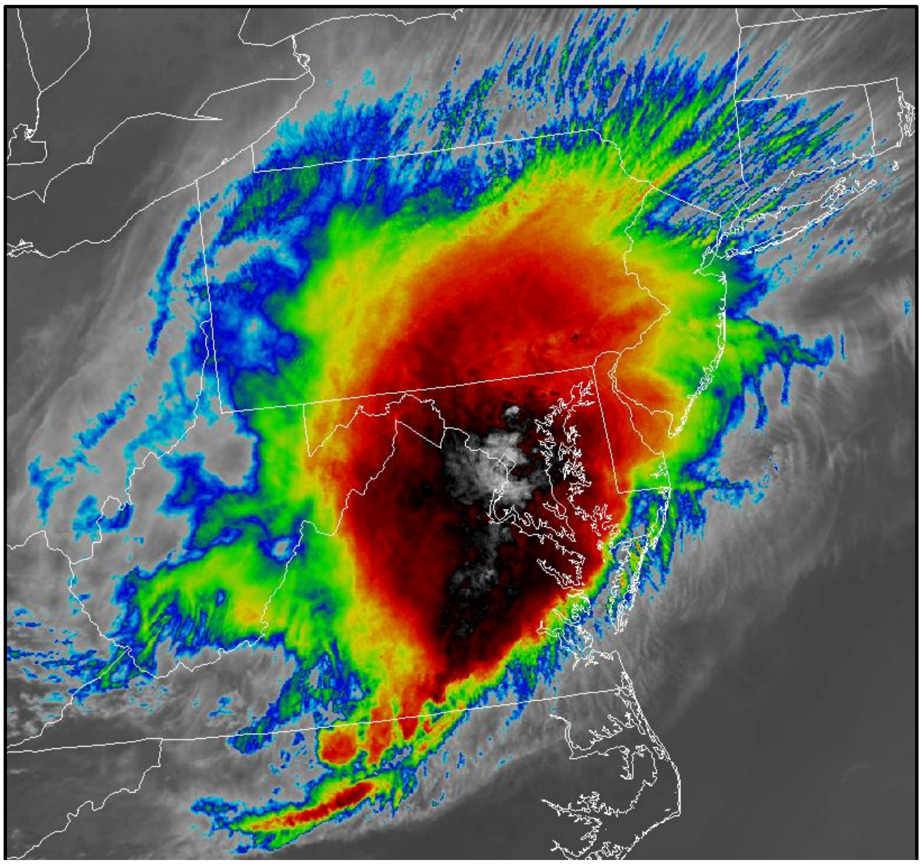
WEATHERING THE STORM

Report of the Grid Resiliency Task Force



September 24, 2012
Office of Governor Martin O'Malley
Executive Order 01.01.2012.15

Table of Contents

List of Tables, Figures, and Maps

I. Executive Summary

On July 25, 2012, Governor Martin O'Malley signed Executive Order 01.01.2012.15 directing his Energy Advisor, in collaboration with identified agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the Maryland electric distribution system. Referencing the potential impact of climate change on regional weather patterns and the prolonged power outages brought by recent hurricanes, blizzards, and the Derecho, the Executive Order specifically charged the Task Force with evaluating:

1. The effectiveness and feasibility of undergrounding supply and distribution lines;
2. Other options for infrastructure investments to improve resiliency of the grid; and
3. Options for financing and cost recovery for capital investment.

Over the past sixty days, the Task Force assembled eight roundtable discussions that included almost 50 experts from around the country, created a website to share information and solicit feedback from the public, analyzed copious data received from the utilities about outage information and staffing levels, synthesized the statutory and regulatory framework in which this conversation takes place, developed eleven recommendations, and drafted this Report. The group's process has been guided, at all times, by the charge of Governor O'Malley's Executive Order: what steps can be taken to strengthen Maryland's electric distribution to better withstand the stresses that come with severe weather events.

To answer this question, the Task Force first had to establish a working definition for reliability and resiliency. In this context, the group defined reliability as the ability of the bulk power and distribution systems to deliver electricity to customer during normal "blue sky" operations. In short, the grid should be able to reliably deliver power as a matter of routine operations. Resiliency was defined as the ability of the distribution system to absorb stresses without experiencing a sustained outage. From these definitions, any improvement that increases grid resiliency will necessarily reduce the frequency of outages during stress events, and may also decrease overall duration of the outage event.

Foundational Principles of the Task Force

The Task Force established several foundational principles that guide its recommendations:

- The current level of reliability and resiliency during major storms is not acceptable.
- Increased reliability and resiliency during major storms is the goal of the Task Force and will inform the recommendations.
- Severe weather events resulting from climate change are likely to continue to occur. It is unacceptable for anyone involved in response efforts to continue to be surprised by the "worst storm" the system or the State has ever seen. Utilities, government and citizens must be prepared for severe weather events.
- If done strategically and appropriately, increased expenditures by the utilities to improve resiliency and harden the gird – to literally ensure that the electric distribution system can

weather the storm – will lead to fewer outages during storms and shorter outages when interruptions happen.

The Task Force considered technological solutions, infrastructure investments, regulatory reforms, and process improvements, and remained always cognizant and focused on cost. It sought information on how much would it cost to make Maryland's system more resilient and insight on how to most appropriately allocate these costs.

With the foundational principles in mind, the Task Force developed a cohesive set of specific recommendations as well as an implementation strategy that maximizes the impact of its recommendations. While some may call attention to certain of the Task Force's recommendations, it is critical to understand that they work best as a unified strategy. The coordinated implementation of the recommendations is as important as the recommendations themselves; if rolled out in an "*a la carte*" manner, they may not produce the expected results.

Recommendations of the Task Force

In light of the Executive Order's charge, the Task Force thought seriously about whether to be proscriptive regarding what infrastructure the utilities should invest in to meet the State's reliability and resiliency metrics, be it at the levels currently outlined in Rule Making 43 ("RM43"), the Maryland Public Service Commission's ("PSC" or "Commission") recent regulatory process to implement changes to the reliability metrics, with the additional metrics proposed for RM43, or on the expedited timetable recommended herein.

After careful thought, the Task Force determined that it would not recommend specific infrastructure improvements. Rather, the Task Force made recommendations that are informed by the foundational principles, guided by the data, and intended to be implemented in a cohesive manner. If followed, the recommendations will logically lead to certain infrastructure investments. This likely will include targeted undergrounding and aggressive tree trimming, as well as improvements in areas that have suffered from repeated outages during storms. In the end, the Task Force created a methodology that would drive investment decisions rather than create a list of improvements to complete.

The following list is a set of specific technology, infrastructure, regulatory, and process recommendations to improve the resiliency of Maryland's distribution grid. They are covered in more detail in Section VI.

1. Improve RM43's Reliability and Reporting Requirements

Several recommendations were made to build upon the foundation of the RM43 regulations. Changes included holding utilities responsible for reliability standards inclusive of major storm outages, tightening the poorest performing feeder standard, and providing a simplified major outage event report for public consumption.

2. Accelerate RM43's March Toward Reliability

The Task Force recommends accelerating several years' worth of RM43 investments into a condensed timeframe. While the Task Force was intentionally not proscriptive regarding which specific remediation measures should be implemented by the utilities, data collected through the working groups demonstrates that selective undergrounding is an effective way to harden the grid.

3. Allow a Tracker Cost Recovery Mechanism for Accelerated and Incremental Investments

The Task Force suggests that utilities advance investment to provide Maryland citizens with a kickstart on the path of improved resiliency. The Task Force also believes it is appropriate to treat the accelerated and incremental investments differently than business as usual investments and recommend the PSC authorize a tracker cost recovery for those selected expenses.

4. Implement a Ratemaking Structure that Aligns Customer and Utility Incentives by Rewarding Reliability that Exceeds Established Reliability Metrics and Penalizes Failure to Reach Those Metrics

The Task Force recommends that the PSC implement a performance-based ratemaking structure to align the motivation of the investor owned utility and its customers. This structure should focus on increased reliability as a priority. Under such a rubric, the lenses through which an investor owned utility makes resource allocation decisions could be altered, with increased reliability rising to the top of the competing list of capital expenditure priorities.

5. Perform Joint Exercises Between the State and Utilities

As much as the Task Force hopes that outages will be reduced through the implementation of these recommendations, it recognizes that they cannot realistically be avoided entirely in the short or medium term. The Task Force recognizes these emergency management processes can be improved with more collaboration between the utilities and State and local government, and will lead to improved situational awareness that will help all concerned identify, prioritize, and respond to customer needs.

6. Facilitate Information Sharing Between Utilities, State Agencies and Emergency Management Agencies

During the roundtables, the Task Force identified numerous opportunities for additional information sharing between the utilities and various State agencies. The purpose of this shared information would be to better prepare the State for an extended outage and to ensure maximum information during an emergency is available to make the State's response as robust as possible.

7. Increase Citizen Participation In List of Special Needs Customers and Share Information with Emergency Management Agencies

While many medically vulnerable individuals live in nursing homes or assisted living facilities regulated by the State, many others reside in private residences and depend upon electricity to run their life-sustaining medical equipment. Utilities currently allow these customers to self-identify for service termination purposes, but the Task Force recommends that the utilities work with emergency managers to expand customer registration and share data during outages.

8. Evaluate State-Wide Vegetation Management Regulations and Practices beyond RM43

While the Task Force is cognizant of the critical and positive role that Maryland's tree canopy plays throughout the State, the Task Force is convinced that improved vegetation management is a highly effective way to improve the resiliency of the grid.

9. Determine Cost-Effective Level of Investment in Resiliency

The Task Force recommends that the PSC determine the cost of outages to different customer classes, i.e., industrial, commercial, institutional and residential, and to the Maryland economy in general to determine what level of investment in resiliency improvements is warranted.

10. Study Staffing Pressures Due to Graying of Workforce

The Task Force remains concerned about the long-term plan among all of the utilities to address the challenge of the "graying" utility workforce. The concern specifically arises because the Task Force recognizes that this issue, if left unchecked, may compromise the ability of Maryland utilities to meet enhanced reliability metrics. As such, the Task Force recommends that the PSC conduct an inquiry into the graying of the utility workforce.

11. Task the Energy Future Coalition with Developing a Pilot Proposal

During the course of the roundtable discussions, there was consensus that the utility industry was transforming at a pace unseen in its history. The Task Force recommends that the Governor formally charge the Energy Future Coalition with scoping out a Utility 2.0 pilot proposal and reporting back to the Governor and the Task Force, by March 15, 2013, on a viable method to explore the contours of the utility of the future.

Implementation Strategy

Along with the set of recommendations, the Task Force developed a coordinated implementation strategy. Recognizing the legislation passed by the General Assembly, as well as the months of work necessary to develop the RM43 regulations, this implementation strategy builds upon, and does not supplant, the work that has already been done. The Task Force recommendations are meant to operate within, rather than apart from, the analytic structure mandated by the legislature and adopted by the PSC.

Although each recommendation could work alone, the potential for significant improvement to resiliency would be diminished. This is particularly true for the first four recommendations, which were specifically crafted to work together to accelerate resiliency improvements and provide Marylanders with a tangible benefit in a short period of time.

While the Task Force recognizes that improvements will be realized through the current RM43 regulations, it believes that enhancements to RM43 will further increase resiliency, specifically in the context of major storms. The first recommendation, "Improve RM43's Reliability and Reporting

Requirements," also increases the consistency and accuracy of data, optimizes the utilization of utility resources, and ultimately produces reliability improvements for more customers in a given time frame.

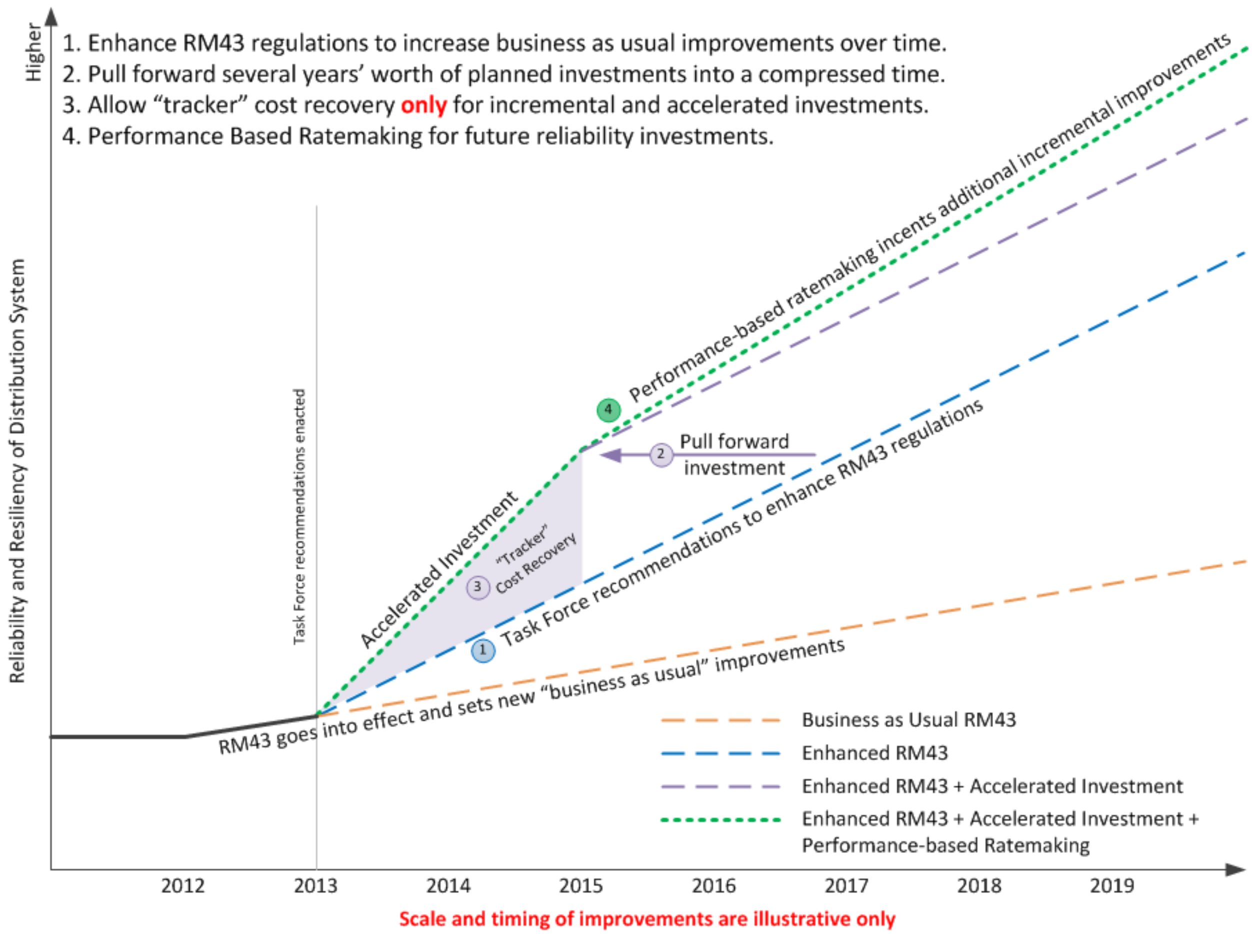
In the second recommendation, "Accelerate RM43's March Toward Reliability," the Task Force recommends accelerating several years' worth of business-as-usual investment to attain an increase in system resiliency into a compressed time frame such as the next 24 months, in order to jump start the pace of reliability improvements. Marylanders want and need reliable and resilient service now; by accelerating the investments needed to achieve these improvements, utilities can provide a tangible benefit for their investment. As illustrated by the chart below, the PSC can direct utilities to invest above and beyond their enhanced RM43 requirements in areas such as vegetation management and poor performing feeder remediation. For example, by condensing four years' worth of investment into a compressed time frame, Maryland ratepayers will likely see an increase in resiliency along formerly problematic lines in the next 24 months.

In the third recommendation, "Allow a Tracker Cost Recovery Mechanism for Accelerated and Incremental Investments," the Task Force recommends allowing utilities to recover costs through a tracker-like mechanism for the accelerated and incremental investment. Given that these investments would be above and beyond what is contemplated by the enhanced RM43 regulations, the Task Force believes that it would be appropriate to provide more contemporaneous cost recovery for these additional expenses. The tracker mechanism would not apply to the normal investment required to meet the enhanced RM43 regulations.

Finally, in the fourth recommendation, "Implement a Ratemaking Structure that Aligns Customer and Utility Incentives by Rewarding Reliability that Exceeds Established Reliability Metrics and Penalizes Failure to Reach Those Metrics," the Task Force encourages the PSC to implement a performance based ratemaking process for investor owned utilities, linking a utilities' progress or failure to meet certain reliability metrics with its authorized rate of return. The Task Force believes that such a structure would better align rewards with performance. By rewarding smart investment that drives incremental improvements to reliability and penalizing lagging performance, the PSC could incent investment choices that will help provide all Marylanders with a more reliable and resilient distribution grid.

The following chart is an illustrative example of reliability improvements that may be realized under a joint rollout of recommendations. Please note that the scale and timing of the improvements are not intended to be exact. The Task Force stresses the synergistic aspect of these recommendations and feels that the best way to improve resiliency in both the near term and long term is to enact all the findings in a cohesive and coordinated manner.

Figure 1 - Task Force Recommendation Implementation Strategy



II. Introduction

On July 25, 2012, Governor Martin O'Malley signed Executive Order 01.01.2012.15 directing his Energy Advisor, in collaboration with identified agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the Maryland electric distribution system. Referencing the potential impact of climate change on regional weather patterns and the prolonged power outages brought by recent hurricanes, blizzards, and the Derecho, the Executive Order specifically charged the Task Force with evaluating:

1. The effectiveness and feasibility of undergrounding supply and distribution lines;
2. Other options for infrastructure investments to improve resiliency of the grid; and
3. Options for financing and cost recovery for capital investment.

In response, the Governor's Energy Advisor assembled the Grid Resiliency Task Force, comprised of representatives from the Governor's Office, the Maryland Energy Administration, the Maryland Emergency Management Agency, the Power Plant Research Project, and the staff of the Public Service Commission. The Task Force hosted eight roundtable discussions, all of which were open to the public. Each discussion focused on a specific topic. Forty-six experts from around the country traveled to Annapolis over the course of three weeks to participate in the roundtables. The Task Force also had several discussions with specialists who were unable to travel to Annapolis, including experts with the Maryland Office of People's Counsel, industry experts, and economists. A summary of each public roundtable is included in Section VIII.A of this Report.

Public engagement, participation, and education were and remain a critical element of the work of the Task Force. An honest, transparent and informed discussion of the challenges facing the electric distribution system must include the citizens that it serves. The public was invited and encouraged to attend the roundtable discussions, either in person or by watching live on the internet. The Task Force also created a website to both share information with and solicit input from the public. Along these lines, this Report is aimed not just at policy experts, but also members of the public who want to understand the electric distribution system, the statutory and regulatory system in which it operates, and potential changes to improve its reliability and resiliency.

A. What problem is the Task Force trying to solve?

As Maryland's citizens know, outages occur during powerful weather events and on blue-sky days. They occur during violent wind storms and when the breeze is not even blowing. Accordingly, this Task Force considered what problem it was trying to solve with regard to reliability, resiliency, and restoration: the case of the power going out for several hundred customers on a sunny afternoon or the situation where thousands, if not hundreds of thousands, of Marylanders go dark following a severe weather event. Acknowledging the work that the PSC has done to address both scenarios, the group determined that its focus was the latter; namely, it would gear its analysis and recommendations to those situations in which a large number of our citizens and businesses are suffering from a power outage following a severe weather event. This clarification is important, as the group considered several modifications to the system that may address blue sky outages, but have little effect when a major storm hits.

While created by Executive Order, the Task Force is not empowered to mandate actions on the part of the utilities, the PSC, or the citizens. Its role is to offer thoughtful and informed recommendations to the Governor about possible statutory, regulatory, and policy changes. The list of recommendations in the Executive Summary represent the Task Force's informed opinion about how to harden Maryland's grid and improve our response to prolonged outages. None, however, can be effectuated by this group.

B. What do reliability, resiliency, and restoration mean?

The Task Force carefully considered the definitions of reliability, resiliency, and restoration because the definitions of these terms are dependent on the context in which they are used. For purposes of this Report, reliability refers to the ability of the bulk power and distribution systems to deliver electricity to customers during normal "blue sky" operations. In short, the grid should be able to reliably deliver power as a matter of routine operations.

Resiliency refers to the ability of the distribution system to absorb stresses without experiencing a sustained outage (i.e., over 5 minutes). These stresses may be in the form of hurricanes, high winds, snow, and high load days. Each of these events can push the grid beyond its normal "blue sky" operating characteristics and potentially expose and exploit weaknesses not readily apparent during normal operations.

By this definition, any improvement that increases grid resiliency will necessarily reduce the frequency of outages during stress events and may also decrease overall duration of the outage event. With fewer outages to restore, the restoration should proceed more quickly. Ideally, grid resiliency would be sufficiently improved to prevent outages from stresses that would have previously caused failure. Resiliency, however, extends beyond the function of the distribution system to the preparedness of Marylanders and the emergency response system. The ability of the State's citizens to prepare for and cope with extended power outages, as well as the skill and effectiveness of our emergency operations system to ensure the safety and wellbeing of our citizens, is another aspect of resiliency upon which the group focused.

Finally, for purposes of this Report, restoration includes all aspects of shortening the duration of an outage once it has occurred. Focusing restoration efforts on critical infrastructure such as hospitals, nursing homes, and first responders, and educating customers to have sufficient emergency supplies on hand to manage a few days of power outages, will help mitigate the social and economic costs of outages.

III. How is Maryland's electric distribution system structured?

A discussion of changes to Maryland's electric infrastructure must be informed both by an awareness of the greater electricity market in which Maryland participates, as well as an appreciation of the way in which the distribution system works. Additionally, the informed consumer should have a general understanding of the way in which the electric distribution utilities are regulated.

A. How does Maryland's electric distribution grid function?

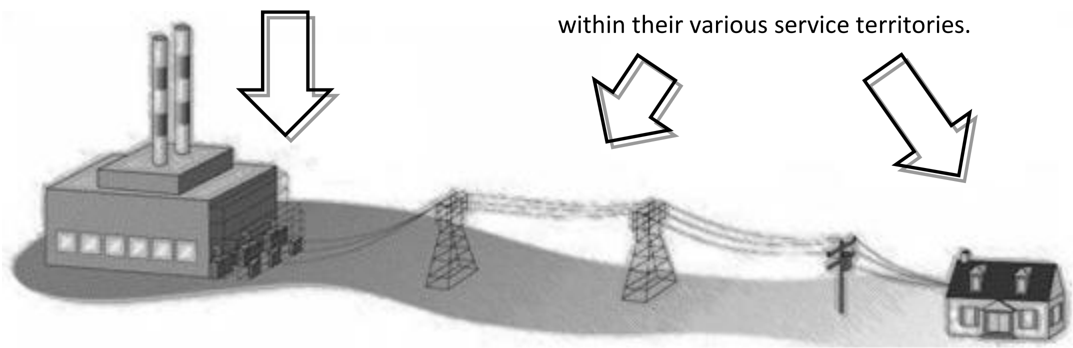
The electricity industry in Maryland is functionally separated into three independent businesses: generation and supply, transmission, and distribution.

Figure 2 - Maryland's Electricity Market

Generation companies produce power for sale in the marketplace. Generation of electricity is a competitive industry in Maryland – customers can choose which supplier they will buy power from.

Transmission is the high-voltage interstate movement of power and **distribution** is the low-voltage local delivery.

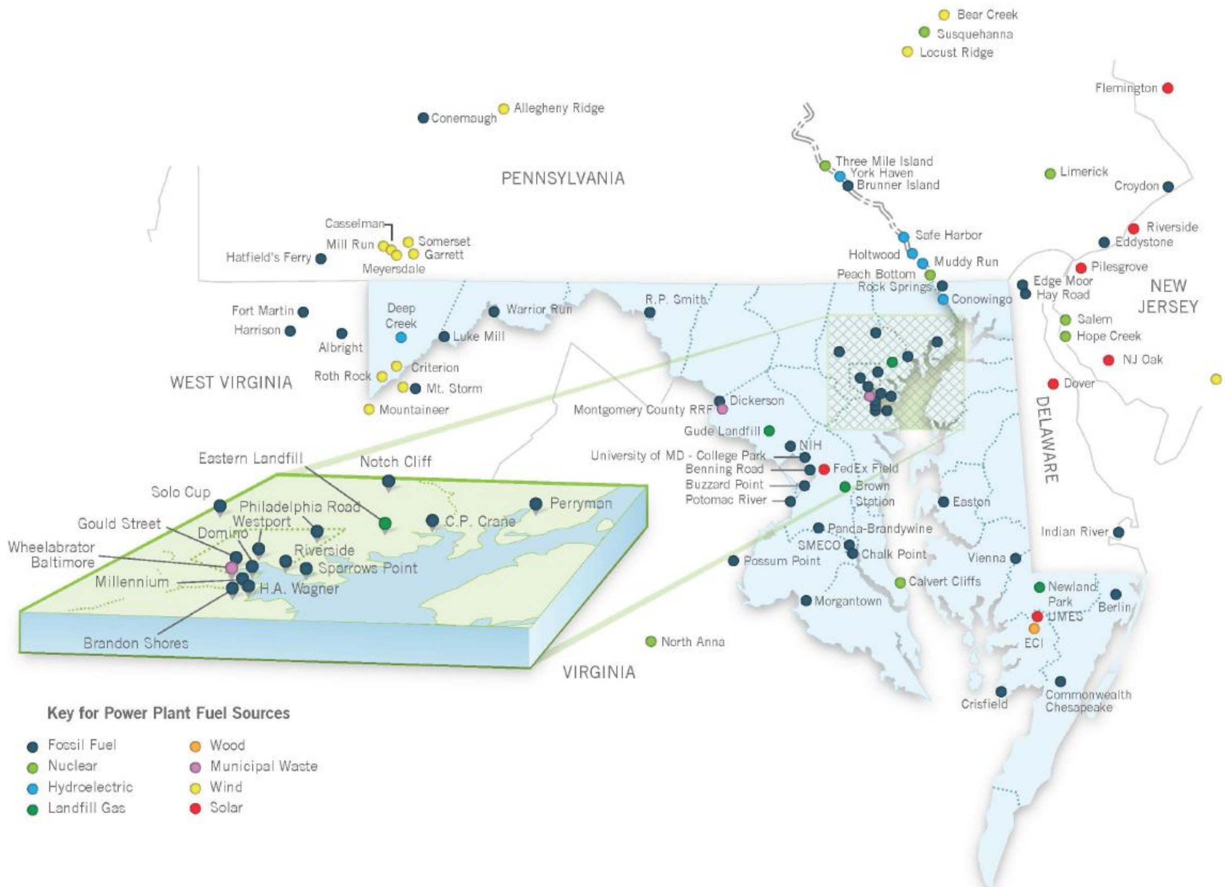
Transmission and distribution of electricity continue to be provided by local utilities within their various service territories.



Maryland does not regulate the generation and supply of electricity. The competitive wholesale and retail electricity markets set prices. For the most part, electricity is generated at centralized generating stations. Marylanders get their power both from generating stations located within the State, as well as generating stations outside of its borders. Currently, Maryland imports almost 40% of its electricity from out-of-state generators.

In addition to centralized generating stations, distributed generation is becoming more widespread. Distributed generation generally refers to electricity generating equipment installed on the customer side of the meter and is typically used to serve on-site power needs. Distributed generators are not centrally dispatched by the regional grid operator. Distributed generation technologies include combustion engines, small wind, solar, small hydroelectric, and fuel cells, and in certain situations may help reduce power needed from the grid during times of peak demand.

Figure 3 - Power Plant Locations In and Around Maryland



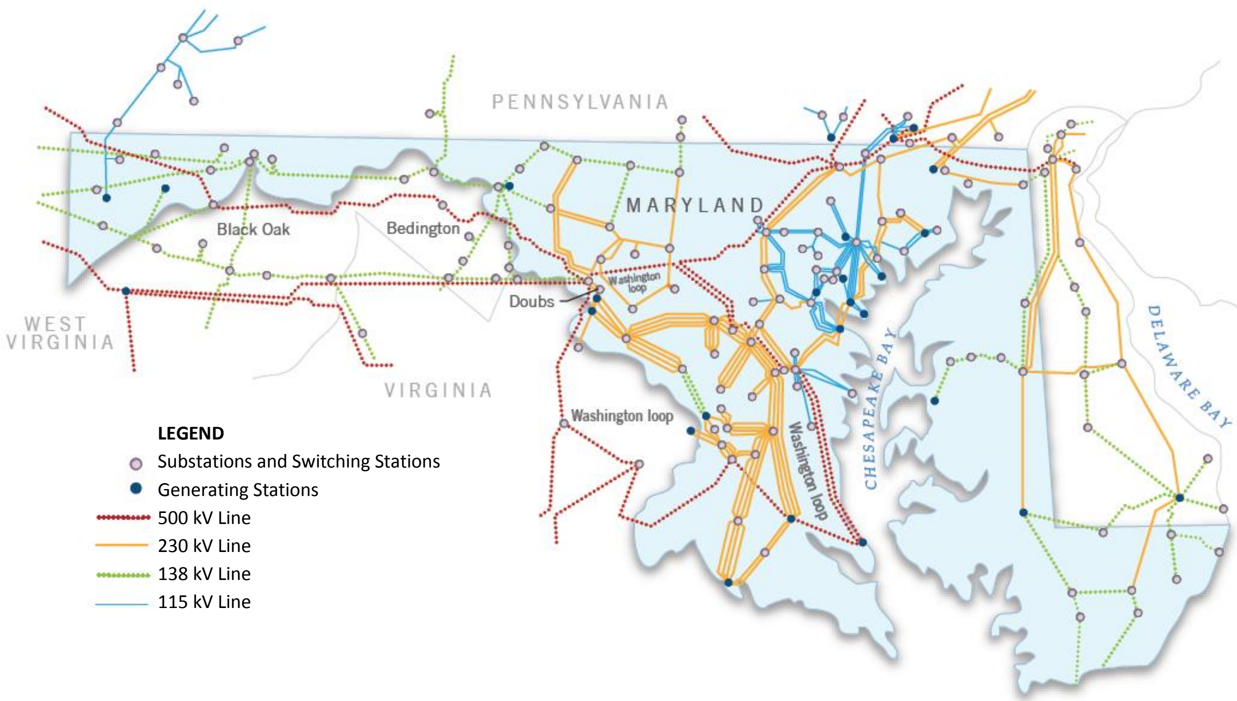
Once electricity is generated it enters the Eastern Interconnection electrical grid through the transmission system.[1] Transmission lines move electricity from generation sites to substations and can be thought of as the electricity equivalent of the interstate highway system. In Maryland, the high-voltage bulk electric transmission system is controlled by regional transmission operator, PJM Interconnection ("PJM"). Transmission services are regulated under the authority of the Federal Energy Regulatory Commission ("FERC"). Voltages in the transmission system range from 69 kilovolts ("kV") to 765 kV, which makes it possible to carry electric power more efficiently over long distances and deliver it to substations near customers.

The North American Electric Reliability Corporation's ("NERC") mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization certified by FERC to establish and enforce reliability standards for the bulk power system. NERC develops and enforces reliability standards, assess annually the adequacy of system capacity using 10-year forecasts and annual summer and winter forecasts, and educates, trains, and certifies industry personnel.

[1] The Eastern Interconnection is the power grid that serves the eastern portion of the United States and Canada. Along with the Western Interconnection and ERCOT (Texas), it is one of the three main power grids serving the country.

PJM – of which Maryland is a participating state – is responsible for balancing the demand and supply of electricity as conditions change throughout the day. Since electricity cannot currently be stored in bulk, supply and demand must be balanced at every second during the day. PJM tells generators when to send power out into the grid based on an economic dispatch model where the least expensive source is used before more expensive sources. This active management is critical as unchecked variations in supply and demand could quickly turn into cascading failures that could lead to widespread blackouts. PJM also ensures that sufficient power is available to meet the expected customer load on the hottest days in the summer and the coldest days in the winter, and sets a reserve margin, typically around 15% above peak load, to ensure that enough power is available when the grid needs it most.

Figure 4 - Maryland Transmission Lines (Greater Than 115,000 Volts)



Substations are located at the ends of transmission lines. A transmission substation located near generation uses transformers to increase the voltage. At the other end of a transmission line, a distribution substation uses transformers to step transmission voltages back down so the electricity can be distributed to customers. Distribution lines, also called feeders, are relatively low voltage (69 kV or lower) and carry electricity from substations to end users. In Maryland, the distribution of electricity continues to be a regulated monopoly function of the local utility, and hence continues to be subject to price regulation by the PSC.

Figure 5 - Distribution Substation

Source: PHI

B. How does Maryland regulate its electric distribution utilities?

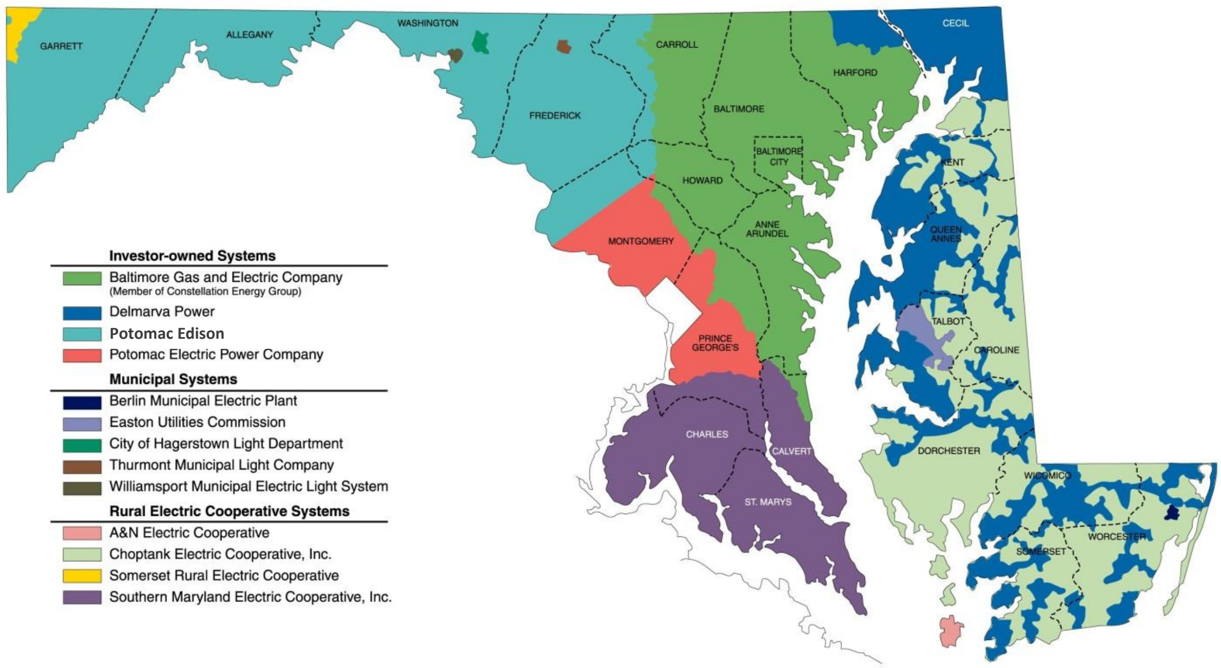
The electric distribution utilities' core function is to ensure "safe and reliable service" to Maryland consumers. This well-established statutory and regulatory construct has been codified, with some changes, over the last century. The distribution of electricity to utility customers differs from many other products and services that Marylanders purchase because the utility owning the distribution system is granted a natural monopoly. In other words, there can be only one set of wires owned by one electric distribution utility that provides electricity to a home or business. Society permits the monopoly because the alternative – having multiple lines, poles, transformers and other electric distribution equipment from different utility companies serving the same geographic area – would be impractical and unwieldy on many levels. To avoid subjecting society to the high costs of duplicative infrastructure, a monopoly is granted to a distribution utility for a specified geographic area.

In exchange for this monopoly, distribution companies in Maryland are subject to regulation by the PSC. This arrangement is frequently referred to as "the regulatory compact." The regulatory compact is essentially a deal between the public and a utility company that allows the utility company to earn a defined (and regulated) return on assets and cost recovery for prudently incurred expenses. In exchange, the public benefits from investment in essential services as well as regulatory oversight of the utility.

Utilities obtain the right to act as a monopoly in a specified geographic area through the grant by the Maryland General Assembly of a utility franchise. Once a utility company receives a franchise, the PSC must authorize the exercise of that franchise before the utility company is permitted to provide electric service to customers in the designated service territory.[2] Once the permission to exercise the franchise is approved, the PSC regulates the utility's activities and the rates the utility is permitted to charge its customers, all to ensure that the utility company is providing safe and reliable service at a just and reasonable rates, as required by Maryland law.[3]

[2] Section 5-201, Public Utility Companies Article, Annotated Code of Maryland.
[3] Sections 4-201 and 5-303, Public Utility Companies Article, Annotated Code of Maryland.

Figure 6 - Service Territories of Maryland Utilities



The number of customers in each utility varies based on the geography that the utility services. Table 1 shows the latest data available for the four investor owned utilities, as well as data for the two coops with reliability targets. Not surprisingly, due to the inclusion of large population centers around Baltimore and Washington, D.C., BG&E has the largest customer base. Pepco has the next highest customer count, followed by Potomac Edison, Delmarva Power and Light, SMECO, and Choptank. In addition to the six utilities with reliability requirements, there are seven other coops and municipal utilities that are regulated by the PSC. Combined, these seven companies serve approximately 35,000 customers.[4]

Table 1 - Customer Counts for Selected Utilities and Coops

Distribution Utility	Residential	Small C & I	Mid C & I	Large C & I	All C & I	Total
Baltimore Gas and Electric	1,115,274	103,539	26,259	670	130,468	1,245,742
Choptank	47,179				5,064	52,243
Delmarva Power & Light	173,946	26,942	5,067	79	32,088	206,034
Potomac Edison	221,470	28,300	6,454	106	34,860	256,330
Potomac Electric Power	488,555	31,676	16,915	553	49,144	537,699
SMECO	136,191				13,961	150,152
Total	**2,182,615**	**190,457**	**54,695**	**1,408**	**265,585**	**2,448,200**

[4] Data taken from July 2012 PSC Electric Choice Enrollment Monthly Reports, except for Choptank and SMECO, which were taken from PSC Ten Year Plan 2011-2020

1. How does Maryland measure reliability?

One way in which the PSC ensures that the utilities are providing reliable service is through regulation. During the 2011 Maryland General Assembly Session, Governor O'Malley co-sponsored, and the General Assembly passed, legislation requiring the PSC to adopt stricter regulations regarding utility performance by July 1, 2012. The legislation also raised the maximum penalty for failure to comply with the regulations from $500 to $25,000 per violation.

Approved by the PSC in April 2012, the regulations that resulted from the PSC's Rule Making 43 proceeding ("RM43") established minimum service quality and reliability standards for Maryland's electric companies.[5] The regulations set minimum reliability metrics for each utility based on past performance, established a mandatory annual performance reporting system, set up a customer communication survey, and mandated vegetation management and periodic inspections. In addition, RM43 requires utilities to submit a major outage event report within three weeks of a major outage, as well as a restoration plan detailing the utilities' response to a major event. The PSC retains the right to enact civil penalties and disallow costs should a utility fail to comply with the regulations.

2. What do Maryland's reliability metrics mean?

RM43 requires utilities to report on three industry-standard indexes: CAIDI, SAIDI, and SAIFI; additionally, the regulations require the utilities to meet specific metrics with regard to the latter two indexes.

The Customer Average Interruption Duration Index ("CAIDI") represents the average outage duration any customer who experienced an outage would experience over the course of a year. It can also be viewed as the average customer restoration time. CAIDI is measured in units of time.

The System Average Interruption Duration Index ("SAIDI") represents the average outage duration for each customer in the service territory over the course of a year. SAIDI is measured units of time.

