The Maryland Public Service Commission

Case No. 9240

Evaluation of the Reliability and Quality of the Electric Distribution System of Potomac Electric Power Company

Final Report

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I. Executive Summary

A. Report Purpose and Scope

The Potomac Electric Power Company (Pepco or Company), a subsidiary of Pepco Holdings, Inc. (PHI), is a regulated electric utility operating in the state of Maryland and in the District of Columbia. Pepco provides electric service to approximately 526,000 Maryland customers in portions of Prince George's and Montgomery Counties. After receiving a large number of complaints from the public, the Maryland Public Service Commission (Commission) initiated Case No. 9240 to investigate the reliability of Pepco's electric distribution system and the quality of the service it provides to customers. A primary objective of the investigation is to determine root causes for the scope, frequency, and duration of Pepco's outages, both storm and non-storm related. Of particular concern to the Commission is the Company's reported failures in communication during four major storm outage events in 2010, including its inability to provide to customers reliable estimated times of restoration.

After ordering a third-party review, the Commission issued a Request for Proposal (RFP) to conduct a thorough evaluation of Pepco's system reliability. The general scope of work outlined in the RFP includes the following:

- A comprehensive assessment of Pepco's maintenance and operating practices that impact electric system reliability (*e.g.*, vegetation management procedures).
- A comprehensive assessment of Pepco's outage preparedness, the efficiency and effectiveness of Pepco's outage response, and the effectiveness of its customer communications as they relate to the major storms experienced by Pepco in February, July, and August 2010 in particular, and to outages in general.
- A comprehensive assessment of Pepco's hardware and software systems, engineering and management protocols and performance, and communications protocols and performance as they relate to the major storms experienced by Pepco in February, July, and August 2010 in particular, and to system reliability in general.
- Determination of the adequacy of Pepco's level of historic and projected investment in new electric distribution infrastructure, and its level of historic and projected reliability-related maintenance of its existing infrastructure.
- Determination as to whether the engineering design of Pepco's existing and proposed new electric distribution infrastructure and plant are adequate.
- A survey of electric industry best practices and comparison to Pepco's current practices.
- A compilation of standards used by other commissions to measure system reliability.

The Commission selected the team of First Quartile Consulting Inc. and Silverpoint Consulting LLC (First Quartile-Silverpoint) to perform the evaluation.

B. Summary of the Investigation

Introduction

The First Quartile-Silverpoint team conducted a brief but thorough evaluation of the reliability and quality of Pepco's distribution system. As part of this investigation, we considered the adequacy of system infrastructure and the sufficiency of the Company's reliability-related capital investments. We identified the root causes for Pepco's chronic reliability problems and critiqued the most recent set of initiatives it has offered up to address them. Part of our charter was to assess Pepco's emergency preparedness and restoration efforts during last years' storm events, and we did so with a particular emphasis on the quality of the Company's customer communications and its inability to provide reliable estimated restoration times. If there was any overall theme to the findings from this investigation, it was that Pepco needs to be more proactive, rather than reactive, in dealing with problems. The Company's piecemeal approach to dealing with reliability issues is a good example.

Approach to the Review

The Commission's initial set of twenty-two questions, and Pepco's responses to them, were very helpful in jump-starting the investigation.[1] Over the ensuing nine weeks, the team conducted over 30 interviews and submitted over 140 data requests; Pepco expedited our requests when possible. We found Company personnel to be candid and forthright in their responses to our inquiries. Much system infrastructure and operational information is confidential, and we appreciated Pepco's assistance in developing ways to present our analysis without the need for a separate confidential version of this report.

The investigation was to a large degree bifurcated. One part focused on determining the root causes for poor reliability performance in Maryland and on evaluating Pepco's current initiatives targeted at improving it. The other focused on evaluating Pepco's restoration performance during the storm events of last year, including the physical restoration activities and the quality of its communications with customers and others. Fairly evaluating Pepco's restoration required us to set aside questions about why so many customers were affected during these events, and to take the number of outages at face value. To offer meaningful and useful insights on both reliability and restoration, we felt it best to keep the issues separate.

Findings and Conclusions

Reliability

During our reliability investigation, we found that Pepco's sub-transmission and distribution system infrastructure is well-designed. The basic configuration of the system, a radial loop design with redundant facilities, is consistent with recognized reliability standards. Without the redundancy of a "belt and suspenders" design, Pepco's reliability problems would be much

[1] A synopsis of the Commission's questions and Pepco's responses to those questions is provided in Appendix D.

worse. Although the system is robustly-designed it is nonetheless still vulnerable. The sub-transmission and distribution systems are particularly vulnerable to tree damage, in part due to their placement, which is primarily along public streets. We found that trees are in fact the primary cause of the most potentially-preventable outages in Pepco's Maryland service area.

Pepco's downturn in reliability after 2004 was triggered by the residual effects of Hurricane Isabel. Normally one would expect a utility to spend more on preventative maintenance after such an event to counteract the increased risk of outages caused by hurricane damage. Pepco, however, responded with insufficient preventative maintenance, which compounded the hurricane's effect on the system's vulnerability to future events. For quite some time, Pepco's spending on vegetation management has been inadequate and it routinely failed to meet its annual trimming goals. Not surprisingly, conditions on the system continued to deteriorate. Maryland laws and ordinances and the customer permission process complicated the problem by adding to the cost of the vegetation maintenance Pepco actually did perform. The Company's insufficient level of system maintenance also contributed to its reliability woes.

Pepco's attitude toward distribution vegetation management did not shift until after trees had overgrown parts of its system, and it reacted by rolling out an aggressive trimming plan. It is now in the first full year of an eight-year program of prescriptive vegetation management designed to reclaim its system. For the first time, Pepco will remove vegetation above its lines rather than just alongside them, which further reduces the system's vulnerability to tree damage. This vegetation management program is clearly the most crucial element of the Company's efforts to significantly improve reliability in Maryland.

Over the last five years, Pepco's level of capital spending was adequate to maintain reliability at existing levels, but not to make much progress toward improving it. Last year, the Company unveiled its Reliability Enhancement Plan, reflecting a quarter of a billion dollar proposed investment aimed at improving reliability. The expanded vegetation management initiative is only one of these programs. Pepco plans, for example, to add switches on its sub-transmission and distribution lines that will allow it to restore these lines more quickly and in some instances avoid customer outages. Pepco acknowledged that it does not know whether the projects in the new plan will actually achieve its reliability goals because it had not fully analyzed them, which is a concern. With this ready-shoot-aim approach a portion of the Company's planned capital spending is almost certainly poorly targeted.

Restoration

Restoration is really a three-pronged effort. The first involves the physical activities—locating the damage, dispatching crews, and effecting repairs—needed to bring customers back on line. The second involves developing estimates of expected restoration times to give to customers. The third is communicating with the public throughout the event. These three parallel efforts occur simultaneously during an outage event, and they are clearly interrelated. Ideally, a utility will excel at all three aspects of the restoration effort. However, it is not uncommon for a utility to do well at one but poorly at the others, which is what we found at Pepco. In this case, poor performance in developing and delivering accurate estimated times of restoration (ETRs),

combined with disjointed communications, helped foster an incorrect perception that Pepco's physical restoration process was handled poorly.

Pepco's physical restoration efforts in the storms of 2010 were reasonably good, with the exception of its failure to complete damage assessments. As a result, it did not always know the full extent of damages, particularly the damage on facilities located closest to customers, such as pole top transformers. In actuality, though, the failure to fully complete these assessments had no real impact on Pepco's total time of restoration. Whether Pepco knows the full extent of smaller outages early in the event or not, in the end it still has the same amount of damage on its system and it will take about the same amount of time to correct it.

The real concern with Pepco not completing full damage assessments is the effect it has on the second prong of the restoration effort—developing ETRs. Incomplete damage assessment exacerbates problems associated with calculating them. Without a complete damage assessment, Pepco could incorrectly assume that a customer group is without power because of only one outage, but in reality it could be due to two or more outages somewhere along the system. Original estimates for when customers can expect to be restored can be substantially off, leaving customers frustrated.

Other problems contributed to Pepco's relatively weak performance in calculating restoration times. In particular, inconsistent and delayed delivery of information from the field workforce to the operations center for input to the Outage Management System (OMS), combined with too few staff to input that information, caused the OMS to fall behind and be unable to develop accurate ETRs. When this occurred, Pepco used an alternative approach for determining ETRs involving global "tiers," whereby large groups of customers all receive the same ETR. These global ETRs clearly were inaccurate, although somewhat better than what the OMS could produce at the peak of the storms.

The third major aspect of a restoration effort is communicating with customers and outside entities, including government officials, the media, community leaders, public safety organizations, and emergency management agencies. Pepco's performance in this area was inconsistent, and the Company was unable to overcome the problems created by the poor ETRs. While Pepco used technology solutions effectively to handle customer contacts, its live call handling process resulted in inconsistent and sometimes inaccurate information being provided to customers.

Periodic failures of various support systems including the OMS, Customer Information System, automated voice response units, and the Pepco website all contributed to inadequate performance in keeping customers and others informed as to progress of the restoration efforts. When these individual failures occurred, Pepco moved quickly to resolve each one. However, when taken in their entirety, all of these issues contributed significantly to the frustration experienced by Pepco's Maryland customers.

Although the 2010 storms were at the center of this investigation, the findings in this report are not static ones. We did not examine the storm event of this January, but our overall conclusions

and recommendations would not change if we had. The root causes of Pepco's reliability problems in Maryland are the same this year as they were last year and will be next year. The best approach for improving reliability does not change. Similarly, we saw nothing during our investigation that would lead us to believe that Pepco's physical restoration efforts, ETRs, or customer communications during the January storm were substantially different from what they were last year. Our recommendations remain valid. In summary, we believe this report provides a good road map for helping Pepco move forward in reliability and service quality.

Recommended Actions

In each chapter of the report we discuss recommendations in some detail. In this executive summary, we provide an overview of the most important of those recommendations. Several of them share the same characteristic, a move from a reactive approach to a more proactive one in facing and resolving major issues.

Improve preventative maintenance practices. The new prescriptive vegetation management program should be implemented over the next two tree-trimming cycles. To get the maximum benefit, though, Pepco must fully fund this program for all eight years through non-discretionary spending. This program will solve many of the routine reliability problems experienced by Pepco's Maryland customers, and help to minimize the amount of damage sustained during storm events. Pepco should also complete maintenance inspections of its distribution and sub-transmission lines over the next four years so it can better prioritize maintenance activities.

Improve analysis of reliability and reliability-related initiatives. Pepco should conduct more complete and in-depth analysis of outage records to aid its understanding of outage causes and results. Similarly, the Company should undertake a more complete analysis of its Reliability Enhancement Plan projects so that goals and priorities are consistent with improving its performance in a cost-effective manner in the shortest time possible.

Improve ETRs during storm restoration. Pepco should substantially enhance its process for developing and delivering ETRs during future storm events. This will require major improvements in internal information flow from the field to the operations center for input to the OMS. It will also require a more complete damage assessment at the beginning of the restoration effort, as well as better solicitation and use of information from customers. Finally, enhanced staffing levels will be necessary to handle the greater information flow and input to the OMS.

Improve customer communications during major storm events. Pepco should effectively coordinate the numerous channels of communications so it is able to adequately explain to customers and outside entities what is going on during the restoration effort. It should be able to provide consistent and comprehensive outage and restoration status messages to all available channels. To ensure the ability to successfully perform during a major storm, Pepco's underlying support systems and related inter-system interfaces should be systematically stress-tested to identify the kinds of failures that occurred during the 2010 storm events, so that it can then apply lasting solutions. Finally, additional emergency response training is needed for customer contact personnel, both regular customer service representatives and non-response employees who fill

customer contact assignments as their second role, to improve performance during storm restoration efforts.

C. Structure of the Report

This report has eight chapters. Chapter I provides an introduction. The next four chapters focus on issues surrounding the reliability of the Pepco distribution system. In Chapter II we discuss the adequacy of Pepco's distribution system design and level of automation; we also review the Company's recent reliability performance and offer our opinion about the underlying causes. Chapter III contains our analysis of outage events, and in Chapter IV we discuss Pepco's prior and current vegetation management practices and spending. In Chapter V, the team discusses the Company's prior and projected reliability-related capital and operating and maintenance (O&M) spending; we also provide our reviews of Pepco's system maintenance practices and reliability enhancement programs.

The final three chapters of the report focus on the effectiveness of Pepco's response to emergency situations such as the storms in 2010. In Chapter VI, we evaluate Pepco's emergency preparedness, and in Chapter VII we discuss our review of Pepco's operational restoration response during the four storm events. Chapter VIII focuses on the effectiveness of the Company's communications during outage events.

II. Pepco's Distribution System Design and Performance

A. Introduction

In this chapter, the First Quartile-Silverpoint team provides an overview of the Pepco distribution system engineering design and evaluates the Company's planning and design practices. As part of our review, we evaluate the robustness of the system's infrastructure, assess its degree of automation, and identify system conditions or design considerations that may impact reliability. Our objective was to determine whether Pepco's system planning, design, construction, and level of automation contributed to the impact of the 2010 storm events, and if there is anything the Company can improve to help minimize the number, scope, or duration of future outages.

We also discuss Pepco's historical reliability performance. Pepco's performance over the last decade has clearly declined—as evidenced by an increase in the frequency and duration of outages—and that decline began shortly after the hurricane event in 2003. The Company has, however, begun to recover some lost ground. The discussion in this chapter provides background for later chapters of this report that explore why this degradation occurred and whether the programs Pepco has proposed will make measurable improvements in its reliability.

B. The Pepco Distribution System

1. Distribution System Design

Pepco's electric distribution system consists of the facilities and equipment, *i.e.*, substations, transformers, circuits, and switches, which connect its transmission system to the end user. The sub-transmission portion of the distribution system takes power from transmission lines and steps it down to a lower level, generally 69 kilovolts (kV), at the a sub-transmission substation. Lines from sub-transmission substations in turn supply distribution substations, located closer to customers, which change voltage to even lower levels, generally 13 kV. Typically, a dozen primary circuits (lines) extend from the distribution substation in different directions toward smaller local load areas. In the case of a residential customer, a primary circuit runs to a pole top or pad mounted transformer that reduces the voltage to 120 or 240 volts; the customer then receives service from a secondary line leaving the transformer. The following table summarizes the major components of Pepco's Maryland distribution system by county.[2]

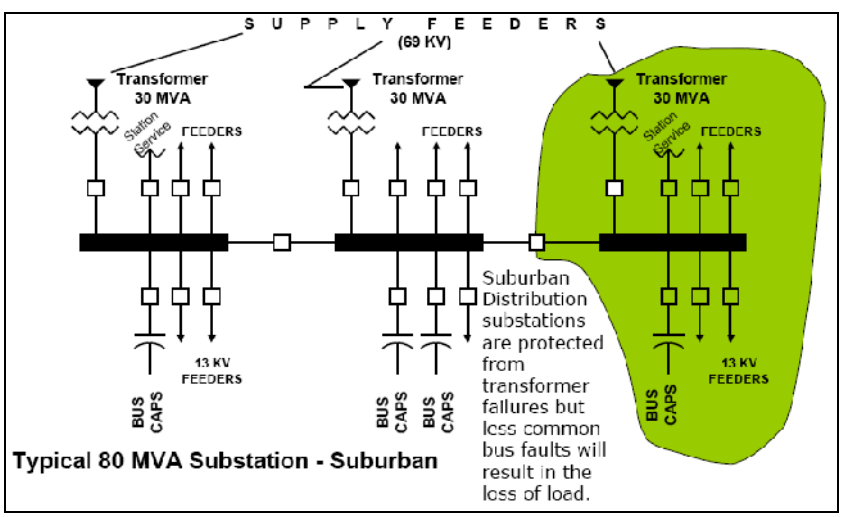
Pepco's Maryland Distribution System

	Montgomery	Prince George's
Overhead circuit miles	1,840	1,632
Substations	34	26
Overhead distribution circuits	317	228
Overhead sub-transmission circuits	23	48

[2] Pepco email dated February 28, 2011, which updates figures in its response to Commission Question No. 11.

The team reviewed Pepco's design standards and planning criteria for its sub-transmission and distribution system.[3] We found that Pepco's planning processes, load forecasting, and analyses of the capability and stability of its system are acceptable and in line with good utility industry practices. The PHI Standards Group establishes and maintains material specifications, engineering and construction standards and practices, and operating guidelines to ensure the safe and reliable operation of Pepco's distribution system. In the course of our investigation, we found no instances in which Pepco did not conform to construction and replacement requirements of the National Electrical Safety Code (NESC).

Consistent with NESC standards, utilities design and operate their systems so that they will continue to operate in a stable fashion, *i.e.*, within emergency current and voltage ratings and stability limits, even after the loss of an important facility such as a transformer. This "N-1" or "worst single contingency" criterion is good utility design practice.[4] The common way to meet this criterion is to design and build redundancy into the system. The configuration of a typical Pepco distribution substation is a good example of that redundancy. The diagram below illustrates the effect of the loss of a transformer.[5]



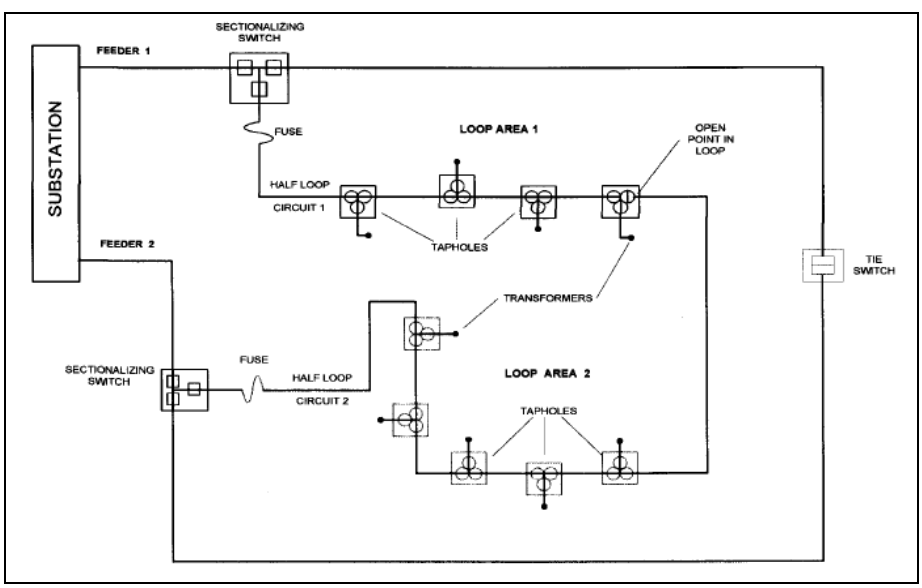
Sub-transmission substations can supply up to four distribution substations in a substation group. Each 69 kV line emanating from a sub-transmission substation extends from a separate bus section and runs along a different route, either along rights-of-way or along public streets, to a distribution substation, which in turn steps power down to the 13 kV level. As illustrated above, Pepco distribution substations typically have three transformers, each with a separate 69 kV

[3] Interview #1, January 7, 2011, and Electric System Planning Criteria for the Transmission & Interconnection Subtransmission (Internal Transmission) and Distribution Systems, provided in response to Data Request #88. Pepco confirmed its transmission system is planned to meet all NERC reliability criteria (response to Data Request #87).
[4] In some instances, a utility may design a portion of its system so that it can withstand the concurrent loss of two or more facilities, that is, according to "N-2" criterion.
[5] Response to Data Request #91. The same redundancy concept applies to Pepco's transmission lines running to sub-transmission substations (response to Data Request #89).

supply feeder from a sub-transmission substation. Distribution feeder circuits extend in various directions from the substation to serve customers.

Each distribution substation is designed with N-1 redundancy, which means that under system peak conditions, a substation can lose a transformer and its associated supply feeder and still adequately supply all load. This is a very reliable design—redundancy allows the system to avoid an outage even after the loss of an important facility.[6] When Pepco experienced an outage at a distribution substation during the storm events of 2010, it did so because there were simultaneous faults along the separate 69 kV feeders supplying the substation.[7]

Distribution system connectivity refers to the means by which circuits are connected through the use of switches and reclosers.[8] In a radial design, a circuit has no interconnection with other circuits (*e.g.*, a single distribution line running down a residential street). Radial loop connectivity consists of circuits with an interconnection to other circuits, which provides multiples paths of supply. An example of such a circuit (in this case a 13 kV underground residential circuit) is shown below.[9]



When a circuit breaker opens, the entire distribution circuit is de-energized. Since this can disrupt power to many customers, some utilities typically design their distribution system with

[6] In off-peak load conditions, a substation may even be able to lose two transformers and their associated supply feeders without loss of substation load.
[7] Response to Data Request #74. We discuss this subject in more detail in Chapter III.
[8] The distribution system has switches located at strategic locations to redirect power flows for load balancing or sectionalizing, and to permit utilities to repair damaged lines or equipment or to perform upgrade work on the system. Automatic reclosers are self-controlling devices for interrupting and reclosing a circuit.
[9] Source: Pepco Comprehensive Reliability Plan for the District of Columbia, September 2010.

many layers of redundancy. Through redundancy, power can be shut off in portions of the system only, or it can be redirected to continue to serve customers. Only in extreme events, or failure of redundant systems, does an entire system become de-energized, shutting off power to a large number of customers. Redundancy consists of the many fuses and fused cutouts throughout the system that can disable parts of the system but not the entire system.

Pepco's distribution system incorporates both radial loop design (multiple sources of supply) and radial design with redundancy (individual lines are not interconnected, but there are multiple lines). Lines from Pepco's 230 kV transmission backbone (which is of radial loop design) to the sub-transmission substations are radial but redundant. Pepco's 69 kV sub-transmission system is configured as a radial loop, and there are multiple sources of supply to a distribution substation. The three lines into each of the distribution substations in a substation group are radial, but the multiple lines reflect redundancy. The 13 kV feeders that run from distribution substations constitute a radial loop, but Pepco does not typically operate it as such; the connections among feeders are usually open, but can be closed to route power around the system when needed to avoid problems.

The basic physical configuration of Pepco's distribution system—a radial loop design with multiple lines in and out of substations and redundant facilities—is robust. Without this "belt and suspenders" design, Pepco's reliability problems would be much worse.

As the storms of 2010 made painfully clear, because a system is "well-designed" does not mean it is not vulnerable. A system can be well-designed regardless of whether the 13 kV feeders serving customers from a distribution substation are located overhead or underground. Similarly, a system can be sound even if the vast majority of its secondary feeder lines, which are what typically supply residential customers from local transformers, are overhead lines. Of the nearly 800 secondary feeders in Pepco's Maryland jurisdiction, only 20 percent are classified as underground.[10] In Pepco's District of Columbia territory, on the other hand, approximately 70 percent are classified as underground. Although their facilities are different, both the Maryland and District of Columbia portions of the Pepco distribution system are well-designed. Maryland's system is, however, inherently more vulnerable to storm events and tree damage. Overhead lines are clearly more vulnerable than underground ones, which is why Pepco's Maryland service territory fared worse in the 2010 storms than the District of Columbia.

2. Distribution System Automation

The team examined the level of automation of the Pepco distribution system. We found that Pepco was very good in some areas, and could use improvement in others. Pepco has complete Supervisory Control and Data Acquisition (SCADA) capabilities for all operational devices at the 69 kV, 34 kV, and 13 kV substations.[11] This is well above the industry norm in this regard.[12] The lines running from the distribution substations, however, are under manual control, as are tie points. We believe that the Pepco system lacks adequate switches on its 69 kV and 34 kV lines.

[10] Response to Data Request #93.

Pepco does not have many switches on its 69 kV lines running into distribution substations, and those it does have, cannot be controlled remotely.

Remote-controlled motor-operated switches automated from the control center can isolate problems and be used to bring the system back to a more secure state. In a potential outage situation such as during a storm event, if Pepco loses a line into a substation, it has to dispatch a crew to manually close the switch, which could take a few hours. If in the meantime the substation loses another feeder (an N-2 contingency or overlapping line outages) the substation could lose power as the number of contingencies is beyond design capabilities. Having controllable switches means that the Company may be able to avoid outages in some cases, or return a substation more quickly. This is usually not an issue in a small storm, but in large storms, it could prove helpful.

Of the approximate 750 distribution circuits on the Pepco 13 kV system, there are only approximately 60 to 65 reclosers, and most are not remotely controlled. One reason for the relatively small number of reclosers is that Pepco had difficult installing them in the past. Pepco has a high interrupting fault level current on its distribution system due to the design of the substations. Also, because of population density, Pepco feeders are short; this limited the Company's ability to use reclosers, as they must be three-quarters of a mile to one mile away from the substation to be within their interrupting capability rating. In recent years, the interrupting capability of sulfur hexafluoride (SF_6) switches has increased, so the Company can install these switches closer to its substations.[13]

Pepco will be installing new reclosers as part of its two percent worst feeder program and as part of its Reliability Enhancement Plan, which we discuss in more detail in a later chapter. These automation additions will help improve Pepco's overall reliability by shortening the duration of outages with one important caveat. These automated recloser schemes typically shut down when there are many outages at one time, essentially reverting back to manual control. They would do little to shorten outage duration during major events such as the storms of 2010.

Another form of automation, advanced metering, is a topic of much focus in the industry. Advanced metering does not change the number of outages that occur, but it can help the utility locate the extent of damage more quickly, and thus possibly speed restoration. With advanced metering systems, a customer that loses power would not have to call to notify the utility, because the control center could detect whether an individual customer had power. Such systems are particularly helpful in identifying "nested outages," whereby a customer is without power due to more than one outage event on the system (a concept we will refer to several times in our report). The following diagram helps illustrate the principle.

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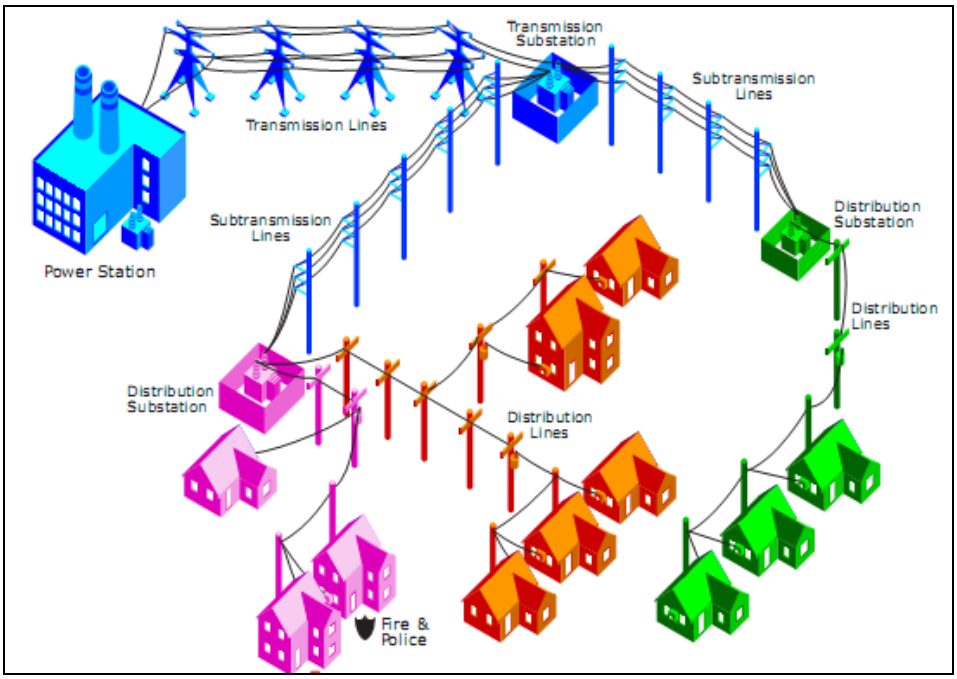
[11] Interview #2, January 7, 2011. SCADA provides for two-way communication of data between a device and the control center.
[12] First Quartile proprietary benchmark analysis.
[13] Interview #4, January 6, 2011.



In the colored illustration above, if a utility loses power at the pink substation, all customers along the pink and orange distribution lines are without power. If there is a concurrent problem along either the pink or orange distribution lines, that is, a nested outage, the utility may not be able to detect it. If, once the utility restores the pink substation, only customers along the pink distribution line receive power, it then knows that it has an outage somewhere along the orange distribution line. Customers along the orange line are without power due to more than one outage event. Pepco often has to rely on customer calls to pinpoint the extent of these nested outages.

C. Pepco Reliability Performance

1. Maryland Reliability

To most people, having reliable electric service means that outages do not happen very often, and when they do, they don't last for very long. Regulators use three primary indices to gauge this reliability:[14]

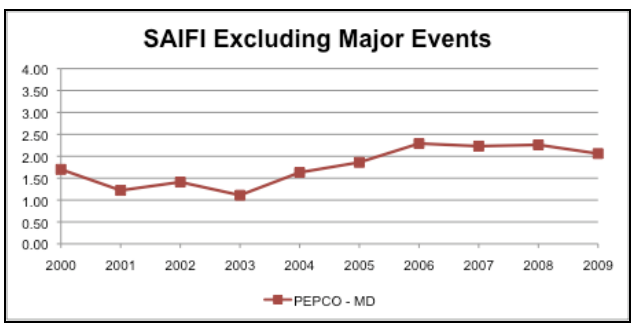
- System Average Interruption Frequency Index (SAIFI), which is the average frequency of sustained interruptions per customers (*i.e.*, how often)
- System Average Interruption Duration Index (SAIDI), which is the average time customers are interrupted (*i.e.*, how long, when averaged over all customers)

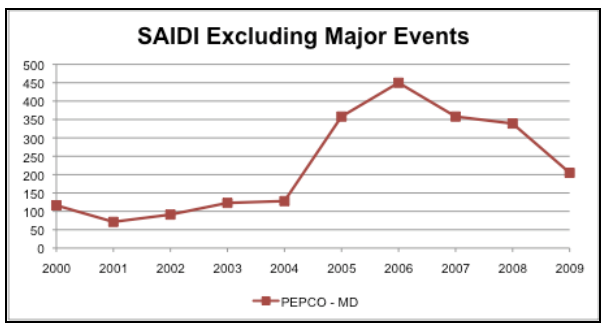
[14] SAIFI is calculated as the sum of the number of customer interruptions divided by the total number of customers served. SAIDI is calculated as the sum of customer interruption hours divided by the total number of customers served. CAIDI is calculated as SAIDI divided by SAIFI.

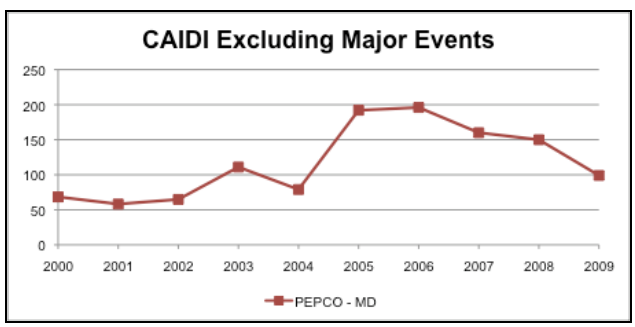
- Customer Average Interruption Duration Index (CAIDI), which is the average time required to restore service to the average customer per sustained interruption (*i.e.*, how long, for customers actually experiencing the outage).

These measures can be expressed on a system-wide basis, county basis, feeder basis, or even portion of a feeder basis.

Pepco routinely reports these indices, calculated with and without the effect of "major events," to the Commission. The following charts show Pepco's reported reliability, as measured by SAIFI, SAIDI, and CAIDI excluding major events, for its Maryland service area over the 2000 to 2009 period.[15]







The values on these graphs exclude "major events," which the Code of Maryland (COMAR), defines as instances in which (a) more than 10 percent of a utility's Maryland, or bordering jurisdiction, customers are without service, and (b) restoration of service takes more than 24 hours.[16] Major events are generally somewhat smaller than major storms.

It is important to stress that what Pepco's SAIFI, SAIDI, and CAIDI, minus major events, represent is <u>not</u> "blue sky" reliability.[17] Maryland utility reliability results reported under

[15] Data taken from Pepco Annual Reliabilities Indices Reporting.
[16] COMAR 20.50.01.03B(9). A major storm is defined in COMAR 20.50.01.03B(10) as a weather-related event during which: (a) more than 10 percent or 100,000, whichever is less, of the electric utility's Maryland customers experience a sustained interruption of electric services; and (b) restoration of electric service to these customers takes more than 24 hours.
[17] Blue sky reliability refers to system performance during fair weather conditions (*e.g.*, no significant winds).

COMAR still reflect events that can have a significant impact when combined over the course of a year. As a general matter, Pepco's reliability as reported under COMAR will look worse than if calculated by other methods common in the industry.

Many industry comparisons of reliability adopt the calculation methods developed by the Institute of Electrical and Electronics Engineers (IEEE). The IEEE method for calculating reliability indices excludes data associated with "Major Event Days" (MEDs), which have a definition more expansive than major events under COMAR. In other words, more "poor performance" is excluded from IEEE-based reliability indicators than those under COMAR. The following table, which compares the days that Pepco excluded from its Maryland reliability indices calculated according to these two methods, illustrates this point.[18]

Major Events Excluded from Calculation Of Reliability Indices

	Excluded as "Major Event" under COMAR	Excluded as "MED" under IEEE
2005	July 27	May 14 June 6 July 23–24 July 27–28 October 7–8
2006	February 12–14 July 4–7	February 12 June 25–27 July 2 July 4 September 1–2 October 20
2007	None	February 14 April 16
2008	June 4–8	February 10 May 31 June 4–5 June 16
2009	None	None

There are other differences in addition to the definition of what constitutes a major event. The IEEE "beta method" used to identify MEDs has the effect of smoothing out the inherent variability in a utility's performance over a time period. At bottom, neither method produces results that one can accurately refer to as indicators of blue sky reliability.

As we discussed earlier, because a system is well-designed does not mean it is not vulnerable. A well-designed and robust distribution system should be able to withstand winds of approximately 35 miles per hour without sustaining outages—above that point any distribution system is

[18] Response to Data Request #95 and Pepco Annual Reliabilities Indices Reporting. The IEEE method refers to cumulative customers experiencing outages; COMAR refers to customers out of service at peak.

vulnerable to damage.[19] Similarly, outages still occur on robust systems on blue sky days; these are usually associated with construction and auto accidents, animal interference, equipment failures, or damage from tree limbs weakened in previous storms. Being able to determine how a distribution system performs in blue sky conditions and in minor storm conditions would provide useful insights into underlying reliability issues.

We tried to break apart Pepco's SAIFI and SAIDI numbers to isolate the system's reliability under three conditions: no storms (blue sky), minor storms, and major storms. Relatively high numbers of outages and long outages, *i.e.*, high SAIFI and SAIDI, in blue sky conditions generally imply equipment issues. Relatively high SAIFI and SAIDI during minor storm conditions generally imply insufficient maintenance, vegetation-related or otherwise. Pepco, unfortunately, does not capture such detail in its outage data.[20] What is Pepco's blue sky reliability? We simply do not know, and neither does Pepco.

Pepco's upsurge in reliability problems in Maryland since 2004 was, we believe, triggered by the residual effects of Hurricane Isabel in 2003, which certainly damaged equipment on the system and weakened surrounding vegetation. Our working theory—and we think it is a reasonable one—is that the primary root cause of Pepco's outages during relatively minor everyday events is the same as the root cause for outages during major events—inadequate vegetation management. The Company until recently has been consistently short on its targeted tree trimming. Insufficient system maintenance and inspections are, however, a contributing factor. On Pepco's sub-transmission and distribution lines, repairs often happen by chance, not by procedure. In that context, frequent outages are no surprise.[21]

Pepco's piecemeal approach to dealing with its reliability issues has, at least until recently, been reactive rather than proactive. Pepco's monthly management reliability reports track Maryland and District of Columbia results separately, as they should, since these systems, and their vulnerabilities, are markedly different.[22] Even so, it appeared to us that until recently Pepco's senior management was not focused on designing initiatives specifically targeted to restoring reliability for Montgomery County and Prince George's County customers.

2. Industry Benchmarking

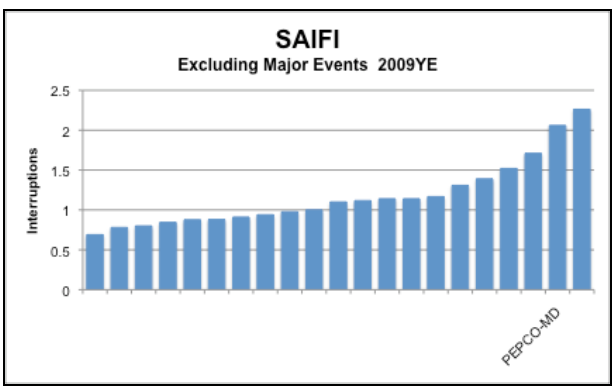
Benchmarking a utility's performance can sometimes offer insights. Benchmarking reliability across utilities, however, is complicated because there are many conditions that can affect measured quality (*e.g.*, weather, population densities) that differ among utilities that are beyond management control. To do a rigorous and meaningful comparative analysis, one must account for these differences. As we discuss in our survey of reliability standards in other states (Appendix A), there is no absolute industry standard for normalizing reliability data to exclude

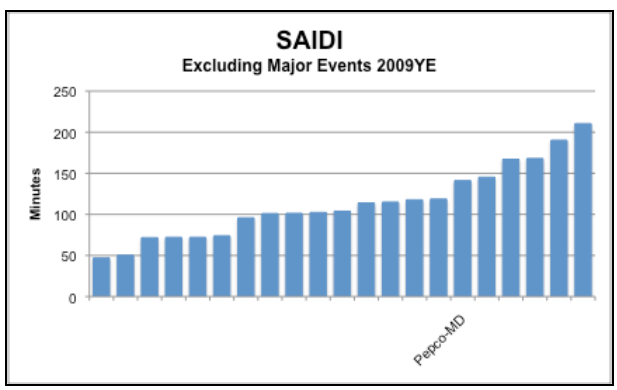
[19] Pepco also believes that its system should be able to withstand storms with wind speeds in the 35 to 40 mph range without significant customer outages (Interview #4, January 6, 2011).
[20] Response to Data Request #72.
[21] Pepco had no major events, as defined by COMAR, during 2004, which may be why this outcome did not materialize sooner than 2005.
[22] Reliability reports provided in response to Commission Question No. 2.

