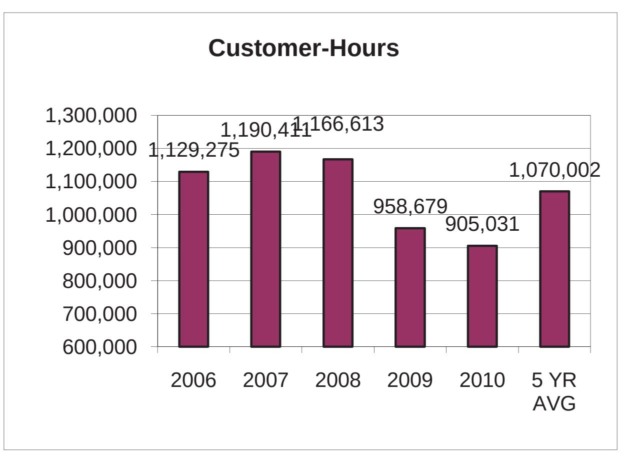
Long Island Power Authority
(Excluding Major Storms)

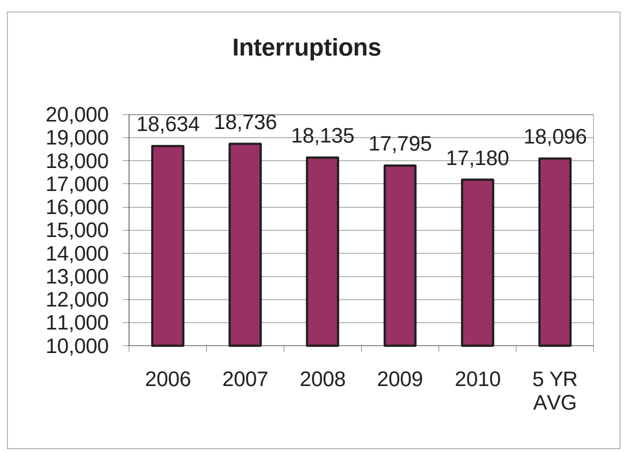






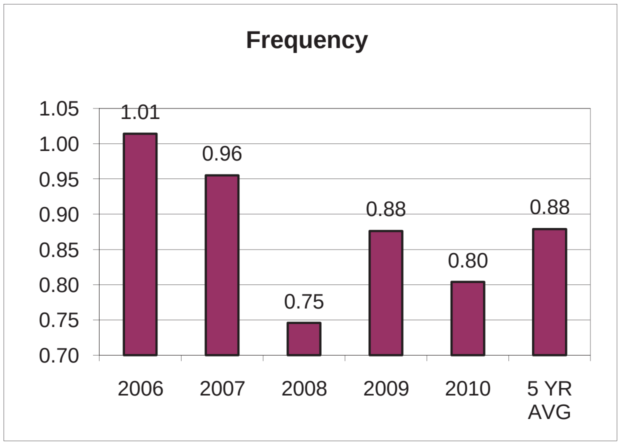


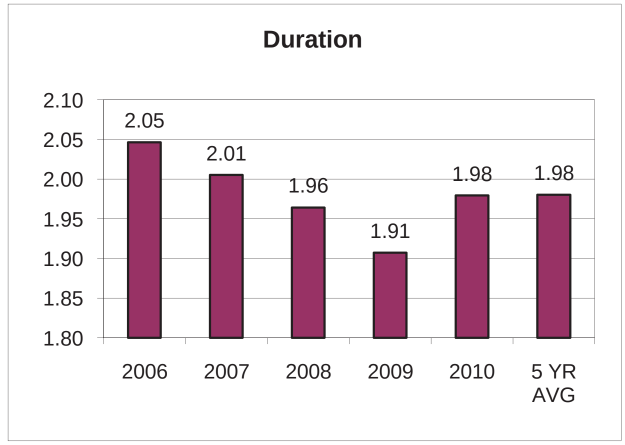


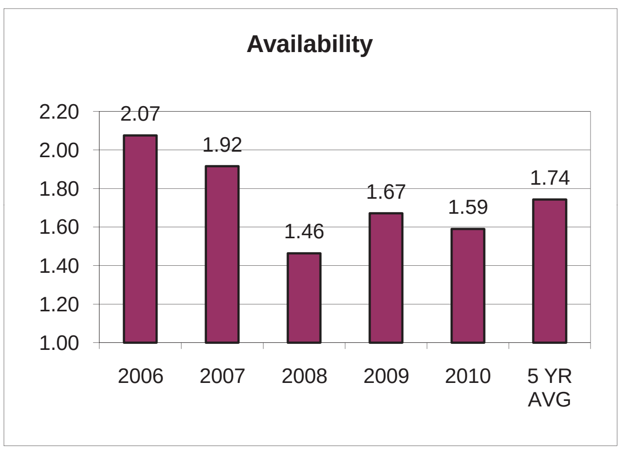


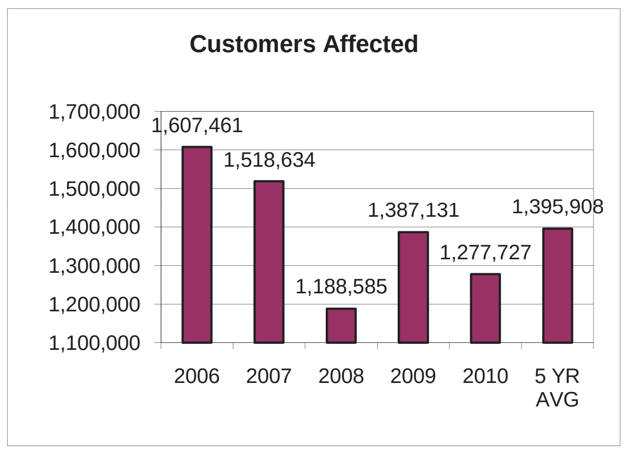
* LIPA is not regulated by the NYS PSC.

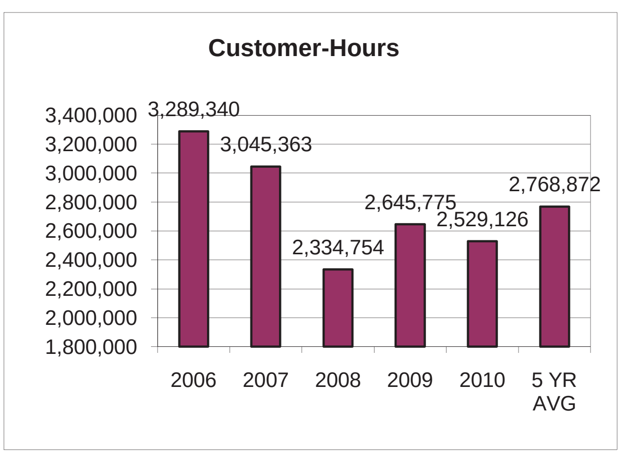
National Grid
(Excluding Major Storms)

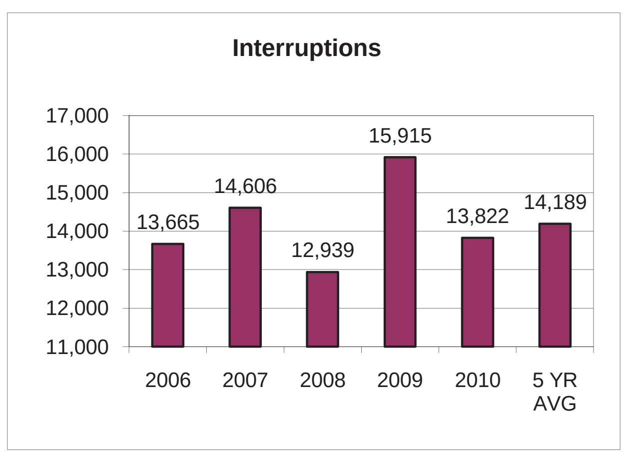




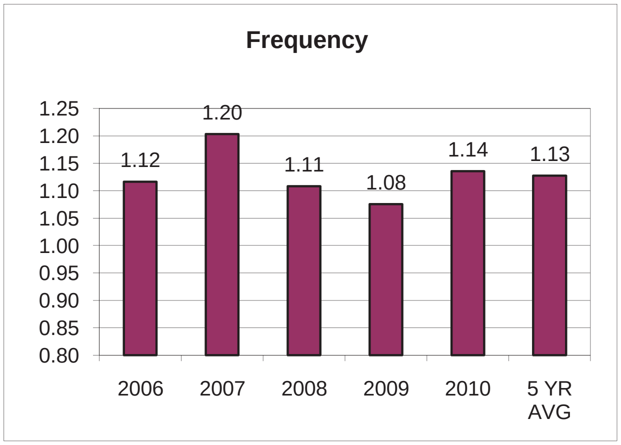


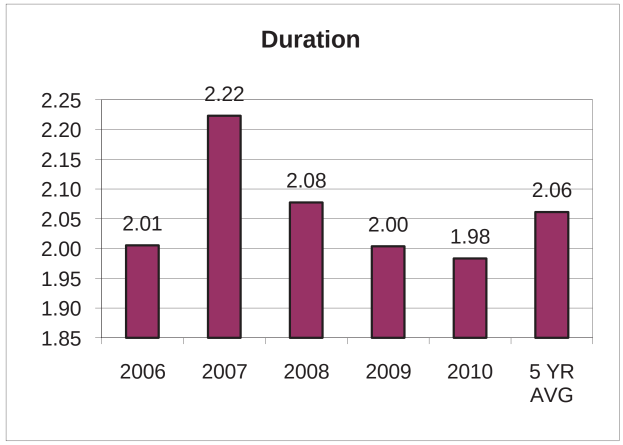


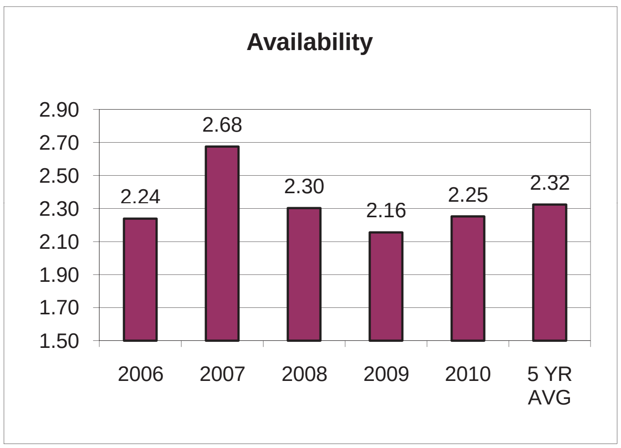


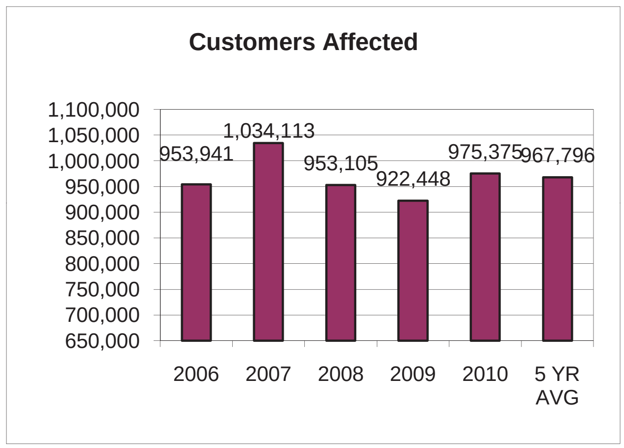


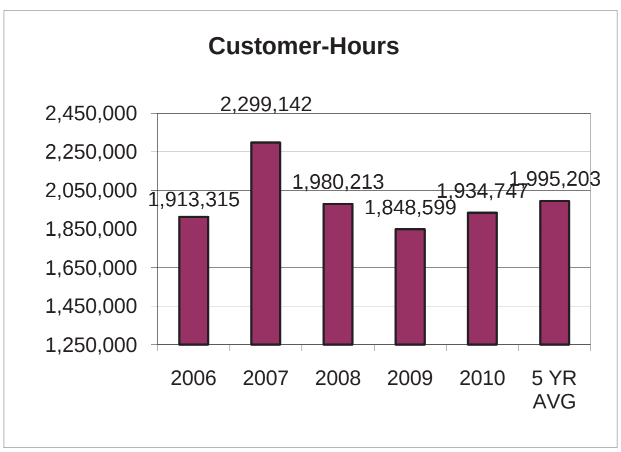
New York State Electric and Gas
(Excluding Major Storms)

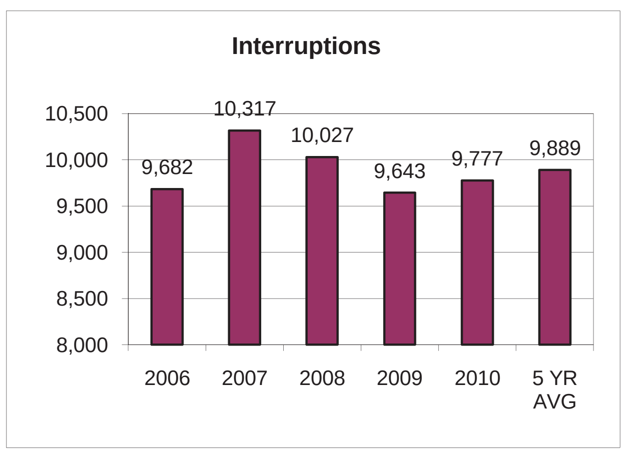




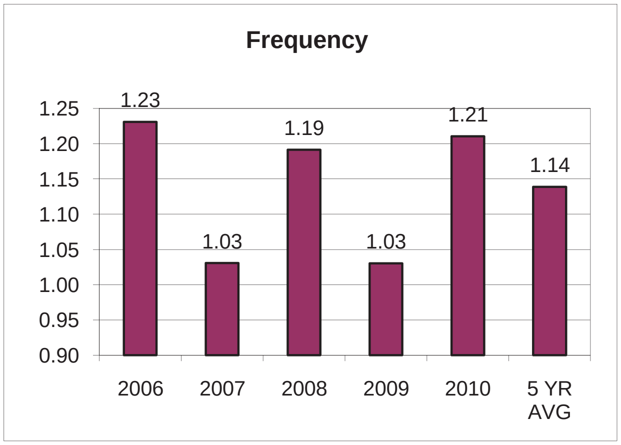


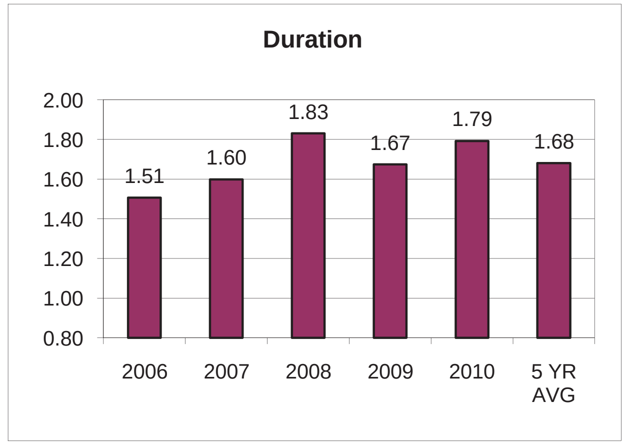


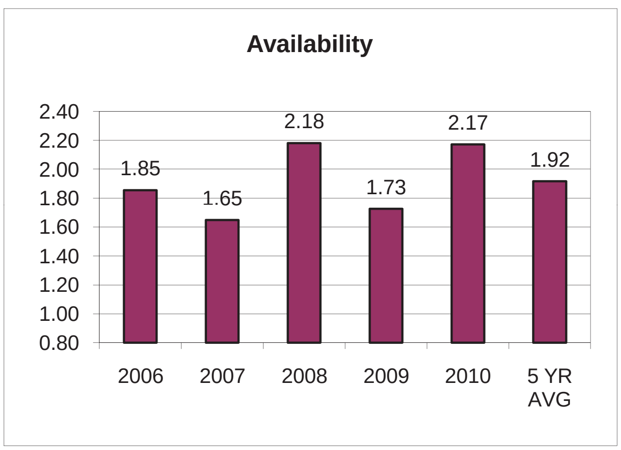


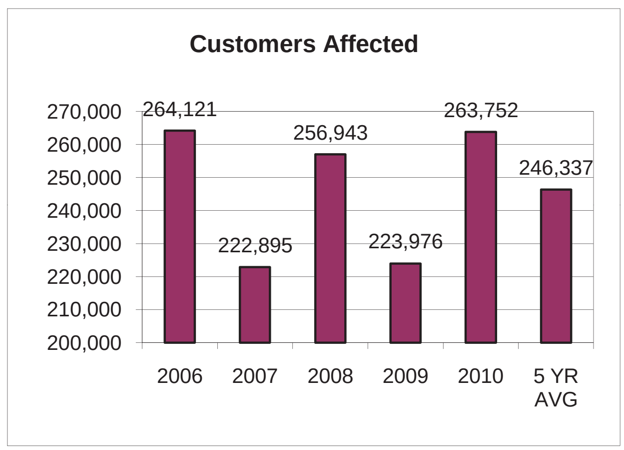


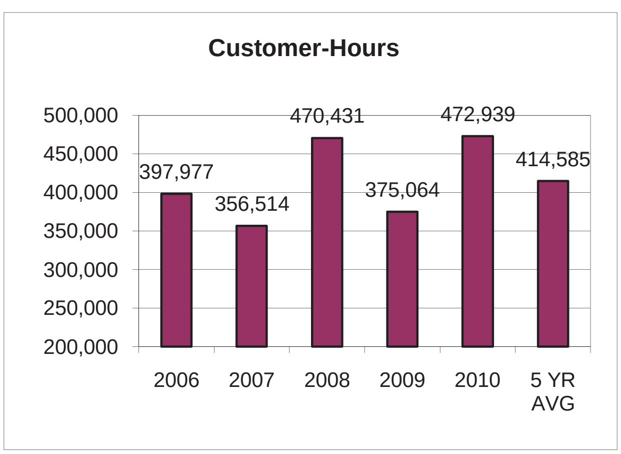
Orange and Rockland Utilities
(Excluding Major Storms)

