

NARUC AND MDPSC COST-BENEFIT ANALYSIS OF VARIOUS ELECTRIC RELIABILITY IMPROVEMENT PROJECTS FROM THE END USERS' PERSPECTIVE

Analysis Summary

November 15, 2013



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A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

TABLE OF CONTENTS

1	INTRODUCTION	6
1.1	INTRODUCTION	6
1.1.1	Statement of the purpose	6
1.1.2	Objectives and significance of the study	6
1.1.3	Questions and Sub-questions	7
1.1.4	Definitions	7
1.1.5	Delimitations & limitations	8
2	EXECUTIVE SUMMARY	10
3	QUANTITATIVE ANALYSIS	13
3.1	ANALYSIS APPROACH – A DESCRIPTION OF METHODS UTILIZED TO IDENTIFY AND QUANTIFY THE COSTS OF OUTAGES INCURRED BY RATEPAYERS FOR VARYING PERIODS OF TIME	13
3.2	HARDSHIPS AND DIRECT COSTS OF BEING WITHOUT ELECTRICITY	14
3.2.1	Residential Customer Hardships and Direct Costs	14
3.2.2	Commercial Customer Hardships and Direct Costs	27
3.2.3	Industrial Customers Hardships and Direct Costs	35
3.3	VALUE OF LOST LOAD - WILLINGNESS TO ACCEPT THE COST OF AN OUTAGE	44
3.3.1	Residential Customers VoLL	47
3.3.2	Commercial Customers VoLL	50
3.3.3	Industrial Customers VoLL	54
3.4	A SURVEY OF COMPENSATION/REFUNDS TO CUSTOMERS FOR OUTAGES	60
3.5	TEMPLATE TO REPLICATE IN OTHER JURISDICTIONS	62
4	MITIGATION MEASURES TO ADDRESS ELECTRICAL OUTAGES	62
4.1	INTRODUCTION TO MITIGATION MEASURES	62
4.2	VEGETATION MANAGEMENT	63
4.3	UNDERGROUNDING OF DISTRIBUTION SYSTEM	69
4.4	DELIVERY SYSTEM IMPROVEMENTS	75
4.4.1	Transmission and Area Distribution	76
4.4.2	Local Distribution System or Microgrid Improvements	78
4.4.3	Local Substation Automation	80
4.4.4	Circuit Loops with Smart Switches	80
4.4.5	Undergrounding Local Cables (Lower Voltage)	80
4.5	END-USE INVESTMENTS	80
4.5.1	Smart Meters	81
4.5.2	Home Automation	81

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

4.6	REPLACEMENT OF FEEDERS	81
4.7	CALL CENTER IMPROVEMENTS	82
4.8	UTILITY WORK FORCE	83
4.8.1	Staffing Levels to Respond to Outages	83
4.8.2	Training Availability	83
4.8.3	Preparing for an Aging Workforce	84
4.9	OUTAGE PROCESS IMPROVEMENTS	84
4.10	FACILITIES THAT REQUIRE BACKUP GENERATION	85
4.11	MARYLAND ENERGY ASSURANCE PLAN	85
4.12	PROTECTING MEDICALLY VULNERABLE CITIZENS	85
5	CRITICAL INFORMATION FOR INFORMED DECISION-MAKING	86
5.1	COMPARISON OF VARIOUS STUDIES	86
5.2	COST/BENEFIT ANALYSIS	86
6	CONCLUSIONS AND RECOMMENDATIONS	86
6.1	CONCLUSIONS	86
6.2	RECOMMENDATIONS	87
7	APPENDICES	88
7.1	NATURAL GAS TARIFF	88
7.2	LIST OF SOURCES	91

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

List of Figures and Tables

Figure 1 Cost to Repair a Septic Tank in Maryland.....	16
Figure 2 Loads/Circuits Relative to Home Backup Generator Capacity.....	17
Figure 3 August 2013 Utility Supplier Prices – BGE12 Month Fixed Price Residential Contract (Source: http://www.opc.state.md.us/opc/ConsumerCorner/Publications.aspx#Gas)	18
Figure 4 List of “Hassles” faced by residential customers (Bates White Economic Consulting, 2012)	25
Figure 5 “Biggest Hassles” of Outages (Bates White Economic Consulting, 2012)	26
Figure 6 2011 Montgomery County PEPCO Work Group Survey Results for Commercial Customers	35
Figure 7 EPRI Costs per Duration (EPRI/primen Report Table 2-1)	38
Figure 8 Example of Industrial Scale Generation	40
Figure 9 Medium & Large US C&I Customer Segments CDF Curve (Lawrence Berkeley National Laboratory: "Estimated Value of Service Reliability for Electric Utility Customers in the United States", Freeman, Sullivan & Co., June 2009)	46
Figure 10 Norwegian CDF Curves for all Customer Segments (“Customer Costs Related to Interruptions and Voltage Problems: Methodology and Results”, IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 23, NO. 3, AUGUST 2008).....	46
Table 1 Cost of Different Sizes of Home Backup Generation.....	17
Table 2 Daily Cost of Operating Backup Generation	18
Table 3 Other costs for residential customers	20
Table 4 Detailed List of Residential Direct Costs for Prolonged Outages	21
Table 5 Sample 1 of How to Use the Data for Residential Customers	23
Table 6 Sample 2 of How to Use the Data for Residential Customers	24
Table 7 Summary of 2011 Montgomery County PEPCO Work Group Survey Results	25
Table 8 Maryland Commercial and Industrial GDP (http://choosemaryland.org/factsstats/Pages/GrossDomesticProduct.aspx).....	28
Table 9 Maryland Companies in Terms of Number of Employees (2009 US Census)	29
Table 10 Maryland Commercial Customers Segmented by Size in Average MWh Consumed per Year (EIA 2011)	29
Table 11 Operating Cost of Backup Generation for Commercial Customers	31
Table 12 Installed Costs of Backup Generation for Commercial Customers	31
Table 13 Detailed List of Commercial and Small Industrial Customers’ Direct Costs for Prolonged Outages	33
Table 14 Sample of How to Use the Commercial Cost Data	34
Table 15 Maryland Industrial Customers Segmented by Size in Average MWh Consumed per Year (EIA 2011)	36
Table 16 EPRI Industrial Customer Segments Surveyed (EPRI/primen Report Table 1-1)	37
Table 17 Individual Costs per Outage (EPRI/primen Report Table 2-1)	39
Table 18 Costs of Industrial Scale Backup Generation	41
Table 19 Detailed List of Industrial Customers’ Direct Costs for Prolonged Outages	42
Table 20 Sample of How to Use the Industrial Cost Data	43
Table 21 Comparison of Various Studies Customer Damage Function Results Standardized to Maryland	47