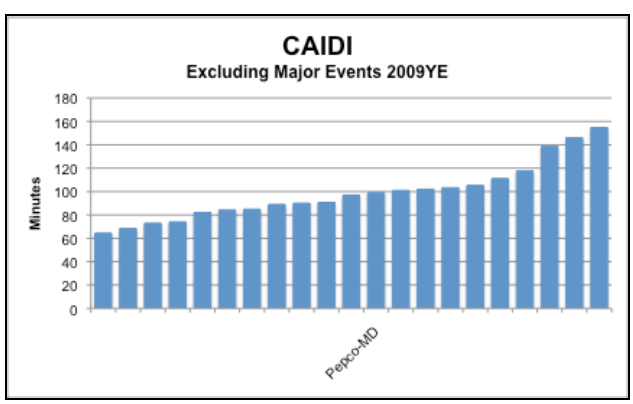
exceptional events such as storms. As such, a considerable amount of insight and discretion is required to make meaningful comparisons between utilities in different states based on indices such as SAIDI, SAIFI, and CAIDI.

Pepco participates in various performance benchmarking programs, such as those run by the Edison Electric Institute (EEI), IEEE, Electric Power Research Institute (EPRI), Southeastern Electric Exchange (SEE), Public Service Enterprise Group (PSEG), and PA Consulting.[23] These benchmarking studies generally show Pepco in the worst performing quartiles for SAIFI, SAIDI, and CAIDI. These comparisons are generally based on Pepco's system-wide reliability, which is considerably different from the Company's performance in Maryland.

We have compared Pepco Maryland 2009 performance against the IEEE-method SAIFI, SAIDI, and CAIDI results of utilities in First Quartile's benchmark panel.[24] We recognize that comparisons of metrics calculated according to COMAR to those calculated using IEEE methods are imperfect; we selected 2009 because no major events were excluded from calculations that year by either method.







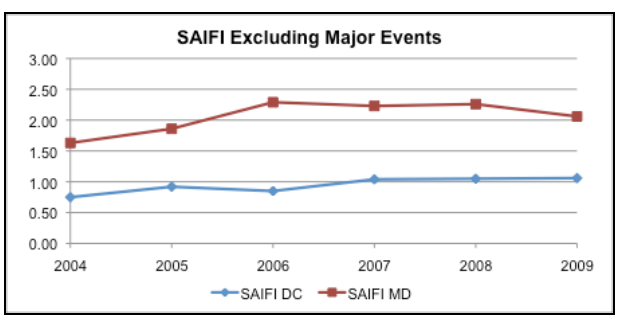
[23] Response to Commission Question No. 6. Pepco also participated in the Salt River Project Large City Survey for its District of Columbia operations.
[24] U.S. utility participants in the First Quartile benchmarking program are shown in Appendix B.

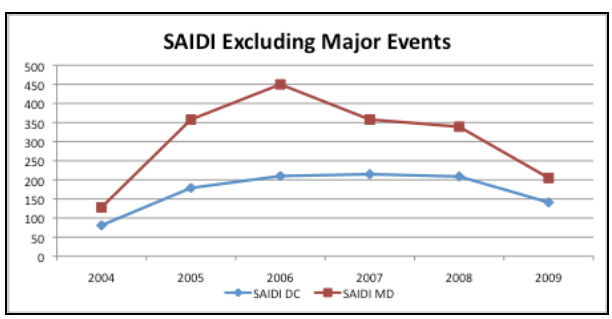
As can be seen from the SAIFI chart, Pepco's performance is on the high end of the comparison panel for outage frequency. This is consistent with how it has performed over the past several years. Pepco's Maryland distribution system has two key characteristics which would lead to a higher SAIFI than some of the other companies in the comparison panel: a high percentage of overhead lines and a high volume of trees in the territory that are in proximity to primary conductors.

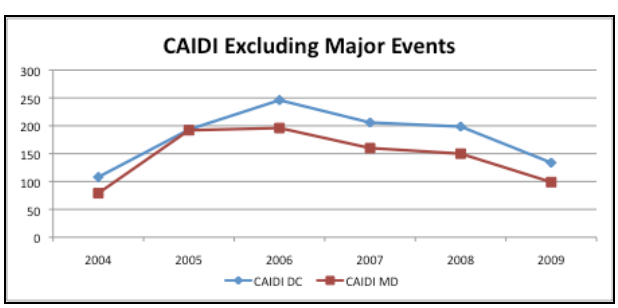
Pepco's CAIDI value is about average for the group, which is what one would expect for a system with a limited amount of SCADA coverage on the distribution lines, radial loop design, and a relatively compact service territory. The combination of an average CAIDI and a very high SAIFI yields a SAIDI value that falls between 3rd and 4th quartile performance.

3. Maryland versus District of Columbia Reliability

We are in this nine-week investigation focusing on Pepco's reliability in Maryland, and our conclusions and recommendations in this report cannot be unilaterally applied to Pepco's District of Columbia territory. Similarly, it is important to distinguish between Pepco's performance on a system-wide basis or in its District of Columbia service territory from its performance in Maryland. The following charts compare reliability indices for Pepco's Maryland and District of Columbia service areas separately.[25]







Pepco's Maryland customers fare worse in the frequency of outages and the average duration of outages across all customers. District of Columbia customers that do experience outages,

[25] Maryland data from the response to Data Request #95 and Pepco Annual Reliabilities Indices Reporting. District of Columbia data from 2010 Consolidated Report filed with the District of Columba Commission in Formal Case No. 991.

however, tend to be without power longer than those in Maryland. This makes sense because of the differences in the configuration of two systems. The higher percentage of underground lines in the District of Columbia means there is less exposure to weather and trees, so the frequency of outages, not surprisingly, is lower. On the other hand, outages in a mostly-underground system are typically more difficult to find and restore than on overhead lines; as such, customers tend to experience longer outages.

D. Major Conclusions

1. Pepco's sub-transmission and distribution system infrastructure is robust and well-designed, consistent with good utility practice.

The sub-transmission system is designed as substation groups with three independently-routed lines into each distribution substation. The redundancy built into the system means that Pepco can lose one sub-transmission line or substation transformer yet still be able to serve peak load with remaining facilities. The basic physical configuration of Pepco's distribution system, a radial loop design with redundant facilities, is similarly consistent with N-1 reliability standards. We did not see a need for any changes in the basic configuration of Pepco's distribution system in order to improve overall reliability.

2. Pepco's distribution system has more than adequate SCADA capabilities.

The Company has complete SCADA control of operational devices at its 69 kV, 34 kV, and 13 kV substations, including the ability to remotely energize individual distribution circuits. Pepco also has incorporated substation equipment monitoring and system-wide voltage profile control into its SCADA capabilities. These capabilities are well above industry norms, and we do not believe further expansion of Pepco's SCADA capabilities within substations is warranted.

3. The Pepco sub-transmission and distribution systems have inadequate switching capabilities. *(Recommendation II-1)*

Pepco's system lacks adequate switches on its 69 kV and 34 kV lines, and the Company has virtually no control over those it does have. By adding more remote-controlled motor-operated switches automated from the control center, Pepco could restore interruptions on these lines more quickly. Faster restoration means more line outages would be momentary rather than sustained. During storm events, faster restoration on a line may enable Pepco to avoid overlapping line outages that cause the loss of entire substations and result in customer outages.

4. Pepco cannot separately quantify its system reliability under blue sky, minor storm, and major storm conditions. *(Recommendation II-2)*

Pepco should know, and be able to inform the Commission, what the inherent reliability of its system is on so-called blue sky days. The Company does not collect adequate information about ambient weather conditions, and so cannot distinguish how its distribution system performs in

fair weather from how it performs during minor or major storm events. Without such information, the Company cannot conduct more sophisticated post-event weather analyses of damaged facilities or weather hardening studies so that it properly targets reliability-improvement efforts.

5. Pepco's upsurge in reliability problems after 2004 was triggered by the residual effects of Hurricane Isabel.

Utilities in the path of Hurricane Isabel in 2003 suffered damaged equipment on their systems and weakening of vegetation surrounding those systems. Normally we would expect a utility to spend more on preventative maintenance after such an event in order to counteract the increased risk of outages caused by such damage. Pepco, however, responded with insufficient preventative maintenance and vegetation management, which only heightened the hurricane's effect of increasing the system's vulnerability to future events.

6. Inadequate vegetation management is the primary cause of Pepco's reliability problems in Maryland.

During our investigation, we found that vegetation is the primary cause of the most potentially-preventable outages in Pepco's Maryland service area. Insufficient system maintenance and lack of sufficient switching capabilities are also contributing factors to the duration of outages. These same factors are at the root of outages during relatively minor everyday events as well as during major storms. We discuss the support for these findings in Chapters III, IV, and V of this report.

E. Recommendations

II-1 Pepco should install additional switches on its sub-transmission lines and add automated control to existing switches. *(Conclusion #3)*

Improved switching capabilities will have a positive impact on the Company's reliability metrics. Pepco plans to install new automated recloser schemes on its distribution system as part of its two percent worst feeder program and its Reliability Enhancement Plan. The Company should also analyze the benefit of adding switching capability to improve its reliability under blue sky, minor storm, and major storm conditions, and prioritize its spending accordingly. For example, automation capability on distribution tie switches is less useful during major events such as the storms of 2010 as it typically shuts down during widespread outages.

II-2 Pepco should conduct more comprehensive analyses of its outages. *(Conclusion #3)*

The Company should immediately begin capturing information about conditions in advance of outages in enough detail so that it can (a) separately quantify its reliability during blue sky, minor storm, and major storm conditions, and (b) conduct fuller analyses of reliability improvement initiatives. For example, certain types of distribution automation help reduce the

number or length of outages during blue sky or minor storm conditions, but do little to help avoid outages during major events. Unless the Company understands under which conditions it is vulnerable, it cannot make informed decisions about appropriate levels of spending, nor can it evaluate the benefit of expediting certain projects, such as the installation of automated reclosers.

III. Analysis of Outages

A. Introduction

In this chapter, the team discusses Pepco's process for collecting information about outages on its system, and how the Company analyzes and applies that data in its distribution reliability programs. We then examine the outages during the storm events of 2010 in order to shed light on the root causes of Pepco's reliability problems. We first describe our analysis, which focuses on outages that occurred on the 69 kV and 34 kV sub-transmission systems during the storms. The team designed this analysis as a means of illustrating the inherent vulnerabilities of Pepco's overall system. As we discussed in the prior chapter of this report, there are direct parallels between the causes of outages that occurred during the storm events and those reflected in Pepco's distribution system SAIFI and SAIDI metrics. In the end, the underlying causes of the outages during the storms events are the same as those undermining Pepco's reliability on an everyday basis.

B. Outage Data and Analysis

Pepco requires that its line personnel collect all outage information, including during storm events. The Company uses the Advantex data system as the mobile dispatch interface to its Outage Management System (OMS). Dispatchers use the system to send orders directly to a field vehicle and to direct the vehicle to the device that the OMS has predicted to be the problem. Line personnel use various screens and drop box menus in Advantex to record data such as on-scene time, estimated time of restoration, actual restoration time, and cause. The Company uses an array of outage cause codes, including weather-related ones like ice, wind, rain, and lightning. Line personnel gather additional information about tree-related outages, such as whether the outage was caused by limbs or downed trees, and whether the offending vegetation was inside or outside of the tree zone.[26]

Pepco generates a daily outage report on the sub-transmission and distribution systems from its OMS. The system also provides information such as number of device operations and feeder lock outs. Pepco uses its outage information to calculate a variety of reliability metrics using the IEEE method including system-wide reliability and Tree SAIFI, *i.e.*, outages caused by trees on a circuit basis. Analysis is the responsibility of Pepco's reliability engineers, who plot daily outages on a rolling basis to help assess reliability problems. In December 2010, these engineers were trained in investigation and data acquisition techniques to improve their analysis skills.[27]

The Company uses this information to construct its list of priority feeders, but also uses it to identify pockets of poor reliability nested within distribution circuits, *i.e.*, protective devices at which customers experience an unusually high number of interruptions. Pepco's asset

[26] Interview #5, January 7, 2011.
[27] Interview #6, January 24, 2011.

management group examines each circuit lock out in further detail. Until recently, the Company conducted its analysis of circuits using a Composite Performance Index (CPI) method unique to Pepco. In simplest terms, CPI uses a five-year average of SAIFI data to determine if a particular feeder was a worst performing circuit. The five-year average approach, however, masks emerging problems for feeders, *i.e.*, circuits with bad performance may not be identified as a candidate for the worst performing feeder program. Pepco recognizes the issues with its CPI assessment and now also relies on the contribution to SAIFI in its evaluations. Pepco is concentrating its current reliability improvement efforts on reducing SAIFI, on the premise that SAIFI reduction will also reduce SAIDI (the opposite may not be true).[28]

We focused in our investigation on Pepco's outages during the 2010 storm events as a proxy for its more everyday reliability issues. The recorded causes of outages in Pepco's customer interruption records or "trouble tickets" are summarized on the following table.[29]

Pepco Recorded Causes of Outages

Cause	February 5–6		July 25–29		August 5–6		August 12–15	
	MC	PGC	MC	PGC	MC	PGC	MC	PGC
Equipment failure	71	30	117	42	43	30	85	25
Lightning	0	0	261	64	6	74	204	86
Other	74	65	232	74	23	87	136	38
Trees	572	251	771	242	33	118	321	49
Ice	83	35	-	-	-	-	-	-
Weather	196	27	405	83	3	95	43	14
Total	996	408	1,786	505	108	404	789	212

Pepco uses its major storm outage data in developing the "lessons learned" included in its major storm reports, but only from a restoration improvement perspective. The Company does not to our knowledge do any more sophisticated analysis such as post-event weather severity root cause analysis of damaged facilities or weather hardening studies.

Pepco believes that 50 percent of the outages during these storms were related to trees, which is consistent with the storm service records shown above. The Company recognizes that the assignment of a cause code is open to interpretation in the field.[30] This is true at most utilities. We think in the case of Pepco, the effect of trees is understated. While outages designated as tree-related were almost certainly caused by vegetation, we think it likely that some caused by "weather" also may have been due to trees. Many of the tree-related sub-transmission outages we reviewed had "storm" listed as the cause on the system operator logs.[31]

The causes of outages during relatively minor events are in our view consistent with the causes of outages during major storm events. It was evident during our system inspections that

[28] Interview #6, January 24, 2011.
[29] Response to Data Request #49.
[30] Interview #5, January 7, 2011.
[31] Response to Data Request #74.

vegetation would impact the on-road components of the sub-transmission system and the distribution system in a similar fashion, even in less severe storms. In our view, vegetation is clearly the cause of the most *potentially-preventable* outages in Pepco's Maryland service area.

C. Effect of the Storms on the Distribution System

1. Description of the Analysis

We focused our analysis on the effect of the four storm events on Pepco's 69 kV sub-transmission system as a proxy for the distribution system as a whole. Of the twenty Maryland distribution substations lost during the 2010 storms due to outages on the 69 kV sub-transmission system, eighteen were due to trees.[32]

The 69 kV lines to distribution substations typically run along the same pathways as Pepco's distribution primary feeder circuits, and are thus vulnerable to similar factors. A large portion of the tree-related outages on the 69 kV system during these storms occurred on public ways. For example, of the fifteen sustained outages on the sub-transmission system caused by trees during the February storm, thirteen were caused by trees not in the right-of-way but on public ways. Similarly, of eight sustained outages in the August 12-15 event, seven were caused by trees in the public way.[33] Distribution lines, located in public ways, are exposed to the same risks as the 69 kV lines—the same tree that can take down a 69 kV line can take down up to two additional distribution feeders.

Just as there are direct parallels between the sub-transmission and distribution systems, there are, we believe, direct parallels between outages that occur during the 2010 major storms and those that occur in smaller events. Everyday outages in our view mimic what happened to the system in these storms, and occur for the same reasons.

There were no losses of customer load due to transmission line outages during the 2010 storms.[34] As a general matter, transmission issues are not part of the reason for reliability problems either in storms or during blue sky days. Reliability statistics for Pepco's substation and distribution system are summarized in the following table; substation reliability statistics reflect outages caused by substation equipment and the sub-transmission lines feeding distribution substations.[35]

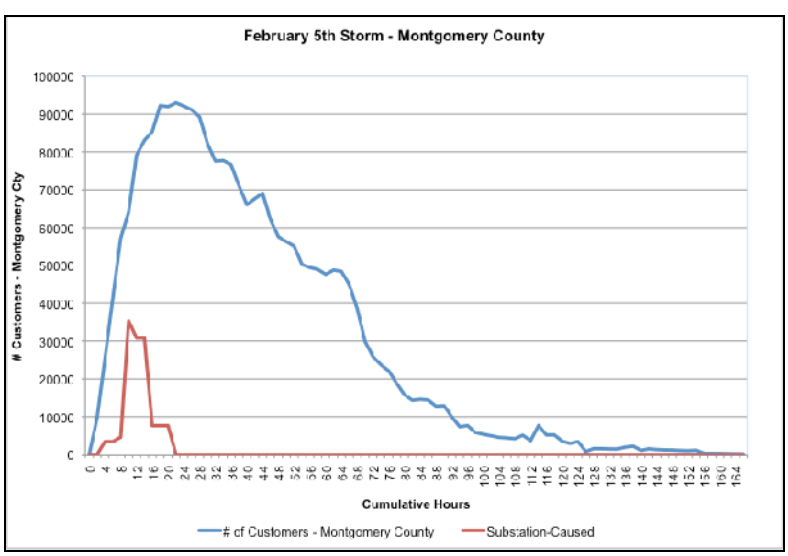
[32] Response to Data Request #74.
[33] Response to Data Request #137.
[34] Response to Data Request #50. During our analysis, we found that eight transmission lines experienced outages but the outages did not result in loss of customer load.
[35] Response to Data Request #72.

Reliability Indices for Substation and Distribution
Exclusive of Major Event Days

	Substation					Distribution			
	Montgomery		Prince George's			Montgomery		Prince George's	
	SAIFI	SAIDI	SAIFI	SAIDI		SAIFI	SAIDI	SAIFI	SAIDI
2008	.29	12	.28	14		1.55	237	1.99	299
2009	.48	24	.49	20		1.59	178	1.57	186
2010	.70	45	.53	29		1.75	265	1.39	163

We asked Pepco for a time line for each of the four storms, showing when each transmission and sub-transmission protection device operated, along with the cause for the interruption and the number of customers interrupted as a result. Pepco assembled a log of events using data from its SCADA system and system operator logs.[36] These data were the basis for our analysis.

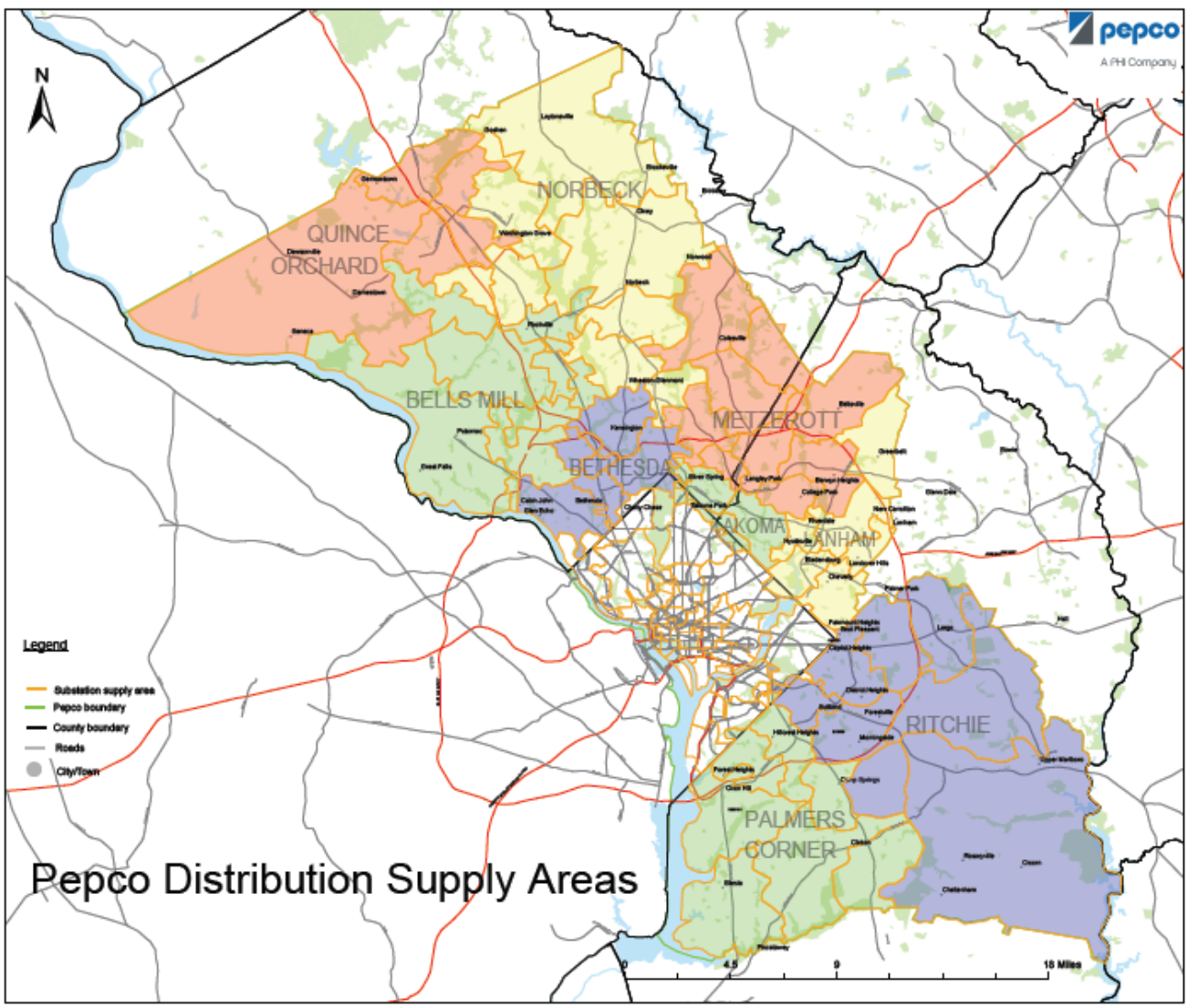
We examined how the Pepco sub-transmission system behaved during these events to provide insight into the inherent vulnerability of the overall distribution system. In each of the four major storm events in 2010, Pepco experienced entire outages of 69 kV or 34.5 kV/13.8 kV substations that contributed to its total number of customer outages. We examined why the 69 kV and 34.5 kV sub-transmission system outages occurred and how they contributed to total customer outage figures. Most of these distribution substation outages happened early in the storms, so the numbers of customers interrupted we show in our analyses is reasonably accurate. After a substation was lost, but before it was restored, other outages typically occurred along the distribution system served by the substation. Because of these nested outages, we had to make assumptions about the number of customers that were restored after Pepco brought the substation back on line. In our analysis, we assumed that all customers were restored when a substation was reenergized, but in actuality the number would be lower due to nested outages. The following graph compares the effect of these substation outages in relation to total customer outages for the February 5–6 storm event. Graphs for other storms are shown in Appendix C.



[36] Response to Data Request #74.

Only a subset of the total outages on the sub-transmission system led to loss of substations. We examined the outages on all circuits on the transmission and sub-transmission system that experienced an outage during each storm, whether they led to a substation loss or not. We focused on the pattern of sustained and momentary outages (those lasting five minutes or less), which provided us with deeper insights into the underlying causes for the outages.

We worked with Pepco to develop the following generic map of "load areas" so that we could discuss the analysis yet avoid talking about Critical Energy Infrastructure Information (CEII).[37] We have defined a load area as an area of sub-transmission substation groups that is supplied by a multitude of higher voltage transmission lines.



[37] Response to Data Request #74.

2. February 5–6, 2010 Snowstorms

The following table summarizes the timing of the loss of distribution substations during the February storm due to sub-transmission events; all were in the Bells Mill load area.

Number of Customers Interrupted Due to Substation Outages
February 5-6, 2010

Load Area (County)	Time	# Customers Interrupted	Substations Lost/In Service
February 5			
Bells Mill (Montgomery)	19:01	3,421	Montgomery Village (#79) Lost due to equipment
Bells Mill	19:36	0	Montgomery Village (#79) In Service
Bells Mill	23:50	4,568	Mt. Zion (#165) Lost due to equipment
February 6			
Bells Mill	01:31	17,961	Beverly Farm (#171) Lost due to trees
Bells Mill	01:47	35,375	Hunting Hill (#79) and Potomac (#2) Lost due to trees
Bells Mill	02:44	30,807	Mt. Zion (#165) Back in service
Bells Mill	06:52	17,414	Beverly Farm (#171) Back in service
Bells Mill	06:54	7,631	Hunting Hill (#79) Back in service
Bells Mill	12:36	0	Potomac (#2) Back in service

Number of customers restored is overstated as it does not reflect those still out due to nested outages.

Substation outages occurred during both days of the event. At 7:01 p.m. on February 5, the trip of a single 69 kV line resulted in loss of load at the Montgomery Village Substation due to what appears to be a breaker malfunction at the substation while clearing the fault. The substation was restored by dispatcher action thirty-five minutes later. Shortly before midnight, another equipment malfunction at the Mount Zion Substation resulted in the loss of customers. This outage was not restored until 2:44 a.m. on February 6.

On February 6 at 1:31 a.m., after a number of sub-transmission outage events, the Beverly Farm Substation was lost due to vegetation issues. The outage of the Hunting Hill and Potomac substations occurred shortly thereafter for similar causes. Pepco restored Beverly Farm at 6:52 a.m., Hunting Hill Substation at 6:54 a.m., and Potomac at 12:36 p.m.

Many of the outages along the sub-transmission system during the February storm did not lead to substation outages. Due to the N-1 design criteria, Pepco must lose at least two lines to its distribution substation before it loses the substation. We examined the pattern of sustained and momentary outages on all transmission and sub-transmission circuits affected during the two-day event; these outages are summarized on the table below. Many of the outages were momentary in

nature. Such an outage pattern is consistent with the snowstorm event. Facilities continued to trip as the weight of the snow brought vegetation into contact with the sub-transmission facilities and the circuit tripped and reclosed, causing momentary outages. Heavy snow broke branches that then caused sustained outages as they fell onto the lines.

February 5–6 Snowstorm Event
Transmission and Sub-transmission Circuit Operations

		Outage Experienced (S – Sustained; M – Momentary)	
Circuit #	**Voltage (kV)**	**February 5**	**February 6**
69138	**69**	**M S**	
69063	**69**	**S #**	
69181	**69**	**M S**	**M S ***
69185	**69**	**M M M M S M**	**M S * M**
69180	**69**	**M M S**	**M S**
69177	**69**	**M M M M**	**M M M M M M M S**
13862	**138**	**S**	
13802	**138**	**S**	
13816	**138**	**S**	
69082	**69**	**S #**	**S**
69179	**69**		**S S**
34951	**34**		**S**
69079	**69**		**M M M M M S M**
69060	**69**		**S**
34021	**34**		**M M S**
34012	**34**		**S M S**
34027	**34**		**M S**
69139	**69**		**S**
69113	**69**		**S**
69141	**69**		**M**
69053	**69**		**S**
69167	**69**		**S**
69104	**69**		**M**
23014	**230**		**S**
69140	**69**		**M**

Substation load lost due to equipment. * Substation load lost due to trees

Some circuits suffered more than one sustained outage during the two-day event. For example, Circuit 69082 had a sustained outage due to equipment on February 5, which led to the loss of a substation; the outage was repaired and there was another outage along the circuit the next day that did not result in the loss of load because a second 69 kV feed into the substation had been established prior to the second event. A sustained outage on Circuit 69185 on February 6 due to trees caused the loss of substations; the same circuit experienced a series of momentary outages (more than likely due to snow-laden branches slapping into wires) and a sustained outage the previous day that did not result in the loss of customer load. In all, a total of 23 sustained and 38 momentary outages occurred on the total Pepco Maryland sub-transmission system during this

event. Of the total outages, nine sustained and 23 momentary outages were related to the substation outage events in the Bells Mill load area. With so many outages on the total sub-transmission system, additional substations could have easily been lost in other load areas had additional contingencies occurred.

3. July 25–29, 2010 Thunderstorms

The following table summarizes the timing of the loss of distribution substations during the July event. All were located in Montgomery County and were due to trees.

Number of Customers Interrupted Due to Substation Outages
July 25–29, 2010

Load Area (County)	Time	# Customers Interrupted	Substations Lost/In Service
July 25			
Quince Orchard (Montgomery)	15:13	7,730	Bureau of Standards (#160) Lost due to trees
	15:21	0	Bureau of Standards (#160) Back in service
July 25			
Bells Mill 69 kV (Montgomery)	15:16	13,393	Beverly Farm (#171) Lost due to trees
	15:19	30,807	Hunting Hill (#79) and Potomac (#20) Lost due to trees
Bells Mill 34 kV (Parklawn area)	15:26	42,692	Linden Street (#56) Lost due to trees
	17:30	29,299	Beverly Farm (#171) Back in service
	17:31	19,516	Hunting Hill (#79) Back in service
	19:45	7,631	Linden Street Back in service
July 26			
	01:38	0	Potomac (#2) Back in service
July 25			
Norbek (Montgomery)	15:20	3,833	Shady Grove (#49) Lost due to trees
	15:26	12,110	Derwood (#209) Lost due to trees
	15:32	0	Shady Grove (#49) and Derwood (#209) Back in service
July 25			
Metzerott Road (Montgomery)	15:33	24,741	Colesville (#144), Metzerott Road (#140), and Fairland (#177) Lost due to trees
	15:43	15,241	Metzerott Road Back in service
	15:50	24,741	Metzerott Road (#140) Lost due to trees
July 26			
	01:50	15,241	Metzerott Road Back in service
	02:20	6,858	Colesville (#144) Back in service
	02:40	0	Fairland (#177) Back in service

Number of customers restored is overstated as it does not reflect those still out due to nested outages.

Pepco declared a storm event on its system on July 25 at 3:07 p.m. Within a few minutes, Pepco began to experience widespread tree-related substation outages in the Quince Orchard, Bells Mill, Norbeck, Parklawn Drive (a subsidiary section of Bells Mill), and Metzerott Road load areas in Montgomery County. There were a large number of sub-transmission outages over a relatively short period of time, the majority of which were sustained. The initial substation outage occurred in the Quince Orchard load area when the Bureau of Standards Substation was lost due to trees; the substation was restored in six minutes. The Bells Mill load area was impacted minutes later. At 3:16 p.m., the Beverly Farm Substation was lost when the last remaining sub-transmission line serving it faulted due to trees. The Hunting Hill and Potomac substations followed at 3:19 p.m. Beverly Farm and Hunting Hill were returned to service after approximately two hours, but Potomac was not returned until the early hours of July 26.

Within minutes of the Bells Mill load area outages, Pepco's Norbeck load area was impacted by substation outages, with the loss of Shady Grove and Derwood due to tree-related damage; both substations were, however, back in service quickly. At 3:26 p.m., the Parklawn Drive area was impacted by the storm when the Linden Substation was lost due to tree-related sub-transmission outages. Linden was returned to service approximately four hours later at 7:46 p.m.

Less than fifteen minutes after the Norbeck load area was affected, the Metzerott Road load area was impacted when the last remaining sub-transmission line to that substation group faulted due to trees, and three substations, Colesville, Metzerott, and Fairland, were lost. The Metzerott Road Substation came back in ten minutes but was subsequently lost again a few minutes later. All three of the Metzerott Road load area substations were out until the early hours of July 26.

Widespread quickly-occurring outages during the July event are consistent with a fast-developing severe storm event that triggered vegetation problems. A table summarizing the sustained and momentary outages that occurred on the transmission and sub-transmission system during the July 25–29 event is located in Appendix C. A total of 41 sustained and 39 momentary outages occurred on the total Pepco Maryland sub-transmission system in this storm event. Of these, 27 sustained and 24 momentary outages were in the load areas sustaining substation loss.

4. August 5–6, 2010 Thunderstorms

The following table summarizes the timing of the loss of distribution substations during the August 5–6 thunderstorm event; these substation outages were confined to the Ritchie load area in Prince George's County.

Number of Customers Interrupted Due to Substation Outages
August 5–6, 2010

Load Area (County)	Time	# Customers Interrupted	Substations Lost/In Service
August 5			
Ritchie (Prince George's)	16:10	48,184	Oak Grove (#122), Crain Hgwy. (#155), Central Ave. (#185), and Largo (#191) Lost due to trees
	16:31	35,350	Largo (#191) Back in Service
	17:11	25,890	Oak Grove (#122) Back in service
	17:13	13,941	Central Ave. (#185) Back in service
	19:02	0	Crain Hgwy. (#155) Back in service

Number of customers restored is overstated as it does not reflect those still out due to nested outages.

At 3:30 p.m. on August 5, Pepco declared a storm event on its system. The sub-transmission outages occurred due to trees and occurred quickly. At 4:10 p.m. on August 5, the outage of the last 69 kV line into this substation group faulted due to trees and the Oak Grove, Crain Highway, Central Avenue, and Largo substations were all lost. Pepco restored Largo within twenty-one minutes. Within a couple of hours, all three of the remaining substations were restored.

A table summarizing the sustained and momentary outages that occurred on the transmission and sub-transmission system during the August 5–6 event is located in Appendix C. Sub-transmission outages were concentrated in the first day of the event and most were sustained outages. Localized quickly-occurring outages are consistent with a severe storm event causing vegetation issues. A total of eight sustained and nine momentary outages occurred on the total Pepco Maryland sub-transmission system in this storm event. Of these, six sustained and three momentary outages were in the Ritchie load area.

5. August 12–15 2010 Thunderstorms

The following table summarizes the timing of the loss of distribution substations during the August 12–15 severe thunderstorm event; the substation outages were confined to the Metzerott Road load area in Montgomery County and were all tree-related.

Number of Customers Interrupted Due to Substation Outages
August 12–15, 2010

Load Area (County)	Time	# Customers Interrupted	Substations Lost/In Service
August 12			
Metzerott Road (Montgomery)	07:25	27,444	Four Corners (#26), Seek Lane (#199), and White Oak (#153) Lost due to trees
	07:35	27,445	Archives (#174) Lost due to trees
	07:58	27,444	Archive (#174) Back in service
	11:52	19,703	Seek Lane (#199) Back in service
	12:12	9,677	Four Corners (#26) Back in service
	12:41	0	White Oak (#153) Back in service

Number of customers restored is overstated as it does not reflect those still out due to nested outages.

At 6:45 a.m. on August 12, Pepco declared a storm event in its service territory. Many sub-transmission outages occurred quickly. At 7:25 a.m., the outage of the last 69 kV line into this substation group faulted due to trees, and the Four Corners, Seek Lane, and White Oak substations were lost simultaneously. Ten minutes later, the remaining feed into the Archives Substation was out, resulting in the loss of that substation. Pepco restored Archives in less than half an hour. The remaining three substations were all restored by 12:41 p.m. the same day.

A table summarizing the sustained and momentary outages that occurred on the transmission and sub-transmission system during the August 12–15 event is located in Appendix C. The majority of sub-transmission system outages occurred in the first day of this storm event. The quick collapse of the multiple feeds in the Metzerott Road load area and the relatively high number of sustained outage events indicate that the event was both fast moving and violent. A total of 19 sustained and 10 momentary outages occurred on the total Pepco Maryland sub-transmission system; four of the sustained outages were in the Metzerott Road load area.

6. Summary of Outage Events in Maryland Load Areas

The table below summarizes the outages on the 69 kV and 34 kV sub-transmission system during the four storms events by load area; the pattern of outages helps illustrate both the robustness and the vulnerability of the Pepco system.[38]

The effect of the February event was widespread in Montgomery County. Even though several load areas suffered sustained outages, there was no loss of customer load due to substations other than in the Bells Mill load area. The redundancy built into the system allowed substations in other load areas to remain in service even after an N-1 contingency. The August 5–6 event, by contrast, was almost totally concentrated in the Ritchie load area. Like the February snowstorms, the effect of the July 25–29 event was more widespread in both counties. Even load areas that

[38] Transmission outages are excluded.

did not experience substation outages were already experiencing N-1 contingencies—and were vulnerable to substation loss if additional contingencies had occurred.

Summary of Sub-transmission System Outages by Load Area

Load Area	Sustained (S)/ Momentary (M)	Feb 5–6	July 25–29	Aug 5–6	Aug 12–15
Quince Orchard	S	2	2	0	2
(Montgomery)	M	0	3	0	0
Norbeck	S	3	4	1	3
(Montgomery)	M	6	8	0	3
Bells Mill *	S	9	12	0	4
(Montgomery)	M	23	10	0	6
Bethesda	S	1	3	0	0
(Montgomery)	M	2	0	0	0
Palmers Corner	S	1	1	1	0
(Prince George's)	M	1	4	4	0
Metzerott Road	S	2	9	0	4
(Montgomery)	M	3	3	0	0
Ritchie	S	0	1	6	1
(Prince George's)	M	0	6	3	0
Takoma	S	3	5	0	3
(Prince George's)	M	0	2	1	0
Lanham	S	2	4	0	2
(Prince George's)	M	3	4	1	0
Other	S	0	0	0	0
(Prince George's)	M	0	0	0	1
Total	S	23	41	8	19
	M	38	39	9	10

* Parklawn/Linden Subarea included.