The System Average Interruption Frequency Index ("SAIFI") represents the average number of interruptions that a customer would experience over the course of a year. Unlike CAIDI and SAIDI figures, which represent interruption durations, SAIFI is measured in units of interruptions per customer.

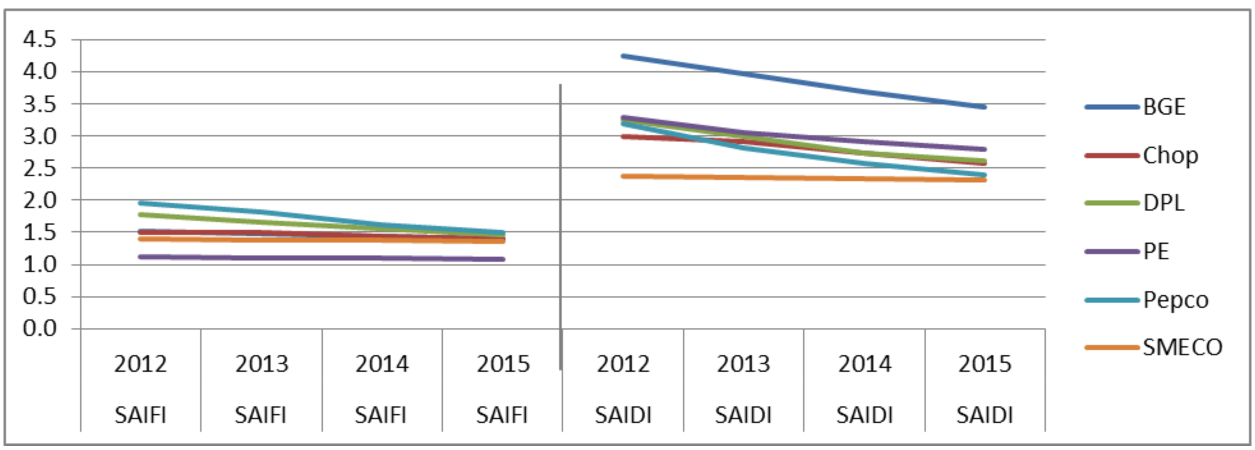
As specified by RM43, each utility's reliability requirements ramp up over time. The PSC based these requirements on past utility performance with the goal of setting realistic metrics to improve performance. Each utility's reliability requirements are reproduced below.

[5] The revisions to COMAR pertaining to RM43 may be found online here: http://webapp.psc.State.md.us/intranet/AdminDocket/CaseAction_new.cfm?CaseNumber=RM43

Table 2 - RM43 Reliability Requirements by Utility

	2012	2013	2014	2015
BGE				
SAIDI	4.24	3.96	3.69	3.44
SAIFI	1.51	1.47	1.43	1.39
Choptank				
SAIDI	2.99	2.92	2.74	2.58
SAIFI	1.50	1.49	1.44	1.39
Delmarva				
SAIDI	3.25	2.99	2.74	2.62
SAIFI	1.77	1.65	1.55	1.46
Potomac Edison				
SAIDI	3.28	3.05	2.92	2.79
SAIFI	1.11	1.10	1.09	1.08
Pepco				
SAIDI	3.18	2.82	2.58	2.39
SAIFI	1.95	1.81	1.61	1.49
SMECO				
SAIDI	2.37	2.35	2.33	2.32
SAIFI	1.39	1.38	1.37	1.36

Figure 7 - RM43 Reliability Requirements by Utility



3. What percentage of the electric bill does the Maryland PSC regulate?

The generation and supply of electricity are not regulated in Maryland; prices for those commodities are set by the competitive wholesale and retail electricity markets. The price for transmission is set by the Federal Energy Regulatory Commission ("FERC"). Therefore, the only portion of a customer's bill regulated by the PSC is the distribution charge, comprised of a customer charge and a volumetric charge. The table below demonstrates that the distribution charge comprises about 27% of a monthly bill.

Table 3 - Components of a Typical Electric Bill in Maryland

BGE

Item	Amount	% of Total Bill	"Decided By"
Customer Charge	$7.50	6%	State – PSC
Distribution	$25.30	21%	State – PSC
Commodity (Electricity)	$82.39	67%	Customer
Transmission	$7.88	6%	Federal – FERC
Total Bill	$123.07	100%	

Pepco

Item	Amount	% of Total Bill	"Decided By"
Customer Charge	$6.78	6%	State – PSC
Distribution	$26.78	22%	State – PSC
Commodity (Electricity)	$82.12	67%	Customer
Transmission	$6.05	5%	Federal – FERC
Total Bill	$121.73	100%	

4. How is the distribution rate set in Maryland?

As discussed above, in exchange for the monopoly to provide electricity, the PSC sets the rates of Maryland's electric distribution companies. The process by which this happens has remained relatively unchanged for over a century, and involves a quasi-judicial proceeding known as a base rate case. The first step involves the Maryland utility filing an application with the PSC seeking a rate increase or decrease. It includes detailed information on why the company believes a change is necessary.[6]

The PSC, as an initial step, suspends the proposed rates filed by the company for a period of 180 days in order to conduct a detailed examination of the rate request. The rates sought by the utility are based on a review of what is known as the utility's revenue requirements. Under traditional ratemaking principles, a utility is generally permitted to recover its revenue requirements through rates. A utility's

[6] Section 4-204, Public Utility Companies Article, Annotated Code of Maryland.

revenue requirements consist of cost recovery for prudently-incurred operating expenses, plus a reasonable allowed rate of return on any capital investments of the utility (known in the industry as the utility's "rate base"). The PSC, as part of its review of a rate change application, determines what operating expenses are eligible for cost recovery and what investments are included in the utility's rate base and subject to the investment return. The PSC also reviews and determines the utility's costs of debt and equity capital when it set the authorized rate of return to be applied to the rate base and may make adjustments to that rate based on the performance of the utility.

The PSC will often base its review of a utility's revenue requirements by examining what is known as a "test year," consisting of a retroactive one-year period of time designated by the utility against which its request for revenue requirements is examined. The PSC looks at expenses incurred and revenues collected by the utility during the test year, as well as the number of customers the utility serviced during the test year and the various classes of ratepayers served by the utility (i.e., residential, commercial, industrial). Utility expenses incurred outside of the test year, such as expenses to restore customers following a widespread outage caused by a storm event occurring after the test year but before the rate change application was filed, may or may not be treated by the PSC as adjustments to the test year utility operating expenses for purposes of calculating the utility's revenue requirements. Other long-term capital improvements such as distribution system upgrades, accelerated line replacements, or the deployment of advanced or "smart" electric meters, may or may not be included by the PSC in the utility's rate base on which the authorized rate of return is to be applied as part of the revenue requirement calculation, depending on the facts and circumstances of those improvements.

Following a process that includes evidentiary hearings, hearings for public comment, and a written comment period, the PSC will issue a decision on the rate change application, including a determination of acceptable operating expenses, what constitutes the utility's rate base, and what the utility's revenue requirements will be. Rate cases can involve multiple parties and multiple witnesses for each party. Pursuant to Maryland law, the PSC has, at most, 180 days from the effective date of the utility's proposed rate change to issue a decision.[7] At the end of the 180 day period, the PSC issues a decision granting new rate levels for the company based on the Commission's determination of costs that have been deemed "just and reasonable" and the rates required to produce the newly authorized revenues for the company. After the PSC issues its rate decision, a utility or other parties to the case may accept the rate decision or appeal the decision to the Maryland courts. If the company accepts the rate decision, or if an appellate court upholds the PSC's decision, the utility changes its rates in accordance with the PSC's decision and the new electric distribution rates appear on customers' bills shortly thereafter.

[7] Section 4-204(b), Public Utility Companies Article, Annotated Code of Maryland.

IV. How is Maryland's electric distribution grid currently functioning?

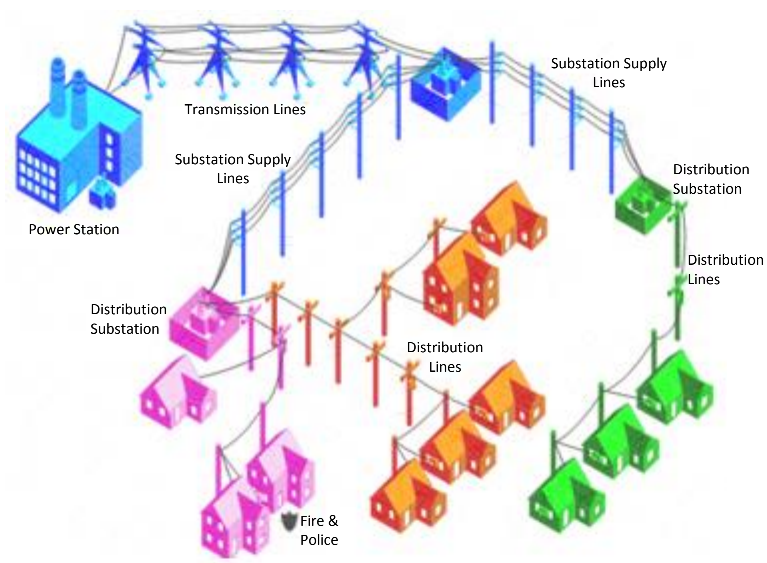
To begin to answer this question, the Task Force relied on the principle that infuses all of Governor O'Malley's endeavors, namely, informed decisions must be guided by data.

A. What does the data indicate about the distribution system's performance during recent major storms?

With that principle in mind, the Task Force endeavored to take a deeper look at three relatively recent major storms: Snowmageddon (2/2/2010 – 2/12/2010); Hurricane Irene (8/27/2011 – 9/6/2011); and the Derecho (6/29/2012 – 7/8/2012). The group hoped to answer three questions when undertaking this analysis. First, what components of a utility's network are the most vulnerable to storms? Second, do undergrounded portions of the distribution system experience fewer outages during major storms? Third, do certain geographic areas experience repeated outages while others are spared? The Task Force's recommendations would then be informed by this analysis.

Three Maryland utilities (Pepco, BGE, and Potomac Edison) voluntarily provided data on the three events, including how various components of their systems were affected by each storm.

Figure 8 - Illustration of Power System Components



Source: PHI

In addition to those components pictured above (and described in Section III.A of this Report), the three utilities also reported on circuit breakers, fuses, line reclosers (overcurrent protection), transformers, and service lines.

Circuit breakers, line reclosers and fuses are protective devices. Circuit breakers are located at substations; they turn off power to an entire distribution feeder in the event of a fault or short circuit. For instance, a tree branch that falls during a windstorm and lands on the line may cause a fault that could cause damage. A significant portion or even an entire distribution line can be out of service while the repair crew finds the fault, repairs any damage, and resets the circuit breaker.

Line reclosers and fuses are usually located along distribution lines. Both devices divide distribution lines into smaller sections. For instance, in the illustration above, each branch point of the distribution lines might be equipped with a either a fuse or a recloser. Reclosers and fuses, because of their position in the network, handle much less power than the circuit breakers at the substations and therefore can be set to trip at much lower power levels. This means that a single event on the grid, for example, a branch on a wire, will cut off only the section handled by the single recloser or fuse. Moreover, some reclosers can automatically re-connect after a brief interval. There is a chance that the fault/interruption will be gone when the power is restored, as with the example of a branch that falls on a wire but then falls to the ground without actually breaking the wire. Fuses, on the other hand, must be reset by a manual process involving a line crew before power to customers can be restored.

Transformers exist at many places in the electric distribution system. In this context, the term refers to the transformers located near the customer end of the distribution system. Overhead transformers are mounted on utility poles (or, in the case of underground installations, are pad mounted transformers) and step down power from distribution line level voltages, sending it to service lines that carry the power the last length from the pole to the customer's home or business.

Table 4 below illustrates the portfolio of each utility's distribution system.

Table 4 - Profile of Electric Systems Currently Operated In Maryland

System Components	BGE	Pepco	Potomac Edison
Transmission Lines	143	121	42
Circuit Miles	1,288	1,009	627
Underground	8%	16%	0%
Transmission Substations	74	14	33
Substation Supply Lines	253	97	65
Circuit Miles	1,428	1,827	494
Underground	24%	9%	0%
Distribution Substations	195	61	81
Fuses	48,834	18.397	33,375
Distribution Lines	1,295	693	323
Circuit Miles	23,568	8,399	8,581
Underground	65%	59%	38%
Reclosers	2,179	109	1,639
Transformers	217,148	76,040	93,962

Note: Some substations function as both a transmission substation and distribution substation. In this table, single locations that serve both functions are counted twice.

1. What effect do major storms have on utility infrastructure?

The tables below show how Snowmaggedon, Hurricane Irene, and the Derecho affected the various components of the three utilities' distribution systems. The numbers represent the cumulative amount of customers who experienced an outage due to an "interruption" associated with a specific system component.

The data is organized in the same sequence that electricity travels from the generating stations to a customer's house or business. Further, they are mutually exclusive, meaning that a system component failure is assigned only to the specific component, and does not impact downstream reporting. In this sense the data represent the incremental failures of the system as one follows the path of electricity. While clearly every customer outage was caused by at least one interruption, multiple interruptions upstream of a home or business are common.

Table 5 shows the estimated number of customer interruptions for each utility by components of its system in each of the three storms. For example, the distribution substation row indicates that problems at distribution substations during these storms were very uncommon. Across the three companies, only 852 customers experienced an interruption because of a malfunction at the substation upstream of their home or business.

Table 5 - Total Customer Interruptions Associated with System Components

	Snowmageddon 2/2/2010 – 2/12/2010			Hurricane Irene 8/27/2011 – 9/6/2011			Derecho 6/29/2012 – 7/8/2012		
System Components	**BGE**	**Pepco**	**Potomac Edison**	**BGE**	**Pepco**	**Potomac Edison**	**BGE**	**Pepco**	**Potomac Edison**
Transmission Lines	0	0	0	0	0	0	0	0	0
Transmission Substations	0	0	0	0	0	0	0	0	0
Substation Supply Lines	4,503	28,637	2,662	65,045	89,233	4,370	113,502	270,012	17,185
Distribution Substations	0	0	0	0	0	0	0	0	852
Fuses	47,742	16,571	1,998	253,622	30,058	3,847	248,710	49,387	3,266
Distribution Lines	38,674	198,508	5,034	182,406	274,382	7,755	160,544	598,161	51,819
Reclosers	48,670	4,579	2,368	238,565	11,405	3,557	216,268	18,076	16,954
Transformers	1,613	2,728	416	9,007	3,869	173	14,492	17,656	391
Service Lines	1,026	740		7,750	1,366		9,265	5,271	
Total Customer Interruptions	**142,228**	**251,763**	**12,478**	**756,395**	**410,313**	**19,702**	**762,781**	**958,563**	**90,467**

Table 6 puts the same information in percentage terms. This shows the aforementioned 852 customer interruptions represented only 1% of the customer interruptions experienced by Potomac Edison customers during the Derecho. The data does not mean, however, that distribution substations were always functional during the storms. Rather, as shown in Figure 8 above, substation supply lines carry power to distribution substations. While each substation is usually fed by multiple supply lines, the substation will go dark if enough supply lines are interrupted. Examination of the rows entitled "Substation Supply Lines" in Tables 5 and 6 below reveals that this happened in each storm. For example, Pepco customers experienced 270,012 interruptions during the Derecho due to substation supply lines going out of service and the corresponding substations going dark.

Table 6 - Percent of Customer Interruptions Associated With System Components

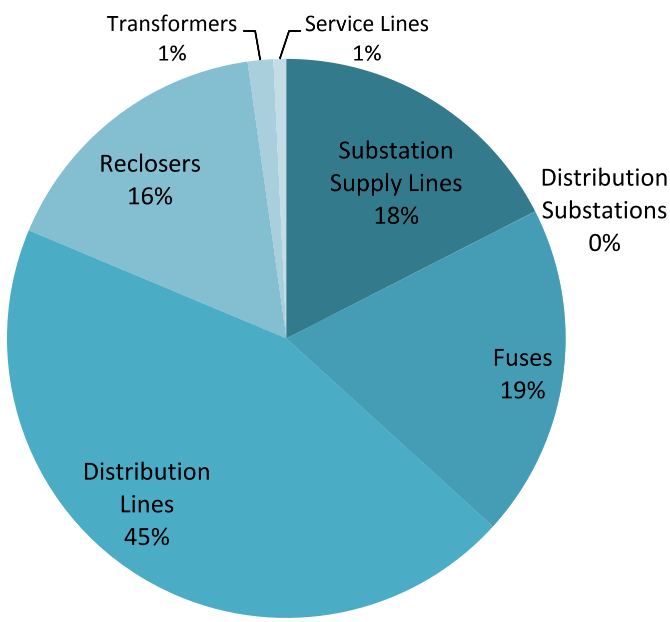
System Components	Snowmageddon 2/2/2010 – 2/12/2010			Hurricane Irene 8/27/2011 – 9/6/2011			Derecho 6/29/2012 – 7/8/2012		
	BGE	Pepco	Potomac Edison	BGE	Pepco	Potomac Edison	BGE	Pepco	Potomac Edison
Transmission Lines	0%	0%	0%	0%	0%	0%	0%	0%	0%
Transmission Substations	0%	0%	0%	0%	0%	0%	0%	0%	0%
Substation Supply Lines	3%	11%	21%	9%	22%	22%	15%	28%	19%
Distribution Substations	0%	0%	0%	0%	0%	0%	0%	0%	1%
Fuses	34%	7%	16%	34%	7%	20%	33%	5%	4%
Distribution Lines	27%	79%	40%	24%	67%	39%	21%	62%	57%
Reclosers	34%	2%	19%	32%	3%	18%	28%	2%	19%
Transformers	1%	1%	3%	1%	1%	1%	2%	2%	0%
Service Lines	1%	0%	unknown	1%	0%	unknown	1%	1%	unknown

Table 7 takes the same interruption data from all three companies and aggregates it. The pie chart in Figure 9 shows percentages. At 45%, damage to distribution lines caused the most interruptions across the three companies. Thus, increasing reliability of the distribution lines should also be a focus of the Task Force.

Table 7 - Cumulative Customer Interruptions Associated with System Component

	Cumulative Three Storms			
System Components	**BGE**	**Pepco**	**Potomac Edison**	**Total**
Transmission Lines	-	-	-	-
Transmission Substations	-	-	-	-
Substation Supply Lines	183,050	387,882	24,217	595,149
Distribution Substations	-	-	852	852
Fuses	550,074	96,016	9,111	655,201
Distribution Lines	381,624	1,071,051	64,608	1,517,283
Reclosers	503,503	34,060	22,879	560,442
Transformers	25,112	24,253	980	50,345
Service Lines	18,041	7,377	-	25,418

Figure 9 - System Component Responsible for Interruption



As the above data demonstrates, these storms did not have a uniform impact on the three utilities. On one hand, Potomac Edison, located in Western Maryland, was not severely affected by Snowmaggedon or Hurricane Irene, but was affected by the Derecho. On the other hand, BGE and Pepco were severely affected by all three storms. Utilities differ in design and location. There is no one size fits all fix. Rather, any solution needs to consider a utility's unique infrastructure, geography, and community. For example, Pepco has historically operated significantly fewer reclosers than the other utilities, because the limitations of recloser technology have prevented its utilization in Pepco's dense network. In recent years, however, improvements in recloser technology have made it possible for Pepco to obtain reclosers that can be used in a dense distribution system with higher fault currents. This, along with other automated distribution equipment, is being funded, in part, by a federal Department of Energy stimulus grant.

The data in the above tables also demonstrates that generation and transmission components remained operational during storms. The integrity of substations (transmission or distribution) was not a significant problem. One data point to note: while there are relatively few substation supply lines, they accounted for 18 % of the system disruptions. Distribution lines and related components also represented the largest vulnerability for each utility in each storm.

To help determine where utilities should focus their efforts, one can determine and compare the number of customer interruptions per circuit miles; the higher the number, the more people that can be helped by an improvement to that line. Tables 8 and 9 show that on a per circuit mile basis, substation supply lines going out of service accounted for significantly more customer interruptions than distribution lines going out of service. This is true even if fuser and recloser interruptions are included in the comparison. This data can be instructive in assisting utilities and regulators in determining the most impactful places to target infrastructure investments.

Table 8 - Getting Power from Transmission Substations and Distribution Substations

	BGE	Pepco	Potomac Edison
Substation Supply Lines	253	97	65
Circuit miles	1,428	1,827	494
Cumulative interruptions three storms	183,050	387,882	24,217
Cumulative customer interruptions per circuit mile	128.19	212.31	49.02

Table 9 - Getting Power from Distribution Substations to Customers

	BGE	Pepco	Potomac Edison
Distribution Lines	1,295	693	323
Circuit miles	23,568	8,399	8,581
Cumulative interruptions three storms	381,624	1,071,051	64,608
Cumulative customer interruptions per circuit mile	16.19	127.52	7.53
Cumulative customer interruptions including fuses and reclosers	1,435,201	1,201,127	96,598
Cumulative customer interruptions including fuses and reclosers per circuit mile	60.90	143.01	11.26

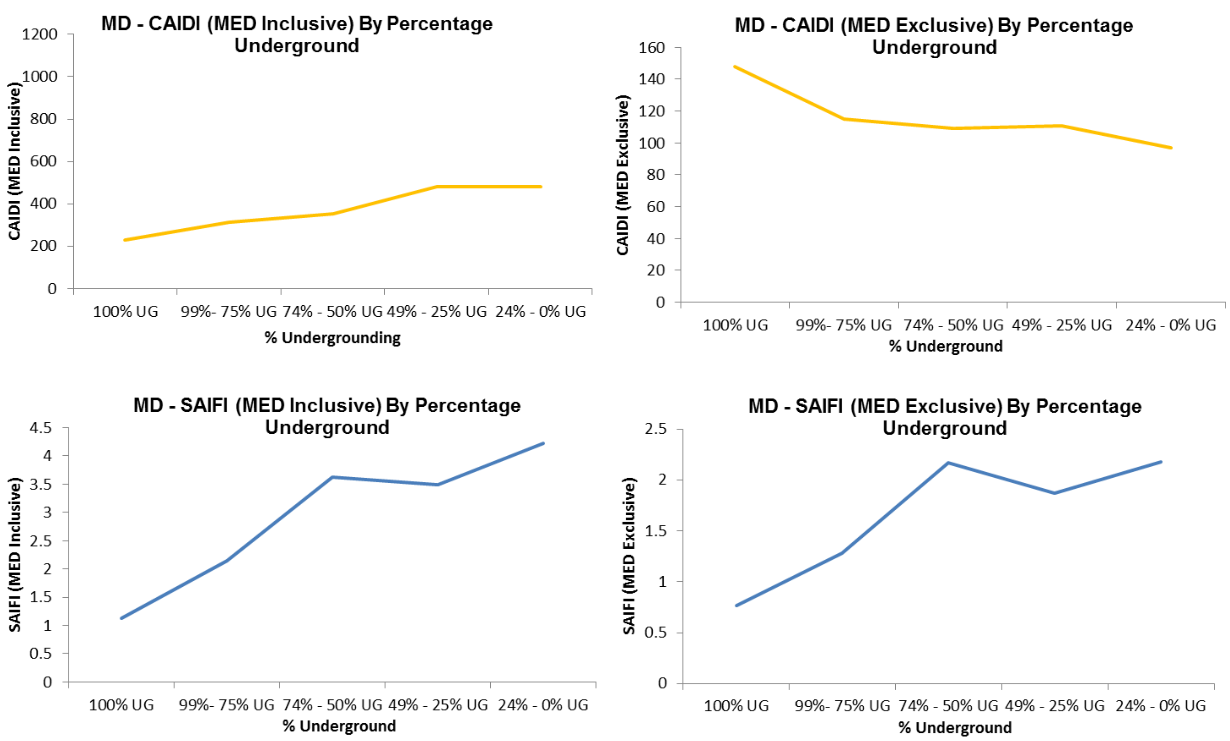
The data contained in this section helps answer the first question: what components of a utility's network are the most vulnerable to storms? Figure 9 answers the question on volume alone: 45% of the outages during the three storms resulted from damage to the distribution lines. However, overlaying this data with an analysis of how many customers are affected per circuit mile, as done in Tables 8 and 9, reveals that modifications to the substation supply lines may be an appropriate investment. The inquiry, however, does not end there. The Task Force also inquired as to whether the location of the components affected vulnerability to storms.

2. How do above ground, underground, and mixed lines affect grid resiliency?

The Task Force was also interested in how the location of a line, i.e., whether it was 100% overhead, 100% underground, or a mix of both, affected its resiliency during major storms. The utilities provided data on this as well.

One interesting data point is based on information that compares various lines with differing locations. As seen below, the graphs on the left include major event days, such as the Derecho, while the graphs on the right exclude such days. The CAIDI graphs (top line) show that Pepco's underground lines reduce outage times during major event days, but actually increase outage times during non-major event days. The SAIFI graphs (bottom line) show that Pepco's underground lines decrease the frequency of outages during both major event days and non-major event days.

Figure 10 - Reliability Comparison of Pepco Overhead and Underground Systems



MED = major event days

Source: PHI

Tables 10, 11, and 12, the next series of tables, compare the reliability of above and below ground infrastructure. Table 10 shows the storm history for substation supply lines. Substation supply lines have redundancy, but if enough supply lines are damaged, entire substations loose supply. The substations are accounted for in Table 11 and the service territories for the substations that lost supply in two storms are shown on Maps 1 and 3. Table 12 provides the storm history data for distribution lines and the maps show the services territories of the distribution lines that lost power in at least two of the three storms.

Table 10 - Substation Supply Lines

		BGE		PEPCO	
	Predominant Relationship to Ground	**Number**	**% of Above, Mixed, Below Ground**	**Number**	**% of Above, Mixed, Below Ground**
System Total	Above	118		42	
	Mixed	60		18	
	Below	75		37	
Remained Functional in All 3 Storms	Above	75	64%	3	7%
	Mixed	46	77%	0	0%
	Below	75	100%	37	100%
Interruption in 1 of 3 Storms	Above	34	29%	15	36%
	Mixed	11	18%	7	39%
	Below	0	0%	0	0%
Interruption in 2 of 3 Storms	Above	9	8%	19	45%
	Mixed	3	5%	8	44%
	Below	0	0%	0	0%
Interruption in 3 of 3 Storms	Above	0	0%	5	12%
	Mixed	0	0%	3	17%
	Below	0	0%	0	0%

Note: Potomac Edison was not included in this analysis because its system was only seriously affected by one of the three storms.

Table 11 - Distribution Substations

	BGE			PEPCO		
	Number	**Estimated Cumulative Customer Interruptions**	**% Estimated Cumulative Customer Interruptions**	**Number**	**Estimated Cumulative Customer Interruptions**	**% Estimated Cumulative Customer Interruptions**
System Total	195			61		
Remained Functional in All 3 Storms	169			30		
Lost supply 1 of 3 Storms	24	103,414	97.2%	23	209,426	54.0%
Lost supply in 2 of 3 Storms	2	3,006	2.8%	8	178,456	46.0%
Lost supply in 3 of 3 Storms	0	0	0%	0	0	0%

Note: Potomac Edison was not included in this analysis. Its system was only seriously affected by one of the three storms.

Table 12 - Distribution Lines

BGE

		Number	% of Above, Mixed, Below	Estimated Cumulative Customer Interruptions	% Estimated Cumulative Customer Interruptions
System Total	Above	105			
	Mixed	606			
	Below	584			
Remained Functional in All 3 Storms	Above	58	55%		
	Mixed	393	65%		
	Below	471	81%		
Interruption in 1 of 3 Storms	Above	36	34%	74,639	11%
	Mixed	169	28%	238,894	36.5%
	Below	94	16%	125,475	19%
Interruption in 2 of 3 Storms	Above	11	10%	35,804	5%
	Mixed	44	7%	126,396	19%
	Below	18	3%	51,952	8%
Interruption in 3 of 3 Storms	Above	0	0%	0	0%
	Mixed	1	0.2%	3,132	0.5%
	Below	0	0%	0	0%

PEPCO

		Number	% of Above, Mixed, Below	Estimated Cumulative Customer Interruptions	% Estimated Cumulative Customer Interruptions
System Total	Above	529			
	Mixed	0			
	Below	164			
Remained Functional in All 3 Storms	Above	60	11%		
	Mixed	0	0%		
	Below	90	55%		
Interruption in 1 of 3 Storms	Above	221	42%	184,993	23%
	Mixed	0	0%	0	0%
	Below	47	29%	22,281	3%
Interruption in 2 of 3 Storms	Above	211	40%	453,758	57%
	Mixed	0	0%	0	0%
	Below	26	16%	19,740	2%
Interruption in 3 of 3 Storms	Above	37	7%	119,547	15%
	Mixed	0	0%	0	0%
	Below	0	0%	0	0%

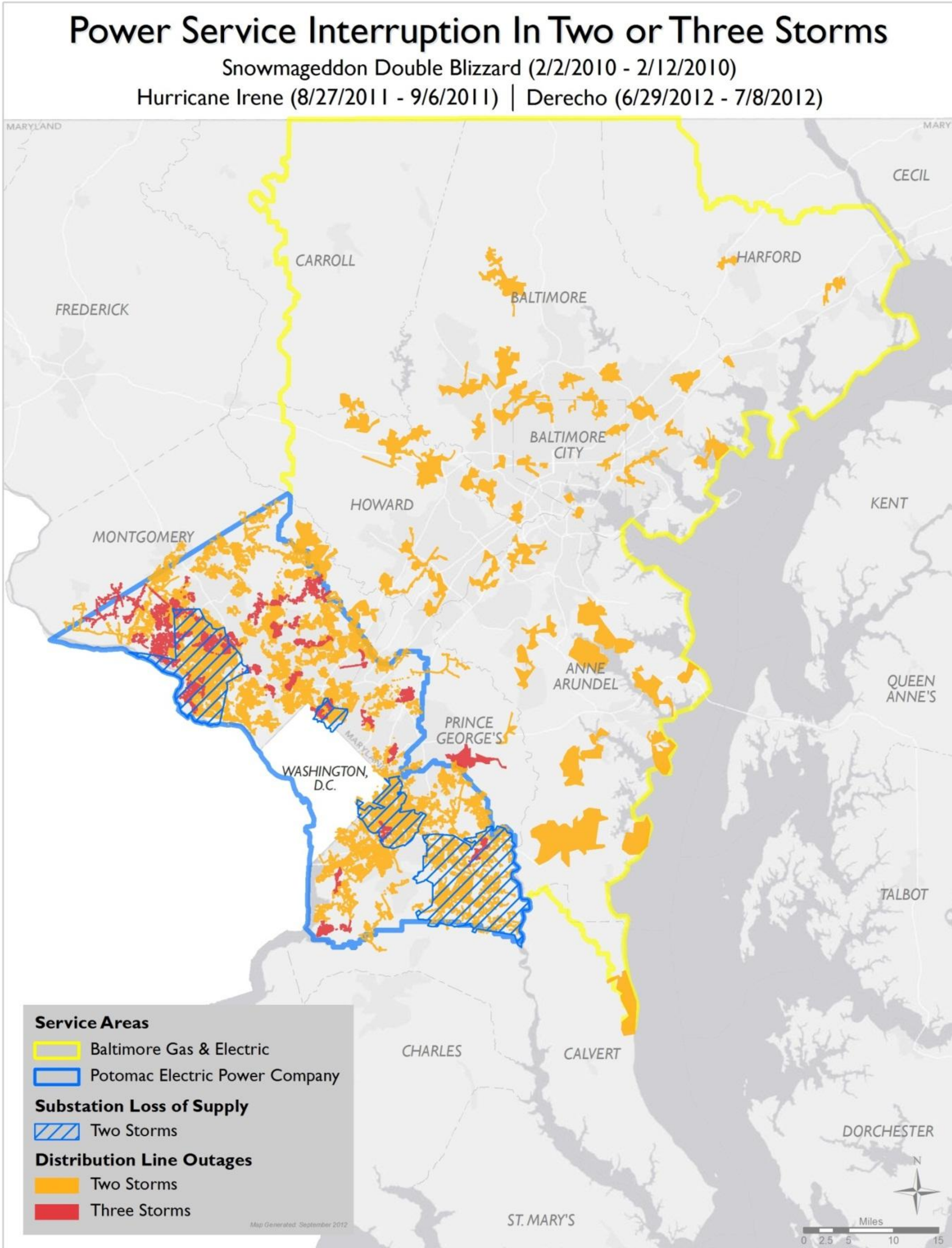
The data contained in these tables helps answer several questions. First, this data answered the inquiry regarding whether underground lines are better able to withstand storms than above-ground lines. The data indicates that the answer is yes; underground lines did offer better protection from the three storms. For example, 100 % of BGE's and Pepco's underground substation supply lines remained operational during all three storms. In comparison, only 64 % of BGE's and 7% of Pepco's above-ground substation supply lines remained operational during all three storms. Again not surprisingly, the survival rate of BGE's mixed lines was 77 % better than the record for above-ground lines, but less than the perfect record of the equivalent underground lines. Second, this data helps determine if underground lines are in fact stormproof. The data says almost. One hundred percent of the substation supply lines that were totally underground remained functional during all three storms. On the distribution line front, 81% of BGE's distribution lines and 55% of Pepco's distribution lines that were totally underground remained operational during all three storms.

Third, this data helps pinpoint whether outages are region and/or circuit specific. BGE's substation loss-of-supply interruptions were more widely and evenly distributed than Pepco's. Neither company had a substation that lost supply in all three storms. Only one BGE substation lost supply in two storms, and it had relatively few customers. Pepco had eight substations, or an estimated 30% associated customer interruptions, from substations that lost supply in two storms. Distribution lines serve particular territories/neighborhoods. BGE's outages were widely distributed: 67% of customer interruptions were associated with distribution lines that lost power in only one of the three storms. The remaining 33% were associated with lines that lost service in two of three storms. Pepco's outages were more concentrated: 15% of customer interruptions were associated with distribution lines that failed in all three storms. While not a perfect science, this data will assist all parties to determine the locations and infrastructure that merit a closer look for investment upgrades.

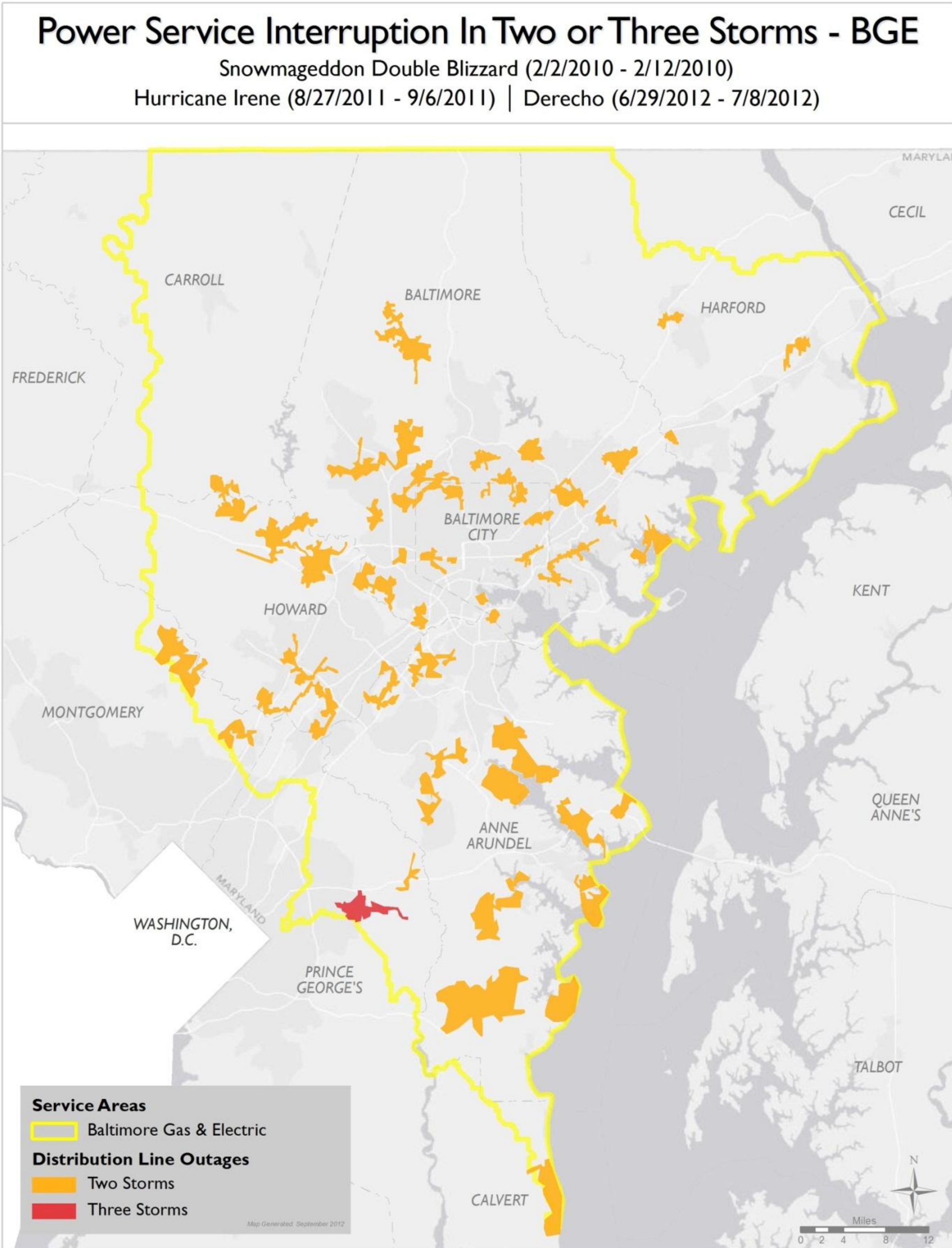
3. Storm Outage Maps

Using the data provided by Pepco and BGE, the Task Force created the following maps, which provide a visual representation of the information contained in the tables above. Specifically, the maps display the location of each distribution utility's inoperable substations and distribution lines during two or three previous major storms. The areas in orange and red are the neighborhoods where the citizens, on average, have been most affected by the frequency of outages.