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Table 22 Cost of Prolonged Outages for Maryland Residential Customers Based on the LBNL 2009 CDF	49
Table 23 Estimate of Maryland Commercial Costs Using the 2009 LBNL CDF.....	53
Table 24 Comparison of Industrial Customer VoLL Results Standardized to \$ 2011 and 7,140	
MWh/Customer.....	56
Table 25 Cost of Prolonged Outages for Maryland Industrial Customers Standardized to \$ 2011 and 135	
MWh/Customer.....	59
Table 26 Summary of Outage Compensation Schemes across the US.....	61
Table 27 Estimate of Maryland Miles and Cost for Vegetation Management	68
Table 28 Project Costs to Underground	72
Table 29 DC Cost for Undergrounding.....	72
Table 30 Maryland Customer Count by Utility.....	73
Table 31 Maryland Cost Estimates for Undergrounding	73
Table 32 Estimated Cost Structure for Maryland Undergrounding	74
Table 33 Transmission and Area Distribution Investments	77
Table 34 Distribution Improvement Costs.....	79

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Acknowledgment:

This material is based upon work supported by the Department of Energy, under Award Number(s) DE-OE0000123."

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NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Analysis Summary

1 INTRODUCTION

1.1 INTRODUCTION

1.1.1 Statement of the purpose

The Maryland Public Service Commission (MDPSC) commissioned a study to be conducted of a Cost-Benefit Analysis of Various Electric Reliability Improvement Projects from the End Users' Perspective through Capacity Assistance of the National Association of Regulatory Utility Commissioners (NARUC). The purpose of the study is to quantify costs to customers of extended outages and the mitigating measures to avoid outages, reduce duration, and restore power.

1.1.2 Objectives and significance of the study

The following three objectives have been identified and constitute the body of this report:

1. Analytical, quantitative section
 - set forth a methodology to identify and quantify the costs of outages incurred by ratepayers for varying periods of time (e.g. one day, two days, three days, four days, one week)
 - establish a template to replicate in other jurisdictions
 - identify, through published and survey research, various hardships of being without electricity
 - develop costs associated with each hardship, including, but not limited to:
 1. ruined food
 2. being without water (if on a well and septic system)
 3. operating a home generator
 4. hotel room
 5. relocating a home-based business
 6. accommodations for the elderly and disabled
 7. reduction in lost productivity, wages, and revenue to businesses
2. Identify mitigation measures to address electrical outages
 - quantify capital costs
 - quantify operating costs
3. Cost-benefit analysis
 - provide data necessary to inform decision-making and improve the quality of life for ratepayers, who are now frequently impacted by these outages

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

The report provides sufficient formulary information to be scalable in other jurisdictions. This study will satisfy this objective by identifying, analyzing, and reporting about public information that may be associated with costs of outages incurred by ratepayers.

As indicated in Section 3.5 of this report, the template to apply the results of this study in other jurisdictions is provided in the Cost/Benefit Analysis deliverable which was provided in Microsoft Excel. The tables from that section are in this report and labeled Table 4.

1.1.3 Questions and Sub-questions

There are three primary questions the study addresses:

- What are the costs of outages incurred by ratepayers for varying periods of time (e.g. one day, two days and/or one week)?
- What are quantifiable capital and operating mitigation measures that address electrical outages and improve reliability?
- What cost-benefit analysis can be provided the Commission so that it can make inform decisions and improve the quality of life for ratepayers frequently impacted by these outages?

1.1.4 Definitions

Added Value of Service Reliability - quantified by the willingness of customers to pay for service reliability, taking into account the resources (e.g., income) of the residential customer or by a firm's expected net revenues associated with the added reliability.

C&I – Commercial and Industrial Electricity Customer Segment.

- The commercial segment consists of facilities that provide services and includes the equipment of: businesses; federal, state, and local governments; and other private and public organizations, such as religious, social, or fraternal groups, including institutional living quarters and sewage-treatment facilities.
- The industrial segment consists of all facilities and equipment used for producing or assembling goods. This segment consists of manufacturing (NAICS codes 31-33); agriculture, forestry, and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); natural gas distribution (NAICS code 2212); and construction (NAICS code 23).