Of the 91 total sustained outages, only 12 of those outages led to the loss of distribution substations, due to the redundancy built in to the system. However, it is sobering to know that other load areas may have been just a tree branch away from even more customer outages.

D. Major Conclusions

1. Pepco's sub-transmission and distribution systems are particularly vulnerable to tree damage due to their placement—as the 2010 storms made evident.

Of the Maryland substations lost due to outages on the sub-transmission system during the 2010 storms, 90 percent were due to trees—the majority of which were not in the Company's rights-of-way but in public pathways. Nearly all of the Company's distribution circuits, and the majority of its sub-transmission circuits running to substations, are located along the same public ways. In many cases, Pepco has a sub-transmission circuit and two distribution circuits on poles along both sides of the street. With the comingled construction, the upper sub-transmission circuit is vulnerable to vegetation damage from above, and the two lower distribution circuits are vulnerable to vegetation damage from the side.

E. Recommendations

We have no separate recommendations in this chapter; our recommendations regarding vegetation management are contained in Chapter IV.

IV. Distribution Vegetation Management

A. Introduction

As we first discussed earlier in this report, damage inflicted by trees is the primary root cause of Pepco's distribution system reliability problems in Maryland. While we believe Pepco's vegetation management efforts over at least the last ten years were insufficient, other factors exacerbated the problem. Utilities in Maryland are subject to rules and ordinances governing tree-trimming that impose time-consuming permitting and approval requirements, and dictate, for example, whether a tree can be removed and how much of it can be trimmed.[39] Residents can also obstruct and frustrate a utility's attempt to remove trees and branches that can cause outages through the permission process. These factors lead to sub-optimal and more costly maintenance practices, and directly impact a utility's ability to provide safe, adequate, and reliable service.

During our investigation, we confirmed that Pepco's vegetation management on its transmission lines is adequate and not a contributing factor to the Company's reliability problems. Pepco's transmission vegetation management program is approved by the North American Electric Reliability Corporation (NERC) and compliant with federal standards.[40] The Company conducts comprehensive inspections of each right-of-way, establishes appropriate brush control and grass mowing programs, and conducts aerial inspections of all lines twice a year; needed tree work is performed by contractors and inspected by Pepco personnel to verify completeness. Pepco has a much better track record of preventing outages on its transmission system; it has wider right-of-ways and greater leeway to remove and trim danger trees.[41] Spending enough money on transmission vegetation management for Pepco is a "must do." Unfortunately, the same cannot be said of sub-transmission and distribution vegetation management efforts.

Vegetation management is a utility's single largest preventative maintenance expense. In the following sections, we describe and evaluate Pepco's prior vegetation management programs, practices, and spending levels.[42] We examine Pepco's current expanded sub-transmission and distribution vegetation management program and offer our opinion as to whether it will be effective in improving the reliability of Pepco's distribution system in Maryland. Finally, we compare Pepco's vegetation management to good utility practice.

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[39] See statutes and regulations provided in response to Commission Question No. 12. The Maryland Tree Law, for example, states that one should allow sufficient clearance for two years of growth normally expected after trimming. ANSI A300 standards dictate that utilities cannot remove more than 25 percent of a tree's foliage within one growing season.

[40] Response to Commission Question No. 11.

[41] Pepco owns approximately 330 linear miles of transmission right-of-ways that encompass roughly 10,000 acres, of which the company owns approximately 95 percent.

[42] While vegetation management programs encompass more than tree trimming and removal *(e.g.*, brush control), we focus primarily on tree-related trimming and removal activities in this chapter.

B. Prior Vegetation Management Programs and Spending Levels

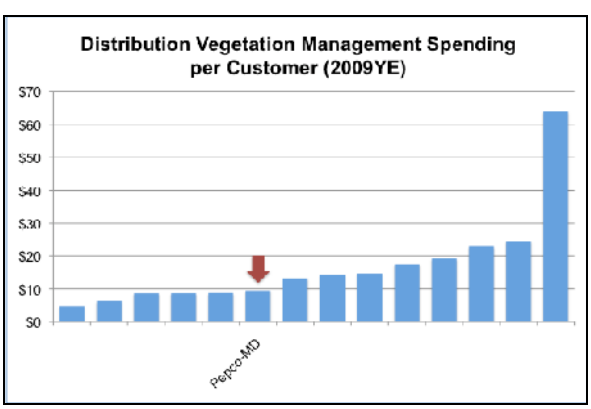
Pepco's budgeted and actual spending for Maryland distribution tree trimming activities for the 2004 to 2009 period is summarized in the following table.[43]

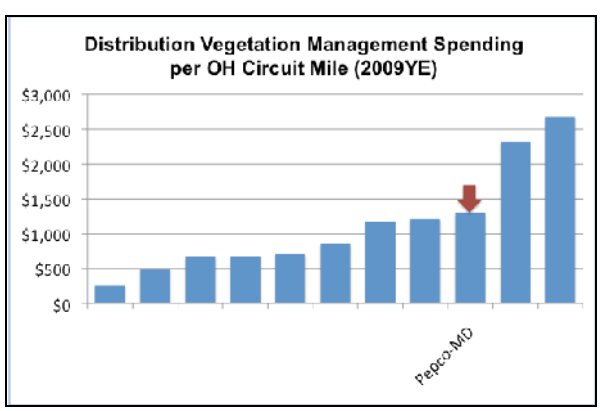
Pepco Maryland
Sub-Transmission and Distribution Tree Trimming
($ Millions)

	Budget	Actual
2004	$5.9	$5.4
2005	3.3	4.5
2006	4.1	3.9
2007	3.4	3.9
2008	4.3	5.1
2009	4.3	5.0

In 2005, Pepco's O&M spending in Maryland for vegetation management was cut further from already low levels and remained essentially flat in real terms, despite substantial increases in costs for this function throughout the industry. Unfortunately, Pepco was unable to provide budget or actual O&M figures before 2004, so it is impossible for us to determine when funding became insufficient to complete the task. Our general theory is that the issue has been developing over a relatively long period of time. In our experience, the cumulative effect of cutting back vegetation management spending can take several years to show up. The impact of insufficient spending showed up in a big way in Maryland reliability beginning in 2003.

When we compare Pepco's level of spending to the utilities in First Quartile's benchmark panel, we find that, on a per-customer basis, its levels are slightly below-average, as shown in the first chart below. We believe it is reasonable to assume that Pepco's Maryland territory is in the top half of the country in terms of tree density. As such, the chart on the right shows what we would expect—that Pepco's per-mile trimming cost for individual circuits is above-average.





[43] Response to Commission Question No. 11. The cost of the regular vegetation management work that is the focus of our investigation is treated as O&M expense. Costs for vegetation management performed in connection with new construction are capitalized as part of overall project costs.

Given the largely overhead configuration of Pepco's Maryland distribution system, it is reasonable to conclude that long-term success will require a higher-than-average spending level for vegetation management. While we understand the limitations of simple benchmark comparisons such as those shown above, the results are clearly in line with what we would have expected—that $5 million of spending in 2009 was not enough.

Until recently, Pepco's mandate was to keep actual spending as close to budget as possible. Unfortunately, the budget was never adequate to do the required level of trimming. In nearly every year beginning in 2003, Pepco was unable to meet its clearing objectives. Even though Pepco outspent its budget in four of the past six years, it still missed its work plan targets.[44]

Pepco's vegetation programs and services are managed at the corporate level by the PHI Vegetation Management Department. In-house staff includes professional foresters and arborists who manage activities, and like most utilities, the corporation uses contractors to perform the actual work in the field. 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.

By 1999, Pepco's company-wide distribution vegetation management program was on a two-year cycle (*i.e.*, the trees around each line were trimmed, if needed, to within two years' growth of the wires once every other year). The Company's program was consistent with COMAR requirements and the Maryland Tree Law that no more than two years of growth could be removed during trimming. The area of clearance between a tree and the wires, and therefore the amount of trimming required, was dictated by tree species, with fast-growing species needing more aggressive trimming to allow more room for growth.[45]

At this point in time, Pepco's existing trim zones around its distribution lines were significantly larger than two years of growth on many parts of its system. Pepco could therefore take advantage of its "clearance reserve" and avoid having to do a certain amount of trimming on the trees that were not within two years' growth of the wires. It is this reserve that helped delay the impact of the company's reduced spending on reliability—and may have lulled Pepco into thinking its lower vegetation management spending was adequate.

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.[46]

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[44] Interview #10, January 25, 2011, and response to Data Request #122.
[45] Interview #10, January 25, 2011.
[46] Interview #10, January 25, 2011.

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.[47] 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.[48]

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 "hot-spot" trimming for the one-phase portion of those circuits.[49]

In the same four years, Pepco's SAIDI and CAIDI in Maryland essentially tripled.

By 2008, Pepco recognized that it had long since used up its trim zone reserves and that the continued cutbacks in real spending levels meant that some trees were now into the wires. It decided to try yet another approach. During 2008 and 2009, Pepco transitioned from the plat-based program to a prescriptive feeder-based program, in which the Company trimmed all circuits out of a substation, half the substations being done each year. It abandoned the distinction between inside and outside the Beltway. It continued to use the 2.5 Tree SAIFI overlay to select where on the three-phase portion of the feeders to focus its trimming, and continued to pay attention to its worst performing feeders. Even though the Company outspent its budget by almost a million dollars in both these years, Pepco still did not complete approximately 20 percent of its scheduled work.[50]

By this time, SAIFI had nearly doubled from where it was in 2003.

C. Recent Changes in Vegetation Management Programs

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. Pepco implemented this new program for the three-phase portion of the feeders that it scheduled for trimming, and instituted an "inspect and trim as needed" program on the one-phase portion. The Company changed its Tree SAIFI screen from 2.5 to 2.0, which also increased the amount of

[47] Interview #10, January 25, 2011.
[48] Interview #10, January 25, 2011.
[49] Interview #10, January 25, 2011.
[50] Interview #10, January 25, 2011.

trimming required by including more circuits in the program. According to Pepco, this program met state and local laws, regulations, and standards.[51]

At the same time, Pepco, as part of its then-current rate case, had proposed to the Commission a new reliability initiative, Enhanced Integrated Vegetation Management (EIVM), to further mitigate tree-related customer outages. The program went beyond traditional tree trimming to include aggressive pruning, removal of undergrowth, and removal of hazard trees and limbs. The EIVM program also targeted healthy limbs overhanging the lines that were not part of normal clearance pruning. In the hazard tree portion of the program, arborists would work with owners of trees that represent threats to reliability to effect safe and timely removal before the trees could cause an outage. Pepco also planned to replace trees under or near the lines with less threatening species under its "Right Tree, Right Place" program. Pepco testified that the aggressive efforts under the EIVM program were twice as costly as routine clearance trimming and would increase O&M expenses by $3 million per year, but that the effort would ultimately, after four to six years, lead to reduced outages and capital expenditures.[52]

In June 2010, vegetation management requirements changed to a maximum four-year trimming cycle by species, and Pepco recognized that it would have to "reclaim" a significant portion of its distribution system in Maryland to meet the new trimming requirements. The Company revised its plan again mid-year to include some trimming on all circuits that were out of compliance by year-end. Pepco also added to its trimming plan all circuits with major outages during the February storm and an additional 10 to 20 feeders with a high Tree SAIFI as of mid-2010. In addition, Pepco added an aggressive hazard tree removal effort for the three-phase portion of feeders in the program.[53]

In its August 2010 order in the rate case, the Commission approved approximately $1.5 million in additional net annual O&M costs to fund the EIVM program.[54] But by that time, Pepco had already recognized that even the EIVM plan was not enough. The Commission initiated Case No. 9240 around this same time.

Pepco ultimately decided to implement the EIVM program in September. In the meantime, it began planning for an even more expansive vegetation management plan for 2011. In order to accomplish the incremental EIVM, Pepco retained additional tree trimming crews and supervisory personnel from Pennsylvania, and worked its vegetation management crews for 60 hours per week.[55] Spending on the EIVM program during the last four months of 2010 was $5.8 million.[56]

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[51] Interview #10, January 25, 2011, and response to Data Request #133.
[52] Supplemental Report of the Potomac Electric Power Company in Case No. 9220.
[53] Interview #10, January 25, 2011, and response to Data Request #79.
[54] Order No. 83516. The Commission concluded that the Company would experience offsetting cost reductions in the interim period.
[55] Interview #10, January 25, 2011.
[56] Response to Data Request #134.

Pepco decided that for 2011 it should start removing all vegetation above both three-phase and one-phase feeder primaries, use a four-year clearance requirement by species, and use Tree SAIFI only to prioritize the year's work. Pepco expects to complete work on its worst performing feeders in the first quarter of the year, expand its hazard tree removal program, and enhance and expand its tree replacement program. Pepco's budget for this work in 2011 is $9 million; it will work its vegetation management crews at 50 hours per week, rather than 60, to reduce overtime. Pepco estimates that two full trimming cycles, *i.e.*, eight years, will be required before it sees the full effects of its latest vegetation management plan.[57]

D. Assessment of Pepco's Current Program

During field inspections in Montgomery and Prince George's Counties, we examined parts of the system that had just been trimmed under the new 2010 and 2011 programs, and some that had not yet had prescribed trimming. We pre-selected eight circuits to inspect, half that had been recently trimmed, and half that had not. Our team member followed individual circuits to inspect trimming on approximately 95 percent or more of the selected feeders.

When we examined circuits that had not been recently trimmed, we could see the impact of Pepco's under-spending and ever-changing vegetation management programs. We saw where trees had very well-established clearances in the past, and how those clearances had eroded over the years. One can "read a tree" in this fashion because the vertical suckers that re-grow in previously-cleared areas of the tree do not have the natural growth characteristics of a tree that has not been previously trimmed. We saw clearly that by reducing real spending every year, the amount of work Pepco did not get done kept increasing; once the Company worked off its clearance reserve, the trees were essentially surrounding the wires, making them more susceptible to damage during wind, snow, and ice.

In addition to the eight circuits we pre-selected for vegetation inspection, our team member added four more circuits to the list while in the field and also spot-checked many others at random while traveling around to do system maintenance inspections. Pepco personnel logged nearly 1,000 miles driving us around during our inspections and we believe we observed an ample-enough portion of the system to support our conclusions.

We believe that vegetation conditions have deteriorated such that the Company will need two cycles of reclamation efforts in order to get clearances back to acceptable levels. This is true in part because the Company cannot remove more than 25 percent of a tree's biomass in any one cycle under American National Standards Institute (ANSI) standards. Also, in order to get the biggest "bang for the buck" in the early years of the program, the Company should tackle, at least to some degree, as much of the system as possible. Based on our experience, after Pepco completes two fully funded four-year cycles, its annual vegetation expenses should decrease by approximately one-third.

[57] Interview #10, January 25, 2011.

When transitioning to a four-year trimming cycle, vegetation conditions will continue to deteriorate on the remainder of the system that has not yet been brought into new standard requirements. These areas will only be hot-spotted and will continue to exhibit less than desirable reliability performance. Based on our experience, reliability trends will not reverse direction until at least one-half of the new vegetation management program is completed.[58]

During our field visits we also reviewed the Company's process for inspecting work performed by its outside contractors. Pepco confirmed that it performs 100 percent inspection of completed work.[59] We found that as a general matter, contractor work was satisfactory, but we did find some instances in which vegetation was not trimmed as prescribed nor identified as deficient after Pepco's inspection of the work. This is an important training issue—one missed location along a circuit can jeopardize otherwise significant and concentrated efforts to reduce feeder outages.

Pepco's vegetation management program for 2011 goes beyond the EIVM program instituted in 2010. The 2010 EIVM program was a limited expansion of the Company's two-year pilot EIVM program in the Oak Grove and Crain Highway/Largo areas in Prince George's County begun in 2007. The objective of the pilot program was to determine the level of reliability improvement that could be obtained by performing significant reclamation of distribution rights-of-way and trimming more aggressively than the normal cycle would otherwise dictate. Pepco experienced gains of 70 to 90 percent in tree-related reliability improvements at the circuit level.[60]

We believe Pepco's 2010 EIVM effort was moving in the right direction, and that the benefits are demonstrable. The 2011 program ramps up the EIVM program by applying EIVM requirements to all three-phase and single-phase primary conductors.[61] We think the new program is even better. By eliminating all vegetation above feeder primaries, many vegetation issues will be resolved—heavy snow cannot sag overhanging vegetation into conductors, ice cannot break branches that then fall into conductors, and weakened vegetation from previous events is not in place to cause potential future outages.

Based on our experience, we believe that Pepco's current aggressive vegetation management program, if adequately and continuously funded over the next eight years, will significantly improve reliability in Maryland in both minor storm and major events. Pepco knows how to perform vegetation management efficiently—the key issue is that of consistent funding.

Pepco could not provide us with its five-year future budget for distribution vegetation management as it does not budget O&M expenses.[62] As such, we are unable to comment on whether Pepco's planned spending levels appear consistent with its clearing objectives.

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[58] Other reliability programs that Pepco implement could help speed these results.
[59] Supplemental Report of the Potomac Electric Power Company in Case No. 9220, and Interviews #34-#37 (Field Visits), January 10-14, 2011.
[60] Supplemental Report of the Potomac Electric Power Company in Case No. 9220.
[61] We found that Pepco's 2011 vegetation management plan is consistent with the majority of currently-proposed changes in Maryland reliability standards.
[62] Response to Data Request #142.

E. Vegetation Management Practices and State Standards

1. Vegetation Management Practices

Good utility practices in vegetation management include the following:[63]

- Aggressive removal of problem trees
- Appropriate balance of cycle and hot spot trimming (*i.e.,* preventative versus corrective)
- Centralized requirements and specifications with local control and implementation
- Cycle trimming intervals based on growth rate, inspections, and circuit criticality (circuit trim versus block or plat trim)
- Multiple metrics in place to understand performance (cost/mile, corrective/preventative)
- Field inspections and audits to verify trimming practices and clearances
- Use of worst performing feeder analysis for trimming work prioritization.

Pepco's earlier vegetation management practices were less comparable to good industry practices. The plat approach, for example, was efficient from an administrative and spending perspective, but not ideal in terms of results. Trimming on a plat basis means that the Company did not always trim the entire length of a circuit in the same year, so it did not always see the full benefit of trimming a circuit.

A four-year trimming cycle is much more common in the industry and has been for quite a while. Pepco's two-year cycle was we believe less efficient. In practical terms, having a two-year cycle means that the Company has to perform lighter, less aggressive trimming, but do it more often compared to a four-year cycle. A shorter trimming cycle requires twice the concentrated administrative expenses, customer contacts, and resource application time, and is more costly and less efficient. In addition, with a two-year vegetation cycle, vegetation resides closer to the primary conductors, which makes them more vulnerable to outage at lower wind velocities.

We examined PHI's detailed vegetation management manuals and procedures, and found them consistent with good utility practice.[64] Pepco's current vegetation management program is much more in line with good industry practices, and ahead of them in some respects.

A common practice in the industry is the use of tree wire, or a slightly different configuration referred to as spacer cables, to help prevent or mitigate tree-related outages in areas with a high concentration of trees. Most recommend that this approach should be limited to 4 kV and 13 kV

[63] 2009 Polaris Transmission and Distribution Benchmarking Program, PA Consulting, 2010 Consolidated Report in District of Columbia Public Service Commission Formal Case No. 766. Similar material provided in response to Commission Question No. 6 and Data Request #99 was marked confidential and we chose to use the public source.
[64] Documents provided in response to Commission Question No. 11.

systems. Pepco has installed tree wire on approximately fifteen percent of its overhead system. The Company has limited its use to areas in which vegetation management is difficult due to location or public resistance, and for new construction.[65] We believe that the addition of insulation to a bare conductor will improve system SAIFI. However, when faults do occur, they are more significant and cause more damage to the feeder conductor due to the higher fault currents. The NESC discourages allowing conductor damage due to vegetation contact. There are also installation issues with the use of tree wire related to electrical gradients across insulators. The tree wire must be stripped of insulation from the conductor and be secured with wire tie wraps with certain insulators. Failure to do so can result in the burn-down of primary conductors.[66] We believe that the use of tree wire masks the root cause of outages, which is proximity of vegetation, and is not a preferred option.

The location of so much vegetation near Pepco's sub-transmission and distribution lines has important preventative maintenance implications. Some of the Company's lines run along roadways. Vegetation between the roadway and the feeder circuit prevents Pepco from using bucket trucks to address vegetation or equipment issues that need to be corrected. Instead, personnel must address them by manually climbing the pole, which during storm events will slow down restoration efforts.

Some of the sub-transmission system is routed along Pepco's transmission rights-of-way. Pepco uses NESC safety clearance requirements to determine if 69 kV circuits can be added between existing high voltage transmission lines and the edge of the right-of-way. In conformance with those requirements, Pepco has added 69 kV sub-transmission circuits with a centerline approximately ten feet from the edge of the right-of-way, which puts vital sub-transmission circuits within five or six feet of vegetation, taking into account cross arm dimensions. Although it adequately maintains the transmission rights-of-way, Pepco does not rigorously enforce danger tree removal along the rights-of-way even though it has the legal rights to do so. We believe Pepco should change its practice and adopt a proactive approach in order to reduce the vulnerability of these sub-transmission system lines to vegetation outages.

2. Vegetation Management Standards in Other States

While a number of states have no vegetation management standards, most do. Many states have adopted, by reference, all or part of the NESC standard (Rules 218) regarding vegetation management, which provides only general guidelines regarding pruning and removing trees that "may" interfere with power lines. Another standard adopted by numerous state commissions is ANSI A300.[67] Several states, including Missouri, Washington, and Nevada, have either rules or statutes that specifically allow utilities to trim trees without liability for damages. Some of these specify clearances allowed for removal by voltage and line design. Missouri's statute, for example, specifies clearances from lines by voltage, but these are allowed clearances to exempt the utility from civil damages, and are not actual requirements.

[65] Response to Commission Question No. 13.
[66] We observed a number of instances of improper tree wire installation during our inspections.
[67] ANSI A300: Tree Care Operations—Tree, Shrub, and Other Woods Plant Maintenance.

Only a few states have mandatory clearance requirements or mandatory cycle requirements. California and Oregon have mandatory clearance requirements. The California Public Utilities Commission rules, for example, state that for lines at voltages higher than 750 volts, in general, trees must be trimmed so as to provide no less than 18 inches of clearance from lines under normal annual weather variations. When trimmed, where practicable, trees must be between four and fifteen feet from power lines over 2,400 volts, depending on voltage. Oklahoma and Delaware require trees to be trimmed on a fixed cycle. The Oklahoma Corporation Commission's rules require utilities to trim trees on a four-year cycle, unless the commission approves another plan, but does not specify any minimum clearance.

F. Major Conclusions

1. Pepco's spending on distribution vegetation management has been insufficient.

In our investigation, we determined found that Pepco's distribution vegetation management budgets in recent years were never adequate enough to provide for the required level of trimming; our benchmark comparison confirmed it. The Company's vegetation management personnel aimed their limited dollars where they would do the most good. However, in nearly every year since 2003, Pepco was unable to meet its clearing objectives, and conditions on the system continued to deteriorate. Maryland laws and ordinances and the customer permission process only complicated the problem by adding to the cost of the vegetation management that Pepco actually did perform.

2. Pepco's current prescriptive distribution vegetation management program, if adequately funded, will significantly improve reliability in Maryland. (*Recommendation IV-1*).

Pepco's current 2011 prescriptive program is more aggressive than the plan it first presented last year. It applies new trimming requirements to both three-phase and single-phase conductors and, for the first time, will eliminate vegetation above feeder primaries. We have little doubt that Pepco's program will significantly improve reliability in both minor and major storm events. Our main concern is that of consistent and adequate funding.

We believe the Company can improve the program further by adding two components: enhanced training for inspectors, and aggressive hazard tree removal to reduce the vulnerability of sub-transmission system lines situated along the edges of transmission rights-of way.[68]

[68] We found that Pepco's transmission vegetation management practices are adequate and do not contribute to reliability problems in Maryland. Our concern is the sub-transmission lines installed between the transmission lines and the edge of the rights-of-way.

G. Recommendations

IV-1 Pepco should fully implement its current prescriptive distribution vegetation management program for eight years, but spending levels must be non-discretionary. *(Conclusion #3)*

In order to obtain the maximum benefits of the 2011 prescriptive distribution vegetation management program, Pepco must fund it fully for eight years. Of all the Company's reliability enhancement programs, vegetation management is the most crucial and will do the most to improve system-wide reliability. It is critical therefore to ensure that the Company cannot divert funding from this program for other purposes. Like most utilities, Pepco considers its O&M expense as discretionary for budget purposes. O&M spending for this vegetation management program simply must be set aside as non-discretionary.

V. Reliability-Related Capital and O&M

A. Introduction

In this section of the report, the team focuses on Pepco's historic and projected O&M and capital spending. The objective of our work in this area was to assess the adequacy of Pepco's spending levels and determine to what extent inadequate spending may have contributed to overall reliability problems. As we noted in an earlier chapter of this report, inadequate system maintenance is a contributor to the Company's reliability problems in Maryland; in this chapter, we discuss the results of our analysis and field inspections in this area. Finally, we examine Pepco's reliability enhancement plans and offer our opinion as to the appropriateness and likely impact of these programs on Pepco's reliability in Maryland.

B. Reliability-Related Capital Spending

We reviewed Pepco's capital budgeting process and found that it was adequate in most regards. The annual five-year capital budgeting process for Pepco and all other PHI subsidiaries is performed at the corporate level. Early in the process, the Company compiles a list of projects by sponsoring group (*e.g.*, planning department, construction department) and develops estimates of internal resources and costs for each project. Pepco develops a draft budget, and uses asset investment strategy tools to rank the projects.[69] The Company ranks non-discretionary and discretionary projects separately. Non-discretionary projects are those for reliability including conversions, load, and other customer-driven projects; projects required by the regional transmission planning organizations; and project for aged infrastructure such as circuit breakers. Discretionary capital projects are not needed to maintain reliability; many are aimed at reducing the frequency or duration of outages, such as adding automatic reclosers.

PHI subjects the projects to a series of peer reviews, and management ultimately sets a target budget. The Company designs the target budget so that it can fund all non-discretionary projects and provide a small amount for discretionary projects.[70] The budget process is a fluid one in that the Company makes adjustments to the list of funded projects as conditions change during the year.

The following table summarizes Pepco's capital spending in Maryland over the past five years.[71]

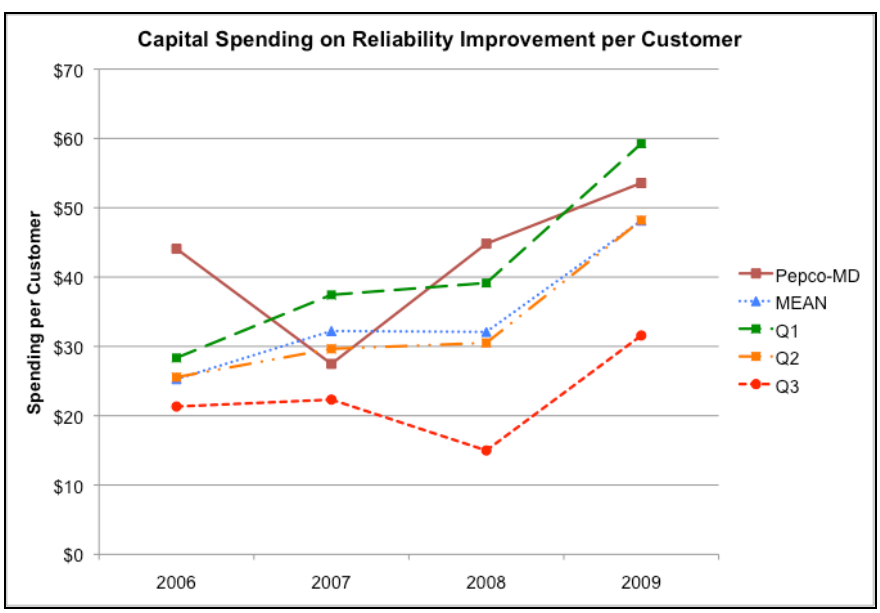
[69] Regional transmission projects are funded by the regional organizations and are not part of the ranking process; these projects are included as a separate line item in the five-year budget.
[70] Interviews #7 and #8, January 24, 2011.
[71] Response to Data Request #130, as amended by Pepco email dated February 28, 2011.

Pepco Maryland
Capital Spending 2005–2010
($ Millions)

	2006	2007	2008	2009	2010
Customer Driven	$43.8	$45.8	$42.8	$30.5	$26.3
Reliability	23.9	29.7	47.0	48.6	39.4
Load	14.4	11.8	22.3	21.3	7.4
Total	$82.1	$87.3	$112.1	$100.4	$73.1

Over this period, Pepco's capital spending in Maryland represented approximately 50 percent of its spending system-wide.

To put this spending level in perspective, we compared Pepco's Maryland capital spending on reliability improvement activities on a per-customer basis against a national panel of utilities, as shown in the graph below. Without making any observations regarding the efficiency of the spending levels, it is accurate to say that Pepco's spending level is certainly well within industry norms.[72]



Pepco was unable to provide its approved construction budgets for this time period.[73] As such we are unable to determine how actual spending levels compared to original budgets. Based on our review, we found that Pepco managed to fund all of its non-discretionary projects and some of its discretionary ones in these years. Unfortunately, it had to borrow from its O&M coffers to do so

[72] Chart based on data provided in response to Data Request #130.
[73] Response to Data Request #130. Pepco stated that its approved construction budgets for these periods are not readily available.

in some cases. Pepco's level of capital spending in these years was adequate to maintain reliability at existing levels, but not to make strides in improving it.[74]

Pepco had treated some of the capital projects in the Reliability Enhancement Plans (REP) as discretionary projects in the past, and those projects usually never got fully funded. The Company currently treats REP programs as non-discretionary budget items. By moving these projects to the non-discretionary category, Pepco's target budget leaves little room for additional discretionary work, particularly since load-driven non-discretionary projects are subject to some adjustment throughout the year.[75] The following table summarizes Pepco's five-year projected capital spending for Maryland.[76]

Pepco Maryland
Projected Capital Spending
($ Millions)

	2011	2012	2013	2014	2015
Customer Driven	$39.1	$39.3	$42.7	$41.2	$45.5
Reliability	70.3	63.1	64.6	64.7	65.7
Load	1.9	10.7	4.1	20.2	22.0
Total	$111.4	$113.1	$111.3	$126.1	$133.2

Pepco currently budgets only small amounts for load-related projects in the early years. Any change in these budget assumptions, such as improvements in the economy, could place significant pressure on the non-discretionary budget, and in turn on funding for REP programs. In such a situation, the designation of REP projects as non-discretionary could turn out to be ephemeral, as those projects could quickly slip back into the "discretionary" category. The following table compares the reliability portion of Pepco's capital budget, above, to its capital budget for REP projects.[77]

Pepco Maryland
Projected Reliability-Related Capital Spending
($ Millions)

	2011	2012	2013	2014	2015
Total Reliability budget	$70.3	$63.1	$64.6	$64.7	$65.7
REP program budget	40.5	41.7	44.0	59.0	59.7

As we note later in this chapter, Pepco is vague on the amount of improvement that it will see from these REP projects overall. As we understand it, Pepco developed the REP in one month. In our view, this is essentially a quick attempt to throw money at the problem, or, more accurately, to quickly promise to throw money at the problem. It is critically important that the money spent actually be directed at projects that will yield the most improvement in reliability. A more

[74] Interviews #7 and #8, January 24, 2011.
[75] Interviews #7 and #8, January 24, 2011.
[76] Response to Data Request #128.
[77] Response to Data Request #128.

rigorous vetting of reliability-related projects would help ensure that Pepco is at least aiming its money at the right target, especially if funds become tight.

We should also note that we found confusing Pepco's references to what is "reliability-related" capital. In its recent rate case, Pepco reported that its reliability-related construction expenditures were for system load relief work, work to improve customer reliability, emergency replacements and repairs, and planned infrastructure replacements. System load relief projects were those to address situations in which equipment had reached thermal limits (*e.g.*, replacing overloaded conductors), work designed to remedy operating voltage drops (*e.g.,* capacitor banks), and projects needed to meet design standards to maintain acceptable reliability levels (*e.g.*, equipment additions). Customer reliability improvement projects included changing or enhancing physical plant serving customers, such as underground cable replacement. Emergency replacement and repairs involved replacing equipment damaged by storms or that experienced mechanical failure with in-kind replacements. Planned infrastructure replacements were repairs that were part of an ongoing project designed to eliminate reliability issues (*e.g.*, planned replacement of aged circuit breakers and poles).[78]

The following table compares rate case "reliability-related construction expenditures" with actual capital expenditures in Pepco's "load" and "reliability" categories; we cannot reconcile the differences.[79]

Pepco Maryland Reliability-related Construction Expenditures
($ Millions)

	2006 Actual	**2007 Actual**	**2008 Actual**	**2009 Actual[80]**
Case No. 9217				
System load relief	$5.5	$9.9	$23.0	$7.4
Customer reliability	5.9	5.6	9.1	15.4
Emergency Replacement/Repair	18.1	21.6	24.0	21.2
Planned Infrastructure Replace.	2.2	4.3	5.7	5.1
Total Pepco MD Capital Expend.	**$31.7**	**$41.3**	**$61.9**	**$49.0**
Case No. 9240				
Reliability	$23.9	$29.7	$47.0	$48.6
Load	22.4	14.1	23.1	28.2
Total	**$46.3**	**$43.8**	**$70.1**	**$76.8**

[78] Testimony of William M. Gausman, Case No. 9217.
[79] Testimony of William M. Gausman, Case No. 9217. In an email dated February 28, 2011, Pepco noted that Case No. 9217 expenditures were a subset of its total distribution and load expenditures.
[80] The Case No. 9217 expenditure figures for 2009 reflect nine months actual and three months forecast.

C. Reliability Related O&M Spending

We asked Pepco for historic O&M spending in categories such as vegetation management, pole inspection and maintenance, line inspection and patrolling, equipment maintenance, and reliability improvement. The Company stated the data were not available in the form we requested. Pepco provided to us total Pepco transmission and distribution O&M expense, and pointed us to Form 1 data.[81] Neither of these sources was satisfactory for the type of benchmarking analysis we intended to perform.

The following table summarizes Pepco's O&M spending as reported on Form 1 reports.

Pepco Total
Distribution O&M Spending
($ Millions)

	2004	2005	2006	2007	2008	2009
Operations Expense	$39.4	$33.2	$35.1	$46.2	$41.4	$45.5
Maintenance Expense	36.8	41.8	42.4	48.0	46.5	48.3
Total	$76.2	$75.0	$77.5	$94.2	$87.9	$93.8

Pepco does not divide its annual O&M budget into discretionary and non-discretionary categories. All O&M expense is considered discretionary for budget purposes.[82] That is not unique to Pepco. When utilities are faced with unexpected non-discretionary capital projects, they often turn to O&M dollars as a way to fund those projects.

We could not estimate to what extent the Company under-spent in the last five years on its planned total O&M expense, let alone its reliability-related O&M expense. The Company indicated that it does not prepare five-year O&M budgets, and so could not provide us original budgets for these years.[83] Similarly, we requested a five year O&M expense budget for 2011 to 2015. Pepco reiterated that it does not prepare five-year O&M budgets, stating that it develops its budget on an annual basis. For whatever reason, it failed to even provide the current O&M expense budget for 2011.[84]

We did learn that during the 2004 to 2010 period, Pepco did not budget its annual O&M costs according to state jurisdiction. Instead, the Company allocated approximately 60 percent of O&M expense to its Maryland jurisdiction. Beginning in 2011, however, the Company began to reflect jurisdictions in its O&M budget.[85] We believe the Company should reflect jurisdictions in both its budget and its tracking of actual expenditures.

It was our intention to make several benchmark comparisons of Pepco's Maryland O&M expenditures versus a panel of other utilities. These comparisons typically include breakouts

[81] Response to Data Request #131.
[82] Interviews #7 and #8, January 24, 2011.
[83] Response to Data Request #142.
[84] Response to Data Request #142.
[85] Interviews #7 and #8, January 24, 2011.

such as: distribution O&M per customer and per asset, and O&M per megavolt ampere of substation capacity and per asset. While comparisons like these are always subject to questions regarding appropriateness of peer group, accuracy of measurement, etc., we find them useful to provide a context for understanding a given company and its operating practices and approaches.

D. System Maintenance

NESC rules require a utility to conduct inspections of its distribution system at specified time intervals as experience has shown to be necessary. Any deficiencies must be recorded, prioritized, and tracked until corrected. Pepco has an established maintenance program for substation equipment. According to the Company, it performs substation inspection activities on a monthly basis, which include:

- Readings of all ampere, volt, watt, and var (reactive power) devices
- Visual inspection for oil leaks at breakers, transformers, and potheads
- Visual inspection of oil levels in potheads and of porcelain insulators for damage
- Inspection of station batteries
- Checks for positive nitrogen pressure on transformers
- Follow-up on stored station alarms
- Transformer tap changer range, oil temperature, and winding temperature readings
- Reviews of number of breaker operations
- Sampling transformer oil for testing.