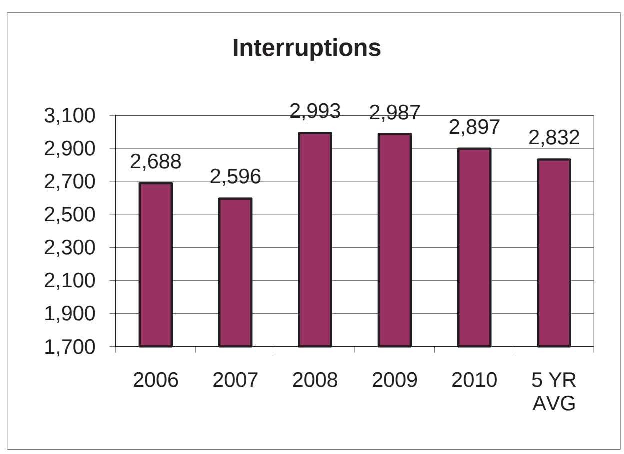




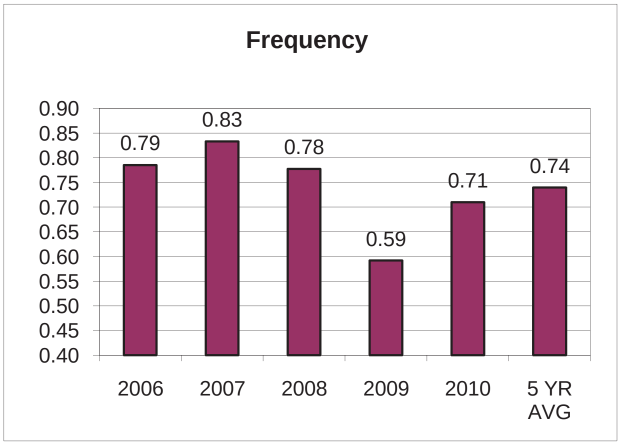


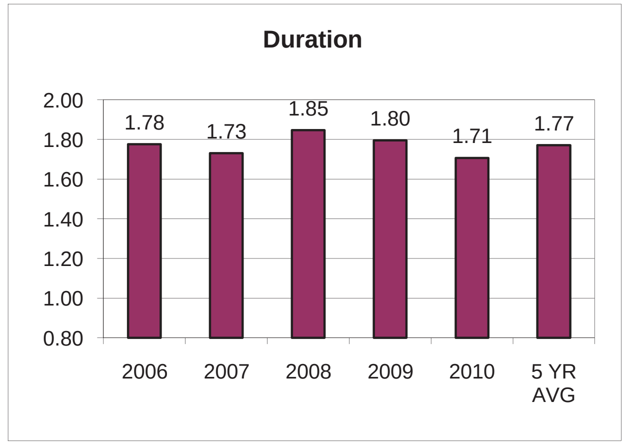


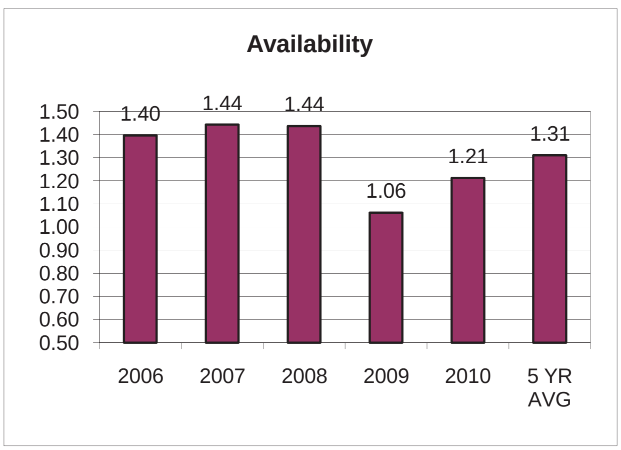


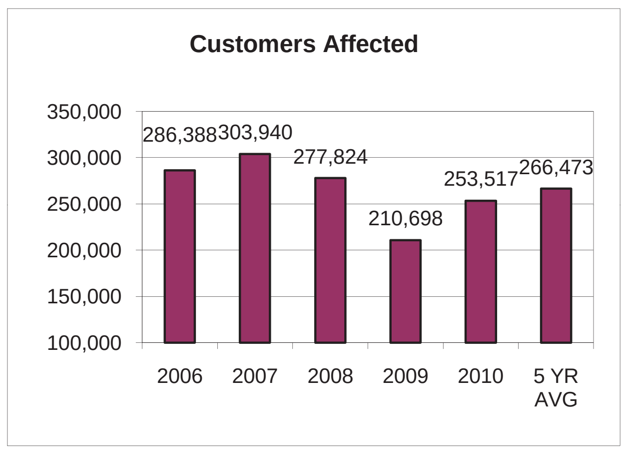


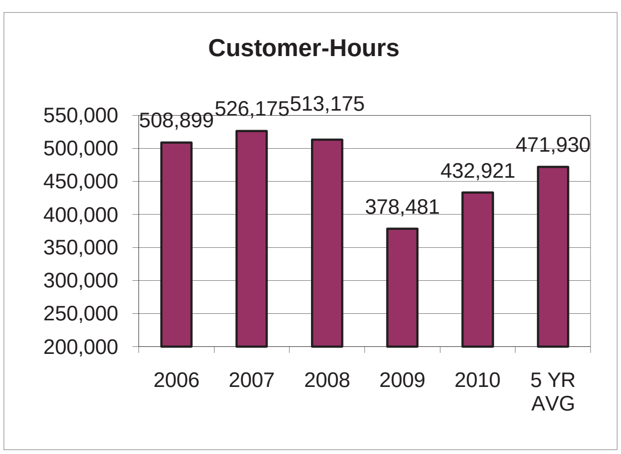
Rochester Gas and Electric
(Excluding Major Storms)

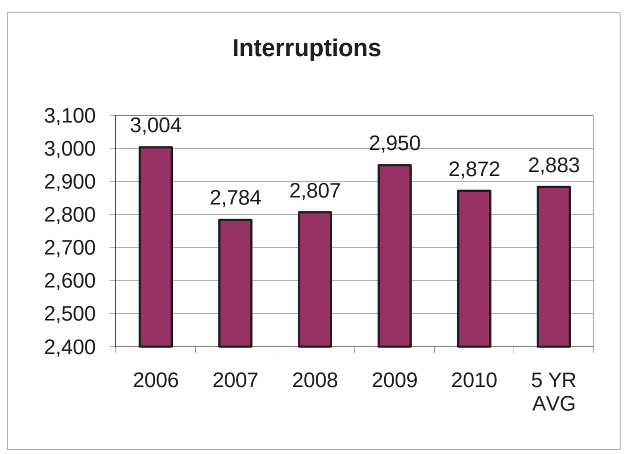












Megan Caulson
SDG&E Regulatory Tariffs Manager
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858-654-1748
Fax: 858-654-1788

February 28, 2012

Paul Clanon
Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: San Diego Gas & Electric Company (SDG&E) Electric System Reliability Annual Report for 2011

Dear Mr. Clanon,

Pursuant to Ordering Paragraph 1 of D.96-09-045, SDG&E hereby submits its Electric System Reliability Report for the calendar year ended December 31, 2011.

As detailed in SDG&E Advice Letter 2256-E (approved June 9, 2011), this report provides SDG&E's Historical System Reliability Data based on IEEE 1366 exclusion criteria, in addition to the Historical System Reliability Data based on D.96-09-045 exclusion criteria.

If there are any questions concerning the enclosed information, please contact Megan Caulson at (858) 654-1748.

Sincerely,

Megan Caulson
Regulatory Tariff Manager

Encl.

cc: Edward Randolph, Energy Division
David Lee, Energy Division
Mike Olson, SDG&E

ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2011

Prepared for

California Public Utilities Commission

February 13, 2012

EXECUTIVE SUMMARY

This Electric System Reliability Annual Report for 2011 has been prepared in response to CPUC Decision 96-09-045. This Decision established additional reliability recording, calculation, and reporting requirements for SDG&E.

The data in this report is presented in tabular form. All statistics and calculations include forced transmission, substation, and distribution outages, and exclude planned outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are those outages that lasted 5 minutes or more in duration, while momentary outages are those outages that lasted less than 5 minutes in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.

2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.

3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.

4. SAIDET* (System Average Interruption Duration Index Exceeding Threshold) - minutes of sustained outages per customer per year exceeding a defined annual threshold of 150 minutes.

5. ERT* (Estimated Restoration Time) - sum of the weighted accuracy of each outage divided by the number of customers who experienced an outage. Weighted accuracy is determined by using the time in play and number of customers who received accurate estimates.

The measurement of each reliability performance indicator excludes CPUC major events and events that are the direct result of failures in the ISO-controlled bulk power market, or non-SDG&E owned transmission and distribution facilities. A Major Event is defined in CPUC Decision 96-09-045 as an event that meets at least one of the following criteria:

(a) The event is caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government, or
(b) Any other disaster not in (a) that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event.

* Introduced as new reliability indices in 2008 as a result of SDGE's General Rate Case Application: (A) 06-12-009 and resulting decision (D) 08-07-046

This report also provides SDG&E's Historical System Reliability Data based on IEEE 1366 exclusion criteria (shown on Page 2), in addition to the Historical System Reliability Data based on D. 96-09-045 exclusion criteria (shown on Page 1).

A summary of 2011 performance is as follows:

CRITERIA	SAIDI	SAIFI	MAIFI	SAIDET	ERT
Including CPUC Major Events (2011)	567.59	1.472	0.239	–	–
Excluding CPUC Major Events (2011)	54.14	0.473	0.239	26.24	59%
10-Year Average (2002-2011) Including CPUC Major Events	155.49	0.751	0.527	–	–
10-Year Average (2002-2011) Excluding CPUC Major Events	64.22	0.580	0.508	–	–

The CPUC Major Events that were declared in 2011 are shown in the following table. Restricted access by a governmental agency that precludes or otherwise delays outage restoration times are considered CPUC Major Events and excluded from reliability results.

Month/Day	SAIDI	SAIFI	Sustained Customer Impact	MAIFI	Momentary Customer Impact	Event Cause(s)
March 7	0.04	0.000	110	-	-	SDPD Request to De-energize
August 21 - 22	0.01	0.000	13	-	-	Restricted Access by Fire Dept.
September 8 -9	513.40	0.999	1,387,249	-	765	Pacific Southwest Electrical Outage
November 21	0.00	0.000	37	-	-	Non-SDG&E Facility; SCE Outage
December 17	0.00	0.000	25	-	-	SD County Sheriff Request to De-energized

In 2011, approximately 15 customers within SDG&E's service territory experienced more than one 5 minute (or longer) outage per month on a rolling annual average basis, after exclusion of CPUC Major Events.

TABLE OF CONTENTS

HISTORICAL SYSTEM RELIABILITY DATA (USING D.96-09-045 EXCLUSION CRITERIA)

	All Forced Interruptions Included			CPUC Major Events Excluded				
Year	**SAIDI**	**SAIFI**	**MAIFI**	**SAIDI**	**SAIFI**	**MAIFI**	**No. of Events**	**Event Cause(s)**
2002	82.68	0.813	0.606	77.35	0.807	0.604	4	Fires (2), Interruptions Due to Non-SDG&E Facilities (2)
2003	298.45	0.860	0.869	76.14	0.717	0.845	2	Firestorm 2003 (1), Wind Storm Affecting >15% of Facilities (1)
2004	93.19	0.672	0.614	78.75	0.615	0.610	5	Fires (3), Interruptions Due to Non-SDG&E Facilities (1), December Storm (1)
2005	61.99	0.637	0.602	58.46	0.567	0.568	10	Fires (4), Interruptions Due to Non-SDG&E Facilities (4), Storms (2)
2006	52.83	0.545	0.494	52.65	0.541	0.494	9	Fires (6), Interruptions Due to Non-SDG&E Facilities (3)
2007	182.17	0.590	0.572	52.00	0.481	0.527	8	State of Emergency Declared (2), Interruptions Due to Non-SDG&E Facilities (2), Load Curtailment (1), Request to De-energize/ Restricted Access (3)
2008	59.17	0.517	0.380	58.92	0.515	0.378	9	Fires (2), Request to De-energize/ Restricted Access (7)
2009	67.06	0.542	0.380	66.01	0.538	0.380	4	Fires (1), Interruptions Due to Non-SDG&E Facilities (1), Request to De-energize/ Restricted Access (2)
2010**	89.77	0.863	0.510	67.74	0.543	0.431	12	Storms (2), Interruptions Due to Non-SDG&E Facilities (6), Load Curtailment (1), Request to De-energize/ Restricted Access (3)
2011	567.59	1.472	0.239	54.14	0.473	0.239	5	Requests to De-energize (2), Restricted Access (1), Southwest Electrical Outage (1), Interruptions Due to Non-SDG&E Facilities (1)

**The 2010 MAIFI impacts were inadvertently under reported in the 2010 annual report and have since been corrected. This correction increased 2010 MAIFI by 0.003 when excluding CPUC events.

HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)

	All Forced Interruptions Included			Threshold Major Event Days Excluded *		
Year	**SAIDI**	**SAIFI**	**MAIFI**	**SAIDI**	**SAIFI**	**MAIFI**
2002	82.68	0.813	0.606	70.71	0.621	0.588
2003	298.45	0.860	0.869	81.49	0.698	0.856
2004	93.19	0.672	0.614	78.83	0.619	0.610
2005	61.99	0.637	0.602	61.99	0.637	0.602
2006	52.83	0.545	0.494	52.83	0.545	0.494
2007	182.17	0.590	0.572	54.89	0.477	0.530
2008	59.17	0.517	0.380	59.17	0.517	0.380
2009	67.06	0.542	0.380	49.71	0.466	0.362
2010**	89.77	0.863	0.510	63.36	0.520	0.444
2011	567.59	1.472	0.239	53.43	0.471	0.239

* Per IEEE Standard 1366-2003 "2.5 beta method" for determining excludable days, days are excluded from a given year's metric if their SAIDI exceeds 2.5 times the standard deviation of daily SAIDI over the previous five year period.

**The 2010 MAIFI impacts were inadvertently under reported in the 2010 annual report and have since been corrected. This correction increased 2010 MAIFI by 0.0003 when excluding Threshold Major Event Days.

TEN LARGEST OUTAGE EVENTS IN 2011*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	September 8 - 9	Pacific Southwest Electrical Outage	513.40	0.999	Yes	1,387,249	981	Not Available
2	June 28 - 29	Faulted Circuit Breaker	1.52	0.004	No	5,147	539	Not Available
3	October 16 - 17	Faulted Underground Cable	0.68	0.002	No	2,422	1,054	Not Available
4	March 15 - 16	Faulted Tee	0.64	0.004	No	5,257	704	Not Available
5	August 4 - 5	Faulted Underground Cable	0.57	0.004	No	5,285	706	Not Available
6	August 28 - 29	Storm	0.51	0.003	No	4,314	1,170	Not Available
7	October 22	Faulted Tee	0.48	0.004	No	5,096	609	Not Available
8	December 23 - 24	Vehicle Contact	0.45	0.001	No	1,210	1,543	Not Available
9	June 29	Faulted Underground Cable	0.44	0.002	No	2,140	453	Not Available
10	November 4	Faulted Cutout	0.43	0.006	No	7,841	77	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2010*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	January 18 - 22	Heavy Rain Storm	12.61	0.085	Yes	117,558	1,752	Not Available
2	December 20 - 23	Heavy Rain Storm	4.93	0.023	Yes	31,376	1,758	Not Available
3	April 1	ISO Ordered Load Curtailment	4.40	0.211	Yes	290,945	43	Not Available
4	September 30 - October 5	Heavy Rain and Lightning Storm	2.88	0.036	No	50,155	1,343	Not Available
5	January 5 - 6	Faulted Tee	1.57	0.004	No	5,111	760	Not Available
6	September 26 - 28	Heat Storm	1.42	0.010	No	13,531	624	Not Available
7	September 30 - October 1	Vehicle Contact	1.34	0.004	No	5,503	1,074	Not Available
8	October 21	Vehicle Contact	1.33	0.002	No	2,753	1,341	Not Available
9	April 4 - 5	Earthquake	1.22	0.003	No	4,512	651	Not Available
10	October 19 - 20	Heavy Rain and Lightning Storm	1.12	0.014	No	18,873	718	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2009*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	December 7 - 10	December Storm**	11.68	0.045	No	61,783	3,624	Not Available
2	December 13 - 14	Overhead Equipment Failure	4.49	0.016	No	21,956	1,099	Not Available
3	August 20 - 21	Vehicle Contact	1.05	0.004	Yes	5,031	970	Not Available
4	June 3 - 4	Lightning Storm	0.97	0.006	No	7,909	1,204	Not Available
5	February 9 - 10	Heavy Rain and Snow Storm	0.86	0.009	No	12,304	1,686	Not Available
6	December 7 -8	Underground Equipment Failure**	0.60	0.003	No	3,889	1,082	Not Available
7	November 18 - 19	Faulted Cable	0.53	0.003	No	4,322	950	Not Available
8	November 28 - 29	Heavy Rain Storm	0.50	0.006	No	8,779	756	Not Available
9	November 23 - 24	Underground Equipment Failure	0.48	0.003	No	4,045	544	Not Available
10	November 9 -10	Heavy Equipment Dig-In	0.47	0.005	No	7,458	1,167	Not Available

* Based on SAIDI impact.

** The information for both the Dec. 7-10 and Dec. 7-8 events have been updated since the filing of the 2009 annual report. The above figures represent the corrected values. An underground equipment failure was inadvertently associated with the December storm event. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts when excluding CPUC events.