Customer Damage Function (CDF) - Customers' economic losses as a result of reliability and power-quality problems can be summarized by what is called a customer damage function (CDF). This idea was first suggested in 1994 by Goel and Billinton. They described the customer damage function as a simple linear equation relating average interruption cost to the duration of an interruption. They used data collected from customers to describe this function. In 1995, Keane and Sullivan suggested a more general form of the CDF – that could be used to predict interruption cost values from a number of variables that have been shown in interruption cost surveys to influence customer interruption costs. Their form of the CDF appears below:

$$\text{Loss} = f \{ \text{interruption attributes, customer characteristics, environmental attributes} \}.$$

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The interruption cost (Loss) in Eq. 1 is expressed in dollars per event, per customer. The factors on which interruption costs depends are defined as follows:

- Interruption attributes are factors such as interruption duration, season, time of day, and day of the week during which the interruption occurs.
- Customer characteristics include factors such as: customer type, customer size, business hours, household family structure, presence of interruption-sensitive equipment, and presence of back-up equipment.
- Environmental attributes include: temperature, humidity, storm frequency, and other external/climate conditions.¹

Direct Worth Approach (DW) - different interruption scenarios are described and the respondents are asked to estimate the costs they would experience if the scenario occurs at a predefined reference time.²

Value-based Reliability Planning - balances the incremental costs of improved reliability in generation, transmission, and/or distribution against the incremental benefits of enhanced (or maintained) system reliability with both costs and benefits defined as societal costs and societal benefits.

Value of Lost Load (VoLL) - the value that represents a customer's willingness to pay or willingness to accept for reliable electricity service (or avoid curtailment). It is generally measured in dollars per unit of power (e.g., megawatt hour, "MWh"). Accurately estimating VoLL for a given region and a specific type of outage is a challenge. VoLL depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, and other specific characteristics of an outage. VoLL reflects what economists call "equivalent variation" (see Willingness to Accept) or "compensating variation" (see Willingness to Pay)³

Willingness to Accept (WTA) – compensation that customers would be willing to accept to have a service interruption.

Willingness to Pay (WTP) – amount of money that customers would be willing to pay to avoid a service interruption.

1.1.5 Delimitations & limitations

The study is limited to a review of literature published in the past ten years. MD PSC Staff and Consultants agreed that studies published previous to that period are most likely out of date due to changes in the US and Maryland economies, and corresponding changes in the use of electric power.

¹ This definition is compiled from "Should Public Utilities Compensate Customers for Service Interruptions?" Ken Costello, Principal Researcher, National Regulatory Research Institute, Report No. 12-08, July 2012; Lawrence Berkeley National Laboratory: "Estimated Value of Service Reliability for Electric Utility Customers in the United States", Michael J. Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A, Freeman, Sullivan & Co., June 2009; Willingness to Pay to Avoid Outages: Reliability Demand Survey, Kathleen King, PhD, Bates White Economic Consulting, Washington, DC, June 2012; and "Estimating the Value of Lost Load", London Economics International LLC, June 17, 2013.

² Ibid.

³ Op. Cit. Compiled definition.

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A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

The study is limited to secondary research. No primary research (direct surveys of customers) was deemed necessary for this Study.

No studies of outages lasting longer than 8 hours were found which had been published in the past ten years. Consultants, after conferring with the authors of two other studies decided that for residential customers, an 8 hour outage cost could be multiplied by 3 to estimate the cost for a 24 hour outage. For commercial and industrial customers, the Consultants agreed that 8-9 hour interruption costs would serve as a good proxy for the cost of a 24 hour outage since most businesses are open for operation for 8-12 hours.

Most studies did not distinguish between capital and operating and maintenance (O&M) costs. Since this is a critical part of the results, Generally Accepted Accounting Principles (GAAP) were applied to expenses to distinguish between capital expenses and O&M costs.

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A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

2 EXECUTIVE SUMMARY

This report provides two of the three deliverables for the Cost Benefit Analysis of Various Electric Reliability Improvement Projects from the End Users' Perspective. One of the two deliverables included in this report is a Summary Analysis of the cost to customers (residential, commercial, and industrial) of extended outages provided by day of the week, each 4 day combination of weekday and weekends, and a week. The other deliverable is a section of Mitigating Measures which describes the types of costs incurred to avoid outages, reduce duration and restore power. The mitigating measures costs are also distinguished as capital or operating and maintenance (O&M).

The third deliverable was provided in a Microsoft Excel spreadsheet and contains the costs to customers of extended outages (Cost-Benefit Analysis). The cost tables are also presented in this report. There are no tables in the spreadsheet which are not included in this report.

This study is the first of its kind. No other recent publically available study determines the cost to customers of outages with durations more than 8 hours. The analysis reveals the tremendous costs, inconveniences, and other effects of outages to customers during catastrophic events.

There are two methods of estimating customer costs discussed in this report; Direct Worth and Value of Lost Load or Willingness to Pay/Willingness to Accept.

Direct Worth costs address the various hardships of being without electricity through published and survey research. Some of these were requested in the original request for proposals and some were found in the 2013 "ERCOT Value of Lost Load Study". Below is the list of items in each:

Original request for proposals costs

- Ruined food
- Being without water (if on a well and septic system)
- Operating a home generator
- Hotel room
- Relocating a home-based business
- Accommodations for the elderly and disabled
- Road/transportation disruption

2013 "ERCOT Value of Lost Load Study" costs

- Gas lanterns
- Gas stoves
- Backup battery supply for electronics
- Candles
- Ice
- Kerosene heaters
- Lost wages

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

A template which includes all the items above was designed to allow customer costs during extending outages to be calculated more accurately at a detailed level per customer. The template can also be applied to more accurately estimate the cost to all customers if used in a matrix design. In other words, the design of the template can calculate an average cost to one customer who has a generator as well as to all customers who have generators.

Examples of how to use the template are provided. Consultant recommendations are also provided throughout the report. The recommendations are focused on collecting additional data that can be used consistently with the template to estimate and project customer costs more accurately.

Value of Lost Load or Willingness to Pay/Willingness to Accept is a method for valuing customer costs of prolonged outages by surveying customers with a series of precise questions leading to a valuation. A number of these surveys have been conducted in the US and abroad over the past 20+ years. This study discusses different survey results and presents a summary of the results of these surveys standardized to Maryland in 2011 dollars. The data collected focuses on the attributes of the interruptions and the characteristics of the customers affected by the outages.