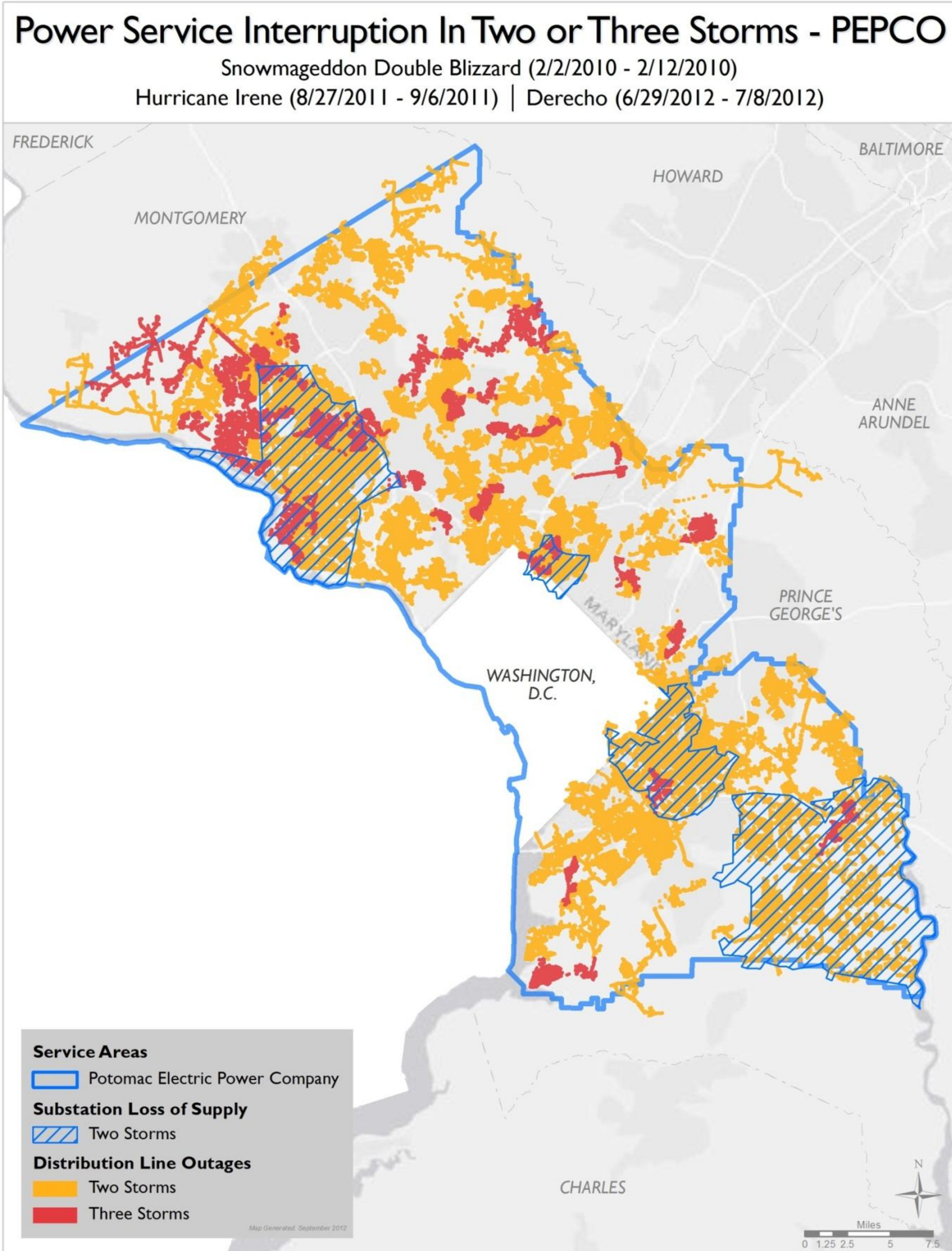
Map 1 - Power Service Interruption for BGE and Pepco



Map 2 - Power Service Interruption for BGE



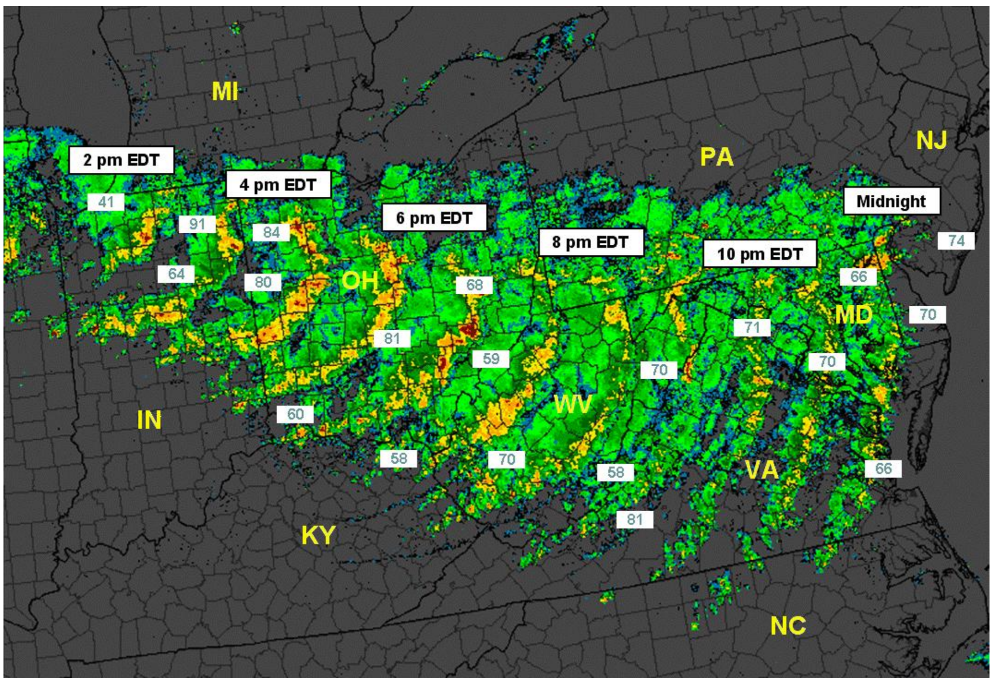
Map 3 - Power Service Interruption for Pepco



B. How does climate change affect the electric distribution system?

On June 29, 2012, a powerful, widespread storm system, known as a derecho, formed in Illinois and quickly moved through the Ohio Valley and Mid-Atlantic States. According to reports from the National Weather Service, the storm travelled at an average speed of 60 miles per hour and crossed the roughly 600 miles between Illinois and Maryland between the hours of 2:00 pm and 12:00 am. Peak wind gusts ranged from 80–100 miles per hour and severe thunderstorms moved with the storm. Based on U.S. Department of Energy Situation Reports, at 8:30 am the morning after the storm approximately 3.85 million customers were without power across 11 states. Almost forty-three percent of Maryland customers (approximately 1,000,000) were without power the morning of June 30, 2012.

Figure 11 - Composite Radar Reflectivity Image of June 29, 2012 Derecho Event



Source: NOAA

According to analysis conducted by the National Oceanic and Atmospheric Administration ("NOAA"), the Derecho's effects "were particularly acute in suburban Washington and Baltimore, where measured 65-75 mph gusts severed numerous overhead electrical feeders."[8] Numerous critical infrastructure lost power during the event, including interruptions in 911 service in Northern Virginia.

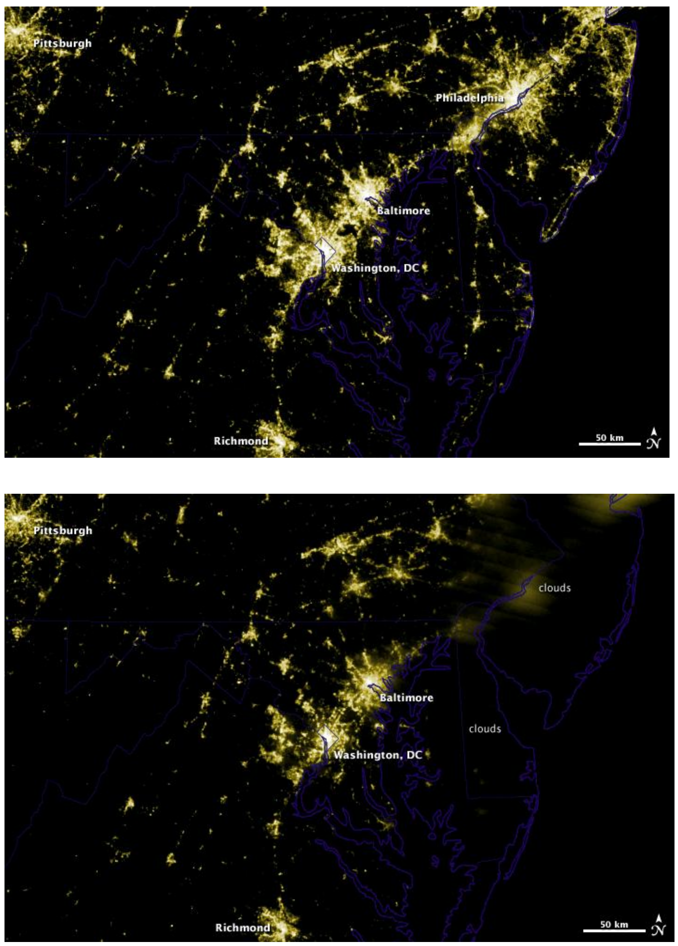
The Derecho was, by no means, an isolated instance of severe weather. Rather, Maryland (and the nation) has been experiencing extreme weather on an increasingly regular basis. Over the past few years, Marylanders have endured Snowmaggedon of 2010, the violent summer storms of 2010, Hurricane Irene in 2011, and the Derecho and heat waves of June/July 2012. In fact, according to the NASA's Goddard Institute for Space Studies, which monitors global surface temperatures on an ongoing basis, 2010 tied with 2005 as the hottest year on record and 2011 was the ninth hottest year to be

[8] http://www.spc.noaa.gov/misc/AbtDerechos/casepages/jun292012page.htm#

recorded. So far, the first eight months of 2012 have surpassed all previous years and stand as the hottest start to any year since record keeping began in 1895. In addition to the rising temperatures, a lack of rainfall has impacted Maryland's agricultural sector and many parts of the State remain under drought conditions.

There is consensus in the scientific community that various models of the impacts of climate change foretell increasing frequency of severe weather events in the coming decades. Similarly, many scientists believe that the drought conditions that are affecting more than half of the contiguous United States are a result of climate change. There is also consensus that even as the State works diligently to curb greenhouse gas emissions, severe weather events will continue to occur and Maryland's citizens and businesses will continue to be affected.

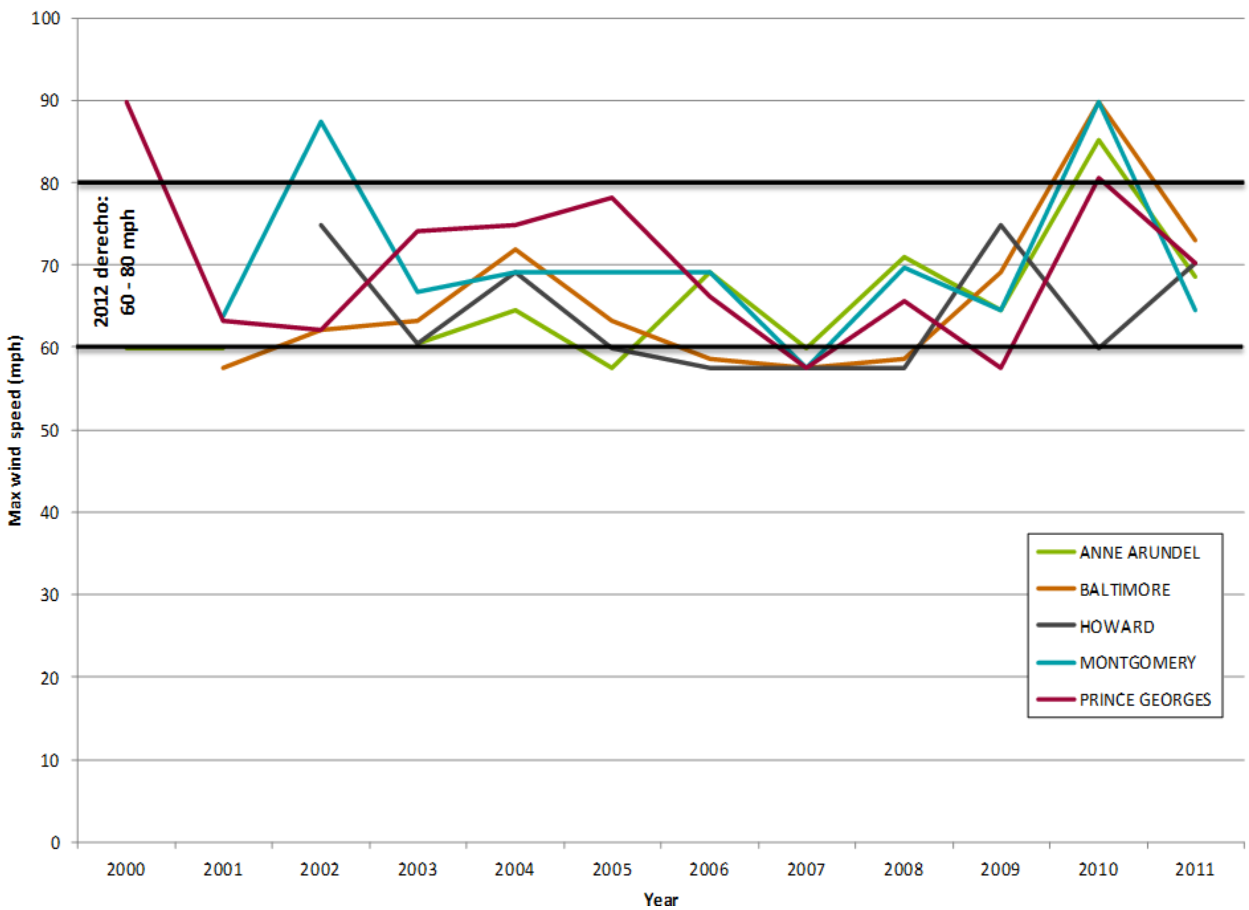
Figure 12 - Mid-Atlantic Region Before and After the Derecho Hit (June 28 and June 30, 2012)



Source: NASA Suomi National Polar-Orbiting Partnership Satellite

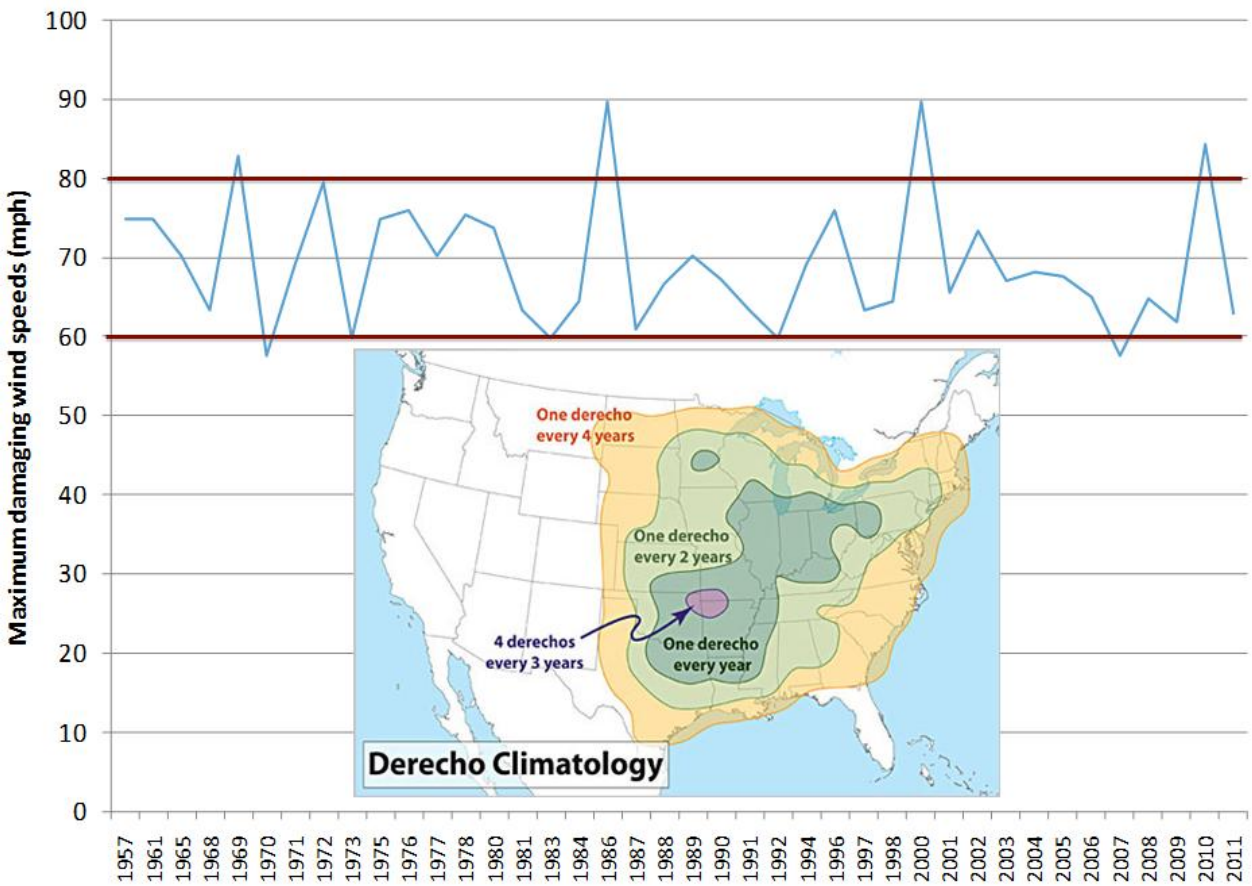
Finally, a review of historical meteorological data, reproduced below, reveals that Maryland has experienced wind speeds equal to or higher than those of the June 29, 2012 Derecho regularly over the last few decades. Climate change is only expected to increase the frequency and severity of extreme weather events. This data is offered to support the Task Force's conclusion that extreme weather events will continue to happen and all involved in restoration efforts should plan for this eventuality.

Figure 13 - Average Yearly Maximum Wind Speed for Select Maryland Counties



Source: NOAA's Damaging Wind Severe Weather Database

Figure 14 - Historical Storm Severity in DC Metro Region



Source: NOAA's Damaging Wind Severe Weather Database

C. What is the cost of loss of electricity?

Power outages result in widespread and complex costs to multiple parties, including consumers, municipalities, governments and the utilities. As discussed above, the PSC has established various regulations to assist the utilities in recovering both lost revenues and extraordinary expenditures for storm restoration. However, consumers have had few options for recapturing their losses. Maryland consumers incur a variety of costs when they lose electric service and these costs differ depending on a wide range of factors, including the type of customer, the duration of the outage, and the prevailing weather conditions. Costs increase with the duration of the service interruption because a multi-day outage is far more costly than an outage lasting just one or two hours.

1. What do power outages cost consumers?

Residential customers incur a variety of costs, or "damages," from the loss of electric service. The costs of replacing perishable food lost during power outages vary widely, but these costs can be substantial. The cost may include restaurant meals and hotel stays during the outage, which may be necessary for some customers. Some residential customers rely on well water which requires the use of electric pumps. During power outages, well water would be unavailable to these customers.

For households that have portable electric generators for use in emergencies, there is a cost for the fuel to operate that generator which can equate to more than $0.75/kWh. Additionally, portable emergency generators typically do not provide all the electric power that might be demanded by a customer and are rarely wired into the house's electrical system. These portable generators may help supply certain critical household loads such as refrigeration, sump pumps, and limited lighting, but they cannot drive heavy loads such as heating and air conditioning, power for well pumps, and water heating. Whole-house generators are capable of providing more power in an outage, but these are very expensive and often require access to natural gas service.

Finally, power outages represent significant inconvenience on many fronts, including interruption of Internet access, possible interruption of telephone service, and potential delays related to transportation if utility crews are repairing power facilities along busy routes. Perhaps of greatest importance is the health-related impacts to the elderly and infirm who are particularly susceptible to extreme heat and cold. Compounding the potential adverse health consequences is the chance that emergency services provided by local and State government also may be compromised during periods of outage.

The types of costs that commercial and industrial ("C&I") customers bear during power outages differ from those incurred by households. These costs also vary by the type of business. First and foremost, a power outage of any duration can result in foregone income because the business may not be able to operate. Another significant cost to food service businesses in particular is the loss of perishables if the business does not have backup generators to provide electricity during the service interruption. The amount of money that businesses invest in backup generators is a function of the reliability of the electric service they receive and the potential cost that they would incur were power not to be available. Finally, State and local governments incur the costs of operating cooling centers and overtime pay for police, fire, and rescue personnel, who frequently work overtime during an extended outage.

2. What is the value of electric service?

The Lawrence Berkeley National Laboratory ("LBNL") analyzed data from 28 studies about how customers valued electric reliability. These studies were conducted by ten electric utilities between 1989 and 2005.[9] The LBNL study included multiple estimates of electric customers' willingness to pay to avoid electric service outages. LBNL combined multiple survey responses to estimate "customer damage functions" for three types of customers: medium and large C&I; small C&I; and residential. The study found that the damages (or costs) incurred from service interruption varied across customer type, time of day, day of the week, and season. The cost of an outage increased in direct correlation to the length of the outage. C&I customers typically incur significantly higher costs than residential customers during service interruptions. LBNL determined that a residential customer incurs a cost of $4.08 on

[9] Sullivan *et. al.* "Estimated Value of Service reliability for Electric Utility Customers in the United States" Ernest Orlando Lawrence Berkeley National Laboratory, June 2009. http://certs.lbl.gov/pdf/lbnl-2132e.pdf

average from a one-hour service interruption on a summer weekday and an $11.20 per hour cost from outages lasting eight-hours during the same period. Small C&I customers incur an $856 average cost from a one-hour outage on a summer weekday versus a $4,991 per hour cost from outages lasting eight-hours during the same period. Medium/large C&I customers incur an average cost of $21,312 from a one-hour interruption on a summer weekday and a $98,278 per hour from cost outages lasting eight-hours interruption.[10]

Focusing on the estimated average cost of an eight-hour interruption on a summer weekday, the medium/large C&I cost is over 8,000 times the cost estimate for the average residential customer. The costs for small C&I customers fall in between the residential and medium and large C&I cost estimates. The study also found that residential customers incur greater costs/damages if the outage occurs on a weekend relative to a weekday, while the opposite is true for small, medium, and large C&I customers. This is not surprising because most businesses (although not all) only operate on weekdays, hence they lose more revenue if an outage occurs on a weekday as compared to during the weekend. Finally, the season also affects the cost of service interruptions. For example, residential and medium/large C&I customers incur a higher cost on average when the interruption occurs during the summer as opposed to the winter, regardless of whether the interruption occurs on a weekend or a weekday. The opposite is true for small C&I customers, who tended to incur higher costs during winter interruptions as compared to summer interruptions.[11] The Task Force notes, however, that there are wide variations in the costs incurred by non-residential customers depending on the size of the customer and the type of business activity in which the customer is engaged.

These figures, while not Maryland-specific, do provide some context on the cost of outages for residential ratepayers. For each of the three main storms covered in this report, the peak or total customer interruptions[12] and total number of outage hours are shown below, using data from the standardized PSC storm reports. Total outage hours were then applied across all utility customers (not just those experiencing outages), and total and average cost estimates were calculated using the residential figure from the LBNL study.

As mentioned above, the costs were allocated to all utility customers rather than only those experiencing outages. This was done as the current reporting standards require peak outages (i.e. the maximum number of customers out at a given time) and cumulative outages (i.e. the total count of customer interruptions), but not the number of unique customers that experience an outage. The number of unique customers experiencing an outage would be between the peak outages and the total customers served. Unfortunately, it is not possible to accurately extract this figure from the current storm reports, so the larger, system-wide customer counts as of the Derecho were used. In this context, the cumulative outage hours and costs per customer can be thought of as the expected cost for a customer selected at random for these three storms. However, if the outages were applied to only

[10] *Id*. at Table ES-3. Costs expressed in 2011 dollars.
[11] *Id*.
[12] For Snowmaggedon and Hurrican Irene, PSC regulations required only the reporting of peak interruptions, not totals. As such, the average duration of an outage is not calculated as it would be artificially high

those customers who actually lost power rather than across the entire service territory, the affected customers would see higher cumulative outages and costs.

Although this is an overly simplified analysis, it also likely understates the total economic cost by not separately calculating the impact on C&I customers but rather using the lower residential cost estimate for the 10% of Maryland utility accounts that are C&I customers. Regardless, it is clear that the cost to residential rate payers can quickly move into the hundreds of millions of dollars per major event. However, it is critical to note that these figures only reflect system-wide averages rather than individual experiences, and that Task Force is in no way implying that customers are owed this amount by any entity.

Table 13 - Potential Cost of Storm Outages for Residential Customers

Storm	BGE	Choptank	DPL	PE	Pepco	SMECO	All Utilities
Snowmaggedon							
Peak Interruptions	45,158	16,867	16,830	14,192	90,858	11,824	292,799
Total Hours	1,145,347	223,146	581,785	110,002	3,591,156	286,540	5,937,976
Cost	**$12,827,886**	**$2,499,235**	**$6,515,992**	**$1,232,022**	**$40,220,947**	**$3,209,248**	**$66,505,331**
Hurricane Irene							
Peak Interruptions	476,664	11,990	63,597	8,554	194,516	104,328	1,139,380
Total Hours	27,697,518	184,483	1,954,386	88,325	4,989,481	4,638,825	39,553,018
Cost	**$310,212,202**	**$2,066,210**	**$21,889,123**	**$989,240**	**$55,882,187**	**$51,954,840**	**$442,993,802**
Derecho							
Peak Interruptions	429,841	7,371	28,059	60,209	410,679	56,424	992,583
Total Interruptions	762,781	13,112	50,476	72,718	786,766	83,250	1,769,103
Total Hours	28,643,177	97,116	436,823	2,149,880	20,465,930	1,203,860	52,996,786
Average Duration	37.6	7.4	8.7	29.6	26.0	14.5	30.0
Cost	**$320,803,582**	**$1,087,694**	**$4,892,418**	**$24,078,656**	**$229,218,416**	**$13,483,232**	**$593,563,998**
Total for Three Storms							
Total Hours	57,486,042	504,745	2,972,994	2,348,207	29,046,567	6,129,225	98,487,780
Total Customers	1,240,173	52,138	194,945	251,236	534,601	151,800	2,424,893
Cumulative Outage Hours Per Customer	46.4	9.7	15.3	9.3	54.3	40.4	40.6
Cumulative Cost Per Customer	$519	$108	$171	$105	$609	$452	$455
Total Cost	**$643,843,670**	**$5,653,139**	**$33,297,533**	**$26,299,918**	**$325,321,550**	**$68,647,320**	**$1,103,063,131**

V. What can be done to improve the resiliency of Maryland's electric distribution system?

During the course of the eight roundtable discussions, the Task Force investigated various ways to strengthen the resiliency of Maryland's electric distribution system, as well as improve the State's emergency response processes. The remedies that the group explored were varied and included technological solutions, infrastructure improvements, regulatory changes, and process improvements. The Task Force also considered various cost recovery mechanisms to pay for improvements.

A. Is undergrounding an appropriate choice?

The first charge of the Executive Order was to evaluate the "effectiveness and feasibility of undergrounding supply and distribution and substation lines in selected areas as a way to strengthen the grid and improve the resiliency of Maryland's electric distribution system." Accordingly, the Task Force spent a great deal of time discussing this option.

1. What are the benefits and detriments of undergrounding lines?

Throughout Maryland, electric distribution lines can be found both overhead and underground. As demonstrated in the data in Section IV above, underground lines provide many benefits during a major storm. For example, the more circuits that are underground, the less frequent outages are on that line during a storm. Additionally, underground lines require significantly less vegetation management. Many communities also find that underground lines provide better aesthetics by delivering electricity without crowding airspace or blighting the viewscape. (Poles would still be visible, however, to carry other utilities, unless all were also undergrounded). There are, however, some negative aspects of underground lines, including higher initial construction costs than overhead lines, potential shorter line life expectancy due to chemicals and abrasions that can degrade the insulation in underground lines, and longer repair times due to increased durations to locate and repair line outages.

A review of the data in Section IV reveals that during major storms, underground lines offer significant improvements in terms of number of outages as opposed to overhead lines.

2. What existing regulations address undergrounding?

Existing Maryland regulations recognize the benefits associated with underground distribution lines and therefore require that most new electric distribution line extensions be placed underground. For example, after August 28, 1969, any extension of an electric distribution line under 33kV that is (1) on property owned or leased by the entity seeking electric service through the line extension, (2) in an industrial park, (3) necessary to deliver electric service to new commercial and industrial buildings, or (4) serving new multiple-occupant buildings, must be placed underground rather than overhead.[13] Similarly, after June 5, 1968, any extension of an electric distribution line necessary to furnish

[13] COMAR 20.85.01.01.

permanent electric service to new residential buildings and mobile homes shall be placed underground.[14] While these regulations require undergrounding for specific types of new lines, there is currently no requirement that existing overhead lines be undergrounded, nor is there any requirement that extension of existing overhead lines be built underground. The effect of these regulations is that nearly all new electricity distribution lines put in service in Maryland after 1969 were placed underground.

Today, Maryland utility companies have a significant portion of their electric distribution system undergrounded. For example, Pepco has undergrounded 48% of its Maryland system, and both SMECO and BGE have undergrounded approximately 65% of their electric distribution systems. This is partly the effect of the COMAR regulations and partly the effect of the utilities' individual initiatives to place underground certain segments of overhead distribution lines that had proven over time to be problematic and subject to frequent outages.

Figure 15 - Underground Distribution Conduit Installation

Source: PHI

3. How much does undergrounding cost?

The costs associated with building underground electric distribution lines are greater than the costs of comparable overhead lines. Based on estimates developed by the Edison Electric Institute ("EEI"), new underground distribution construction and overhead-to-underground conversions can cost five to ten times more than comparable overhead construction.[15] The substantial variability in costs results from local-area and site conditions and prevailing labor rates.

The higher development costs associated with new underground utility facilities relative to overhead facilities are largely driven by higher labor and material costs, longer installation times, and additional logistical and design complexities. A 2005 report from the Virginia State Corporation Commission

[14] COMAR 20.85.03.01.
[15] Edison Electric Institute. *Out of Sight, Out of Mind Revisited*, December 2009, Page 23.

identifies the primary cost components associated with converting existing overhead electric distribution facilities to underground:

- Materials associated with new underground facilities (net of salvage value of existing overhead facilities);
- Labor associated with removal of the existing overhead facilities and installation of the new underground facilities (mostly trenching/boring);
- Planning, design and engineering;
- General, administrative, construction, and material overheads;
- Contingencies; and
- Acquisition of easements.[16]

The EEI study referenced above utilized survey data from utilities to estimate the cost per mile for new overhead construction, new underground construction, and the cost to convert from overhead to underground. Importantly, costs are affected by customer density, soil conditions (e.g., sandy, rocky, etc.), prevailing labor costs, construction techniques used, type and density of vegetation, and voltage levels.[17] The EEI study identifies costs for three distinct customer density categories:

- Urban – 150+ customers per square mile;
- Suburban – 51 to 149 customers per square mile; and
- Rural – 50 or fewer customers per square mile.

To put these population density numbers in some perspective, the population density for Maryland is 595 people per square mile. Baltimore City has a population density of 7,670 people per square mile; Annapolis, Gaithersburg, and Bethesda all have population densities of between 4,500 and 5,900 people per square mile; and Silver Spring has a population density of over 9,000 people per square mile.[18]

Figure 16 below shows the estimated cost-per-mile for the construction of new overhead and underground utility distribution lines, and the estimated cost-per-mile of undergrounding existing overhead utility distribution lines. These data, extracted from the EEI study, include minimum, average, and maximum costs. As shown in Figure 16, the construction costs associated with underground utility line construction are uniformly greater than the costs associated with overhead utility line construction.

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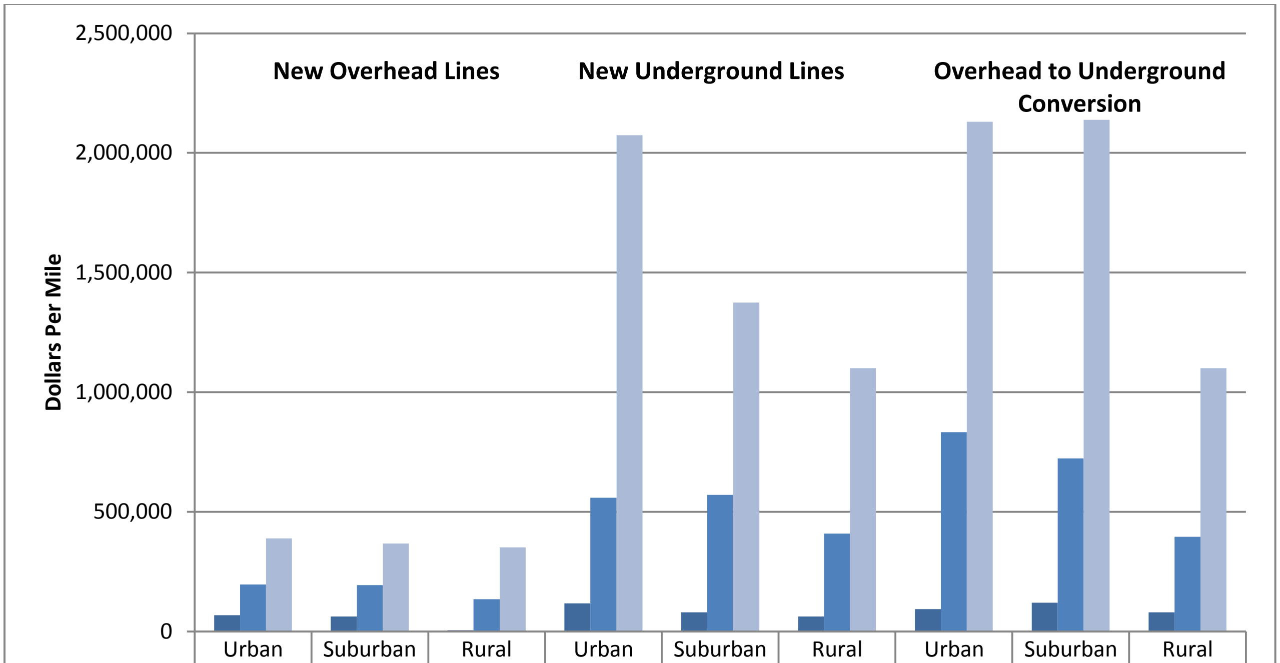
[16] Virginia State Corporation Commission. *Placement of Utility Distribution Lines Underground*, January 2005, Page 18.
[17] Edison Electric Institute. *Out of Sight, Out of Mind Revisited*, December 2009, Page 23.
[18] These figures are based on 2010 U.S. Census data.

Figure 16 - Cost of Distribution Power Lines (Dollars per Mile)



	Urban	Suburban	Rural	Urban	Suburban	Rural	Urban	Suburban	Rural
Minimum	67,892	63,000	5,300	117,000	80,000	63,000	93,202	120,000	80,000
Average	196,628	193,850	135,307	559,293	571,400	408,532	832,383	723,692	395,874
Maximum	388,600	367,000	351,000	2,074,000	1,375,000	1,100,000	2,130,000	2,138,400	1,100,000

Source: Edison Electric Institute, *Out of Sight, Out of Mind Revisited*, December 2009

Based on the data shown in Figure 16, the costs of building new electric distribution lines or converting from an overhead to an underground system can vary significantly. For example, the cost of new underground lines in urban areas is shown to vary between approximately $120,000 per mile and $2.1 million per mile, that is, the maximum cost shown is more than 17 times the minimum cost and the cost-per-mile differential is almost $2 million. The 2005 report from the Virginia State Corporation Commission found that the main factors that influence undergrounding conversion costs are the extent of community development, soil conditions, and burial methods.[19] Cost differences can also be attributed to different work methods, engineering design, and the materials utilized by the utility.[20]

A 2010 study conducted by Shaw Consultants International, Inc. for the Public Service Commission of the District of Columbia addressed the costs of converting a specific distribution line (10 circuit miles) from overhead to underground in the District of Columbia.[21] The Shaw cost estimate was $3.0 million per mile. The $3.0 million cost-per-mile estimate developed by Shaw Consultants is higher than the EEI

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[19] Virginia State Corporation Commission. *Placement of Utility Distribution Lines Underground*, Jan. 2005, 5.
[20] Public Staff of the North Carolina Utilities Commission. *The Feasibility of Placing Electric Distribution Facilities Underground*, November 2003, 20.
[21] Shaw Consultants International, Inc. *Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia – Formal Case No. 1026*, prepared for the Public Service Commission of the District of Columbia, July 1, 2010, Pages 69-76.

estimates, but includes recognition of the reduced construction workday due to District of Columbia regulations that restrict construction work to between 9:30 am and 3:30 pm. if the work entails roadway interference. That restriction resulted in an added cost of approximately $200,000 per mile.[22] The project also entailed concrete encasement of conduit and repaving of the entire roadway (due to District of Columbia regulations). With recognition of these factors that would upwardly affect overall project costs, along with the purely urban setting in which the project was located, the costs estimated by Shaw Consulting are roughly consistent with the higher end of the cost ranges developed by EEI.

The EEI study included a review of estimated/actual undergrounding costs from various state studies and actual projects. Table 14 below shows the cost range associated with the various projects and state estimates. As indicated above, actual costs are specific to each project and are influenced by numerous factors.

Table 14 - Undergrounding Cost Comparison

State (Year of Study)	Estimate / Actual Cost	Description	Cost per Mile
EEI (2009)	Estimate	Minimum Cost	**$80,000**
North Carolina (2003)	Estimate	Minimum Cost	**$151,000**
Maryland (1999)	Estimate	Minimum Cost	**$350,000**
Florida (2007)	Actual	Allison Island	**$414,802**
Florida (2007)	Actual	County Road 30A	**$883,470**
Florida (2007)	Actual	Sand Key	**$917,532**
Virginia (2005)	Estimate	Average Cost	**$1,195,000**
Oklahoma (2008)	Estimate	Average Cost	**$1,540,000**
Florida (2007)	Actual	Pensacola Beach	**$1,686,275**
Maryland (1999)	Estimate	Maximum Cost	**$2,000,000**
EEI (2009)	Estimate	Maximum Cost	**$2,130,000**
North Carolina (2003)	**Estimate**	**Maximum Cost**	**$3,000,000**

Source: Edison Electric Institute. *Out of Sight, Out of Mind Revisited,* December 2009

The Shaw study also reported undergrounding cost estimates prepared by or for other states and found that these costs ranged between $400,000 to $1.6 million per circuit mile depending on the type of construction, the relevant topography, and congestion.[23] Average installation costs were assessed to be approximately $1 million per circuit mile. The states for which costs studies were obtained included Oklahoma (2008), Florida (2006), and Maryland (2000).[24]

When analyzing the statement that underground electric utility systems can be more expensive to operate and maintain than comparable overhead systems, the EEI study identified several reasons why

[22] *Id.* at 73.
[23] *Id.* at 12.
[24] *Id.* at 13–14.

operation and maintenance costs may be more costly for underground systems. Repair times for underground lines are longer than for overhead lines, which can drive up maintenance costs. Because visual inspection is impossible with underground systems, damage to underground facilities typically takes longer to locate and longer to repair than similar damage to overhead facilities. In addition, underground systems generally have more complex operational needs, which can make them more difficult and costly to maintain and repair. Furthermore, underground facilities are generally less flexible than overhead facilities (e.g., more difficult to upgrade capacity, add unplanned transformers, etc.). Underground facilities are also subject to damage from dig-ins, and specialized training and equipment may be required for manhole/vault access. Finally, installation of underground services typically requires much more coordination between the utility and customer than similar overhead service installations.[25] Conversion to underground lines, however, can serve to improve service reliability, discussed elsewhere in this Report.

In addition to the direct costs of undergrounding electric lines, i.e., the actual costs incurred by the utility including capital costs and the incremental operation and maintenance costs of underground lines, there are also indirect costs. Indirect costs can be broadly defined as the additional costs to customers, municipalities/governments, and other utilities that may result from the conversion to underground lines. Individual customers and municipalities, for instance, may have to bear the costs associated with adapting their facilities to accept underground service. In addition, burying power lines requires disrupting existing landscapes, which can affect anything from the aesthetic benefits of a flower bed in a front yard to traffic flows on major roadways.[26] If the trenching takes place near existing trees, there is the possibility that root systems will be damaged and eventually weaken or kill the trees. A properly maintained underground right-of-way must be kept clear of trees. Thus, while properly trimmed trees can grow near overhead power lines, no trees would be permitted in the underground right-of-way. These costs, however, are not easily quantifiable. Furthermore, other utilities, such as land-line telephone companies, cable television companies, and internet service providers may share space on utility poles with the electric service. If power lines are buried to eliminate the utility poles, the lines from these other services will also have to be buried, presenting another set of indirect cost that must be taken into consideration.[27]

Indirect costs can also be defined as "… costs that [are] incurred, but not directly assignable to a project."[28] One such indirect cost is road-user costs stemming from construction and the resulting detour delays due to undergrounding overhead utility lines.[29] Although not easily quantified, time lost is an actual cost borne by road users. Further, added fuel costs and the health costs associated with increased automobile emissions should be included in the accounting.

[25] Edison Electric Institute. *Out of Sight, Out of Mind Revisited*, December 2009, 20-21.
[26] Public Staff of the North Carolina Utilities Commission, *The Feasibility of Placing Electric Distribution Facilities Underground*. Raleigh, North Carolina. November 2003, 30-31.
[27] *Id*. at 32.
[28] Paul Goodrum, et al. *An Analysis of the Direct and Indirect Costs of Utility and Right-of-Way Conflicts on Construction Roadway Projects*. Lexington, Kentucky: University of Kentucky, College of Engineering. Prepared for the Kentucky Transportation Center. August 2006, 24.
[29] *Id. at* 24.