TEN LARGEST OUTAGE EVENTS IN 2008*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	December 17 - 22	Heavy Rain and Snow Storm throughout Service Territory, Part II	3.51	0.010	No	13,113	6,783	Not Available
2	January 5 - 8	Rain & Lightning Storm throughout Service Territory	1.33	0.011	No	15,438	1,731	Not Available
3	December 15	Heavy Rain and Snow Storm throughout Service Territory, Part I	1.02	0.006	No	8,421	421	Not Available
4	May 31	C138 & HC3 Tree Contact (also affecting C139 & 4kVs)	0.92	0.003	No	3,735	746	Not Available
5	October 19	C213 - Damaged Underground Cable	0.91	0.001	No	2,035	942	Not Available
6	June 22 - 23	C990 - Faulted Terminator	0.67	0.002	No	2,198	870	Not Available
7	April 8 - 9	C486 - Motor Vehicle Contact, Terminator and Cable Replaced	0.61	0.003	No	4,708	910	Not Available
8	December 25 - 26	C286 & EN2 - Multiple Circuits affected during Restoration	0.58	0.004	No	5,364	601	Not Available
9	May 23	C159 - Pothead Failure	0.56	0.002	No	3,178	298	Not Available
10	September 24	Bank 20 Bad Relay affecting circuits WA3, WA4, WA5 and WA6	0.56	0.004	No	6,128	178	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2007*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	October 21 - November 24	Firestorm 2007 - Declaration of State of Emergency	128.42	0.055	Yes	74,088	40,453	Not Available
2	September 1 - 4	HEATWAVE 2007 (Labor Day Weekend)	1.59	0.010	No	13,662	833	Not Available
3	October 22	ISO Request - Load Curtailment during Firestorm 2007	1.18	0.051	Yes	68,826	34	Not Available
4	June 04	Laguna Niguel Outages - Faulted CB impacted Bus	1.15	0.016	No	21,425	254	Not Available
5	August 30	TL 629 & TL 6946 Lightning Contact on Swi 629-8	1.09	0.003	No	4,117	359	Not Available
6	July 28	Circuit 582 Underground Cable Failure	1.01	0.002	No	2,761	606	Not Available
7	October 11	Paradise Substation Bank 42 Lightning Arrestor Failure	0.80	0.017	No	23,121	85	Not Available
8	September 15 - 17	Circuit 221 Pine Valley Fire	0.77	0.000	No	585	2,942	Not Available
9	January 12 - 13	Circuits WA3, WA4, and UP1 - Downed Overhead Conductor	0.66	0.003	No	4,052	347	Not Available
10	December 25 - 26	Circuit EOS2 - Connector Failure	0.57	0.001	No	1,349	614	Not Available

*Based on SAIDI impact.
**The information for the largest event was inadvertently under reported in the 2007 annual report and has since been corrected above. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts when excluding CPUC events.

TEN LARGEST OUTAGE EVENTS IN 2006*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	July 22 - 23**	Heat Storm	2.89	0.020	No	26,477	1,280	Not Available
2	March 10 - 14	Storm / Winds	1.98	0.003	No	4,501	4,160	Not Available
3	July 21	TL 685 - Misoperation of a Relay (7 Substations)	1.84	0.033	No	45,007	55	Not Available
4	July 15 - 17	Lighting/ Heat Storm	1.03	0.009	No	12,048	869	Not Available
5	January 2 - 3	Storm / Winds	0.68	0.011	No	15,329	811	Not Available
6	June 15	Circuits 416 and 76 Private Motor Vehicle Contact	0.60	0.002	No	3,124	644	Not Available
7	September 6 - 7	Circuits 509 and 506 Private Motor Vehicle Contact	0.53	0.002	No	2,908	946	Not Available
8	May 23	Circuit 592 Damaged Connector Failure	0.49	0.002	No	3,246	397	Not Available
9	May 26	Circuit 1077 Private Motor Vehicle Contact	0.42	0.002	No	2,158	636	Not Available
10	July 31 - August 1	Circuit WY1 - Vegetation Contact	0.42	0.001	No	1,070	1,058	Not Available

* Based on SAIDI impact.
** Includes outages initiated on July 23rd and restored on July 24th.

TEN LARGEST OUTAGE EVENTS IN 2005*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	September 19	September Storm	2.78	0.015	No	19,399	1,447	Not Available
2	July 28	Laguna Niguel Transmission Event	1.57	0.028	No	37,267	72	Not Available
3	August 25	Poway, Escondido, Cannon Sub - Load Curtailment	1.36	0.039	Yes	51,411	51	Not Available
4	February 18	February Storms	1.35	0.024	Yes	31,885	2,495	Not Available
5	July 23	Lightning Storm July	1.20	0.013	No	17,309	1,450	Not Available
6	October 6	Damaged OH Switch	0.89	0.004	No	5,226	468	Not Available
7	April 22	Poway Sub	0.89	0.008	No	10,896	108	Not Available
8	February 22	Vehicle Contact	0.82	0.003	No	4,143	310	Not Available
9	February 2	Feb 2nd storm	0.77	0.005	No	6,361	904	Not Available
10	January 3	January Storms	0.75	0.005	Yes	7,156	2,146	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2004*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	Dec. 28 - 31	December 2004 Storm	14.41	0.056	Yes	74,000	2,074	Not Available
2	Dec. 1	Substation - Equipment Failure	2.88	0.017	No	22,716	393	Not Available
3	Jun. 12	Substation - Animal Contact	2.16	0.011	No	14,708	204	Not Available
4	Jan. 23 - 24	Conductor Failure	1.88	0.003	No	3,951	625	Not Available
5	Sep. 30 - Oct. 1	Private Vehicle Contact	1.51	0.003	No	4,322	459	Not Available
6	Oct. 17 - 21	Storm / Winds	1.24	0.013	No	16,833	1,026	Not Available
7	Dec. 5	Private Vehicle Contact	1.14	0.005	No	6,292	276	Not Available
8	Dec. 5	Connector Failure	1.10	0.004	No	5,824	502	Not Available
9	Nov. 10	Transmission Equipment Failure	0.82	0.004	No	5,095	414	Not Available
10	Dec. 5 - 6	Storm / Winds	0.78	0.001	No	1,265	808	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2003*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	Oct. 26 - Nov. 25	Firestorm 2003	193.33	0.071	Yes	91,443	43,032	Not Available
2	Jan. 6 - 8	Storm / Winds	28.98	0.072	Yes	92,715	2,548	Not Available
3	Oct. 27 - 28	Substation - Animal Contact	3.10	0.017	No	22,285	227	Not Available
4	Dec. 25 - 26	Storm / Winds	3.00	0.017	No	21,611	1,303	Not Available
5	May 14 - 15	Transmission Line - Heavy Equipment Contact (Crane)	1.47	0.002	No	2,900	1,832	Not Available
6	Mar. 28 - 30	Storm / Winds	1.25	0.003	No	3,767	1,440	Not Available
7	Sep. 2 - 3	Storm / Winds	1.06	0.014	No	18,025	678	Not Available
8	Oct. 5 - 6	Underground Cable Failure	0.97	0.004	No	5,255	841	Not Available
9	Jan. 12	Substation - Animal Contact	0.97	0.014	No	17,990	73	Not Available
10	Sep. 19 - 20	Underground Cable Failure	0.88	0.004	No	5,334	1,010	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2002*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	Feb. 27	Accidental Trip of Circuit Breaker	6.00	0.173	No	219,522	62	Not Available
2	Feb. 9 - 11	Storm / Winds	3.41	0.023	No	28,987	1,587	Not Available
3	Feb. 10 - 13	Fallbrook (Gavilan) Fire - Request by CDF	2.99	0.003	Yes	3,732	4,107	Not Available
4	Aug. 31 - Sep. 3	Storm / Heat	2.94	0.023	No	28,836	775	Not Available
5	July 29 - Aug. 12	Pines Wildland Fire - State of Emergency	2.34	0.003	Yes	3,498	10,227	Not Available
6	Nov. 25 - 30	Storm / Winds	2.16	0.014	No	18,108	1,493	Not Available
7	Apr. 5	Circuit Breaker Failure	1.79	0.008	No	10,591	306	Not Available
8	Apr. 22 - 23	Crossarm Failure	1.35	0.004	No	5,219	603	Not Available
9	Dec. 16 - 18	Storm / Winds	1.23	0.008	No	10,078	1,106	Not Available
10	July 23 - 24	Switch Faulted / Mechanical	1.07	0.006	No	7,284	586	Not Available

*Based on SAIDI impact.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2011

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	2	4	6	8	10	12	14	16
September 8 - 9	Pacific Southwest Electrical Outage	1,387,249	0	0	0	0	0	0	0	0	1,387,249
			Customers Interrupted - Hours Into the Event Day (continued)								
			18	20	22	24	26	28	30	32	34
			1,387,249	1,373,940	1,204,968	842,831	201,230	2,310	761	765	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2010

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	**2**	**4**	**6**	**8**	**10**	**12**	**14**	**16**
January 18 - 22	Heavy Rain Storm	117,558	0	0	0	0	0	0	4,482	12,271	4,618
			Customers Interrupted - Hours Into the Event Day (continued)								
			18	**20**	**22**	**24**	**26**	**28**	**30**	**32**	**34**
			4,974	884	568	491	492	489	483	565	110
			Customers Interrupted - Hours Into the Event Day (continued)								
			36	**38**	**40**	**42**	**44**	**46**	**48**	**50**	**52**
			50,447	26,607	10,492	7,046	5,131	4,272	993	797	517
			Customers Interrupted - Hours Into the Event Day (continued)								
			54	**56**	**58**	**60**	**62**	**64**	**66**	**68**	**70**
			269	279	115	91	8,380	4,603	2,138	754	753
			Customers Interrupted - Hours Into the Event Day (continued)								
			72	**74**	**76**	**78**	**80**	**82**	**84**	**86**	**88**
			385	385	18,984	15,114	6,600	30,186	10,106	13,140	3,475
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	**92**	**94**	**96**	**98**	**100**	**102**	**104**	**106**
			2,352	2,806	4,638	448	102	17,158	18,330	5,084	420
			Customers Interrupted - Hours Into the Event Day (continued)								
			108	**110**	**112**	**114**	**116**	**118**	**120**	**122**	**124**
			490	465	3,093	271	155	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2010

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	2	4	6	8	10	12	14	16
April 1	ISO ordered mandatory load curtailment	290,945	290,945	0	0	0	0	0	0	0	0

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2010

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	5	10	15	20	25	30	35	40
December 20 - 23	Heavy Rain Storm	31,376	0	110	5,326	12,271	7,252	4,618	2,769	4,974	2,983
			Customers Interrupted - Hours Into the Event Day (continued)								
			45	50	55	60	65	70	75	80	85
			884	884	568	593	491	517	492	492	489
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	95	100	105	110	115	120	125	130
			489	483	474	565	583	110	24,456	50,447	38,085
			Customers Interrupted - Hours Into the Event Day (continued)								
			135	140	145	150	155	160	165	170	175
			26,607	15,698	10,492	9,863	7,046	6,168	5,131	4,325	4,272
			Customers Interrupted - Hours Into the Event Day (continued)								
			180	185	190	195	200	205	210	215	220
			3,146	993	967	797	793	517	780	269	269
			Customers Interrupted - Hours Into the Event Day (continued)								
			225	230	235	240	245	250	255	260	265
			279	276	115	116	91	5,061	8,380	7,127	4,603
			Customers Interrupted - Hours Into the Event Day (continued)								
			270	275	280	285	290	295	300	305	310
			2,380	2,138	772	754	754	753	731	385	385
			Customers Interrupted - Hours Into the Event Day (continued)								
			315	320	325	330	335	340	345	350	355
			385	7,378	18,984	16,315	15,114	7,157	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2009

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
August 20 - 21	Vehicle Contact	5,031	0	0	0	0	0	0	0	0	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	22	24	26	28	30	32	34	36
			0	5,031	2,958	1,102	1,102	1,102	1,102	1,102	1,102
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	40	42	44	46	48	50	52	54
			1,102	0	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2008

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

There were no CPUC Major Events from 2008 to be extracted.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2007

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**
October 21 - November 24	Firestorm 2007 - Declaration of State of Emergency	74,088	0	0	994	5,847	1,439	4,016	26,645	25,770	23,560
			Customers Interrupted - Hours Into the Event Day (continued)								
			45	**50**	**55**	**60**	**65**	**70**	**75**	**80**	**85**
			21,810	21,651	16,940	21,349	17,522	18,435	17,213	17,263	20,582
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	**95**	**100**	**105**	**110**	**115**	**120**	**125**	**130**
			18,341	17,699	17,699	17,927	17,503	14,693	14,012	13,117	13,064
			Customers Interrupted - Hours Into the Event Day (continued)								
			135	**140**	**145**	**150**	**155**	**160**	**165**	**170**	**175**
			11,787	10,935	9,682	8,676	8,640	7,881	6,755	6,503	7,801
			Customers Interrupted - Hours Into the Event Day (continued)								
			180	**185**	**190**	**195**	**200**	**205**	**210**	**215**	**220**
			6,582	5,670	4,791	4,786	5,154	4,700	4,702	4,104	4,104
			Customers Interrupted - Hours Into the Event Day (continued)								
			225	**230**	**235**	**240**	**245**	**250**	**255**	**260**	**265**
			4,111	4,105	3,010	2,862	2,862	2,862	3,455	3,568	2,911
			Customers Interrupted - Hours Into the Event Day (continued)								
			270	**275**	**280**	**285**	**290**	**295**	**300**	**305**	**310**
			2,725	2,986	3,008	2,303	2,303	2,358	2,277	3,211	1,946
			Customers Interrupted - Hours Into the Event Day (continued)								
			315	**320**	**325**	**330**	**335**	**340**	**345**	**350**	**355**
			1,882	1,882	2,141	2,107	1,825	1,825	1,825	2,296	1,734
			Customers Interrupted - Hours Into the Event Day (continued)								
			360	**365**	**370**	**375**	**380**	**385**	**390**	**395**	**400**
			1,540	1,540	2,657	1,472	1,506	1,211	2,292	1,255	1,985

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

**The total customer impact as well as customers out of service for hours 35, 45, and 50 were inadvertently incorrectly reported and have since been corrected. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts for Non-CPUC events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2007

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day (continued)								
			405	410	415	420	425	430	435	440	445
October 21 - November 24	Firestorm 2007 - Declaration of State of Emergency (Continued)	74,088	1,036	987	987	994	861	721	721	811	692
			Customers Interrupted - Hours Into the Event Day (continued)								
			450	455	460	465	470	475	480	485	490
			883	410	410	456	504	225	225	225	216
			Customers Interrupted - Hours Into the Event Day (continued)								
			495	500	505	510	515	520	525	530	535
			49	9	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			540	545	550	555	560	565	570	575	580
			31	31	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			585	590	595	600	605	610	615	620	625
			6	6	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			630	635	640	645	650	655	660	665	670
			6	6	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			675	680	685	690	695	700	705	710	715
			6	6	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			720	730	740	750	760	770	780	790	800
			0	0	0	0	0	0	0	0	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			810	815	820	825	830	835	840	845	850
			0	30	30	60	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

**The total customer impact as well as customers out of service for hours 35, 45, and 50 were inadvertently incorrectly reported and have since been corrected. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts for Non-CPUC events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2007

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
October 22	ISO Request - Load Curtailment during Firestorm 2007	68,826	0	0	0	0	0	0	0	68,826	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	22	24	26	28	30	32	34	36
			0	0	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2006

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

There were no CPUC Major Events from 2006 to be extracted.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2005

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**
January 3 - January 13	January Storms - Declaration of State of Emergency	7,156	0	0	0	0	0	25	68	43	123
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	**38**	**40**	**42**	**44**	**110**	**112**	**114**	**116**
			25	194	183	176	25	1,075	1,762	110	55
			Customers Interrupted - Hours Into the Event Day (continued)								
			118	**120**	**130**	**132**	**134**	**136**	**166**	**168**	**170**
			0	55	55	55	55	12	55	70	70
			Customers Interrupted - Hours Into the Event Day (continued)								
			172	**174**	**176**	**178**	**180**	**182**	**184**	**186**	**194**
			0	110	820	0	0	0	0	55	25
			Customers Interrupted - Hours Into the Event Day (continued)								
			196	**198**	**200**	**202**	**204**	**206**	**208**	**210**	**212**
			1179	577	258	215	98	135	135	135	110
			Customers Interrupted - Hours Into the Event Day (continued)								
			214	**216**	**218**	**220**	**222**	**224**	**226**	**228**	**230**
			122	110	110	110	110	110	110	110	110
			Customers Interrupted - Hours Into the Event Day (continued)								
			232	**234**	**236**	**238**	**240**	**242**	**244**	**246**	**250**
			110	110	110	110	110	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.
**The customers interrupted were inadvertently reported in the incorrect time slot in 2005. This table has been corrected in 2007; the adjustment had no affect on the reported SAIDI and SAIFI impacts for these events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2005

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	**4**	**6**	**8**	**10**	**22**	**32**	**34**	**36**
February 18 - February 25	February Storms - Declaration of State of Emergency	31,885	0	0	155	52	226	25	36	1,506	608
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	**40**	**42**	**44**	**46**	**48**	**50**	**52**	**54**
			204	188	1,008	31	31	31	19	19	129
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	**58**	**60**	**62**	**64**	**66**	**68**	**70**	**72**
			129	129	19	226	19	19	19	19	19
			Customers Interrupted - Hours Into the Event Day (continued)								
			74	**76**	**78**	**80**	**82**	**84**	**86**	**88**	**90**
			19	19	19	19	19	110	199	72	41
			Customers Interrupted - Hours Into the Event Day (continued)								
			92	**94**	**96**	**104**	**108**	**110**	**112**	**114**	**124**
			8	63	1	25	8	8	62	62	5067
			Customers Interrupted - Hours Into the Event Day (continued)								
			126	**128**	**130**	**132**	**134**	**160**	**162**	**164**	**166**
			191	690	577	19	1	84	358	860	540
			Customers Interrupted - Hours Into the Event Day (continued)								
			168	**170**	**172**	**174**	**176**	**178**	**180**	**182**	**184**
			460	234	87	31	31	7	7	7	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.
**The customers interrupted were inadvertently reported in the incorrect time slot in 2005. This table has been corrected in 2007; the adjustment had no affect on the reported SAIDI and SAIFI impacts for these events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2005

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
August 25	ISO ordered mandatory load curtailment	51,411	0	0	0	0	0	0	0	51,411	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

**The customers interrupted were inadvertently reported in the incorrect time slot in 2005. This table has been corrected in 2007; the adjustment had no affect on the reported SAIDI and SAIFI impacts for these events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2004

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
December 28 - 31	December Storm - Declaration of State of Emergency	74,000	0	0	0	31	3,725	5	30	1,381	48,480
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	22	24	26	28	30	32	34	36
			36,187	26,037	18,190	11,941	7,393	5,017	3,093	1,372	709
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	40	42	44	46	48	50	52	54
			411	159	91	36	36	50	34	7	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	58	60	62	64	66	68	70	72
			6	110	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2003