The study concludes that daily outage costs for residential customers can range from a low of \$33 to a high of \$363. Many factors discussed in the report explain this variation. Among these factors include time of year, weekday versus weekend day, methodologies, and customer perceptions. Residential customer behavior characteristic have changed in the last 20 years due in part to the ubiquity of electronics and the internet. Therefore, additional data collection and analysis should be done.

The mitigation measures are the areas, departments, activities, policies, procedures, etc. at the utility company that can be implemented, changed or improved in order to avoid, eliminate, or reduce the occurrence and duration of outages. The gains in mitigation measures help reduce the cost to the utility and direct costs incurred by customers during outages while improving reliability and time to restore power. Such measures also improve safety to utility and emergency response personnel during maintenance and outages.

The major types of mitigation measures discussed include:

- Vegetation management,
- Undergrounding of distribution system,
- Delivering System Improvements,
- End-Use Investments,
- Replacement of Feeders,
- Call Center Improvement,
- Utility Work Force,
- Outage Process Improvements,
- Facilities that Require Backup Generation,
- Maryland Energy Assurance Plan, and
- Protecting Medically Vulnerable Citizens.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Recommendations are also provided in the mitigating measures section which can be used as a roadmap for collection new or existing data in a format that can facilitate analysis of capital and operating and maintenance costs more precisely.

The costs incurred by customers and the mitigating costs analysis can be applied and used in other jurisdictions. Using standardized methodologies throughout the United States will allow the data to be rolled up for national profiles as well as provide the cost comparisons by state.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

3 QUANTITATIVE ANALYSIS

3.1 ANALYSIS APPROACH – A DESCRIPTION OF METHODS UTILIZED TO IDENTIFY AND QUANTIFY THE COSTS OF OUTAGES INCURRED BY RATEPAYERS FOR VARYING PERIODS OF TIME

A literature review was conducted resulting in the discovery of over 75 articles, studies, rate cases and reports from the US and abroad. Many of these referenced each other. Only the most recent or the most detailed studies referenced were used.

The two primary questions investigated in this report are:

- “What is the cost to a customer of a prolonged outage?” and
- “What are the costs to utilities to prevent or shorten prolonged outages?”

Section 3 analyzes the cost to customers of prolonged outages. Section 4 identifies and values the costs of mitigation measures to reduce the duration or prevent prolonged outages.

Two methods of estimating customer costs were investigated for this study:

1. Direct Worth which is covered in section 3.2.
2. Value of Lost Load or Willingness to Pay/Willingness to Accept concepts which are covered in section 3.3.

“Weathering the Storm, Report of the Grid Resiliency Task Force” was studied and analyzed first. The study’s next step was the literature review.

In addition to the literature review, the telephone calls were made to the state public utility commissions for which no reports had been found during the literature review process. These calls were made to investigate the possible availability of any similar reports or rate cases. None were found during this process.

After these processes were completed, the authors of two key primary reports were interviewed for additional information and clarity. Specifically, the Consultants questioned:

- Josh Schellenberg of Freeman, Sullivan & Co., who co-authored the 2009 Lawrence Berkeley Laboratory Report titled “Estimated Value of Service Reliability for Electric Utility Customers in the United States”, and
- Julia Frayer of London Economics International LLC, who was the lead author of the 2013 Electric Reliability Council of Texas report titled “Estimating the Value of Lost Load”.

Both assisted with understanding and using the complex multiple regression customer damage functions, which were utilized to determine the costs of outages to customers under the Value of Lost Load concept. Their contributions and assistance were greatly appreciated.

The literature review determined that the most accurate CDF was published by the Lawrence Berkeley National Laboratory – “Estimated Value of Service Reliability for Electric Utility Customers in the United

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A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

States", Michael J. Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A, Freeman, Sullivan & Co., June 2009.

Individual components of customers' outage costs were researched and analyzed separately for residential, commercial and industrial customers. The results and supporting analysis are explained in section 3.2.

3.2 HARDSHIPS AND DIRECT COSTS OF BEING WITHOUT ELECTRICITY

This section provides information about the various hardships of being without electricity through published and survey research.

3.2.1 Residential Customer Hardships and Direct Costs

An analysis of a list of costs was requested in the original request for proposals. Those costs are listed next:

1. Ruined food,
2. Being without water (if on a well and septic system),
3. Operating a home generator,
4. Hotel room,
5. Relocating a home-based business,
6. Accommodations for the elderly and disabled, and
7. Road/transportation disruption.

During the research and review process other residential customer costs were found in the 2013 "ERCOT Value of Lost Load Study".⁴ These include the costs of:

1. Gas lanterns,
2. Gas stoves,
3. Backup battery supply for electronics,
4. Candles,
5. Ice,
6. Kerosene heaters, and
7. Lost wages.

The study includes estimates of all of these costs in this report.

The following section describes the causes of possible costs in a prolonged outage.

3.2.1.1 *Ruined Food*

Probably the most common cost for residential customers in a prolonged outage is that of ruined food. According to the USDA:

⁴ "Estimating the Value of Lost Load", London Economics International, LLC, 2013, p 12.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

“The refrigerator will keep food safe for up to 4 hours. If the power is off longer, you can transfer food to a cooler and fill with ice or frozen gel packs. Make sure there is enough ice to keep food in the cooler at 40°F or below. Add more ice to the cooler as it begins to melt. A full freezer will hold the temperature for approximately 48 hours (24 hours if it is half full). Obtain dry ice or block ice if your power is going to be out for a prolonged period. Fifty pounds of dry ice should hold an 18-cubic-foot freezer for 2 days.”⁵

Therefore, the study assumes a residential customer’s food spoils in 4 hours if there is no additional refrigeration.