Another indirect cost identified includes the monetary impacts sustained by businesses affected by the conversion.[30] Such impacts could result from the temporary loss of power or disruptions from trenching on nearby roadways and sidewalks. Costs borne due to disruptions incurred by a business, however, may be largely a distributional issue, meaning that the impacts are specific to an individual business and do not result in overall efficiency losses in the economy. For example, if a restaurant loses a customer because the sidewalk in front is temporarily closed, there would not be an efficiency loss if the potential customer chose to dine at a nearby restaurant. If, however, road closures dissuaded a potential customer from going out to dinner for the evening, there would be an overall loss in the economy. As a practical matter, there are both distributional issues and efficiency issues associated with undergrounding.

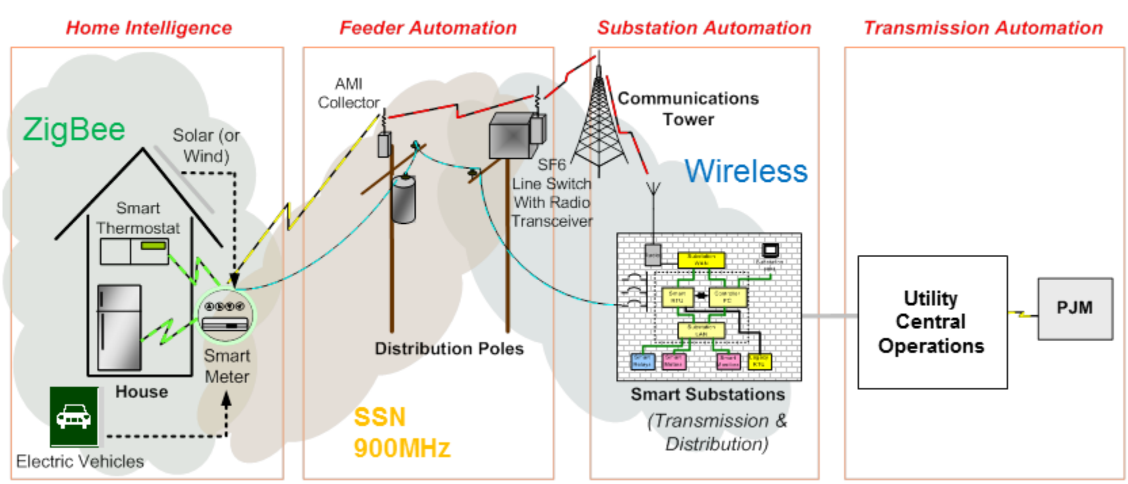
B. Are there other infrastructure investments that improve the resiliency of the distribution grid?

The Task Force also discussed other infrastructure investments that could be made to improve the resiliency of the distribution grid during major storms. The data gathered from the three large storms indicates that the majority of outages happen on the overhead distribution lines. Anything that can be done to lessen the likelihood that those lines fail will improve the resiliency of the distribution system.

1. How will the Smart Grid affect reliability and resiliency?

Maryland is at the forefront of the implementation of smart meters. By 2014, BGE and Pepco together will have installed over 1.6 million smart meters in the central region of Maryland. Delmarva Power has a smart grid program approved, and SMECO is currently seeking approval. Following installation and implementation of the smart meters, or advanced meter infrastructure ("AMI"), it is likely that there will be an improvement in reliability and resiliency in several important ways, though the improvements will have limited applicability in major storm events.

Figure 17 - "Smart Grid" Design Features



Source: PHI

[30] *Id.*

The AMI system will work in unison with new automated restoration systems during electrical interruption events to try to automatically restore power. For example, in blue sky outages and small storms, the automated system will be able to recognize an outage and utilize the reclosers on the grid to isolate the outage and reroute the flow of electricity around the outage, thereby reducing the number of customers affected by an interruption. This development, while important, will not have as large of an impact in a significant storm as there will not be sufficient lines operable to reroute the flow of electricity.

Smart meters will also allow utilities to receive notification of power outages immediately. Using smart grid technology, utilities will be able to "ping" smart meters to determine if they are receiving electricity. This will provide utilities with a more contemporaneous indication of when power is out. While this may reduce the time required to assess the initial outage situation, it will not negate the need for the utility to do a visual damage inspection. Therefore, this functionality will not greatly improve resiliency, though it could impact the ease with which underground faults are identified. Successful meter pings, however, will reduce some truck rolls to check that power has been restored, thereby increasing the efficiencies and reducing time from the end of outage restoration activities following a major event.

The Task Force also discussed how smart grid technology will allow utilities to conduct preventative maintenance. A series of sensors on the distribution network will allow utilities to monitor equipment in real time and repair or replace equipment before it fails.

2. Are there other infrastructure investments that should be considered?

As mentioned in the previous section on AMI, sensors and automated devices on the distribution grid may also contribute to increased reliability and resiliency of the system. For example, automated reclosers and sectionalizers improve reliability and resiliency on blue sky days and during minor storms.[31] Using feeder sectionalizing, utilities can cut off feeder lines at certain points. If lines are down at one point on the feeder's system, this allows utilities to provide service to some customers while shutting down the portion of the line in need of a repair. However, their effectiveness decreases during major events because there is nowhere to switch load. Utilities find that returns diminish as they install more reclosers and sectionalizers. To this end, BGE has automated only about 40% of its reclosers.

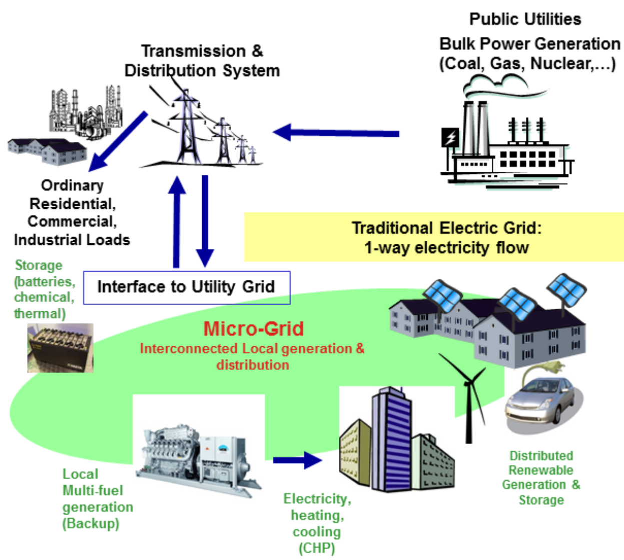
The Task Force also explored the various available wiring options. It appears that Maryland's utilities are already employing the appropriate wire strength. The group also discussed potential future improvements, such as the use of insulated wires on overhead lines and improved hydrophobic coatings. The group also investigated whether improvements to the pole and wire design could improve the resiliency of the system. For example, during the Derecho, Pepco alone had to replace 220 broken utility poles. While pole replacement can be a time-consuming process, it is only a small percentage of the outage jobs during the storm. Utilities in other parts of the country prone to hurricanes frequently use poles made of concrete or other more substantial material. This may be worth pursing here in Maryland.

[31] A recloser is an electrical isolating device that can automatically close the breaker when a fault clears, thereby restoring customers to service. Sectionalizers work in unison with reclosers to redirect power around faults in the event a fault persists on a portion of the distribution system.

3. Can microgrids increase the reliability of Maryland's electricity supply?

Microgrids are networks of distributed energy resources, energy storage devices, and interconnected loads typically across multiple buildings within clearly defined electrical boundaries. These networks act as single controllable entities with respect to the grid and can connect and disconnect from the grid to enable it to operate in either grid-connected or island-mode. Islanded distributed generation ("IDG") functions similarly to a microgrid but on a smaller scale, typically on a building-by-building basis. Importantly, IDG differs from ordinary distributed generation because it allows buildings to separate from the macrogrid and remain fully operational.

Figure 18 - Example of Microgrid Structure



Microgrids are a welcome and appropriate solution for customers whose need for consistent and reliable electricity is paramount. For example, labs with hundreds of thousands of dollars in research that will be lost if power goes out clearly put more emphasis on an uninterruptible power supply than a residence that can absorb intermittent outages with minimal disruption. The Federal Department of Agriculture in White Oak, Maryland has installed a microgrid on its campus to protect the valuable work that is happening there.

The Task Force generally agreed that microgrids are currently not feasible for private residential settings due to a number of factors including cost constraints and federal and State regulatory barriers.

The Task Force also recognized the potential for on-site generation as a backup energy source during power outages. Fuel cells can run on a number of fuels, including natural gas, and can provide base-load power generation without battery backup. Distributed solar PV generation coupled with battery backup represents another solution. However, due to safety concerns, distributed generation systems are currently required to shut off when the utility grid shuts down. That said, there may be opportunities for distributed generation combined, as appropriate, with battery storage to provide a backup generation solution for customers desiring or requiring higher levels of reliability than their local distribution grid can provide. In all installations, IDGs and microgrids must be wired appropriately and be able to be separated (islanded) from the utility grid.

C. Are there regulatory changes that can improve the resiliency of the distribution grid?

The Task Force acknowledges that the recent reliability regulations issued by the PSC represent a tremendous amount of work by the stakeholders and mark a significant development in ensuring reliable service in Maryland. The Task Force, however, evaluated whether certain improvements could be made to the regulations to offer additional transparency, encourage specific outcomes, and accelerate progress.

1. How are the poorest performing feeders handled?

Under COMAR 20.50.12.03(A)(4), utilities must identify the three percent worst performing feeders in their service territories, both in storm and excluding storm conditions. According to the PSC, if those two lists are different, then the utility should compile one list for remediation that contains the lowest 3% overall.

2. How is vegetation management handled?

There was consensus at numerous roundtable discussions that appropriate vegetation management is one of the most effective ways to improve the resiliency of the grid; the fewer trees that are likely to fall on lines, the more likely the system is to weather the storm. The following is an evaluation of the statutory and regulatory framework that affects Maryland's trees.

Trees are one of Maryland's most treasured and important natural and economic resources. Among other things, they create critical wildlife habitat, help mitigate climate change and protect the Chesapeake Bay, and are an integral feature of Maryland's esthetic and cultural landscape. Fallen trees, branches, and overgrown vegetation, however, account for one of the most common causes of power outages in Maryland. Thus, proper planting and maintenance of trees and other vegetation is essential for providing reliable electric service to Maryland customers. There is a complex structure of State and local laws, regulations, ordinances, and private property rights that affect the tree trimming, clearing, and vegetation management practices of Maryland's electric utilities.

a) Roadside Tree Law

Maryland's Roadside Tree Law is defined in Subtitle 4 of the Maryland Code, Natural Resources Article. The Roadside Tree Law regulates the trimming, removal, planting, and care of trees and shrubs growing partly or fully within the right of way of any public road. This law potentially impacts the vegetation management practices of most Maryland utilities because the distribution infrastructure is frequently co-located with or adjacent to these public roadways with a significant, mature tree canopy. The Forest Service at the Maryland Department of Natural Resources administers the Roadside Tree Law.

- *Permit Required* – A person, including a utility, must obtain a permit from the Forest Service before trimming, removing or performing tree care on roadside trees.[32]

- *Required Tree Care Standards* – The regulations implementing the Roadside Tree Law establish several detailed tree care standards, including tree clearance standards for overhead utility lines.[33] According to the regulation, "a person who trims a tree to provide clearance for utility wires, cables, or other facilities shall: (a) allow sufficient clearance for 2 years growth normally expected after trimming, unless otherwise directed by the Forest Service."[34] DNR interprets this regulation to mean that trees should be trimmed to allow for *at least* two years of growth. While trimming, the health of the tree must be "taken into account" and cuts must be made that "direct growth away from overhead wires and facilities in compliance with safety standards and government regulations."[35]

- *Replacement of Trees* – Under the regulations, if a trimmed tree dies within 1 year or is in poor condition due to trimming, if required by the Forest Service, the permittee shall remove the tree and replace it in a location to be determined by the Forest Service. The Forest Service also maintains a list of recommended trees.

- *Underground Facilities* – The regulations protect roadside trees and tree roots during excavation, including excavation for installation and maintenance of electric cable or conduits.

b) RM43 Vegetation Management Standards

With RM43, the PSC recently adopted vegetation management regulations that became effective on May 28, 2012.[36] These regulations establish, for the first time in Maryland, vegetation management standards for distribution and transmission lines not regulated by FERC.

- *Other Laws/Regulations and Property/Contractual Rights* – The vegetation management regulations establish minimum standards applying "to the extent not limited by contract rights, property rights, or any controlling law or regulation of any unit of State or local government."

- *Required Vegetation Management Program* – Utilities are required to develop vegetation management programs that address several technical requirements such as tree pruning and removal, vegetation management around poles, substations and overhead lines, vegetation management along rights of way, inspection of vegetation management, public education and notice, and debris management. The programs are to be filed with the PSC within 90 days of the effective date of the regulations, and no later than 30 days of implementing any changes to such programs, except in exigent circumstances.

[32] Md. Code, NR 5-406; COMAR 08.07.02.03.
[33] *See* COMAR 08.07.02.07.
[34] *Id.*
[35] *Id.*
[36] *See* COMAR 20.50.12.01, *et seq.*

- *Site Specific Vegetation Management Factors* – Utilities are to determine the extent and priority of vegetation management at a site based on several factors set forth in the regulations, such as the voltage of the conductor, relative importance of the affected conductor in maintaining reliable and safe power, likely regrowth rate, potential movement of conductors and vegetation during various weather conditions, legal rights to access area where vegetation management is to be performed, State/local laws and regulations that affect vegetation management at the site, customer acceptance of vegetation management at the site, maturity of the vegetation, and identification of structural condition of the vegetation.

- *Training Recordkeeping and Reporting* – Requires utilities to adopt proper standards for tree and shrub care, including safety standards. Also requires utilities to monitor and document vegetation management practices, including when a utility is not able remove a tree or limb due to lack of consent. Such information is to be provided to the PSC as part of the utility's annual performance report, which shall also include prior year expenditures on vegetation management and vegetation management budget for current calendar year.

- *Public Notice and Outreach* – Requires utilities to make reasonable attempts to notify owners/occupants of all properties on which cyclical, planned vegetation management is to occur, including written notice to each county/municipality affected. Also requires utilities to conduct annual public education programs on the importance of vegetation management.

- *Vegetation Management Schedule* – Regulations establish a vegetation management schedule that, over the next four years, requires utilities to perform vegetation management on an increasing percentage of its total distribution miles, until, within about 4 or 5 years, the utilities will have performed vegetation management on 100% of their total distribution miles. For example, beginning on January 1, 2013, a utility with a 4-year trim cycle shall, within 12 months, perform vegetation management on not less than 15% of its total distribution miles. That percent increases to 40% within 24 months, 70% within 36 months, and 100% within 4 years.

- *Minimum Clearances* – Regulations set minimum clearances of vegetation from conductors, to the extent not limited by contract/property rights or other controlling legal authority. The regulations set both horizontal and vertical minimum clearances and vary depending on the voltage of the conductor. Mature trees may be exempt from the minimum clearance requirements "at the utility's reasonable discretion" for voltage levels at 34.5 and below.

c) Local Laws/Regulations and Private Property Rights

Local laws and regulations also impact vegetation management practices. Several municipalities, for example, have ordinances that impact utility vegetation management practices with respect to trees and shrubs. Additionally, private property and contractual rights impact utility vegetation management practices. According to the report of the RM43 Working Group, most of Maryland's electric distribution lines are located on property not owned by a utility. Rather, utilities usually acquire right of way easements on property.

The terms of right of way easements vary and impact the extent to which a utility can perform vegetation management on the property. The utility may need to obtain the consent of the property owner to allow vegetation management work to proceed. Similarly, if large trees grow on private property that is adjacent to a utility's right of way, the utility needs to obtain the adjacent property owner's consent in order to perform vegetation management on such trees. Even if landowner consent is obtained, the RM43 Working Group noted that other State, county or municipal regulations may impose additional obligations and restrictions on vegetation management.

3. Penalties

The PSC also has authority to assess penalties against utilities. If the PSC finds a utility has violated a statute, regulation, or order, it may assess a civil penalty for the violation up to exceeding $25,000, with each day a separate violation. In addition to or instead of enacting a civil penalty, the PSC may revoke or suspend the license of an electricity supplier. Utilities pay civil penalties into the Maryland General Fund and not directly to the customer, as the PSC has no authority to direct the electric companies to pay customers compensatory or monetary damages. The PSC, through its consideration of utility rate cases may, and has, considered service quality in its evaluation of requests for rate increases.[37]

D. Do the utilities have sufficient personnel to ensure a reliable electric distribution system and adequate storm response?

The Task Force evaluated several factors related to utility staffing levels, including a comparison of staff over a number of years, the mutual aid system, and whether Maryland utilities are adequately preparing for the aging ("graying") of the utility work force.

1. How do historic personnel levels compare with current ones?

Any discussion of extended power outages must include an inquiry into whether the utilities have sufficient personnel available to conduct restoration efforts. Such an inquiry also leads, inevitably, to questions about historic staffing levels. Have utilities reduced personnel over the past decade? If so, can any conclusions be drawn between decreased staffing levels and reliability metrics? In order to better understand these questions, the Task Force asked the utilities to provide information about historic staffing levels. The raw data received from them is reproduced below and, while informative, must be overlaid with other changes that happened during the same twelve year period in order to allow meaningful analysis.

The data below includes only Maryland-assigned resources for utilities whose service territory spans multiple states. For certain utilities, this method may underreport their ability to react to major storm events in Maryland as they could be able to utilize their resources from adjoining states if they are available.

[37] *See* SECTION II.E.3, *infra*.

Table 15 - Staffing Levels of Maryland Utilities

BGE

As of December 31,	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
OH Primary	400	407	385	312	307	320	331	364	367	356	383	395	**373**
Total Alliance OH Primary Contractors*	0	0	0	0	131	0	113	133	149	115	107	182	194
OH Primary Resources Subtotal	*400*	*407*	*385*	*312*	*438*	*320*	*444*	*497*	*516*	*471*	*490*	*577*	*567*
Underground/URD	137	150	167	158	162	173	168	178	168	195	184	192	194
Substation	184	170	172	135	128	133	139	141	135	145	144	151	148
Secondary/Metering	287	310	323	295	313	311	320	304	307	284	282	287	297
Training Program	13	4	3	28	38	54	71	64	52	44	61	86	120
Total BGE Field Employees	***1021***	***1041***	***1050***	***928***	***948***	***991***	***1029***	***1051***	***1029***	***1024***	***1054***	***1111***	***1132***
Grand Total Field Resources	***1021***	***1041***	***1050***	***928***	***1079***	***991***	***1142***	***1184***	***1178***	***1139***	***1161***	***1293***	***1326***

Pepco

As of December 31,	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Internal Overhead Personnel	102	110	109	101	112	116	111	113	102	107	109	116	130	128
Internal Overhead Management	10	16	17	14	15	16	13	12	14	13	14	15	15	14
Sustaining Contract Overhead Line Personnel	77	77	79	79	78	79	89	97	109	131	139	151	151	235
Bid Contract Line Personnel	0	0	0	0	0	0	0	0	41	41	41	72	198	213
Available Contract Tree Trimming Personnel	53	53	53	53	53	53	53	53	53	65	73	198	269	235
Total Overhead Personnel	*241*	*256*	*258*	*247*	*257*	*264*	*266*	*275*	*318*	*356*	*375*	*552*	*763*	*825*
Internal Underground Personnel	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Internal Underground Management	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Underground Personnel	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*
Total Personnel	***263***	***278***	***280***	***269***	***279***	***286***	***288***	***297***	***340***	***378***	***397***	***574***	***785***	***847***

PE

As of December 31,	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PE-MD OH/UG Linemen	116	122	117	111	108	109	112	109	111	117	114	112
PE-MD Substation	19	20	19	19	21	19	19	26	26	24	22	20
PE-MD Metering	35	33	32	30	32	32	31	33	30	34	33	31
Subtotal PE-MD	*170*	*175*	*168*	*160*	*161*	*160*	*162*	*168*	*167*	*175*	*169*	*163*

DPL

As of December 31,	2007	2008	2009	2010	2011	2012
Internal Overhead Line Personnel[1]	106	106	99	100	101	101
Bid Contract Overhead Line Personnel[2]	23	23	23	22	35	21
Total Overhead Line Personnel	*129*	*129*	*122*	*122*	*136*	*122*
Available Contract Tree Trimming Personnel	25	27	27	25	29	77
Total Overhead Line and Tree Personnel	*154*	*156*	*149*	*147*	*165*	*199*

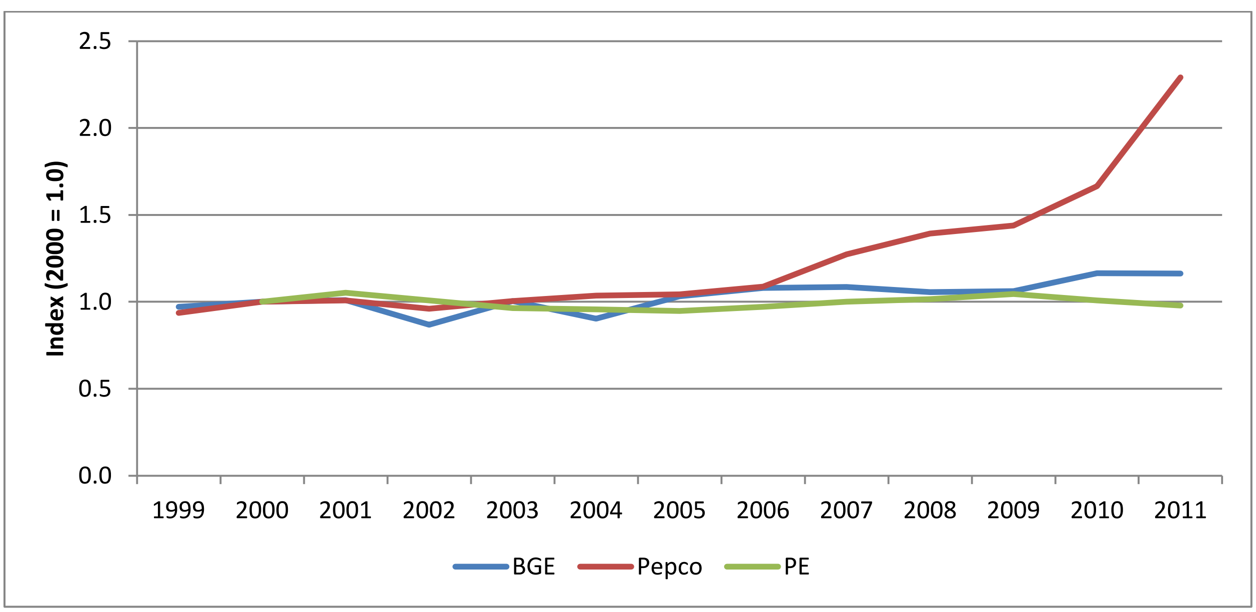
To help compare staffing levels across utilities, the Task Force determined the number of "network technicians." This broad category includes employees or contractors who are eligible to work on the hardware assets of the distribution grid, whether above ground or underground. Major categories such as trainees, meter readers, and tree trimmers were excluded from this particular definition. Clearly, these workers are vital to maintaining a reliable distribution grid, but their counts are not included solely for the purposes of comparing categories across utilities. Some of the utilities provided data on Bid Contract employees, who may or may not have the same annual availability as internal personnel.

The following table shows the total number of network technicians based on the above definition for all utilities, while the chart indicates relative additions or subtractions based on a 2000 staffing level index. DPL only provided data back to 2007, and thus is excluded from the graph.

Table 16 - Network Technicians – Maryland Only

Network Technicians	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BGE	1008	1037	1047	900	1041	937	1071	1120	1126	1095	1100	1207	1206	
DPL									129	129	122	122	136	122
Pepco	211	225	227	216	226	233	235	245	287	314	324	375	516	612
PE		135	142	136	130	129	128	131	135	137	141	136	132	

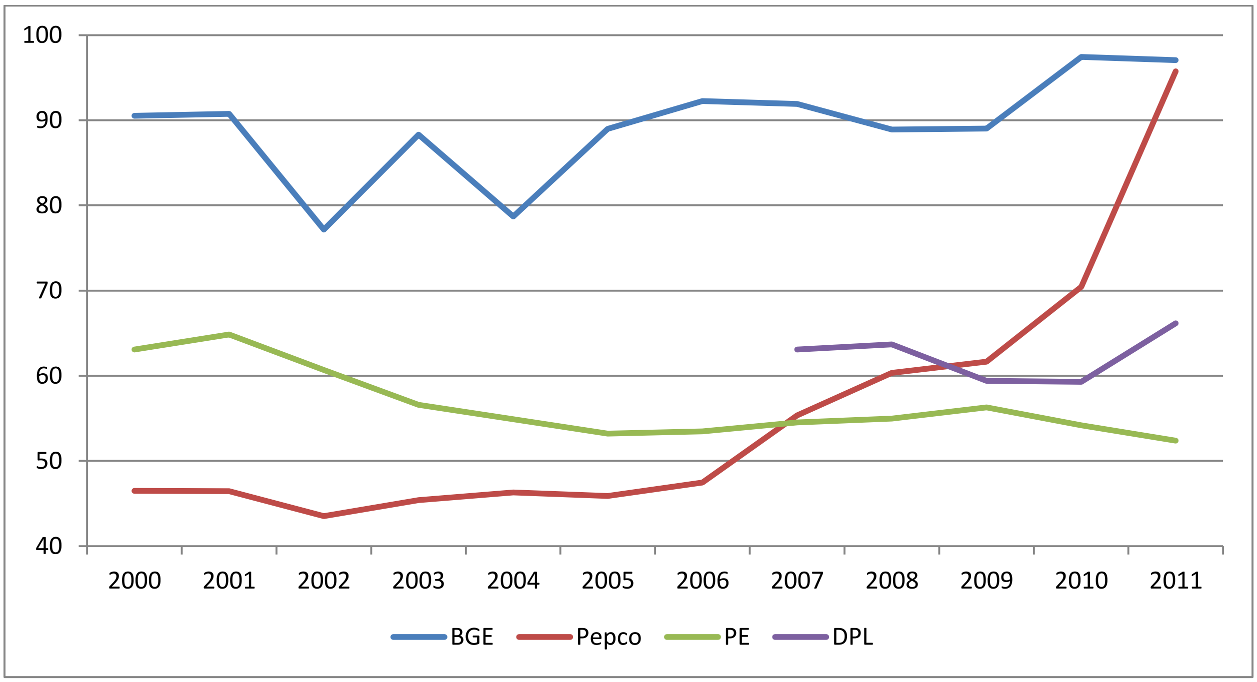
Figure 19 - Network Technicians Index



Of course, staffing levels must be viewed relative to the scale of the utility. While there are many ways to determine the scale of the utility using data such as miles of wire, total value of assets, and counts of transformers, not all of this information was readily available for each utility for each year in the past 12 years. However, customer counts were available and serve as a useful proxy for other network measurements. As of 2011, BGE had roughly 1.25 million customers, while DPL served roughly 200,000. As such, it would be unexpected for the two utilities to have the same number of network technicians.

The Task Force obtained data for utility customer counts from the PSC Electric Choice Enrollment Monthly Reports[38] and the PSC Ten Year Plans.[39] This information was used to develop a standard metric of network technicians per 100,000 customers. This helps remove the impact of relative scale between the utilities and see how their performance no this metric varies over time.

Figure 20 - Network Technicians per 100,000 Customers



While it is difficult to extract too many conclusions about these figures, it can be observed that the total number of available technicians per customer remained flat or decreased from 2000 to 2005, and, with the exception of PE, have been generally increasing since 2006.

As mentioned above, a count of customers is only one of many aspects of a utility's scale. The Task Force also collected information about the distribution assets for BGE, Pepco, and PE. The data is shown below for both absolute figures, per 100,000 customers, and per network technician.

[38] http://webapp.psc.state.md.us/Intranet/CaseNum/submit_new.cfm?DirPath=\\Coldfusion\Electric%20Choice%20Reports\&CaseN=Electric%20Choice%20Enrollment%20Monthly%20Reports

[39] http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm

Table 17 - Distribution Assets of BGE, Pepco and PE

System Components	BGE	Pepco	PE
Transmission Lines	143	121	42
Circuit Miles	1,288	1,009	627
Transmission Substations	74	14	33
Substation Supply Lines	255	108	65
Circuit Miles	1,428	1,827	494
Distribution Substations	195	61	81
Fuses	48,834	18,397	33,375
Distribution Lines	1,295	693	323
Circuit Miles	23,568	8,399	8,581
Reclosers	2,179	109	1,639
Transformers	212,148	76,040	93,962
Customers (2011)	1,242,692	539,048	252,054
Network Technicians (2011)	909	591	132

Table 18 - Distribution Assets of BGE, Pepco, and PE per 100,000 Customers.

	Per 100,000 Customers			Per Network Technician		
System Components	**BGE**	**Pepco**	**PE**	**BGE**	**Pepco**	**PE**
Transmission Lines	12	22	17	0.1	0.2	0.3
Circuit Miles	104	187	249	1.1	2.0	4.8
Transmission Substations	6	3	13	0.1	0.0	0.3
Substation Supply Lines	21	20	26	0.2	0.2	0.5
Circuit Miles	115	339	196	1.2	3.5	3.7
Distribution Substations	16	11	32	0.2	0.1	0.6
Fuses	3,930	3,413	13,241	40.5	35.6	252.8
Distribution Lines	104	129	128	1.1	1.3	2.4
Circuit Miles	1,897	1,558	3,404	19.5	16.3	65.0
Reclosers	175	20	650	1.8	0.2	12.4
Transformers	17,072	14,106	37,279	175.9	147.3	711.8

It should be noted that the nature of each utility's geographic characteristics will to some extent dictate their distribution grid asset mix. For instance, BGE's and Pepco's service territories are on average much more urban than PEs, and thus the relative number of distribution circuit miles per is understandably lower. Further, Pepco's system design has prevented the widespread use of reclosers, thus their substantially lower measure on this metric.

The following chart shows normalized data for each point. That is, the lowest figure of a given metric is assigned a value of 1, and the other utilities are assigned a multiple based on their relative value. This allows comparison across utilities and across system components to be visualized together. The first chart shows the data per 100,000 customers, while the second is per network technician. When data went off the scale, the values are indicated above the bar.

Figure 21 - Distribution Assets of BGE, Pepco, and PE per 100,000 Customers (Normalized)

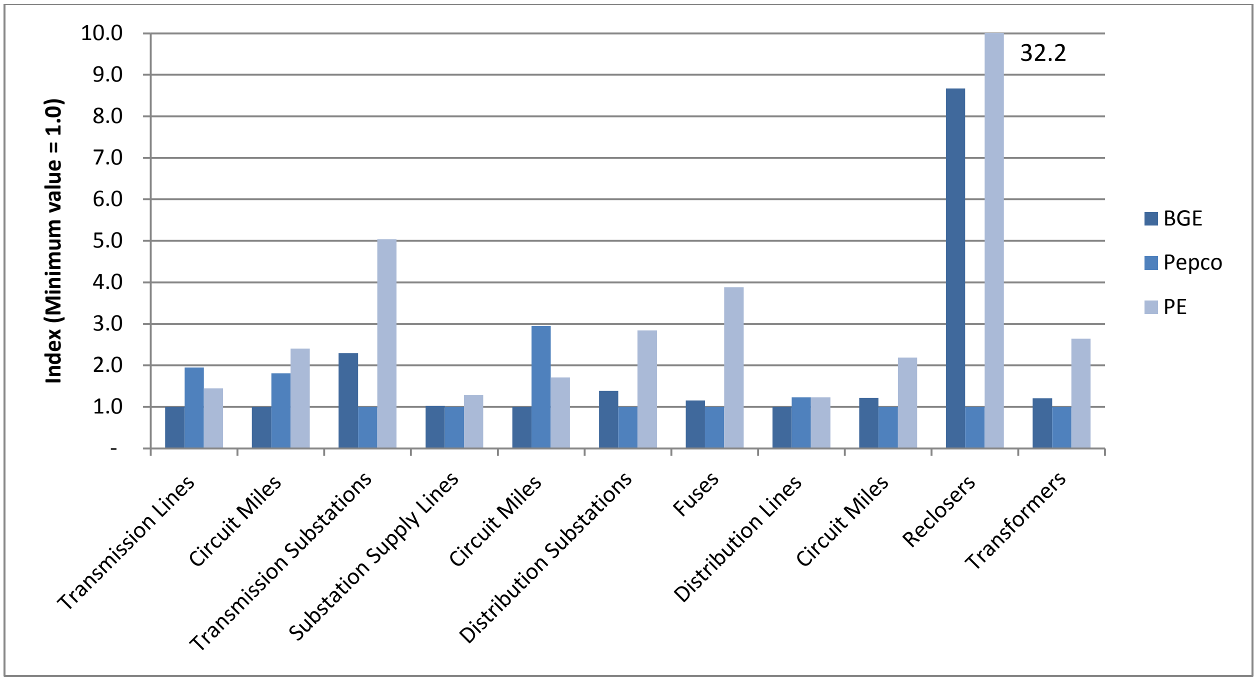
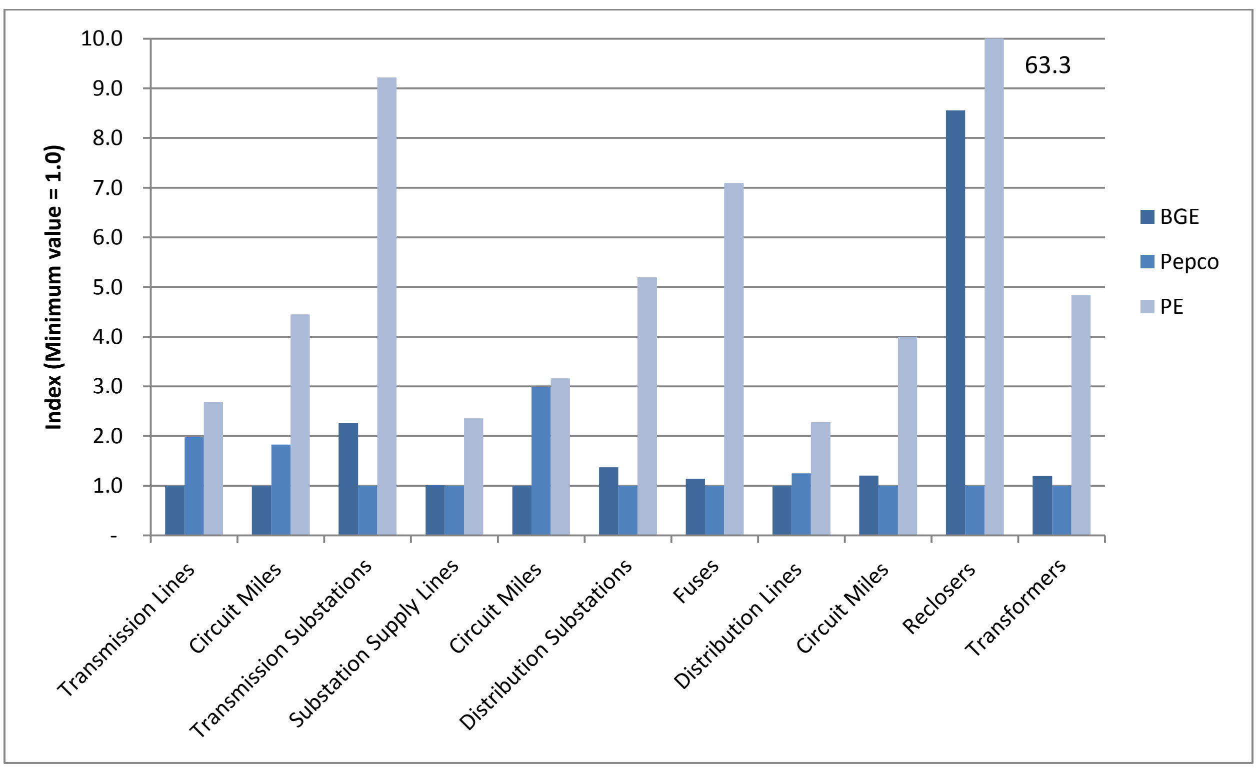


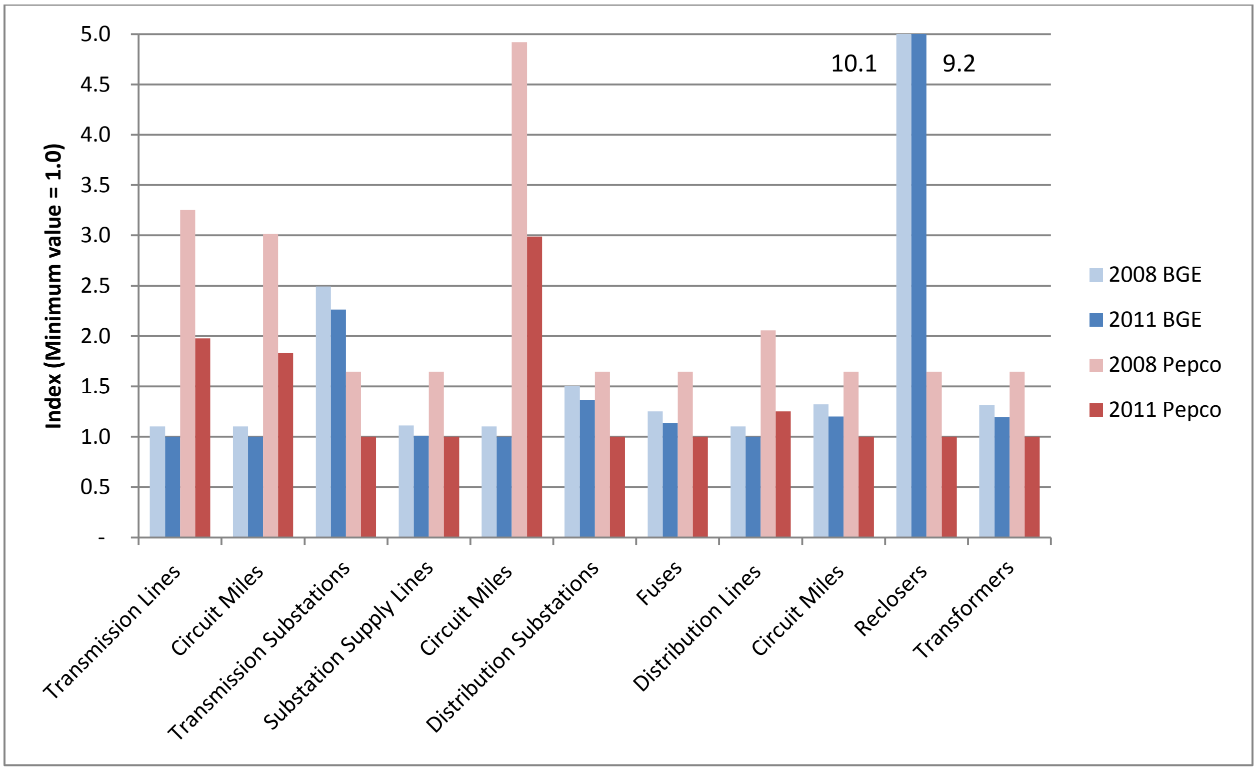
Figure 22 - Distribution Assets of BGE, Pepco, and PE per Network Technician (Normalized)



From these charts, one can observe that PE is relatively more asset heavy per customer and per network technician than BGE or Pepco. Also, BGE and Pepco appear similar when normalizing based on customers or network technicians, with the already mentioned difference in the use of reclosers.

It warrants highlighting that Pepco has increased their network technician levels substantially in the past three years. As shown above in Figures 19 and 20, Pepco substantially trailed BGE in the count of network technicians per 100,000 customers for most of the recent past, but has since then has made available many more contractors. Given the substantial change in the counts of network technicians since 2008, it is instructive to see how these charts have changed relative to recent staffing changes.[40]

Figure 23 - 2008 and 2011 Statistics per Network Tech



When comparing the two systems in 2008, BGE consistently had fewer assets per technician (or conversely, more technicians per asset) than Pepco. While BGE continued to lower their assets per technician between 2008 and 2011, Pepco improved their metrics further. In 2008, Pepco had fewer assets per network tech than BGE in only 2 of the 11 categories above. By 2011, this increased to 7 of the 11.