Pepco personnel also perform incidental visual inspections while doing work in the substations. Company personnel inspect 13 kV breakers monthly and maintain them on a scheduled basis; they maintain capacitor banks and 34 kV and 69 kV breakers based on the number of operations (which Pepco also tracks for analysis purposes on an as-needed basis). The Company prioritizes substation maintenance items, records them on maintenance inspection sheets, and corrects items requiring immediate attention immediately. Personnel place maintenance tags on defective items and enter them into the SAP plant maintenance system. Maintenance, construction, and relay groups all place identification tags on station equipment using a variety of methods.[86]

Pepco expects to inspect all of its 69 kV sub-transmission system between September 2010 and the end of 2011, and it currently inspects 34 kV and 13 kV reclosers, regulators, pad mounted equipment, and capacitors on a frequency basis. The Control Center monitors and controls a very high percentage of distribution capacitors as part of its distribution var dispatch responsibilities through newer smart relays. Pepco stated that it has no formal inspection program for the remainder of the 34 kV or 13 kV systems, however.[87]

[86] Interview #9, January 24, 2011.
[87] Interview #9, January 24, 2011.

Since Pepco does not conduct regular inspections of its sub-transmission and distribution lines, it is not in full compliance with COMAR, which specifies NESC requirements for routine inspections and follow-up maintenance. Although Pepco has no formal circuit inspection it does bring poles and the equipment on them up to NESC code when it works on them.[88]

One of our team members spent a week in the field with Pepco personnel conducting vegetation and condition inspections in Montgomery and Prince George's Counties. We pre-selected eight substations and eight circuits for formal condition inspections, but requested additional circuit trimming and condition inspections while in the field and made observations while in transit between sites. We saw no real weaknesses in the Company's inspection and maintenance practices in substations. All batteries were in very good condition, adequately charged, and well maintained. We saw no recent oil leaks and little evidence of previous leaks. Oil levels in potheads were at appropriate levels; nitrogen blankets on transformers had positive pressure and had reserve nitrogen in bottles. We found all substations that we visited generally neat with good housekeeping. We did note, however, improper grounding at some substation gates and at the substation itself. Some substations had grass rather than crushed rock within the substation as floor material, which raises a concern about step-and-touch potentials.

During substation visits, we reviewed log books, which indicated that Pepco has been continuing normal maintenance activities. We also reviewed breaker operation books, and noted that the number of operations in some cases appeared high. Some circuits had approximately 40 circuit breaker operations in June through August 2010 and an additional 40 operations from September 2010 to the present.[89] This is a concern, as operating circuit breakers a high number of times can lead to failures. However, more importantly, a high number of circuit operations indicate a high number of customer interruptions. High numbers of customer interruptions, both during major events and not, are due to reliability problems, with vegetation being the most likely cause.

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:[90]

- 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.

[88] Interviews #34-#37 (Field Visits), January 10-14, 2011.
[89] Interviews #34-#37 (Field Visits), January 10-14, 2011.
[90] Interviews #34-#37 (Field Visits), January 10-14, 2011.

Some of this damage appeared to be storm-related. This is not surprising, as Pepco does not perform after-storm inspections or patrols to look for, for example, broken branches in overhanging trees that can easily come down in the next storm—faults waiting to happen. Company procedure is to address any maintenance issues on a pole only when one of its line personnel has to visit a pole for some reason.[91]

We also noticed that telephone poles carrying Pepco equipment are generally in poor condition. While Pepco inspects its poles every 12–18 years, the same cannot be said of the telephone company, which owns approximately ten percent of the distribution poles carrying Pepco 13 kV distribution circuits. The most recent inspection tag we observed on a telephone pole was over twenty years old. [92]

As we noted in an earlier chapter of this report, we believe that system maintenance issues contribute to some degree to the frequency and duration of outages, but we cannot predict to what extent. We could not determine, for example, whether a blown arrestor happened recently, or whether it has been that way for years and thus was not operable during last year's storm events. Such policies may save on O&M expense but are unwise in the long run. Pepco may be following the unfortunate trend in the industry of "operate until failure." While this practice is not unusual, we believe it is inconsistent with good utility practice.

Pepco inspects its distribution and sub-distribution systems on a component basis, consisting of separate inspection programs for various elements of the system. These inspections are part of the Company's maintenance procedures filed under COMAR. Equipment inspected under these procedures includes capacitors, regulators, reclosers, pad mount transformers, and poles. Any issues the Company identifies during these inspections are prioritized for remediation based on severity. Also, as field resources operate, restore, and maintain the system on a day-to-day basis, any observed issues relevant to NESC codes requirements at the work location are immediately addressed or prioritized for later correction. Pepco acknowledges that this approach does not capture all potential issues or fully comply with NESC standards, and it is not opposed to establishing a more robust feeder inspection program.

We see the system maintenance issue as a question of quantity, not quality. Pepco is required by COMAR to keep sufficient records to give evidence of compliance with its O&M procedures. During our inspections we saw no evidence that the Company was not complying with these procedures.[93] Pepco participates in best practices studies, such as those performed by PA Consulting, and has conducted its own reviews in areas such as secondary fault repair and thermovision scanning and repair.[94]

Only a few states, California, Delaware, Ohio, and Iowa, have specific maintenance requirements for utilities that were put in place in an effort to ensure reliability. These range

[91] Interviews #34-#37 (Field Visits), January 10-14, 2011.
[92] Interviews #34-#37 (Field Visits), January 10-14, 2011.
[93] O&M procedures required under COMAR 20.50.02.04 provided in response to Commission Question No. 3.
[94] Response to Data Request #99.

from minimal requirements for inspection and maintenance to detailed, time-based requirements for inspection and repair. The most stringent of these is California. The California Public Utilities Commission instituted inspection cycle and record-keeping requirements for utility distribution equipment. For example, utility records must specify the condition of inspected equipment, any problems found, and a schedule date for corrective action. A utility must submit an annual report summarizing its inspections, equipment condition observed, and repairs made.

E. Reliability Enhancement Plans

Pepco recognized within the last two years that its reliability indices were not improving. The REP represents Pepco's transition from a reactive approach to reliability problems to a more proactive one. The concept behind the REP is for Pepco to expand the amount of more robust work it performs across the entire distribution system, through, for example, enhanced and more frequent vegetation management, more major rebuilds of priority feeders, fusing of all mainline and downstream taps, and expanding the underground residential distribution (URD) cable replacement projects.[95]

Pepco's REP for Maryland consists of six reliability programs that are either new programs or an extension of existing ones. Overall, Pepco expects to spend more than $256 million in the next five years, or $115 million more than it originally budgeted. The Company indicated that it will be able to fund early-year REP projects because of a change in timing of major capital expansion projects. Pepco's estimated REP expenditures for Maryland as of August 2010 are detailed in the following table; the majority of REP spending is capital.[96]

Pepco REP Spending for Maryland ($ Millions)

	Current Annual	Current 5-Year Plan	REP Planned Annual	REP Planned 5-Year
Enhanced Vegetation Management	$4.3	$21.5	$7.3	$36.5
Priority Feeders	4.5	22.5	6.5	32.5
Load Growth	12.0	60.0	12.0	60.0
Distribution Automation	1.2	6.0	3.0	15.0
URD Cable Replacement	6.3	31.5	7.5	37.5
Selective Undergrounding/Substation Improvements	0.0	0.0	15.0	75.0
Totals	**$28.3**	**$141.5**	**$51.3**	**$256.5**

Pepco normally selects projects for reliability work based on prior year's performance, but for the REP based its selection on data through August 2010 in order to capture the most recent deterioration in reliability on the system. In the near term, Pepco will concentrate on reducing SAIFI (which in turn reduces SAIDI if the outage does not occur); it set a SAIFI goal of 2.0 for feeders in the REP in order to keep the workload manageable in the future. Pepco does not know

[95] Interview #4, January 6, 2011.
[96] Pepco Reliability Enhancement Plans, Case No. 9240.

whether the REP will actually achieve that goal as it did not perform a reliability improvement analysis. In 2010, the Company did not do a project-by-project analysis in order to select projects for the REP, but in 2011, the Company plans to priority-rank projects within the six reliability programs. Within three to five years, Pepco plans to transition to selecting reliability projects based on a 75 percent SAIFI and 25 percent SAIDI weighted reliability value.[97]

We examined Pepco's REP programs for their possible effectiveness in improving the system frequency and duration of outages. We considered the effect of these programs on blue sky reliability, on system reliability during minor events, and on reliability during major events, such as the storms of 2010.[98]

REP Program Impact on Pepco Maryland Reliability
Frequency and Duration of Outages

	Blue Sky	Minor Event	Major Event
Enhanced Vegetation Management	Little	Major	Major
Priority Feeders	Little	Little	Little
Load Growth	None	None	None
Distribution Automation	Modest	Modest	Little
URD Cable Replacement	Little	Little	Little
Selective Undergrounding/Substation Improvements	Little	Little	Little

Enhanced Vegetation Management – Pepco plans to increase vegetation clearances and removal of all vegetation above primary conductors. As we discussed in Chapter IV of this report, we believe that spending as planned will markedly reduce vegetation contact during minor and major events involving wind or snow.

Priority Feeders – Pepco plans to increase priority feeder work by 45 percent, and increase the program in Maryland from 13 feeders per year to 19 feeders per year. Maryland contains over 700 circuits, and in our view adding six feeders will not produce marked results. We believe that the number of priority feeders is too low for a system of this size – 40 is a more appropriate number under good utility practice. Even if Pepco increased the number of feeders, however, we believe that most of the improvement in these feeders will come through other efforts such as vegetation management.

Load Growth – Pepco will perform this work as needed to meet minimum reliability standards. As such, it will have no impact on system reliability. If requirements for load growth do not materialize due to economic conditions, a portion of this funding can be used for other REP programs.

[97] Interview #4, January 6, 2011.
[98] Our evaluation is for system-wide reliability. Pepco may garner more significant results for the area of the system directly impacted by the REP program.

Distribution Automation – The Pepco distribution system is designed to meet N-1 conditions with up to four operations of tie switches to other circuits. The vast majority of switching is currently done on a manual basis. Automating switches means that the switching process will be done in five minutes or less and outages will be momentary rather sustained, which, as we discussed earlier in the report, will improve SAIDI and SAIFI. Automation of this kind functions well during blue sky or minor event days, but does little in major events.

URD Cable Replacement – Replacement of defective and aging URD cable is an industry-wide problem. Pepco indicated that it had relatively small amounts of the problem vintage cable remaining on its system.[99] Replacing a small portion of cable on the system cannot therefore have a significant impact on future reliability.

Selective Undergrounding/Substation Improvements – Undergrounding and substation work is very expensive, and these projects account for approximately half of the increased spending under the REP. These expenditures cannot markedly impact overall system reliability because only a few projects can actually be completed. Because of cost, we believe that the use of selective underground and substation improvements for the purposes of improving system-wide reliability should be carefully considered on a case-by-case basis, and the cost and timing weighed against other alternatives.

Since it presented its original REP to the Commission last August, Pepco has added approximately $20 million more to the five-year total budget for its REP projects, and moved some dollars among the various programs.[100] For example, it appears that Pepco has added about $25 million over five years to its URD cable upgrades. It is not clear that this is a particularly good application of dollars. As far as we know, Pepco has not yet conducted the type of in-depth analysis or studies needed to make informed choices about where it should direct capital to best use.

We have not attempted to evaluate individual REP projects.[101] Of Pepco's six REP program categories, though, we see enhanced vegetation management and distribution automation as the most critical and as having the highest potential for system-wide reliability improvements. In Chapter II, we identified system automation as a needed improvement, and so we examined the Company's distribution automation program in more detail.[102]

Pepco started a three-year automatic sectionalizing and restoration (ASR) scheme expansion project in April 2010, funded in part by a grant from the Department of Energy (DOE); the Company subsequently included the program in its REP.[103] ASR consists of automated switches,

[99] Response to Data Request #84.
[100] Response to Data Request #128.
[101] For example, Pepco mentioned that it was doing an additional 300 reliability projects, but it is unclear if those are part of the REP and if so, under what category.
[102] We discuss the enhanced vegetation management program in more detail in Chapter IV.
[103] Pepco indicated that $105 million of the $168 million grant from the DOE was earmarked for Pepco Maryland, of which $10.25 million was for distribution automation projects; it is unclear whether any of the remaining funds are part of the company's REP budget (Response to Data Request #85).

controllers, smart sensors, and substation electronic relays that are connected to the distribution system, allowing for continuous visibility and remote control of the system. These devices work together to identify faults, automatically isolate identified problem areas and reconfigure the controlled feeders. As such, they reduce the number and length of outages and minimize impacts on customers. In its application to the DOE, the Company projected this distribution automation would yield, on a system-wide basis, improvements in SAIFI, SAIDI, and CAIDI of 13 percent, 19 percent, and 7 percent, respectively.[104] Pepco pilot projects indicated that the installations could improve reliability by 50 percent on a circuit basis.[105]

The program includes 67 ASRs, which involves the installation of about 90 reclosers and SF_6 switches in Montgomery and Prince George's Counties. The SF_6 switches are more suitable for a system of Pepco's configuration, as they can withstand higher fault current than typical oil-filled switches. Pepco based its selection of feeder locations for the ASR application based on substations with the worst two-year feeder lockout history; it gave preference to selecting feeders within close geographic proximity of each other because of communication limitations.[106] Pepco also selected distribution feeders based on pockets of customers identified by Customer Experiencing Multiple Interruptions (CEMI). The Company selected some feeders with a CEMI of six or more. Industry practice is to investigate pockets of the system with a CEMI of greater than three.

The benefit of ASR is that it could reduce what would ordinarily be a sustained outage to a momentary outage. If Pepco has to dispatch a crew to manually close a switch, restoring the outage may take hours; with ASR, the interruption is momentary, and as such does not count in reliability indices. This portion of the REP will make a measurable difference during blue sky and minor event conditions, but will do little during major events. The logic of these systems cannot make proper decisions when there are many outages on the system, as was the case as in 2010 during major events. In such cases, switch automation is designed to shut down and revert back to manual mode.

F. Major Conclusions

1. Pepco fully funded its non-discretionary reliability projects over the last five years.

Non-discretionary capital projects are those required for reliability purposes, including projects dictated by the regional transmission planning organizations and those needed to replace aged infrastructure. Discretionary capital projects, on the other hand, are not necessary to maintain reliability; many are aimed at reducing the frequency or duration of outages (*e.g.*, adding automatic reclosers). During the last five years, Pepco managed to fund all of its non-discretionary projects and some of its discretionary ones (although in some cases it had to adjust

[104] Response to Data Request #83.
[105] Interview #4, January 6, 2011.
[106] Interview #2, January 7, 2011.

O&M budgets to do so). Pepco's level of capital spending was therefore adequate to maintain reliability at existing levels, but not to make much progress towards improving it.

2. Pepco's sub-transmission and distribution line inspections are not in full compliance with NESC and COMAR requirements. *(Recommendation V-1)*

Rule 218 of the NESC requires that inspections of the system be conducted at a frequency that has shown to be required. Pepco conducts set periodic inspections of its transmission system, substations, and sub-transmission and distribution equipment, but does not do so for its sub-transmission and distribution system lines. The Company instead has a policy of correcting any identified maintenance issue when working on a specific pole location. This practice, while correcting system defects, does not fully comply with the requirements of the NESC, which COMAR references.

3. Pepco assembled its Reliability Enhancement Plan without the benefit of detailed analysis. *(Recommendation V-2)*

Pepco expects to spend approximately $275 million in the next five years on its Reliability Enhancement Plan. The Company cobbled together the plan in one month's time; it is a combination of new projects and old discretionary projects that were never fully funded. Pepco acknowledged that it does not know whether the plan will actually achieve its goals, as it did not perform reliability improvement analyses. With this ready-shoot-aim approach, a portion of the Company's planned capital spending is almost certainly poorly targeted.

G. Recommendations

V-1 Pepco should complete an initial full four-year inspection of its sub-transmission and distribution lines and schedule inspections accordingly thereafter. *(Conclusion #2)*

The Company does not periodically inspect its sub-transmission and distribution lines as required by the NESC, although it is currently in the process of inspecting its entire 69 kV system. Pepco should initiate a four-year program to identify pending corrective maintenance issues. After this initial fast-track inspection is complete, the Company should integrate, where practical, its line inspection program with its vegetation management and pole inspection program, a best practice that allows a utility to be more cost effective in identifying corrective maintenance items. Pepco should also explore maintaining all poles as the telephone company inspection program appears to be below par.

V-2 Pepco should conduct detailed analyses of its Reliability Enhancement Plan projects to determine which ones will truly advance reliability in a cost effective manner, and set its goals and priorities accordingly.

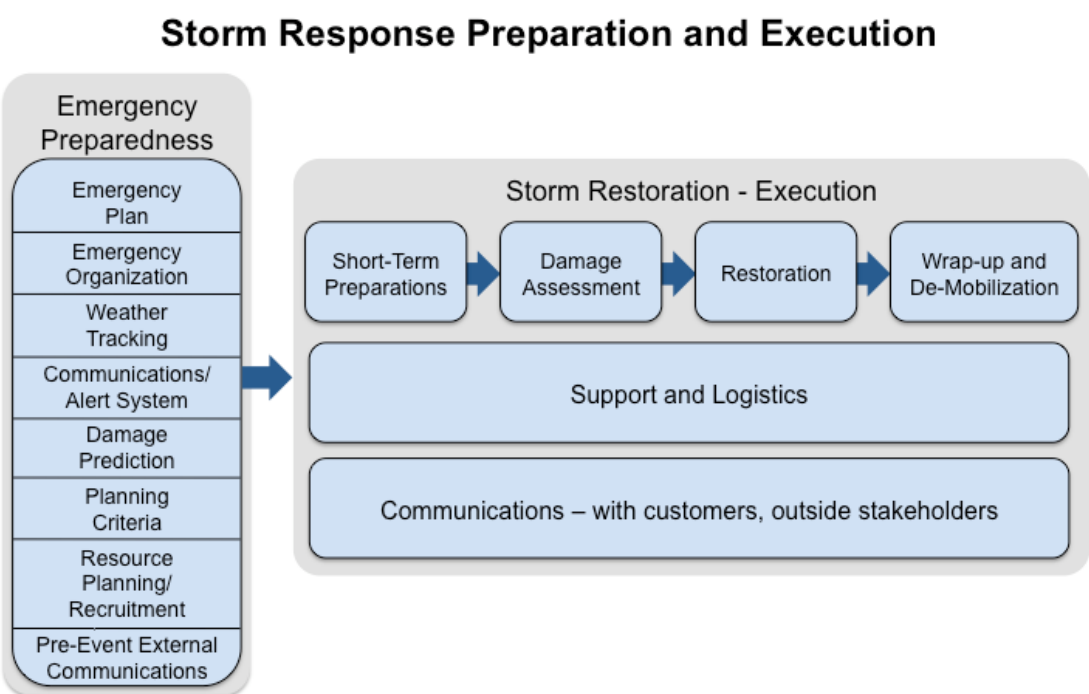
Pepco should determine the expected impact of its individual projects on reliability during blue sky, minor storm, and major storm conditions. In that way it can better prioritize the projects from a cost-benefit perspective. The Company may find it beneficial to forgo certain projects in order to expedite or expand others. For example, the enhanced vegetation management and distribution automation initiatives are in our view the two most important programs for improving reliability for Maryland customers. The Company should examine if it is advantageous to expand or escalate portions of these programs in order to realize larger improvements to reliability in the near-term.

VI. Emergency Preparedness

A. Introduction

Utilities like Pepco routinely deal with restoration of common, small-scale outage events as part of their normal day-to-day operation and maintenance activities. Large-scale outages, on the other hand, force utilities to abandon their normal routine and instead operate under emergency protocols. Events such as the storms that are the focus of this investigation place extraordinary demands on utility resources and present challenges for which utilities must be prepared. One of the objectives of the First Quartile-Silverpoint team in this investigation was to answer a basic question – had Pepco done everything it should have done to be prepared to effectively and efficiently respond to the events of last year.

Being prepared to respond to a major outage event requires a level of planning and preparation that is significantly greater than that required for responding to routine outages. The following figure illustrates the key elements of preparedness, and of the storm restoration process itself.



Planning and preparation are important. However, like in sports, what ultimately counts is how well the team executes its plays on game day. Utilities that excel at restoration are always well-prepared. Those that are well-prepared, however, do not always execute well. In this chapter we focus on Pepco's preparation, and evaluate, among other things, the quality of Pepco's restoration "playbook." How well Pepco executes its plans is the subject of the next chapter. We

do in this chapter, however, evaluate Pepco's performance in certain pre-event activities such as weather tracking, pre-event communications with external entities, and pre-event planning.

B. Emergency Response Plans

All utilities are experienced, and to varying degrees efficient, in responding to common outages, but a major outage event brings more and greater challenges in both degree and complexity. For any utility to be prepared to respond appropriately, it must begin with comprehensive, user-friendly emergency plans that encompass all aspects of the response process, from pre-event planning and alerts through ramp down and the return to normal operations. The plans should address all types of major outage events, including storms, catastrophic facility or equipment failures, overload emergencies, terrorist activities, and other crises. They should be designed to allow flexibility so that specific details can be tailored to fit each event.

Utilities must actually use their emergency plans, so response employees must have a good general knowledge of all aspects of the plans and a verified working knowledge of those sections of the plans dealing specifically with their functional area. To ensure that the employees have this degree of knowledge and are comfortable using the plans, utilities must conduct regularly scheduled drills and training activities. Good utility practice dictates that all key responders be drilled or receive supplemental training at least once per year.

Plans have to be kept up to date. Not only does out-of-date or lacking information cause confusion and lost efficiency, but it sends a signal that management does not put a high priority on the plans. A good test of a utility's commitment to having an outstanding response organization is the quality of its emergency plans, and the resources it expends in drilling and training its responders and in updating its plans.

PHI adopted an incident command structure to guide its crisis management response following Hurricane Isabel, based on the recommendations in a report by James Lee Witt Associates, LLC (Witt Report).[107] It developed multiple levels of emergency response plans, ranging from high level plans that outline how the organization should respond to crises to more tactical or operational-level plans that deal with the loss of major electrical system components, facility environmental incidents, and PJM emergency operating procedures.

The two highest-level emergency response plans are (1) the corporate Crisis Management Plan, which outlines PHI's corporate response to a wide range of potential emergency events, and (2) Pepco's Incident Response Plan (IRP), which outlines operational activities in major restoration events. At the more tactical level, the Company has Substation Emergency Response Plans, which are detailed tactical plans for potential major impairment of every substation, covering actions necessary for emergency recovery of these facilities. Pepco's environmental response at service centers and substations is covered by spill prevention emergency response plans filed

[107] Response to Commission Question No. 10.

with emergency agencies. All Pepco facilities with regulated materials—oil, chemicals, etc.—are covered by detailed site-specific plans.[108]

We focused our investigation on the IRP, which was the guiding document or "playbook" for Pepco's response to the 2010 storms. The layout of Pepco's IRP is orderly and logical; topics include situation and assumptions; concept of operations; organization and responsibilities; plan maintenance; and exercises and drills. Pepco's system for classifying the severity of events, *i.e.*, Level 1 through Level 4, is comprehensive and well-defined in the IRP. The organization and responsibilities portion of the IRP sets forth the specifics of the organization, showing reporting relationships and responsibilities, and specifies top priorities for incident management and crew management efforts. The Company includes in the plan tools such as conference call agendas and staff roster forms that are important and useful in major outage response.

We found that Pepco's IRP is built on the key principles of major outage response that are consistent with good utility practice. "Good utility practice" as we use that term in this report means standard practices that lead to good, solid, workmanlike results. "Best practices" refers to leading-edge practices that, over time, become the new standard as they are more widely adopted. When conducting utility reviews, we expect to find a combination of good utility practices and best practices, which was the case with Pepco's IRP. We identified several industry best practices in its plan, such as four-hour patrols during damage assessment, maintaining pending incident preparation checklists and a resource pool of employees in "second roles" to assist during emergencies, and developing man-hour estimates for storm damage repair.

While the plan was good, we nonetheless found a few opportunities for improvement. For example, a number of the key response functions—safety, transportation, human resources, logistics, and material supply—have plans and checklists that are not contained in the IRP nor referenced therein.[109] Pepco should update its IRP to include them. Also, as we discuss later in this chapter, Pepco's pre-event alerting process should be documented in the IRP.

The IRP places a good emphasis on training. Pepco conducts periodic drills, exercises, and training, and holds one full-scale functional exercise once a year to ensure that its emergency response organization is familiar with the plan. The full-scale functional exercise includes members of the service centers and the Pepco Incident Management Team, which is responsible for managing the Company's emergency response. The objectives of these exercises are to (1) provide PHI district incident management teams an opportunity to use the OMS under controlled circumstances, (2) to test outage restoration process flows, and (3) to identify potential improvements to work processes and technologies that can be implemented prior to storm season.[110] We reviewed controller handbooks and exercise plans and found the covered functions and content of the exercises comprehensive. Pepco's practices in place for drills and training exercises prior to and during the time of the 2010 storms were consistent with good utility

[108] Emergency response plans provided in response to Commission Question No. 5.
[109] Interviews #25 and #31, January 10, 2011; Interview #32, January 13, 2011; Interviews #29 and #30, January 12, 2011; and response to Data Request #102.
[110] Response to Data Request #3.

practice, and reflected a commitment to maintaining a response team well-familiar with and trained in the IRP.

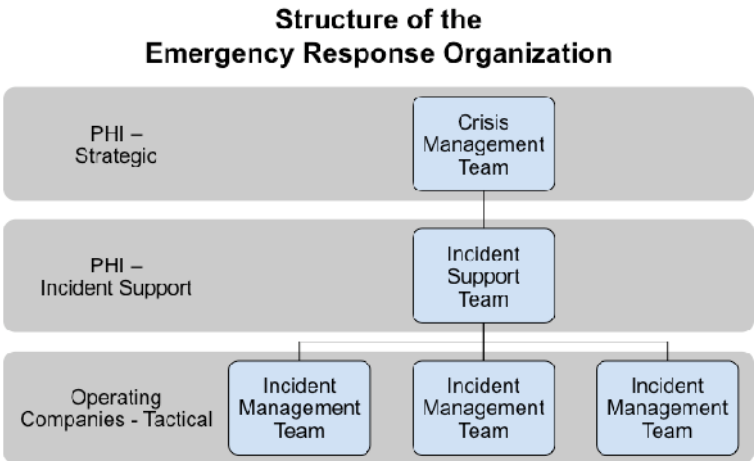
Pepco recognizes the importance of establishing and maintaining a major outage response emergency plan. It assigns direct responsibility to an experienced manager with an adequate staff and assigns ultimate responsibility for plan maintenance at the officer level, specifically, the PHI vice president of operations.[111] The Company has a process in place to update the IRP, has assigned responsibilities to do so, and makes changes on a regular basis. Pepco made its last changes to the IRP in late 2009, but as yet has made no changes based on experienced gained in the 2010 storms.[112] The IRP places good emphasis on post-event evaluation. The Company is considering clarifying certain roles and responsibilities based on its actual experience from the storms, such as those for crew guides and patrollers. Pepco is still meeting with local government officials regarding post-restoration activities, which could result in future plan modifications.[113]

C. Emergency Response Organization

Utilities have regular management organizations that handle day-to-day operations, but because they periodically face situations such as major power outages due to storms, utilities typically have a separate organization devoted to emergency response. A utility must be able to transition to the emergency organization during a crisis, and then when the crisis is past, smoothly transition back to its regular management structure. Good utility practice dictates that the roles and responsibilities of all members of the emergency organization be clearly set forth in emergency response plans. Each key leader or coordinator should have a back up, and all personnel should be regularly trained in their emergency assignment. Ideally, a utility should make good use of "non-response" personnel in assignments for which they are qualified.

The Pepco emergency response organization is part of a larger PHI organization, which has three levels as illustrated below. The first two levels, the Crisis Management Team and Incident Support Team (IST), are at the corporate level. Each PHI operating company including Pepco has its own Incident Management Team (IMT). The IST coordinates and supports the actions of the PHI utilities during major storms; IMTs concentrate on their own company's operations.

[111] Interview #18, January 7, 2011.
[112] Response to Data Request #2.
[113] Interview #18, January 7, 2011.



We found that the Pepco emergency response organization, roles, and responsibilities set forth in the IRP are consistent with prevalent utility standards. The plan describes the IMT, which is headed by a regional IMT leader; reporting directly to this position are five regional IMT team leaders responsible for liaison, operations, planning and analysis, logistics, and finance and administration. The IRP outlines the responsibilities for almost every position in the response organization—from the regional IMT leader down to patrollers and patroller support.

Pepco assigns each of its non-response employees with a "second role" within the emergency response organization that is usually based upon the employee's normal job assignment and location. For example, engineers may be assigned to operations, customer care personnel to the phone center, and financial or legal personnel to the logistics support pool. Pepco provides training for employees in second roles that require special skills and experience (*e.g.*, logistics, call handling) or that have regulatory requirements for training.[114] Using employees not normally assigned to operations for emergency response during major outages is a key element in a successful restoration effort, and we consider it an industry best practice.

D. Weather Tracking

Weather tracking is a key element of emergency preparedness. The goal of weather tracking is early detection. Good utility practice dictates that utilities preferably have more than one outside weather vendor, and have firm contracts for 24/7 coverage with timely, concise, and accurate reports delivered to designated recipients in the right format. There should be prompt, aggressive follow-up—by both the utility and the service provider—on all weather forecasts and alerts that indicate the potential for severe weather. The utility should proactively review with the service provider instances of significant weather events that the vendor failed to forecast accurately.

[114] Interview #18, January 7, 2011.

Pepco has contracted weather monitoring service from two well-known, nationwide weather service vendors, WSI Corporation (WSI) and Impact Weather, which are tailored to the PHI/Pepco service area. WSI provides 24/7 nationwide monitoring and weather service to Pepco for three forecast groups: the District of Columbia, Montgomery County, and Prince George's County. WSI services include its EnergyCast direct web site, which provides StormCast Radar (30 minute storm projections); severe weather risk analysis and projections; current temperature, winds, and conditions; radar and satellite imagery; watch and warning zones; and customized weather briefings. WSI also provides storm alerting and following services, including round-the-clock monitoring for Pepco and other PHI regions and email alerts for severe weather.

Impact Weather provides forecasts to Pepco about activity during the Atlantic Tropic Season. The company issues tracking and forecasting reports daily either as morning briefings or storm-specific advisories. The Emergency Management group of PHI is responsible for distributing these reports via e-mail to System Operations, IMT leaders, and senior supervisory personnel.

In order to determine the adequacy of the Company's weather tracking preparedness, we examined the level of service that Pepco received from its vendor in connection with the four storms of 2010. We reviewed copies of the alerts that Pepco received from WSI in the periods leading up to these storms.[115]

- February 5–6 snowstorms: The WSI alerts began with predictions of a moderate amount of snow about three days prior to the onset of the storm, but as the time drew nearer, the prediction turned to a much more serious storm with larger accumulations. The prediction vacillated back and forth on the significant issue of the type of snow—wet or dry, and was changed from dry to wet just twenty minutes before the snow began to fall.[116]
- July 25 thunderstorms: WSI issued a severe weather alert at 8:00 a.m. stating that a line of thunderstorms would be passing through the area beginning at 5:30 p.m. At 2:55 p.m., WSI advised that the National Weather Service (NWS) had issued a severe thunderstorm warning including northwest Montgomery County. At 3:30 p.m. WSI relayed an updated warning issued by the NWS at 3:07 p.m. including both Montgomery and Prince George's Counties.[117] The storm hit the Pepco system at 3:07 p.m.[118]
- August 5 thunderstorms: WSI issued an alert at 8:30 a.m. for a 50 percent chance of "strong-to-severe" thunderstorms. At 1:15 p.m. and again at 1:30 p.m., the alerts set the probability at 40 percent. A severe thunderstorm watch was issued until 10:00 p.m. At 2:40 p.m. the alert advised of strong thunderstorms developing over northern Virginia moving east; the confidence level of the prediction was high for the District of Columbia area and medium for Montgomery and Prince George's Counties. At 3:05 p.m. WSI

[115] WSI is Pepco's primary supplier. Impact Weather provides data during limited times of the year, and typically only about large moving storms for which a utility can prepare.
[116] Response to Data Request #105 and Interview #20, January 14, 2011.
[117] Response to Data Request #105.
[118] Storm reports provided in response to Commission Question No. 1.

advised that a severe storm was moving toward the District of Columbia.[119] The storm entered Pepco's service area at 3:30 p.m.[120]

- August 12 thunderstorms: WSI issued an alert at 6:20 a.m. stating that the storm would graze Montgomery County and otherwise be north of the Pepco service area. At 6:45 a.m. WSI advised of a 6:28 a.m. NWS severe thunderstorm warning for Montgomery County. Later alerts advised Pepco that both the District of Columbia and Prince George's County were also in the path of the storm.[121] The storm entered Pepco's service area at 6:45 a.m.[122]

Pepco expressed no dissatisfaction with the performance of its weather service vendor in providing advance warning of the 2010 storms. Only in the case of the February 5 snowstorm did Pepco receive more than a few hours' advance warning.[123] The Company noted that all weather services failed to provide any advance warning of the summer storms.[124] We found that Pepco has adequate weather tracking services in place, but suggest that it explore with the vendors possible ways to help mitigate the problem of short notice in the future.

E. Communications and Alert Systems

A utility should have an effective communications system to inform, alert, and mobilize its response organization on short notice. Good industry practice dictates that a company establish pre-determined alert triggers, alert lists by expected event severity level, and work centers and staging areas for first responders. If necessary, the utility should be able to mobilize some key first responders prior to the impact of an event.

The IRP discusses practices for communicating pending severe weather advisories and alerting the response organization in advance of a major outage event.[125] It also contains sample lists of actions to be undertaken at certain time intervals (*e.g.*, T minus one day) prior to an expected emergency event. Pepco follows certain general practices in alerting and communicating with key response team functional heads:[126]

- Pepco holds a weekly conference call each Monday with key response team leaders to discuss the week's weather forecast
- The head of system operations takes the lead in alerting IST-level operations lead coordinators and the Pepco regional IMT leader
- The IST lead (during the 2010 storms, the vice president of operations) "pulls the trigger" to activate the crisis management organization

[119] Response to Data Request #105.
[120] Storm report provided in response to Commission Question No. 1.
[121] Response to Data Request #105.
[122] Storm report provided in response to Commission Question No. 1.
[123] Pepco storm reports and response to Data Request #105.
[124] Interviews # 19 and #26, January 11, 2011.
[125] Response to Data Request #5.
[126] Interviews #19 and #26, January 11, 2011 and Interview #31, January 10, 2011.

- The Pepco regional IMT holds a conference call to discuss preparations and decide whether to call in workers
- Communications from the IST are sent out to the response team and others in the Pepco organization
- Each functional leader is responsible for contacting key response leaders in his or her organization (*e.g.*, the logistics leader is responsible for alerting the transportation group).

We identified no apparent problems with the alert process. Similarly, we identified no problems in the initial communications of the Pepco response organization or the organization as a whole prior to or at the outset of the four 2010 storms. This communication process is not mentioned in the IRP; we believe this response function is important and should be covered in the plan.[127]

F. Damage Prediction, Planning Criteria, and Resource Planning

Pepco's IRP outlines procedures and practices for recruitment of outside assistance, both from contractors and other utilities, for help in restoration during emergency events. The Company relies on older standard practices for predicting how many resources it may need to solicit. Although many utilities still do the same, these older practices are becoming increasingly outdated.

A recognized utility best practice in major outage response is a pre-event damage prediction process. Based upon specific forecasted weather data and historical damage records associated with such weather events, a utility can formulate a reasonably accurate ballpark prediction of the course of a likely event. Such a prediction aids the utility in two important ways:

- Based upon the predicted damage and the targeted restoration period, the utility can make an informed decision as to the total resources needed in the restoration effort
- More informed and realistic initial restoration expectations can be communicated to internal and external stakeholders.

Damage prediction models can be developed in-house or purchased from vendors, but in either case they require good historical meteorological and damage data from previous storms. Pepco did not have a damage prediction process in place during the 2010 storms, but rather based their damage predictions on previous weather-related outage events and general industry practices.[128]

Storm response planning criteria are based on two things—the pre-event damage prediction and the restoration time target as set by the utility. For example, a utility could establish planning criteria for a severe windstorm (*e.g.*, 65 mile per hour sustained winds and 90 mile per hour gusts), moving southwest to northeast, with a duration of one to one-and-one half hours that would impact all service areas equally. It could then determine the estimated man-hours it would

[127] We believe these communications should also be recorded in the Company's documentation of restoration efforts.
[128] Responses to Data Requests #53 and #54.

need to repair damage and calculate a targeted restoration time. Use of such a process helps refine a utility's pre-event planning and preparation activities. Pepco does not have the pre-event damage prediction process necessary to develop such criteria.

Successful resource planning and recruitment depend on two elements—a planning process to determine in advance the total amount of resources needed, and a recruitment process that provides good contacts with allies who can furnish needed outside resources. Pepco does have good working relationships with outside assistance groups, but does not have in place a pre-event damage prediction or planning criteria process. Instead, it bases any pre-event estimate of needed resources on past experience with prior storms.[129]

The three summer storms during 2010 arrived with very little notice, and pre-event damage prediction and resource planning were not an option. During the February storm, however, we do question whether Pepco's process was adequate to allow it to make resource decisions in a timely fashion. We discuss the adequacy of Pepco's recruitment of outside assistance during the storms in the next chapter. In the context of emergency preparedness, however, given the inherent vulnerability of the Pepco distribution system to damage during major events, the Company should adopt a more proactive approach by implementing best practices in this area.