The research indicated the cost of ruined food can run anywhere from \$72 to \$450. According to a Con Edison study filed with the New York PSC the average values of food spoilage in a refrigerator and freezer for 12 or more hours ranged from \$72 to \$125. Con Edison refunds up to \$450 for residential food spoilage.⁶ Multiple sources stated that homeowner’s insurance typically covers up to \$500 for spoiled food.

3.2.1.2 Well Water/Septic Systems

The study indicated that some rural customers would experience costs due to inoperable electric pumps for wells and septic systems. These costs include the purchase of drinking water. There is a possible cost of repairing septic systems due to “...wastewater collecting in the septic tank, treatment unit or dosing tank during the electrical outage. Components that will have to be treated and dispersed when electrical service resumes possibly include:

- Aerobic treatment units and recirculating media filters,
- Pump chambers to leaching (soil absorption) trenches,
- Sand filters,
- Dosing or flow equalization tanks,
- Low pressure distribution, and
- Subsurface drip distribution.”⁷

The study includes an estimate of repair costs which might be incurred due to a loss of power to a septic system (Figure 1).⁸ Average reported cost was \$1,492, which is the cost estimate used in this report.

⁵ "Keep Your Food Safe During Emergencies: Power Outages, Floods & Fires", USDA

⁶ "GIS Verification of Perishable Refrigerator Contents in New York City", Julie McCormick and Larry Anderson, PhD

⁷ "Power Outages and Sewage Treatment Systems", OH Dept. of Health 2011

⁸ <http://www.homeadvisor.com/cost/plumbing/repair-a-septic-tank/>

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Figure 1 Cost to Repair a Septic Tank in Maryland



3.2.1.3 Operating a Home Generator

Many residential customers investigate the possibility of installing permanent backup generation. Issues to be considered include:

- The cost of purchasing, operating and maintaining backup home generation,
- The circuits that homeowners consider necessary to be powered,
- The level of comfort desired during an outage,
- Local noise and air pollution ordinances,
- Building codes, and
- Generator fuel type.

Local ordinances and regulations as well as building codes are considered outside the scope of the study. The study estimates the costs of purchasing, operating and maintaining backup generation which are further explained next.

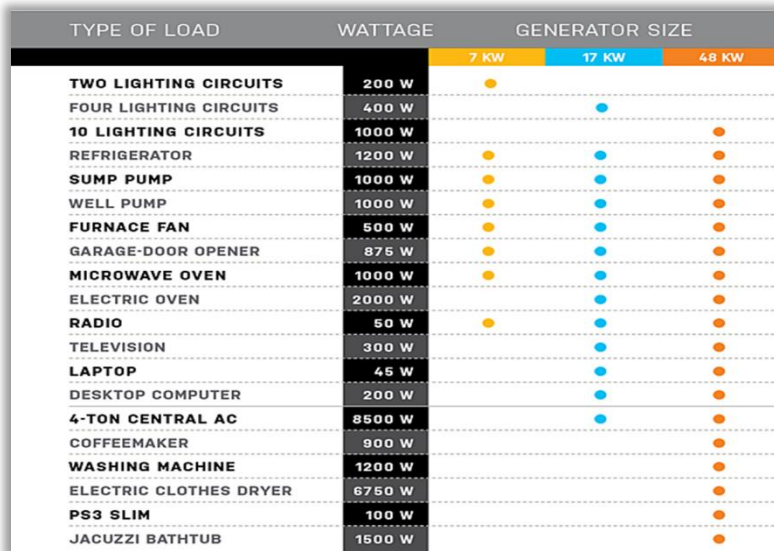
A recent article in Popular Mechanics succinctly covers the costs of installing backup residential generation.⁹ The article explains three levels of needs and how these needs relate to the capacity of generation a homeowner might install. These levels are categorized next and explained in detail in Figure 2.

⁹ <http://www.popularmechanics.com/home/improvement/electrical-plumbing/should-you-buy-a-standby-generator-14880060-2>

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A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Figure 2 Loads/Circuits Relative to Home Backup Generator Capacity



The costs of purchasing, installing and operating home generation are contained in Table 1. Fuel is assumed to be natural gas. Natural gas costs are based on natural gas delivery charges (Appendix **Error! eference source not found.**) and market rates for a fixed 12 month contract (Figure 3) in the BGE service territory for August 2013. Costs do not include capacity expenses (i.e., ROI if any, depreciation, etc.)

Table 1 Cost of Different Sizes of Home Backup Generation

Description	Size	Installed Cost	Operating Cost (incl. fuel)
Essential Circuits - About the size of a large trash can, it can energize up to 16 critical loads, though not all at once.	7 kW to 12 kW	\$4,000 to \$8,000	\$1.62/hour
Creature Comforts - Midsize generators often have load-shedding devices that shut down nonessential appliances when powering up high-priority circuits.	12 kW to 20 kW	\$4,000 to \$14,000	\$3.47/hour
Whole House - Comparable to a mini power station crammed into a 2-ton dumpster, a high-capacity, liquid-cooled generator can energize an entire home.	20 kW to 48 kW	\$8,000 to \$20,000	\$9.26/hour

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A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Figure 3 August 2013 Utility Supplier Prices – BGE12 Month Fixed Price Residential Contract (Source: <http://www.opc.state.md.us/opc/ConsumerCorner/Publications.aspx#Gas>)

UTILITY SUPPLIER OFFERS

Natural Gas Suppliers	Contract	Length of Contract	Fees	Fee to Cancel*	August 2013
BGE SERVICE AREA					DOLLARS PER
BGE/Gas Supply Price	N/A	Month to Month	N/A	N/A	.5261 Therm
BGE HOME (Constellation Energy Gas)	Fixed	12 Months	N/A	\$150.00	.6191 Therm

Estimated costs of three different sizes of natural gas fired back up generation are presented in Table 2.