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
January 6 - 8	January Storm - >15% of System Facilities Affected	92,715	0	165	2,374	3,500	5,231	4,985	2,916	4,272	33
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	**22**	**24**	**26**	**28**	**30**	**32**	**34**	**36**
			2,908	2,875	299	8,799	42,386	62,337	44,408	34,801	29,472
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	**40**	**42**	**44**	**46**	**48**	**50**	**52**	**54**
			23,942	18,661	7,533	4,709	3,687	3,391	2,489	1,563	1,077
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	**58**	**60**	**62**	**64**	**66**	**68**	**70**	**72**
			1,021	648	581	92	94	69	69	37	37
			Customers Interrupted - Hours Into the Event Day (continued)								
			74	**76**	**78**	**80**	**82**	**84**	**86**	**88**	**90**
			25	25	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2003

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**
October 26 - November 25	Firestorm 2003 - Declaration of State of Emergency	91,443	0	697	12,087	25,599	33,856	33,575	35,317	43,272	44,623
			Customers Interrupted - Hours Into the Event Day (continued)								
			45	**50**	**55**	**60**	**65**	**70**	**75**	**80**	**85**
			43,523	38,774	28,412	26,932	24,552	24,157	21,108	20,628	17,709
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	**95**	**100**	**105**	**110**	**115**	**120**	**125**	**130**
			16,330	17,074	17,074	16,013	14,356	12,195	11,878	11,878	11,878
			Customers Interrupted - Hours Into the Event Day (continued)								
			135	**140**	**145**	**150**	**155**	**160**	**165**	**170**	**175**
			11,214	6,643	1,050	833	813	379	635	820	820
			Customers Interrupted - Hours Into the Event Day (continued)								
			180	**185**	**190**	**195**	**200**	**205**	**210**	**215**	**220**
			820	820	777	777	777	635	2,357	2,563	2,563
			Customers Interrupted - Hours Into the Event Day (continued)								
			225	**230**	**235**	**240**	**245**	**250**	**255**	**260**	**265**
			2,563	2,835	2,149	2,149	2,149	1,166	1,089	890	873
			Customers Interrupted - Hours Into the Event Day (continued)								
			270	**275**	**280**	**285**	**290**	**295**	**300**	**305**	**310**
			849	827	867	948	948	948	795	738	566
			Customers Interrupted - Hours Into the Event Day (continued)								
			315	**320**	**325**	**330**	**335**	**340**	**345**	**350**	**355**
			535	535	432	432	432	432	432	324	312
			Customers Interrupted - Hours Into the Event Day (continued)								
			360	**365**	**370**	**375**	**380**	**385**	**390**	**395**	**400**
			312	312	312	82	68	68	68	51	52

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2003

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day (continued)								
			405	410	415	420	425	430	435	440	445
October 26 - November 25	Firestorm 2003 - Declaration of State of Emergency (continued)	91,443	49	49	49	49	49	49	49	49	49
			Customers Interrupted - Hours Into the Event Day (continued)								
			450	455	460	465	470	475	480	485	490
			49	49	49	49	48	48	48	48	48
			Customers Interrupted - Hours Into the Event Day (continued)								
			495	500	505	510	515	520	525	530	535
			48	48	48	48	48	48	48	48	48
			Customers Interrupted - Hours Into the Event Day (continued)								
			540	545	550	555	560	565	570	575	580
			47	47	47	47	47	47	47	47	47
			Customers Interrupted - Hours Into the Event Day (continued)								
			585	590	595	600	605	610	615	620	625
			48	40	40	40	40	40	40	40	40
			Customers Interrupted - Hours Into the Event Day (continued)								
			630	635	640	645	650	655	660	665	670
			40	40	40	40	40	40	40	9	9
			Customers Interrupted - Hours Into the Event Day (continued)								
			675	680	685	690	695	700	705	710	715
			9	9	9	9	9	9	9	9	9
			Customers Interrupted - Hours Into the Event Day (continued)								
			720	725	730	735	740	745	750	755	760
			9	9	9	9	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2002

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
February 10 - 13	Fallbrook (Gavilan) Fire - Request by CDF	3,732	0	0	0	0	0	0	2,083	3,732	2,592
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	22	24	26	28	30	32	34	36
			2,083	1,008	1,008	1,008	1,008	1,008	1,008	1,008	1,008
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	40	42	44	46	48	50	52	54
			871	871	871	762	762	762	762	762	762
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	58	60	62	64	66	68	70	72
			762	762	762	762	762	728	728	728	728
			Customers Interrupted - Hours Into the Event Day (continued)								
			74	76	78	80	82	84	86	88	90
			19	19	19	19	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2002

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**
July 29 - August 12	Pines Wildland Fire - State of Emergency	3,498	0	0	0	0	0	0	0	3	3
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	**22**	**24**	**26**	**28**	**30**	**32**	**34**	**36**
			338	338	338	338	338	338	338	338	866
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	**40**	**42**	**44**	**46**	**48**	**50**	**52**	**54**
			794	794	338	338	338	338	338	338	338
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	**58**	**60**	**62**	**64**	**66**	**68**	**70**	**72**
			338	338	338	338	338	338	338	338	338
			Customers Interrupted - Hours Into the Event Day (continued)								
			74	**76**	**78**	**80**	**82**	**84**	**86**	**88**	**90**
			338	338	338	338	338	338	338	338	3
			Customers Interrupted - Hours Into the Event Day (continued)								
			92	**94**	**96**	**98**	**100**	**102**	**104**	**106**	**108**
			3	3	3	3	3	3	3	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2002

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			110	112	114	116	118	120	122	124	126
July 29 - August 12	Pines Wildland Fire - State of Emergency	3,498	0	0	0	0	0	0	10	10	10
			Customers Interrupted - Hours Into the Event Day (continued)								
			128	130	132	134	136	138	140	142	144
			10	10	10	10	10	10	10	10	10
			Customers Interrupted - Hours Into the Event Day (continued)								
			146	148	150	152	154	156	158	160	162
			10	10	10	10	10	10	10	10	10
			Customers Interrupted - Hours Into the Event Day (continued)								
			164	166	168	170	172	174	176	178	180
			10	10	10	258	258	258	258	258	258
			Customers Interrupted - Hours Into the Event Day (continued)								
			182	184	186	188	190	192	194	196	198
			258	258	258	258	258	258	258	258	258
			Customers Interrupted - Hours Into the Event Day (continued)								
			200	202	204	206	208	210	212	214	216
			258	258	258	258	258	258	258	258	258
			Customers Interrupted - Hours Into the Event Day (continued)								
			218	220	222	224	226	228	230	232	234
			258	258	258	258	224	224	224	224	224

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2002

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day (continued)								
			236	238	240	242	244	246	248	250	252
July 29 - August 12	Pines Wildland Fire - State of Emergency	3,498	224	224	224	224	217	122	122	122	122
			Customers Interrupted - Hours Into the Event Day (continued)								
			254	256	258	260	262	264	266	268	270
			122	122	122	122	122	122	122	122	122
			Customers Interrupted - Hours Into the Event Day (continued)								
			272	274	276	278	280	282	284	286	288
			122	12	12	12	12	12	12	12	12
			Customers Interrupted - Hours Into the Event Day (continued)								
			290	292	294	296	298	300	302	304	306
			0	0	0	0	0	0	0	0	0
			308	310	312	314	316	318	320	322	324
			0	0	0	0	0	0	0	0	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			326	328	330	332	334	336	338	340	342
			0	0	0	0	0	0	0	0	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			344	346	348	350	352	354	356	358	360
			0	0	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2011

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	Eastern	444	15
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E’s Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2010

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	Northeast	221	290
November	Northeast/Eastern	221/444	289/15
December	Eastern	444	15

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2009

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2008

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2007

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2006

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2005

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2004

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E’s Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2003

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	Northeast	212	62
February	Northeast	212	60
March	Northeast	212	60
April	Northeast	212	60
May	Northeast	212	60
June	Northeast	212	60
July	Northeast	212	60
August	Northeast	212	62
September	Northeast	212	62
October	Northeast	212	60
November	Northeast	212	60
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2002

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

Megan Caulson
SDG&E Regulatory Tariffs Manager
8330 Century Park Court
San Diego, CA 92123-1548
Tel: 858-654-1748
Fax: 858-654-1788
Mcaulson@SempraUtilities.com

February 28, 2013

Paul Clanon
Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: San Diego Gas & Electric Company (SDG&E) Electric System Reliability Annual Report for 2012

Dear Mr. Clanon,

Pursuant to Ordering Paragraph 1 of D.96-09-045, SDG&E hereby submits its Electric System Reliability Report for the calendar year ended December 31, 2012.

As detailed in SDG&E Advice Letter 2256-E (approved June 9, 2011), this report provides SDG&E's Historical System Reliability Data based on IEEE 1366 exclusion criteria, in addition to the Historical System Reliability Data based on D.96-09-045 exclusion criteria.

If there are any questions concerning the enclosed information, please contact Megan Caulson at (858) 654-1748.

Sincerely,

____

Megan Caulson
Regulatory Tariff Manager

Encl.

cc: Edward Randolph, Energy Division
David Lee, Energy Division
Mike Olson, SDG&E

ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2012

Prepared for

California Public Utilities Commission

February 14, 2012

EXECUTIVE SUMMARY

This Electric System Reliability Annual Report for 2012 has been prepared in response to CPUC Decision 96-09-045. This Decision established additional reliability recording, calculation, and reporting requirements for SDG&E.

The data in this report is presented in tabular form. All statistics and calculations include forced transmission, substation, and distribution outages, and exclude planned outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are those outages that lasted more than 5 minutes in duration, while momentary outages are those outages that lasted 5 minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.

2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.

3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.

4. SAIDET* (System Average Interruption Duration Index Exceeding Threshold) - minutes of sustained outages per customer per year exceeding a defined annual threshold of 150 minutes.

5. ERT* (Estimated Restoration Time) - sum of the weighted accuracy of each outage divided by the number of customers who experienced an outage. Weighted accuracy is determined by using the time in play and number of customers who received accurate estimates.

The measurement of each reliability performance indicator excludes CPUC major events and events that are the direct result of failures in the ISO-controlled bulk power market, or non-SDG&E owned transmission and distribution facilities. A Major Event is defined in CPUC Decision 96-09-045 as an event that meets at least one of the following criteria:

(a) The event is caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government, or
(b) Any other disaster not in (a) that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event.

* Introduced as new reliability indices in 2008 as a result of SDGE's General Rate Case Application: (A) 06-12-009 and resulting decision (D) 08-07-046

This report also provides SDG&E's Historical System Reliability Data based on IEEE 1366 exclusion criteria (shown on Page 2), in addition to the Historical System Reliability Data based on D. 96-09-045 exclusion criteria (shown on Page 1).

A summary of 2012 performance is as follows:

CRITERIA	SAIDI	SAIFI	MAIFI	SAIDET	ERT
Including CPUC Major Events (2012)	64.63	0.533	0.301	–	–
Excluding CPUC Major Events (2012)	64.38	0.532	0.301	31.80	32%
10-Year Average (2003-2012) Including CPUC Major Events	153.69	0.723	0.496	–	–
10-Year Average (2003-2012) Excluding CPUC Major Events	62.92	0.552	0.477	–	–

The CPUC Major Events that were declared in 2012 are shown in the following table. Restricted access by a governmental agency that precludes or otherwise delays outage restoration times are considered CPUC Major Events and excluded from reliability results.

Month/Day	SAIDI	SAIFI	Sustained Customer Impact	MAIFI	Momentary Customer Impact	Event Cause(s)
January 6 -7	0.02	0.000	402	0.00	526	Restricted Access by Fire Dept.
April 9	0.00	0.000	13	-	16	Fire Dept. Request to De-energize
September 23 -24	0.14	0.000	167	-	-	Fire Dept. Request to De-energize
November 2	0.09	0.001	1,158	-	-	Fire Dept. Request to De-energize

In 2012, approximately 1,354 customers within SDG&E's service territory experienced more than one 5 minute (or longer) outage per month on a rolling annual average basis, after exclusion of CPUC Major Events.

TABLE OF CONTENTS

HISTORICAL SYSTEM RELIABILITY DATA (USING D.96-09-045 EXCLUSION CRITERIA)

	All Forced Interruptions Included			CPUC Major Events Excluded				
Year	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI	No. of Events	Event Cause(s)
2003	298.45	0.860	0.869	76.14	0.717	0.845	2	Firestorm 2003 (1), Wind Storm Affecting >15% of Facilities (1)
2004	93.19	0.672	0.614	78.75	0.615	0.610	5	Fires (3), Interruptions Due to Non-SDG&E Facilities (1), December Storm (1)
2005	61.99	0.637	0.602	58.46	0.567	0.568	10	Fires (4), Interruptions Due to Non-SDG&E Facilities (4), Storms (2)
2006	52.83	0.545	0.494	52.65	0.541	0.494	9	Fires (6), Interruptions Due to Non-SDG&E Facilities (3)
2007	182.17	0.590	0.572	52.00	0.481	0.527	8	State of Emergency Declared (2), Interruptions Due to Non-SDG&E Facilities (2), Load Curtailment (1), Request to De-energize/ Restricted Access (3)
2008	59.17	0.517	0.380	58.92	0.515	0.378	9	Fires (2), Request to De-energize/ Restricted Access (7)
2009	67.06	0.542	0.380	66.01	0.538	0.380	4	Fires (1), Interruptions Due to Non-SDG&E Facilities (1), Request to De-energize/ Restricted Access (2)
2010	89.77	0.863	0.510	67.74	0.543	0.431	12	Storms (2), Interruptions Due to Non-SDG&E Facilities (6), Load Curtailment (1), Request to De-energize/ Restricted Access (3)
2011	567.59	1.472	0.239	54.14	0.473	0.239	5	Requests to De-energize (2), Restricted Access (1), Southwest Electrical Outage (1), Interruptions Due to Non-SDG&E Facilities (1)
2012	64.63	0.533	0.301	64.38	0.532	0.301	4	Restricted Access (1), Requests to De-energize (3)

HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)

	All Forced Interruptions Included			Threshold Major Event Days Excluded *		
Year	**SAIDI**	**SAIFI**	**MAIFI**	**SAIDI**	**SAIFI**	**MAIFI**
2003	298.45	0.860	0.869	81.49	0.698	0.856
2004	93.19	0.672	0.614	78.83	0.619	0.610
2005	61.99	0.637	0.602	61.99	0.637	0.602
2006	52.83	0.545	0.494	52.83	0.545	0.494
2007	182.17	0.590	0.572	54.89	0.477	0.530
2008	59.17	0.517	0.380	59.17	0.517	0.380
2009	67.06	0.542	0.380	49.71	0.466	0.362
2010	89.77	0.863	0.510	63.36	0.520	0.444
2011	567.59	1.472	0.239	53.43	0.471	0.239
2012	64.63	0.533	0.301	64.63	0.533	0.301

* Per IEEE Standard 1366-2003 "2.5 beta method" for determining excludable days, days are excluded from a given year's metric if their SAIDI exceeds 2.5 times the standard deviation of daily SAIDI over the previous five year period.

TEN LARGEST OUTAGE EVENTS IN 2012*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	September 9 - 11	September 9th - Storm	1.64	0.019	No	26,024	1,126	Not Available
2	June 23 - 24	Faulted Underground Cable	1.48	0.003	No	4,430	680	Not Available
3	July 12 -13	Faulted Tee and Circuit Breaker	1.45	0.014	No	20,177	686	Not Available
4	May 28	Faulted Tee	1.27	0.002	No	3,174	626	Not Available
5	May 6 - 7	Faulted Connector	0.79	0.003	No	4,608	501	Not Available
6	February 27 - 28	February 27 - Storm	0.76	0.004	No	5,760	1,000	Not Available
7	April 28	Faulted Switch	0.67	0.002	No	2,643	467	Not Available
8	March 26	Faulted Glass Insulator	0.64	0.003	No	4,288	209	Not Available
9	August 12 - 13	Damaged Overhead Conductor and Underground Cable	0.63	0.003	No	4,535	1,024	Not Available
10	March 17 - 21	March 17 - Storm	0.62	0.004	No	6,006	3,000	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2011*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	September 8 - 9	Pacific Southwest Electrical Outage	513.40	0.999	Yes	1,387,249	981	Not Available
2	June 28 - 29	Faulted Circuit Breaker	1.52	0.004	No	5,147	539	Not Available
3	October 16 - 17	Faulted Underground Cable	0.68	0.002	No	2,422	1,054	Not Available
4	March 15 - 16	Faulted Tee	0.64	0.004	No	5,257	704	Not Available
5	August 4 - 5	Faulted Underground Cable	0.57	0.004	No	5,285	706	Not Available
6	August 28 - 29	Storm	0.51	0.003	No	4,314	1,170	Not Available
7	October 22	Faulted Tee	0.48	0.004	No	5,096	609	Not Available
8	December 23 - 24	Vehicle Contact	0.45	0.001	No	1,210	1,543	Not Available
9	June 29	Faulted Underground Cable	0.44	0.002	No	2,140	453	Not Available
10	November 4	Faulted Cutout	0.43	0.006	No	7,841	77	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2010*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	January 18 - 22	Heavy Rain Storm	12.61	0.085	Yes	117,558	1,752	Not Available
2	December 20 - 23	Heavy Rain Storm	4.93	0.023	Yes	31,376	1,758	Not Available
3	April 1	ISO Ordered Load Curtailment	4.40	0.211	Yes	290,945	43	Not Available
4	September 30 - October 5	Heavy Rain and Lightning Storm	2.88	0.036	No	50,155	1,343	Not Available
5	January 5 - 6	Faulted Tee	1.57	0.004	No	5,111	760	Not Available
6	September 26 - 28	Heat Storm	1.42	0.010	No	13,531	624	Not Available
7	September 30 - October 1	Vehicle Contact	1.34	0.004	No	5,503	1,074	Not Available
8	October 21	Vehicle Contact	1.33	0.002	No	2,753	1,341	Not Available
9	April 4 - 5	Earthquake	1.22	0.003	No	4,512	651	Not Available
10	October 19 - 20	Heavy Rain and Lightning Storm	1.12	0.014	No	18,873	718	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2009*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	December 7 - 10	December Storm**	11.68	0.045	No	61,783	3,624	Not Available
2	December 13 - 14	Overhead Equipment Failure	4.49	0.016	No	21,956	1,099	Not Available
3	August 20 - 21	Vehicle Contact	1.05	0.004	Yes	5,031	970	Not Available
4	June 3 - 4	Lightning Storm	0.97	0.006	No	7,909	1,204	Not Available
5	February 9 - 10	Heavy Rain and Snow Storm	0.86	0.009	No	12,304	1,686	Not Available
6	December 7 -8	Underground Equipment Failure**	0.60	0.003	No	3,889	1,082	Not Available
7	November 18 - 19	Faulted Cable	0.53	0.003	No	4,322	950	Not Available
8	November 28 - 29	Heavy Rain Storm	0.50	0.006	No	8,779	756	Not Available
9	November 23 - 24	Underground Equipment Failure	0.48	0.003	No	4,045	544	Not Available
10	November 9 -10	Heavy Equipment Dig-In	0.47	0.005	No	7,458	1,167	Not Available

* Based on SAIDI impact.