G. Pre-event External Communications

Communicating with outside agencies, field forces, and outside crews prior to an event is crucial, and having a plan for pre-event external communications is therefore a key component of any emergency response plan. Good utility practice dictates that a utility identify its audiences in advance, and then develop the right approach for addressing each one. Part of pre-event communications preparation involves developing and maintaining relationships with a variety of entities, such as news media of all types, city, county, and state emergency response organizations, and utility mutual assistance organizations. Through these relationships, the utility will be able to develop protocols for the best ways to communicate before and during emergency events. Having those protocols in place means the utility can simply execute the procedures, rather than having to develop them under the pressure of emergencies.

To assure appropriate communications, it is critical for a utility to develop the internal mechanisms for conveying information so that the company delivers a consistent message through all channels and on all levels on a timely basis to all target audiences. These procedures should ensure that information is routinely and systematically gathered and forwarded to the key utility personnel responsible for communicating with outside audiences. A company's different media and its messages—from news releases, web sites, advertisements, text and social network messages, and conversations with utility and outside crews before the event—should be coordinated and consistent so that it presents a coherent picture of what should be expected.

[129] Responses to Data Requests #53 and #54.

A utility should develop the basic content of many of the messages ahead of time, so that when the emergency actually occurs, only minor editing and tailoring are needed. The process is not unlike preparing responses to various types of customer inquiries for use by call center telephone agents, so that they are available on an as-needed basis. We should note that the communications aspect of response plans focus on internal communications with field forces and coordination with outside entities in order to achieve restoration. Plans for communicating with customers are not normally part of utility emergency response plans and are handled separately.[130]

When we reviewed the IRP, we found the external communications aspects to be its weakest portion. While the IRP is well-developed in many other respects, it is incomplete in the area of pre-event (as well as during-event) external communications activities. For example, the IRP places insufficient emphasis on getting information back from field crews to better understand the system situation. The plan addresses how to deal with the emergency management agencies, but provides no guidance about how often to visit them during non-emergency times.

Our interviews with emergency management agencies highlighted the fact that Pepco's pre-event communications efforts were insufficient, and led to communications problems during the course of the 2010 storms.[131] For example, poor pre-event communications concerning the need for support from snow plows decidedly slowed down restoration efforts during the February storm. Pepco's IRP and its activities should be expanded and improved in the area of pre-event communications.

We should note that Pepco has a pre-event procedure in place to notify customers prior to *planned* outages. The Company practice is to notify customers three days ahead of the outage by placing door hangers at customers' locations alerting them to the upcoming outage. These notifications include the date, time, and anticipated length the outage. Pepco identifies critical care or special needs customers who will be affected to be sure they are contacted ahead of time.

H. Major Conclusions

1. **Pepco's Incident Response Plan (IRP) is built upon a strong base of key principles of major outage response and contains several industry best practices, but the plan is incomplete, lacking segments/plans dealing with key response functions.** *(Recommendation VI-1)*

The overall plan is very good, and reflects several industry best practices. However, there are several plans for support groups that are missing. These plans exist in separate documents maintained by the support groups, but should be included in the main IRP, to allow consistent, comprehensive update and maintenance of those plans.

[130] We discuss these plans in Chapter VIII of this report.
[131] Interview # 11, January 14, 2011, and interviews with EMA representatives.

2. **Pepco's emergency preparedness process does not include a damage prediction process and resource planning process, and is weak in the area of pre-event public communications.** *(Recommendation VI-2)*

Pepco's process for damage prediction relies on the experience of key individuals, and is not effectively documented. Commercially-available damage prediction models have helped other companies in their storm preparations, both in assessing resource needs and in preparing customer communications. An established model and approach would be accessible to more people within the organization, and likely to produce more precise results. This in turn would allow a more precise resource planning approach.

In pre-event communications, Pepco has plans in place for how to respond during the event, but they are weak in terms of providing specifics for customers as to what they should expect. More precise information would help customers with their own plans.

I. Recommendations

VI-1 Pepco should expand its Incident Response Plan (IRP) to include all key response support functions. *(Conclusion #1)*

The separate emergency plans, checklists, and other documentation maintained by supporting functions such as a safety, transportation, human resources, logistics, material supply, and alert communications should be included in the IRP to facilitate consistent, comprehensive update and maintenance of those plans. Pepco should expand its emergency response plan in the area of pre-event external communications and devote adequate resources to activities in this area. This includes more precise information than is currently available to customers, EMAs, and the public, explaining more of the process of restoration, so when customers call, they already have more understanding of the situation.

VI-2 Pepco should implement a damage prediction model/process and a resource planning process as part of their emergency response preparations, and should strengthen its pre-event public communications plan and performance. *(Conclusion #2)*

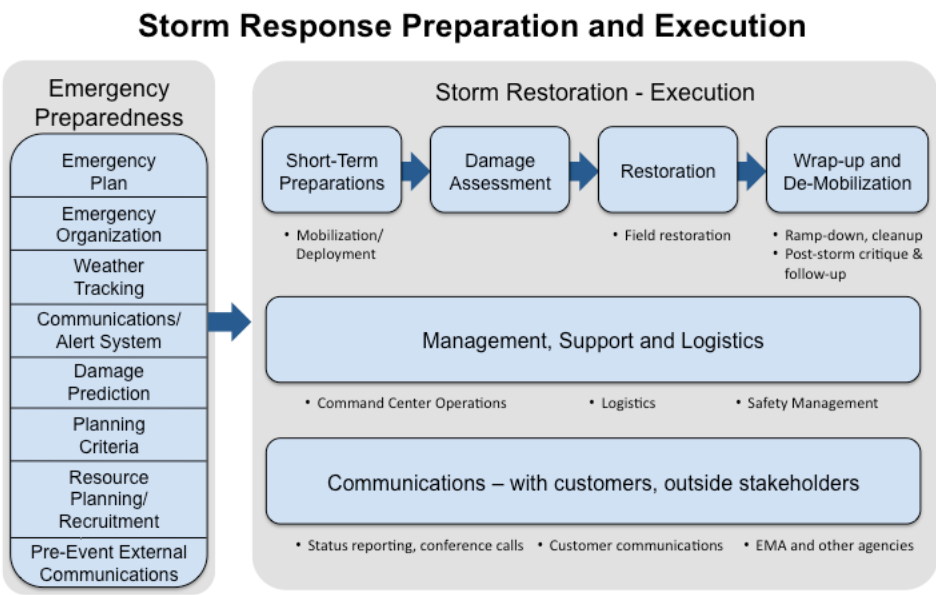
Development or purchase of a damage prediction model, followed by implementation and training of the appropriate response staff in its use should be undertaken right away. Building of an appropriate resource planning model and process can then follow.

The pre-event communications process should be analyzed and enhanced to provide more complete information to customers and the public. Evaluation of the procedures used by other companies as they prepare for storms can inform this analysis process.

VII. Outage Response – Operations

A. Introduction

The ultimate goal in major outage response is to restore electric service to all customers as safely, promptly, and efficiently as possible. Responding to a major outage requires more than good planning and preparation—a utility has be able to execute the activities in its outage recovery playbook in a crisp and effective manner. Those activities include keeping customers informed about how the restoration process works and, most importantly, when they can realistically expect to have power again. The following figure illustrates the key elements of the outage restoration process.



In this chapter, the team focuses primarily on the operational aspects of Pepco's restoration efforts; customer communications-related aspects are the focus of the next chapter.

In our review, we took the number of outages in each storm as a given. We set aside issues about the apparent causes of the outages or the reasons that so many customers were affected. Our focus was to determine whether or not Pepco's restoration efforts were reasonable and consistent with good utility practice. In that context, we found that in nearly all operational aspects, Pepco's performance in the aftermath of the 2010 storms compared favorably to that of other utilities in similar situations. The most glaring exception was Pepco's inability to provide accurate estimated restoration times for its customers. This shortcoming cast a dark shadow over the rest of Pepco's efforts, leaving many with a negative opinion about the quality of the restorations as a whole.

B. Mobilization and Deployment Processes

The mobilization process covers the activation and deployment of the response organization at the onset of the storm. At this stage, corporate, regional and work center command centers are activated. Key response team leaders and core function leads report to their assigned work locations. First responders are in place as the storm impacts. Staging sites are set up, logistics are confirmed, and resources from outside the stricken area are dispatched and moved in to assist.

Pepco characterizes its response efforts in activating its command centers, work centers, and staging sites as "proportional to the magnitude of the event and the amount of advanced warning given prior to the onset of the event." In the case of the February storm, preparations began several days in advance, but due to the lack of advance notice in the three summer storms, the advance activation process was not possible.[132]

Pepco's Incident Response Plan (IRP) specifies the following trigger levels that provide guidance in the activation and mobilization of the response organization:

- Field services branches are activated when ten percent or more of the total customers in that service center are affected
- The regional Incident Management Team (IMT) is activated when there are 20,000 or more customers out of service in that region
- The regional IMT is activated when two or more service center branches are activated.

Pepco staging sites are set up and activated depending on the amount of outside resources coming in and the timing of their arrival.[133] Pepco used staging sites in all four of the 2010 storms, and the sites were set up and activated within eight hours of the decision to open them.[134]

A crucial element of mobilization and deployment is securing restoration assistance from resources outside the utility—from outside contractors, from utility affiliates, or from other utilities. Pepco is a member of two mutual assistance groups, Mid-Atlantic Mutual Assistance (MAMA) and the Southeast Electric Exchange (SEE). Pepco also has "sustaining contractors", who routinely work on the Pepco system, and who are available to help Pepco with storm response efforts.[135] During storm events, Pepco has the first opportunity to use those contractors versus other nearby utilities who also might be soliciting outside resources, based on their ongoing working relationship.

During our interviews with Pepco personnel, we explored with them the timelines of when the Company contacted outside resources and when those resources arrived to assist in the restoration efforts.[136] For three of the storms, Pepco had essentially no advance notice, and as

[132] Response to Data Request #6.
[133] Response to Data Request #6.
[134] Interviews #29 and #30, January 12, 2011.
[135] Pepco essentially has the right of first refusal on these contractors. These contractors cannot accept work from other utilities if Pepco wants them to remain on its system during storm events.
[136] Interviews #19 and #26, January 11, 2011.

such, the earliest opportunity to request assistance was on the day of impact. The dates that outside resources arrived are summarized on the following table.[137]

Pepco Requests for Outside Assistance

Date of Storm Impact	Date of First Contact with Allies	Dates Outside Resources Arrived
February 5	February 4	February 6, 7, 9, 11
July 25	July 25	July 26, 27, 29
August 5	August 5	August 5, 7
August 12	August 12	August 12, 13

Pepco did have advance notice for the February snowstorm. PHI participated in MAMA and SEE calls on behalf of its three utilities impacted by the storm, Pepco, Delmarva Power & Light (DPL), and Atlantic City Electric (ACE). These calls began the day before the storm arrived, on February 4, and continued with one or both groups every day until February 11. PHI did not officially request assistance until February 6, when it requested 400 personnel—200 from each association. As a result of these requests, Pepco received a total of 149 overhead line workers on February 7 from Progress Energy, an SEE member. MAMA utilities released crews to assist ACE. Pepco also received 94 additional outside workers from five overhead line contractors and one electric cooperative.

As discussed in the previous chapter, Pepco does not have a pre-event damage prediction model and associated resources planning, but instead relies on its experience with prior events and standard industry practices. Although we found Pepco's practice insufficient, the Company nonetheless was able to recruit resources in a reasonable and timely manner given the circumstances it faced in the 2010 storms. We found no major deficiencies in Pepco's mobilization and deployment, either as set forth in its IRP or in the Company's execution of that plan in its response to the four 2010 storms.

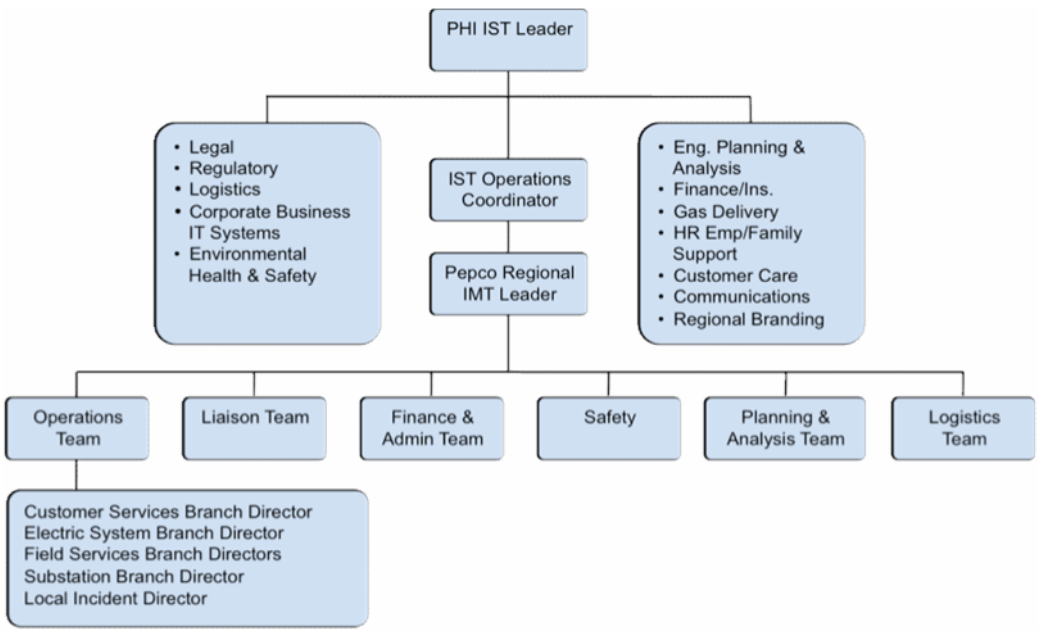
C. Command Center Operation

An effective command center operation is a key element in the restoration effort; it provides the leadership and oversight needed at all levels of the emergency response organization—corporate, regional, and work center. Good utility practice dictates that all necessary functions be represented at the primary command center and available to support subordinate command centers. Command center personnel should be well-trained and knowledgeable in their assigned area. Core team members should be physically present at the location, and "virtual" participation should be avoided if at all possible. Communications with subordinate centers and field workers should be scheduled and structured in such a way as to facilitate accurate and timely communications as needed.

The Pepco command center for the four 2010 storms was located in the Maryland control center, and was staffed with personnel from the operations, logistics, planning and analysis, liaison,

[137] Pepco storm reports.

finance and administration, and safety functions.[138] The chain of command in the PHI/Pepco emergency response organization is depicted in the following organization chart. The PHI Incident Support Team (IST) leader is responsible for leading the overall response effort.



Ongoing, concise two-way communications between field restoration personnel and the command centers, as well as between different command center levels, provides crucial information needed to effectively manage the restoration effort. Pepco stated that during the four 2010 storms, it held IMT conference calls regularly. IMT operations personnel and IST and field operations leaders generally held operations coordination calls once or twice a day. The following table lists the calls Pepco personnel held during the February 5-12 snowstorm; this frequency was typical except for the August 5 storm restoration, which only lasted two days.[139]

Command Center Conference Calls – February Storm

Date	IMT Conference Calls	Operations Coordination Calls
February 5	8 a.m.	9 a.m.
February 6	8 a.m., 3 p.m	9:30 a.m., 4 p.m.
February 7	8 a.m., 3 p.m.	8:30 a.m., 8:30 p.m.
February 8	8 a.m., 4 p.m.	9:30 a.m., 6 p.m.
February 9	8:30 a.m., 4 p.m.	9:30 a.m., 6 p.m.
February 10	8:30 a.m., 4 p.m.	6 p.m.
February 11	8:30 a.m., 4 p.m.	6 p.m.
February 12*	8:30 a.m.	2 p.m.

* IMT deactivated at 6:00 p.m. February 12

[138] Interview #20, January 14, 2011, and response to Commission Question No. 5.
[139] Response to Data Request #75.

Pepco did a good job of communicating and monitoring the restoration status internally through its conference call process. Overall, we found that the PHI and Pepco command center operations during the four 2010 storms were consistent with good emergency response practice and provided adequate leadership during the response to each storm.

D. Logistics

Logistics includes transportation, material and tool supply, security, site staging, and meals and lodging. Effective logistics support requires year-around attention, including training and communications with key suppliers. The effective management of logistics issues such as vehicle refueling and material delivery can have a significant positive effect on restoration productivity.

At Pepco, the logistics function has its own incident response plan that logistics employees carry with them during the restoration effort. During the 2010 storms, the logistics group used its own employees for the tasks requiring prior experience, and brought in 15–20 second role personnel for other assignments.[140] As a general matter, we found that Pepco's logistics efforts during the 2010 storms were well-planned and efficiently executed, aiding in the restoration effort.

More specifically, Pepco set up staging sites quickly, and was able to support outside crews with vehicle storage, materials, security, lodging, and meal service throughout the events. Pepco's material supply group moved on-hand "storm boxes" to the staging sites for each event to supply outside crews. Transportation successfully supported the response effort with on-site mechanics; Pepco provided 24-hour security at the staging sites so vehicles could remain there overnight. The logistics team arranged for hotel rooms for all necessary outside crews during the events.[141] In total, the logistics group successfully supported the repair crews working to restore power.

E. Field Restoration

Field restoration is the "boots and wheels on the ground" part of the restoration process. Field restoration involves: (1) determining the damage, (2) prioritizing the restoration, (3) procuring and deploying the necessary resources, and (4) safely and effectively utilizing and directing field workers in restoring power. Prompt, accurate and thorough damage assessment is essential in field restoration. The keys to a timely restoration effort include having the right number of repair workers in place at the right time, having pre-established work hours that maximize "daylight hours" and provide coverage overnight, and effectively tracking and managing progress so that further work can be assigned as work activities are completed.

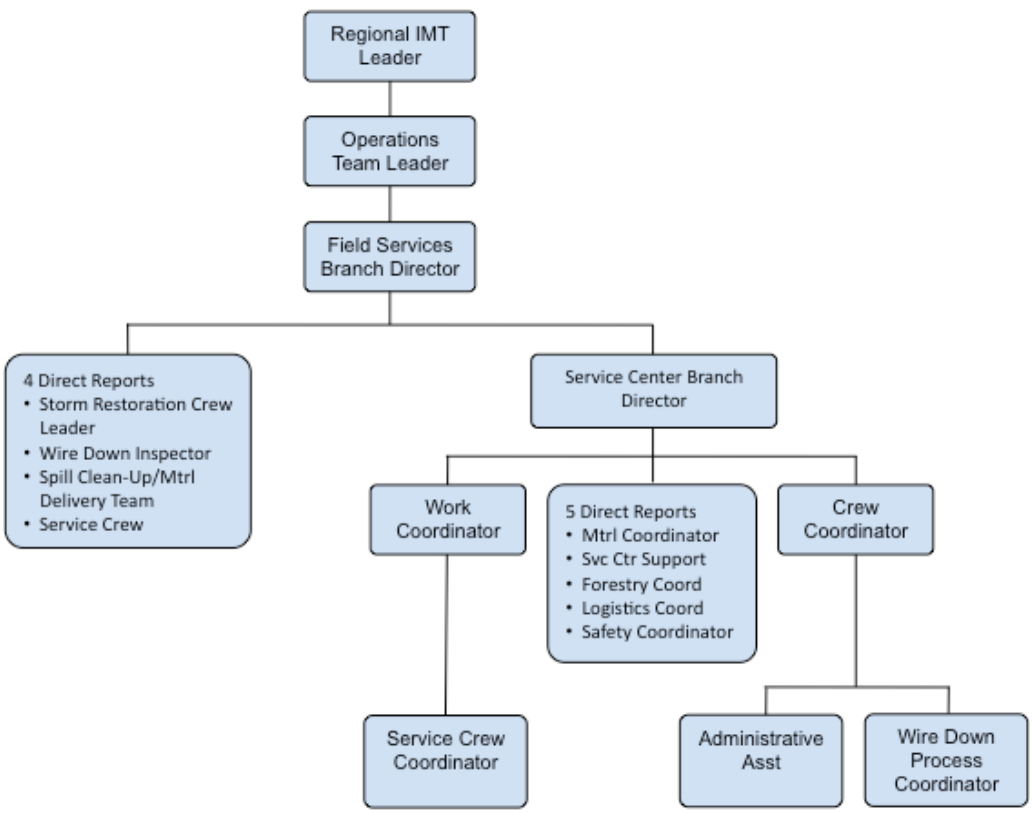
Good field restoration practices include making the best use of experienced and trained personnel to provide leadership, assist as guides, and offer necessary support assistance to the repair crews. Proper prioritization of field restoration assignments depends upon accurate, regularly-updated lists of critical feeders, loads, and customers. As such, effective use of an

[140] Interviews #29 and #30, January 12, 2011.
[141] Interviews # #29 and #30, January 12, 2011, Interview #31, January 10, 2011, and response to Data Request #18.

outage management system is very important to support the field restoration process. A utility's switch operations process should be designed to ensure safety and at the same time minimize delays in restoring power. Response teams should be trained and empowered to change from a process based on system-generated outage orders to one based on restoration of entire feeder circuits when conditions dictate it would expedite restoration. In our investigation, we reviewed Pepco's field restoration performance in the following areas: field organization, damage assessment, restoration priorities, restoration workforce and work practices, and rate of restoration.

1. Field Organization

The Pepco organization that managed field restoration effort during the 2010 storms is depicted in the following figure.



Two of the three Pepco service centers—Rockville and Forestville—were activated during the 2010 storms, and the organization depicted above was in place at both of these centers.[142] The field services branch director and service center branch director lead the essential restoration and restoration support functions. We found that Pepco's field restoration organization during the

[142] The third service center, Benning, serves the District of Columbia area. The vast majority of Pepco's facilities in that area are underground, and as a result there were relatively fewer problems during the 2010 storms.

2010 storm responses was consistent with its IRP and appropriately placed all essential restoration and restoration support functions under the field supervisors.

A work coordinator matches the work with the crews. There is one such coordinator at each service center, but Pepco at times assigns one to the staging sites where outside crews are headquartered. The forestry coordinator reports to the service center branch director, but receives direction from system operations. The service center branch director decides how many crew leaders are needed. The Rockville director asked for 40 crew leaders during the February storm and 50 crews during the July 25 storm, and got them as requested. The maximum number of crew leaders for any one storm was 65.[143]

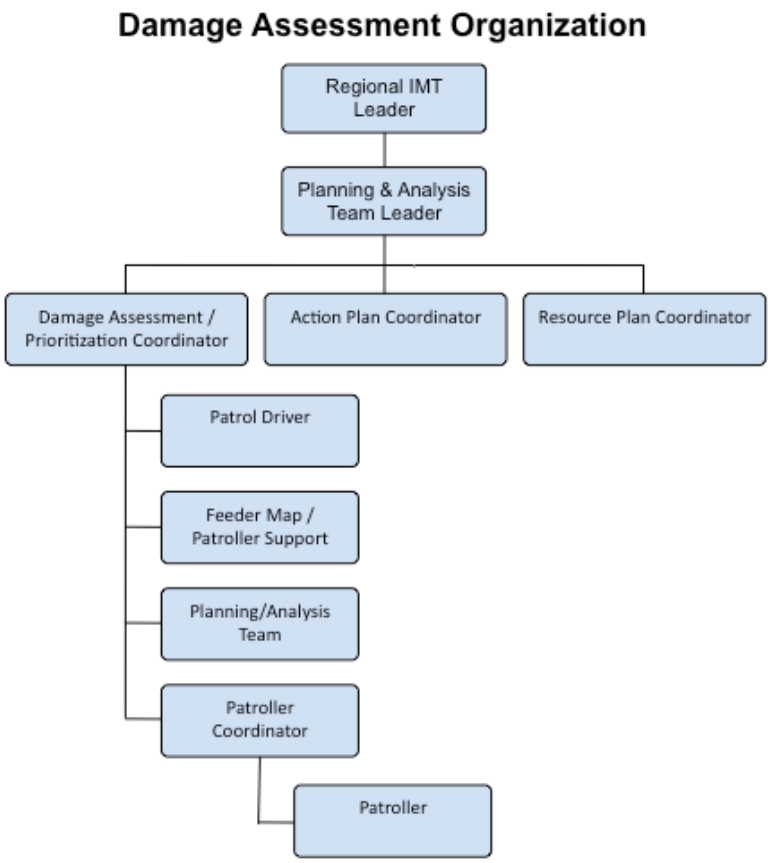
2. Damage Assessment

Prompt, comprehensive, and complete damage assessment is essential for an effective and efficient restoration effort. The best practice among electric utilities is to approach damage assessment in three phases:

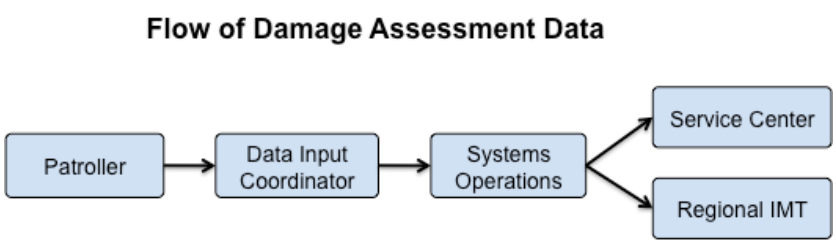
- Backbone feeder assessment: This assessment is made within the first few hours of the impact of the event, or as soon thereafter as possible; the goal is for the utility to verify and confirm the amount of damage sustained in a general assessment.
- Detailed assessment: This core assessment process provides specific damage information on circuits, tap lines, switches, transformers, and services; the goal is for the utility to make a thorough assessment that will aid command centers, restoration workers, material supply, and others in responding effectively.
- Job site assessment: In this phase, utility personnel are assigned to patrol ahead of field repair crews at the current or next job site to be sure that the crews have damage assessment information that is accurate and complete.

The Pepco damage assessment organization is depicted in the following figure. Damage assessment reported through the team leader of planning and analysis to the regional IMT leader.

[143] Interview #24, January 7, 2011 and Interviews #19 and #26, January 11, 2011.



The following schematic depicts the flow of the damage assessment data. Patrollers send their information directly to a data input coordinator, who reports to a damage assessment coordinator. There was one damage assessment coordinator at each service center during the four 2010 storms. Data are sent to system operations, which routes the information to the appropriate service center based on the feeder number of the circuit assessed, and also to the regional IMT.[144]



Initial requests for damage assessment come from the regional IMT. Pepco stated that it usually tries to get patrollers out early on detailed assessment when there is enough advance notice of an impending storm. This did not happen during the four 2010 storms, however, ostensibly due to

[144] Interview #22, January 7, 2011.

either short notice for the summer storms or difficulty getting around in the winter snow storm. The number of personnel that Pepco used for damage assessment varied among the storms.[145] In three of the storms, the IST brought in damage assessment personnel from other PHI service areas, and when possible, Pepco enlisted the help of some underground system personnel from its Benning service center.

In its major storm reports to the Commission, the Company noted that it had an opportunity for improvement in damage assessment. Specifically, Pepco wanted to enhance its training for patrollers to include the use of mobile data terminals (MDTs) so that they could send damage information directly to the OMS. The Company's patrollers had no MDTs in their vehicles, but in some cases were paired with meter services personnel who did.[146]

We saw more problems with the Company's damage assessment process beyond the use of MDTs. First and foremost, damage assessment was not a high priority during the storm events. Pepco's lack of strong emphasis on damage assessment is puzzling, given the importance the utility industry ascribes to this part of the restoration process. Pepco set no firm targets for completing damage assessment—as such it is no surprise it was never finished. In the July 25 storm, Pepco ran short of crew guides, so it just stopped its damage assessment and shifted patrollers to the role of crew guide.[147] The "four hour patrol" described in Pepco's IRP and introduced in Chapter VI of this report is a utility best practice, but the Company used the process in only two of the four storms.[148] Pepco essentially failed to follow its own restoration playbook on damage assessment.

During our interviews, Pepco operations personnel expressed more concern about damage assessment performance than any other area of restoration. Some employees stated that damage assessment takes too long and is too detailed. Others indicated that they need more training to know what to look for.[149] Employees may be getting a mixed message about the importance of damage assessment; at a minimum, more adequate training is needed.

Other than its process for determining estimated times of restoration (ETRs), Pepco's damage assessment process during the 2010 storms was the weakest part of its physical restoration efforts. By foregoing thorough damage assessment, a utility is less able to accurately determine the resources it needs and estimate the total length of restoration. Completing a full damage assessment is especially important for Pepco; it would allow the Company to better identify the source of nested outages without having to rely so heavily on customer calls. Promptly identifying nested outages in turn helps Pepco be more efficient in its restoration activities, and in providing more accurate ETRs to customers.

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[145] Pepco storm reports.
[146] Interview #2, January 7, 2011. Getting crews where they need to go to restore power is critically important, and we do not suggest the Company delay restoration efforts. It should instead have adequate numbers of crew guide and damage patrol personnel trained and available so that it can perform both activities simultaneously.
[147] Interview #20, January 14, 2011, and Interview #22, January 7, 2011.
[148] The four hour patrol refers to the quick initial survey of system damage after an event.
[149] Interviews #19 and #26, January 11, 2011.

3. Restoration Priorities

The priorities of the Pepco system control center are to first stabilize the transmission system, and then get one firm sub-transmission feed into each substation. When there is one firm feed into each substation, the crews are released to assist with restoration of customer service. The control center has final authority over when the crews will be released.[150]

Overall, we found that Pepco has a good process for work prioritization and utilized it well during the restoration efforts following the 2010 storms. Pepco prioritizes its work on circuits based on "weighted" customer count. All customers start with a weight of one, but certain customers are given a higher weight due to their type of facility. Facilities given a weighted priority include hospitals, fire fighting and police, sewage and water treatment, radio and television, and health care. When the OMS displays circuit outages, it shows both the actual and weighted number of customers affected. This process allows the Company to readily identify special needs customers.

The work coordinator at each service center uses damage assessment information and weighted customer counts to make decisions about crew assignments.[151] Pepco keeps an updated list of critical loads and customers by circuit number and by service center, which it updates regularly.[152] Special restoration requests and inquiries are all routed through the control center manager and shift supervisors coordinate them with the appropriate personnel. System operators are responsible for managing all feeder outages; all taps and smaller outages are managed by the service centers.

4. Restoration Workforce, Work Practices, and Safety

Restoration Workforce

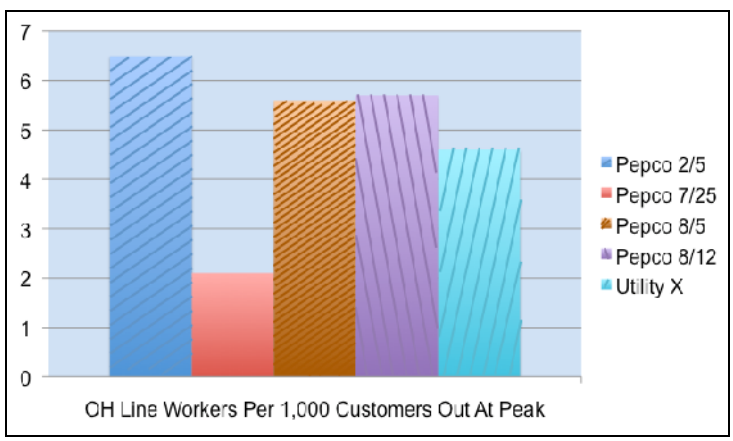
The restoration workforce refers to those identified as "primary overhead line personnel" in the major storm reports filed with the Commission, and includes Pepco's own personnel, its regular contractors, additional contractors, and mutual assistance personnel from other utilities. Marshalling the right amount of resources at the right time has a significant impact on the speed and efficiency of the restoration effort. The following table summarizes Pepco's workforce during each of the four storms.[153]

[150] Interview #27, January 12, 2011.
[151] Response to Data Request # 65.
[152] Response to Data Request #52.
[153] Pepco storm reports.

Pepco Storm Restoration Workforce

Storm Date	Peak Outages	Total Personnel	Outside Primary OH Line Personnel	Internal Primary OH Line Personnel	Total Restoration Workforce	Length of Restoration
February 5	97.6K	1,143	243	388	631	7 + days
July 25	323.7K	1,299	585	105	690	5.5 days
August 5	76.7K	535	210	218	428	2 days
August 12	101K	1,227	461	119	580	3.5 days

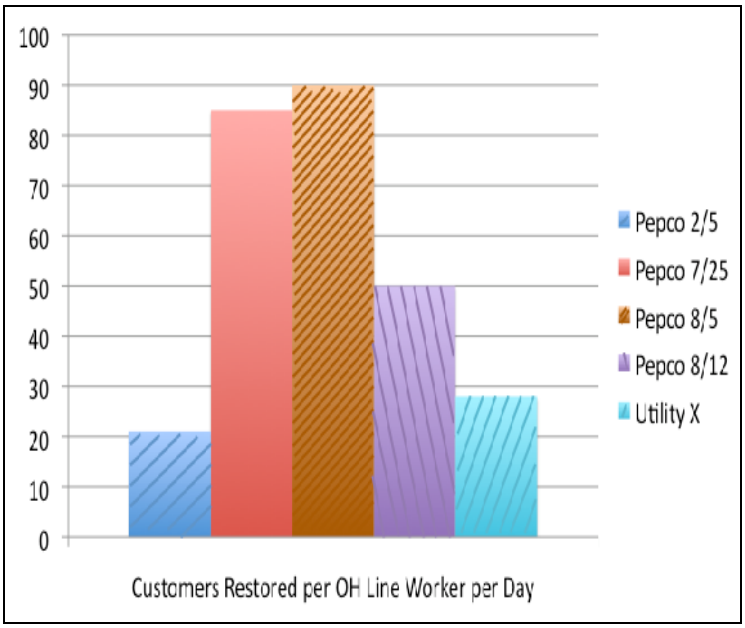
For the purposes of our analysis, we compared Pepco in some regards to "Utility X." We chose this utility because its response to Hurricane Isabel was reviewed by a group of utility emergency response professionals and determined to be "reasonable" in terms of restoration rate. We use that utility as a yardstick—admittedly an imprecise one—against which to calibrate Pepco's performance. The following chart compares the relative size of the Pepco restoration workforce during the four storms with that of "Utility X."



If Utility X represents an acceptable standard in restoration rate, Pepco generally compares favorably in terms of sizing its restoration workforce to the size of the event, the one exception being the July 25 severe thunderstorm.

Another basis for comparison is workforce productivity. The following chart compares the number of customers restored per day per overhead line worker.[154]

[154] Pepco storm reports and First Quartile Consulting file data.



This measure is impacted by the length of time outside workers spend on site in addition to other restoration rate factors. But as a general matter, Pepco's productivity compares favorably to our anonymous yardstick utility. Workforce productivity during Pepco's restoration effort during the February snowstorm event was clearly significantly impacted by working conditions.

Some Pepco restoration responders that we interviewed opined that in some cases the Company may have brought in too many workers, making the restoration process more difficult for field supervisors to manage. Others indicated that Pepco brought in the right number to respond to the original amount of damage, but as the workload decreased, it became more difficult to manage the larger workforce.[155] Overall, we found that Pepco's performance in procuring the proper size restoration workforce and in managing its productivity during the four 2010 storms was reasonable and compares favorably to generally accepted practices in the industry. The Company should, however, improve its process for timing the release of outside restoration crews.

Work Practices

The Pepco practice regarding the work hours for field restoration workers during the 2010 storms is consistent with the widely accepted best practice in the industry. Workers are limited to sixteen hours of duty per day with eight hours rest. Pepco schedules the hours in such a way as to maximize the amount of work done during daylight. Pepco keeps a skeleton crew of first responders on duty overnight, along with some sustaining contractors.[156]

Pepco set up staging areas for each storm response that were used to as headquarters for mutual assistance crews from other utilities. Staging site leaders report to the service center branch director; only outside crews, a site supervisor, and logistics personnel are at these sites. As a

[155] Interviews #19 and #26, January 11, 2011.
[156] Interview #24, January 7, 2011.

generally matter, Pepco keeps its crews at its own headquarters and does not move them to the service center crew yard; it also keeps other PHI utility crews away from the mutual assistance yards. PHI crews headquartered at their place of lodging and had their own supervisors with them. Outside line crews reported initially to a staging site to receive their orientation.

Pepco had storm restoration crew leaders in all four of the 2010 storms, each of whom was responsible for one outside crew and served as guide and "tag-holder" (*i.e.*, the person to whom the Pepco control center gives a switching permit). All Pepco's tree crews were contract crews. Some tree crews were assigned directly to specific crews rather than dispatched.[157]

The system operations control center is responsible for all switching on Pepco's transmission, sub-transmission, and distribution systems. The Pepco control center has thirteen system operators for distribution, seven senior system operators for transmission, and seventeen dispatchers, who dispatch orders, take customer calls, and at times update the OMS. System operators and senior system operators give switching and tagging orders, and open and close switches. System operators handle anything involving a feeder.

Pepco follows normal utility procedures for giving up clearance on a line, performing switching, and issuing work and tagging permits. Local crews are permitted to switch tap and lateral lines. During the storms, Pepco experienced some small delays in getting switching orders, due to the number of requests the first day or two of the larger storms. By the time most outside crews had arrived, however, the number of switching requests had declined to a more manageable level. Each crew called in what was needed at the end of the work day, and Pepco performed some switching at night in preparation for work the following day. The Company stated that in the last two years, substation crews have been permitted to do switching without a coordinator. A small number of sustaining contractors are qualified to act as tag holder, but most crews require a Company tag holder.

Pepco had no union work rules problems in any of the restoration efforts with either PHI crews or outside crews, as there is generally good flexibility in job descriptions. Pepco had a reasonably good experience with outside crews, and was satisfied with crew complements and capabilities. It had very limited problems in splitting the crews up, as a few utilities would not split up their personnel into two-man crews. We found nothing out of the ordinary and no serious issues in Pepco's switching procedures and work rules during its response to the 2010 storms.