Table 2 Daily Cost of Operating Backup Generation

Outage Length	Natural Gas Operating Costs (7 kW)	Natural Gas Operating Costs (17 kW)	Natural Gas Operating Costs (48 kW)
1 Day	\$ 38.88	\$ 83.32	\$ 222.19
2 Days	\$ 77.77	\$ 166.64	\$ 444.39
3 Days	\$ 116.65	\$ 249.97	\$ 666.58
4 Days	\$ 155.54	\$ 333.29	\$ 888.77
1 Week	\$ 272.19	\$ 583.26	\$ 1,555.35
Per hour	\$ 1.62	\$ 3.47	\$ 9.26

Does not include capacity costs (i.e., ROI if any, depreciation, etc.)

August 2013 Natural Gas Suppliers Chart

BGE Rate D Residential Delivery Charges

3.2.1.4 Hotel Room(s)

In cases of prolonged outages or due to damage to the home, customers may choose to relocate to a hotel. The study considers only the cost of nightly hotel stays, due to power outages, not due to damage from weather. These costs were estimated at \$100/night for a family of four.

3.2.1.5 Relocating a Home-based Business

Many people work out of their homes. Home-based work requires a work-space, telecommunications, internet connection, filing and storage space and climate control. The research indicates that for the first few days of an outage, customers may not require a new workplace. In this case, customers would be focused on other matters such as home repairs, food, etc. Additionally, workers might be able to

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

temporarily relocate to a hotel, or coffee shop to work part-time. The study then envisions that a customer would return to work full-time after 5 days. Therefore the largest expense – finding and paying for a workspace would not be necessary until a work week has passed. Due to the unpredictability of the timing of a home office recovery, the study calculates workspace cost on a weekly basis.

A recent query of The Baltimore Sun's advertising section indicated a cost of shared office spaces was about \$499/month. If a worker can rent space for a week at a time, then the cost would be about \$116 ($\$499 \div 4.3$ weeks in a month).

3.2.1.6 Accommodations for the Elderly and Disabled

The study uses the cost of a hotel room as a proxy for the cost of relocating the elderly from residences or from assisted living. Therefore, the study estimates this cost at \$100/night. Elderly and disabled can self-identify to the utility companies in Maryland so that emergency managers can ensure their well-being during extended outages if they are medically vulnerable. See section 3.12 below for more details about this program's use in extended outage planning as part of mitigating measures.

3.2.1.7 Road/Transportation Disruption

Customers who live in areas where travel becomes difficult or impossible due to downed power lines or inoperative traffic lights may be delayed in travel or find it necessary to detour around troubled areas. According to the Texas Transportation Institute at Texas A&M University, traffic delays cost motorists \$22 per hour delayed. If motorists must take a detour, a good proxy is the US Internal Revenue Service mileage allowance, which is \$0.565/mile for 2013. These can be used as accurate costs of transportation disruptions for residential customers.

3.2.1.8 Lost Wages

For workers who are paid hourly, lost wages become a very substantial cost. Other salaried workers may also face the loss of income. The study reviewed Maryland median wages for service workers, which are higher than the national median wage. The median wage in Maryland is \$35 per hour. Maryland's median service worker's wage is approximately \$24 per hour.¹⁰ Service workers are more likely to be paid on an hourly basis rather than an annual salary. As such they are more vulnerable to lost wages as a result of extended power outages.

3.2.1.9 Other Costs:

These are primarily costs necessary to maintain basic comfort and necessity levels in a residence. They include:

1. Gas lanterns – electric battery operated lanterns typically last 10 hours or so. Therefore, the study assumes the cost of gas lanterns since they can be more readily fueled during a prolonged power outage.
2. Gas stoves – the study assumes cooking using portable gas stoves rather than over a wood burning fireplace or back yard grill.

¹⁰ <http://www.choosemaryland.org/factsstats/pages/wages.aspx>

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

3. Backup battery supply for electronics – electronics will be able to be operated long enough to be shut down properly to avoid damage and loss of data.
4. Candles – for lighting.
5. Ice – used for maintaining food in freezers or refrigerators or for ice chests to store food transferred from freezers or refrigerators.
6. Kerosene heaters – for cold weather comfort. This also serves as a proxy cost for wood or natural gas burning fireplaces.

Calculations of these costs are presented in Table 3.

Table 3 Other costs for residential customers

Type of Cost	Metric/Rate	Purchase Price		Daily Cost
		Low	High	
Gas Lantern	\$10 per gallon, 2 pints per tank for 7 hours, therefore 4 pints for 14 hours	\$ 100	\$ 100	\$ 5
Gas Stove purchase	2 pints of fuel cooks for 2 hours, 2 hours of cooking per day, \$2.50 per day	\$ 130	\$ 130	\$ 2.50
Backup battery supply for electronics	\$40 per 30 minutes, 30 minutes per day			\$ 40
Candles	5 hours of candle use per night			\$ 5
Ice	\$2 per 8 hours			\$ 6
Kerosene Heater	10,000 BTU heater heats 1,000 square feet for 15 hours on 1.2 gallons of kerosene, 2 gallons to heat 1 day, \$3 per gallon	\$ 100	\$ 100	\$ 6

3.2.1.10 Detailed Summary of Residential Customer's Direct Costs Due to Prolonged Outages

This section summarizes in tabular form the cost data discussed and explained in the previous sections.

Table 4 contains a detailed summary of all direct residential customer costs. The study calculates weekend and weekday costs separately. The original request asked for a calculation of one to four days and for one week. Since these periods may include a mix of weekend and/or weekday costs, the table includes costs on a daily basis for one full week. Examples of differing combinations of four day period are included in the last three columns. The costs in this table are *not* cumulative.