Although useful for comparative purposes, caution must be taken when trying to extrapolate these results to direct impacts on system reliability. It is clear from the data that Pepco has added more network technicians since 2008, and that they have improved their per network technician statistics more so than BGE and PE since that time frame. However, there are many different characteristics that

[40] Since detailed system component information was not available in 2008, the latest data is used. During this time, BGE and Pepco customer counts increased by 0.9% and 3.7%, respectively.

influence reliability than just quantities of a given asset or counts of staff, such as age of infrastructure and percentages of lines underground. The Task Force views this staffing data as one of many pieces of information that inform the recommendations.

2. Are there sufficient training opportunities for workers?

While the Task Force is not inclined to opine on whether there are sufficient training opportunities for prospective and new utility hires, it notes the BGE training facility that opened last year. According to the company, it puts 120 people through its training program each year.

Following the merger, in 2011 Potomac Edison was able to take advantage of FirstEnergy's Power Systems Institute ("PSI") program. This unique, two-year program combines classroom learning with hands-on training to address workforce development needs. PSI is an academic and skills training program combining an Associate of Applied Science degree in Electric Utility Technology with the skills and experience to perform either Lineworker of Substation Electrician work at the time of hire. There are currently 5 students enrolled in the company's Pierpont Community College partnership school with all five slated to join the Potomac Edison workforce as interns in 2013.

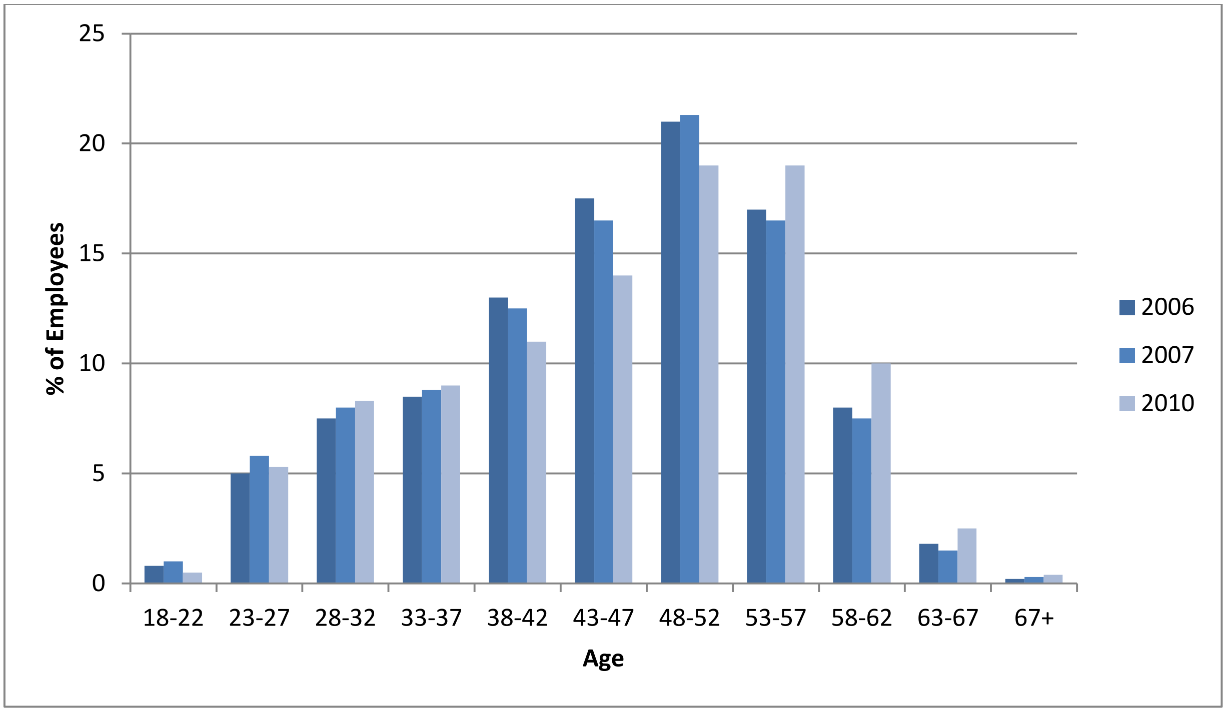
3. Are the utilities adequately preparing for an aging workforce?

The Task Force found that the average age of utility field crews is higher than ever, with many of the most senior crew chiefs and field managers nearing or past retirement age. Given the significant lead time for utility crew training – as long as seven years – utilities may find they are unable to replace their retiring crew members. BGE specifically acknowledged this as an issue, recently opening a training center for new personnel in White Marsh. Both NERC and the Department of Labor ("DOL") have expressed concerns about these staffing trends.[41] As explained by DOL, "[p]erhaps the most complex and pressing challenge facing the energy industry is the retirement of incumbent workers. The average age of workers currently employed in the energy industry is near 50, and the average age at which most workers retire is 55. Within the next 5 to 10 years, may companies will need to replace a huge portion of their workforce."[42]

[41] Are Utility Workforces Prepared for New Demands? Recommendations for State Commission Inquires, NRRI, 3 (2010), *available at* http://www.nrri.org/pubs/multiutility/NRRI_graying_jan10-01.pdf.

[42] U.S. DEP'T OF LABOR, EMPLOYMENT & TRAINING ADMIN., Identifying and Addressing Workforce Challenges in America's Energy Industry 12 (2007), available at www.doleta.gov/BRG/pdf/Energy%20Report_final.pdf

Figure 24 - Age Distribution of Electric and Natural Gas Utilities



Source: 2011 CWED Survey Results

The Task Force also discussed the utilization of mutual assistance crews. As Maryland citizens have witnessed, during any major storm, crews from other jurisdictions come to Maryland to assist with restoration. There were many questions raised during the roundtable discussion regarding the efficiency of this system. In addition to the challenge of procuring crews amidst the numerous other requesting utilities, there were numerous questions about the effectiveness of the visiting crews. Specifically, there were concerns raised about the lack of familiarity of the mutual assistance crews and the way in which they are incorporated into the utility's restoration efforts.

E. Are there process improvements that can improve the effectiveness of Maryland's response to outages?

The Task Force considered whether there could be improvements in the State's emergency preparedness or actions after an emergency that, while not reducing the number of outages, could increase the effectiveness of the response. Many of these evaluations are informed by other efforts that the State has already undertaken to increase the resiliency of our citizenry.

1. What work has already been done in this area?

a) How are Governor O'Malley's Homeland Security Core Goals relevant?

In 2009, the O'Malley Administration developed 12 Homeland Security Core Goals, one of which is to ensure the operation of critical infrastructure in the event of a natural or manmade event. This requires (1) the identification of critical infrastructure and (2) the investment in backup power and communications systems where it is needed. Critical infrastructure can be defined as everything from privately owned gas stations along evacuation routes to Emergency Operations Centers to key traffic signals. Through cooperation between State and local government, and the private sector, Maryland is currently determining the best way to prioritize facilities for energy assurance and emergency generation. A two-part study by the University of Maryland Center for Health and Homeland Security commissioned by the State will first examine how to prioritize broader categories of critical infrastructure, while the second part will examine prioritizing emergency power at specific facilities in Maryland. The first phase is expected to be completed by the end of calendar year 2012.

In many cases, investments are already underway to provide backup power capability to Maryland infrastructure during an outage. The State owns and operates a number of generators with the capacity to sustain shelter sites during a prolonged outage. The State Highway Administration has already installed over 200 uninterrupted power supply systems at key traffic intersections to provide up to eight hours of continuous services and has plans to install hundreds more. The State's Public Safety Intranet provides backup communications, voice over internet protocol ("VoIP") capability, and redundancy to existing systems to ensure that 911 call centers, local emergency operations centers, and key State agencies will be able to communicate even when a primary network is inoperable.

b) What facilities require backup generation?

There exists a matrix of federal and State statutes and regulations that require various facilities to have back-up generation. Generally, these include, among others, hospitals, nursing homes, assisted living facilities, facilities with medically fragile children, and buildings with more than 25 people in occupancy and over four stories.

c) What is the Maryland Energy Assurance Plan?

In July 2012, Maryland released its Energy Assurance plan,[43] a document developed by the Maryland Energy Administration ("MEA"), Maryland Emergency Management Agency ("MEMA"), and the PSC. It is intended to assist with the creation of "a more resilient energy infrastructure that recovers quickly from disruption." Specifically, the Energy Assurance Plan provides a broad overview of the existing energy assurance landscape. It is intended to be a platform for more specific, detailed plans to guide future infrastructure investment and emergency planning by both public and private entities in all aspects of energy, from production to delivery and end use. Currently, it is helping to guide the development of the list of critical infrastructure referenced in the section above regarding Core Capacities.

d) What regulations affect medically vulnerable citizens?

COMAR 20.31.03.01 establishes the procedure by which customers that are seriously ill or rely on medical equipment (requiring electricity) can self-identify to the utility, in order that the utility not be able to terminate their service for lack of payment. However, this list of medically vulnerable citizens is an important piece of information for emergency managers to have, not so that their electrical

[43] The Maryland Energy Assurance Plan may be found online here: http://energy.maryland.gov/energyassurance/documents/MarylandEnergyAssurancePlan.pdf

restoration can be prioritized, but rather so that the emergency managers can ensure their well-being during extended outages.

2. Is there a role for citizens to assist in recovery efforts?

During several roundtable discussions, participants discussed what role citizens can play in assisting the utilities with storm restoration. There was resounding consensus, from utility experts, labor union representatives, and consumer advocates, that placing anyone other than utility linemen anywhere near utility lines was a potentially lethal combination and highly undesirable. The participants did brainstorm, however, about other roles for the citizenry, especially with regard to guarding a downed line, assisting with removal of downed trees, and other tasks.

F. How should infrastructure investments be paid for?

1. Should the PSC continue to use traditional rate making principles?

As discussed above, under traditional ratemaking principles, the PSC conducts a thorough review of a utility's rate base (the used and useful assets in place during the test year), expenses and revenue. The PSC also sets the utility's authorized rate of return ("ROR"), which includes a determination of the utility's return on equity. This analysis determines what the utility's revenue requirement will be, therefore dictating how much of a rate increase (or decrease) is required.

The benefits of traditional ratemaking schemes include the vigorous vetting that the utility's costs and expenses receive from all parties, including consumer advocates; certain costs can be disallowed if the PSC deems them imprudent. The downside, as articulated by utilities, focuses on regulatory lag (i.e., the time between the expenditure and the recovery of an expense), the uncertainty of whether costs will be able to be recovered, and the time and expenses involved in a rate case. During the roundtable discussion on this topic, a representative from an investment bank voiced concerns about what Wall Street perceives to be a "hostile regulatory environment" in Maryland.

2. Should the PSC institute a different cost recovery mechanism?

Roundtable participants discussed various cost recovery mechanisms during their meetings. One option to change the traditional base rate case cost recovery mechanism is to allow a utility to recover reliability costs through a surcharge, sometimes referred to as a "tracker." The PSC has authorized such recovery for the costs expended on the EmPower Maryland program. Under an infrastructure surcharge, for example, if a utility plans to spend $100 million over five years to improve infrastructure, it would be allowed, following an examination of those plans by regulators and other interested parties, to begin recovering the costs from its ratepayers immediately upon its expenditure, rather than waiting until it filed its next rate case. Utilities contend that such recovery is critical because revenues have been and continue to be flat while reliability investments and expenses are increasing dramatically. This places increased demands on their balance sheets which may increase financing costs that customers pay, and makes the currently delayed and uncertain cost recovery more difficult to manage. Opponents of such mechanisms argue that recovery outside of base rate cases reduces public transparency, limits the PSC's ability to conduct a "big picture" rate case prudency review where all of the company's costs, investments and revenues can be reviewed at one time and in the context of one another, and inappropriately shifts the risk to ratepayers from shareholders.

Other options discussed by the panelists were:

1. Formula rates (where rates are set by a formula discussed by the parties and determined by the Commission and trued up – or down – at the end of a predetermined, often yearly, period);

2. Multi-year rate plans (where the parties would discuss and the Commission would determine a schedule of smaller annual rate changes designed to keep the utility in financial health as it makes the reliability investments);

3. Use of projected or forecasted, rather than purely historical, test years; and

4. Use of terminal rate bases (using the rate base as it exists at the end of the test year instead of using the average of the rate base amounts for each month of the test year).

As with the surcharge proposal, utilities argued that these methods reduce regulatory lag and ultimately reduce costs to customers, while consumer advocates argued that these methods can reduce transparency, increase reliance on projections rather than actual historic costs, and place costs on customers without comprehensive regulatory and stakeholder review.

Another method of cost recovery raised during the Task Force's inquiry was securitization. In recent years, securitization has been used as an alternative to rate base recovery for the costs of large well-defined events or projects incurred or undertaken by some utilities. Examples include the costs of storm restoration in the South, environmental costs in the Midwest and stranded costs (associated with electric utility industry restructuring) in the Northeast. Securitization involves the sale of bonds for which the repayment is guaranteed or secured by a dedicated stream of income collected from ratepayers. These bonds are issued by a Special Purpose Entity ("SPE"), rather than the utility, that is established for the specific purpose of financing the designated investments.

In order to make the SPE bankruptcy remote and achieve the highest possible bond ratings (and the lowest possible interest rates), certain requirements must be met. These include: (1) a dedicated stream of funds to be collected from ratepayers (not utility funds) is used to pay the principal and interest on the bonds; (2) the utility can act as the collection agent, but the funds are not comingled with utility funds and are swept daily to a separate trust account; and (3) an irrevocable financing order must be issued by the public service commission which ensures that neither it nor the utility will interfere with or impair the use of the ratepayer funds to pay for the bonds. The primary benefit of securitization is that the bonds historically have received "AAA" (or equivalent) ratings and can be sold for extremely low interest rates. For example, in late 2011, The Louisiana Public Service Commission authorized the securitization of just over $200 million for the recovery of costs of a cancelled electric power generation facility. The bonds were AAA rated and were issued at an interest rate of 2.04%.

If securitization of undergrounding distribution facilities is to be pursued in Maryland, legislation will be required to establish the ability to securitize in order to assure the rating agencies and the investment community that PSC has the authority to establish the irrevocable pledge of ratepayer dollars to repay the bonds. The legislation would need to include a pledge of non-impairment by the State and would establish the purposes for which securitization could be used, i.e., for reliability improvements including the undergrounding of distribution facilities, the installation of looped feeds and other measures as deemed appropriate. Once legislation is passed, securitization could then be used to establish a fund for each utility to draw upon to pay for the improvements on its system. This would require that the PSC issue an irrevocable financing order for each utility that provides a dedicated, broad based, non-by-passable component of each utility's rate for the repayment of the bonds.

As noted previously, the primary benefit of securitization is the ability to finance costs through the use of low interest bonds rather than at the utilities' much higher overall cost of capital. There are, however, potential negative aspects of securitization. These include the fact that the bonds must be paid off over much shorter periods, typically in the range of seven to 12 years instead of over the life of the assets (20 or 30 years), although payments are still lower than costs under traditional rate base/rate of return regulation. In addition, a true-up (or reconciliation) mechanism is required to ensure that the dollars needed to repay the bonds are collected. This results in the possibility of rate increases to recover revenue shortfalls, contrary to the normal prohibition against retroactive ratemaking. Finally, because of the shortened repayment period, there will be a desire to spend proceeds from the securitization bonds over a relatively short period of time to "put the money to work." This will require careful oversight of how the funds are expended to ensure that they are used prudently.

3. Should citizens be permitted to elect and pay for an increased level of reliability?

A familiar theme throughout the roundtable discussions was the recognition that different citizens have different expectations and needs for reliable electrical supply. While there was consensus that, as a society, our demand and reliance on electricity have increased, there was also acknowledgement that needs may vary among the population. For example, an older Marylander who depends on medical equipment is less able to tolerate any interruption in service than a younger person who has no medical needs.

The Task Force explored the question of whether some structure could be devised to allow certain Marylanders the option of paying a premium for a guaranteed higher level of reliability. The group considered different scenarios. One involved communities voting for increased reliability with sharing of money across communities that voted for upgraded service.

There was unanimity amongst both the Task Force and the invited experts that such a model was inequitable and unworkable. There was recognition, however, that customers could choose to purchase products that ensure electricity, even if the distribution grid fails. For examples, microgrids, IDG, and backup generators are options available to those customers.

4. How should the costs of infrastructure investments be allocated among customers?

Because undergrounding distribution facilities, installing looped feeds and other measures designed to improve reliability often involve significant incremental costs, the question arises as to who should pay for those costs. That is, should the costs be borne by all customers of the utility or only those customers that directly benefit from the undergrounding or other reliability improvement measures? This question can be evaluated in the broad context of traditional ratemaking and in the narrower context of the equity issues associated with the cost coverage of improving service reliability.

Normal ratemaking practice is that a utility's overall costs are shared by all customers based on the service received. For electric distribution utilities, cost differentiation among different customer (or rate) classes is made based on voltage levels, peak demands compared to average usage, etc. However, accepted ratemaking practice is to recover costs within customer or rate classes without regard to location or other differences in the facilities necessary to provide service to similar customers. For example, a residential customer of a given utility that is located near a generation facility is not charged less than a residential customer further away even though more transmission facilities are required to serve the more distant customer. Similarly, a small commercial customer of a utility in an urban area is not charged a different rate than similar distribution customers in suburban or rural areas even though the facilities necessary to deliver each customer's power could be quite different. Hence, it would seem appropriate that costs of undergrounding or other measures necessary to provide reliable service should be shared by all customers.

Recovery from all customers of the costs of undergrounding distribution lines (or other measures) in order to ensure reliable service is also justified based on equity and other considerations.[44] First, all customers are entitled to safe and reliable service. If undergrounding is required to provide that service, the additional costs compared to overhead distribution lines should not be treated differently than other incremental costs required to serve some customers based on location or other factors. Second, undergrounding distribution facilities reduces storm restoration costs, which is a benefit to all customers because storm restoration costs are normally recovered from all customers. Third, customers whose facilities are not undergrounded benefit in the form of reduced storm outage restoration times because available resources are not required to the same extent in areas where undergrounding has taken place. Fourth, if undergrounding costs are collected only from the customers whose facilities are directly affected, then an argument can be made that those customers should not be required to pay the tree trimming, line clearance, other maintenance, and storm restoration costs associated with the overhead lines that serve other customers. Attempting to differentiate cost responsibility based on the type of distribution facility utilized to provide reliable service would be burdensome to the utilities. Finally, Maryland law prohibits utilities from setting discriminatory rates. Maryland Public Utility Companies Article § 4-503 provides that utilities may not "charge, demand, or receive from a person compensation

[44] The reference to the installation of underground distribution facilities in order to provide reliable service is distinct from circumstances where reliable service can be provided by overhead distribution lines but customers demand underground facilities for aesthetic or other reasons.

that is greater or less than from any other person under substantially similar circumstances."[45] It also prohibits utilities from "discriminat[ing] against a person, locality, or particular class of services."[46]

[45] Section 4-503(b)(1) 5-201, Public Utility Companies Article, Annotated Code of Maryland.
[46] § 4-503(b)(3).

VI. Task Force Recommendations

The Task Force spent a great deal of time before, during, and after the roundtable discussions, considering the various ways in which the electric distribution system in Maryland can be hardened. The group considered technology solutions, infrastructure investments, regulatory changes, and process improvements.

A. Introduction

1. What are the principles guiding these recommendations?

As a result of the process, several themes emerged which ultimately guided the Task Force's recommendations. First, the group heard from elected officials, consumer advocates and citizens: Marylanders demand reliable electric service. This reliable service is critical not only for our citizens' comfort, but for the health, safety, and economic welfare of our residents. The underpinnings of a modern economy are dependent on a reliable energy supply: waste water treatment plants, hospitals, traffic signals, modes of mass transit, and refrigeration all depend on electricity. It is nearly impossible to overemphasize how ubiquitous and critical electricity has become in ensuring the health, safety, and wellbeing of Maryland's citizenry.

With that in mind, the Task Force established several foundational principles that guided its recommendations:

- The current level of reliability and resiliency during major storms is not acceptable.
- Increased reliability and resiliency during major storms is the goal of the Task Force and will inform its recommendations.
- Severe weather events resulting from climate change are likely to continue to occur. It is unacceptable for anyone involved in response efforts to continue to be surprised by the "worst storm" the system or the State has ever seen. Utilities, government and citizens must be prepared for severe weather events.
- If done strategically and appropriately, increased expenditures by the utilities to improve resiliency and harden the gird – to literally ensure that the electric distribution system can weather the storm – will lead to fewer outages during storms and shorter outages when interruptions happen

With these foundational principles in mind, the Task Force turned to another theme that emerged during many of the roundtable discussions, namely, whether utilities were properly incented to make the requisite infrastructure investments needed to ensure reliable service. Some experts questioned the very construct of the regulatory compact: does the grant of monopoly power take away the incentive to innovate? Does it misalign the objectives between distribution utility and customer? Others questioned whether the current cost recovery mechanisms are adequate. Should the utilities be permitted to recover their capital expenditures in a more contemporaneous manner or would such a recovery scheme circumvent the careful and holistic prudence review currently offered by a rate case? Are utilities being properly incented to improve reliability? Are there adequate incentives and penalties available to align the desires of customers for improved reliability with the interests of utilities?

With the foundational principles in mind, the Task Force developed a cohesive set of specific recommendations as well as an implementation strategy that maximizes the impact of its recommendations. While some may call attention to certain of the Task Force's recommendations, it is critical to understand that they work best as a unified strategy. The coordinated implementation of the recommendations is as important as the recommendations themselves; if rolled out in an "*a la carte*" manner, they may not produce the expected results.

2. What are the recommendations of the Task Force?

In light of the Executive Order's charge, the Task Force thought seriously about whether to be proscriptive regarding what infrastructure the utilities should invest in to meet the State's reliability and resiliency metrics, be it at the levels currently outlined in RM43, with the additional metrics proposed for RM43, or on the expedited timetable recommended herein. After careful thought, the Task Force determined that it would not recommend specific infrastructure improvements. Rather, the Task Force made recommendations that are informed by the foundational principles, guided by the data, and intended to be implemented in a cohesive manner. If followed, the recommendations will logically lead to certain infrastructure investments. This likely will include targeted undergrounding and aggressive tree trimming, as well as improvements in areas that have suffered from repeated outages during storms. In the end, the Task Force created a methodology that would drive investment decisions rather than create a list of improvements to complete.

With regard to the various cost recovery proposals, the Task Force will offer one specific proposal regarding cost recovery relevant to hardening the grid and recommend that the PSC implement a ratemaking mechanism that offers both rewards and penalties based on a utility's ability to meet reliability metrics. As for the broader cost recovery questions, while well informed, especially after this process, the Task Force is not inclined to offer a blanket endorsement or rejection of these questions regarding cost recovery in all contexts.

The following list is a set of specific technology, infrastructure, regulatory, and process recommendations to improve the resiliency of Maryland's distribution grid. They are discussed in more detail in the pages that follow.

1. Improve RM43's Reliability and Reporting Requirements
2. Accelerate RM43's March Toward Reliability
3. Allow a Tracker Cost Recovery Mechanism for Accelerated and Incremental Investments
4. Implement a Ratemaking Structure that Aligns Customer and Utility Incentives by Rewarding Reliability that Exceeds Established Reliability Metrics and Penalizes Failure to Reach Those Metrics

5. Perform Joint Exercises Between State and Utilities
6. Facilitate Exchange of Information Between Utilities, State Agencies, and Emergency Management Agencies
7. Establish and Maintain List of Special Needs Customers
8. Streamline State-Wide Vegetation Management Regulations and Practices Beyond RM43
9. Determine Cost-Effective Level of Investment in Resiliency
10. Study Staffing Pressures Due to Graying of Workforce
11. Task the Energy Future Coalition with Developing a Pilot Proposal

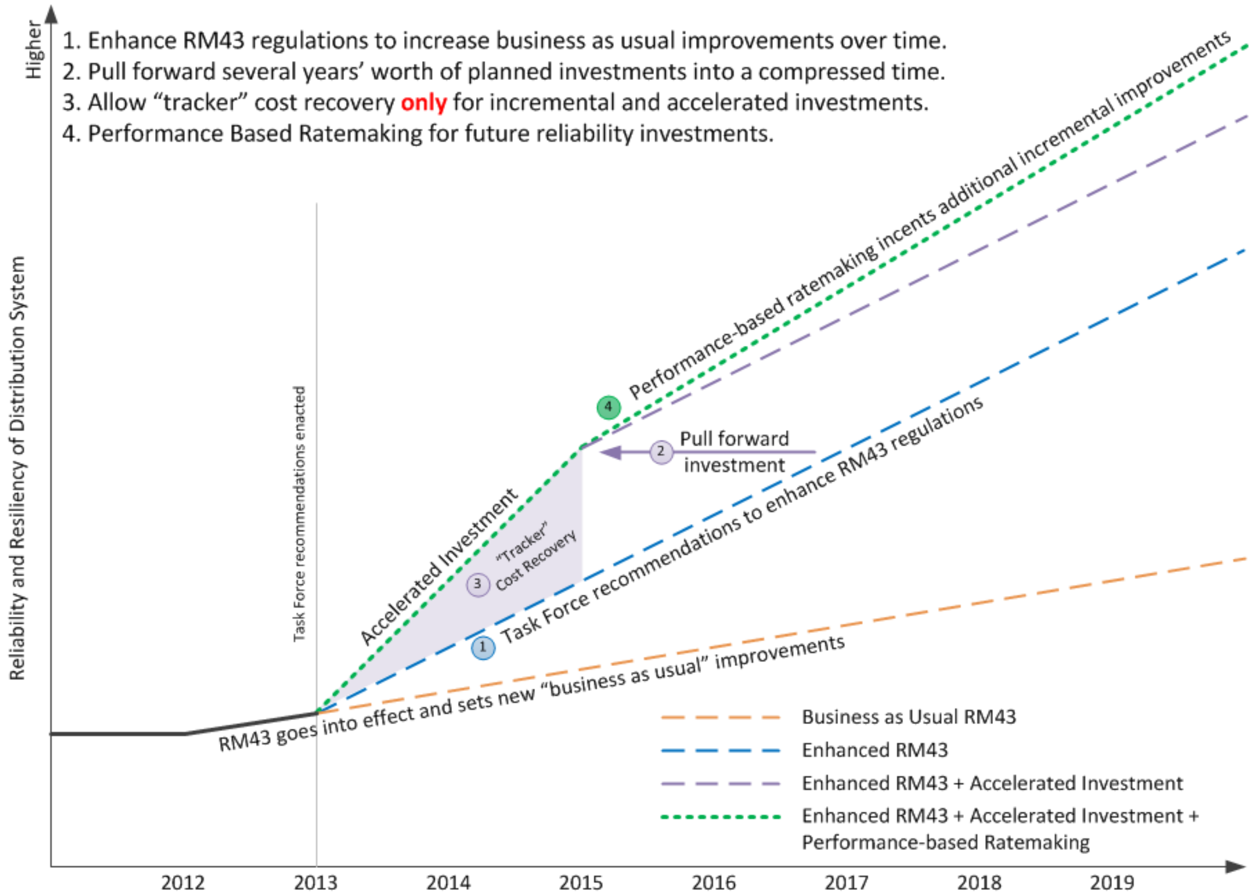
3. How should these recommendations be implemented to maximize the effectiveness of investments and improvement in reliability?

Along with the set of recommendations, the Task Force developed a coordinated implementation strategy. Recognizing the legislation passed by the General Assembly, as well as the months of work necessary to create the RM43 regulations, this implementation strategy builds upon, and does not supplant, the work that has already been done. The Task Force recommendations are meant to operate within, rather than apart from, the analytic structure mandated by the legislature and adopted by the PSC.

Although each recommendation could work alone, the potential for significant improvement to resiliency would be diminished. This is particularly true for the first four recommendations, which were specifically crafted to work together to accelerate resiliency improvements and provide Marylanders with a tangible benefit in a short period of time.

The following chart is an illustrative example of reliability improvements that may be realized under a joint rollout of recommendations. Please note that the scale and timing of the improvements are not intended to be exact. The Task Force stresses the synergistic aspect of these recommendations and feels that the best way to improve resiliency in both the near term and long term is to enact all the findings in a cohesive and coordinated manner.

Figure 25 - Task Force Recommendation Framework



B. Recommendation #1: Improve RM43's Reliability and Reporting Requirements

The PSC's changes to COMAR pursuant to RM43 constitute a significant and important step towards improving the Commission's ability to monitor the quality and reliability of service provided by the electric distribution companies. However, the Task Force believes that there is opportunity to strengthen the regulations in order to address both major event (i.e., storm) and "blue sky" outages, as well as improve the quality and uniformity of the data gathered by these standards. The improvements suggested below may require additional changes to COMAR and will require the active involvement of the distribution utilities in order to implement them.

1. Require System Wide Reliability Standards for Data Including Major Outage Events

Most of the focus of this Task Force has been on major event outages and their impact on Maryland's citizens and businesses. While "blue sky" outages certainly cause inconvenience and annoyance, sustained outages present different challenges. Food may last in a refrigerator for a day or two, but beyond that it will have to be discarded. Spending one afternoon without air conditioning on a hot summer day may be tolerable, but going without power for four or five consecutive days results in cumulative impacts on health and well-being.

Currently, while RM43 requires utilities to calculate CAIDI, SAIDI, and SAIFI metrics that include major storm outages, reliability standards are only set for SAIFI and SAIDI data that excludes major outage events.[47] The Task Force recommends that additional reliability standards be developed that include major outage events, in order to hold utilities accountable for restoration after major events as well as during normal operations. While the metrics involved in non-storm related outages are important when assessing reliability (especially on blue sky days), the metrics of major storm related outages are also critical in understanding and evaluating utility performance.

Specifically, COMAR 20.50.12.02(D) should be amended to limit the number of major storms excluded from the utilities' compliance with system-wide reliability standards. As currently written, COMAR's system-wide reliability standards allow utilities to exclude major outage event interruptions without limit to the number of days this may represent. This should be amended to include a limit on the number of days that are allowed for exclusion. Due to the potential variation in the number and severity of major outage events, it may be appropriate to mitigate the impact of major outage event data on the metrics. One approach may be to allow utilities to exclude the first 24-48 hours of each major outage event from the metrics. Another approach may be to apply weights to major outage event data, such as a 50% discount for the first 24 hours and a 25% discount for the next 24 hours, with no discounts beyond 48 hours. The exact methodology could be determined by the PSC during the regulatory process.

2. Adjust Poorest Performing Feeder Standard

The current RM43 regulations (COMAR 20.50.12.03) require the utilities to produce an annual list of the worst performing 3% of feeders (or distribution lines) with and without major outage event data. According to the PSC, if those two lists are different, then the utility should compile one list for remediation that contains the lowest 3% overall. The regulations provide that after allowing for one year to perform mitigation, the feeder cannot reappear on the list for two years. If the bottom 3% of feeders were moved to the top of the list each year, and assuming there were no repeats, it would take approximately 33 years for a utility to cycle each feeder through this upgrade process.

The Task Force is troubled that there is not a more targeted approach to responding to feeders that perform poorly during major storms, as well as those that perform poorly during blue sky days. Accordingly, the Task Force recommends that COMAR 20.50.12.03 be modified to require that the feeders targeted for remediation be expanded to 4.5%, from the current 3%, in the following way. First, the utilities would continue to develop the two separate lists: the 3% poorest performing feeders with

[47] The regulation actually refers to a "Major Event Day," defined as any day during which more than 10% or 100,000, whichever is less, of the electric utility's Maryland customers experience a sustained interruption of electric service and restoration of electric service to any of these customers takes more than 24 hours. COMAR 20.50.01.03(27). It also includes situations where "[t]he federal, State, or local government declares an official State of emergency in the utility's service territory and the emergency involves interruption of electric service." *Id.*

and without major event data. Utilities would then take the 3% list that includes major event data and add in the worst performing feeders from the blue sky list based on the methodology reported in the utility's annual report until the combined remediation list contains 4.5% of the feeders in the utility's system. Accordingly, the total number of feeders each year targeted for improvement would increase 50% over the current standard. This would also ensure that the remediation efforts first focus on feeders associated with storm outages, while adding in substantial effort to improve blue sky outages as well. Recalling back to the maps in Section IV.A.2, it is likely that those feeder lines in orange and red, which have lost power repeatedly over the past few weather events, will be among the first to be addressed under this revised regulation.

In order to maximize the utilization of resources, the Task Force also recommends limiting the number of feeders from a single substation that appear on the poorest performing feeder list to 150% of the specific utility's average number of feeders per substation. Data reported by the utilities show that distribution substations feed, on average, between 4 and 11 feeders, depending on the service territory. (Population dense areas have more feeders per substation; more rural areas less.) Based on outage information reported by the utilities, it appears that multiple feeder outages may result from problems originating at the substation. Therefore, fixing a problem at a substation may remedy multiple feeders. While this is an important and cost-efficient result, it also may not utilize all of the resources a utility could devote to improving resiliency. For example, Pepco must fix 32 feeders under an updated 4.5% worst performing rule. Based on their system average, these feeders would be serviced by 3 substations, but in actuality they could be serviced by as few as 1 and as many as 7. Given that Pepco must be staffed to service the least dense scenario, they could be underutilizing their resources if they are only servicing 1 or 2 substations. If RM43 were to allow feeders from a given substation to only contribute to 150% of the utility's average number of feeders per substation, the regulations would enable better utilization of the utility's resources and allow more lines to be improved in a given year.

3. Simplified Major Outage Event Reporting

The Task Force recommends that the Major Outage Event Reports, as currently required by COMAR 20.50.07.07, be amended to provide more relevant detail. Specifically, the reports do not contain sufficient granularity to observe differences in the number and duration of interruptions across different types of systems (overhead/underground) and load densities (urban/suburban/rural) to allow regulators or other interested parties to make specific recommendations regarding hardening systems, improving operational flexibility, or reducing restoration times.

COMAR should be amended to require the utilities to file a succinct report that the public can understand.

Such a report, which could be called "The Days Out Report" ("DOR") would be filed by a utility within 10 days of all events declared by the PSC. It would report in a PSC specified format:

- Number of customers without service per zip code for 1 day, for 2 days, for 3 days, etc.

- Number of full-time utility employees on duty in specified restoration job definitions 1 day after event commenced, 2 days after event commenced, etc.
- Same as 2 but for part-time employees, contract personnel and mutual assistance personnel, separately reported
- Utility's estimate of the total restoration costs and broken down into a limited number of PSC specified categories.

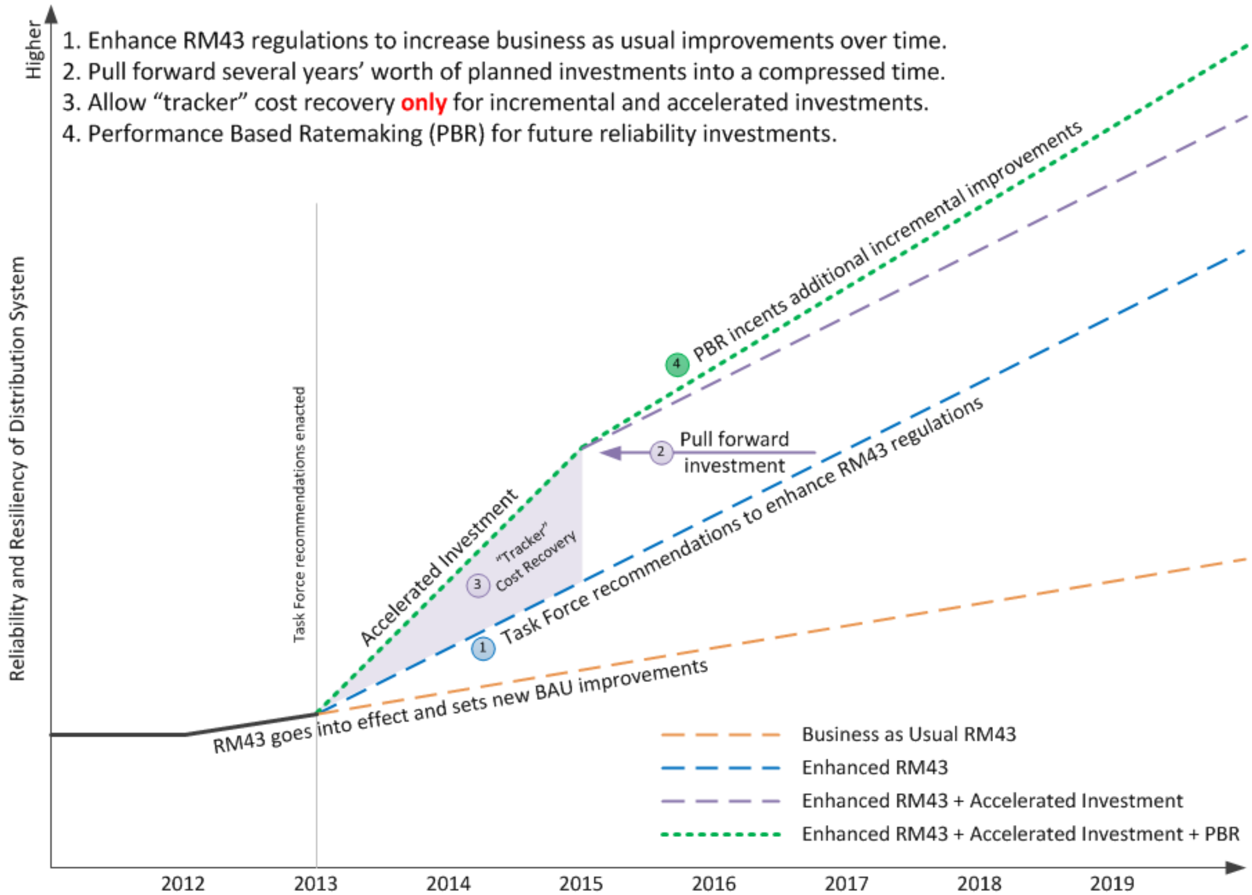
This basic information would allow simple comparison across service territories, and ensure transparency for the public regarding outage and restoration information.

C. Recommendation #2: Accelerate RM43's March Towards Reliability

Pursuant to RM43, the PSC set reliability metrics for six of Maryland's utilities, namely, BGE, Pepco, Delmarva Power & Light, Potomac Edison, SMECO, and Choptank Electric. The goal of these metrics is to move Maryland's utilities to the first quartile of reliability among its utility peers in other states. These metrics are currently established through 2015 and may be recalculated at that point.

As discussed throughout this Report, these regulations represent an important and critical step in the right direction. Enhancements to the regulations are recommended above, with the expectation of additional annual increases in resiliency. While the Task Force appreciates that a systemic change in the design and functioning of the distribution system is years in the making, Recommendation #2 asks the utilities to temporarily go above and beyond their requirements under RM43 in order to jumpstart the improvements and enable Marylanders to see real results in a compressed time frame such as the next two years. The Task Force recognizes that certain types of investment, such as tree trimming, will be more easily accelerated than heavy infrastructure improvements such as undergrounding distribution supply lines. Nonetheless, accelerated progress on some of Maryland's worse performing feeders has the potential to make a meaningful difference both in actual interruptions and customer confidence.

Figure 26 - Task Force Recommendation Framework



Scale and timing of improvements are illustrative only

As seen above in Figure 26, the Task Force recommends accelerating several years' worth of resiliency investments into a condensed timeframe in order to begin providing Marylanders with more reliable service, both in blue sky and major storm outages. While the enhanced RM43 regulations pursuant to Recommendation #1 would require the worst 4.5% of feeders to be improved each year, under the proposed accelerated schedule, the worst 18% would be remediated in the first 24 months, rather than four years. The accelerated time frame would not be limited to the poorest performing feeders. Rather, as discussed in this Report, the Task Force notes the power of vegetation management to increase the resiliency of the grid. Therefore, utilities should embrace an accelerated tree trimming schedule. Additionally, depending on which trimming cycle the utility has elected, the current vegetation management regulations require between 75% and 100% of trees to have been trimmed after four years. These targets could also be accelerated to 24 months. (The Task Force understands that Pepco has already made the commitment to conduct the first round of tree trimming by the end of 2012.)