Pepco's IRP outlines two approaches to restoring power:

- Order-based restoration: This approach is used in normal outage situations and in smaller (Level 1 and Level 2) storms. As the name implies, repair crews are assigned work based on OMS orders.
- Circuit-based restoration: This approach is usually employed during major outage restoration, and is considered a best practice in the industry. Repair crews are assigned to restore all customers on a given circuit, rather than working individual orders.

[157] Interview #24, January 7, 2011, and Interviews #29 and #30, January 12, 2011.

The decision to use circuit-based restoration is made at the IMT level, and the approach can be different for each service center depending on the circumstances. Pepco used circuit-based restoration during the first two days of the February and July storms in Montgomery County.[158]

Each crew calls in a daily report one hour before the end of the day, providing an update of the progress it made during the day and noting work that remained to be done. For individual work orders, the Company can dispatch OMS orders and receive completion notices via MDTs. Pepco field crews and senior restoration crew leaders assigned to work with outside crews have MDTs. Pepco indicated that having additional MDTs during the restorations would have been helpful.[159] Getting information from the field crews is critical during major outage events in order for the Company to properly inform customers and other stakeholders.

Overall, we found that Pepco's field restoration work practices during the 2010 storm were efficient and effective. Pepco's procedures for communicating with field work crews during the restoration efforts were adequate, but the quality of outage status and estimated restoration information from crews was not. Pepco has acknowledged that the information it received from the field during the 2010 storm restorations needed improvement.

Safety

Individual and vehicular safety should be a top priority for the entire response organization. Safe work practices should be strongly reinforced by corporate and regional management throughout the restoration. Good safety management during major outage restorations requires aggressive and comprehensive safety orientation for all outside resources coming in to assist. In good utility practice, a safety culture should exist in which any employee feels empowered to shut down a job if he or she has safety concerns. A utility should keep accurate and complete safety records and conduct a thorough review of safety performance and management issues after restoration is complete. Pepco indicated that safety is a core Company value; it stresses safety with contractors and mutual assistance personnel and conducts safety orientations with all outside crews.

According to Pepco, there were no reported employee incidents in any of the four storms.[160] In the area of public safety, Pepco reported that it knew of no incidents. Pepco has a very structured and proactive wire down process. Wire down calls draw an immediate response from Pepco, even to the point of utilizing resources that might be better used elsewhere. A problem for Pepco is that cable and telephone utilities do not send people out to check and clear their wires. Fire and police calls come through a direct line from a 911 operator to the Company control center. Pepco's policy is to stop restoration and respond to 911 calls if needed. Pepco received no complaints from either the fire or police department in the aftermath of any of the four 2010 storms.[161] Overall, Pepco's safety management during the storms was very good.

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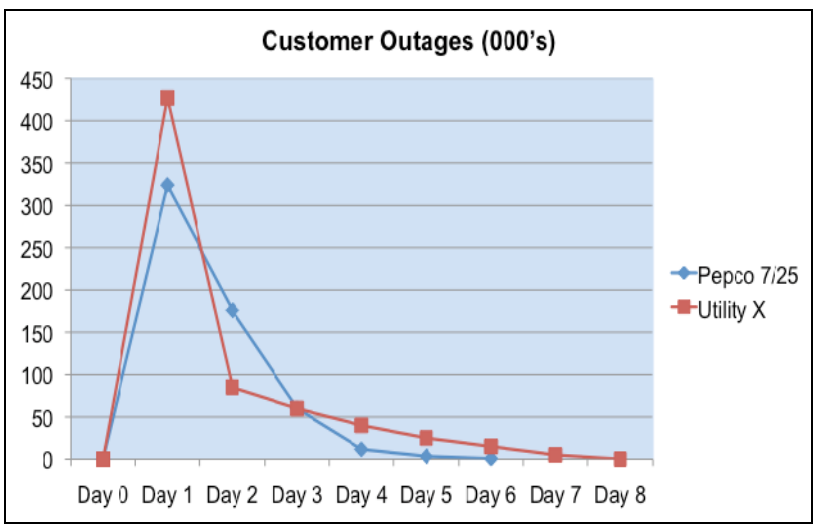
[158] Interview #24, January 7, 2011.
[159] Interview #24, January 7, 2011.
[160] Response to Data Request #112.
[161] Interview #25, January 10, 2011, Interviews #19 and #26, January 11, 2011, and response to Data Request #112.

5. Restoration Rate

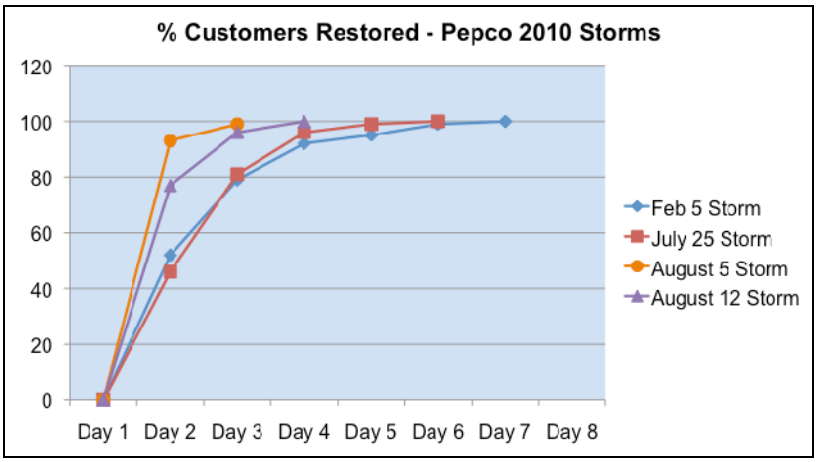
The rate of restoring customers during an outage is a key measure of success. The following graph compares Pepco's restoration rate in restoring power to approximately 323,000 customers in the July 25 storm to that of Utility X, which restored power to approximately 400,000 customers in the aftermath of Hurricane Isabel.[162]



Comparisons such as these have obvious limitations—factors such as severity of damage, customer density, weather during restoration, and topography have a significant effect on restoration rate. In a real sense, there is no "apples to apples" comparison that one can make even between two utilities responding to the same storm, let alone a different storm at a different time. We selected the July 25 storm for comparison based upon the number of customers, the length of restoration, and the characteristics of the storm.[163] With these caveats, Pepco's rate of restoration in the July 25 storm is comparable to what is considered acceptable restoration performance in the industry.

Another way to view restoration rate is to measure the percentage of customers restored each day as compared to the total peak number of outages. The following graph shows Pepco's rate of restoration in terms of the percentage of customers restored by day for the four 2010 storms.[164]

[162] Pepco storm report and First Quartile Consulting file data.
[163] Winter storms, such as the one in February 2010, are inherently different from hurricanes and wind storms; the mobility problems that Pepco experienced during the snowstorm would make comparisons even more difficult.
[164] Pepco storm reports.



Pepco's restoration rate for all four of the 2010 storms, especially considering some of the differing characteristics as to type of storm and severity of damage, was comparable, although, not surprisingly, the restoration rate for the winter storm was worst. Overall, Pepco's rate of restoration for the four storms is comparable to what is considered acceptable restoration performance in the industry.

F. Estimated Time of Restoration

During a major outage event, customers are anxious to find out when they will have their power back so they can make their own plans for coping with the circumstances. During the 2010 storms, many Pepco customers were frustrated by delayed, expired, or extraordinarily long ETRs.[165] Providing customers with reasonable estimates is critical. Customer satisfaction research has shown that providing accurate, timely information regarding service restoration, and adequately explaining how the process works, is as important to customers as is the actual speed of restoration. How the utility communicates with customers about the restoration process is as important as the dependability of its restoration time estimates. In this chapter of the report, we focus primarily on Pepco's process for developing those estimates. We discuss the communications aspects in greater depth in Chapter VIII.

We found that Pepco's process for providing ETRs was not timely and was hampered by systems and technology issues. Pepco is not alone in having difficulty with providing accurate restoration times. Many utilities have very similar approaches for developing ETRs, and experience the same inherent process and system limitations.

We should point out that the quality of ETRs and the quality of restoration efforts are two separate things. ETRs are extremely important from a public relations standpoint, but have little or nothing to do with how actual physical restoration activities unfold. A utility's effort to calculate ETRs run parallel to its restoration activities but does not affect them. The length of

[165] Response to Data Requests #41 and #123.

time a company takes to restore all customers after a major outage event is the same regardless of whether it produces very good or very bad estimated outage restoration times.

1. Outage Management System Calculation of ETRs

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.[167]

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.

Under normal circumstances (*i.e.,* small localized outages), the OMS can calculate accurate ETRs. However, in the early stages of a fast-hitting storm that creates a lot of damage quickly, the OMS calculates improbably long restoration times because it calculates these assuming routine staffing levels. Until the Company can update the staffing information in the OMS to reflect the addition of mutual assistance and other resources, output from the OMS is very misleading, and essentially useless. In these situations, Pepco does what it should do—and what other utilities do—it turns the automated ETR calculations off.

During larger storm events, Pepco temporarily suspends the automated calculation of ETRs and does not disseminate them to customers. The decision to suppress ETRs is made by an experienced shift supervisor or system operations manager, based on system activity. For example, if Pepco has 10,000 customers with outages, it would likely decide to suppress ETRs. The Company, however, has no formal guidelines for making this decision.[168]

When routine outage calls from customers come in, the OMS ties the calling customer to a device on the distribution system. The OMS creates orders, and dispatchers send work orders to crews in trucks who acknowledge receipt of the order. The crews provide a revised estimate of restoration time back to the OMS after arriving at the job site, and provide the system operator

[166] Response to Data Request #141. The OMS makes an informed prediction of which device causes a customer outage but it cannot determine in all cases if a customer is without power due to two or more simultaneous or nested outages,
[167] Interview #14, January 14, 2011.
[168] Interview #13, January 19, 2011 and Interview #14, January 14, 2011.

with more information about the situation in the field as required. After the crew completes the repair or restoration, it typically closes the OMS order via an MDT.

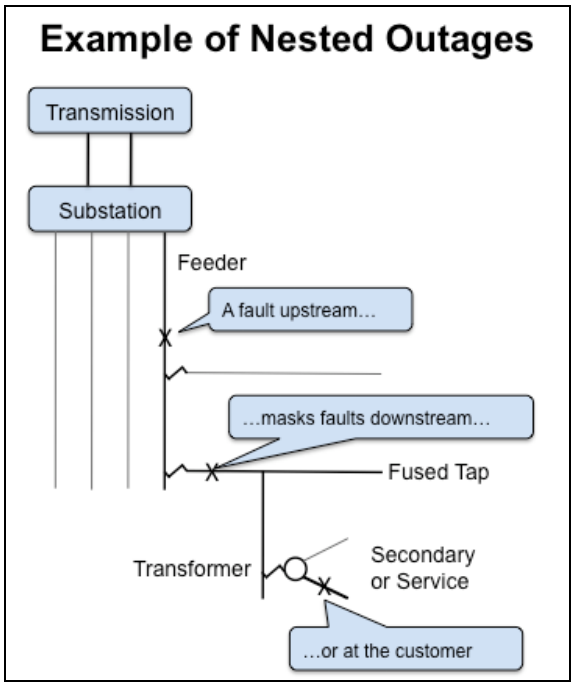
During major storms, the standard work order dispatch process does not always work well, particularly with outside crews. During the 2010 storms, crews did not always transmit information back in from the field to the OMS to close orders on a timely basis. Crews pushed the closeout activity to the dispatchers because of their workload, which slowed the flow of information. According to Pepco, this delay hampered its capability for providing accurate and reliable ETRs, because the information in OMS was not up to date. The Company also experienced problems in the first days of each storm getting updates about damage repair status to the system operator by telephone or radio. When it used the circuit-based restoration process in the February 5 and July 25 storms, Pepco kept the OMS current by modeling in OMS what was re-energized or left open as the work was done. During some of the storms, Pepco added some dispatchers from DPL in its service centers to dispatch crews.

Pepco indicated that it has taken several steps since the 2010 storms to address these issues. The Company has assigned a person in the dispatch center to monitor ETRs, and an alarm sounds to alert the dispatchers when an ETR is near its expiration. Pepco has also initiated a process to ensure that the automated OMS ETR function is quickly deactivated as soon as it becomes apparent that a major outage event has begun.[169]

2. Relationship between Nested Outages and Restoration Time Estimates

Every utility has some difficulty in identifying the extent of its outages. For example, a utility may lose 30,000 customers early in a storm due to the loss of a substation. In the same timeframe, the utility may experience additional faults along its system on feeders emanating from that substation, at local transformers, or on secondary lines serving some of those same 30,000 customers. The utility may not know of the extent of downstream problems until after it restores the substation; in our example, the utility would find it has nested outages when, after re-energizing the substation, less than 30,000 customers are restored. A customer (and the utility) will not know he or she is without power due to multiple outages until after the restoration process is underway. The following diagram illustrates how these events can occur.

[169] Interview #23, January 7, 2011, and response to Data Request #65.



Pepco has SCADA equipment that can identify full-circuit outages on essentially all of its circuits, and therefore will know that all customers on a given circuit have experienced an outage. The Company can reasonably estimate how long it will take to restore power to the circuit by switching the circuit back on. What it cannot do is automatically detect where all nested outages have occurred. If the Company has not located these nested outages during damage assessment, it has to rely on calls from customers.

The OMS uses information about known outages in its calculation of ETRs. If Pepco uncovers significantly more outages after it has provided customers with ETRs, those initial estimates will almost certainly be superseded once the Company updates the OMS with new damage information. Customers in turn will become frustrated when their estimated restoration times pass and they are still without power. It is not unusual for customers that are without power due to recently-discovered nested outages to receive revised ETRs, because the location of the outage causing them to still be without power been more clearly identified.

As we discuss in the next chapter, Pepco was not proactive enough in soliciting information from customers to identify nested outages. If customers knew the importance of this feedback loop, and the effect it can have on the accuracy of ETRs, many would be more willing to accept callbacks during the restoration process.

3. Alternative Method to Prioritize Restoration and Calculate ETRs

When it has to suppress the OMS algorithm that calculates ETRs because the system cannot provide it with accurate estimates, Pepco switches to a predominantly manual process called "tiering" to both calculate restoration time estimates and prioritize work orders. The OMS can

predict the number of customers associated with each known outage. In the tiering process, Pepco prioritizes outages depending on their weighted customer count and assigns ETRs to groups of outages and customers according to priority order. The Company's policy is to restore outages affecting the largest number of customers first, consistent with good utility practice. As such, tiers (*i.e.*, groups) of outages that affect the largest numbers of customers are assigned the earliest ETRs. For example, all outages affecting 100 customers are assigned the same ETR; outages affecting between 50–100 customers are given the same, but later, ETRs. The smallest tier is for one to five customers. To determine the ETR for each tier, Pepco uses input from its field patrollers, line mechanics, and others to understand the extent of the damage and necessary time to repair it. Pepco has no formal process for making tiering decisions. The systems operations manager in his role as an IMT leader makes the final decisions based on triage with the IMT leader.[170]

If a group of customers is out due to a feeder lockout, all customers on that feeder receive an ETR that is tied to that feeder and updated when the restoration occurs. However, when Pepco identifies a nested outage on that feeder, such as a local transformer outage, it has to generate a new outage order or trouble ticket. This means the customers on the feeder affected by the newly-detected outage receive a new ETR, because they are now part of a smaller outage group with a lower restoration priority. In some cases, the crew doing an initial repair may find a nested outage, and if it is not making the second repair, it will call the outage in to the dispatcher, who then records the newly-detected outage in the OMS. If the nested outage was not detected by a crew, Pepco would only find out about it when a customer calls to report he or she is still without power, or if the Company calls back customers after restoration of the feeder lockout and learns that some customers are still without power.

Generally, restoration crews do not spend time patrolling for secondary or nested outages and instead move on to the next assigned job based on the restoration priority. The Company may be able to use secondary patroller or service vehicles to pursue nested outages. Such options, however, may be limited by how Pepco plans its restoration deployment and organizes mutual assistance requests. The fact that the Company did not complete its damage assessment during the 2010 storms only exacerbated the problem.

Pepco used the tiering process in the initial stages of the 2010 storms. In the February 5–12 storms, Pepco did not provide any ETRs to customers until February 7. The Company stated publicly that it had difficulty assessing the impact of the storm due to road conditions.[171] Pepco used tiering for the July 25 storm, but it took the Company over 24 hours to determine the tiers because it had problems calculating the ETRs.[172] By contrast, Pepco determined tiers in less than six hours in the August storms.[173]

[170] Interview #13, January 19, 2011 and Interview #14, January 14, 2011.
[171] Response to Data Request #15.
[172] Interview #13, January 19, 2011.
[173] Interview #13, January 19, 2011.

At a certain point, Pepco switches from the tiering process back to using the OMS to calculate ETRs. While the tiering process is underway, Pepco continues to feed the OMS with status information about outages and restoration status. As noted earlier, it was Pepco's delays in getting updated information from the field, either about completed restorations or damage assessment, which caused its delays in updating the OMS. But, as the restoration progresses, and the outage status catches up, the OMS ETRs become more accurate and reliable. At that point, Pepco ends the tiering process and goes back to relying on the OMS for ETRs.

While the tiering process is the best practice to follow, it is cumbersome and does not necessarily yield accurate ETRs. Whenever nested outages are found, some ETRs have to be revised, which leads to customer confusion and frustration.

4. ETR Accuracy and Reporting

Utility best practice is to track, report, and analyze the results for ETRs after major events to determine where operational improvements can be made and how ETRs could be developed differently in order to improve accuracy. Some utilities include outage communication performance in their corporate "performance scorecards."

Pepco could not supply reports showing the accuracy of its ETRs during the 2010 storm events or how those reports, if available, are used to make improvements or enhancements.[174] We did learn, however, that during the February 5 and August 12 storms, Pepco revised its ETRs and tiers twice. During the July 25 and August 5 storms, Pepco revised its ETRs and tiers five times.

G. Ramp-Down Process and Post-Event Critique/Follow-Up Process

An important part of any restoration effort is efficiently reducing the workforce, deactivating command centers and staging sites, and processing remaining clean-up items. Ramp-down begins when the amount of unrepaired damage remaining is small enough so that the utility can release some resources. The storm response leader should control the decisions to release or re-assign outside resources. Good utility practice means that clear principles governing ramp-down are established, well-communicated, and understood by the leadership of all command centers, teams, and functional groups. Close coordination and effective communications with the mutual assistance utilities is essential throughout the restoration effort, but especially so during ramp-down.

The clean-up process begins after power is restored to all customers. A utility should make complete and accurate records of any instances in which its crews performed temporary repairs to expedite restoration and follow-up is needed. The same is true of any debris or needed tree trimming the utility is responsible to clean up. Utilities should develop a specific clean-up plan designating the number of line and tree workers needed and a targeted timeframe.

[174] Response to Data Request #140.

We found that Pepco's ramp-down plan adequately addressed all of the factors involved in an efficient shutdown of the restoration effort. When the IMT and systems operations leaders find that the restoration effort is nearing an end, they determine release dates for all out of town crews based on factors such as crew capabilities. They review the level and nature of "referred work" to determine if that work need be done immediately or if it can wait until after the Company returns to normal operations. After mutual assistance crews are released, Pepco crew leads, trouble crews and emergency crews are also released to normal schedules.

Good utility practice dictates that all functional response teams should compile a list of "lessons learned" during the restoration within a week after the effort has been completed. The utility should hold a regional-level meeting to review, prioritize, and assign responsibility and aggressive target completion dates for the issues identified; follow-up reports should monitor the current status of implementation. After the 2010 storms, the PHI emergency management group had a lessons learned process. Pepco's IMT had its own process and held official "lessons learned" meetings after each storm. It is not clear, however, that Pepco follows up to see that the high priority items are addressed.[175] The Company appears to have no structured follow-up process to track progress on identified needs.

H. Major Conclusions

1. Pepco's performance in restoring power to its customers during the four 2010 storms, in terms of total time to eventually restore power to all customers, was reasonable given the scope of the outages.

The scope of each of the outages was extensive, in part due to the condition of the electric system prior to the storms. Given the extent of the outages, the physical restoration effort compared favorably to that of other utilities facing similar levels of damage. Logistics and supply efforts were well-planned and effectively executed. The use of a circuit-based restoration process during the February and July storm events reflects industry best practice. The restoration workforce in place during the 2010 storm events was generally adequate.

2. Pepco failed to complete a full damage assessment during each 2010 storm event, contrary to its emergency response plans. *(Recommendation VII-1)*

Failure to complete the 4-hour patrols and the detailed damage assessment contributed to the difficulties in developing timely and accurate ETRs. While the electric system has excellent SCADA penetration at the circuit level, the lack of automated switches and devices farther out on the lines makes the damage assessment a critical piece of the job in understanding the full extent of the damage, and helps with identifying nested outages.

[175] Responses to Data Requests #20 and #21, Interview #20, January 14, 2011 and Interviews #19 and #26, January 11, 2011.

3. **The performance of the Pepco field restoration organization in transmitting accurate and timely outage status information and updating the Outage Management System (OMS) was inconsistent and created problems in developing and communicating Estimated Time of Restoration to customers.** *(Recommendation VII-2)*

Collection and delivery of accurate outage status information for input to the OMS is the best way to enable the OMS to calculate better ETRs, The OMS depends substantially on the field workforce and on customer reporting of outages to be able to identify nested outages, accurately model the status of the system, and thus create more accurate ETRs. From the customer perspective, the inaccurate and unavailable ETRs were one of the most frustrating parts of the outage events.

4. **Pepco appropriately performs a post-event "lessons learned" analysis, but has no structured follow-up process.** *(Recommendation VII-3)*

There is an organized lessons-learned process, which includes most of the right elements of such an assessment. One key element that isn't included is an analysis of the accuracy of ETRs. Follow-up in taking action on the findings from the lessons learned wasn't systematic and comprehensive.

I. Recommendations

VII-1 Pepco should strengthen its Incident Response Plan (IRP) to make more consistent use of the "four hour patrol", and emphasize the necessity for a timely and complete detailed damage assessment. *(Conclusion #2)*

Damage assessment is a key necessary step in order to plan and prioritize the restoration effort. It is also critical in providing accurate information to the OMS, which in turn results in more accurate ETRs. An upgrade in the IRP, followed by refresher training of response personnel, and continued emphasis on completion of the damage assessments by response leaders during storm events is necessary to assure this critical step is completed during major events.

VII-2 Pepco should amend the Incident Response Plan (IRP), provide necessary equipment (such as Mobile Data Terminals), and increase staffing as required to adequately provide timely, complete, and accurate updates of outage status to the Outage Management System (OMS). *(Conclusion #3)*

Improvement of the ETRs requires that better information about outage status be input on a timely basis. Providing more MDTs to field forces will enable more automated updates of the OMS. Additional clerical staff to support manual input of status information called in from field forces will contribute to more timely updates. Assuring that each field crew has adequate people assigned to update Dispatch regarding outage status will improve the accuracy and timeliness of the information flow. Taken together, these actions will improve the ability to deliver ETRs developed by the OMS rather than using the tiering approach.

VII-3 Pepco should improve its process for developing ETRs and the flow of restoration information within the Company to better position it to communicate effectively with customers. *(Conclusions # 3 and #4*)

An initiative to improve upon the development of ETRs would begin with the appropriate and timely flow of information into the OMS, including from field forces and from customers. Elements to cover include a more proactive outbound calling process to ensure restoration has occurred, and more effective analysis of the accuracy of ETRs. Further, the tiering process used for creation of ETRs needs to be analyzed for improvement opportunities.

VIII. Outage Response – Customer and Public Communications

A. Introduction

One of the most critical aspects of effective outage response is effective, accurate, and timely communications with the public, which encompasses all contacts outside of the utility—customers, government officials, community leaders, the media, public safety organizations, and emergency management agencies. Poor communications can negatively impact what is otherwise a logistically and statistically effective restoration. Successful communications during storm restorations depends on certain key factors:

- Effective internal and external organizational structures that enable the communications necessary to manage and coordinate storm response
- Supporting communication channels, processes, and actions to ensure that provided information meets customer needs during each phase of the event in a timely, reliable, and consistent manner
- Adequate and capable staff in place to respond to customer inquiries on a timely basis that have been trained to provide clear, consistent and accurate responses to customer inquiries
- Effective system interfaces between critical-to-mission systems such as the OMS, customer information system (CIS), interactive voice response (IVR), and web-based applications to support outage functions such as communication of ETRs
- A post-event communications review process, with feedback and corrective actions.

In this chapter we discuss our review of the communications aspects of Pepco's response during the 2010 storm events. As part of that review, we assess the adequacy of Pepco's customer communications systems, policies, procedures, and practices; determine if its customer communications are consistent with best practices in the industry; and identify the root causes for problems in outage-related communications.

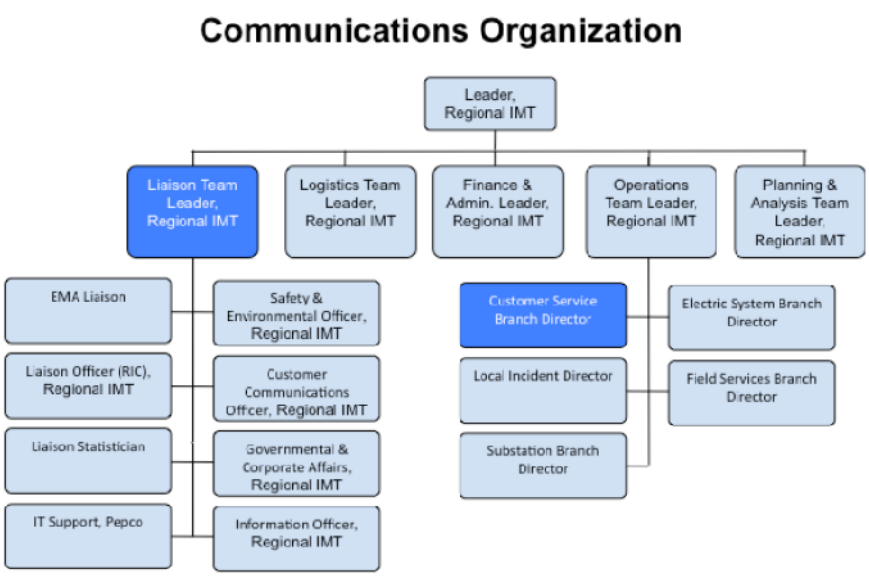
We found that while Pepco had internal and external organizational structures in place to manage and coordinate storm response and has taken positive steps since the Witt Report to implement changes, it did not provide adequate storm status and restoration information to meet Maryland customer needs over the various phases of the 2010 events in a timely, reliable, and consistent manner. While Pepco used technology to effectively answer high volumes of customer calls, the consistency and quality of Pepco's live customer interactions, specifically call taking functions, was not adequate. Through our review and call monitoring, we found that Pepco in its live interactions with customers did not adequately provide consistent and accurate information. The Company also did not solicit feedback and reinforce the customer's role in supporting its restoration efforts (*i.e.,* using the callback process to support identifying nested outages). Lastly we found that overall system performance of the OMS, CIS (Customer Information System) interfaces, voice response units, and website, was not adequate in the storm events of 2010 and

contributed to the negative impact on customer communications and communication processes. The combination of the above difficulties was a key driver in contributing to the frustrations experienced by Maryland customers.

B. Internal and External Communications Structure

Overall, we found the organizational structure that Pepco used for internal and external communications during the 2010 storms was in line with the Company's IRP, and that the basic structure represented an improvement over the situation described in the Witt Report.[176]

The PHI Crisis Management Plan outlines the corporate response to a wide range of potential emergency events. Pepco's IRP, which the Company used to guide communications during the 2010 storm events, outlines operational activities during major storm restoration events, including those related to communications.[177] The overall organization of the Incident Management Team (IMT) is shown in the following chart; key communications positions are in dark blue.[178] The Liaison team and team leader, as well as the customer service branch director, play important roles in communicating with various operating functions, such as the call centers, during storm events. The communications organization is also a key link to the Joint Information Center (JIC) that we discuss later in this section.



At the regional IMT level, the Liaison team leader oversees all activities that involve communications with internal and external departments and agencies to facilitate the collection and dissemination of information across the Company, and supports overall incident response and the coordination and management of resources assigned to the IMT. The responsibilities of

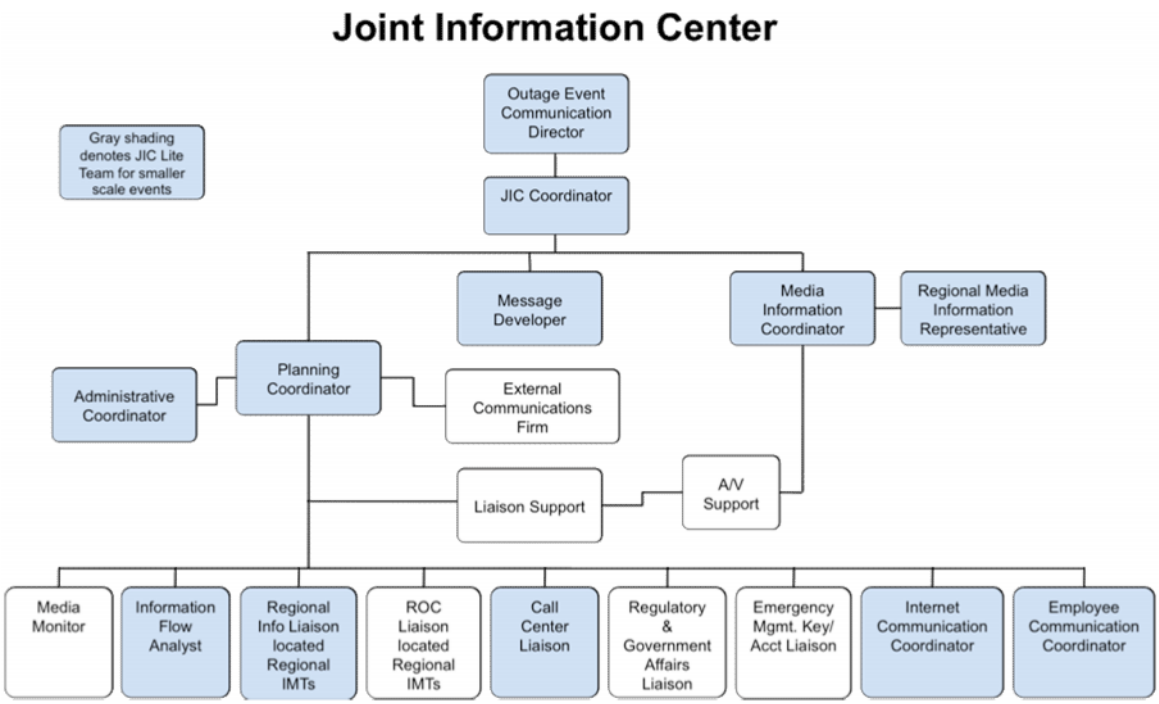
[176] Response to Commission Question No. 10.
[177] Responses to Data Requests #25 and #30.
[178] IRP provided in response to Commission Question No. 5.

the customer service branch director are to oversee the operation of the call centers, designate appropriate call center coordinators, review assignment lists and rosters, and arrange for additional resources.[179] A call center supervisor manages operations and ensures outages are entered into the system on a timely basis. Auxiliary support provides trained personnel to augment the call center during significant events.[180]

The primary role of the JIC is to execute communications strategies and tactics during an emergency, potential crisis, or crisis; Pepco activates the JIC for Level 3 or 4 events.[181] Pepco created this structure and role based on Witt Report recommendations. From a communications standpoint, the JIC works with corporate communications, which provides external strategic and corporate communications, media relations, advertising, and public information, as well as management and employee communications within PHI. In the case of storm events, corporate communications personnel process information updates from and conduct discussion with the Incident Support Team (IST), IMT, systems operations, and other groups to develop news releases for review and approval by the JIC prior to distribution to media outlets and channels.[182]

The structure and role of the JIC and its relationship to corporate communications and other key communications channels is critical. The JIC acts as an information clearinghouse, not only disseminating but also gathering input; its goal is to communicate with "one voice" to Pepco constituents. The JIC is composed of employees whose second role jobs are to facilitate the flow of information within PHI and its subsidiaries and support those who interact with the public. The JIC is a single organization, but it may have representatives in multiple geographic sites in order to better serve stakeholders and audiences at those sites.[183] The organization as structured in 2010 is depicted in the following chart.

[179] Interview #11, January 14, 2011.
[180] IRP provided in response to Commission Question No. 5.
[181] Response to Data Request #25.
[182] Response to Data Request #25.
[183] Response to Data Request #25.



C. Supporting Communication Channels, Processes, and Activities

We reviewed Pepco's communications materials for the 2010 storm events, including news releases, daily situation reports, and talking points provided to the contact centers for messaging to customers and for other non-live channels (*e.g.*, Pepco's website and IVR).[184] We reviewed current policies and procedures.[185] We also reviewed Pepco's "web presence" during the events, including related outage maps, weather communications, and blogs.

Pepco generally had adequate processes in place to address communications during each of the storms, but had repeated communications and systems problems. Some of these related to computer systems, such as the OMS, CIS, Graphical User Interface (GUI), and other critical systems. Others problems involved its website, outage maps, and calculation and provision of ETRs, particularly during the February and July storm events.[186] These problems impacted the content, quality, and timing of communications.

Pepco stated that it corrected most all individual technical issues and problems once it identified what they were, but this was typically after its communications with customers had been negatively impacted. When taken in their entirety, we found that these problems were one of the primary drivers in the levels of dissatisfaction of Maryland customers in Pepco's outage and restoration efforts.[187]

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[184] Responses to Commission Questions No. 1 and 20 and responses to Data Requests #15 and #145.
[185] Responses to Commission Questions No. 16 and 17.
[186] Response to Data Request #21.
[187] Responses to Data Requests #41 and #123.

JIC and Corporate Communications

The JIC was activated in each of the 2010 storms and worked with the IMT and other operations functions to support restoration and preparation efforts. People moved into their roles on the JIC in some cases remotely because of weather conditions.

For the February 5 storm event, members of the JIC participated in pre-event IMT and IST calls on February 4 and in on-going calls with the IMT several times per day through February 12; corporate communications personnel also participated in the IST calls. The JIC participated in on-going calls with the IMT several times per day in all four storm events, while also communicating with areas such as the call centers and systems operations in order to learn what these organizations were hearing from customers and field crews working on restorations.

Pepco corporate communications staff began holding communications calls within the first hour of the summer storms impacting the region on July 25, and continued holding them through the subsequent restoration efforts. As with the February storm, these calls allowed participants to discuss how to appropriately disseminate internal employee communications and external messages through various communications channels, including broadcast and print news media, Pepco's website, and social media sites.[188] The regional information coordinators appointed to the IMTs and customer call centers worked as information conduits between their respective IMTs and the JIC throughout the various events.[189]

During the storms, the JIC facilitated the drafting of news releases and media advisories (which alerted the media of pending news conferences at which Pepco executives updated customers on restoration efforts) issued prior, during, and after the storm. Corporate communications personnel developed news releases for review and approval by the JIC prior to distribution to the media. The JIC also supported the development of talking points issued to customer service representatives (CSRs).[190]

We found that Pepco should improve its customer communications by instilling more consistency in the information it conveys to customers regarding restoration status via press releases, updates, and its own CSRs. We identified instances during the storms in which Pepco issued press releases and communications notifying customers to get ETRs, but the ETRs were not available when customers called. The Company was not timely in communicating to customers about technical issues such as the unavailability of ETRs and website outage maps, or systems issues preventing access to accurate information. On several occasions, based on feedback from customers calling, CSRs notified the JIC that systems were not working. We recognized that while the intent of effective two-way communications is to create feedback loops that allow for such problems to be identified by parties experiencing them, they should not be primary sources to capture problems, in this case those related to technology.[191] Although the

[188] Response to Data Request #15.
[189] Response to Data Request #25.
[190] Response to Data Request #25.
[191] Response to Data Request #15, and Interview #38, February 4, 2011.

Company typically addressed these problems the same day, many customers were nonetheless frustrated and communications occurred after-the-fact.

We found that, while the JIC process and role in communications was an improvement over prior major storm events, it lacks an effective link to those ensuring the integrity of systems and was not able to consistently ensure that the Company delivered accurate communications about key aspects (particularly technology-related issues) of the outage across the various customer communications channels.

Press Releases and Local Media

We reviewed Pepco's use of press releases and its interactions with local media in connection with the storm events.[192] Pepco engaged often with print, television, radio, and web-based media. During the February storm, for example, Pepco issued 10 press releases and aired 84 television or radio interviews. We found that Pepco followed appropriate protocol for news release preparation, review and release, did a good job communicating information on health and safety and personal storm preparation tips, and actively promoted its 1-877-Pepco number for reporting of outages.

The Company should, however, institute a more standard means of conveying the status of its outage preparation and restoration operations to the public before and during a major outage event. The Company could communicate alert level or priority level status, associated mobilization levels, and situational status through a standardized, comprehensive, "emergency operations status message." In Pepco's case, it could be tied to the current Level 1–4 mobilization and status designations in the IRP.[193] The Company should also engage in proactive and timely public communications about matters such as Pepco's organizational status, activation of emergency operations in the IMT, extending of regular work shifts, communication or calls to alliance contractors and mutual assistance groups, assignment of safety personnel, and structured county-specific data.