Table 4 Detailed List of Residential Direct Costs for Prolonged Outages

		RESIDENTIAL CUSTOMER COSTS													
Type of Cost	Metric/Rate	One time costs		Weekend		Weekdays					1 week	4 Day Period			
		Low	High	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday		2 Weekend/ 2 Weekdays	1 Weekend/ 3 Weekdays	4 Weekdays	
1 Ruined food	After 8 hours without refrigeration, food is assumed spoiled. Con Edison refunds up to \$450 for residential customers, reports \$72 to be average.	\$ 72	\$ 450												
2 Being without water (if on a well and septic system)	\$1.50 per gallon, 50 gallons per day for a family of 4 (2 for drinking water, 4 per toilet flush, 3 flushes per person)			\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 525	\$ 300	\$ 300	\$ 300
3 Damage to septic tank	Cost of repair	\$ -	\$ 1,492												
4 Operating a home generator:															
7 kW Essential Circuits	\$1.62/hour to generate	\$ 4,000	\$ 8,000	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 272	\$ 156	\$ 156	\$ 156
17 kW Creature Comforts	\$3.47/hour to generate	\$ 4,000	\$ 14,000	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 583	\$ 333	\$ 333	\$ 333
48 kW Whole House	\$9.26/hour to generate	\$ 8,000	\$ 20,000	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 1,555	\$ 889	\$ 889	\$ 889
5 Hotel room	\$100 for a family of four.			\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 700	\$ 400	\$ 400	\$ 400
6 Relocating a home-based business	Office shared space per Baltimore Sun cost \$499/month, therefore 1 week is \$116.	\$ 116	\$ 116									\$ 116	\$ -	\$ -	\$ -
7 Accommodations for the elderly and disabled	\$100 for hotel room for one person.			\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 700	\$ 400	\$ 400	\$ 400
8 Road/transportation disruption															
Detour Costs	\$0.565 per mile per IRS reimbursement rates														
Delay Costs	\$22/hr. delayed														
9 Other (determined over the course of the study):															
Gas Lantern	\$10 per gallon, 2 pints per tank for 7 hours, therefore 4 pints for 14 hours	\$ 100	\$ 100	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 35	\$ 20	\$ 20	\$ 20
Gas Stove purchase	2 pints of fuel cooks for 2 hours, 2 hours of cooking per day, \$2.50 per day	\$ 130	\$ 130	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 18	\$ 10	\$ 10	\$ 10
Backup battery supply for electronics	\$40 per 30 minutes, 30 minutes per day			\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 280	\$ 160	\$ 160	\$ 160
Candles	5 hours of candle use per night			\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 35	\$ 20	\$ 20	\$ 20
Ice	\$2 per 8 hours			\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 42	\$ 24	\$ 24	\$ 24
Kerosene Heater	10,000 BTU heater heats 1,000 square feet for 15 hours on 1.2 gallons of kerosene, 2 gallons to heat 1 day, \$3 per gallon	\$ 100	\$ 100	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 42	\$ 24	\$ 24	\$ 24
10 Lost Wages	Ave MD wage \$35/hour for 8 hour shift			\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 1,960	\$ 1,120	\$ 1,120	\$ 1,120

Table 5 and Table 6 illustrate how to use the data. Many of the costs are not cumulative. For example, a customer with backup generation may not need candles, lanterns or stoves. White sections indicate costs included in total costs. Shaded sections indicate costs not included.

Sample 1 illustrates the cost of outage to a customer with:

- With a well that works and is not damaged,
- With a 17 kW generator,
- Who is not disabled,
- Who does not get a hotel,
- Has an hourly job and works every day, and
- Does not have home office.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 5 Sample 1 of How to Use the Data for Residential Customers

SAMPLE 1: Cost of outage to customer with well that works and is not damaged, with a 17 kW generator, not disabled, who does not get a hotel, hourly job and works every day, does not have home office															
RESIDENTIAL CUSTOMER COSTS															
Type of Cost	Metric/Rate	One time costs regardless of outage duration		Weekend		Weekdays					1 week	4 Day Period			
		Low	High	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday		2 Weekend/ 2 Weekdays	1 Weekend/ 3 Weekdays	4 Weekdays	
1 Ruined food	After 8 hours without refrigeration, food is assumed spoiled	\$ 72	\$ 450												
2 Being without water (if on a well and septic system)	\$1.50 per gallon, 50 gallons per day for a family of 4 (2 for drinking water, 4 per toilet flush, 3 flushes per person)			\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 525	\$ 300	\$ 300	\$ 300
3 Damage to septic tank	Cost of repair	\$ -	\$ 1,492												
4 Operating a home generator:															
7 kW Essential Circuits	\$1.62/hour to generate	\$ 4,000	\$ 8,000	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 272	\$ 156	\$ 156	\$ 156
17 kW Creature Comforts	\$3.47/hour to generate	\$ 4,000	\$ 14,000	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 583	\$ 333	\$ 333	\$ 333
48 kW Whole House	\$9.26/hour to generate	\$ 8,000	\$ 20,000	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 1,555	\$ 889	\$ 889	\$ 889
5 Hotel room	\$100 for a family of four.			\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 700	\$ 400	\$ 400	\$ 400
6 Relocating a home-based business	Office shared space per Baltimore Sun cost \$499/month, therefore assumed	\$ 116	\$ 116	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
7 Accommodations for the elderly and disabled				\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 700	\$ 400	\$ 400	\$ 400
8 Road/transportation disruption				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Detour Costs	\$0.565 per mile per IRS reimbursement rates														
Delay Costs	\$22/hr. delayed														
9 Other (determined over the course of the study):															
Gas Lantern	\$10 per gallon, 2 pints per tank for 7 hours, 1 gallon for 14 hours	\$ 100	\$ 100	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 35	\$ 20	\$ 20	\$ 20
Gas Stove purchase	2 pints of fuel cooks for 2 hours, 2 hours of cooking per day, \$5 per day	\$ 130	\$ 130	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 18	\$ 10	\$ 10	\$ 10
Backup battery supply for electronics	\$40 per 30 minutes, 30 minutes per day			\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 280	\$ 160	\$ 160	\$ 160
Candles	5 hours of candle use per night			\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 35	\$ 20	\$ 20	\$ 20
Ice	\$2 per 8 hours			\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 42	\$ 24	\$ 24	\$ 24
Kerosene Heater	10,000 BTU heater heats 1,000 square feet for 15 hours on 1.2 gallons of kerosene, 2 gallons to heat 1 day, \$3 per gallon	\$ 100	\$ 100	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 42	\$ 24	\$ 24	\$ 24
10 Lost Wages	Ave MD wage \$35/hour for 8 hour shift			\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 1,960	\$ 1,120	\$ 1,120	\$ 1,120
TOTAL		\$ 4,000	\$ 14,000	\$ 363	\$ 363	\$ 363	\$ 363	\$ 363	\$ 363	\$ 363	\$ 363	\$ 2,543	\$ 1,453	\$ 1,453	\$ 1,453