By putting more resources on the ground than is required even by the enhanced RM43 regulations, a corresponding increase in near-term reliability and resiliency is likely to be realized. Correspondingly, the PSC should simultaneously adjust the system wide reliability standards to match the increased investment. For example, if the utilities were to pull forward four years' worth of investment into the first two years, it would follow that they should be targeting the reliability standards of the fourth year rather than the second. If the timing follows the illustrative example in Figure 26, this means that by 2015, the utilities should be hitting 2017 reliability targets. In their current form, the RM43 regulations require the PSC to set reliability standards beyond 2015, but allow the option of holding them constant at their 2015 levels. To prevent the head start on reliability from flagging after the initial accelerated investment is completed, the Task Force recommends that the PSC revisiting the timing and level of the reliability standards to ensure continued improvement is required from the utilities.

In light of the Executive Order's charge, the Task Force thought seriously about whether or not to be proscriptive regarding what infrastructure the utilities should invest in to meet the reliability and resiliency metrics, be it at the levels currently outlined in RM43, with the additional metrics proposed for RM43, or on the expedited timetable recommended herein.

After careful thought, the Task Force determined that it would not recommend specific infrastructure improvements, nor would it recommend specific locations for infrastructure improvements. Rather, in the context of the data provided by the utilities, it would answer the questions posed by the Executive Order.

With regard to the first charge, the Task Force finds that selective undergrounding is an effective way to harden the distribution grid. The data reveals that underground lines – be they substation supply lines or distribution lines – lost power much less frequently during the three recent storm events than lines that were either entirely overhead or mixed. If the regulations change, such that utilities have to address poorest performing feeders during major events, it is likely that some of those distribution lines are troubled because the substation that feeds it is losing power. And, as the data shows, it's not actually the substations that are having problems (no substations had malfunctions in the BGE and Pepco service territories during any of the three storms), but the substation supply lines feeding the substation that are losing power. Therefore, the Task Force notes that any selective undergrounding or hardening scheme should give high priority to substation supply lines. While there are relatively few substation supply lines, they accounted for 18% of the system interruptions in the three storms that the Task Force evaluated. Tables 19 and 20 show that on a per circuit mile basis, substation supply lines going out of service accounted for significantly more customer interruptions than distribution lines going out of service. In other words, a utility can prevent more customer outages per circuit mile by undergrounding substation supply lines than any other type of line. This is true even if fuses and recloser interruptions are included in the comparison.

Table 19 - Getting power from transmission substations and distribution substations

	BGE	Pepco	Potomac Edison
Substation Supply Lines	253	97	65
Circuit miles	1,428	1,827	494
Cumulative interruptions three storms	183,050	387,882	24,217
Cumulative customer interruptions per circuit mile	128.19	212.31	49.02

Table 20 - Getting power from distribution substations to customers

	BGE	Pepco	Potomac Edison
Distribution Lines	1,295	693	323
Circuit miles	23,568	8,399	8,581
Cumulative interruptions three storms	381,624	1,071,051	64,608
Cumulative customer interruptions per circuit mile	16.19	127.52	7.53
Cumulative customer interruptions including fuses and reclosers	1,435,201	1,201,127	96,598
Cumulative customer interruptions including fuses and reclosers per circuit mile	60.90	143.01	11.26

While affecting fewer customers, the Task Force also notes that undergrounding of the three-phased distribution feeders should be considered in any hardening of the distribution system; particular focus should be given to those lines that have gone out multiple times in various storms. The maps produced in Section IV illustrate where those are. It is anticipated that by adopting Recommendation #1 and #2 herein, those lines will be given priority for infrastructure investments.

The second charge of the Executive Order was to evaluate other infrastructure investments that could affect the resiliency of the distribution grid. While there are certainly other infrastructure investments that can and are being made to improve reliability and resiliency, namely, the addition of reclosers, increased use of sectionalization, and automated sensors, to name a few, the Task Force has determined that the most effective manner of increasing the resiliency of the grid is not additional infrastructure, but rather aggressive tree trimming. The experts at the roundtable discussion agreed that vegetation management is critical to weathering a storm; if the branches don't fall, the lines don't break. Similarly, during the investigation into Pepco's reliability issues last year, the PSC and its consultant opined that that an aggressive tree trimming program would have a major impact on reliability. Therefore, Recommendation #2 recognizes this reality, by encouraging the acceleration of the tree trimming schedule. Recommendation #8 described below also recognizes the importance of the vegetation management scheme, by seeking to streamline and simplify the statutes and regulations regarding tree management in Maryland.

D. Recommendation #3: Allow a Tracker Cost Recovery Mechanism for Accelerated and Incremental Investments

The third charge of the Executive Order was to consider the appropriate cost recovery mechanisms for resiliency improvements. Clearly, asking the utilities to exceed their regulatory requirements will come with additional costs. Staffing will have to be increased and capital expenditures will be performed sooner than otherwise anticipated. In order to prevent undue financial pressure on the utilities, the Task Force recommends that the PSC authorize contemporaneous cost recovery through a tracker-like mechanism **exclusively for these accelerated and incremental investments and expenses.**

In the worst feeder example above, the enhanced RM43 regulations would expect that 9% of feeder lines would be remediated in the first 24 months after the updates went into effect. The acceleration asks utilities to do 18% instead. A tracker could be used for the incremental 9% that is above and beyond the standard, but not for the 9% that would be completed under a business as usual scenario. In order to prevent any adverse selection pressures, the PSC should set the tracker to recover the prorated costs of the entire 18% of improvements performed by the utility, rather than on the specific costs of the incremental improvements the utility performed for the 9%.

A similar calculation could be performed for the vegetation management improvements. Under the accelerated schedule, 24 months into the program utilities would be expected to have trimmed 100% and 75% of their miles under the original 4 and 5 year trim cycle, respectively. Advancing the schedule would allow tracker recovery for the incremental 60% (100% - 40%) and 43% (75% - 32%) worth of expenses for the 4 and 5 year trim cycle, respectively. Again, costs associated with meeting the standards of the enhanced RM43 regulations could not be recovered through the tracker mechanism. While the Task Force understands that Pepco has already made this commitment to conduct its first round of tree trimming in two years (by the end of 2012) the Task Force believes it is an important recommendation for the other utilities.

While the cost calculations contained in this Report for undergrounding are estimates, any tracker recovery mechanism must include significant oversight and approval by the PSC, as well as review and input from consumer advocacy groups, including the Office of People's Counsel, prior to initiation of the tracker; the utility would have to project, with some degree of certainty, the costs of the various resiliency measures to be undertaken in advance of PSC approval of the plan. In this way, there would be transparency surrounding the process, as well as oversight on the costs to be collected from ratepayers.

As evidenced by Pepco's movement on vegetation management, utility efforts to improve resiliency have not abated either before or during this inquiry. Rather, various utilities are actively engaged in reliability and resiliency planning. For example, Pepco announced a five-year Reliability Enhancement Plan in August 2010; the plan is reviewed annually and currently runs through 2016. Funding was initially set at $256.3 million for planned reliability spending during the period 2011—2015. The current total five year plan for the period 2012–2016 has been increased to $542.4 million, which includes vegetation management and other REP initiatives. Some of these costs have already been approved during Pepco's most recent rate case. BGE is also actively engaged in reliability enhancement; it's most well-known recent effort may be Bowie, where the company's Customer Reliability Support organization implemented a series of measures to address reliability concerns, including tree trimming, distribution automation, selective undergrounding, and using open wire construction.

E. Recommendation #4: Implement a Ratemaking Structure that Aligns Customer and Utility Incentives by Rewarding Reliability that Exceeds Established Reliability Metrics and Penalizes Failure to Reach Those Metrics

While Recommendation #3 addresses one aspect of cost recovery, the Task Force also recommends that the PSC implement a ratemaking structure whereby the utility is penalized on its return on equity for failing to meet identified reliability metrics. Similarly, if the utility exceeds these metrics, it would be entitled to an increase in its return on equity. Such an incentive regime, if properly structured, has the potential to clearly align the motivation of the utility and its customers. Under such a rubric, the lenses through which a utility makes resource allocation decisions could be altered, with increased reliability rising to the top of the competing list of capital expenditure priorities.

Additionally, the Task Force believes that the citizens of Maryland would welcome a more transparent methodology that delivers sanctions to a utility's earnings if it fails to provide reliable electric service. The Task Force also believes that Marylanders would understand that if a utility did not just meet, but actually exceeded, specific targets for reliability, the utility would receive a small bonus.

There have been some examples of this type of ratemaking structure, including in California for the San Diego Gas and Electric Company ("SDG&E").

Table 21 - Example of a Performance Based Ratemaking (PBR) Structure from SDG&E (1999-2002)

Performance Area	*Indicator*	*Benchmark*	*Dead-band*	*Live-band*	*Unit of Change*	*Incentive Per Unit ($'000)*	*Maximum Incentive ($m)*
Safety	OSHA	8.80	±0.20	±1.20	0.01	25	±3
Reliability	SAIDI	52 min	0	±15	1.00	250	±3.75
	SAIFI	.90 outages/year	0	±0.15	0.01	250	±3.75
	MAIFI	1.28 outages/yr	0	±0.30	0.015	50	±1
Customer Satisfaction	Very Satisfied	92.5%	±0.5%	±2.0%	0.1%	75	±1.5
Call Center Response	Answered in 60 secs	80%	0	±15%	0.1%	10	±1.5

The Task Force appreciates that the success of such a program will depend on the creation of the appropriate metrics; it suggests, however, that the metrics already established by RM43 provide a natural starting point for this process. Other metrics, such as safety and customer satisfaction, could be included in the appropriate metrics.

The Task Force also considered other modifications to the traditional rate making structure and suggests that the PSC consider forward looking test years when faced with significant, projected capital expenditures.

F. Recommendation #5: Perform Joint Exercises Between the State and Utilities

Building upon the robust emergency response plans filed pursuant to COMAR 20.50.12.13, the Task Force recommends that the utilities provide copies of their emergency response plans to State and local Emergency Management Agencies ("EMAs") and that they run a joint annual exercise with EMAs and other pertinent State and local government entities. Throughout the roundtables, the parties consistently emphasized the need for collaboration, information sharing, and relationship building between various parties, with special emphasis on that between the local EMA and its utility.

Reviewing the utilities' plans will help EMAs gain a strategic understanding of the utilities' priorities and decision-making processes which will allow EMAs to better aid the utilities in recovery efforts. Implementing the plans through joint exercises with EMAs, local and State law enforcement, DOT, local public works, military and local fire departments will measure the plans' efficiency and effectiveness at various levels (table-top, functional, full-scale). MEMA will be the agency responsible for designing and managing the annual exercise in which all utilities participate together to simulate a widespread, multi-service territory outage. Funding for the training will be split between the utilities in proportion to their customer base. Post exercise Corrective Action Plans ("CAP") should then be developed and implemented prior to any real-world events. The CAPs should likewise be tested and evaluated as the process progresses.

The Task Force recognizes these emergency management processes can be improved with more collaboration between the utilities and State and local government. The above recommendations will lead to improved situational awareness that will help all concerned identify, prioritize, and respond to customer needs. Establishing a dialogue prior to a disaster will increase the comfort level of decision-makers. Understanding and familiarity with the planning and response processes of all parties will provide for a safe, rapid, organized, and prioritized response.

MEMA is currently engaged in creating a Business Operations Center ("BOC") that will be housed in the State Emergency Operations Center ("SEOC") in Reisterstown. The BOC will include utility companies as well as other industry and commercial stakeholders, and is focused on improving coordination and communication between government and private sectors before and during emergency events. The BOC can be a useful organizing forum to pull together and engage with the utilities to implement the abovementioned recommendations.

G. Recommendation #6: Facilitate Information Sharing Between Utilities, State Agencies, and Emergency Management Agencies

During the roundtables, the Task Force identified numerous opportunities for additional information sharing between the utilities and various State agencies. The purpose of this shared information would be to increase the resiliency of the State's response, i.e., to better prepare the State for an extended outage and to ensure maximum information provided during an emergency, so that the State's response is as robust as possible.

1. Customer Outage Information During Emergency

During the Derecho and subsequent heat emergency, the health and safety of those citizens who remained without power during extreme temperatures was a priority for emergency responders. Emergency managers had volunteers and manpower ready to conduct wellness checks on those citizens. Despite requests for customer outage information, the utilities initially refused to provide this data. Following the storm, the executives from the largest jurisdictions across the State raised this issue with the PSC. This concern was also raised during the roundtable discussions.

The Task Force understands that there is a difference of opinion among the various utilities regarding whether or not this disclosure of information is prohibited by law. One utility has concluded that there is no federal or State statute that prevents the disclosure. Another points to Section 7-505(a)(6) of the Public Utilities Article, whereby "[t]he Commission shall issue orders or regulations to prevent an electric company .... from disclosing a retail electric customer's billing, payment and credit information without the retail electric customer's consent, except as allowed by the Commission for bill collection or credit rating reporting purposes." That company also points to COMAR 20.40.02.01B.(5), "[e]xcept with the informed consent of the customer and in compliance with the Commission's consumer protection regulations, a utility may not disclose any customer-specific information obtained in connection with the provision of regulated utility service."

Without making a determination on the legality of the disclosure, the Task Force recommends that this ambiguity be clarified, either by the issuance of a regulation from the PSC or a piece of legislation clarifying that disclosure to specified EMAs during a Major Outage Event does not constitute a violation of any relevant PSC statutes or regulations.

2. Data Exchange

The Task Force recommends that the utilities and the State cooperate to exchange data to facilitate responses to emergencies. This opportunity for data flow is facilitated by the availability of smart meters. For example, where smart meters exist, State and local governments should provide a list of facilities they would like to monitor to utilities. In addition to buildings owned by the government agency, the list could include critical infrastructure and institutions with vulnerable populations. As this type of disclosure is similar to that recommended in Recommendation # 7(1), any legislation or regulation could permit this release as well. Alternatively, for those institutions that are regulated by the State, there could be some other regulatory process to permit disclosure.

The Task Force also recommends that where smart meters exist, utilities, the PSC and MEMA should collaborate and agree on automated mapping of outages. While it is not necessary for utilities to send every dot on the map, "heat maps" could provide sufficient information without revealing the status of individual home and businesses. This more accurate and automated process could replace zip code mapping.

The Task Force recommends that various opportunities for collaboration between the Maryland Geographic Information Officer ("GIO") and the utilities be explored. Specifically, the GIO should invite the utilities to participate in Maryland Situational Awareness mapping program. This program fosters the two-way exchange of real time information making everyone situational awareness tools less expensive and more useful. Additionally, the GIO should coordinate joint data collection and maintenance programs between State agencies, local governments including 911 PSAPs, and utilities. There is potential for significant savings and improved service for all partners. For example, smart meters will soon be located in the majority of Maryland homes and business. The addresses, phone numbers and coordinates of those same homes and businesses are being maintained in multiple government systems. By working together and exchanging information, governments and businesses should be able improve the quality of data while lowering the cost maintaining it.

H. Recommendation #7: Increase Citizen Participation In List of Special Needs Customers and Share Information with Emergency Management Agencies

While many medically vulnerable individuals live in nursing homes or assisted living facilities regulated by the State, many others reside in private residences and depend upon electricity to run their life-sustaining medical equipment. It has long been a challenge of emergency management agencies to identify those citizens in the community that need special assistance during an emergency.

COMAR 20.31.03.01 provides that electric utility customers “may not be terminated for an initial period of up to 30 days beyond the scheduled date of service termination when the termination will aggravate an existing serious illness or prevent the use of life-support equipment of any occupant of the premises.” In order to qualify for this protection, individuals must self-identify and provide supporting documentation from their health care provider. Once approved, the utilities maintain a list of medically vulnerable citizens, which could be extremely useful to emergency personnel during an emergency.

The Task Force has two recommendations relative to this population. First, the utilities and the State should collaborate to increase citizens’ awareness of this program. Currently, Pepco, Delmarva, BGE, SMECO and Potomac Edison notify customers at regular intervals (at least annually) of the availability of this program; information is also available on each utility’s website along with downloadable forms for customers to complete. There are likely numerous opportunities, through the State’s interface with vulnerable populations, to increase participation in this program.

Utilities maintain lists of their medically vulnerable customers. The lists are used to notify these customers of planned outages and impending severe storms so that the customer may plan accordingly. These lists, however, would be extremely helpful to emergency managers, who could use them as another data point in assessing the wellbeing of vulnerable citizens during emergencies.

Utilities are reluctant to provide this information to the State, citing privacy concerns. One simple fix would be to include on the application form permission from the customer for disclosure to emergency management agencies during emergencies.

I. Recommendation #8: Evaluate State-Wide Vegetation Management Regulations and Practices beyond RM43

While the Task Force is cognizant of the critical and positive role that Maryland's tree canopy plays throughout the State, the Task Force is convinced that improved vegetation management is a highly effective way to improve the resiliency of the grid. By removing trees and branches that can fall on the lines, the distribution system will literally be able to weather the storm much more effectively.

There are, however, two aspects of the current state of vegetation management about which the Task Force is concerned. One is the complexity of State and local statutes and regulations that govern vegetation management. The Task Force is concerned that multiple regulatory schemes might hinder the effective maintenance of the trees.

The second issue about which the Task Force is concerned is the issue of danger trees, those tree that are located off the right of way that have the potential to contact an electric power line. While danger trees located off the right of way are outside the utilities' jurisdiction, they still can fall on the utility lines, causing outages.

In light of these two concerns, the Task Force recommends that the Department of Natural Resources, the PSC, and the Maryland Energy Administration, in collaboration with the Attorney General's Office, initiate a Task Force to identify and study the interrelationships of State and local laws, regulations and ordinances, as well as the property and contractual issues affecting utility vegetation management, to identify any possible legal observations/guidance on the ability to better coordinate State and local legal and regulatory structures to allow for more clarity and efficiency with respect to allowable utility vegetation management practices while also minimizing and mitigating environmental impacts associated with utility vegetation management practices. Similarly, the Task Force could investigate current utility practices with respect to right of way easements and contractual obligations/limitations related thereto and possible opportunities for improvement with respect to the ability to perform proper vegetation management. The Task Force recommends that this group report back to the Governor within 120 days of its formation.

J. Recommendation #9: Determine Cost-Effective Level of Investment in Resiliency

While the Task Force supports rapid implementation of Recommendations #1-3 above, it recognizes that in planning the technical and operational improvements, Maryland's utilities will be faced with the questions of how far to go and which improvements to select. Both questions will have to be answered by comparing the cost of the improvements to the benefits the improvements provide. The utilities routinely apply some form of cost-benefit test in their planning but typically only consider the benefits to the utility, or at best, the cost of the undelivered energy during an outage the improvements are expected to prevent. The cost of the outage to the customer and the economy are not usually considered.

Since an important objective of the Task Force is to reduce the economic impact to Maryland's electricity consumers and the state's economy, the current cost-effectiveness criteria must be expanded to consider outage costs to the utility customers and, to some degree, other costs to the Maryland economy. Thus, the Task Force recommends that the PSC conduct an inquiry into the cost of outages to different customer classes, i.e. industrial, commercial, institutional and residential, and to the Maryland economy.

Customer interruption costs can be estimated by using functions generally known as customer damage functions ("CDF"). CDFs are typically established based on data obtained from case studies of past outages for which customer accounting records and damage claims data are available, or indirectly based on customer surveys. The inquiry should investigate the applicability of existing research to Maryland's economy and electricity consumers, and identify what gaps, if any, that new research can address. This research can be carried out in collaboration with the Maryland utilities, electric sector R&D institutions, universities, and market research consultants.

A key outcome of the PSC's inquiry into customer interruption costs should be the level of resiliency improvement that Maryland's electricity consumers are willing to fund through rates, as this should determine the magnitude of the investments that the utilities should be allowed to make in this area. The consumer research necessary to make this determination should consider well-established survey-based methods, both direct and indirect.

Direct methods include the direct worth approach ("DW") and the willingness to pay ("WTP") or willingness to accept ("WTA") approach. In the DW approach, different interruption scenarios are described and the respondents are asked to estimate the costs they would experience if an interruption were to occur at a predefined reference time. In the WTP approach, the utility customer is asked to estimate how much they are willing to pay to avoid such an incident, or in the WTA case, how much they are willing to accept in compensation to be indifferent to the interruption. WTP and WTA approaches are especially useful where intangible costs, such as inconvenience or security, are present which are difficult to estimate using the DW approach. For residential customers, who are less likely to keep detailed records of expenses and opportunity costs, customer surveys are better fielded soon after experiencing an extended interruption.

It is not the Task Force's intention to delay implementation of resiliency efforts in order to conduct this survey. Rather, this survey will play a role over the next decades as utilities continue to make decisions on how to deploy capital dollars to improve the infrastructure.

K. Recommendation #10: Study Staffing Pressures Due to Graying of Workforce

The Task Force recommends the PSC commence a proceeding or proceedings aimed at studying and addressing various issues relating to the utilities' human infrastructure, including the so-called "graying" utility workforce. First, the Task Force is concerned that the data reveals a significant downturn in personnel per circuit mile over the past decade. While there was not sufficient time during this process to investigate this issue in great detail, it would be an appropriate line of inquiry for the PSC to determine whether there are sufficient personnel on the ground to make the repairs necessary. The concerns raised during the Human Infrastructure roundtable about the adequacy of current staffing levels deserve a substantive vetting that is beyond the scope of this Task Force. Additionally, the mutual aid assistance program remains somewhat of a black box; the Task Force suggests that the PSC review how that works, whether Maryland's utilities get their "fair share" of crews, whether those crews are properly and effectively deployed in Maryland, and whether there are any improvements to be made to the utilities' methods of acquiring mutual aid.

Most importantly, the Task Force recommends that the PSC conduct an inquiry into the "graying" utility workforce. While the Task Force noted BGE's new training facility, as well as the increased number of trainees in its personnel, it remains concerned about the long-term plan among all of the utilities to address this challenge. The concern specifically arises because the Task Force recognizes that this issue, if left unchecked, may compromise the ability of Maryland utilities to meet enhanced reliability metrics.

This "graying" proceeding would serve three purposes. First, it would allow the PSC to determine the extent of this issue. Second, it would allow utilities to share best practices. Third, if necessary, it would help facilitate further regulatory or State and local government actions. Potential topics of inquiry include:

- Key staffing metrics, including: (1) staffing-related service quality data (e.g., call center response times); (2) current staffing levels; (3) recruitment and hiring plans; (4) anticipated retirements, (5) anticipated skill set needs, (6) retention plans; and (8) efforts to capture knowledge from retiring personnel.[48] This data should be equivalent among all utilities and over pre-specified time periods.[49]

- The potential for independent utility audits, followed by utility action plans subject to PSC approval, to identify and address key staffing challenges.[50] This would present an opportunity for the PSC and Maryland's utilities to address staffing challenges in a coherent fashion, with recognition that utilities have a significant role in key management decisions.

- Comments by various interested parties, including citizens, labor representatives, utilities, Office of People's Counsel, industrial customers and other large end-users, State agencies, NGOs, educational institutions, and veterans groups.[51]

- Creation of joint utility-community college training programs designed to facilitate new worker pipelines and increased job opportunities for Marylanders.

- Enhanced opportunities for military veterans to reenter the civilian workforce.

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[48] For more, *see* Are Utility Workforces Prepared for New Demands? Recommendations for State Commission Inquires, NRRI, 18 (2010), *available at* http://www.nrri.org/pubs/multiutility/NRRI_graying_jan10-01.pdf.

[49] *Id.*

[50] *Id.* at 21 – 36.

[51] *Id.* at 19–20.

L. Recommendation #11: Task the Energy Future Coalition with Developing a Pilot Proposal

The Task Force recommends that the Governor formally charge the Energy Future Coalition with scoping out a Utility 2.0 pilot proposal and reporting back to the Governor and the Task Force, by March 15, 2013, on a viable method to explore the contours of the utility of the future. During the course of the roundtable discussions, there was consensus that the utility industry was transforming at a pace unseen in its history. Between the breakthroughs in technology regarding the delivery of energy, the analytics involved in evaluating the usage of energy, and the numerous and varied ways to communicate with customers, utilities are constantly reacting and adapting to changing paradigms. Layered on top of these formidable challenges are significant policy goals, including the increase of renewable energy sources, the reduction of energy usage, and the decrease in greenhouse gas emissions, that require additional adaptation from the utilities.

The new reality facing the utility industry is that they must perform in an environment rife with change, pressure, and demands that far exceed their traditional scope of expertise and past consumer expectations. The Task Force concurs with the analysis offered by the Energy Future Coalition, that this is a transformative time in Maryland's energy future, and that big, bold thinking is required.

The Task Force is also cognizant of its recommendations regarding changes to the cost recovery model. Specifically, by modifying the incentives for utilities, i.e., offering benefits if they exceed reliability metrics and promising penalties if they fail to meet them, the group has already embraced a review of the traditional regulatory construct. Therefore, we are intrigued by the vision that the Energy Future Coalition has posited; that by rewarding performance, consumers will receive better performance.

The Task Force thought seriously about the recommendations proposed by the Energy Future Coalition to use a pilot approach to transition the electric utility industry into a new, "Utility 2.0" model. While the proposal was too vague for the Task Force to embrace it at this time, it appreciates the progressive thinking of the Coalition and is interested in learning more about the potential of a pilot program in Maryland to explore how to best enable utilities to meet the myriad challenges that are awaiting them.

VII. Acknowledgements

This Report is the joint effort of numerous individuals, many of whom were extremely generous with their time and expertise. The Task Force wishes to thank the many individuals who travelled to Maryland by planes, trains, and automobiles to share their expert knowledge, clear thinking, and solid recommendations. A list of participants, complete with their biographies, is included in Appendix C. Without these individuals, the Task Force would not have been able to achieve its task; their insight and experience was invaluable and each has our sincere appreciation.

The Task Force would also like to thank Maryland's utilities, which were forthcoming with data and information that helped to inform the conversation. Finally, thanks are due to the Office of People's Counsel and Paula Carmody; the Task Force appreciated her insight and acknowledges her commitment to protecting the interests of Maryland's residential ratepayers.

VIII. Appendix

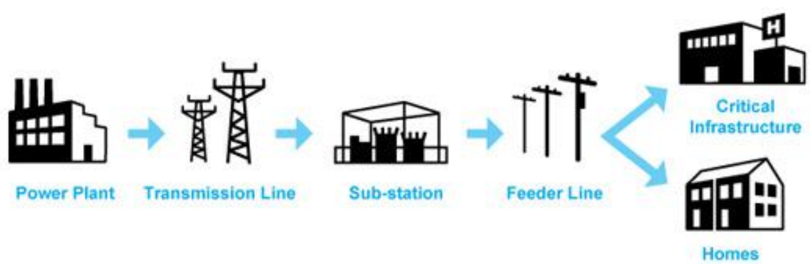
A. Summaries of Roundtable Discussions

In response to Governor O'Malley's July 25, 2012 Executive Order, the Governor's Energy Advisor assembled a far-reaching team of 46 experts from government, industry, and academia to discuss solutions to improve the reliability and resiliency of Maryland's electric distribution system. Biographies of invited guests are provided in following section of this appendix. The team met eight times from August 21 to September 11 in the Miller Senate Office Building. All meetings were open the public and streamed live on the internet. In anticipation of each meeting, the Governor's Energy Advisor requested the invited guests to prepare presentations and policy recommendations on specific topics. Summaries of all eight meetings are reproduced below.

1. Roundtable Discussion #1: Introduction to the Topic

The first roundtable discussion, held on August 21, 2012, served as an introduction to the topic of grid reliability and resiliency and aimed to frame the debate for later meetings. The discussion began with an overview of Maryland's electricity market, including the distribution system.

Figure 27 - Diagram of Electric Distribution System



The group heard from the Staff Counsel of the Maryland Public Service Commission ("PSC") regarding the recently adopted reliability regulations known as RM43. The final speakers discussed customer expectations, as well as future trends in and visions for the utility industry and how those trends may impact grid reliability and resiliency.

From the outset, all participants agreed that the loss of electric service has consequences far beyond the hours of missing services, especially during periods of extreme temperatures. In addition to the challenges faced by repair crews braving harsh conditions to restore service, residents and businesses suffer discomfort, health consequences, including death, lost business, and numerous other effects. There was, not surprisingly, consensus that increasing distribution reliability and resiliency would benefit Maryland's citizens and businesses.

In discussing how the State might achieve increased distribution grid reliability and resiliency, the conversation focused on several points. One was the recognition of the utilities' obligation under their franchise: providing safe and reliable service at just and reasonable rates. Participants agreed that reliability is a social construct, that is, that different citizens may have different, and equally reasonable, expectations of reliability.

The group agreed that the reliability standards created pursuant to RM43 serve as the floor regarding reliability. Some raised the possibility that consumers may be willing to pay extra for increased reliability and other changes to the electric distribution system. Participants also discussed whether utilities have adequate incentives to increase reliability. One participant noted that the PSC has authority to impose civil penalties if a utility fails to meet RM43's reliability performance standards. Other participants discussed whether regulators should use clearer incentives and penalties to incent utilities to provide increased reliability. Some discussed whether certain customers should have the option of paying more for increased reliability depending on their needs.

Finally, participants questioned whether the existing regulatory and business construct is best suited for the significant changes that are and will be taking place in the electric utility industry, including smart meters, distributed generation, and energy efficiency improvements. Many recognized that Maryland's utilities must undertake massive infrastructure improvements in the coming decades and urged that the State, utilities, and all stakeholders work together to ensure the best model for a reliable and resilient grid.

2. Roundtable Discussion #2: Undergrounding

The second roundtable discussion, held August 27, 2012, focused on undergrounding Maryland's electricity distribution system. The discussion touched broadly on the economic feasibility of undergrounding, whether undergrounding truly increases reliability, and the effect of undergrounding on grid resiliency.

The group agreed that undergrounding can significantly reduce outages caused by falling vegetation and high winds. Other benefits include lower tree trimming costs and improved aesthetics.[52] However, the group overwhelmingly agreed that selective undergrounding is preferable to complete undergrounding of the electric distribution system. One group member noted that no studies have shown quantifiable benefits to undergrounding the entire system. Furthermore, the states that have conducted comprehensive studies of undergrounding have concluded it is cost prohibitive to underground the entire system. In some instances, non-underground improvements cost significantly less and have similar effects on grid reliability. For instance, the group noted the potential to use insulated, underground-type cables above ground. Another group member suggested moving above ground lines away from trees. The group recognized that RM43's comprehensive vegetation management regulations, which will enter into full force in 2015, may prove to be a significantly more cost-effective method of outage reduction than undergrounding.

[52] Other advantages include the ability to optimize capital spending previously dedicated to reliability improvement efforts to offset the cost of undergrounding; fewer momentary interruptions; improved customer relations with utilities regarding tree trimming and fewer outages; future construction methods and technology will allow for faster restoration time compared to past design due to greater system interconnection flexibility.

The group listed three main disadvantages to undergrounding.[53] First, installing underground lines costs significantly more than above ground lines. Costs can climb to as much as $3 million per mile in urban areas.[54] Suburban and rural areas are generally less expensive, but lines must be significantly longer than in urban areas, eliminating their cost advantage. One participant claimed that undergrounding electrical distribution assets is 5 to 10 times more expensive than overhead construction.

Second, repairs of underground lines take more time and cost more money than above ground lines, potentially reducing average recovery times of the grid. However, one group member noted that enlarged repair crews may shorten such repair times. One participant discussed whether undergrounding increases or decreases utility O&M costs compared to above ground lines. While some studies do suggest a decrease in cost, others suggest an increase in cost. In the end, the O&M costs of underground lines are site specific and difficult to predict.

Third, the group recognized that underground lines introduce their own reliability concerns. Above ground lines feeding underground portions of the system are still susceptible to extreme weather events. One presenter explained that many of Maryland's underground distribution circuits are fed by above ground lines. Furthermore, underground lines have a life of 25-40 years, after which they must be replaced. The group predicted that technological innovations, such as improved hydrophobic coatings, may greatly increase the long-term reliability of underground lines. Smart grid sensors will also allow utilities to monitor underground lines and accurately pinpoint problem areas.[55]

The group recognized that there must be a strategic approach to undergrounding, namely, those lines that provide benefit to the largest number of customers. One participant suggested undergrounding 69 Kv high voltage substation supply lines because roughly 20% of outages per utility are due to these lines. Another participant recommended that the State employ the 80/20 rule when making undergrounding decisions. Under this approach, utilities would attempt to target and underground the minority of distribution lines that cause the majority of all outages. Another participant suggested looking to rural and suburban subdivisions and hardening main circuits. He also suggested selectively undergrounding lateral lines, which generally run behind houses in suburban areas or along public roads. However, another member pointed out that these installations would occur on private property and, unlike in the underground areas, no public easement current exists in these traditionally overhead areas. The group recognized that it is perhaps impossible to determine precisely the optimal undergrounding plan. One participant suggested that the State and utilities should determine the best plan possible and move forwards.

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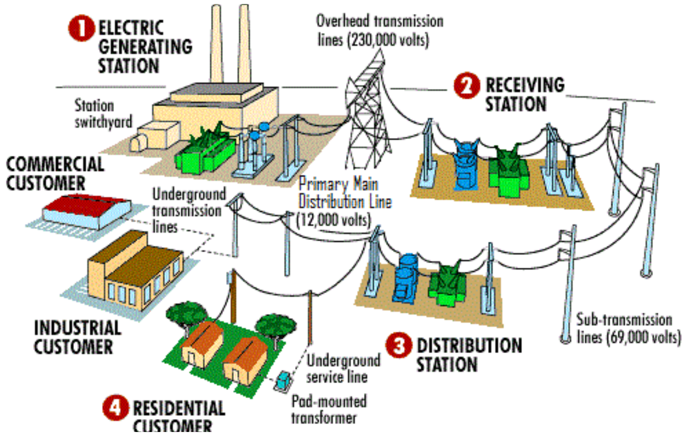
[53] Other disadvantages include possible tree damage in conversion areas (root structures); susceptibility to flooding; and higher replacement costs.

[54]Study of Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia, SHAW CONSULTANTS INTERNATIONAL, 6, 2010, *available at*http://www.governor.maryland.gov/documents/ePSCstudy2010.pdf. One participant cited a 2008 EEI study that showed construction of new distribution lines ranges from $53,000 (rural) to $386,000 (urban) per mile while construction of new underground distribution lines costs significantly more: from $80,000 (rural) to $2 million (urban). In 2006, Pepco estimated it would cost $3.5 million per mile to underground its system.

[55] Other cited areas of future improvement include thermal conductivity improvements, robotic maintenance, and superconductive cables.

Figure 28 - Example of Electric Distribution System



Source: SRP

The group also covered what other states have done to use undergrounding to increase the reliability of their electric distribution systems. No states required undergrounding of their entire systems. Some states, including Maryland, require undergrounding of new residential buildings.[56] Additionally, some municipalities with municipal utilities, such as Anaheim, California, have engaged in far reaching undergrounding campaigns. Manassas, VA also has a 30 year plan to underground its entire distribution system. Some municipalities use general funds to pay for undergrounding. Anaheim, however, funds its undergrounding efforts by a 3% surcharge on its municipal utility's bills.

Finally, the group noted a general need to quantify the cost of power outages to customers. While the cost of undergrounding may be high, the group recognized that there exist no means of quantifying the economic effect of frequent and prolonged power outages on Marylanders. The group generally believed that such an approach would make costly reliability improvements like undergrounding look more attractive. One participant recommended the State engage in comprehensive risk analysis to determine the true cost of outages.[57]

3. Roundtable Discussion #3: What investments should customers be encouraged to make to increase their reliability?

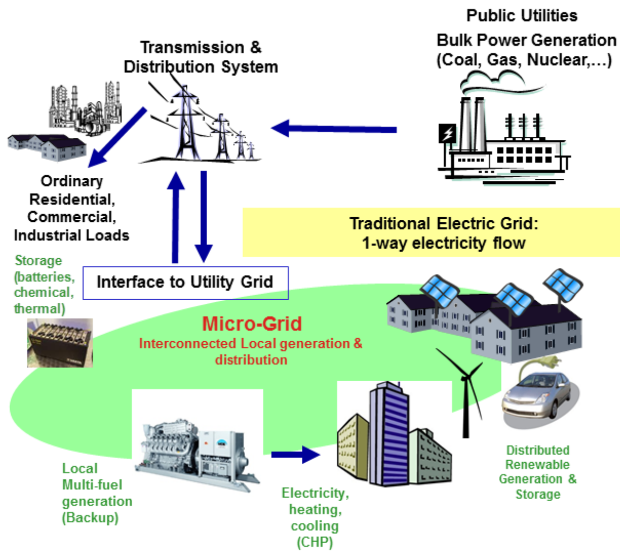
The third roundtable discussion, held August 28, 2012, covered potential investments for consumers to increase the reliability of their electricity supply. The meeting touched broadly on microgrids in commercial and residential settings, distributed generation and storage, and business continuity in emergency situations.

The participants agreed that microgrids have four essential elements. First, a microgrid includes a group of interconnected loads, distributed energy resources, and energy storage devices within clearly defined electrical boundaries. Second, a microgrid acts as a single controllable entity with respect to the wider

[56] COMAR 20.85.03.01(A) ("Extensions of electric distribution lines made after June 5, 1968, which are necessary to furnish permanent electric service to new residential buildings and mobile homes, shall be made underground."). *See also* SECTION II.B.2, *supra*.
[57] *See generally* Ayyub, Risk Analysis in Engineering and Economics, Chapman & Hall/CRC Press, 2003.

distribution and transmission system (the "macrogrid"). Third, a microgrid can connect and disconnect from the macrogrid as needed. Fourth, a microgrid can operate absent assistance from the macrogrid.

Figure 29 - Example of Microgrid Structure



Source: Honeywell

Under this common definition, the group discussed three different purposes of microgrids. Under the first view, a microgrid serves as a complete, isolated system that runs without assistance from the macrogrid. Under the second view, a microgrid runs in unison with the macrogrid, adjusting generation as needed based on cost concerns. Under the third view, a microgrid serves as a redundant backup system that runs only when the macrogrid is down.

Most participants agreed that, generally speaking, market forces will not incentivize widespread adoption of residential microgrids in the short term. One participant stated that private microgrids in residential settings will cost roughly double that of utility assets. He explained that residential customers will not find microgrids cost-effective even if they receive full value for reactive power, blackstart, and spinning reserve. However, he noted some residential customers may find microgrids attractive if those customers greatly value reliability, lose electricity three weeks or more per year, or utilize combined heat and power generation.

The group also recognized that, due to their cost, residential microgrids will potentially benefit more high income Marylanders than low income Marylanders. For certain subsets of customers, microgrids may present an intriguing solution to increase reliability. For lower-income residents, the cost of such systems will likely render them financially impractical. However, participants recognized that microgrids may allow emergency responders to provide more resources to lower-income communities, thus decreasing the duration of outages. Under this scenario, increased use of microgrids may increase the resiliency of the macrogrid. Furthermore, multi-unit dwellings – including State-owned facilities – can utilize master-metering combined with distributed generation and battery backup to provide electricity in emergency situations. State prisons are also an option for microgrid implementation.