** The information for both the Dec. 7-10 and Dec. 7-8 events have been updated since the filing of the 2009 annual report. The above figures represent the corrected values. An underground equipment failure was inadvertently associated with the December storm event. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts when excluding CPUC events.

TEN LARGEST OUTAGE EVENTS IN 2008*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	December 17 - 22	Heavy Rain and Snow Storm throughout Service Territory, Part II	3.51	0.010	No	13,113	6,783	Not Available
2	January 5 - 8	Rain & Lightning Storm throughout Service Territory	1.33	0.011	No	15,438	1,731	Not Available
3	December 15	Heavy Rain and Snow Storm throughout Service Territory, Part I	1.02	0.006	No	8,421	421	Not Available
4	May 31	C138 & HC3 Tree Contact (also affecting C139 & 4kVs)	0.92	0.003	No	3,735	746	Not Available
5	October 19	C213 - Damaged Underground Cable	0.91	0.001	No	2,035	942	Not Available
6	June 22 - 23	C990 - Faulted Terminator	0.67	0.002	No	2,198	870	Not Available
7	April 8 - 9	C486 - Motor Vehicle Contact, Terminator and Cable Replaced	0.61	0.003	No	4,708	910	Not Available
8	December 25 - 26	C286 & EN2 - Multiple Circuits affected during Restoration	0.58	0.004	No	5,364	601	Not Available
9	May 23	C159 - Pothead Failure	0.56	0.002	No	3,178	298	Not Available
10	September 24	Bank 20 Bad Relay affecting circuits WA3, WA4, WA5 and WA6	0.56	0.004	No	6,128	178	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2007*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	October 21 - November 24	Firestorm 2007 - Declaration of State of Emergency	128.42	0.055	Yes	74,088	40,453	Not Available
2	September 1 - 4	HEATWAVE 2007 (Labor Day Weekend)	1.59	0.010	No	13,662	833	Not Available
3	October 22	ISO Request - Load Curtailment during Firestorm 2007	1.18	0.051	Yes	68,826	34	Not Available
4	June 04	Laguna Niguel Outages - Faulted CB impacted Bus	1.15	0.016	No	21,425	254	Not Available
5	August 30	TL 629 & TL 6946 Lightning Contact on Swi 629-8	1.09	0.003	No	4,117	359	Not Available
6	July 28	Circuit 582 Underground Cable Failure	1.01	0.002	No	2,761	606	Not Available
7	October 11	Paradise Substation Bank 42 Lightning Arrestor Failure	0.80	0.017	No	23,121	85	Not Available
8	September 15 - 17	Circuit 221 Pine Valley Fire	0.77	0.000	No	585	2,942	Not Available
9	January 12 - 13	Circuits WA3, WA4, and UP1 - Downed Overhead Conductor	0.66	0.003	No	4,052	347	Not Available
10	December 25 - 26	Circuit EOS2 - Connector Failure	0.57	0.001	No	1,349	614	Not Available

*Based on SAIDI impact.
**The information for the largest event was inadvertently under reported in the 2007 annual report and has since been corrected above. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts when excluding CPUC events.

TEN LARGEST OUTAGE EVENTS IN 2006*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	July 22 - 23**	Heat Storm	2.89	0.020	No	26,477	1,280	Not Available
2	March 10 - 14	Storm / Winds	1.98	0.003	No	4,501	4,160	Not Available
3	July 21	TL 685 - Misoperation of a Relay (7 Substations)	1.84	0.033	No	45,007	55	Not Available
4	July 15 - 17	Lighting/ Heat Storm	1.03	0.009	No	12,048	869	Not Available
5	January 2 - 3	Storm / Winds	0.68	0.011	No	15,329	811	Not Available
6	June 15	Circuits 416 and 76 Private Motor Vehicle Contact	0.60	0.002	No	3,124	644	Not Available
7	September 6 - 7	Circuits 509 and 506 Private Motor Vehicle Contact	0.53	0.002	No	2,908	946	Not Available
8	May 23	Circuit 592 Damaged Connector Failure	0.49	0.002	No	3,246	397	Not Available
9	May 26	Circuit 1077 Private Motor Vehicle Contact	0.42	0.002	No	2,158	636	Not Available
10	July 31 - August 1	Circuit WY1 - Vegetation Contact	0.42	0.001	No	1,070	1,058	Not Available

* Based on SAIDI impact.
** Includes outages initiated on July 23rd and restored on July 24th.

TEN LARGEST OUTAGE EVENTS IN 2005*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	September 19	September Storm	2.78	0.015	No	19,399	1,447	Not Available
2	July 28	Laguna Niguel Transmission Event	1.57	0.028	No	37,267	72	Not Available
3	August 25	Poway, Escondido, Cannon Sub - Load Curtailment	1.36	0.039	Yes	51,411	51	Not Available
4	February 18	February Storms	1.35	0.024	Yes	31,885	2,495	Not Available
5	July 23	Lightning Storm July	1.20	0.013	No	17,309	1,450	Not Available
6	October 6	Damaged OH Switch	0.89	0.004	No	5,226	468	Not Available
7	April 22	Poway Sub	0.89	0.008	No	10,896	108	Not Available
8	February 22	Vehicle Contact	0.82	0.003	No	4,143	310	Not Available
9	February 2	Feb 2nd storm	0.77	0.005	No	6,361	904	Not Available
10	January 3	January Storms	0.75	0.005	Yes	7,156	2,146	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2004*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	Dec. 28 - 31	December 2004 Storm	14.41	0.056	Yes	74,000	2,074	Not Available
2	Dec. 1	Substation - Equipment Failure	2.88	0.017	No	22,716	393	Not Available
3	Jun. 12	Substation - Animal Contact	2.16	0.011	No	14,708	204	Not Available
4	Jan. 23 - 24	Conductor Failure	1.88	0.003	No	3,951	625	Not Available
5	Sep. 30 - Oct. 1	Private Vehicle Contact	1.51	0.003	No	4,322	459	Not Available
6	Oct. 17 - 21	Storm / Winds	1.24	0.013	No	16,833	1,026	Not Available
7	Dec. 5	Private Vehicle Contact	1.14	0.005	No	6,292	276	Not Available
8	Dec. 5	Connector Failure	1.10	0.004	No	5,824	502	Not Available
9	Nov. 10	Transmission Equipment Failure	0.82	0.004	No	5,095	414	Not Available
10	Dec. 5 - 6	Storm / Winds	0.78	0.001	No	1,265	808	Not Available

*Based on SAIDI impact.

TEN LARGEST OUTAGE EVENTS IN 2003*

Rank	Date	Description	SAIDI Impact	SAIFI Impact	CPUC Major Event?	Total Number of Customers Affected	Longest Customer Interruption (minutes)	Number of People Used to Restore Service
1	Oct. 26 - Nov. 25	Firestorm 2003	193.33	0.071	Yes	91,443	43,032	Not Available
2	Jan. 6 - 8	Storm / Winds	28.98	0.072	Yes	92,715	2,548	Not Available
3	Oct. 27 - 28	Substation - Animal Contact	3.10	0.017	No	22,285	227	Not Available
4	Dec. 25 - 26	Storm / Winds	3.00	0.017	No	21,611	1,303	Not Available
5	May 14 - 15	Transmission Line - Heavy Equipment Contact (Crane)	1.47	0.002	No	2,900	1,832	Not Available
6	Mar. 28 - 30	Storm / Winds	1.25	0.003	No	3,767	1,440	Not Available
7	Sep. 2 - 3	Storm / Winds	1.06	0.014	No	18,025	678	Not Available
8	Oct. 5 - 6	Underground Cable Failure	0.97	0.004	No	5,255	841	Not Available
9	Jan. 12	Substation - Animal Contact	0.97	0.014	No	17,990	73	Not Available
10	Sep. 19 - 20	Underground Cable Failure	0.88	0.004	No	5,334	1,010	Not Available

*Based on SAIDI impact.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2012

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

There were no CPUC Major Events from 2012 to be extracted.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2011

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	2	4	6	8	10	12	14	16
September 8 - 9	Pacific Southwest Electrical Outage	1,387,249	0	0	0	0	0	0	0	0	1,387,249
			Customers Interrupted - Hours Into the Event Day (continued)								
			18	20	22	24	26	28	30	32	34
			1,387,249	1,373,940	1,204,968	842,831	201,230	2,310	761	765	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2010

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	2	4	6	8	10	12	14	16
January 18 - 22	Heavy Rain Storm	117,558	0	0	0	0	0	0	4,482	12,271	4,618
			Customers Interrupted - Hours Into the Event Day (continued)								
			18	20	22	24	26	28	30	32	34
			4,974	884	568	491	492	489	483	565	110
			Customers Interrupted - Hours Into the Event Day (continued)								
			36	38	40	42	44	46	48	50	52
			50,447	26,607	10,492	7,046	5,131	4,272	993	797	517
			Customers Interrupted - Hours Into the Event Day (continued)								
			54	56	58	60	62	64	66	68	70
			269	279	115	91	8,380	4,603	2,138	754	753
			Customers Interrupted - Hours Into the Event Day (continued)								
			72	74	76	78	80	82	84	86	88
			385	385	18,984	15,114	6,600	30,186	10,106	13,140	3,475
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	92	94	96	98	100	102	104	106
			2,352	2,806	4,638	448	102	17,158	18,330	5,084	420
			Customers Interrupted - Hours Into the Event Day (continued)								
			108	110	112	114	116	118	120	122	124
			490	465	3,093	271	155	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2010

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	2	4	6	8	10	12	14	16
April 1	ISO ordered mandatory load curtailment	290,945	290,945	0	0	0	0	0	0	0	0

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2010
EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**
December 20 - 23	Heavy Rain Storm	31,376	0	110	5,326	12,271	7,252	4,618	2,769	4,974	2,983
			Customers Interrupted - Hours Into the Event Day (continued)								
			45	**50**	**55**	**60**	**65**	**70**	**75**	**80**	**85**
			884	884	568	593	491	517	492	492	489
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	**95**	**100**	**105**	**110**	**115**	**120**	**125**	**130**
			489	483	474	565	583	110	24,456	50,447	38,085
			Customers Interrupted - Hours Into the Event Day (continued)								
			135	**140**	**145**	**150**	**155**	**160**	**165**	**170**	**175**
			26,607	15,698	10,492	9,863	7,046	6,168	5,131	4,325	4,272
			Customers Interrupted - Hours Into the Event Day (continued)								
			180	**185**	**190**	**195**	**200**	**205**	**210**	**215**	**220**
			3,146	993	967	797	793	517	780	269	269
			Customers Interrupted - Hours Into the Event Day (continued)								
			225	**230**	**235**	**240**	**245**	**250**	**255**	**260**	**265**
			279	276	115	116	91	5,061	8,380	7,127	4,603
			Customers Interrupted - Hours Into the Event Day (continued)								
			270	**275**	**280**	**285**	**290**	**295**	**300**	**305**	**310**
			2,380	2,138	772	754	754	753	731	385	385
			Customers Interrupted - Hours Into the Event Day (continued)								
			315	**320**	**325**	**330**	**335**	**340**	**345**	**350**	**355**
			385	7,378	18,984	16,315	15,114	7,157	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2009

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
August 20 - 21	Vehicle Contact	5,031	0	0	0	0	0	0	0	0	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	22	24	26	28	30	32	34	36
			0	5,031	2,958	1,102	1,102	1,102	1,102	1,102	1,102
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	40	42	44	46	48	50	52	54
			1,102	0	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2008

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

There were no CPUC Major Events from 2008 to be extracted.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2007

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**
October 21 - November 24	Firestorm 2007 - Declaration of State of Emergency	74,088	0	0	994	5,847	1,439	4,016	26,645	25,770	23,560
			Customers Interrupted - Hours Into the Event Day (continued)								
			45	**50**	**55**	**60**	**65**	**70**	**75**	**80**	**85**
			21,810	21,651	16,940	21,349	17,522	18,435	17,213	17,263	20,582
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	**95**	**100**	**105**	**110**	**115**	**120**	**125**	**130**
			18,341	17,699	17,699	17,927	17,503	14,693	14,012	13,117	13,064
			Customers Interrupted - Hours Into the Event Day (continued)								
			135	**140**	**145**	**150**	**155**	**160**	**165**	**170**	**175**
			11,787	10,935	9,682	8,676	8,640	7,881	6,755	6,503	7,801
			Customers Interrupted - Hours Into the Event Day (continued)								
			180	**185**	**190**	**195**	**200**	**205**	**210**	**215**	**220**
			6,582	5,670	4,791	4,786	5,154	4,700	4,702	4,104	4,104
			Customers Interrupted - Hours Into the Event Day (continued)								
			225	**230**	**235**	**240**	**245**	**250**	**255**	**260**	**265**
			4,111	4,105	3,010	2,862	2,862	2,862	3,455	3,568	2,911
			Customers Interrupted - Hours Into the Event Day (continued)								
			270	**275**	**280**	**285**	**290**	**295**	**300**	**305**	**310**
			2,725	2,986	3,008	2,303	2,303	2,358	2,277	3,211	1,946
			Customers Interrupted - Hours Into the Event Day (continued)								
			315	**320**	**325**	**330**	**335**	**340**	**345**	**350**	**355**
			1,882	1,882	2,141	2,107	1,825	1,825	1,825	2,296	1,734
			Customers Interrupted - Hours Into the Event Day (continued)								
			360	**365**	**370**	**375**	**380**	**385**	**390**	**395**	**400**
			1,540	1,540	2,657	1,472	1,506	1,211	2,292	1,255	1,985

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

**The total customer impact as well as customers out of service for hours 35, 45, and 50 were inadvertently incorrectly reported and have since been corrected. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts for Non-CPUC events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2007

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day (continued)								
			405	410	415	420	425	430	435	440	445
October 21 - November 24	Firestorm 2007 - Declaration of State of Emergency (Continued)	74,088	1,036	987	987	994	861	721	721	811	692
			Customers Interrupted - Hours Into the Event Day (continued)								
			450	455	460	465	470	475	480	485	490
			883	410	410	456	504	225	225	225	216
			Customers Interrupted - Hours Into the Event Day (continued)								
			495	500	505	510	515	520	525	530	535
			49	9	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			540	545	550	555	560	565	570	575	580
			31	31	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			585	590	595	600	605	610	615	620	625
			6	6	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			630	635	640	645	650	655	660	665	670
			6	6	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			675	680	685	690	695	700	705	710	715
			6	6	6	6	6	6	6	6	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			720	730	740	750	760	770	780	790	800
			0	0	0	0	0	0	0	0	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			810	815	820	825	830	835	840	845	850
			0	30	30	60	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

**The total customer impact as well as customers out of service for hours 35, 45, and 50 were inadvertently incorrectly reported and have since been corrected. This had no impact on the filed SAIDI, SAIFI, and MAIFI impacts for Non-CPUC events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2007

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
October 22	ISO Request - Load Curtailment during Firestorm 2007	68,826	0	0	0	0	0	0	0	68,826	0
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	22	24	26	28	30	32	34	36
			0	0	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2006

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

There were no CPUC Major Events from 2006 to be extracted.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2005

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
January 3 - January 13	January Storms - Declaration of State of Emergency	7,156	0	0	0	0	0	25	68	43	123
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	38	40	42	44	110	112	114	116
			25	194	183	176	25	1,075	1,762	110	55
			Customers Interrupted - Hours Into the Event Day (continued)								
			118	120	130	132	134	136	166	168	170
			0	55	55	55	55	12	55	70	70
			Customers Interrupted - Hours Into the Event Day (continued)								
			172	174	176	178	180	182	184	186	194
			0	110	820	0	0	0	0	55	25
			Customers Interrupted - Hours Into the Event Day (continued)								
			196	198	200	202	204	206	208	210	212
			1179	577	258	215	98	135	135	135	110
			Customers Interrupted - Hours Into the Event Day (continued)								
			214	216	218	220	222	224	226	228	230
			122	110	110	110	110	110	110	110	110
			Customers Interrupted - Hours Into the Event Day (continued)								
			232	234	236	238	240	242	244	246	250
			110	110	110	110	110	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.
**The customers interrupted were inadvertently reported in the incorrect time slot in 2005. This table has been corrected in 2007; the adjustment had no affect on the reported SAIDI and SAIFI impacts for these events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2005

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	**4**	**6**	**8**	**10**	**22**	**32**	**34**	**36**
February 18 - February 25	February Storms - Declaration of State of Emergency	31,885	0	0	155	52	226	25	36	1,506	608
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	**40**	**42**	**44**	**46**	**48**	**50**	**52**	**54**
			204	188	1,008	31	31	31	19	19	129
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	**58**	**60**	**62**	**64**	**66**	**68**	**70**	**72**
			129	129	19	226	19	19	19	19	19
			Customers Interrupted - Hours Into the Event Day (continued)								
			74	**76**	**78**	**80**	**82**	**84**	**86**	**88**	**90**
			19	19	19	19	19	110	199	72	41
			Customers Interrupted - Hours Into the Event Day (continued)								
			92	**94**	**96**	**104**	**108**	**110**	**112**	**114**	**124**
			8	63	1	25	8	8	62	62	5067
			Customers Interrupted - Hours Into the Event Day (continued)								
			126	**128**	**130**	**132**	**134**	**160**	**162**	**164**	**166**
			191	690	577	19	1	84	358	860	540
			Customers Interrupted - Hours Into the Event Day (continued)								
			168	**170**	**172**	**174**	**176**	**178**	**180**	**182**	**184**
			460	234	87	31	31	7	7	7	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.
**The customers interrupted were inadvertently reported in the incorrect time slot in 2005. This table has been corrected in 2007; the adjustment had no affect on the reported SAIDI and SAIFI impacts for these events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2005