Government Affairs

Pepco had an appropriate process in place and made its personnel available for communications with outside representatives. In each of the 2010 storms, Pepco conducted numerous conference calls with county and local governments, elected officials, members of the Commission, as well as hospital and homeowners associations. The Company conducted press conferences and briefed county executives and other officials.[194] The government affairs department invited officials to participate in daily conference calls to discuss the restoration efforts at which Company officials shared updated information and fielded question; approximately 20–60 officials typically participated in these calls.[195]

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[192] Response to Data Request #15.
[193] Response to Commission Question No. 5.
[194] Response to Commission Question No. 1.
[195] Responses to Data Requests #30 and #16, Interview #15, January 20, 2011.

Pepco Website

We reviewed the effectiveness of Pepco's website in supporting outage communications, and reviewed issue reporting and customer perceptions in post-storm surveys conducted by the Company.[196]

The Company maintained copies of the latest restoration press releases and other customer messages on its website in a chronological fashion, and used the website as a repository for Frequently Asked Questions (FAQs) related to storm conditions and possible customer questions. The website hosts Pepco's digital outage maps, which visually display outage locations and Company crew deployments. Pepco posted storm preparation and power restoration information on the Company website and updated it on a regular basis; it also provided a "Pepco Powercast" where customers could watch a customized weather update and forecast developed specifically for Pepco.[197]

The website can provide customers with ETR information (via an OMS interface) on maps that zoom down to a one-mile area view. Customers can view their situation at a street level and check the status of events *(e.g.*, whether a crew was dispatched); this information is displayed as stacked triangles on the map, with each triangle representing an order at a feeder level. Pepco's website does not provide the capability for customers to report outages, which we see as an emerging industry best practice. While relatively few utilities have this system communications capability, more are evolving OMS linkages to include not only online outage status maps, but also text-based outage and "outage detected" information, ETR updates, and outage restored messages down to a customer level. Pepco is still evolving in its use of web-based technology for outage communications. Pepco mentioned steps to place outage maps on mobile devices and at the time of our review had applications available. We did not evaluate these.[198] It does not have the capability for customers to report via phone application.

The website was functional for most of the storm events, however it was either slow or down for periods of time during the July storm events such that customers had trouble obtaining accurate outage maps. While Pepco did initiate repairs to address the situation, it should have an ongoing process to ensure the reliability of the website and outage maps during future high volume events.

Post-storm survey data indicate that during the summer storms, less than 25 percent of customers used the website to obtain outage information, compared to 15 percent during the February storm. Among those who visited the website during the summer storms, only half found it helpful in staying current on restoration efforts. Half of customers accessing the website did use the outage maps; half of those found the outage maps useful.[199] The delays and interruptions that Pepco customers experienced when trying to use the website and outage map function

[196] Interview #12, January 7, 2011 and response to Data Request #40.
[197] Interview #12, January 7, 2011.
[198] Interview #12, January 7, 2011.
[199] Response to Data Request #41.

contributed to customers' overall unfavorable perception of Pepco communications, particularly during the July storm.

Social Media

Pepco used its PepcoConnect Blog for storm communications during the 2010 events, as well as social media such as Twitter, blog postings, and videos to expand its customer outreach. PepcoConnect supported customers using it on a real-time basis with storm status updates during each of the storms. We found that some of the blogging was sporadic, and that video postings and informational materials were not always timely. However, Pepco did receive recognition for evolving this channel.[200] More utilities are starting to use this channel as a best practice in supporting storm events and communicating with customers. Pepco should continue to develop the use of social media channels through greater real-time use of videos, on-the-scene reporting, and other means of conveying storm and restoration information.

Emergency Management Agencies (EMAs)

We reviewed the effectiveness of the communication and engagement process with EMAs. We interviewed both EMA and Pepco managers, reviewing the process at the Maryland county level. Pepco and County agencies have different overall perspectives on the quality and effectiveness of their communication with each other and resulting effectiveness of established processes during Emergency Operations Center (EOC) activations.

Pepco has a formal process in place, including participation on planning calls and or physical staffing of Pepco liaisons at EMAs during the initiation, staffing and operation EOCs at the County level during significant weather events. Not all EMAs in Maryland activate EOCs, which means that Pepco's participation in some cases is purely via phone or conference call, e-mails etc. This was the case in the storm events of 2010. However, it was clear from our review that Pepco communicated with EMAs at the county level, and those communications varied depending on each county's needs.

Prior to the February 5 storm, Pepco participated in calls with the Montgomery County EMA and provided email communication to the Prince George's County EMA. The February 5–12 storm was the only major storm event that had a "pre-event" conference call. The Montgomery County EMA was activated and operated until the end of response operations on February 12. For the July 25 event the EMA was activated on July 26 and ended operations on July 28. Pepco supported the EMA with two liaisons during those periods. The Prince George's County EMA did not activate an EOC during either of the storms.[201]

Pepco provides liaisons to support counties (per request and agreement) who act as two-way communicators of decisions and County needs. Pepco liaisons are not, nor are they intended to be, decision-makers.[202] The liaisons report to the Liaison team leader in the Incident

[200] Response to Data Request #15.
[201] Interview #39, February 7, 2011.
[202] Interview #39, February 7, 2011.

Management Structure. EMAs stated that they had good working relationships with the Pepco personnel with whom they interacted.

Requests from EMAs go back and forth between the parties but are not formally logged and the process for any documentation and informal record keeping is manual and kept by the liaisons themselves. Requests are typically in areas of critical importance or outage events, in the form of listed needs for wires down, road closures, critical care, and coordination with transportation for plowing or road clearance. Beyond these types of coordination and communications, Pepco does not provide any other forms of web-based or electronic communications other than Graphical Information System (GIS) layers. These are in the form of an e-mailed file that would show areas of outage location so that EMA can assist in placement of road plows, increase law enforcement, etc. Pepco also stated it conducted annual emergency management program training for EMAs to refresh on, for example, restoration and setting of ETRs.

From the EMA perspective, Pepco needs to be more proactive with communications and actions in such areas as: timely provision of quality GIS information; identification of critical facilities with outages greater than one, two, three or more days; participation in emergency training to familiarize the specific Pepco-assigned liaisons with county practices and operations; participation in county-adopted systems for tracking and disseminating support needs and status; and proactive outreach and engagement in those communities that are not as technology-enabled. Such outreach would allow Pepco to convey what role the community can have in being prepared for major storms and in helping Pepco's restoration efforts, such as the importance of reporting of downed wires and outages and confirming restoration callbacks.

EMAs differed in their opinion about the current quality and effectiveness of communications, but all felt that the quality of information, flowing both ways, needed to be enhanced. Pepco, on its behalf, sees a need for better prioritization and quality of information coming from the EMAs, including accurate locations, and more but less redundant information.

Pepco and the EMAs have opportunities to proactively enhance these relationships to the benefit of both by addressing mutual concerns in a direct and structured manner. There has been some progress; for example, plowing and access issues were identified as an issue in the February storms.[203] Now, both counties have plows dedicated and coordinated to support Pepco crews in providing access for restoration activities. However, we concluded that there are still operating and communications gaps that need to be bridged.

D. Response to Customer Inquiries

In this section, we discuss Pepco's handling of the largest communication channel—customers calling the contact center for reporting, status and update purposes—and Pepco's communication with those customers. We first provide a best practices model for effective contact center

[203] Response to Commission Question No. 1.

responsiveness, and then examine Pepco's performance in handling volume and service level needs. Lastly, we look at the quality of Pepco's live interactions with customers.

Contact center storm responsiveness is a function of stable and effective systems, good planning, proactive preparation with regards to staffing, and an effective strategy for handling the stages of an outage event. Utilities need a well-articulated internal strategy and a plan for clearly communicating with customers as to what they should expect, from reporting the initial outage through to the completion of the restoration process.

In some instances, a utility has some level of advanced warning and should be able to staff and prepare escalation efforts ahead of time. Where there is little advance warning, a utility's initial levels of responsiveness can be dictated by when and how rapidly and severely the storm hits. In this case, the utility is faced with the basic challenge of ramping up quickly; it has to have its people ready and available, and have a timely plan for handling anticipated call volumes. The call center response efforts can be roughly broken down into three time periods within an event, each with its own requirements.

Initial Stages: Outage and Emergency Reporting

In the first hours or day of a severe event, effectiveness in customer service is a question of how well the utility can handle the huge volume of simultaneous calls to report outages and public and individual emergencies. The utility should have enough queue space, capacity, and channels to receive these calls. It should make sure no trunk blockages are occurring, get outage calls to and from the automated reporting system, and properly handle the emergency queue. The utility should have messaging and effective call routing in place to ward off all other normal business than the outage at hand. As the storm progresses, and depending upon live CSR capacity, the company should be focused on maintaining adequate staffing levels or ramping up in anticipation of heavier call volumes, and have alternate plans in place in case it cannot support its efforts with internal resources.

Secondary Stage: ETR Reporting and Status Communications

After customers report their outages, they shift their focus to seeking information on their restoration status. Customers need reasonable ETR information to keep from calling back in less than a reasonable amount of time. The information has to be in the OMS so that it can be pulled up by the CSRs on the High Volume Call Answering (HVCA) system, used primarily for automated outage reporting, by the Voice Response Unit (VRU), and by the outage website.

When CSRs speaking with customers do not have ETRs to provide, the company must have a fallback plan, so that its representatives are giving consistent levels of information.

At this point in the event, the utility should migrate to live call handling, usually via the use of third party call handling or extensions of existing call handling agreements with call taking/handling providers to support higher volumes. A key to success in this stage of the outage is to try to eliminate the need for such a call in the first place. Good approaches include IVR customer recognition abilities that can repeat back what the company also knows about the

customer's situation. Being more proactive with information and clear, structured communication can help reduce further calls and customer dissatisfaction.

These aspects are difficult to do well from both a technology and process standpoint. The challenges of being more proactive are significant. There are important internal processes that support this phase, ranging from timely closeout and reporting of outage status in the field to customer-interfacing systems that are reliable and not sporadic in their performance.

Final Stage: Ramp-Down and Resumption of Normal Business

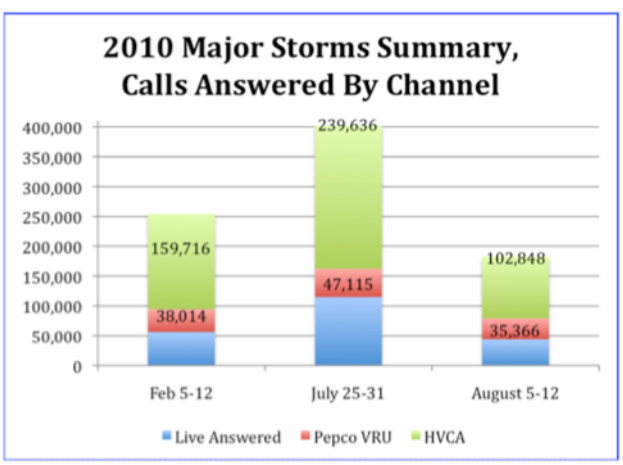
Companies should have ramp-down procedures in their contact center storm plan so that they can start adding back call handling for regular business. This takes some extra planning and cost, particularly as staff is typically tired and overworked. Companies should plan on maintaining some level of additional support and not drop to regular staffing levels immediately.

With this best practice model in mind, we looked at Pepco's handling of call volumes and service levels, and then at Pepco's handling of live interactions.

Pepco's Performance: Meeting Call Volume and Service Level Needs

Contact volumes—838,067 in all during the four 2010 storm events—presented a significant challenge for Pepco. The following diagram summarizes calls answered by channel for each event and overall.

Allocation of Calls Answered by Channel, 2010 Major Storm Events



Overall, HVCA represented sixty percent of all calls handled, with another fourteen percent going through the Pepco VRU.[204] Live answered calls were 26 percent of the total. The only totals not depicted were those processed by Mutual Assistance Routing Agents (MARS), who

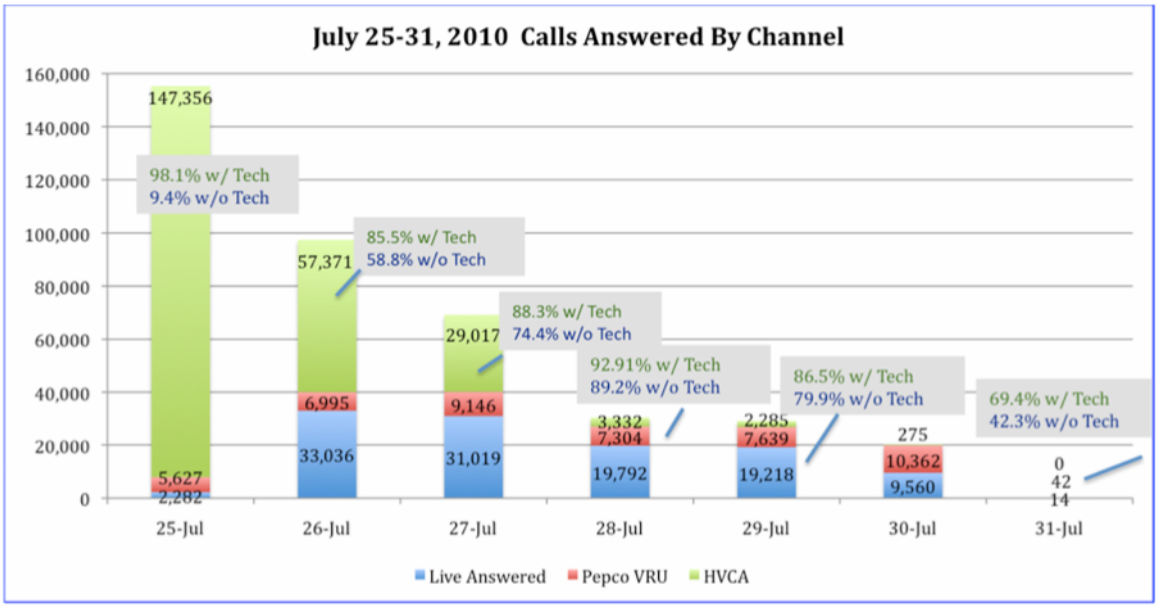
[204] Responses to Data Requests #36 and #132.

were used in the February 5–12 storm, as Pepco stated they could not provide reliable totals. [205] As would be expected, Pepco did not have enough regular CSRs during any of the storms to address this type of volume, and had to turn to the use of planned internal "second role" employees, third party companies, such as ER Solutions or MARS.

We reviewed the various channels for access to the Company that Pepco provided. Pepco confirmed that it maintained the appropriate telephony.[206] During the 2010 storm outages, customers were able to report outages and obtain restoration status information by calling Pepco, speaking with a CSR or using the IVR and HVCA systems. The information available to customers via the IVR or CSR is at the customer's individual premise level.[207] Customers were also able to get outage and restoration information from the outage maps that were available on the Company's website. The information available on the website was at the outage order level, which means that affected premises are grouped to a common point of failure. Customers did not have the ability to report an outage online during the 2010 storm events, nor do they have that ability now. Subsequent to the storms the Company began developing an iPhone and Android mobile phone outage map application, which was to be available as a free download. These applications would function like the outage maps on the website.[208]

We reviewed service levels and Pepco's approach toward managing them. Pepco's internal service level goal, also referred to as the Time Service Factor or TSF, is to answer 70 percent of incoming calls within 30 seconds for all calls answered (by CSRs and the IVR systems); this goal was in effect for the 2010 storms. The statistics that Pepco submits to the Commission in accordance with COMAR are based on calls answered within 60 seconds. The following diagram shows an example of contact volumes and daily service level results within 30 seconds, with and without technology, for the July 25–31 storm period. We reviewed similar information for all of the other events.

[205] Interview #38, February 4, 2011.
[206] Response to Data Request #35.
[207] Response to Data Request #33.
[208] Interview #11, January 14, 2011.



Our observations about these results follow:

- Overall service level reported in aggregate is weighted toward the service provided in the channel that has the greatest volume, in this case, 74 percent of all contacts answered in the 2010 storms were answered "with technology," either the HVCA or the Pepco VRU.
- Calls that were blocked due to exceeded trunk capacity ("all trunks busy") would not be counted in any calculation.
- Service level is not a measure of call quality. Whether the customer successfully gets ETR information or is satisfied with the transaction is not measured.
- Measures for service levels are most appropriately viewed when looking at various points during the outage process rather than in aggregate. For example, customers calling to report an outage at the onset of an event will usually get an excellent service level in an HVCA environment. In initial outage situations, 85-90 percent of calling customers use, and are encouraged to use this channel. Later, as more customers seek to speak to agents about ETR status during the secondary stage of restoration communications, the Company prompts customers to speak with a live agent and the measurement of service level typically is weighted toward live-handled calls. Poor performance in this area, even with a relatively smaller number of customers can be result in repeat calls, repeat dialing, and frustrated attempts to get to a CSR. For example, on July 26, while the aggregate TSR with technology looked good at 85.5 percent, the "without technology" statistic of 58.8 percent warranted further review, and there were hours during the day and evening when live service levels were poor.[209]
- Moving customers to effective technology use is clearly a best practice in outage restoration. When the normal restoration communications cycle is broken—ETRs are not

[209] Response to Data Request #146.

provided for extended time periods or are noticeably off, technology fails, or messaging is incorrect or reactive—service levels can be impacted.

With that in mind, we concluded the following regarding Pepco's ability to handle call volume and manage to appropriate service levels:

- Aggregate service levels at the onset of outages were high. Initial outage reporting to Pepco was consistently done using the HVCA, which is a good practice.
- Service levels with technology were generally above the Company's internal targets.
- The use of aggregate performance goals such as service level with technology may be a good overall measure, but it is not best suited as a measure for how the call center matches staff with volume it expects to have answered by live agents.
- The Company struggled with meeting live calling needs on specific days during the storm events. The volumes on these days, however, were not high relative to total volumes. Nevertheless, customers were impacted.
- Live call volume that came in to the Company increased during certain days due to unavailable ETRs (in particular during the several days after customers had reported their outages).
- At certain points during the storms, Pepco's trunk capacity was exceeded and some customers received busy signals when trying to reach either a live CSR or the Downed Wires and Emergency lines.[210] Pepco's storm reviews allude to customer frustration with receiving a busy signal.[211] Pepco does not receive trunk reporting from its telecom provider, but does have call management system reports.
- *Live* agent service levels in 2010 under *regular* operating conditions (approximately 45 percent answered in 30 seconds) were below the benchmark averages (62 percent answered in 30 seconds) of utilities benchmarked operating under overall operating conditions. Monthly levels of abandons for *live* offered calls, excluding storm months, averaged slightly over 15 percent for the year. This is significantly below the benchmark average of approximately 5 percent.[212] In addition to high abandon rates, the wait times for those customers seeking to speak to agents would be higher than the average experienced by benchmarked companies.
- Pepco's live agent service levels and productive staffing levels in regular conditions may require Pepco to place additional emphasis on the use of third party and second role call takers. This may make it more difficult to respond on a timely basis to surprise storm situations under certain conditions.
- The Down Wires and Emergency Line showed a high number of days with levels of "all trunks busy."

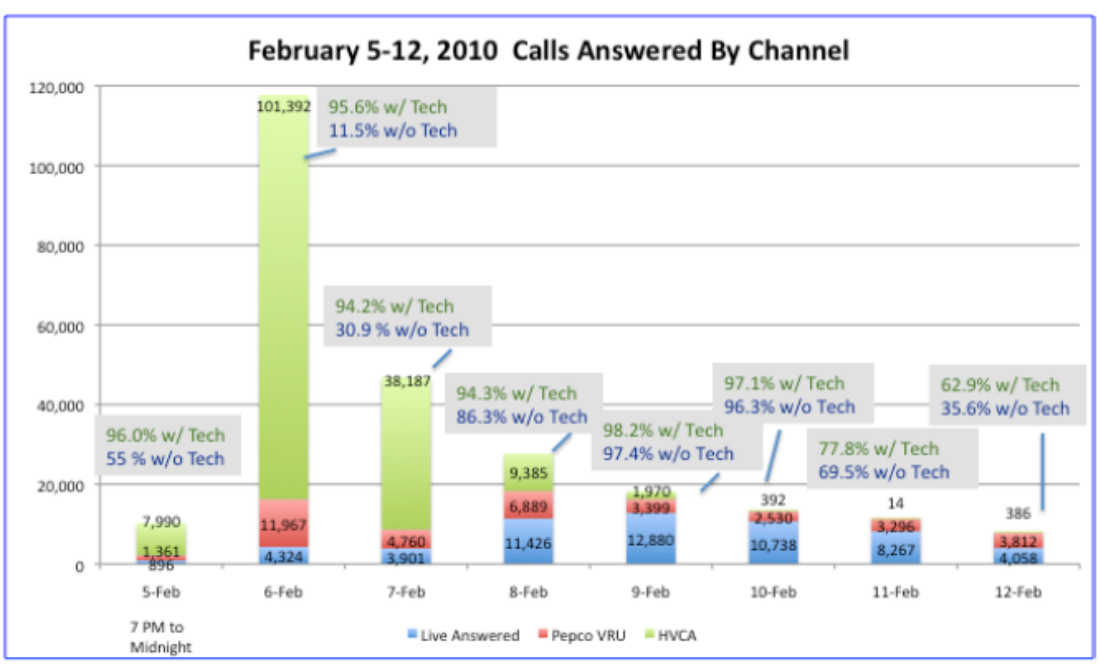
[210] Response to Data Request #146.
[211] Response to Data Request #20.
[212] Response to Commission Question No. 6 and response to Data Request #132.

Overall, we concluded that Pepco's response to customer call volume (as measured via services level/TSF) was adequate with regards to technology and, with several exceptions, adequate in support of live calls. However, Pepco does not have expected service level (TSF) goals/targets for live call answering during outage events and Pepco customers trying to reach a live call taker on occasion did experience busy signals and does need to address issues with customer busy signals on its Down Wires and Emergency Line.

Lastly, we reviewed the source of Pepco's resources to meet the aforementioned volumes and specifically how it applied resources to meet live call handling requirements, Pepco applied resources from a number of sources, including CSRs; 21st Century Communications for its IVR, which is capable of handling 100,000 calls per hour; MARS, which allows other utilities to support the response effort through their call centers; ER Solutions, a contract vendor who handles calls for Pepco on a regular basis; and auxiliary Pepco staff in their second roles. The combination of these resources was adequate in most situations.

Pepco has a process for pre-event planning and one for when pre-event planning is not possible to determine, for example, staffing needs, solicitation of overtime, and holding over employees. The process also includes activation of Auxiliary Support, which plays a key role in contact center outage support. We noted that there were many occasions in which the staffing levels of the auxiliary or second role personnel were higher than CSR staffing levels.

We reviewed each of the 2010 storm events to evaluate Contact Center performance and how it related to the ongoing storm restoration efforts. The following chart shows the number of calls answered and the service level associated with call answering by live agents or through various technologies in the February storms.



We prepared and reviewed similar charts for each of the other storm events for 2010.

We found that Pepco generally responded with appropriate staffing and call routing in the February 5–12 storm, with certain exceptions. ETR availability may have impacted live call volumes on February 8 through 10. Pepco effectively deployed MARS and ERS staffing throughout the storm. Pepco faced difficulty with the transition back to normal operations on February 12 once normal service was started, including low service levels, long customer wait times, and some evidence of busy signals.

For the July 25–31 storms, we found that Pepco was hampered in its call handling by technology challenges. We found that on July 26 and most of July 27, customers seeking ETR status after not having this information or being provided erroneous information drove call volume.

In the calls that we listened to in our sampling, some customers calling for ETRs were not able to get them. Pepco had to rapidly handle large volumes of live calls and performed well from a service level standpoint with the exception of several instances, but was not able to provide customers with consistent and adequate information as to the status of ETRs.

Pepco's Performance: Meeting Live Call Communications Needs

The team examined how well Pepco supported the effectiveness of its CSRs and third party call takers with regards to the message being provided to customers, training, consistency, approach, and overall responsiveness to customer needs. We interviewed Pepco personnel, reviewed training materials and CSR guides, and reviewed quality monitoring forms and processes related to outages and storms.[213] We also sampled from over 400 recorded calls of outage and ETR reporting that took place during the July and August 2010 storms (February recordings were not available). While agents were hampered by the aforementioned lack of information, we found inconsistencies in the quality and content provided by those sampled that should be addressed by the Company. We also found a need for more proactive communications about how customers can engage in supporting Pepco's restoration efforts.

The team reviewed Pepco's training practices and approach, and interviewed training managers. The Company provides new hire training and refresher training, including training focused on outages.[214] CSRs and second role employees receive training on call handling, including the proper escalation of high priority calls. Interviewees stated that with regard to call taking performance, the Company had performed better in the July and August storm events than in February.[215]

Based on our review of recorded calls, we did not find call handling to be consistent in quality and message. Pepco should consider implementing more focused refresher training for all functions on proper handling of outage contacts, placing emphasis on structured and scripted

[213] Interview #38, February 4, 2011, and responses to Data Requests #38 and #144.
[214] Response to Data Request #144 and Interview #38, February 4, 2011.
[215] Interview #38, February 4, 2011.

communication of ETR information under specific circumstances. Pepco should create and train on a "fallback plan" in cases where it does not have ETRs to ensure it is providing consistent customer communications. Second role employees, who at many times constitute a larger staffing presence than regular CSRs, would particularly benefit from such training.

The team also reviewed Pepco's process for quality monitoring during storms. A quality monitoring group is a standard element of any well-run call center, both during normal operating periods and during major storm events. A quality monitoring group is staffed and in place. We reviewed Pepco's program and processes and sampled calls to assess the results of the quality process during the 2010 storms. We found that Pepco does not have an adequate formal review and testing of specific outage call handling quality for all parties taking calls. For example, Pepco does not have a quality monitoring program for MARS agents and, given the large proportion of "second role" call takers applied, quality reviews for this group are not as structured and formal as they should be to ensure consistent and quality communication.

We also concluded that Pepco needs to promote, via messaging and with live agents who handle outage or ETR requests, the use of callbacks to confirm restoration and gather customer input. Pepco can gather information that helps it discover nested outages, which will improve its damage assessments and ability to provide accurate ETRs during the restoration process. As we discussed in the prior chapter, customers may be more likely to help if they understood that it will improve the quality of ETRs.

Post-event Communications Review

We reviewed post-event reports and self-assessments that Pepco prepared after each of the major storm events in 2010.[216] We reviewed Pepco's "lessons learned" summaries and research conducted by an independent research firm at Pepco's request.[217] The following table summarizes complaints by category.

Pepco Maryland
Outage Reliability Complaints
February 5–May 6, 2010
July 25–November 10, 2010[218]

	Dates	
Complaint Type	**February 5–May 6**	**July 25–November 10**
Outage Duration/ETRs	24	115
Repeat Outage	69	124
Tree/Vegetation	3	10
Total	96	249

[216] Responses to Commission Questions No. 1 and No. 2.
[217] Responses to Data Requests #20, #21, and #40.
[218] The date range includes complaints received from the date of the storm to 90 days after the first date of the storm.

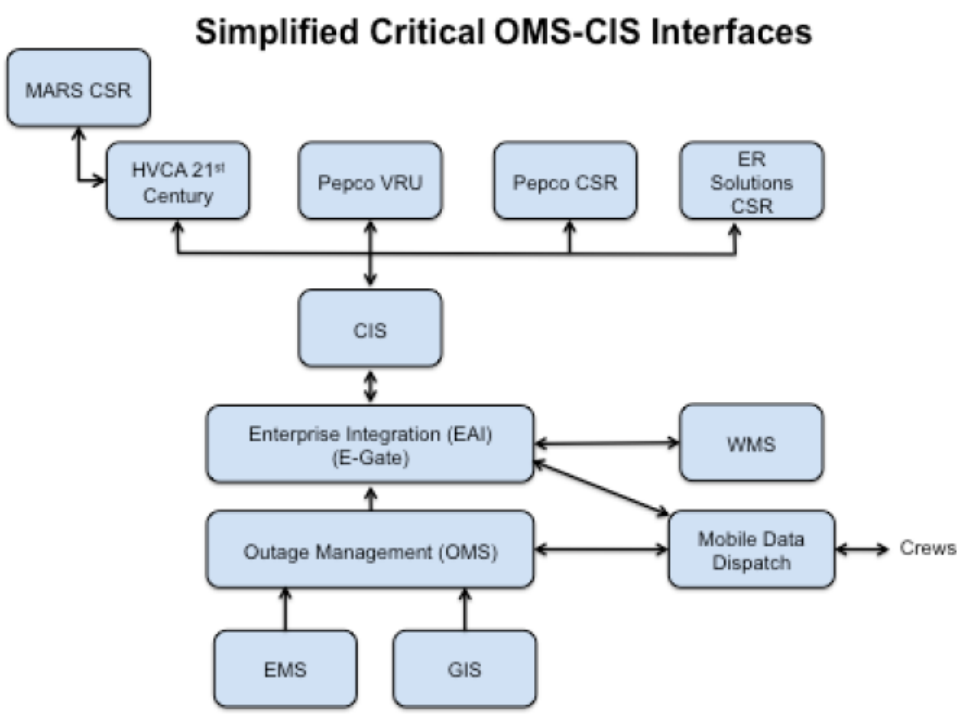
With regards to the post-storm surveys that we reviewed, customers were least satisfied with being kept informed about restoration efforts and being given accurate information about restoration efforts.[219]

E. Systems and Interfaces Supporting Customer Communications

Customers want to know four key things about their outage situation: (1) that that utility knows they are out of power; (2) when power will be restored, and that Pepco shares their sense of urgency to effect repairs; (3) what the cause may be, including the extent and scale of damage; and (4) what action is being taken and that it is being done by competent Pepco representatives. The team assessed Pepco's process and key "mission-critical" systems interfaces between the OMS and CIS as used by Pepco to convey key outage status and restoration information to its customers.

Key Systems Interfaces

The team reviewed the effectiveness of system interfaces between critical-to-mission systems such as the OMS, CIS, IVR and web-based applications.[220] The following diagram offers a simplified view of the systems we reviewed.



[219] Responses to Commission Questions No. 6 and No. 7 and responses to Data Requests #40 and #41.
[220] Response to Commission Question No. 15, response to Data Request #141, Interview #14, January 14, 2011, and Interview #12, January 7, 2011.

These systems have to interact successfully in order to enable timely, accurate communications to customers. All the information that is ultimately provided to customers via various channels—live, VRU, web—essentially comes through the CIS. The CIS receives information from many sources, in outage situations primarily the OMS. In turn, the GIS and EMS feed data to the OMS. When any of the interfaces between these systems break down or slow down, Pepco's ability to inform its customers is compromised. In a number of these interfaces there were issues that impacted the communications accuracy, integrity and timeliness.[221]

Inputs to the OMS—Building The System Model and Determining Status

The main and critical inputs to OMS are the EMS and the GIS. The EMS is a one-way interface communicating status of SCADA-controlled distribution devices (breakers/reclosers/switches) to the OMS. There are a limited number of switches (19 percent) and reclosers (48 percent) that are SCADA-controlled. We note that Pepco implemented a new General Electric EMS in late 2010. The change was driven by NERC compliance requirements.

The GIS provides data elements of the "as built" distribution electrical model. Data elements include structures (*e.g.*, poles, manholes) and devices (*e.g.*, wire, cable, transformers, fuses, reclosers, and breakers). These data elements are extracted from the GIS, and the OMS then builds a distribution model within the OMS. This model is used to represent the "as operated" or real time configuration of the distribution system.[222]

We found that the EMS and GIS interface with OMS worked well. Responsibility for the GIS was transferred to the asset management group after the winter storms.

OMS and CIS Interface—Processing the Customer Contact

The CIS interfaces with the OMS. The pictured Enterprise Integration (EAI) layer in the diagram above acts as an interface between the two. Normal processing of customer contacts has customer calls first entered in the CIS Database. These contacts are replicated from the CIS database to the OMS database. The OMS then reads them and processes them into events (also may be referred to as "jobs" or "orders"), and subsequently attempts to identify a common interrupting device based on prediction rules set up within the OMS. The OMS will group contacts into a common "event" if one is identified.

Events, processed calls/contacts and affected transformers are placed by the system in the OMS database. The event data contains information on the event including the start time, size of outage, call types, ETR, dispatcher remarks, major cause of outage, and restore time. Processed contacts have a relationship to the event, identifying of which event they are members. Dispatch information is placed by the system in the OMS database when crews are assigned. Data from the OMS database are replicated to the CIS database.[223]

[221] Response to Data Request #21.
[222] Response to Data Request #141.
[223] Response to Data Request #141.

We found that the OMS and OMS/CIS Interface did not at times perform as necessary in the storm events of 2010, causing inaccuracy in ETRs and delays in providing customers with ETRs, which added to customer dissatisfaction with the restoration process.

Pepco provided 2 software issues with the OMS during the February 5 storm.[224] There were other issues with the interface and the posting of ETRs to the CIS and also the calculation of ETRs (not an interface issue) during the July 25 storms, on July 25 and July 27. In the case of July 25, the OMS when looking at crew availability calculated ETRs well into the future and passed them through the CIS for information to customers when they called the HVCA.[225] Some of these issues were related to process and technology control. Pepco corrected the issues in both cases.

OMS and Mobile Data/Dispatch Interface—Assigning, Dispatching, and Completing the Order

This is a critical interface for getting the restoration work into the field. Events in the OMS can be assigned and dispatched to a crew in the Advantex system. Event data is sent to the crew MDT. The interface between the systems is wireless and near "real-time" although importantly, the team noted that the process for dispatching is done manually through OMS. Additionally for crews without MDTs, crew status updates are manually input into OMS, typically by the Dispatcher. Other than these processes, this is done on a near "real-time" basis.

Pepco noted that Pepco crews lead mutual assistance crews. If such a crew does not have an MDT then the crew is created in the OMS as a "non-MDT crew." The Dispatcher will "voice dispatch" these crews and manually update the status in the OMS, which automatically updates the CIS. When working an order, the crew selects the order in MDS and moves through various statuses as it drives to, arrives, and works the order. The crew can then update the ETR on the MDT, which sends the update to OMS, which sends the update to CIS. When the crew completes repairs, they should enter the restoration information and details of work performed on the MDT. This information is sent to the OMS, which restores the event and sets the status to 'Dispatcher to Review'. The dispatcher reviews the completion information in the OMS and makes any necessary changes then completes the event in the OMS. This information is then sent to the CIS system.[226]

We found there were some communications issues between the Pepco control center and Company vehicles equipped with MDTs during the storms in 2010. There were also outages with Advantex and the OMS/Advantex, although Pepco was able to resolve these issues. Overall, while the OMS-MDS interface had some problems in the February storms, it performed as needed in the summer storms.

VRU and CSR—Customer Channels for Outage Contacts

[224] Response to Data Request #21.
[225] Interview #13, January 19, 2011.
[226] Response to Data Request #141, and Interview #14, January 14, 2011.

Customers use two primary means of contacting Pepco during outages: "live" (via a Pepco or third Party CSR) or the VRUs, also sometimes referred to as the IVR.

Overall in the storms reviewed, 74 percent of customer calls were interactions occurring in either of the two VRUs, those being Pepco's and the HVCA.[227] For outage purposes, after the customer is identified (this can be via a phone match or self identification via phone, address, account) in the VRU, a query is placed to the CIS requesting current outage information. The CIS Database is queried to identify outages currently affecting this customer, in addition a query checks for active outage calls from this customer.

If an active outage is found, the VRU/HVCA plays the ETR, dispatch status and any major cause (traffic accident, cable cut, etc.) information entered by the Dispatcher back to the customer, and then proceeds to permit the customer to enter a trouble call. At the end of the input of the trouble call, the VRU/HVCA asks the customer if they would like to be called back when restoration is completed. This is an optional selection. The VRU/HVCA then sends the call to CIS, which writes it to the database and on through the layer for input to the OMS.

The CSR via the GUI has a direct interface to the CIS system. This channel represented 26 percent of all calls. In this process, after the customer is identified to the CSR GUI, a query is placed to the CIS requesting current outage information. The CIS transaction queries the database in the same manner as with the VRU process described above. If an active outage is found this information is displayed for the CSR who can provide this information to the caller during the call. The CSR then proceeds to enter a trouble call for the customer, noting if the customer requests a callback. The CSR GUI then sends the call to the CIS, which writes it to the database.

We reviewed the interface with regard to third parties and found that ER Solutions (a third party provider of call answering) accessed the exact same CSR GUI as a Pepco CSR. There was no difference in the timing of the data receipt between ER Solutions and a Pepco CSR. In the case of MARS, agents had information on ETRs, could handle calls from the customer and could enter a callback request from the customer. The MARS agent did not have the major cause or dispatch status available to provide to customers. MARS agents were used during the February 5–12 storms only.

We found that overall the above systems used by customers were impacted by process and technology issues. Customers were not able to get timely and quality information.

[227] 21st Century High Volume Call Answering, 877-Pepco-62 for outage reporting.

ETR and System Interface Issues

Storm (Date)	Initial ETR Communication	OMS Issues	Pepco Website Issues	CIS Interface Issues	HVCA Messaging Issues	Customer Delay Issues
February 5	Delayed- Started February 7	Yes- Access and Availability	No	No	Yes- Expired ETRs provided	Yes
July 25	Initially erroneous, then stopped; Delayed and started afternoon of July 27	Yes- Calculation of extended ETRs; multiple restoration times	Yes, several occasions	Yes- CIS/GUI Interface- locking up ; timeliness of ETRs due to backlog in interface with OMS	Yes- Announcements not working by county	Yes

The diagram above outlines some of the issues. In the storms of February 5–12, customers in some cases experienced long wait times, in particular driven by lack of ETR information in the early days (February 6 and 7) of the event. Customers having expired ETRs and calling the HVCA line for status, were again provided the expired ETRs.