The group discussed whether communities can band together to install their own microgrids. While potentially appealing as a means to foster electricity independence, the model quickly runs into numerous regulatory barriers. First, the State grants a legal franchise to utilities for electricity distribution. For residential community microgrids, communities would need to utilize the distribution lines of the utility, thereby triggering questions about the use of the franchise. Additionally, if these distribution lines are out during a storm event, the microgrid itself won't be able to function. Additionally, the distributed generation within the microgrid could be subject to some barriers in this setting. Specifically, in Maryland, the net metering rules are limited to parties selling solar, wind, or other qualified renewable energy up to 2 MW. Second, during outages, it is critical that the lines remain de-energized while linemen are serving them; dire consequences will ensue if that is not the case. Under a residential microgrid model, there would have to be significant communication with the utility in order to avoid serious safety concerns. Third, the sale of electricity to consumers via microgrids may implicate FERC jurisdiction over wholesale rates, especially if a microgrid seeks to sell excess capacity into PJM.[58]

Most participants agreed that microgrids entirely upon private commercial property or State-owned campuses are more feasible in the short term than microgrids using utility assets. This type of arrangement, such as on a university or corporate campus, can avoid utility assets entirely. Furthermore, commercial customers have more options to blend the use of their own generating assets with those of the macrogrid. One participant noted that ratcheting electricity rates for commercial customers make it economically rational to run a blend of electricity from the grid and self-generated electricity from within the microgrid.

The group recognized that another complex challenge for microgrids in both commercial and residential applications is load management. One essential function of a microgrid is managing load when it is operating in island mode so that users never run out of power. For a microgrid, all controls need to make decisions automatically and in real time. When the macrogrid goes down, the system needs to adapt immediately. Microgrids in residential settings also introduce unique challenges. For a microgrid with 25 individual households, where does load balancing and voltage regulation take place? How do such systems communicate with homes to reduce their demand as needed?

The group also recognized the potential for on-site generation as a backup energy source during power outages. Fuel cells can run on a number of fuels, including natural gas, and can provide base-load power generation without battery backup. Distributed solar PV generation coupled with battery backup represents another solution. Due to safety concerns, distributed generation systems shut off when the macrogrid shuts down. For distributed solar PV systems with battery backup, however, the system can continue to operate. The system uses electricity from the solar panels to charge its batteries. The system owner can then utilize the electricity, even if the macrogrid is not functional. One participant explained that such systems can provide 30% of a typical customer's electricity usage, enough for lighting and other limited functions. While this is not enough to run full-house air conditioning, such systems would likely be capable of operating high efficiency geothermal heat pumps.

[58] *See generally* 16 U.S.C. § 824d(a) (giving FERC jurisdiction over wholesale rates).

An additional topic was the impact of microgrids on first responders in emergency situations, including major outage events. The group recognized that many federal government facilities, such as the FDA facility in Silver Spring, are already operating microgrids. Some participants explained the State can leverage these parties' continuous supplies of electricity when responding to future extreme weather events. Since many microgrids are capable of operating on their own, first responders can apply more resources to vulnerable populations as needed. Additionally, one participant noted that microgrids may be useful for partial restoration of service over smaller areas that include critical pieces of infrastructure. One possibility is to employ transportable generation systems that can move from location to location during emergencies, providing electricity to discrete portions of the distribution system.

Some participants questioned the reliability of microgrids during solar storms and cyber-attacks. While solar storms do present challenges to microgrids, they generally only impact transmission lines. Additionally, while such events would likely impact wireless communication systems, wired communications systems would likely remain operational. Furthermore, many microgrids are designed without outbound communication capabilities, thus isolating them from cyber-attacks. One member of the group opined that microgrids do not pose an increased risk to the macrogrid from cyber-attacks.

Finally, participants again stressed the importance of quantifying the human impact of power outages. While microgrids, fuel cells, and battery backup systems may require considerable up-front investment, the participants recognized that these costs may be justified considering the human impact of prolonged outages in Maryland. The group emphasized the increased importance of reliable electricity supply in an electronic age. Participants generally supported the concept of a decision matrix guiding decision makers as they seek to increase reliability and resiliency.

4. Roundtable Discussion #4: The "smart grid" and grid reliability and resiliency

The fourth roundtable discussion, held September 4, 2012, covered the smart grid's impact on reliability and resiliency. The discussion touched broadly upon smart meters, sensors, automatic grid controls, and future trends in the electric distribution industry. The group ultimately concluded that smart grid technologies will have a significant impact in shortening outages on blue sky days and minor to moderate storms. However, smart grid technology will have only a limited impact on outage durations during major outage events.

The group began its meeting by discussing the meaning of the term "smart grid." The group recognized that, broadly speaking, the smart grid is a set of systems combining different electric distribution equipment to operate in a coordinated fashion that was impossible in the past. However, the group had two views about the trajectory of the smart grid. Under the first view, implementation of smart grid technology will lead to a specifically delineated outcome. This typically involves incremental modernization of preexisting assets. Under the second view, the transition to a smart grid is an ongoing process that will completely transform the electric distribution system. One participant opined that the ability of Maryland's electric distribution system's to withstand major storms will not improve if the State rebuilds the overhead electric distribution system as it is today.

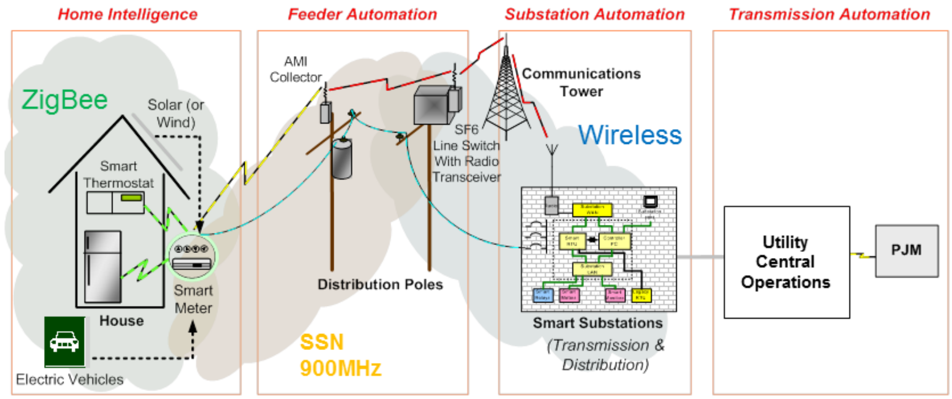
The group then turned to the near term benefits of smart grid technology. Advanced meter infrastructure ("AMI") will work in unison with new automated restoration systems during outage events to automatically restore power. Smart meters will allow utilities to pinpoint power outages. Using smart grid technology, utilities will be able to "ping" smart meters to determine if they are receiving electricity. A meter currently receiving electricity from the grid will respond but will remain silent if not receiving electricity. This will allow utilities to pinpoint outages. It will also allow utilities to determine if power has come back on, saving resources by stopping the dispatch of trucks to unaffected areas.[59] One participant suggested consumers can use smart meters to notify themselves remotely that their electricity is back, allowing them to switch off backup generators and transition back to grid power.

Smart grid improvements also include sensors and automatic switches that will allow utilities to reroute power within seconds after lines come down. This will allow utilities to significantly shorten the duration of some weather related power outages. New sensors will also allow utilities to more accurately pinpoint downed lines and shut off damaged circuits to allow crews to begin work immediately. However, the group recognized that technical challenges limit these improvements. First, rerouting only works in service areas that use redundant lines. In areas with linear lines, automatic sensors can do little to restore service. Second, in major outage events, even systems with automatic switches, sensors, and redundant lines will suffer long outages. Utilities cannot reroute power if all lines are down. There is simply no place to transfer load.

The group also discussed how smart grid technology will allow utilities to conduct preventative maintenance. A series of sensors on the distribution network will allow utilities to monitor equipment in real time and repair or replace equipment before it fails. For instance, one participant described transformers that can actively monitor gasses. If the sensors show warning signs, utilities can repair or replace them as needed. Since transformers are multi-million dollar assets, there is a huge potential for cost savings in addition to increased reliability. Sensors also have the potential to significantly shorten the duration of outages on underground circuits. However, one participant noted that these sensors are not yet mainstream. One Maryland utility needed to develop underground sensors with its suppliers for a recent pilot project.

[59] Frequently, by the time a utility can respond to a customer notification of a power outage that customer's power has already been restored. This allows utilities to check before sending crews out to the site. In one instance, using this technology a utility stopped trucks from responding to 30% of requests because power came back on before they could be dispatched.

Figure 30 - “Smart Grid” Design Features



Source: PHI

The group recognized the complex back office infrastructure required by utilities to process information received from smart meters and other sensors. The group overwhelmingly acknowledged that back office infrastructure is essential to realizing the benefits of smart grid technology. Utilities are currently laying the physical groundwork for AMI and sensors. However, utilities are only beginning to take full advantage of the voluminous data available from these devices.

The group also discussed future trends in the industry. The group recognized that widespread, unpredictable innovation will occur in this field during the next five to ten years. A significant amount of innovation and excitement are growing the sector, driven especially by foreign markets. One participant noted that smart phone apps will give consumers new ways to save energy. Another explained that battery storage within the wider context of the smart grid will be a game changer within the next ten years. He stated fuel cells are another viable option, already in use in the Delmarva region near substations. Generally speaking, the group believed the industry is trending towards more distributed generation which, combined with other smart grid technologies, will increase grid reliability during storms.

The group also discussed a potential disconnect between customer expectations and technical limitations. The group acknowledged that some consumers expect real time online access to electricity usage. However, technical limitations only allow for online access of the previous day’s electricity usage. Still, customers can purchase devices that interface from their meters directly, allowing real time monitoring. One participant noted that situating such technology into customer homes is a significant issue. The group recognized that it is essential for stakeholders to educate customers about the benefits of the smart grid.

Finally, the group again discussed allowing customers to opt-in for increased reliability.[60] The group agreed that in the future economy, different customers will begin to expect different levels of reliability. One participant stated that Japan and China already provide higher reliability for certain customers.

[60]One participant described this as the homogenous versus heterogeneous grid.

5. Roundtable Discussion #5: Other investments on the utility side of the meter

The fifth roundtable discussion, held September 6, 2012, aimed to cover all investments on the utility side of the meter not included in other meetings. The discussion began by discussing current initiatives in Maryland and the future of the State's utilities. The group identified two trends. First, the group recognized that distribution system automation will increase reliability. However, if significant portions of the distribution system are down, automation systems will prove ineffective. Second, the group agreed that comprehensive vegetation management programs – such as required by RM43 – are essential to prevent outages during major storms. The group recognized that regular and systematic tree trimming is the most cost effective approach to increasing grid reliability. One participant suggested the PSC allow utilities to recover tree trimming/removal as part of capital expenses.

The group noted that sensors and automated devices on the distribution grid will contribute significantly to increased reliability and resiliency of the system. The group cautioned, however, that utilities must employ grid sensors and automation selectively to achieve optimal reliability and resiliency improvements while limiting costs. Automated reclosers and sectionalizers improve reliability and resiliency on blue sky days and during minor storms.[61] However, their effectiveness decreases during major events because there is nowhere to switch load. Communication systems also may be down. Furthermore, utilities find that returns diminish as they install more reclosers and sectionalizers. Reclosers cost about $50,000. Utilities must therefore weigh the cost of installation to the benefit of their installation. For feeder sectionalizing, the main issue revolves around economies of scale. Using feeder sectionalizing, utilities can cut off feeder lines at certain points. If lines are down at one point the feeder line, this allows utilities to provide service to some customers while shutting down the portion of the line in need of a repair. At a certain threshold, however, additional sectionalizing is no longer cost effective given the diminished increase in reliability to a limited number of customers. To this end, BGE has automated only about 35-40% of its reclosers.

The roundtable also discussed the integration of data from smart grid devices. The group recognized that smart grid devices are pushing utilities to be communications expert even though they have little experience in the field. The group acknowledged that utilities must integrate new smart meter technologies, such as sensors and automation devices, with centralized data control. Currently, there is no universal standard for smart grid devices. One participant suggested a universal "plug-and-play" standard is necessary.[62] Another participant warned that utilities are spending money on new technology – like AMI – which may be obsolete soon.[63]

[61]A recloser is a circuit breaker with a mechanism that can automatically close the breaker when a fault clears. Sectionalizers work in unison with reclosers to redirect power around faults in the event a fault persists on a portion of the distribution system isolated by reclosers.

[62]However, another participant noted that universal standards are developing, which should make integration a less arduous process going into the future. Furthermore, one participant noted that distribution automation systems are not tied to the SCADA sensor system. The participant suggested that utilities must have to take full advantage of this technology. Utilities have numerous opportunities for streamlining once their systems are

The group discussed potential hard improvements to electric distribution system wiring. Currently, utilities design poles to break before electric lines, which can lead to one tree bringing down numerous poles. One participant suggested engineering lines to break before poles. This would improve resiliency by allowing repair crews to replace wires instead of entire poles. Such lines would need to shut down immediately after breakage to ensure public safety. The participant also suggested different approaches to pole and line siting, such as "zigzagging" lines across streets.

One participant discussed the traditional regulatory model and various changes States are undertaking to reform and improve it. He explained that traditionally the utility model has been based on increasing the rate base of utilities. Utilities seek to avoid taking action when it comes off their profits. The primary purpose of this structure was to ensure universal electrification of the country. The participant opined, however, that this model is defunct because the entire United States is electrified. The focus is shifting towards increased reliability, integration smart grid technology, and widespread distributed generation. Rapid innovation is now the norm. In response to this, some states have the reduced the "regulatory lag" period faced by utilities.[64] These principles as discussed more fully in eighth roundtable discussion summary below.

6. Roundtable Discussion #6: Energy Assurance: How can emergency and infrastructure planning help with resiliency?

The sixth roundtable discussion, held September 7, 2012, covered the impact of emergency and infrastructure planning on distribution grid reliability and resiliency. The discussion touched broadly upon Maryland's energy assurance plan, the State's critical infrastructure, and the potential for grid backup.[65]

From the outset, the group recognized the importance of community to Marylanders during emergencies. The participants acknowledged the one of the best way for citizens to prepare for major outage events is to get to know their neighbors and develop local support systems. One participant also recognized it is important to educate the public about how the electric distribution system works, as well as to set realistic priorities and expectations. The participant explained that promising utilities will restore electric service faster than physically possible frustrates consumers. This is especially true for major outage events, which impact large portions of the electric distribution system. Along these lines, a participant urged the utilities to increase transparency when dealing with major outages.

One participant noted that one component of emergency management is managing expectations: informing the public when their lives will return to normal. To this end, one participant recommended

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integrated. For example, one participant noted that automated systems can potentially automatically enter work orders when lines go down.

[63] The participant identified AMI as a technology that may be obsolete within 2-3 years.

[64] The participant named Rhode Island and Massachusetts as leading this charge.

[65] Maryland's Energy Assurance Plan is available at http://energy.maryland.gov/energyassurance/documents/MarylandEnergyAssurancePlan.pdf.

improving communications and coordination between State and utility actors during major outage events. He stressed that many Maryland agencies, such as MEMA, are partners of the utilities, not adversaries. Along these lines, a group member suggested that the State and utilities coordinate on damage assessments in order to accelerate restoration timelines. The group also discussed the importance of utility and State actors working together on "what-if" scenarios that analyze the impact of natural disasters of increasing severity on the State and its electric distribution infrastructure.[66]

One participant discussed what he perceived is a growing threat of cyber-attacks to Maryland's critical infrastructure. He explained that with automated sensors and switches on the electric grid, hackers can potentially commandeer and sabotage the system. He urged that the State and utilities should make the electric infrastructure more defensive to cyber-attacks when making improvements aimed at natural disasters.

The group next discussed how to improve Maryland's response during major outages. One participant suggested the utilities and the State work together to employ portable generators and grid sectionalizing to restore power to areas of critical need. Another participant suggested the State should incentivize filling stations to have manual pumps on-site. This would allow stations to disburse gasoline without electricity. Additionally, one participant suggested outfitting critical infrastructure, such as gas lines and nursing homes, with back-up generation.[67] However, another participant noted that some assets require significant generation assets. As such, entities need to prioritize their investments in back-up generation using comprehensive cost-benefit analysis.

The roundtable also devoted significant time to the growing prevalence of electricity dependent medical devices. One participant explained that many people have electric medical equipment at home and that hospitals are increasingly sending patients home with such equipment. The participant noted that utilities currently have a process for collecting information about the needs of citizens reliant on electric medical equipment. In theory, this information allows utilities to pinpoint citizens with critical needs and, if possible, prioritize service restoration during major outage events. However, under the current system, citizens must inform utilities on their own. Several participants suggested the State create an automated system for health providers to inform the State government and/or utilities when they prescribe such medical equipment.[68] One participated warned, however, that such a system would potentially create a false assumption that utilities will restore power immediately, leading individuals to under prepare for prolonged outages.

Near the end of the discussion, a participant turned the group's attention to the dire toll major outages can have on small businesses. He explained that during major outage events, small businesses can be driven out of business due to lack of cash flow. He suggested utilities and the State find ways to bring

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[66] One participant suggested utility and State actors should determine: (1) the probability and event will occur, (2) the vulnerability of their systems to such events, and (3) the consequences of the event occurring.
[67] The State could also ensure such back-up generation can be used as peak generation, providing a source of income for the owners of larger back-up generators.
[68] Another option is to require health care providers to provide patients with forms to sign up for this service when they receive the electric equipment.

small businesses into restoration and recovery efforts after major storms and thus provide a financial lifeline. One participant suggested local electricians can help with recovery efforts. However, the group recognized this would pose significant safety issues.

The group finally discussed tapping Maryland's nationally recognized education system to develop reliability and resiliency improvements. Several participants supported developing challenges and contests to develop solutions to the reliability challenges faced by the State. Several others suggested the State include electric reliability issues in its K-12 curriculum, allowing students to solve real life problems in their communities.

7. Roundtable Discussion #7: Human Infrastructure

The seventh roundtable discussion, held September 10, 2012, covered the human element of distribution grid reliability and resiliency efforts. Topics for discussion included how the mutual assistance process works, how current staffing levels of utilities compare to staffing levels 10-15 years ago, and whether increasing staffing levels would increase reliability and resiliency. The discussion also touched upon the cost of increased staffing and whether utilities are prepared for the future in terms of staffing.

From the outset, all participants recognized the dangerous conditions utility crews endure as they restore power. Utility crews must work long hours in harsh conditions to restore service. All Marylanders are grateful for the essential service they provide to the State.

The group spent a significant portion of its meeting discussing the so-called "greying" of the utility work force. One presenter explained that by 2015, utilities may need to replace 36% of their workforce due to age. He explained there is a significant lead time to fill empty positions because it takes up to seven years to train utility linemen. A group member noted some utilities are working hard to stay in front of this demographic shift. For instance, BGE recently complete a large-scale training facility. It puts 120 people through its training program each year.[69]

Figure 31 - BGE's White Marsh Skill Development Center

Source: BGE

[69]Some participants noted machines can partially lessen the physical burden on aging workers.

Several participants noted that since the 1990s utilities have shifted their workforce significantly to contractors rather than full time employees. The group disagreed as to whether contractors are beneficial. One group member claimed that contractors are beneficial because they work on multiple systems rather than just one utility, allowing them to share best practices. However, another group member stated contractors are less familiar with the systems they work on, thus reducing efficiency. Showing a similar divide, one participant claimed that contractors cost about the same as regular employees, while another claimed they can cost significantly more than regular employees. One participant questioned what the best metric is to base staff levels on, such as taking into account line length, number of transformers, and the age of the system. Another participant responded that staffing levels are currently determined based on the number of customers. One participant criticized Maryland utilities for understaffing repair crews and then relying on mutual assistance crews in their place. Along these lines, a group member stated it would be useful to conduct a comprehensive study of overtime hours worked by utility employees. He suggested utility linemen working significant overtime hours is evidence of understaffing. One participant stated that some repair crews work 16 hours/day and can accumulate as much as 1000 hours of overtime annually.[70]

The group also discussed utility mutual assistance programs at length. Mutual assistance programs allow utilities to share crews when their employees are overwhelmed in the aftermath of a major storm. With advanced warning, utilities coordinate their mutual assistance responses before storms strike. To do this, they use data from similar past storms to determine the effect of an imminent storm on their systems. As it becomes more apparent a storm will hit their Maryland service areas, utilities begin to call in mutual assistance crews. In the Maryland service area, mutual assistance crews come from as far away as Quebec. As explained by one participant, mutual assistance rates are set in advance. For major events, he noted that costs don't drive personnel decisions during major storms, as those costs are recovered in rates. Turning to storms like the Derecho, which hit with little to no warning and cause major damage, participants recognized that there is little utilities can do to ensure appropriate mutual assistance crew levels immediately after the storm.

Several group members strongly suggested that Maryland's utilities employ the "Alabama Model" for staffing mutual assistance crews during major outage events, including unpredictable storms like the Derecho. Under this decentralized approach, utilities station mutual assistance crews at each substation and run recovery efforts from there. Mutual assistance groups generally come as a package with their own supervisors and workforces. Under the "Alabama Model," crew groups can split themselves up as necessary on circuits leading from the substation. One participant stated this has two advantages. First, it allows mutual assistance crews to begin working immediately and adopt to the different standards of the Maryland utilities. Second, it reduces "windshield" time by preventing crews from driving long distances to different regions of the State. In addition to mutual assistance, one participant noted that utilities can increase crew levels for day-to-day repairs and then ratchet-up those assets in the aftermath of extreme weather events. BGE reported that during the Derecho, it used this model for the first time.

[70] One participant noted that overtime is normally included in ratemaking.

The group also discussed the potential of having State entities drill with utilities in preparation for major outages. Along these lines, one participant noted that road closures are not coordinated between country and local government and utilities and suggested the State look to increase coordination. Additional, the group discussed the possibility of leveraging public citizen participation in order to increase grid resiliency. Several participants noted that primary overhead workers are highly skilled, making an augmentation workforce unfeasible. However, some suggested augmentation may be possible for safety standby positions.

Finally, one participant recommended that local community colleges and utilities create training centers for utility pre-employees.[71] Several participants suggested that our nation's veterans are highly qualified for the intensive training required for utility repair jobs and recommended working with veterans group to recruit veterans into training programs. While the group recognized the importance of training, another participant noted that utilities currently receive more qualified applicants than necessary.

8. Roundtable Discussion #8: Cost Recovery

The eighth and final roundtable discussion, held September 11, 2012, covered the impact of current utility cost recovery methods on Maryland's distribution grid reliability and resiliency. It touched broadly on new cost recovery methods, whether certain communities should be able to pay for upgraded service, who should bear the financial risk of unreliability, and the feasibility of performance-based ratemaking.

From the outset, the group recognized the importance of striking a balance between affordable rates and increased reliability. The group reached a consensus that consumers expect – and rely on – both affordable and reliable service. The participants also recognized Maryland's economic competitiveness depends in part on affordable electricity rates. Several participants also stressed the negative impact of increasing rates on low to moderate income households and retirees, especially those living on fixed incomes.

The conversation began with a discussion of the scale of the distribution costs as compared to other aspects of a consumer's electricity bill. Specifically, distribution costs, the only segment of the bill regulated by the PSC, comprises about 27% of a monthly bill.

[71] One participant stated such a training center is necessary in Frederick-Hagerstown area.

Table 22 - Components of a Typical Electric Bill in Maryland

BGE

Item	Amount	% of Total Bill	"Decided By"
Customer Charge	$7.50	6%	State – PSC
Distribution	$25.30	21%	State – PSC
Commodity (Electricity)	$82.39	67%	Customer
Transmission	$7.88	6%	Federal – FERC
Total Bill	$123.07	100%	

Pepco

Item	Amount	% of Total Bill	"Decided By"
Customer Charge	$6.78	6%	State – PSC
Distribution	$26.78	22%	State – PSC
Commodity (Electricity)	$82.12	67%	Customer
Transmission	$6.05	5%	Federal – FERC
Total Bill	$121.73	100%	

The group extensively discussed Maryland's traditional ratemaking structure. Under the current regulatory construct, the PSC utilizes a backward looking test year that sets rates prospectively based on average expenses in the immediately preceding year. During a ratemaking case, the PSC and advocacy groups scrutinize utility expenses for whether they were prudently incurred. At the end of the process, the PSC authorizes new rates, which include only prudently incurred costs and an authorized rate of return.[72] One participant explained that the timing rate cases are at the discretion of each utility. He also noted Maryland law gives utilities the "opportunity" to receive a certain rate of return, not a guarantee. As discussed by one group member, some consumer advocacy groups support this traditional regulatory structure because it gives them, as well as the PSC, an opportunity to examine each utility's expenditures.

Several participants suggested the State's ratemaking structure is outdated and ineffective. One participant explained that utilities are experiencing less organic reserve growth, which utilities previously used to fund investments. He explained that customers consumed an increasing amount of electricity during the 1990s, but the trend has recently reversed.[73] Additionally, another participant warned Maryland's ratemaking system creates regulatory lag. He explained utilities are making more significant investments than in the past, ranging from smart grid improvements to replacement of aging infrastructure. He claimed utilities are investing 2.5 to 3 times depreciation. Accordingly, he asserted that backward looking test years do not capture risings costs. The participant claimed Wall Street views

[72] This process does not include electricity generation because Maryland is a decoupled State.
[73] Furthermore, he claimed decoupling keeps utility revenues flat and does not provide for growth.

Maryland regulatory environment as hostile and is affecting the terms on which Maryland's utilities can borrow capital.

One participant suggested Maryland institute an infrastructure cost recovery mechanism, otherwise known as a tracker, to respond to these perceived problems. Such a mechanism would capture additional costs outside of the traditional ratemaking structure. One participant claimed that tracking mechanisms serve consumers by bringing additional investment to utility distribution systems. He also claimed such mechanisms lower the utilities' cost of debt. Another participant asserted that decreasing the cost of debt positively impacts consumers because utilities can share the savings with consumers.

In response, other group members expressed concern with trackers. First, one participant stated they allow utilities to play catch up for deferred maintenance without the scrutiny of rate cases. Second, another participant argued that utilities have a monopoly to provide reliable distribution services; this is the core responsibility. Thus, in the participant's view, trackers are unnecessary because utilities should prioritize reliability without additional financial incentives. Third, a participant stressed that such mechanisms remove power from regulators and prevent advocacy groups from scrutinizing utility expenses. Fourth, a participant warned that trackers can create a slippery slope where regulators increasingly find it easier to give utilities more than allotted during rate cases.

The group also discussed performance based ratemaking as a means to improve reliability. As described by one participant, a performance based ratemaking model would provide financial incentives, through higher rates of return, to utilities that meet or exceed predetermined reliability metrics. Conversely, the system would lower a utility's rate of return if it failed to meet the reliability metrics. Similarly, one group member suggested that Maryland move from a backward looking test year to a forward looking test year. He noted Pennsylvania has recently made such a transition. He claimed a forward looking test year would reduce regulatory lag by allowing utilities recover the costs of upcoming infrastructure improvements.

Table 23 - Example of a Performance Based Ratemaking (PBR) Structure from SDG&E (1999-2002)

Performance Area	*Indicator*	*Benchmark*	*Dead-band*	*Live-band*	*Unit of Change*	*Incentive Per Unit ($'000)*	*Maximum Incentive ($m)*
Safety	OSHA	8.80	±0.20	±1.20	0.01	25	±3
Reliability	SAIDI	52 min	0	±15	1.00	250	±3.75
	SAIFI	.90 outages/year	0	±0.15	0.01	250	±3.75
	MAIFI	1.28 outages/yr	0	±0.30	0.015	50	±1
Customer Satisfaction	Very Satisfied	92.5%	±0.5%	±2.0%	0.1%	75	±1.5
Call Center Response	Answered in 60 secs	80%	0	±15%	0.1%	10	±1.5

Source: Meyrick & Associates

One participant explained that Maryland utilities cannot ensure an adequate return on equity (ROE), which in turn increases costs to consumers. In his view, the PSC has not allowed utilities to receive consistent or large enough ROEs. As a result, he claimed Maryland's regulatory structure lowers the access of Maryland's utilities to capital. One participant asked whether a study has ever compared utility ROE to service quality. The group could not identify such a study. While several participants noted this comparison deserves further study, they also realized that each State's regulatory landscape is different, making comparisons difficult.

The group also discussed allowing communities to opt-in for increased reliability. Under this approach, communities would vote for low, medium, or high reliability with an increasing price tag. The group determined such a scheme is both unfair and infeasible in most instances. As one participant explained, such a system would introduce discriminatory practices into electricity delivery. Furthermore, such a program would be extremely difficult to implement because the distribution system is not necessarily organized on a community-by-community basis. However, the group did recognize that an opt-in system for increased reliability may be feasible for businesses and universities, as well as in microgrid applications.

The group ended its meeting by discussing potential outcomes under a business-as-usual path. One participant explained that, if left unchecked, the current regulatory structure could lead to credit downgrades, higher borrowing costs and, as a result, higher rates for consumers.

B. Summary of Public Comments

As part of the convened Task Force's effort to solicit feedback from the public on ways to improve the reliability and resiliency of the Maryland grid, Marylanders were encouraged to contribute ideas, comments, and concerns through a feedback forum on the website accompanying the Executive Order (www.discussion.maryland.gov). In addition, the Governor's Energy Advisor received a number of letters and emails from Maryland electricity customers. The recommendations and comments from the public indicated a high-level of appreciation regarding the complexities of improving the electric grid and were largely consistent with recommendations received through the expert roundtables. Several themes surfaced in the public's correspondence:

Underground where possible. Numerous citizens expressed support for undergrounding electric lines, where possible, and suggested that savings from tree trimming on those underground lines could help offset the upfront cost of the undergrounding.

Tree Trimming. Many citizens also highlighted the need for aggressive tree-trimming along utility lines, combined with more clarity about ways to report problem trees to the utility. One comment suggested utilizing the out-of-State contractors that provide assistance in response to severe outages to wage a campaign to trim foliage across the State.

Impact of outages on Marylanders. There was also a clear interest in highlighting the impact of power outages on Maryland families, ranging from lost work days to potentially unsanitary conditions resulting from no well water. Several citizens emphasized the effect that lack of power has on our most vulnerable populations, including those citizens who rely on electricity to power their medical equipment.

Distributed, local electricity generation. Several Marylanders identified distributed generation as a strategy to rectify reliance on centralized power generation and the requisite distribution system. Distributed generation can take many forms; some argued for solar panels, others for natural gas micro-turbines. Several citizens also suggested that the government provided no interest loans for purchase and installation of distributed generation systems.

Improving Communication with Utility Companies. Some comments further brought to our attention the challenges in reporting outages to utility companies and contacting the correct responder when a utility-related issue is identified. One commenter reported that some utility companies encourage customers to report outages online, when it is impossible to do this while the electricity is out. Another was frustrated that his utility company did not respond to a potentially hazardous situation involving an electricity line, forcing him to contact the fire department.

Management Incentives. One citizen suggested that an evaluation of the utilities' operational processes and management systems is in order. Specifically, the citizen raised questions about whether distribution performance targets are set, evaluated, and tied to management compensation.

C. Invited Roundtable Speaker Biographies

Rajnish Barua, Ph.D.
Executive Director, National Regulatory Research Institute
Dr. Barua has served as Executive Director of the National Regulatory Research Institute since January 2012.

For the previous five years, Dr. Barua served as executive director of the Organization of PJM States, Inc., (OPSI), a non-profit association of utility regulatory agencies in the 13 states and the District of Columbia within the PJM Interconnection footprint. In this role, Dr. Barua oversaw OPSI's day-to-day functions, including coordinating data/issues analyses and policy formation on issues related to PJM, its market monitor, and related federal agency matters.

Prior to joining OPSI, Dr. Barua served as the energy advisor for former Pennsylvania Public Utility Commission Chairman Wendell Holland. He also worked as director of integrated resources planning at the Maryland Public Service Commission and as a regulatory policy administrator at the Delaware Public Service Commission.

In addition, Dr. Barua provided training and technical assistance in energy regulation to government agencies in Africa, Eastern Europe, and South Asia. He has been published and presented extensively in regional, national, and international conferences. Dr. Barua is a Senior Fellow at the University of Florida's Public Utility Research Center. He earned his doctorate from the University of Delaware, specializing in energy policy, and has taught courses in electricity and regulatory policy.

The National Regulatory Research Institute, established in 1976, is the national research entity devoted to improving the economic regulation of utility companies. Through research papers, widely attended webinars, and educational workshops held throughout the country, NRRI seeks to empower State public utility commissioners with the most relevant information and research about regulation with an academic focus.

Leslie Romine
Staff Counsel, Maryland Public Service Commission
Leslie Moore Romine joined the Public Service Commission in 2008, and currently serves as Chief Staff Counsel, a position she has held for one year. She previously served as Deputy Staff Counsel.

As Chief Staff Counsel, she is responsible for representing the Technical Staff of the PSC in proceedings before the Commission, for rendering legal advice to the Technical Staff, and for managing and coordinating the development of Staff's position and presentation in PSC matters. She oversees a staff of seven attorneys.

Prior to joining the Staff of the PSC, Ms. Romine has held positions as Deputy Counsel to the Comptroller of Maryland, and as a partner at Linowes and Blocher LLP, and O'Malley, Miles, Farrington and McCarthy. She was appointed People's Zoning Counsel for Prince George's County by then-County Executive Parris N. Glendening.

She has been actively involved in community and professional endeavors, and has previously held positions as Chair, Real Property, Planning and Zoning Section Council of the Maryland State Bar Association; Panel Member, Attorney Grievance Commission; Board Member of the Maryland School of Law Alumni Association, Inc. and various PTA committee chairs at her daughter's schools.

Ms. Romine received her Bachelor of Arts degree, cum laude, from Bucknell University, and her Juris Doctor, with honors, from the University of Maryland, Francis King Carey School of Law. She is a member of the bars of Maryland and the District of Columbia.

Roger Berliner
President, Montgomery County Council

Montgomery County Council President Roger Berliner has been intimately involved in the intersection of energy policy and utility law for the past 38 years as a staffer, lawyer, and public official.

As a staffer, Mr. Berliner served as Director of Congressional Liaison for the Federal Energy Regulatory Commission; energy advisor and Legislative Director to U.S. Senator Howard Metzenbaum, who served on the Senate Energy & Natural Resource Committee; Senior Advisor to House Energy & Commerce Committee Chairman Henry Waxman; legislative analyst for 250 members of the House Democratic Study Group; energy aide to Congressman Tom Luken (D-Ohio), a member of the then House Interstate and Foreign Commerce Committee; and Principal Consultant to the California State Assembly Utilities & Commerce and Energy & Natural Resources Committees.

As a lawyer, Mr. Berliner has served a wide range of energy interests, including the Province of Alberta; the County of Los Angeles; the Los Angeles Area Chamber of Commerce; the Nevada utilities; the Sacramento Municipal Utility District; co-generators; solar generation facilities; and the Canadian natural gas industry. He has practiced before various regulatory bodies including the Federal Energy Regulatory Commission and the California Public Utility Commission; argued before the District of Columbia Court of Appeals; and briefed the 9^{th} Circuit and United States Supreme Court.

As a member of the Montgomery County Council, Councilmember Berliner was the lead sponsor on a comprehensive energy & environmental law that, among other things, establishes the goal of reducing carbon emissions by 80% by 2050; requires home sellers to provide 12 months of past fuel bills to potential purchasers; provides property tax credits for energy conservation and solar installations; and authorized the County to participate in regulatory proceedings before the Maryland Public Service Commission. Councilmember Berliner was also the lead sponsor on a measure that imposed a carbon tax on major emitters, a law that was ultimately struck down by the 4th Circuit Court of Appeals. Councilmember Berliner led the Council in formally requesting the MPSC to launch an investigation into Pepco's reliability and he provided the first draft to the Governor and the legislature of what ultimately became the Maryland Electric Service Quality Reliability Act (HB 391).

Councilmember Berliner currently serves as Chairman of the Council's Transportation, Infrastructure, Energy & Environment Committee; Co-Chair of the Washington Region Council of Government's Climate, Energy & Environment Committee; and has participated in a national dialogue on energy policy hosted annually by the Aspen Institute for the past twenty years. He is a member of the California and District of Columbia bars.

John Jimison
Energy Future Coalition

John W. Jimison serves as the Managing Director of the Energy Future Coalition, a broad-based, non-partisan public policy initiative that brings diverse stakeholders together to identify energy policy options that address the great challenges of oil dependence, global climate change, and the maintenance of strong and growing economies. From 2007 through 2010, Mr. Jimison served as Senior Counsel to the Energy and Commerce Committee of the U.S. House of Representatives, advising the committee's members on energy efficiency, regulatory matters, natural gas policy, energy markets, and electric grid modernization.

Mr. Jimison practiced energy and regulatory law from 1987 through 2006 in Federal and State forums. From 1982-1985, he was Principal Administrator at the International Energy Agency in Paris, France, responsible for electricity and natural gas policy and analysis, as well as country expert for Spain and Australia. During the period from 1972 through 1981 he held several positions on Capitol Hill, including a previous period as Counsel to the Energy and Commerce Committee, service as Head of the Energy Section of the Congressional Research Service (Library of Congress), and as Professional Staff to the Senate Commerce Committee when it had jurisdiction over natural gas and electricity policy.

Jim Fama
Vice President, Energy Delivery, Edison Electric Institute

Mr. Fama is Vice President, Energy Delivery, and joined EEI in April 2002. The Energy Delivery group is responsible for all business, regulatory, operational, reliability and public policy matters related to energy delivery. Much of this work focuses on the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), and Regional Transmission Organizations (RTOs).

Prior to joining EEI, Mr. Fama was Senior Counsel with the Washington, D.C. office of LeBoeuf, Lamb, Greene and MacRae. During his three-year tenure with LeBoeuf, he represented various energy companies in mergers and other transactions, and in matters before FERC and the Florida Public Service Commission.

Prior to joining LeBeouf, Mr. Fama spent two years as Vice President and General Counsel of ECWerks, Inc., a Tampa, Florida e-commerce software company which is now part of CGI Group, Inc., the largest information technology service company in Canada.

Mr. Fama also has served as Deputy General Counsel for Florida Power Corporation in St. Petersburg, Florida, where he was the legal officer responsible for managing Florida Power's legal affairs. During his eight-year tenure with Florida Power, Mr. Fama represented the company in litigation, regulatory, commercial and other legal matters.

Prior to joining Florida Power, Mr. Fama was Assistant General Counsel for the Bonneville Power Administration in Portland, Oregon, where he was responsible for all legal matters related to power and transmission rates. Mr. Fama was with Bonneville for seven years.

Mr. Fama began his career as a trial attorney at FERC. He received his undergraduate degree from the University of Virginia and his law degree from the University of Baltimore.

Matt Olearczyk
Senior Program Manager, Distribution Systems Program, EPRI
Matthew Olearczyk is a Senior Program Manager responsible for the Distribution Systems program area of the Power Delivery Sector. His current research activities focus on overhead and underground distribution systems design, engineering, planning, operations and maintenance. He joined EPRI in 2005.

The primary focus of Matthews's career has been on electric utility power delivery systeMs. Matthew's positions have required highly developed skills in driving executive decision-making, group facilitation, problem solving and business excellence. He attributes much of his success to the mentorship of dozens of thoughtful and exceptional people that have high standards for themselves and others.

Previously Matthew launched a privately held consultancy practice focused on helping utilities, regulators, and industrial users of electric services by providing information, analyses, and expertise in the area of electric distribution. Matthew also worked for over ten years at Public Service Electric and Gas Company, New Jersey in various Management, Staff and Supervisory positions.

Mr. Olearczyk received a BS degree in mechanical engineering from Widener University in Chester, Pennsylvania.

Philip DiDomenico
Shaw Group
Philip DiDomenico is an accomplished manager, management consultant and electrical engineer with extensive and diversified experience in electric utility management, planning and, engineering. His areas of expertise range from strategic and capital planning, to resource planning, electric system planning and engineering as well as fossil power plant planning and engineering. He also facilitates and advises senior managers on strategic issues including; reshaping business management strategies, financial planning, asset transactions, and operations and maintenance practices in both Electric Delivery and Fossil Power Production organizations.