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS**

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
August 25	ISO ordered mandatory load curtailment	51,411	0	0	0	0	0	0	0	51,411	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

**The customers interrupted were inadvertently reported in the incorrect time slot in 2005. This table has been corrected in 2007; the adjustment had no affect on the reported SAIDI and SAIFI impacts for these events.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2004

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
December 28 - 31	December Storm - Declaration of State of Emergency	74,000	0	0	0	31	3,725	5	30	1,381	48,480
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	**22**	**24**	**26**	**28**	**30**	**32**	**34**	**36**
			36,187	26,037	18,190	11,941	7,393	5,017	3,093	1,372	709
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	**40**	**42**	**44**	**46**	**48**	**50**	**52**	**54**
			411	159	91	36	36	50	34	7	6
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	**58**	**60**	**62**	**64**	**66**	**68**	**70**	**72**
			6	110	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2003

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			2	4	6	8	10	12	14	16	18
January 6 - 8	January Storm - >15% of System Facilities Affected	92,715	0	165	2,374	3,500	5,231	4,985	2,916	4,272	33
			Customers Interrupted - Hours Into the Event Day (continued)								
			20	**22**	**24**	**26**	**28**	**30**	**32**	**34**	**36**
			2,908	2,875	299	8,799	42,386	62,337	44,408	34,801	29,472
			Customers Interrupted - Hours Into the Event Day (continued)								
			38	**40**	**42**	**44**	**46**	**48**	**50**	**52**	**54**
			23,942	18,661	7,533	4,709	3,687	3,391	2,489	1,563	1,077
			Customers Interrupted - Hours Into the Event Day (continued)								
			56	**58**	**60**	**62**	**64**	**66**	**68**	**70**	**72**
			1,021	648	581	92	94	69	69	37	37
			Customers Interrupted - Hours Into the Event Day (continued)								
			74	**76**	**78**	**80**	**82**	**84**	**86**	**88**	**90**
			25	25	0	0	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2003

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day*								
			0	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**
October 26 - November 25	Firestorm 2003 - Declaration of State of Emergency	91,443	0	697	12,087	25,599	33,856	33,575	35,317	43,272	44,623
			Customers Interrupted - Hours Into the Event Day (continued)								
			45	**50**	**55**	**60**	**65**	**70**	**75**	**80**	**85**
			43,523	38,774	28,412	26,932	24,552	24,157	21,108	20,628	17,709
			Customers Interrupted - Hours Into the Event Day (continued)								
			90	**95**	**100**	**105**	**110**	**115**	**120**	**125**	**130**
			16,330	17,074	17,074	16,013	14,356	12,195	11,878	11,878	11,878
			Customers Interrupted - Hours Into the Event Day (continued)								
			135	**140**	**145**	**150**	**155**	**160**	**165**	**170**	**175**
			11,214	6,643	1,050	833	813	379	635	820	820
			Customers Interrupted - Hours Into the Event Day (continued)								
			180	**185**	**190**	**195**	**200**	**205**	**210**	**215**	**220**
			820	820	777	777	777	635	2,357	2,563	2,563
			Customers Interrupted - Hours Into the Event Day (continued)								
			225	**230**	**235**	**240**	**245**	**250**	**255**	**260**	**265**
			2,563	2,835	2,149	2,149	2,149	1,166	1,089	890	873
			Customers Interrupted - Hours Into the Event Day (continued)								
			270	**275**	**280**	**285**	**290**	**295**	**300**	**305**	**310**
			849	827	867	948	948	948	795	738	566
			Customers Interrupted - Hours Into the Event Day (continued)								
			315	**320**	**325**	**330**	**335**	**340**	**345**	**350**	**355**
			535	535	432	432	432	432	432	324	312
			Customers Interrupted - Hours Into the Event Day (continued)								
			360	**365**	**370**	**375**	**380**	**385**	**390**	**395**	**400**
			312	312	312	82	68	68	68	51	52

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

EXCLUDABLE CPUC MAJOR EVENT DETAILS FOR 2003

EXTRACTED FROM THE TEN LARGEST OUTAGE EVENTS

Date of Outage	Description of Outage	Total Number of Customers Out of Service	Customers Interrupted - Hours Into the Event Day (continued)								
			405	**410**	**415**	**420**	**425**	**430**	**435**	**440**	**445**
October 26 - November 25	Firestorm 2003 - Declaration of State of Emergency (continued)	91,443	49	49	49	49	49	49	49	49	49
			Customers Interrupted - Hours Into the Event Day (continued)								
			450	**455**	**460**	**465**	**470**	**475**	**480**	**485**	**490**
			49	49	49	49	48	48	48	48	48
			Customers Interrupted - Hours Into the Event Day (continued)								
			495	**500**	**505**	**510**	**515**	**520**	**525**	**530**	**535**
			48	48	48	48	48	48	48	48	48
			Customers Interrupted - Hours Into the Event Day (continued)								
			540	**545**	**550**	**555**	**560**	**565**	**570**	**575**	**580**
			47	47	47	47	47	47	47	47	47
			Customers Interrupted - Hours Into the Event Day (continued)								
			585	**590**	**595**	**600**	**605**	**610**	**615**	**620**	**625**
			48	40	40	40	40	40	40	40	40
			Customers Interrupted - Hours Into the Event Day (continued)								
			630	**635**	**640**	**645**	**650**	**655**	**660**	**665**	**670**
			40	40	40	40	40	40	40	9	9
			Customers Interrupted - Hours Into the Event Day (continued)								
			675	**680**	**685**	**690**	**695**	**700**	**705**	**710**	**715**
			9	9	9	9	9	9	9	9	9
			Customers Interrupted - Hours Into the Event Day (continued)								
			720	**725**	**730**	**735**	**740**	**745**	**750**	**755**	**760**
			9	9	9	9	0	0	0	0	0

*Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2012

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	Eastern	444/445	4/358
June	Eastern	444/445	4/363
July	Eastern	444/445	4/362
August	Eastern	444/445/1215	62/898/86
September	Eastern	444/445/1215	62/985/86
October	Eastern	444/445/1215	24/985/86
November	Eastern	444/445/1215	163/980/86
December	Eastern	79/444/445/1215	120/163/980/86

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2011

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	Eastern	444	15
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2010

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	Northeast	221	290
November	Northeast/Eastern	221/444	289/15
December	Eastern	444	15

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2009

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E’s Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2008

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2007

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2006

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2005

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2004

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	N/A	N/A	None
February	N/A	N/A	None
March	N/A	N/A	None
April	N/A	N/A	None
May	N/A	N/A	None
June	N/A	N/A	None
July	N/A	N/A	None
August	N/A	N/A	None
September	N/A	N/A	None
October	N/A	N/A	None
November	N/A	N/A	None
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E’s Outage Management System.

CUSTOMERS EXPERIENCING MORE THAN 12 SUSTAINED OUTAGES IN A ROLLING 12-MONTH PERIOD (EXCLUDING CPUC MAJOR EVENTS) FOR 2003

Month	District	Circuit	Number of Customers Experiencing >12 Sustained Outages
January	Northeast	212	62
February	Northeast	212	60
March	Northeast	212	60
April	Northeast	212	60
May	Northeast	212	60
June	Northeast	212	60
July	Northeast	212	60
August	Northeast	212	62
September	Northeast	212	62
October	Northeast	212	60
November	Northeast	212	60
December	N/A	N/A	None

Data is based upon station outages as reported through SDG&E's Outage Management System.

SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

Robert G. Woods
Director
Electric Systems Planning
(909) 274-1276

March 1, 2012

Mr. Paul Clanon, Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

Subject: Reporting Standards, System SAIDI, SAIFI, and MAIFI Report
Decision 96-09-045

Dear Mr. Clanon:

Pursuant to Appendix A of D.96-09-045 as modified by Advice Letter 2673-E, attached is Southern California Edison's 2011 Annual System Reliability Report.

Attachment 1A provides values of SAIDI, SAIFI, and MAIFI for each of the past ten years calculated using the guidance of IEEE Standard 1366-2003, "*IEEE Guide for Electric Power Distribution Reliability Indices.*" Following the guidance of this standard, six days in 2011 were deemed excludable as major event days.

Attachment 1B provides reliability metrics for this same time period calculated per the original directions of CPUC D.96-09-045. Following the guidance of Appendix A of D.96-09-045, one day in 2011 was deemed excludable as a major event day.

Attachment 1C provides details of all excluded days, whether excluded under IEEE 1366 or D.96-09-045.

Attachments 2 – 5 provide additional information on significant outages as required by D.96-09-045.

Of particular note, was the windstorm in Los Angeles County occurring on November 30 and December 1, 2011 which resulted in daily levels of SAIDI significantly greater than any seen in the past ten years.

If you have any questions regarding this submittal, please contact me or Roger Lee at 714-973-5545.

Best regards,

Robert G. Woods
Director, Electric System Planning

Attachments

CC: Edward Randolph, Energy Division Director
Michelle Cooke, Consumer Protection & Safety Division Director
Liza Malashenko, Energy Division
David K. Lee, Energy Division

Southern California Edison
Annual System Reliability Report - 2011
Table of Contents

Southern California Edison
Historical System Reliability (IEEE Std 1366-2003)
2002 - 2005 Using DTOM Outage Database
2006 - 2011 Using ODRM Outage Database

	All Interruptions Included			Major Event Days Excluded Per IEEE 1366		
YEAR	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI
2002	52.29	1.27	1.15	44.95	1.05	1.09
2003	89.26	1.39	1.43	53.37	1.11	1.15
2004	74.93	1.34	1.21	55.30	1.15	1.05
2005	92.26	1.53	1.47	72.57	1.33	1.23
2006	142.14	1.05	1.85	96.59	0.89	1.52
2007	151.32	1.10	1.74	85.34	0.88	1.37
2008	118.91	1.06	1.73	99.35	0.95	1.56
2009	105.80	0.90	1.45	88.77	0.83	1.31
2010	140.91	1.05	1.69	98.69	0.82	1.41
2011	232.39	1.04	1.53	108.15	0.91	1.36

All calculations utilize a definition of "sustained" interruption as described in IEEE Std 1366, 2003 Edition, which is an interruption lasting longer than 5 minutes.

In years 2006 - 2011, values of SAIDI, SAIFI, and MAIFI were calculated per the guidance of IEEE 1366 with the exception of using five years of historical data in applying the "2.5 beta method" to determine excludable days. Per IEEE 1366, days are excluded from a given year's metric if their SAIDI exceeds 2.5 times the standard deviation of the natural logarithm of daily SAIDI over the previous five year period. However, complete ODRM data did not exist prior to 2006. Therefore, excludable days for years 2006 and 2007 were both determined based on daily SAIDI data in year 2006. Excludable days for 2008 were determined based on daily SAIDI data in years 2006 and 2007. Excludable days for 2009 were determined based on daily SAIDI data in years 2006, 2007, and 2008. Excludable days for 2010 were determined based on daily SAIDI data in years 2006, 2007, 2008, and 2009. This interim approach is consistent with IEEE 1366.

Southern California Edison

Historical System Reliability (CPUC D.96-09-045)

2002 - 2004 Using DTOM

2005 Using DTOM & ODRM

2006 - 2011 Using ODRM

	All Interruptions Included[1]				Major Event Days Excluded Per D.96-09-045[2]		
YEAR	SAIDI[3]	SAIFI	MAIFI		SAIDI[3]	SAIFI	MAIFI
2002	52.75	1.23	1.11		50.44	1.11	1.10
2003 (w/o sub)[5]	87.23	1.39	1.37		63.90	1.19	1.17
2003 (w/ sub)	79.20	1.35	1.37		57.78	1.15	1.18
2004 (w/o sub)	75.21	1.34	1.19		67.11	1.26	1.12
2004 (w/ sub)	68.39	1.30	1.19		62.83	1.24	1.13
2005 (w/o sub)	91.64	1.52	1.44		74.25	1.27	1.21
2005 (w/ sub)	91.45	1.52	1.44		74.16	1.27	1.21
2005 (ODRM)[4]	106.41	1.02	2.00		82.10	0.82	1.67
2006 ODRM	142.27	1.08	1.81		116.34	1.00	1.64
2007 ODRM	151.60	1.15	1.68		141.95	1.11	1.60
2008 ODRM	119.21	1.12	1.67		119.21	1.12	1.67
2009 ODRM	105.98	0.94	1.41		105.98	0.94	1.41
2010 ODRM	141.14	1.09	1.64		141.14	1.09	1.64
2011 ODRM	232.60	1.08	1.49		173.03	1.03	1.43

All calculations utilize a definition of "sustained" interruption as described in D.96-09-045, which is an interruption lasting 5 minutes or longer.

[1] This excludes ISO-directed firm load curtailment, Protective Outage Plan (POP) outages, Remedial Action Scheme (RAS) outages.
[2] Major Event Exclusions are defined in D.96-09-045 under Appendix A Section I - Item 4c.
[3] Metrics for 1999 - 2005 have been adjusted upward to reflect the variance introduced by Southern California Edison's former convention of declaring All Load Up (ALU) when power had been restored up to the last residential transformer. An estimate was added to the annual CMI base to arrive at the normalized SAIDIs. No adjustment was necessary beyond 2005.
[4] ODRM data in 2005 only does not include Area Outages.
[5] "Sub" refers to substitution of historical average metrics in circuits affected by the Bark Beetle Infestation.

No.	YEAR	DATE	CAUSE	Excluded under IEEE 1366	SAIDI	SAIFI	MAIFI	Excluded under D.96-09-045	SAIDI	SAIFI	MAIFI	Source of data
1	2002	6/26/2002	Louisiana Fire	Y	2.15	0.15	0.00	Y	2.15	0.15	0.00	DTOM
2	2002	6/27/2002	Louisiana Fire					Y	0.05	0.00	0.00	DTOM
3	2002	6/28/2002	Louisiana Fire					Y	0.11	0.00	0.00	DTOM
4	2002	11/8/2002	Rain/Wind Storm	Y	2.42	0.04	0.03					DTOM
5	2002	12/16/2002	Rain/Wind Storm	Y	2.78	0.03	0.02					DTOM
	Total			**3**	**7.34**	**0.22**	**0.06**	**3**	**2.31**	**0.15**	**0.01**	

No.	YEAR	DATE	CAUSE	Excluded under IEEE 1366	SAIDI	SAIFI	MAIFI	Excluded under D.96-09-045	SAIDI	SAIFI	MAIFI	Source of data
1	2003	1/5/2003	Santa Ana Wind Storm	Y	2.44	0.01	0.03					DTOM
2	2003	1/6/2003	Santa Ana Wind Storm	Y	14.95	0.09	0.11	Y	14.95	0.09	0.11	DTOM
3	2003	1/7/2003	Santa Ana Wind Storm	Y	1.86	0.02	0.03	Y	1.86	0.02	0.03	DTOM
4	2003	1/8/2003	Santa Ana Wind Storm					Y	0.40	0.01	0.01	DTOM
5	2003	2/25/2003	Rain Storm	Y	2.30	0.02	0.01					DTOM
6	2003	10/24/2003	Southern California Wild Fires					Y	0.16	0.01	0.03	DTOM
7	2003	10/25/2003	Southern California Wild Fires					Y	1.13	0.01	0.01	DTOM
8	2003	10/26/2003	Southern California Wild Fires	Y	5.98	0.06	0.02	Y	5.98	0.06	0.02	DTOM
9	2003	10/28/2003	Southern California Wild Fires	Y	1.87	0.00	0.00					DTOM
10	2003	11/12/2003	Lightning Storm	Y	3.02	0.03	0.03					DTOM
11	2003	12/25/2003	Rain Storm & Mud Slides	Y	3.47	0.04	0.04					DTOM
	Total			**8**	**35.88**	**0.28**	**0.28**	**6**	**24.48**	**0.20**	**0.21**	

No.	YEAR	DATE	CAUSE	Excluded under IEEE 1366	SAIDI	SAIFI	MAIFI	Excluded under D.96-09-045	SAIDI	SAIFI	MAIFI	Source of data
1	2004	8/12/2004	Lightning Storm	Y	1.57	0.00	0.01					DTOM
2	2004	9/11/2004	Moorpark A-Bank Transformer Failure	Y	1.62	0.03	0.01					DTOM
3	2004	10/17/2004	Rain Storm	Y	1.99	0.02	0.03					DTOM
4	2004	10/20/2004	Rain Storm	Y	1.61	0.03	0.02					DTOM
5	2004	10/27/2004	Wind Storm	Y	2.39	0.02	0.02					DTOM
6	2004	11/21/2004	Wind Storm	Y	2.57	0.02	0.02					DTOM
7	2004	12/28/2004	Winter Rain Storm	Y	2.71	0.03	0.05	Y	2.71	0.03	0.05	DTOM
8	2004	12/29/2004	Winter Rain Storm	Y	3.55	0.03	0.01	Y	3.55	0.03	0.01	DTOM
9	2004	12/30/2004	Winter Rain Storm					Y	0.22	0.00	0.00	DTOM
10	2004	12/31/2004	Winter Rain Storm	Y	1.62	0.01	0.00	Y	1.62	0.01	0.00	DTOM
	Total			**9**	**19.63**	**0.19**	**0.16**	**4**	**8.10**	**0.08**	**0.07**	