The issues in the storm of July 25 were more pronounced in the above areas, with 3 times more customers out in a short period of time than in the February 5–12 event, we found issues with numerous communication channels as shown above.[228] Many of these were isolated events, although some did occur on several separate days. Pepco did report taking care of the issues.[229]

We concluded that overall system performance for the Web, OMS, IVR (both regular and HVCA) and CIS/GUI interfaces was not adequate in the storm events of 2010. While less than adequate in the February storms, they significantly fell short of meeting the needs of Pepco's customers in the July storm event. Pepco should perform structured and proactive stress tests of these systems and their interfaces in a systematic and regular manner, including a thorough web stability review.

F. Major Conclusions

1. **Pepco did not have adequate, structured pre-, during and post-storm communications in place that effectively prepared and kept customers and constituents informed of the Company's storm mobilization/action status and condition** *(Recommendation VIII-1)*

Pepco had internal and external organizational structures in place to manage and coordinate storm responses and has taken positive steps since the Witt Report to implement changes. Pepco did not however provide adequate storm status and restoration information to meet Maryland customer needs over the various phases of the 2010 events in a timely, reliable, and consistent manner. Pepco did not have a standardized, comprehensive, "emergency operations status

[228] Responses to Data Requests #20 and #21, Interview #13, January 19, 2011, and Interview #14, January 14, 2011.
[229] Responses to Data Requests #20 and #21, Interview #13, January 19, 2011, and Interview #14, January 14, 2011.

message" as a means of conveying the status of its outage preparation and restoration operations, alert levels or priority level status, associated mobilization levels, and situational status. Such structured, consistent messaging would have helped both Pepco and its customers in the communication process.

2. **The overall system performance of the OMS, CIS/GUI interface, VRUs (HVCA and Pepco), and Web, was not adequate in the storm events of 2010 and resulted in a negative impact on customer communications and communication processes** *(Recommendation VIII-2)*

There were repeated communications and systems issues related to computer systems (OMS, CIS, GUI and other critical systems), web sites, outage maps, calculation and provision of ETRs.

The availability and functionality of the OMS, and its interface with the CIS was at times inadequate. The performance of the HVCA used to receive customer outage calls and provide messaging to customers was at times also inadequate. While issues occurred with these systems in the February storms, they fell significantly short of meeting the needs of Pepco's customers in the July storm event. Lastly, the availability and functionality of the outage reporting status information on Pepco's web site was inadequate at times during the July 2010 storm events.

While Pepco addressed most all of the presented problems individually in a timely manner, the totality of issues hampered the communication of effective ETRs and contributed to Maryland customer frustration and lack of customer satisfaction with the restoration response.

3. **Pepco was unable to provide customers with timely and quality information about restoration times (ETRs), which seriously impacted its ability to communicate effectively with them throughout the major storm periods.** *(Recommendation VIII-3)*

A key requirement during a major storm is to make sure that all employees present the same information about storm restoration to their customers and contacts outside the company. In addition, it must effectively provide storm restoration status information to stakeholders—state and local government officials, business customers, the media, employees, and customers. The goal is to deliver the same message to all constituents as well as each customer calling into the call center. A critical component of this message is an accurate and consistently communicated time and date of restoration. Pepco was not able to do so effectively during the February and July storms. Delay and accuracy issues with ETRs prevented Pepco from meeting this key requirement and frustrated customers, prompting repeat calls.

4. **Pepco's response to customer calls (as measured via service level/TSF) was adequate with regards to technology and, with several exceptions, adequate in support of live calls.** *(Recommendation VIII-4)*

Pepco used High Volume Call Answering (HVCA) automation to capture and record customer outage reporting calls at the onset of the storms. When Pepco transitioned to live agents for

handling customer calls, mostly in the second to third days of the storm events, it provided adequate service overall. However, there were periods during days where service levels (e.g. how quickly a call is answered by Pepco) deteriorated. Such days and periods occurred in each of the 2010 storms reviewed. These were periods of time where over 2-4 hours live call taking service levels were poor. Pepco also had difficulty in transitioning back to normal operations (resumption of regular customer billing, service calls etc.) as well at the end of most of the storms, as evidenced by low service levels, indicative of long customer wait times.

5. **Pepco does not have expected service level (TSF) goals/targets for live call answering during outage events** *(Recommendation VIII-4)*

Pepco's internal service level (70 percent calls answered in 30 seconds) measure is an aggregate one that combines both calls handled by technology, mainly the VRUs, and calls handled by live agents. Pepco does not have a formal requirement for serving Maryland customers at any level. Pepco does not have a formal internal service level target or measure for live call handling during storm events. Establishing a guideline or goal for live handling would be appropriate given the aforementioned conclusion. Such a target could be useful in stipulating expected service goals for live call handling at various storm/mobilization levels as well as effectively setting staffing expectations and eliminating dips in service to the extent possible.

6. **Pepco customers trying to reach a live call taker on occasion experienced busy signals.** *(Recommendation VIII-5)*

At points during days (not entire days) in each of the four storms reviewed, trunk capacity was exceeded and some customers received busy signals when trying to reach either a live CSR via the Pepco x7500 line or the Downed Wires and Emergency (DW&E) line. In most all cases, these volumes were small but in the case of the DW&E line they were more frequent and pronounced. Customers were also found to be using the DW&E line to report regular outages. Callers possibly wanting to alert Pepco to a dangerous situation could therefore have received busy signals while trying to reach dedicated emergency lines. The blocking of emergency phone calls is a public safety concern, delaying the dispatch of first responders to assess and secure, lengthening public exposure to unsafe conditions.

7. **The consistency and quality of Pepco's live customer interactions, specifically call taking functions, during the storm events was not adequate.** *(Recommendation VIII-6 and VIII-7)*

Based on review of recorded calls, call handling during the storm events was not consistent in quality and messages pertaining to the Company's restoration efforts, process, and approach. Adequate formal review and testing of specific outage call handling quality for *all* parties taking calls was not in place. While CSRs, "second role" employees and third parties taking calls were hampered by the lack of timely and quality restoration information, inconsistencies in the quality, content and consistency of communications provided should be addressed by the Company.

8. **Pepco did not, in its live interactions with customers, proactively solicit feedback or reinforce the customer's role in communicating outage status information via available automated call back means to support its restoration efforts, particularly in identifying nested outages.** *(Recommendation VIII-6 and VIII-7)*

Pepco does not actively promote or reinforce through its live agents who handle outage or ETR requests, the use of callbacks to confirm restoration and gather customer input. Customers do not have a clear sense of the value of this input as information that can help the Company discover nested outages, which will improve its damage assessments and ability to provide accurate ETRs during the restoration process.

G. Recommendations

VIII-1 Pepco should implement a proactive, comprehensive, and clear communication of standardized, structured emergency operations status that includes the details of its outage preparation/mobilization, response and restoration efforts. *(Conclusion #1)*

Pepco should communicate alert level or priority level status, associated mobilization levels, and situational status through a standardized, comprehensive "emergency operations status message." This message should be tied to the current Level 1–4 mobilization and status designations in the IRP. The Company should also engage in and include proactive and timely public communications about matters such as Pepco's organizational status, activation of emergency operations in the IMT, extending of regular work shifts, communication or calls to alliance contractors and mutual assistance groups, assignment of safety personnel, and structured county-specific data, again in a structured manner.

VIII-2 Pepco should conduct routine structured stress tests of its key customer contact, customer information, and outage support systems and their interfaces, and improve capabilities as required. *(Conclusion #2)*

Prior to the Summer 2011 storm period, Pepco should undertake a thorough technology review focusing on outage-related systems and interfaces between those systems, their stability and backup technologies. This includes a technical review, evaluation of redundancy, and review of processing rules and capability under high volume conditions etc. The systems included should be the OMS, CIS GUI and related EAI layer, between the OMS and CIS, HVAC, and data flow to and from third party vendors. Such evaluations should be done on a routine basis afterwards.

VIII-3 The process for communicating, explaining and clarifying quality estimated restoration times (ETR) to customers should be revised and significantly improved. *(Conclusion #3)*

Pepco should develop a more proactive process for getting outage status and restoration activity information from field restoration crews, damage assessors, customers, and the Operations Center. In particular a more timely communication of initial ETRs and any shift to or from

tiered, global ETRs over the course of the storm event is necessary. Pepco should better integrate this more timely information with its communications approach, including how it communicates this information to customers, reasons for any changes and updates along with emphasis on what customers can do to support restoration efforts (callbacks, process for notifying of outage etc).

VIII-4 Pepco should update its Contact Center storm plan and enhance its approach to staffing and performance measurement for live call volume, including documentation of triggers for ramp-up and ramp-down in staffing and stipulation of the expected live service level goals/thresholds. *(Conclusions #4 and #5)*

Pepco should develop plans for more consistent levels of live call handling in its anticipation of, planning for and response to storm events, particularly given its high level of reliance on "second role" employees and secondary use of third party providers.

The plan should be detailed and stipulate the expected service level goals at different levels of emergency response (Level 1, 2, 3...) and strategies for calling in/retaining enough resources to meet targeted service levels at intervals within days of the outage and restoration. Integrated with this plan should be a staffing model that will provide guidelines for adding not only "second role" but third party resources, based on the predicted severity of the event, the timing, and expected duration, and projected call volumes and targeted live service levels.

VIII-5 Pepco should improve its approach to providing access, capacity and guidance of customers in the use of its emergency phone line (x3432) during outages to eliminate blocked trunks and allow better customer access during storm events. *(Conclusion #6)*

Pepco should alleviate telephony capacity constraints to minimize instances when callers receive busy signals on the Down Wires & Emergency Line. Pepco should also ensure customers using the DW&E lines are using it for true emergency situations during storm events. Pepco should continually review its call volumes, handle times, and service level performance to ensure the call center is adequately sized (trunks, seats) to deliver responsive service and integrate trunk review into its formal reporting process on a real-time basis during storms and for post-storm review.

VIII-6 Pepco should institute more frequent outage communications refresher training that includes provision of consistent, structured key outage-related information for all customer service representatives and "second role" employees who handle customer calls during emergency events. *(Conclusion #7)*

Pepco should reinstitute focused refresher training for all functions (CSRs and in particular "second role" employees) with regard to handling outage contacts, with particular emphasis on structured and scripted communication of ETR status information under specific circumstances including but not limited to customers reporting an outage; customers who do not have an ETR; customers who still have an outage after having received a callback from Pepco.

Pepco also should train on and promote, via VRU messaging and with live agents who handle outage or ETR requests, the use of callbacks to confirm restoration and the importance of gathering customer input. Pepco can gather information that helps it discover nested outages, which will improve its damage assessments and ability to provide accurate ETRs during the restoration process. Customers may be more likely to help if they understood that it would improve the quality of ETRs and service they receive.

Lastly, Pepco needs to create and train on a fallback plan and communications in cases where they do not have ETRs, at least so the information provided is as consistent as possible, correct and of the highest quality available under such circumstances.

VIII-7 Pepco should implement a quality control process that includes specific call monitoring, sampling and scoring of all call taker groups during outage events as a tool for quality improvement, feedback and consistency purposes. *(Conclusion #7)*

Pepco should implement a formal review and testing process specific to outage call handling quality. The process should be consistently applied to all parties taking calls, including a Quality Monitoring Program for MARS agents where none exists today and quality reviews of "second role" call takers that are more structured and formal than they currently are. Reviews of specific calls and outage call types should be conducted after each storm event and integrated back into the training process for each of these and the regularly staffed CSR group on a timely basis.

Appendix A. Survey of Reliability Standards

Most state commissions have implemented some form of service quality regulation.[230] Each commission's service quality program has been shaped by a combination of factors unique to that state. In some cases, commissions adopted new regulations, or tightened existing ones, in response to events such as legislative action, electric industry restructuring, and utility mergers. The framework of a service quality program reflects the commission's temperament, *e.g.*, its preference for preserving the opportunity to exercise discretion versus setting pre-established rules, or its desire to improve quality rather than maintain it. Within that framework, commissions generally design the components of these programs according to one of three broad regulatory approaches:

- Monitoring—the commission requires a utility to routinely report its performance as measured by defined indicators
- Target setting—the commission establishes benchmark standards and requires a utility to submit an action plan to improve if its performance is worse than targeted levels
- Target setting with incentives—the commission establishes benchmark standards; utility performance compared to target levels triggers automatic incentives (typically negative).[231]

Implementing target-based initiatives forces commissions to wrestle with the none-too-easy task of setting appropriate benchmark standards for the utilities in their state, which may be why monitoring remains the most common approach.

While most states focus their service quality programs on reliability, some include requirements related to, for example, public safety (e.*g.*, guarding downed wires), telephone responsiveness (e.*g.*, speed of answer), or customer satisfaction (e.*g.*, response to complaints). The concept of service quality certainly goes beyond just reliability. For the purposes of this report, however, we focus only on reliability standards.

The most common means by which regulators gauge performance is by measuring overall system reliability using indices such as SAIDI, SAIFI, CAIDI, and in some states, MAIFI. The following table lists the states that formally track system-wide reliability indicators and the approach they have adopted—monitoring or setting targets for performance, with or without associated penalties or rewards.

[230] Thirteen states have no formal approach for reliability and service quality regulation, although some have implemented informal monitoring as part of their merger approval process. State commissions that do have a formal approach in some cases have programs that apply only to investor-owned utilities (*e.g.*, Texas).
[231] Plans typically specify a dead band around benchmarks within which utilities are neither penalized nor rewarded.

States with Reliability Programs
Based on System-wide Reliability Indicators[232]

State	Monitoring	Targets/ Incentive	State	Monitoring	Targets/ Incentive
Alabama	●		*Minnesota*		❍ ●
California	●	●	*Missouri*	●	
Colorado		●	*Nevada*	●	
Connecticut	●		*New Jersey*	●	
Delaware		●	*New Mexico*	●	
DC		❍	*New York*		●
Florida	●		*North Dakota*	●	
Georgia	●		*Ohio*		❍
Hawaii	●		*Oklahoma*	●	
Illinois		❍	*Oregon*		●
Indiana	●	❍	*Pennsylvania*		❍
Iowa	●		*Rhode Island*		●
Kansas	●		*Texas*		❍
Kentucky	●		*Utah*		❍
Louisiana		●	*Vermont*		●
Maine	●	●	*Virginia*	●	
Maryland	●		*Washington*	●	❍
Massachusetts		●	*Wisconsin*	●	
Michigan	●				

❍ Indicates target only ● Indicates target plus incentives

Notes: California currently imposes targets plus penalties only on SDG&E; Indiana imposes targets only on Duke Energy Indiana; Maine imposes targets plus penalties only on Central Maine Power; Minnesota imposes targets plus penalties only on Xcel Energy; Washington imposes targets only on Puget Sound Energy.

The majority of states have no set standards for system-wide reliability. Only nineteen states have implemented regulatory programs with target standards; of these, only eleven have added penalties for failure to meet these targets. In five states—California, Indiana, Maine, Minnesota and Washington—commissions do not apply the same type of program to all utilities they regulate.

Most regulators acknowledge that reliability can be affected by demographic factors including terrain, local vegetation management strictures, amount of undergrounding, and system age, among others. What constitutes an acceptable level of performance can vary across utilities, and as a result regulators typically develop company-specific benchmarks based on each utility's past performance. When setting reliability standards, commissions face price versus quality trade-

[232] One of the most complete publicly-available surveys of service quality standards was performed recently on behalf of the Ontario Energy Board, specifically, "System Reliability Regulation: A Jurisdictional Survey," dated August 23, 2010, prepared by Pacific Economics Group LLC. This survey was the primary source for the data in this and other tables in this section of the report. We have not independently substantiated all data.

offs. These trade-offs differ between utilities in the same state, and it is therefore reasonable that reliability performance can vary across companies. This inherent variability in system-wide reliability is reflected in the utility-specific benchmark standards set by the New York State Public Service Commission, as summarized on the following table.

CAIDI and SAIFI Standards
For New York Utilities

	CAIDI (hours)	SAIFI
Rochester Gas & Electric	1.90	0.90
Consolidated Edison – network ***- radial***	3.74 1.85	0.015 0.530
Niagara Mohawk	2.07	0.93
Central Hudson Gas & Electric	2.50	1.45
New York State Electric & Gas	2.08/2.18	1.20/1.26
Orange & Rockland	1.70	1.10

In addition to the inherent system differences among utilities, there is no industry standard for normalizing reliability data to exclude exceptional events such as storms. As such, a considerable amount of insight and discretion is required to make meaningful comparisons between utilities in different states based on indices such as SAIDI, SAIFI, and CAIDI.[233] The following table highlights the variability in benchmark standards that complicates comparisons among states.

Comparison of State Benchmark Standards[234]

	SAIDI (minutes)	SAIFI	CAIDI (minutes)
California (SDG&E)	68	0.61	
Colorado	101		
Delaware	295		
District of Columbia	291	1.18	291
Indiana (Duke Energy)	175	1.65	115
Louisiana	172	2.28	
Maine (Central ME Power)		2.10	131
Minnesota (Xcel Energy) ***(Otter Tail)***	98 74	1.00 1.30	
Oregon (Pacific P&L) ***(Portland General)***	168 80	1.50 1.00	120 120
Utah	217	2.21	
Vermont (Central Vermont) ***(Green Mt Power)***		2.50 1.70	210 132
Washington (Puget Sound)	136	1.30	

[233] We also concur with Pepco's response to Commission Question No. 4 that there are no industry standards for minimum levels of reliability performance.
[234] Some states use averages to set standards; Massachusetts, for example, sets a utility's ten-year average of SAIDI and SAIFI, plus one standard deviation, as its benchmark standards.

A large number of state commissions recognize that system-wide indicators can mask pockets of reliability problems for certain groups of customers. More than half the states track reliability performance indices such as SAIDI and SAIFI at the circuit level. The following table lists the states that require utilities to report on their worst-performing circuits, and indicates which have programs that impose penalties for poor performance as compared to benchmark standards.

States with Reliability Programs
Based on Worst-Performing Circuit Indicators

State	Report or Plan only	Penalty		State	Report or Plan only	Penalty
Alabama	●			***Minnesota***	●	
California	●			***Nevada***	●	
Colorado	●			***New Jersey***	●	
Connecticut	●			***New York***	●	
Delaware	●			***Ohio***	●	
DC	●			***Oklahoma***	●	
Florida	●			***Oregon***	●	
Idaho		●		***Pennsylvania***	●	
Illinois	●			***Rhode Island***	●	
Kansas	●			***Texas***		●
Louisiana	●			***Utah***		●
Maryland	●			***Vermont***	●	
Massachusetts		●		***Washington***		●
Michigan[235]		●		***Wisconsin***	●	

In most states, utilities under these programs must explain their performance, or submit action plans to address their worst performers. Only six states have incorporated penalties into their regulatory program in this area. The details of circuit reliability programs, *i.e.*, the number of circuits examined and the reliability indices used, vary considerably among the states. For example, some commissions focus on a specified number of worst-performing circuits (e.*g.*, ten in Delaware and 100 in Connecticut) while other focus on a specific percentage (e.*g.*, eight percent in Ohio and three percent in the District of Columbia).

A small number of states have added service restoration to their reliability programs. Severe storms are usually normalized out of reported system-wide reliability measures such as SAIDI and SAIFI, so these programs help ensure that pockets of reliability problems are nonetheless addressed by regulation. The following table lists the states that require utilities to report on their restoration efforts as compared to benchmark standards, and indicates which have programs that impose penalties for poor performance.

[235] Michigan is somewhat unique in that it established penalties for poor reliability at the circuit level but not at the system-wide level.

States with Reliability Programs
Based on Speed of Restoration

			Benchmark Standard			
State	**Report only**	**Penalty**	**End within 24 hrs**	**Begin within 2 hrs**	**End 80% within 3 hr**	**Other[236]**
Arkansas	●		√			
California	●					√
Colorado		●	√			
Delaware	●			√		
Idaho		●	√		√	
Michigan		●				√
New Jersey		●		√		
New York		●				√
Utah		●	√		√	
Washington		●	√		√	
Wisconsin	●		√			

The indicators that commissions use for these reliability programs typically pertain to restoring all, or nearly all, customers within 24 hours. Except for Michigan, restoration standards do not extend to extreme storm situations. Most of the states that have implemented specific standards for restoration performance impose penalties, usually paid directly to customers.

[236] The benchmark standard in California is based on system-wide CAIDI. New York invokes penalties for any outage lasting more than three hours. Michigan requires utilities to end repairs in 16 hours under normal conditions or in 120 hours under emergency conditions; it requires utilities to end repairs on 90 percent of circuits in 8 hours under normal condition or 60 hours under emergency conditions.

Appendix B. First Quartile Consulting Benchmark Utilities

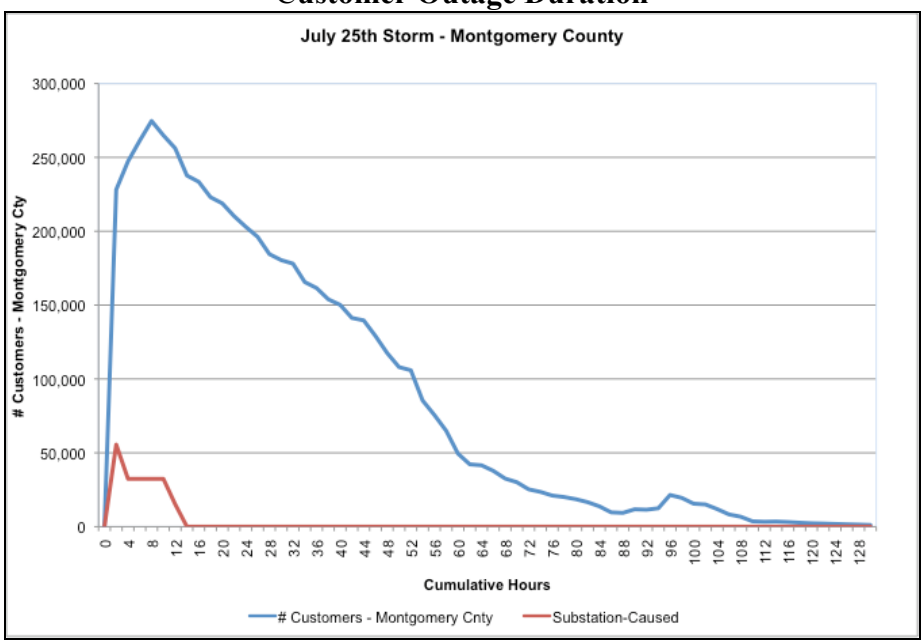
Benchmarking Companies		
Arizona Public Service	Austin Energy	Baltimore Gas & Electric
BC Hydro	Bonneville Power Administration	CenterPoint Energy
Commonwealth Edison	CPS Energy	Entergy
Granite State Electric	Hydro One	Hydro Quebec
Kansas City Power & Light	Kentucky Utilities	Long Island Lighting
Louisville Gas & Electric	Massachusetts Electric	Narragansett Electric
Niagara Mohawk	Northwestern Energy Montana	Northwest Energy South Dakota
Oncor Electric Delivery	Omaha Public Power District	PECO
Public Service Electric and Gas	Puget Sound Energy	Tennessee Valley Authority
Tucson Electric	Westar Energy	

Pepco Holdings, Inc. (PHI) utilities participated, in a limited fashion, in the benchmarking study for the first time during 2010, on a no-fee basis. We removed PHI data from the panel for purposes of this project

Appendix C. Outage Analysis Graphs and Tables

July 25–29, 2010 Thunderstorm Event

Customer Outage Duration



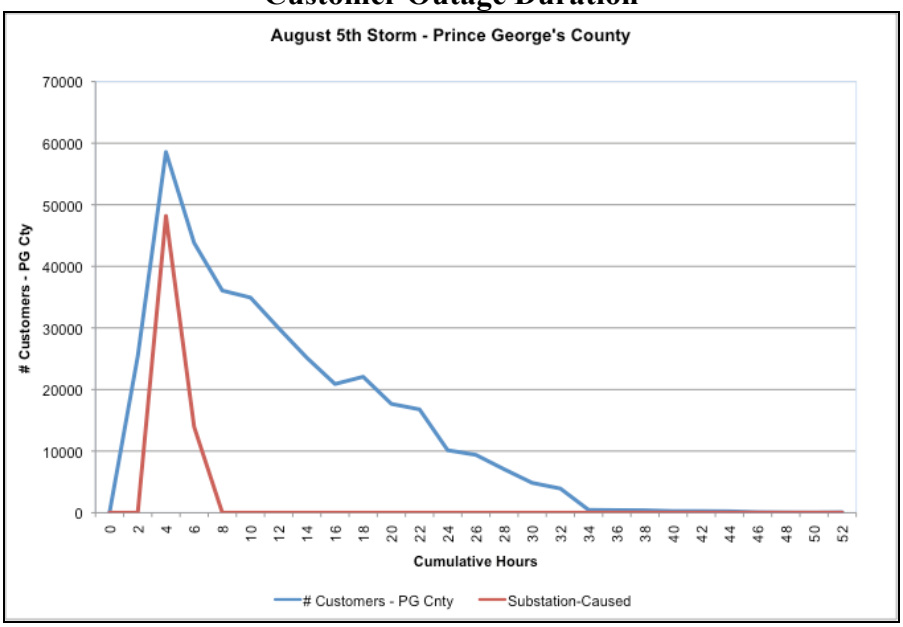
July 25–29 Thunderstorm Event
Transmission and Sub-transmission Circuit Operations

		Outage Experienced (S–Sustained; M–Momentary)				
Circuit Number	**Voltage (kV)**	**July 25**	**July 26**	**July 27**	**July 28**	**July 29**
69063	69	M S				
69060	69	M				
69061	69	S *				
69062	69	M				
69179	69	S				
69185	69	S				
69077	69	S		M		M
69080	69	S M				
69180	69	S * M M				
69181	69	S S M M M M			M	
69079	69	S		M M		M
34977	34	S				
69082	69	M M S				

34973	**34**	**S**				
69177	**69**	**S**				
34978	**34**	**M * S M**	**S**			
34012	**34**	**S**				
34013	**34**	**S**				**S**
69178	**69**	**S**				
69175	**69**	**S**				
69143	**69**	**S**				
34984	**34**	**S**				
69139	**69**	**S M S S S**				
69140	**69**	**M S S**				
69144	**69**	**S**				
34954	**34**	**S**				
34981	**34**	**S**				
69053	**69**	**M**				
69167	**69**	**M**				
34951	**34**	**S S**				
69138	**69**	**MS**				
34023	**34**	**M**				
34021	**34**	**S**				
34024	**34**	**M**				
34025	**34**	**S**				
34027	**34**	**MS**				
34028	**34**	**S**				
69001	**69**	**M**				**M**
69002	**69**	**M M**				
69026	**69**	**M**				
69027	**69**	**M**			**S**	**M**
69031	**69**	**M**				
34022	**34**	**M**				
69006	**69**	**M**				
69185	**69**	**S**				**M**
69003	**69**					**S**

#-Substation Load Lost Due to Equipment. *-Substation Load Lost Due to Trees.

Customer Outage Duration

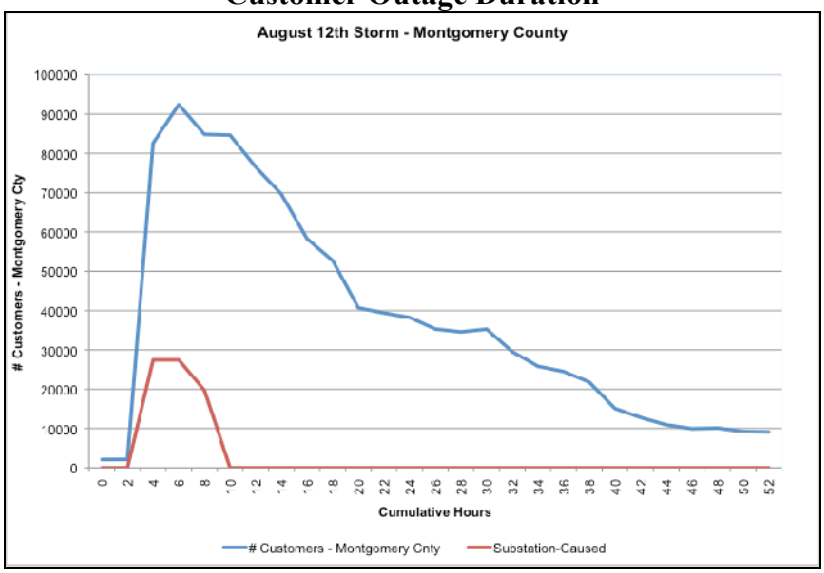


August 5–6 Thunderstorm Event
Transmission and Sub-transmission Circuit Operations

		Outage Experienced (S–Sustained; M–Momentary)	
Circuit Number	**Voltage (kV)**	**August 5**	**August 6**
34980	34	M	
69026	69	M M M M	
69027	69	S	
23016	230	M	M
34024	34	M	
69003	69	M S S	
69002	69	S	
69006	69	S	
69085	69	M S *	S
69001	69	M	
23059	230		M
69080	69		S
23020	230		S
23046	230		S

#-Substation Load Lost Due to Equipment. *-Substation Load Lost Due to Trees.

Customer Outage Duration



August 12–15 Thunderstorm Event
Transmission and Sub-transmission Circuit Operations

		Outage Experienced (S–Sustained; M–Momentary)			
Circuit Number	**Voltage (kV)**	**Aug 12**	**Aug 13**	**Aug 14**	**Aug 15**
69072	69	S #			
69077	69	S #			
69079	69	M M M			
34977	34	M M			
34978	34	M			
69080	69	S			
69061	69	S			S
69177	69	S			
69144	69	S		S	
69141	69	S			
69053	69	S *			
69167	69	S			
69180	69	M S	M S		
34954	3	S			
69175	69	S			
69142	69	S *			
69001	69	S			
69176	69	M			
69101	69	M			
34022	34		S S		

#-Substation Load Lost Due to Equipment. *-Substation Load Lost Due to Trees.

Appendix D. Pepco Responses to Commission Questions

Commission Question No. 1
Full storm reports relating to the July 25, 2010, August 5, 2010 and August 12, 2010 storms.

Pepco's Response
The Company provided the major storm reports and Forms OE-417 filed with the U.S. Department of Energy.

Commission Question No. 2
All documents and data relating to the company's internal reviews or analyses of its electric system performance, analyzed with and without major storm data, including but not limited to all monthly reports to or by its internal "reliability group" and all annual plans relating to electric system performance, reliability, maintenance or upgrades.

Pepco's Response
The Company provided monthly PHI Reliability Reports and annual maintenance plans for the years 2003 to 2010.

Commission Question No. 3
All company internal operating and maintenance procedures relating to electric system maintenance, upgrades or reliability.

Pepco's Response
The Company provided twenty-seven attachments that related to electric system maintenance and two that related to internal operating procedures.

Commission Question No. 4
All documents and data relating to industry standards for electric system reliability performance.

Pepco's Response
The Company stated that it was not aware of any industry standards that identify minimum levels of distribution electric system reliability.

Commission Question No. 5
All documents that constitute the company's existing "emergency response plan."

Pepco's Response
The Company provided its Crisis Response Plan, Incident Response Plan, and made available at its offices the Substation Emergency Response Plan and environmental response plans. In its supplemental response, the Company provided substation maps and more detail regarding its environmental plans.

Commission Question No. 6
All documents and data relating to the company's measurement of its reliability and customer service performance against other utility companies, including but not limited to all documents relation to the Edison electric Institute, PA Consulting and Public Service Electric Benchmarking Surveys.

Pepco's Response
The Company provided material such as PA Consulting reports, MSI customer satisfaction analysis, PHI call satisfaction tracking, IEEE benchmarking results, and quartile rankings from EEI reliability surveys.

Commission Question No. 7
All documents and data relating to customer satisfaction surveys and the company has conducted for in which it has participated, included but not limited to MSI and Internal surveys.

Pepco's Response
The Company indicated this question was covered in its responses to Question No. 6.

Commission Question No. 8
All documents and data relating to compensation arrangements for company employees and executives that tie any aspect of their compensation to system reliability, customer satisfaction, or other system performance metrics, and documents or data sufficient to show whether and to what extent that compensation has been paid.

Pepco's Response
The Company made documents available for review at its offices.

Commission Question No. 9
All documents and data relating to the Company's budgeting and spending for electric system reliability construction, maintenance or upgrades, including undergrounding of existing overhead feeders, from January 1, 1998 through all future periods for which the Company has planned or is planning, including but not limited to the details of specific electric system reliability projects the Company plans to undertake and the timelines for commencing and completing construction.

Pepco's Response
The Company provided two attachments showing 2006–2010 budgeted and actual reliability distribution system activities and one showing its current 2011–2015 five-year construction budgets. The Company does not maintain O&M records on a jurisdictional level. The Company provided an attachment showing its 2004–2010 reliability-related distribution system scheduled maintenance spending. It stated that data for 1998–2003 are no longer maintained and are not readily available.

Commission Question No. 10
All documents and data relating to the company's responses or reactions to the hurricane Isabel response assessment prepared by James Lee Witt Associates, LLC (The "Witt Report")

Pepco's Response
The Company provided nineteen documents and noted there were no system upgrades made as a result of the Witt Report.

Commission Question No. 11
All documents and data relating to the company's vegetation management procedures, standards, budgeting, spending, planning and execution, from January 1, 1998 through all future periods for which the company has planned or is planning.

Pepco's Response
The Company provided twenty-one attachments, including 1998–2010 actual and budget costs for O&M and capital tree trimming costs.

Commission Question No. 12
All documents and data relating to any statutes, regulations, ordinances, agreements, rules, or any authority currently limiting the company's ability to conduct vegetation management in its service territory

Pepco's Response
The Company provided ten attachments regarding vegetation management limitations.

Commission Question No. 13
All documents and data relating to the effectiveness of tree wire in preventing or mitigating outages.

Pepco's Response
The Company provided several documents discussing the spacer cable and tree wire; it also provided a chart showing that SAIFI is significantly lower when tree wire is used.

Commission Question No. 14
All documents and data relating to the company's current storm restoration plan, policies, procedures and protocols, including but not limited to the company's process for triaging and prioritizing service restorations; work rules for company and contractor crews; and timing and terms for requests for assistance from contractors and mutual assistance utilities.

Pepco's Response
The Company provided several attachments and referenced the storm reports it provided in response to Question No. 5. The Company also discussed triage and prioritization methods, second roles, work and safety rules, and the mutual assistance process.

Commission Question No. 15
All documents and data relating to the company's current processes and procedures for determining and disseminating estimated times of restoration (ETRs) to customers, including but not limited to the role and functional capabilities of the storm management system, the algorithms and "tiering" methodologies used to estimate restoration times, and the company's rules and procedures for determining and releasing ETR information to company employees, company customers, and the public at large.

Pepco's Response
The Company provided several documents, and provided a text explanation of how the OMS calculates ETRs, and how tiers are used.

Commission Question No. 16
All documents and data relating to the company's current policies, procedures and protocols for communicating with customers during outage situations, including but not limited to

(a) the capabilities of the company's telecommunications and information technology systems to handle customer contacts and to allow customers to speak to a live representative.
(b) Staffing and outsourcing policies for customer service representatives during outage situations

(c) Messaging policies during outage situations, and
(d) Company's policies, procedures and practices regarding providing customers the opportunity to speak to a live representative during and outage.

Pepco's Response
The Company provided information about it telephone numbers, and attachments regarding its policies. It also discussed policies and procedures regarding the increase in call volumes during outage events.

Commission Question No. 17
All documents and data relating to the identification of special needs customers, including but not limited to the company's current practices and procedures for identifying and communicating with special needs customers in emergencies and community outreach to make special needs customers aware of the need to identify themselves to the company.

Pepco's Response
The Company provided three attachments related to special needs; it also discussed its special needs identification process.

Commission Question No. 18
Timelines for all pre-mobilization and restoration activities relating to the July 25, 2010, August 5, 2010, and August 12, 2010 storms including mutual assistance and company personnel cross-trained for storm duty.

Pepco's Response
The Company indicated this question was covered in its responses to Question No. 1.

Commission Question No. 19
A list of the ten least reliable feeders, by year, since 1998, with and without inclusion of major storm outages, showing their location on a map, and provide the cause and duration of each listed feeder's outages and any associated short-term and long-term remediation and preventive measures taken.

Pepco's Response
The Company provided nine attachments that showed annual feeder reports for the years 2001–2009; reports for 1998–2000 are not available as the program began in 2001.

Commission Question No. 20
A chronology of measures taken to remediate and prevent the reliability, restoration, and communications problems that occurred and, if measures are underway, the estimated dates of their completion.

Pepco's Response
The Company indicated that it had initiated an assessment of its system restoration and communications processes immediately following the July 25 major storm and the scope was expanded to include the subsequent Aug 5 and Aug 12 storms. It provided a expanded discussion of specific issues that it addressed following the events.

Commission Question No. 21
A complete list of standards and performance metrics used by the company in providing customer service and assuring reliability in connection with outage restoration and communication during outage events.

Pepco's Response
The Company stated that Pepco and the Maryland Commission currently have not established formal standards and performance metrics. It stated that it currently reports on a number of metrics in the storm reports it files following a major events, and noted that SEE and IEEE metrics its tracks are on file with the Commission. The Company also stated that it tracks the average time required to restore customers, performance relative to meeting ETRs, average wait time on the phone, and the quality of data provided by field crews.

Commission Question No. 22
A complete list of criteria used by the company in evaluating and setting its goals and standards for assuring reliability in connection with outage restoration and communication during outage events.

Pepco's Response
The Company indicated that its primary goals are CAIDI and ETR; it noted that based upon internal research, customers expect ETRs to be accurate within a two-hour window. The Company also noted that it had telephone response goals and referenced its self-assessments in the major storm report.