Dr. Bilal Ayyub
University of Maryland
Dr. Bilal Ayyub is a Professor and Director of the Center for Technology and Systems Management (CTSM) at the University of Maryland, College Park. Dr. Ayyub is a world famous expert on uncertainty and risk analysis. He is engaged in research activities focused on uncertainty modeling and analysis,

systems modeling, decision analysis, homeland security, various defense and infrastructure systems, safety systems, and mathematical modeling using statistics, probability theory, fuzzy sets, and the theory of evidence. He is a fellow of ASCE, ASME, and SNAME; a recipient of the ASNE 'Jimmie' Hamilton Award for the best paper in the Naval Engineers Journal during 1985, 1992, 2000 and 2002; the award for the outstanding research oriented paper in the ASCE Journal of Water Resources Planning and Management in 1987; and the ASCE Edmund Friedman Young Engineer Award for Professional Achievement, 1989; the North American Fuzzy Information Processing Society's K. S. Fu Award for Distinguished Service 1995; the ASCE Walter L. Huber Research Prize, 1997; and several leadership and distinguished service awards. He is the founder and co-chairman of the International Symposia on Uncertainty Modeling and Analysis held in 1990, 1993, 1995, and 2003. Dr. Ayyub is the author and co-author of about 450 publications including many edited books and textbooks. He is also head of a team at the Intelligent Systems Laboratory (ISL), within CTSM, assisting Robotic Technology Inc. developing the Energetically Autonomous Tactical Robot (EATR).

George E. Owens
Downes Associates

George E. Owens serves as President of Downes Associates, Inc,. a consulting engineering company specializing in the design and operation of electrical utilities. For the past thirty-eight years, Mr. Owens' work has included utility power system studies, utility power system design, utility electrical rate studies, industrial power system studies, industrial electrical cost evaluations, high and low voltage electrical apparatus specification, high and low voltage electrical system layout and design, electrical conservation studies, energy cost studies, system coordination studies, electrical power substation and power plant designs, energy management studies, utility construction practices, as well as meter and relay system installation, calibration, and maintenance. Mr. Owens has also provided consulting services for a number of offshore and land-based wind projects. Additionally, for the past ten years Mr. Owens has served as the official representative within the PJM Interconnection ("PJM") Regional Transmission Organization ("RTO") for several municipally-owned electrical utilities. He is a member of PJM's Planning Committee, Transmission Expansion Advisory Committee, Markets and Reliability Committee, and Members Committee. During this same time period, Mr. Owens has served as a member of numerous PJM Working Groups and Task Forces focusing on RTO reliability, transmission planning, and new generation interconnection. He also served for two years on the Mid-Atlantic Area Council ("MAAC") Administrative Board.

Mr. Owens received his Bachelor of Engineering Science Degree in Electrical Engineering from the Johns Hopkins University in 1969, a Master of Science Degree in Physical Oceanography from Texas A&M University in 1971, and completed two additional years of graduate study in Coastal and Ocean Engineering within the Civil Engineering Department of Texas A&M University. In 1974, Mr. Owens graduated from the U.S. Army Corps of Engineers Basic Engineering Officer Training program at Ft. Belvoir, Virginia. Additionally, Mr. Owens has taken numerous professional development courses in electrical metering, electrical short circuit analysis, and electrical system operation. Mr. Owens has also addressed various groups and seminars on energy conservation, energy management, electrical system operations, utility environmental impact, and utility deregulation. Mr. Owens is a registered professional engineer licensed in seventeen states and the District of Columbia. He is also a member of the National Society of Professional Engineers, the Institute of Electrical and Electronics Engineers Inc., the American Public Power Association, the National Rural Electric Cooperative Association, and the National Fire Protection Association.

William M. Gausman
Senior Vice President, Strategic Initiatives, Pepco Holdings Inc.
William M Gausman is Sr. Vice President – Strategic Initiatives for Pepco Holdings Inc. (PHI). Mr. Gausman is responsible for the oversight of strategic projects that focus on the long term support of the transmission and distribution systems. This includes the implementation of PHI's Advanced Metering Infrastructure (AMI), and other PHI Blueprint initiatives, procurement of energy, (both gas and electric), compliance with NERC and State reliability standards to ensure the safe and reliable operation of the electric system and the construction of the Mid-Atlantic Power Pathway Project (MAPP Project).

Mr. Gausman received a BS Electrical Engineering Technology degree from Temple University in 1974 and joined Pepco as a Project Engineer overseeing the construction of high voltage transmission facilities. He has served in various management positions with increasing responsibility for the operation, maintenance and construction of both the transmission and distribution systems. Mr. Gausman recently served as Sr. Vice President Asset Management and Planning for Pepco Holdings, Inc. (PHI).

Mr. Gausman was responsible for the engineering and design of all assets that support the transmission and distribution of electric service across the entire PHI service territory, which includes three electric utilities Pepco, Delmarva Power and Atlantic City Electric. He was also responsible for the development of the reliability program, the short and long-term electric system planning process, telecommunication and system protection and Business Transformation for PHI.

Dr. Eric Wachsman
Director, University of Maryland Energy Research Center
Dr. Eric D Wachsman, Director of the University of Maryland Energy Research Center, is the William L. Crentz Centennial Chair in Energy Research with appointments in both the Department of Materials Science and Engineering, and the Department of Chemical Engineering at the University of Maryland.

He received his Ph.D. in Materials Science & Engineering from Stanford University, and his B.S. in Chemical Engineering from the University of California at Berkeley. He is a Fellow of The Electrochemical Society and The American Ceramic Society. In addition, he is Editor-in-Chief of Ionics, Editor of Energy Systems, formerly an Associate Editor of Journal of the American Ceramic Society, Chair of the New Technology Subcommittee and the National Capitol Section of The Electrochemical Society, former Councilor of the Florida Section of the American Ceramic Society, and a member of the American Chemical Society, the International Society for Solid State Ionics, and the Materials Research Society. He has more than 200 publications and 8 patents on energy related technologies.

Dr. Wachsman is a frequent invited panelist on fuel cell and hydrogen energy research, ranging from the US Department of Energy "Fuel Cell Report to Congress" and "Basic Research Needs Related to High Temperature Electrochemical Devices for Hydrogen Production, Storage and Use," to the National Science Foundation "Workshop on Fundamental Research Needs in Ceramics," NATO "Mixed Ionic-Electronic Conducting (MIEC) Perovskites for Advanced Energy Systems," and the National Academies "Global Dialogues on Emerging Science and Technologies." He also serves on numerous boards and was appointed by the Governor to the Board of Directors of the Maryland Clean Energy Center.

Mary Lasky
Business Continuity, Johns Hopkins Applied Physics Lab

Mary Lasky is the Program Manager for Business Continuity Planning for the Johns Hopkins University Applied Physics Laboratory ("JHU/APL"), and also coordinates the APL Incident Command System ("ICS") Team. Mary is Chair of the Community Emergency Response Network ("CERN") in Howard County, Maryland. She has been the co-chair of the CERN Continuity of Operations Planning ("COOP") team. She is also the President of the Central Maryland Chapter of the Association of Contingency Planners ("ACP").

Mary has held a variety of supervisory positions in Information Technology and in business services. In addition, she is on the adjunct faculty of the Johns Hopkins University Whiting School of Engineering, teaching in the graduate degree program in Technical Management.

Chris Cook
President and General Counsel, Solar Grid Storage, LLC

Chris Cook is President and General Counsel of Solar Grid Storage, LLC, a new company focused on the use of battery storage to enhance the value of solar power on electric grids. Mr. Cook was previously of counsel to the law firm of Keyes & Fox, a boutique firm specializing in distributed resources law and providing counsel to businesses, utility regulators, and policy makers on the various facets of the distributed generation business.

Mr. Cook was formerly Sr. Vice-President of Regulatory Affairs for SunEdison, a company he helped found with three others in 2003. In his role at SunEdison, Mr. Cook worked with policy makers and electric utilities to create new solar energy programs. His team helped establish programs in most of the leading solar states in the U.S. He also served as General Counsel at SunEdison and during that time helped write one of the earliest solar power purchase agreements ("PPA") that has become the model contract for the solar industry.

Mr. Cook was the chief architect of the renowned New Jersey solar program and was instrumental in creating the technical standards that allow solar and small generators to interconnect with the electric utility grid. He is considered by many to be the leading national expert on net metering – the economic arrangement by which a customer generating their own power is compensated by their local utility. Mr. Cook also provided consultation to municipalities on purchasing competitive electricity supply and structured wholesale deals worth nearly $100 million. Prior to starting his consulting company, Mr.

Cook was Assistant Counsel with the Maryland People's Counsel and Director of Energy Policy at the Maryland Energy Administration.

Mr. Cook is a member of the Bar of Maryland and a Member of the Institute of Electrical and Electronics Engineers. He serves on the Board of Directors of the Interstate Renewable Energy Council and holds awards from the Governor of Maryland and the US Department of Energy for outstanding service in promoting solar energy use.

Dr. Ben Hobbs
Johns Hopkins University
Benjamin F. Hobbs is Founding Director of the Johns Hopkins University Environment, Energy, Sustainability & Health Institute. He holds the Theodore M. and Kay W. Schad Chair of Environmental Management in the JHU Whiting School of Engineering, where he has been in the Department of Geography & Environmental Engineering since 1995. He has served as Chair of that department, and also holds a joint appointment in the Department of Applied Mathematics & Statistics Dr. Hobbs earned a Ph.D. in Environmental Systems Engineering in 1983 from Cornell University.

Previously, he was at Brookhaven and Oak Ridge National Laboratories and a member of the Systems Engineering and Civil Engineering faculty at Case Western Reserve University. Dr. Hobbs has held visiting appointments at the Helsinki University of Technology, University of Washington, the Netherlands Energy Research Center, and the Electricity Policy Research Group at Cambridge University. In 2009-2010, he was Overseas Fellow at Churchill College, Cambridge University.

Dr. Hobbs chairs the Market Surveillance Committee of the California Independent System Operator, which he has been a member of since 2002. He also serves on the Public Interest Committee of the Gas Technology Institute. Dr. Hobbs is a Fellow of the IEEE and INFORMS.

His research and teaching concerns the application of systems analysis and economics to electric utility regulation, planning, and operations, as well as environmental and water resources systems. He has published 130 refereed journal articles and several books. Funding for his work has come from the National Science Foundation, PJM, the Maryland Power Plant Research Project, USEPA, USDOE, and other private and public sources. His work has received best paper awards from the Decision Analysis Society (INFORMS); the Energy, Natural Resources, and Environment Section of INFORMS; and the American Society of Civil Engineers, Water Resources Management and Planning Division.

Dr. Danny Ervin
Professor of Finance, Salisbury University
Dr. Dan Ervin, Professor of Finance, is the Founder of ShoreENERGY: The Energy, Economic, and Sustainability Program at Salisbury University in Salisbury, MD. Dr. Ervin provides economic and public policy research for positive change of local, regional, and national energy policy. Combining an expertise in business needs, technical disciplines and environmental concerns, Dr. Ervin contributes and promotes emerging energy-related educational activities.

Dr. Ervin provides practical and academic research on energy topics including; energy infrastructure development, energy infrastructure security and the effect on national and regional security, environmental consequences of energy usage, natural resource management policies, and sustainable and renewable energy practices. In addition, Dr. Ervin has testified before the Maryland Public Service Commission regarding electricity demand forecasts.

Dr. Ervin holds a Ph.D. in Finance from the University of Kentucky and a B.S. in Civil Engineering from North Carolina State University. His extensive experience includes electric utility employment where his responsibilities included financial analysis and forecasting. His current research addresses management decisions and how these decisions affect the value of corporations with particular focus on electric utilities and electric merchant companies. He is an expert in various measures of value creation and their implementation for project evaluation. His expertise includes financial risk management and the array of measures used in this complex and important field.

He has published academic research on international finance, portfolio diversification, and the economic impact of employee discrimination in appropriate journals.

Steven G. Hauser

Director of Engineering Service and Chief Technology Officer, New West Technologies, LLC

Steven G. Hauser is a national and internationally recognized expert on transforming the power sector to meet future economic, environmental and energy security mandates. For more than 25 years, Mr. Hauser has been a leader in clean energy technology development efforts including solar, wind, batteries, electric vehicles, geothermal, hydrogen, and building energy efficiency. He has been featured in numerous executive conferences and various national media describing the concepts and benefits of a Smart Grid. He recently authored the lead chapter in a book titled "Smart Grid: Integrating Renewable, Distributed, and Efficient Energy" published by Academic Press.

Mr. Hauser was the driving force behind the creation of the GridWise Alliance and related smart grid organizations. Since 2000, he has brought together hundreds of companies to create a broad industry vision to transform energy systems, markets, and technologies. Mr. Hauser has also led the creation of new international bands like GridWise and GridWeek significantly raising the visibility of these issues with federal State policy makers. He recently participated as a key advisor to the National Science and Technology Council's Smart Grid Task force, resulting in the White House release in 2011 of the "Policy Framework for a 21st Century Grid."

Previously, Mr. Hauser has held senior management positions at the National Renewable Energy Laboratory, Battelle, CH2M Hill and SAIC. He serves on various advisory boards and committees.

Brian Deaver
Technical Executive, EPRI
Brian Deaver is a Technical Executive in the Distribution Systems program area of the Power Delivery Sector. His current research activities focus on distribution sensors, distribution automation, Volt/VAR control and reliability. He joined EPRI in 2011.

The primary focus of Brian's career has been on the automation, monitoring and control of the electric distribution system and the application of these technologies to the key distribution utility objectives of proving safe, reliable and affordable electric service.

Brian presently leads EPRI research on the application of sensors and sensing technology on the electric distribution system, with a focus on the applications which the sensors will enable. Focusing on key distribution applications such as Distribution Automation, Automated Service Restoration, Volt/VAR Control, Conservation Voltage Reduction, Fault Location and Switching, Distribution State Estimation and Asset Management, this program will clearly articulate the type, location and requirements for distribution sensors and provide guidance on their selection, application, commissioning and life cycle management.

Additionally, Brian is spearheading EPRI research on the application of automated switching and restoration on the electric distribution system. Initially this research is focusing on performing DA Immersions at various utilities to gain an understanding of the variety of approaches being deployed at key utilities. This work will initially result in a database of DA practices, architectures and design philosophies.

Prior to joining EPRI, Brian was the Vice President of Product Management for CURRENT Group, a privately held Smart Grid products and services provider. In this executive leadership role, he was responsible for product strategy, life cycle management, and the development of product marketing and technical requirements. During his time with CURRENT, Brian was awarded four patents for work in sensors and power system control, with another eleven pending.

Brian also served for twenty years at Baltimore Gas and Electric Company where he held technical leadership positions in Distribution and Substations. His most notable accomplishments were founding and leading both the Distribution Automation and Substation Automation programs, each of which won Southeastern Electric Exchange Excellence In Engineering Awards. He also served as technical lead on BGE's Electric System Redesign Program, a comprehensive reliability improvement investment program.

Mr. Deaver received a BS degree in electrical engineering from the University of Maryland, and is a registered professional engineer in the State of Maryland.

Sunil Pancholi
Director of Strategy, Lockheed Martin Energy Solution
Sunil Pancholi is the Director of Energy Strategy at Lockheed Martin. He leads strategy development and execution for Lockheed Martin's Energy Solutions portfolio, including identifying new technologies. He has over 25 years of experience in the electrical power transmission and distribution industry. Prior to

joining Lockheed Martin, he worked for Pepco Holdings, Inc. ("PHI"). He was a major contributor to shape and implement PHI's smart grid technology investments. He managed PHI's $170M Smart Grid Investment Grant (SGIG) program, from 2009 to 2012. His previous roles at PHI included Process Management for Electric System Operations and managing Pepco's overhead and underground T&D systems. He has a MBA from Wharton School of Business Management and a MSEE from George Washington University

Bruce Walker
Davies Consulting

For more than 20 years, Mr. Walker has been an integral part of three gas and electric investor owned utilities in the Northeast United States. He has held leadership positions in Asset Management, System Operations, Regulatory and Legal Services and Emergency Management. Most recently, Mr. Walker was the Vice President of Asset Strategy and Policy for National Grid. In that capacity, he oversaw the development and execution of asset strategies and policies for a $3 billion five-year capital investment plan in New York, Massachusetts, Rhode Island and New Hampshire. He was a member of the Biological and Chemical Weapons Response Team for Con Edison Inc. in New York City.

He serves as a member of the Board of Directors for GridWise Alliance, Inc., the Vice Chairman of its Executive Committee, and a co-founder of the Global Smart Grid Federation ("GSGF"). He is a member of GRID 21 Inc.'s Board of Directors, announced by the White House in 2011 in conjunction with the release of the policy framework for the 21st Century Grid; "Enabling our secure Energy future". In 2008, he was appointed by then-Secretary of Energy Samuel Bodman to the Department of Energy's Electricity Advisory Committee (EAC).

He holds a Bachelor of Electric Engineering from Manhattan College and a Juris Doctor in Law from Pace University where he was the technical editor on the Environmental Law Review and received an Environmental Law Certificate. In 2001, he was admitted to the NY State Bar Association. He completed the Power Technologies Inc. (Siemens) 18 month Distribution Engineering course in 2002. Mr. Walker is certified through the Federal Emergency Management Agency's Emergency Management Institute on the Incident Command System, the National Incident Management System, and the National Response Framework.

Christopher Burton
Vice President, Smart Grid and Technology, BGE

Christopher Burton is vice president, smart grid & technology. Burton and his team are responsible for the implementation and strategic direction of smart grid – the modernization of the grid that will provide more information to customers and enhance energy delivery. This includes integration of new technologies to support the grid automation and increase efficiency.

Burton joined BGE in 1987 and has held senior leadership positions in strategic planning and development, customer accounts and metering services, gas and electric operations and planning, and asset management services. He has previously led large projects including BGE's transition to Customer

Choice. He serves on the Southeastern Electric Exchange Engineering and Operations Executive Committee and is a member of the North American Transmission Forum and the American Gas Association Managing Committee.

Burton is a registered professional engineer in the State of Maryland and a senior member of the IEEE, the world's leading professional association for the advancement of technology. He serves on the board of directors for St. Vincent de Paul of Baltimore, and was a past chairman for the Power Engineering Society, Baltimore Chapter. He is a graduate of Leadership Baltimore County.

Burton holds a Bachelor of Science degree in electrical engineering from Virginia Polytechnic and State University and a master's degree in business administration from University of Baltimore.

Robert S. Stewart
Manager, Advanced Technology and New Business, PHI
Rob Stewart is Manager, Advanced Technology and New Business for PHI's Strategic Initiatives Group.

In his present role, Rob leads an effort that is responsible for further developing and managing PHI's approach to evaluating and deploying advanced technologies and concepts for application on the electric system. One of Rob's specific areas of responsibility deals with the interface between the customer and the Smart Grid. This includes the development of PHI's Home Area Network (HAN) strategy as well as the integration of electric vehicle chargers and renewable generation / intelligent management and control capabilities

Rob is a graduate of the University of South Florida with a B.S. in Electrical Engineering and M.S. in Electrical Engineering (Power Systems) and holds a Certificate of Process Mastery from Hammer and Company. He also holds several patents associated with the connection of an on-site power source to the electric meter, and has published several articles and presentations related to the deployment of Smart grid Technologies.

Rob has served as a faculty member in 2010, 2011 and 2012 for the University of Idaho, Utility Executive Course where he presented a curriculum on the Smart Grid. He is on the Board of Directors for the Electric Vehicle Drive Association (EDTA), a member of the Smart Grid Interoperability Panel (SGIP), the SGIP Interoperability Methods Committee (IMC), the OpenSG Technical Committee, the Institute of Electrical and Electronic Engineers and an active member of the community where he lives in Alexandria Virginia.

Dr. Stephen Flynn
Professor and Founding Co-Director, George J. Kostas Research Institute for Homeland Security, Northeastern University
Stephen E. Flynn is the Founding Co-Director of the George J. Kostas Research Institute for Homeland Security and Professor of Political Science at Northeastern University.

Dr. Flynn is the author of the critically acclaimed The Edge of Disaster: Rebuilding a Resilient Nation (Random House, 2007), and the national bestseller, America the Vulnerable (HarperCollins, 2004). He is a Senior Research Fellow at the Wharton School's Risk Management and Decision Processes Center at the University of Pennsylvania. Since 9/11 he has provided testimony on twenty-eight occasions on Capitol Hill.

Professor Flynn is one of the world's leading experts on transportation security and infrastructure and community resilience issues. Prior to September 11, 2001, he served as an expert advisor to U.S. Commission on National Security (Hart-Rudman Commission), and following the 9/11 attacks he was the principal advisor to the bipartisan Congressional Port Security Caucus. Dr. Flynn also advised the Bush Administration on maritime and homeland security issues and after the November 2008 election of President Barack Obama, served as the lead policy advisor on homeland security as a part of the presidential transition team. He is currently a member of the Bipartisan Policy Center's Homeland Security Project Panel, co-chaired by former 9/11 commissioners, Governor Tom Kean and Congressman Lee Hamilton.

Prior to his joining the faculty at Northeastern University, Dr. Flynn served as President of the Center for National Policy. He was selected to lead the Center after spending a decade as a senior fellow for National Security Studies at the Council on Foreign Relations. Before that, Dr. Flynn served in the Coast Guard on active duty for 20 years, including two tours as commanding officer at sea. He received several professional awards including the Legion of Merit, and retired at the rank of Commander. As a Coast Guard officer, he was assigned to the White House Military Office during the George H.W. Bush administration and as a director for Global Issues on the National Security Council staff during the Clinton administration. He is a 1982 graduate of the U.S. Coast Guard Academy where he was also a member of the faculty from 1988-1991 and 1994-2002. Flynn was a Guest Scholar in the Foreign Policy Studies Program at the Brookings Institution from 1991-92, and in 1993-94 he was an Annenberg Scholar-in-Residence at the University of Pennsylvania.

Dr. Flynn is a frequent media commentator and has appeared on Meet the Press, 60 Minutes, The Today Show, the Charlie Rose Show, and CNN. Five of his articles have been published in the prestigious journal *Foreign Affairs*. Excerpts of his books have been featured in *Time*, as the cover story *for U.S. News & World Report*, and as the subject of two CNN documentaries.

Charles Fischer
Vice President, Preparedness Operations, Witt Associates

Charlie Fisher is the Vice President for Preparedness Operations for Witt Associates, an emergency management and public safety consulting firm founded by James Lee Witt, the former FEMA director.

Charlie overseas teams of consultants who help the leaders of public, private, university and non-profit organizations enhance preparedness for their next disaster event. Current efforts include earthquake preparedness in Los Angeles County, business continuity planning for a Fortune 100 corporation and risk assessments for Miami-Dade and surrounding counties in South Florida.

Charlie has led teams working with communities across the country, and the utilities which serve them on steps to better prepare for future major electricity outages; recent efforts include Denver, Newark and Philadelphia. At the recommendation of Governor O'Malley, Connecticut Governor Dan Malloy asked Witt Associates to conduct an independent assessment of the restoration effort in response to the pre-Halloween snow storm last year. That report was widely read in the emergency management and utility sectors.

Charlie led the Illinois Commerce Commission, the State public utility commission, in the 1990's and has spoken on utility and emergency preparedness issues in North America, Europe and Australia.

Brian Daschbach
Vice-President, Integrated Field Services, BGE

Brian C. Daschbach Sr. is vice president of Integrated Field Services, BGE's largest division. In this role, he leads the efforts of 1,400 utility employees and 2,000 contractor employees who are engaged daily in gas and electric transmission, substation, distribution, meter construction, operations and maintenance activities.

Daschbach joined BGE in 1980 and has held various leadership positions in the areas of engineering, logistics, information technology management, and gas and electric utility construction and operations.

Daschbach is a member of the Institute of Electrical and Electronics Engineers, the Power Engineering Society and the Engineering Society of Baltimore. He serves on the board of advisors for the Little Sisters of the Poor (St. Martin's Home) in Catonsville and is a past board member of Parents Anonymous of Maryland.

He earned a bachelor's degree in electrical engineering from the Georgia Institute of Technology, and has completed several management programs, including the Rutgers Program for Management Development, and Leadership Maryland – Baltimore County.

Scott H. Strauss, Esq.
Spiegel & McDiarmid, LLP

Scott Strauss has dedicated his three-decade career to protecting the interests of consumers. Through his representation of states, ratepayer advocates, labor unions and municipal and consumer-owned utilities — typically against resource-rich opponents — Scott has helped to reshape the landscape of regional electricity markets, creating millions of dollars in savings for his clients and their consumers, while helping to ensure the quality and reliability of utility services.

A five-time DC SuperLawyer, Scott describes the "David and Goliath" aspect of his practice as its most engaging feature: "What I love most about my job is that every so often I get to topple a big guy while working for a little guy." And battling on behalf of the resource underdog is just part of the challenge: "What our clients may lack in resources we make up for by developing creative approaches to solving problems."

As lead trial counsel in proceedings before both federal administrative agencies (including the Federal Energy Regulatory Commission, the Federal Communications Commission, the Federal Election Commission and the Nuclear Regulatory Commission) and State public service commissions across the country, Scott has spent extensive time in the hearing room, cross-examining everyone from technical experts to CEOs. He has earned a reputation for being able to present highly complex material to tribunals in a manner that is both engaging and persuasive. However, whether in the courtroom or at the negotiating table, for Scott it all comes down to the arguments he can muster and the strategies he can develop to present them: “Litigators are in the ideas business — if you have good ideas to offer, and can present them in a manner that will be well-received by the tribunal, then you always have a shot at winning.”

Scott recognizes that his career path has been somewhat unusual — he joined the firm right after law school graduation from the University of Pennsylvania and never left. The explanation is simple: “Everything I want is right in front of me. The clients are worth fighting for, the issues facing the energy industry are only becoming more challenging, and my colleagues are a wonderful mix of supportive and stimulating people — why go anywhere else?”

Jim Hunter
Director, Utility Department, International Brotherhood of Electrical Workers

Jim worked for Potomac Electric Power Company as a Relay Tech. for over 20 years. During that time he worked in transmission/distribution substations and in the fossil fuel power plants that PEPCO owned. In 1994 he was elected as the President and Business Manager of IBEW Local 1900 in Washington D.C.. In 1996 he intervened in the Pepco/BGE merger and testified as an expert witness on electric system design. From 1997 to 2002 Jim intervened and testified in numerous cases before FERC, the D.C. and Maryland Public Service Commissions and at Department of Energy Hearings. In 1998 Maryland Governor Paris Glendenning appointed him to the Governor’s Task Force on Electric System Reliability. In 2002, Jim was appointed to the IBEW International staff and in 2004 was promoted to Director of the Utility Department. The IBEW has 220,000 members in the Utility branch, which includes electric, gas and water utilities in the U.S. and Canada.

Jim serves on the advisory boards for Carnegie Mellon Institute and Electric Power Research Institute (EPRI) and on sustainability Boards for American Electric Power and Energy Future Holdings. Jim is also on the Executive Council for the Center for Energy Workforce Development and is on the Board for the IBEW Utility Training Trust. Jim has most recently worked as a subject matter expert to help formulate the IBEW’s position on global warming including working on the Bingaman/Specter, Lieberman/Warner and most recently the Waxman/Markey climate change bills. He also worked on the IBEW/AEP International piece (boarder adjustments) that was in all three climate change bills.

Jim represented the IBEW at the U.N. climate change conferences in 2008 thru 2010 and is President of Unions for Jobs and the Environment (UJAE).

Robert Whalen
President, System Local 102, Utility Workers Union of America

Robert Whalen began his career with Allegheny Energy on January 31, 1977 as an Apprentice Lineman. Bob progressed through the classifications, Lineman B and Lineman A and then moved in to the Meter Technician position in 1982. In 1984, Bob became a Control Technician until 1989 when he worked as Service Foreman. In 1990, Bob settled into his current job as a Control Technician in Pleasant Valley. During these years of service with Allegheny, Bob earned an Associate Degree in Electronics which was funded by Allegheny.

Bob and his wife Lori have two children, a daughter Kimberly and a son Robert. Their home town is Mt. Pleasant, Pennsylvania where Bob is an active member of the community. In his spare time, he coaches local softball and baseball teams. Bob is an avid drag race driver and crew chief and is a Certified Technical Inspector for the National Hot Rod Association. When time permits, Bob enjoys hunting as well.

Bob has kept very busy during his career, belonging to the Pleasant Valley Service Center Safety Committee and holding the office of president in his home local, Local 102-F. Bob's commitment to the union earned him the elected position of Area C Vice-President for System Local 102. As Area Vice-President, he services Uniontown/ Pleasant Valley/ Connellsville - 102-F and Cumberland / Oakland - 102-R. Bob is a member of the Local 102 Executive Committee and the Local 102 Executive Board. The 102 E-Board has also elected Bob to the 102 Negotiating Committee. Bob has served as Local 102's Chairperson of the Labor Day Parade Committee and Local 102's delegate to the Allegheny County Labor Council Labor Day Parade Event.

Mark Case
Vice President, Strategy and Regulatory Affairs, BGE

Mark D. Case is vice president of strategy and regulatory affairs. His responsibilities include electric and gas energy supply, PJM load settlement, customer choice programs, and regulatory and pricing issues before the Maryland Public Service Commission. He also leads BGE's demand response and energy efficiency programs, and serves as an executive sponsor to the Company's smart grid initiative.

Since he joined BGE in 1983, Case has held various leadership positions, including vice president of business performance, strategy and regulatory services from 2004-2007.

Case serves on the Habitat for Humanity of the Chesapeake Region Board as a director, the University of Maryland MTECH Program Board of Advisors, and the Maryland Strategic Energy Investment Fund. He is also a past board member and vice president of the Baltimore Museum of Industry. He is a member of the EEI Strategic Issues Committee and the American Society of Mechanical Engineers.

Case earned a Bachelor of Science degree in mechanical engineering from the University of Maryland, a master's degree in administrative science from Johns Hopkins University and has completed several management programs, including the Rutgers Program for Management Development, the Executive Management Program at Penn State University and Leadership Maryland – Baltimore County.

Charles R. Dickerson
Vice President of Customer Care, Pepco Holdings, Inc.
Charles R. Dickerson is Vice President of Customer Care of Pepco Holdings, Inc. (PHI).

Mr. Dickerson is responsible for all aspects of customer care including meter services, meter reading, billing, energy procurement, customer contact centers, marketing and customer relationship management along with credit & remittance for PHI's customers across its three regulated (gas and electric) utilities.

Prior to assuming his current role he served as PHI Vice President, Strategic Planning and Chief Risk Officer responsible for corporate strategic planning and enterprise risk assessment and management.

Prior to that, Mr. Dickerson served as Vice President, Gas Delivery for Delmarva Power. In this capacity in addition to the gas business' profit and loss he was responsible for all aspects of planning, engineering, construction, operations and maintenance.

Mr. Dickerson joined Pepco in 1989 and served in a number of positions including Construction and Production Engineering. In 2000 he was promoted to Manager, Customer Operations Division. Under his leadership, Pepco was ranked number one for the JD Power and Associates "Customer Satisfaction Survey" and Pepco won Call Center Magazine's "Best Call Center of the Year." In 2001, he was named Call Center Magazine's "Manager of the Year."

Mr. Dickerson has a B.S. degree in Mechanical Engineering and a M.S. in Applied Management both from the University of Maryland.

Presently, Mr. Dickerson serves as a member of the Board of Trustees for the Treatment Learning Center and as an Adjunct Professor for the District of Columbia's School of Business.

Paula Carmody
Maryland Office of People's Counsel
Paula Carmody was appointed People's Counsel by Douglas F. Gansler, Attorney General of Maryland, and confirmed by the Senate in 2007. She has extensive experience working on consumer issues with government agencies, including the Office of People's Counsel, and nonprofit legal services organizations. In her capacity as President (formerly Vice-President and Treasurer) and member of the Executive Committee of the National Association of State Utility Consumer Advocates (NASUCA), she is able to advocate for Maryland consumers on national issues.

Prior to her appointment, Ms. Carmody was an Assistant Attorney General in the Consumer Protection Division, Office of the Attorney General of Maryland, from 2004 – 2007. While there, she was responsible for investigating violations of, and enforcing, Maryland's Consumer Protection Act and related consumer protection laws.

From 1988 - 2003 Ms. Carmody served as an Assistant People's Counsel with the Office of People's Counsel, representing the interests of residential consumers of gas and electricity before the Maryland

Public Service Commission and the Federal Energy Regulatory Commission, as well as the Maryland General Assembly. During that time she developed a particular expertise in consumer protection issues related to the restructured gas and electric industries.

Before coming to the Office of People's Counsel, Ms. Carmody was the Managing Attorney of the Baltimore, Maryland office of the UAW-GM Legal Services Plan, and represented autoworkers, family members and retirees in a variety of civil matters in State and federal courts. Additionally, she served as a Staff Attorney for the Legal Aid Bureau, Inc., in Maryland.

Ms. Carmody graduated with a Juris Doctor degree from Antioch School of Law, Washington, D.C. She received a Bachelor of Arts degree in Political Science from McGill University, Montreal, Quebec, Canada.

Tammy Bresnahan
Associate Director of Advocacy, AARP Maryland

Tammy Bresnahan is the Associate Director of Advocacy for AARP Maryland. Tammy has over 20 years' experience in Maryland health and social services programs that provide much needed services for adults and children that include but are not limited to: protective services, temporary assistance to needy families, supplemental nutrition assistance program, energy assistance, Medicaid eligibility and other social services programs that provide a safety net for Maryland's most vulnerable. She has experience in health and social services policy, regulation, legislation, administration and management.

Currently she represents AARP Maryland before the Maryland General Assembly, State and local governments lobbying for programs and services for adults 50+. She works with elected and appointed officials to address the most relevant wants/needs of people 50+ in collaboration with key stakeholders, which can help close gaps, drive social change, and enrich the lives of the 50+ population.

From 2003-2011 she was the Executive Director of Government Affairs for the Maryland Department of Human Resources. As Executive Director she advised the Department's cabinet secretary on all legislative and regulatory initiatives for programs affecting children and adults. She has worked on passing laws, regulation; and implementing policy to protect individuals from abuse and neglect; maintaining utility costs; and to ensure that vulnerable adults and children have access to programs that provide the safety net.

From 1986-2003, Tammy worked in four local departments of social services where she held a number of positions including case manager, policy analyst, supervisor, assistant director and director.

Tammy has a Bachelor of Science Degree from Salisbury University in Political Science and Sociology. She has taken Master level courses in public policy and administration.

Reid Detchon
Energy Future Coalition
Reid Detchon is the Executive Director of the Energy Future Coalition. He previously served as Director of Special Projects in Washington for the Turner Foundation, managing a portfolio of major grants aimed at increasing the effectiveness of environmental advocacy and encouraging federal action to avert global climate change. He also spent six years at Podesta Associates, a government relations and public affairs firm in Washington, D.C., where he was a Principal.

From 1989 to 1993, Mr. Detchon served as the Principal Deputy Assistant Secretary for Conservation and Renewable Energy at the U.S. Department of Energy. Previously he was Principal Speechwriter for Vice President George H. W. Bush. Mr. Detchon worked for five years in the U.S. Senate, advising Senator John Danforth of Missouri on energy and environmental issues and serving as his Legislative Director. He was a reporter for the Columbia (Mo.) Daily Tribune from 1974 to 1980. He is a graduate of Yale University.

Daniel L. Eggers
Managing Director, Investment Banking Division, Credit Suisse
Daniel L. Eggers is a Managing Director of Credit Suisse in the Investment Banking division, based in New York. He is a member of the Equity Research department and leads the US Electric Utilities team, covering a universe of twenty-six Regulated Utility, Integrated Power, and Independent Power Producer stocks. In addition, Mr. Eggers has macro coverage responsibilities for the Power sector and oversees the broader Energy Research team.

Mr. Eggers has been a top ranked analyst in the Institutional Investor Poll for the past four years, was ranked third in the 2012 Bloomberg/Greenwich Associates poll, first in Earnings Estimation and second in Stock Picking in the 2012 Starmine Awards in his sector, and in previous years, has received multiple top three rankings in the Starmine analyst surveys. In 2008, he was awarded the Farsight Award for outstanding Long-term and Extra Financial Investment Research.

Prior to his current responsibilities, Mr. Eggers covered fifteen companies within the Institutional Investor and Greenwich ranked Oil Service and Equipment team. Mr. Eggers joined Credit Suisse in 1997 as an Associate on the top ranked Integrated Oils and Independent Refiners group.

Mr. Eggers received his BBA in Finance with Honors from Texas Christian University and was awarded the Chartered Financial Analyst designation in 2000.

Peter J. Lanzalotta
Principal, Lanzalotta & Associates LLC
Peter J. Lanzalotta is a Principal of Lanzalotta & Associates LLC, which he founded in 2000. He is licensed as a Professional Engineer in the states of Maryland and Connecticut. Mr. Lanzalotta holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration with a concentration in Finance from Loyola College of Baltimore. He is a member of the

Institute of Electrical & Electronics Engineers, the National Fire Protection Association, and the American Solar Energy Society.

Mr. Lanzalotta has more than thirty-five years of collective experience in the following utility-related areas: Electric utility system transmission, and distribution planning, including reliability analyses, load flow studies, voltage profile analysis, short circuit analysis, smart grid applications, distributed generation interconnection, and interconnection planning; Electric utility system operations and maintenance, including interconnected transmission system operations and maintenance, distribution operations and maintenance, failure analyses, SCADA and automated grid operation, transmission and distribution interconnection analyses, and electric system reliability analyses; Electric power sales and procurement, including market analysis, load and price forecasting and analyses, power purchase and power sales agreement development and analyses, transmission adequacy analyses, and metering applications and technologies; Quality of service analyses, guarantees, and indices, including customer service indices and reliability indices; and Utility cost allocation, rate design, retail rate studies, and line extension charges.

Mr. Lanzalotta has appeared as an expert witness on utility planning and operation matters and on utility rate matters in more than 100 proceedings in at least 22 states, the District of Columbia, the Provinces of Alberta and Ontario, and before the FERC.

Among the clients he has assisted are the U. S. Department of Justice, various State agencies in the states of Maine, Maryland, Delaware, Pennsylvania, South Carolina, New Jersey, New York, Hawaii, and South Dakota, the cities of Chicago IL and New York NY, municipal electric utilities in California, New Jersey, New York, Massachusetts, and Wyoming, various large energy-consuming entities, various power project developers, and various public interest groups.

D. State Roundtable Participants

Office of Governor O'Malley

Abigail Hopper, Esq.
Energy Advisor, Office of Governor Martin O'Malley and
Acting Director of the Maryland Energy Administration
Email: abigail.hopper@maryland.gov

Matthew Raifman
StateStat Analyst, Office of Governor Martin O'Malley
Email: matthew.raifman@maryland.gov

Maryland Public Service Commission

Merwin Sands
Executive Director, Maryland Public Service Commission
Email: msands@psc.state.md.us

Jerry Hughes
Chief Engineer, Maryland Public Service Commission
Email: jthughes@psc.state.md.us

Maryland Energy Administration

Malcolm Woolf
(Former) Director, Maryland Energy Administration
Email: mwoolf@energy.state.md.us

Kevin Lucas
Director Energy Market Strategies, Maryland Energy Administration
Email: klucas@energy.state.md.us

David St. Jean
Planning Manager, Energy Assurance, Maryland Energy Administration
Email: dstjean@energy.state.md.us

David Beugelmans, JD
Program Manager, Special Projects, Maryland Energy Administration
Email: dbeugelmans@energy.state.md.us

Nicolas Puga, consultant to Maryland Energy Administration
Partner, Bates While, LLC
Email: nick.puga@bateswhite.com

Maryland Department of Natural Resources

Sandi Patty
Maryland Department of Natural Resources, Power Plant Research Project
Email: spatty@dnr.state.md.us

Maryland Emergency Management Agency

Ken Mallette
Executive Director, Maryland Emergency Management Agency
Email: ken.mallette@maryland.gov

Michael Fischer
Director of Administration, Maryland Emergency Management Agency
Email: michael.fischer@maryland.gov

Maryland Department of Information Technology

Barney Krucoff
State Geographic Information Officer, Maryland Department of Information Technology
Email: bkrucoff@maryland.gov

Ken Miller
Deputy State Geographic Information Officer, Maryland Department of Information Technology
Email: ken.miller@maryland.gov