Major Event Days Detail

No.	YEAR	DATE	CAUSE	Excluded under IEEE 1366	SAIDI	SAIFI	MAIFI	Excluded under D.96-09-045	SAIDI	SAIFI	MAIFI	Source of data
1	2005	1/9/2005	Winter Rain Storm	Y	1.49	0.02	0.01					DTOM
2	2005	1/10/2005	Winter Rain Storm	Y	1.48	0.03	0.01	Y	1.48	0.03	0.01	DTOM
3	2005	1/11/2005	Winter Rain Storm	Y	1.57	0.02	0.01	Y	1.57	0.02	0.01	DTOM
4	2005	1/12/2005	Winter Rain Storm					Y	0.36	0.01	0.00	DTOM
5	2005	2/19/2005	Winter Rain Storm	Y	2.26	0.03	0.02					DTOM
6	2005	7/24/2005	Lightning Storm	Y	1.50	0.01	0.02					DTOM
7	2005	8/6/2005	Wind Storm	Y	1.68	0.01	0.02					DTOM
8	2005	9/3/2005	Brush Fire	Y	2.12	0.01	0.00					DTOM
9	2005	9/20/2005	Lightning Storm	Y	3.89	0.04	0.09	Y	3.89	0.04	0.09	DTOM
10	2005	10/17/2005	Lightning Storm	Y	3.69	0.04	0.04					DTOM
	Total			**9**	**19.69**	**0.21**	**0.24**	**4**	**7.30**	**0.10**	**0.12**	

No.	YEAR	DATE	CAUSE	Excluded under IEEE 1366	SAIDI	SAIFI	MAIFI	Excluded under D.96-09-045	SAIDI	SAIFI	MAIFI	Source of data
1	2006	1/2/2006	Wind storm & Rain storm	Y	10.48	0.05	0.10	Y	10.48	0.05	0.10	ODRM
2	2006	7/15/2006	Heat Storm	Y	2.49	0.02	0.02					ODRM
3	2006	7/20/2006	Heat Storm	Y	2.30	0.01	0.03					ODRM
4	2006	7/22/2006	Heat Storm	Y	15.44	0.04	0.07	Y	15.44	0.04	0.07	ODRM
5	2006	7/23/2006	Heat Storm	Y	4.87	0.01	0.02					ODRM
6	2006	7/24/2006	Heat Storm	Y	2.82	0.01	0.01					ODRM
7	2006	12/27/2006	Wind storm, Others	Y	4.05	0.02	0.04					ODRM
8	2006	12/28/2006	Wind storm, Others	Y	3.09	0.01	0.02					ODRM
	Total			**8**	**45.55**	**0.16**	**0.33**	**2**	**25.92**	**0.08**	**0.18**	

No.	YEAR	DATE	CAUSE	Excluded under IEEE 1366	SAIDI	SAIFI	MAIFI	Excluded under D.96-09-045	SAIDI	SAIFI	MAIFI	Source of data
1	2007	1/5/2007	Wind storm & Rain storm	Y	2.17	0.02	0.04					ODRM
2	2007	3/27/2007	Wind storm & Rain storm	Y	5.71	0.03	0.04					ODRM
3	2007	4/12/2007	Wind storm, Others	Y	2.21	0.02	0.04					ODRM
4	2007	8/31/2007	Lightning storm & Heat storm	Y	3.28	0.02	0.03					ODRM
5	2007	9/1/2007	Lightning storm & Heat storm	Y	3.40	0.01	0.03					ODRM
6	2007	9/2/2007	Lightning storm & Heat storm	Y	6.13	0.02	0.02					ODRM
7	2007	9/3/2007	Lightning storm & Heat storm	Y	10.33	0.03	0.02					ODRM
8	2007	9/4/2007	Lightning storm & Heat storm	Y	2.33	0.01	0.01					ODRM
9	2007	10/21/2007	Wind Storm, Wild Fires & 10% Major Event (higher customers interrupted on momentary with low duration)	Y	9.61	0.04	0.09	Y	9.61	0.04	0.09	ODRM
10	2007	10/22/2007	Wind Storm, Wild Fires, (less customers interrupted with high duration) i.e. Snow Valley 12KV, Taggert 12KV, Oak Knoll were de-energized requested by Fire Dept.	Y	18.31	0.04	0.03					ODRM
11	2007	12/25/2007	Wind storm	Y	2.49	0.01	0.02					ODRM
	Total			**11**	**65.98**	**0.23**	**0.36**	**1**	**9.61**	**0.04**	**0.09**	

Major Event Days Detail

No.	YEAR	DATE	CAUSE	Excluded under IEEE 1366	SAIDI	SAIFI	MAIFI	Excluded under D.96-09-045	SAIDI	SAIFI	MAIFI	Source of data
1	2008	1/4/2008	Rain storm & Wind storm	Y	3.00	0.02	0.03					ODRM
2	2008	1/5/2008	Rain storm & Wind storm	Y	2.10	0.01	0.01					ODRM
3	2008	1/24/2008	Rain storm & Wind storm	Y	3.63	0.01	0.01					ODRM
4	2008	2/3/2008	Rain storm & Wind storm	Y	2.63	0.02	0.06					ODRM
5	2008	7/2/2008	Wild Fires	Y	3.30	0.02	0.02					ODRM
6	2008	12/15/2008	Rain storm & Wind storm	Y	2.18	0.01	0.02					ODRM
7	2008	12/17/2008	Rain storm & Wind storm	Y	2.72	0.01	0.02					ODRM
	Total			**7**	**19.57**	**0.10**	**0.18**	**0**	**0.00**	**0.00**	**0.00**	
1	2009	6/3/2009	Lightning Storm	Y	3.85	0.02	0.05					ODRM
2	2009	8/27/2009	Wild Fires	Y	2.93	0.00	0.01					ODRM
3	2009	8/29/2009	Wild Fires	Y	1.98	0.00	0.00					ODRM
4	2009	8/31/2009	Wild Fires	Y	3.84	0.00	0.00					ODRM
5	2009	10/27/2009	Wind Storm	Y	1.99	0.01	0.03					ODRM
6	2009	12/7/2009	Rain/Wind Storm	Y	2.43	0.02	0.03					ODRM
	Total			**6**	**17.03**	**0.07**	**0.13**	**0**	**0.00**	**0.00**	**0.00**	
1	2010	1/18/2010	Vegetation Blown	Y	3.97	0.02	0.04					ODRM
2	2010	1/21/2010	Vegetation Blown	Y	5.83	0.02	0.03					ODRM
3	2010	1/22/2010	Vegetation Blown	Y	3.52	0.01	0.01					ODRM
4	2010	1/23/2010	Vegetation Blown	Y	1.98	0.01	0.00					ODRM
5	2010	7/15/2010	Lightning & TOPPLED/BROKEN	Y	2.39	0.01	0.03					ODRM
6	2010	9/27/2010	Overloaded	Y	3.38	0.01	0.01					ODRM
7	2010	10/1/2010	Lightning	Y	2.48	0.03	0.02					ODRM
8	2010	10/4/2010	Lightning & Fire	Y	3.15	0.02	0.01					ODRM
9	2010	10/19/2010	Lightning & PROTECTION	Y	3.50	0.04	0.04					ODRM
10	2010	12/19/2010	Vegetation Blown & Overload	Y	2.99	0.01	0.03					ODRM
11	2010	12/22/2010	Vegetation Blown	Y	3.82	0.02	0.02					ODRM
12	2010	12/29/2010	Vegetation Blown & Low Voltage	Y	2.25	0.01	0.02					ODRM
13	2010	12/30/2010	Vegetation Blown & Wind	Y	2.97	0.01	0.02					ODRM
	Total			**13**	**42.22**	**0.23**	**0.28**	**0**	**0.00**	**0.00**	**0.00**	
1	2011	1/1/2011	Unknown	Y	2.40	0.00	0.00					ODRM
2	2011	3/20/2011	Snow & Vegetation Blown	Y	8.85	0.03	0.05					ODRM
3	2011	3/21/2011	Vegetation Blown & Lightning	Y	2.76	0.01	0.01					ODRM
4	2011	7/31/2011	Lightning	Y	2.77	0.01	0.01					ODRM
5	2011	11/30/2011	Vegetation Blown & Wind	Y	47.89	0.02	0.02					ODRM
6	2011	12/1/2011	Wind & Vegetation Blown	Y	59.56	0.05	0.06	Y	59.57	0.05	0.06	ODRM
	Total			**6**	**124.24**	**0.12**	**0.17**	**1**	**59.57**	**0.05**	**0.06**	

Southern California Edison

Historical System Reliability Data

2002 - 2011

Customers experiencing > 12 sustained outages

Year	Circuit	Circuit Name	Number of customers experiencing > 12 sustained outages
2002	1630	BIG ROCK	469
2002	4635	DANBY	57
2002	9060	IVERSON	124
2002	14814	REDSTONE	1,246
2003	2290	BROOKINGS*	1
2003	2370	BUDD	287
2003	2881	CAPANERO	292
2003	3240	CEDAR GLEN*	440
2003	5850	ELSTER	132
2003	8410	HIGH SCHOOL*	341
2003	8670	HOOK CREEK*	550
2003	9320	JORDAN	665
2003	9549	KELLPEAK*	10
2003	11448	MCCLENNY	55
2003	12190	MORITZ*	1,345
2003	12860	NORTH SHORE*	528
2003	14349	POSO PARK	49
2003	14690	RANGER*	730
2003	15922	SAUNDERS*	733
2003	16049	SEALS	93
2003	16839	SQUINT*	777
2003	17190	SUGARLOAF	131
2003	17997	TORONTO*	53
2004	390	ALPINE*	302
2004	1630	BIG ROCK	534
2004	3387	CHAWA	894
2004	5085	DINKEY CREEK	85
2004	6432	FINGAL	189
2004	8670	HOOK CREEK*	297
2004	8930	INTAKE	13
2004	9060	IVERSON	125
2004	9194	JEEP*	1,079
2004	9205	JENKS LAKE*	121
2004	9290	JOHNSONDALE	119
2004	11760	METTLER	340
2004	12136	MONTREAL*	630
2004	12190	MORITZ*	1,447
2004	12840	NORTH BAY*	226

Year	Circuit	Circuit Name	Number of customers experiencing > 12 sustained outages
2004	12860	NORTH SHORE*	245
2004	13959	PERIMETER	1,090
2004	14705	RANIER	7
2004	15090	RIM*	1,328
2004	15275	ROBIN	45
2004	15415	ROSEBUD	734
2004	15986	SCHMIDT	470
2004	17915	TITAN	79
2004	17985	TOPOC	92
2004	17997	TORONTO*	690
2004	19694	ANGELES	1,088
2005	2664	CALCADIA	4
2005	5090	DISCOVERY	32
2005	7490	GRANITE	267
2005	9777	KINSEY	70
2005	10216	LAVA	55
2005	10670	LOMBARDY	94
2005	12722	NIPTON	33
2005	13776	PAT	1,151
2005	15282	ROBINSON CREEK	199
2005	15415	ROSEBUD	581
2005	16308	SHEEPHOLE	3
2005	17731	THACHER	457
2005	19136	WEISS	177
2006	5085	DINKEY CREEK	29
2006	14955	RHINEDOLLAR	64
2007	1832	BLUE CUT	193
2007	12847	NORTHPARK	436
2007	17121	STROH	112
2008	2290	BROOKINGS	1
2008	3240	CEDAR GLEN	605
2008	4221	COVE	10
2008	4360	CRESTLINE	22
2008	4170	FROZEN	3
2008	8268	HEAPS PEAK	4
2008	8670	HOOK CREEK	147
2008	8848	HURST	6
2008	10119	LARK	147

Year	Circuit	Circuit Name	Number of customers experiencing > 12 sustained outages
2008	10216	LAVA	52
2008	12011	MIST	7
2008	14482	PUFF	2
2008	14690	RANGER	343
2008	14955	RHINEDOLLAR	31
2008	17997	TORONTO	47
2008	19036	WASP	46
2009	3240	CEDAR GLEN	19
2009	4136	COSO	45
2009	5492	EARTH	4
2009	8268	HEAPS PEAK	6
2009	14690	RANGER	306
2009	14955	RHINEDOLLAR	31
2009	16395	SHOSHONE	1
2009	17997	TORONTO	23
2010	12960	OAK GLEN	4
2010	13194	OPPORTUNITY	9
2010	14955	RHINEDOLLAR	31
2010	15415	ROSEBUD	41
2010	17061	STONELEY	82
2011	04223	COVEVIEW	184
2011	04367	CRESTWIND	28
2011	04170	FROZEN	3
2011	09185	JAWBONE	2
2011	09275	JOB	35
2011	12190	MORITZ	983
2011	14758	RED BOX	8

* bark beetle circuit

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2011 **Attachment 3**

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Wind & Vegetation Blown	12/1/2011	59.564	569,969	14,806	3,300	Y	Y
2	Vegetation Blown & Wind	11/30/2011	47.890	234,977	10,255	3,300	N	Y
3	Snow & Vegetation Blown	3/20/2011	8.851	385,628	45,068		N	Y
4	Lightning	7/31/2011	2.769	116,749	21,682		N	Y
5	Vegetation Blown & Lightning	3/21/2011	2.763	122,222	4,795		N	Y
6	Unknown	1/1/2011	2.403	22,886	260,236		N	Y
7	Vegetation Blown	2/18/2011	1.737	119,202	5,501		N	N
8	Vegetation Blown & Snow	2/26/2011	1.563	92,686	4,226		N	N
9	Lightning	9/10/2011	1.531	161,304	6,904		N	N
10	Wind & Vegetation Blown	11/2/2011	1.490	90,559	2,752		N	N

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2010 **Attachment 3**

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Vegetation Blown	1/21/2010	5.832				N	Y
2	Vegetation Blown	1/18/2010	3.966				N	Y
3	Vegetation Blown	12/22/2010	3.817				N	Y
4	Vegetation Blown	1/22/2010	3.518				N	Y
5	Lightning & PROTECTION	10/19/2010	3.495				N	Y
6	Overloaded	9/27/2010	3.378				N	Y
7	Lightning & Fire	10/4/2010	3.153				N	Y
8	Vegetation Blown & Overload	12/19/2010	2.992				N	Y
9	Vegetation Blown & Wind	12/30/2010	2.973				N	Y
10	Lightning	10/1/2010	2.483				N	Y

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2009

Attachment 3

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Lightning Storm	6/3/2009	3.848				N	Y
2	Wild Fires	8/31/2009	3.837				N	Y
3	Wild Fires	8/27/2009	2.935				N	Y
4	Rain/Wind Storm	12/7/2009	2.436				N	Y
5	Wind Storm	10/27/2009	1.993				N	Y
6	Wild Fires	8/29/2009	1.983				N	Y
7	Wind Storm	3/22/2009	1.724				N	N
8	Wild Fires	4/3/2009	1.564				N	N
9	Rain Storm	2/9/2009	1.543				N	N
10	Car Hit Pole	12/12/2009	1.222				N	N

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2008 **Attachment 3**

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Rain/Wind Storm	1/24/2008	3.633				N	Y
2	Wild Fires	7/2/2008	3.304				N	Y
3	Rain/Wind Storm	1/4/2008	3.006				N	Y
4	Rain/Wind Storm	12/17/2008	2.723				N	Y
5	Rain/Wind Storm	2/3/2008	2.628				N	Y
6	Rain/Wind Storm	12/15/2008	2.186				N	Y
7	Rain/Wind Storm	1/5/2008	2.103				N	Y
8	Rain/Wind Storm	12/25/2008	1.793				N	N
9	Rain/Wind Storm	1/27/2008	1.555				N	N
10	Rain/Wind Storm	1/25/2008	1.404				N	N

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2007 **Attachment 3**

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Wild Fires	10/22/2007	18.310				N	Y
2	Summer heat storm	9/3/2007	10.336				N	Y
3	Wild Fires	10/21/2007	9.649	628,093	6,632	1,258	Y	Y
4	Summer heat storm	9/2/2007	6.162				N	Y
5	Rain/Wind Storm	3/27/2007	5.711				N	Y
6	Summer heat storm	9/1/2007	3.398				N	Y
7	Summer heat storm	8/31/2007	3.285				N	Y
8	Wind Storm	12/25/2007	2.494				N	Y
9	Summer heat storm	9/4/2007	2.334				N	Y
10	Wind Storm	4/12/2007	2.215				N	Y

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2006 **Attachment 3**

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Summer heat storm	7/22/2006	15.441	527,572	6,748	1,616	Y	Y
2	Winter rain storm	1/2/2006	10.478	720,251	4,532	684	Y	Y
3	Summer heat storm	7/23/2006	4.866	170,590			N	Y
4	Winter rain storm	12/27/2006	4.055	285,211			N	Y
5	Winter rain storm	12/28/2006	3.084	155,839			N	Y
6	Summer heat storm	7/24/2006	2.821	98,614			N	Y
7	Summer heat storm	7/15/2006	2.492	159,258			N	Y
8	Summer heat storm	7/20/2006	2.305	208,040			N	Y
9	Summer heat storm	7/21/2006	2.085	238,707			N	N
10	Winter rain storm	1/22/2006	1.966	157,613			N	N

Southern California Edison

Top 10 SAIDI Events

2002 - 2011

2005

Attachment 3

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Winter Rain Storm	1/01/2005 - 01/11/20(	7.786	954,312	23,269	1,005	Y	Y
2	Winter Rain Storm	2/16/2005 - 02/23/20(	5.713	696,946	8,233	641	Y	Y
3	Lightning Storm	9/20/2005	3.887	624,737	2,910	391	Y	Y
4	Lightning Storm	10/17/2005	3.693				N	Y
5	Brush Fire	9/3/2005	2.121				N	Y
6	Wind Storm	8/6/2005	1.683				N	Y
7	Lightning Storm	7/24/2005	1.500				N	Y
8	Lightning Storm	5/6/2005	1.235				N	N
9	Wind Storm	11/26/2005	1.089				N	N
10	Rain/Wind Storm	12/31/2005	1.061				N	N

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2004 **Attachment 3**

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Winter Rain Storm	2/28/2004 - 12/31/200	8.100	708,044	38,065	1,005	Y	Y
2	Wind Storm	11/21/2004	2.571				N	Y
3	Wind Storm	10/27/2004	2.389				N	Y
4	Rain Storm	10/17/2004	1.999				N	Y
5	Moorpark A-Bank	9/11/2004	1.622				N	Y
6	Rain Storm	10/20/2004	1.610				N	Y
7	Lightning Storm	8/12/2004	1.574				N	Y
8	Rain Storm	10/19/2004	0.989				N	N
9	Wind Storm	11/22/2004	0.904				N	N
10	Lightning Storm	8/13/2004	0.883				N	N

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2003

Attachment 3

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Santa Ana Wind Storm	1/06/2003 - 01/08/200	17.228	1,236,698	7,731	2,551	Y	Y
2	Southern California Wild Fires	)/24/2003 - 10/26/200	6.105	601,653	12,808	1,919	Y	Y
3	Rain Storm & Mud Slides	12/25/2003	3.468				N	Y
4	Lightning Storm	11/12/2003	3.024				N	Y
5	Santa Ana Wind Storm	01/05/2003	2.438				N	Y
6	Rain Storm	02/25/2003	2.303				N	Y
7	Rain Storm	10/31/2003	1.127				N	N
8	Wind Storm	03/17/2003	0.946				N	N
9	Wind Storm	02/12/2003	0.796				N	N
10	Lightning Storm	08/20/2003	0.770				N	N

Southern California Edison
Top 10 SAIDI Events
2002 - 2011

2002

Attachment 3

Rank	Description	Date	SAIDI	Number of customers affected	Longest customer interruption (min)	Number of people used to restore service	D.96-09-045 Major Event?	IEEE 1366 Major Event?
1	Rain/Wind Storm	12/16/2002	2.780				N	Y
2	Rain/Wind Storm	11/8/2002	2.416				N	Y
3	Mira Loma RAS / Louisiana Fire	6/26/2002 - 06/28/200	2.307	600,607	3,996	50	Y	Y
4	Rain/Wind Storm	11/9/2002	1.043				N	N
5	Rain Storm	11/25/2002	1.015				N	N
6	Wind Storm	2/9/2002	0.862				N	N
7	Car Hit Pole	10/4/2002	0.847				N	N
8	Rain/Wind Storm	11/7/2002	0.712				N	N
9	Heat Storm	9/1/2002	0.662				N	N
10	Rain Storm	2/17/2002	0.643				N	N

Southern California Edison

Major Events

Number of customers w/o service at hourly interval

THIS TABLE CONTAINS ROLLING DAY DATA.

Attachment 4

	Mira Loma RAS	*Mira Loma RAS*	*Mira Loma RAS*	*Santa Ana Wind Storm*	*Santa Ana Wind Storm*	*Santa Ana Wind Storm*			⇦ *Description of event*
Time	*6/26/2002*	*6/27/2002*	*6/28/2002*	*1/6/2003*	*1/7/2003*	*1/8/2003*			⇦ *Date of event*
0	1,973	459	119	150,974	24,149	5,099			
1	1,995	459	808	177,276	26,720	9,867			
2	22	459	870	189,656	35,678	7,212			
3	-	9,716	1,364	169,700	23,267	5,691			
4	-	459	9,866	127,917	41,711	4,315			
5	-	4,571	285	112,215	48,693	4,155			
6	469	2,136	223	99,427	35,370	4,102			
7	-	589	3,485	84,646	31,423	4,137			
8	131	589	4,033	86,946	15,173	6,844			
9	-	501	352	58,992	13,628	7,833			
10	412	522	1,533	63,936	26,491	9,774			
11	114	1,302	599	60,261	35,427	8,491			
12	1,053	205	186	69,743	30,025	11,349			
13	622	114	124	77,406	24,075	11,607			
14	622	29	29	61,304	10,701	24,521			
15	-	101	29	45,025	9,033	6,537			
16	-	1,176	29	25,292	8,628	4,368			
17	-	1,918	4,095	25,852	11,222	4,000			
18	540,502	4,243	2,704	25,773	7,709	3,030			
19	16,349	119	227	29,423	12,265	2,930			
20	4,058	119	1,068	51,181	14,995	2,091			
21	1,690	119	227	27,891	12,993	2,026			
22	459	119	227	20,583	10,023	2,313			
23	2,827	119	227	33,400	11,230	1,540			

Southern California Edison

Major Events

Number of customers w/o service at hourly interval

THIS TABLE CONTAINS ROLLING DAY DATA.

Attachment 4

	Southern California Wild Fires	Southern California Wild Fires	Southern California Wild Fires	Winter Rain Storm	Winter Rain Storm	Winter Rain Storm	Winter Rain Storm		⇦ Description of event
Time	**10/24/2003**	**10/25/2003**	**10/26/2003**	**12/28/2004**	**12/29/2004**	**12/30/2004**	**12/31/2004**		⇦ Date of event
0	-	99	6,168	12,202	84,434	3,841	1,127		
1	81	4,491	60,988	7,187	71,180	4,368	1,906		
2	1,681	47	7,531	24,357	60,971	3,324	1,444		
3	110	47	193,783	40,904	47,181	3,834	2,590		
4	81	1,847	68,576	21,739	30,328	3,737	3,755		
5	602	14,854	45,513	15,563	24,823	3,249	3,888		
6	6,403	41	29,836	11,448	19,659	1,972	9,143		
7	521	3,546	7,319	30,504	18,040	1,219	7,295		
8	1,134	15,078	9,418	80,953	15,674	4,717	12,424		
9	637	1,317	5,937	30,040	13,206	1,640	19,566		
10	120,708	4,454	8,839	42,290	15,031	1,745	7,628		
11	653	3,256	7,889	30,355	11,669	5,737	8,981		
12	574	2,912	6,350	16,991	14,253	4,276	16,928		
13	15,893	2,295	28,195	17,970	15,084	5,481	10,208		
14	600	2,991	16,756	13,537	11,345	4,109	6,843		
15	590	30,036	14,368	5,871	7,682	6,491	11,140		
16	575	7,055	11,336	11,953	13,496	807	8,410		
17	575	9,159	10,253	92,301	5,765	629	2,556		
18	1,171	1,279	8,013	7,091	5,112	2,592	2,034		
19	616	2,759	5,758	12,949	7,681	2,904	2,536		
20	586	3,800	5,992	10,576	5,121	705	2,522		
21	727	3,087	5,619	7,987	4,092	1,738	4,294		
22	3,652	4,829	5,754	6,779	3,280	2,262	4,122		
23	1,606	4,722	4,065	17,630	6,271	4,535	4,375		

Southern California Edison

Major Events

Number of customers w/o service at hourly interval

THIS TABLE CONTAINS ROLLING DAY DATA.

Attachment 4

	Winter Rain Storm	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	⇦ *Description of event*
Time	**1/1/2005**	**1/2/2005**	**1/3/2005**	**1/4/2005**	**1/5/2005**	**1/6/2005**	**1/7/2005**	**1/8/2005**	⇦ *Date of event*
0	2,344	118	8,955	2,091	89	327	1,136	1,172	
1	2,921	398	1,652	2,270	5,160	281	488	24	
2	34	398	-	3,830	82	281	3,387	73	
3	358	420	5,475	600	82	281	555	18,858	
4	1,600	2,571	7	3,827	82	281	960	190	
5	4,906	303	3,637	807	66	275	3,054	379	
6	7,949	303	1,997	627	2,669	275	3,383	589	
7	2,774	1,665	7,844	3,186	3,824	2,611	2,136	26	
8	4,609	223	16,398	2,784	179	729	5,964	1,758	
9	540	223	5,447	33,282	166	981	3,644	2,049	
10	2,162	5,192	479	35,214	7,332	2,008	18,416	1,749	
11	4,074	6,462	29,734	6,727	2,209	1,911	14,005	1,156	
12	1,259	1,261	7,823	2,813	1,194	2,913	18,630	2,928	
13	508	1,860	4,983	1,239	1,192	675	12,035	10,653	
14	832	2,845	1,139	5,954	6,876	454	12,229	8,270	
15	508	140	5,396	1,593	2,886	620	5,695	5,987	
16	2,442	140	4,085	533	361	1,813	7,314	12,102	
17	172	140	825	116	385	1,783	6,025	7,942	
18	172	141	8,390	116	444	776	6,402	6,594	
19	42	141	13,318	2,102	278	1,561	4,794	3,573	
20	992	65	1,012	116	312	1,617	2,449	5,256	
21	1,068	64	5,787	1,011	2,716	304	5,710	7,556	
22	118	64	619	331	2,923	304	4,910	3,131	
23	118	64	619	89	336	1,074	1,313	10,803	

Southern California Edison

Major Events

Number of customers w/o service at hourly interval

THIS TABLE CONTAINS ROLLING DAY DATA.

Attachment 4

	Winter Rain Storm	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	*Winter Rain Storm*	⇦ *Description of event*
Time	***1/9/2005***	***1/10/2005***	***1/11/2005***	***2/16/2005***	***2/17/2005***	***2/18/2005***	***2/19/2005***	***2/20/2005***	⇦ ***Date of event***
0	4,634	9,150	14,206	849	-	2,485	10,466	6,564	
1	5,353	12,379	17,009	125	229	1,495	17,924	3,539	
2	12,050	7,614	23,761	9	17	1,441	13,917	7,293	
3	5,806	6,362	11,891	3,916	837	1,441	20,607	1,694	
4	2,602	8,523	11,603	10	1,623	1,441	52,009	2,959	
5	14,378	7,153	17,849	10	323	4,579	48,850	2,831	
6	9,300	10,555	21,763	397	574	908	33,786	2,148	
7	14,493	12,129	19,731	397	622	2,737	27,551	5,496	
8	12,429	21,583	12,136	178	371	2,523	28,434	3,496	
9	24,223	25,889	11,853	191	706	502	9,986	1,428	
10	20,625	11,663	13,268	26	10,010	470	26,295	2,064	
11	15,716	14,795	14,945	2,782	9,127	4,659	21,866	2,673	
12	15,434	14,101	14,518	1,746	715	133	20,560	4,118	
13	14,768	25,907	16,991	1,092	1,406	133	12,826	1,424	
14	9,396	18,741	9,700	822	8,316	4,986	10,386	928	
15	12,776	17,297	8,543	227	946	6,229	8,937	646	
16	14,157	15,005	8,302	5,306	782	141	10,151	2,152	
17	18,536	11,146	12,089	2,379	4,792	141	7,290	3,921	
18	18,384	8,124	10,778	5,322	4,205	141	9,393	4,268	
19	10,382	15,219	1,684	4,002	4,969	1,123	8,156	3,741	
20	8,367	13,053	19,597	933	1,357	2,100	4,481	1,904	
21	16,640	11,746	11,712	933	1,357	1,246	5,405	13,372	
22	11,723	17,482	1,331	288	2,455	213	5,280	6,753	
23	10,832	13,659	971	-	2,401	21,056	7,146	17,008	

Southern California Edison

Major Events

Number of customers w/o service at hourly interval

THIS TABLE CONTAINS ROLLING DAY DATA.

Attachment 4

	Winter Rain Storm	*Winter Rain Storm*	*Winter Rain Storm*	*Lightning Storm*	*Winter Rain Storm*	*Summer Heat Storm*	*Wild Fires*		⇦ *Description of event*
Time	*2/21/2005*	*2/22/2005*	*2/23/2005*	*9/20/2005*	*1/2/2006*	*7/22/2006*	*10/21/2007*		⇦ *Date of event*
0	17,643	1,611	23,794	35,324	934	8,131	8,346		
1	13,966	1,398	23,651	73,173	2,485	6,528	13,208		
2	16,136	7,833	5,401	117,966	979	7,269	13,475		
3	12,916	5,314	4,219	94,719	3,901	7,257	42,878		
4	6,111	167	9,519	70,986	16,033	6,504	33,204		
5	10,876	3,305	5,111	59,321	23,872	4,299	54,764		
6	16,259	342	26,381	36,987	14,740	4,956	20,957		
7	9,266	339	9,743	44,392	35,171	4,806	45,298		
8	13,975	619	8,601	38,176	77,681	4,932	59,570		
9	5,374	4,169	7,510	59,889	191,661	2,263	53,648		
10	7,730	3,222	8,704	42,516	162,780	2,674	71,391		
11	10,107	6,973	11,041	62,892	169,871	3,161	67,827		
12	6,323	2,308	6,804	26,698	115,365	7,451	51,300		
13	12,967	3,533	5,970	21,128	87,849	19,300	43,260		
14	10,061	7,288	1,898	23,744	83,069	53,902	60,972		
15	3,940	2,330	1,347	16,056	79,866	105,045	49,155		
16	10,584	1,275	2,009	14,467	76,523	129,964	41,000		
17	10,439	7,048	2,811	10,871	57,515	134,398	51,141		
18	2,793	4,279	2,117	13,237	47,499	89,342	42,154		
19	4,762	4,235	1,142	9,521	36,870	145,110	53,578		
20	5,291	1,504	722	6,935	36,921	84,274	54,253		
21	7,568	2,594	620	6,730	29,519	76,624	45,699		
22	2,452	984	1,956	4,476	28,745	66,383	85,099		
23	5,496	20,739	2,630	4,349	21,198	53,678	38,793		

Southern California Edison

Major Events

Number of customers w/o service at hourly interval

THIS TABLE CONTAINS ROLLING DAY DATA.

Attachment 4

	Winter Storm	*Wind Storm*	*Wind Storm*	*Summer Lightning*	*Los Angeles Wind Storm*	*Los Angeles Wind Storm*			⇦ *Description of event*
Time	*1/1/2011*	*3/20/2011*	*3/21/2011*	*7/31/2011*	*11/30/2011*	*12/1/2011*			⇦ *Date of event*
0	152	2,253	3,756	1,553	346	53,827			
1	848	3,614	25,090	17,863	27	195,848			
2	1,802	3,218	6,775	23,571	93	224,491			
3	906	4,366	6,002	23,258	136	185,094			
4	245	4,836	13,142	50,469	905	175,500			
5	221	1,982	14,204	31,683	136	168,896			
6	256	19,346	7,630	32,030	101	182,264			
7	1,635	19,464	7,215	24,115	101	157,517			
8	2,055	22,334	3,739	37,987	101	153,781			
9	449	14,170	5,171	6,264	1,953	159,094			
10	434	21,641	32,945	8,203	635	153,681			
11	1,896	38,613	33,472	10,251	3,655	149,957			
12	1,213	50,469	29,369	6,656	2,473	160,856			
13	448	65,147	29,585	8,299	9,002	148,958			
14	338	59,645	28,413	11,004	3,810	138,162			
15	6,185	54,173	12,384	5,024	671	130,026			
16	286	54,319	10,565	4,815	6,934	120,737			
17	446	46,595	6,619	4,835	14,239	115,884			
18	3,814	75,305	8,154	7,279	17,008	110,628			
19	2,062	68,778	10,209	1,612	30,999	110,607			
20	2,393	42,090	6,559	1,818	47,924	101,914			
21	2,871	35,941	3,779	3,094	33,931	99,117			
22	2,301	32,844	4,307	1,880	60,206	95,108			
23	2,334	33,134	4,136	2,084	124,610	92,330			

Southern California Edison

Major Events

Number of customers w/o service by outage duration

Attachment 5

	Mira Loma RAS	Santa Ana Wind Storm	Southern California Wild Fires	Winter Rain Storm	Winter Rain Storm	Winter Rain Storm	Lightning Storm	Winter Rain Storm	Summer Heat Storm	Wild Fires	⇦Description of event
Outage Duration	06/26/2002 - 06/28/2002	01/06/2003 - 01/08/2003	10/24/2003 - 10/26/2003	12/28/2004 - 12/31/2004	01/01/2005 - 01/11/2005	02/16/2005 - 02/23/2005	9/20/2005	1/2/2006	7/22/2006	10/21/2007	⇦Date of event
0 to 1 hour	583,670	788,468	491,078	409,325	561,834	377,235	440,023	572,274	422,684	522,063	
1 to 5 hours	7,126	172,308	58,450	151,123	203,015	153,424	64,816	101,467	55,577	67,433	
5 to 10 hours	5,835	59,570	11,547	60,160	101,172	70,856	33,672	25,500	15,986	21,017	
10 to 15 hours	1,203	57,778	4,883	38,830	45,767	54,924	28,181	10,751	7,881	4,637	
15 to 20 hours	2,744	55,373	1,996	16,205	17,431	30,162	17,358	3,862	4,703	4,349	
20 to 24 hours	-	15,325	4,081	10,963	7,955	6,708	11,119	898	3,591	1,585	
1 to 2 days	-	56,503	11,169	17,805	12,906	3,634	29,487	5,004	12,458	5,157	
2 to 3 days	29	24,949	1,734	1,062	13	-	81	459	4,036	1,574	
3 to 4 days	-	5,524	5,040	-	2,569	-	-	36	646	133	
4 to 5 days	-	-	7,169	2,564	504	-	-	-	10	145	
5 to 6 days	-	900	3,478	-	-	3	-	-	-	-	
6 to 7 days	-	-	25	-	-	-	-	-	-	-	
> 7 days	-	-	1,003	7	1,146	-	-	-	-	-	
Total	600,607	1,236,698	601,653	708,044	954,312	696,946	624,737	720,251	527,572	628,093	

Southern California Edison

Major Events

Number of customers w/o service by outage duration

Attachment 5

	Winter Storm	*Wind Storm*	*Wind Storm*	*Summer Lightning*	*Los Angeles Wind Storm*	*Los Angeles Wind Storm*					⇦*Description of event*
Outage Duration	*1/1/2011*	*3/20/2011*	*3/21/2011*	*7/31/2011*	*11/30/2011*	*12/1/2011*					⇦*Date of event*
0 to 1 hour	19,856	299,989	79,997	86,125	141,793	353,515					
1 to 5 hours	2,181	53,535	31,620	5,895	13,080	54,549					
5 to 10 hours	231	11,804	6,513	22,012	11,329	25,877					
10 to 15 hours	180	5,112	2,755	1,929	7,067	30,380					
15 to 20 hours	170	3,359	455	331	2,323	16,495					
20 to 24 hours	17	3,680	278	261	5,031	12,249					
1 to 2 days	50	6,901	567	189	16,105	47,274					
2 to 3 days	-	1,035	23	2	19,471	21,220					
3 to 4 days	111	158	14	-	9,901	3,719					
4 to 5 days	49	43	-	2	5,395	3,538					
5 to 6 days	-	-	-	-	3,244	848					
6 to 7 days	-	7	-	-	221	272					
> 7 days	41	5	-	3	17	33					
Total	22,886	385,628	122,222	116,749	234,977	569,969					