Sample 2 illustrates the cost of outage to customer:

- Who has 10 miles of detours on a daily basis,
- Who has a road delay of ½ hour on a daily basis,
- With no well or septic tank,
- No generator,
- Not elderly/disabled,
- Who does not get a hotel,
- Does not lose wages, and
- Has no home office.

Table 6 Sample 2 of How to Use the Data for Residential Customers

SAMPLE 2: Cost of outage to customer with no well, no generator, has road disruption, not elderly/disabled, who does not get a hotel, does not lose wages, no home office															
RESIDENTIAL CUSTOMER COSTS															
Type of Cost	Metric/Rate	One time costs regardless of outage duration		Weekend		Weekdays					1 week	4 Day Period			
		Low	High	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday		2 Weekend/ 2 Weekdays	1 Weekend/ 3 Weekdays	4 Weekdays	
1 Ruined food	After 8 hours without refrigeration, food is assumed spoiled	\$ 72	\$ 450												
2 Being without water (if on a well and septic system)	\$1.50 per gallon, 50 gallons per day for a family of 4 (2 for drinking water, 4 per toilet flush, 3 flushes per person)			\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 75	\$ 525	\$ 300	\$ 300	\$ 300
3 Damage to septic tank	Cost of repair	\$ -	\$ 1,492												
4 Operating a home generator:															
7 kW Essential Circuits	\$1.62/hour to generate	\$ 4,000	\$ 8,000	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 39	\$ 272	\$ 156	\$ 156	\$ 156
17 kW Creature Comforts	\$3.47/hour to generate	\$ 4,000	\$ 14,000	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 83	\$ 583	\$ 333	\$ 333	\$ 333
48 kW Whole House	\$9.26/hour to generate	\$ 8,000	\$ 20,000	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 222	\$ 1,555	\$ 889	\$ 889	\$ 889
5 Hotel room	\$100 for a family of four.			\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 700	\$ 400	\$ 400	\$ 400
6 Relocating a home-based business	Office shared space per Baltimore Sun cost \$499/month, therefore assumed	\$ 116	\$ 116	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
7 Accommodations for the elderly and disabled				\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 100	\$ 700	\$ 400	\$ 400	\$ 400
8 Road/transportation disruption															
Detour Costs (10 mile detour 1 time per day)	\$0.565 per mile per IRS reimbursement rates			\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 39	\$ 22	\$ 22	\$ 22
Delay Costs (1/2 hour delay 1 time per day)	\$22/hr. delayed			\$ 11	\$ 11	\$ 11	\$ 11	\$ 11	\$ 11	\$ 11	\$ 11	\$ 77	\$ 44	\$ 44	\$ 44
9 Other (determined over the course of the study):															
Gas Lantern	\$10 per gallon, 2 pints per tank for 7 hours, 1 gallon for 14 hours	\$ 100	\$ 100	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 35	\$ 20	\$ 20	\$ 20
Gas Stove purchase	2 pints of fuel cooks for 2 hours, 2 hours of cooking per day, \$5 per day	\$ 130	\$ 130	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 2.50	\$ 18	\$ 10	\$ 10	\$ 10
Backup battery supply for electronics	\$40 per 30 minutes, 30 minutes per day			\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 280	\$ 160	\$ 160	\$ 160
Candles	5 hours of candle use per night			\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ 35	\$ 20	\$ 20	\$ 20
Ice	\$2 per 8 hours			\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 42	\$ 24	\$ 24	\$ 24
Kerosene Heater	10,000 BTU heater heats 1,000 square feet for 15 hours on 1.2 gallons of kerosene, 2 gallons to heat 1 day, \$3 per gallon	\$ 100	\$ 100	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 42	\$ 24	\$ 24	\$ 24
10 Lost Wages	Ave MD wage \$35/hour for 8 hour shift			\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 280	\$ 1,960	\$ 1,120	\$ 1,120	\$ 1,120
TOTAL		\$ 402	\$ 780	\$ 81	\$ 81	\$ 81	\$ 81	\$ 81	\$ 81	\$ 81	\$ 81	\$ 567	\$ 324	\$ 324	\$ 324

3.2.1.11 Further Information Which Supports the Residential Cost Analysis

In October 2010, the Montgomery County Maryland Executive commissioned a Work Group of county residents and charged them with the mission of investigating “...causes for Pepco’s frequent electricity outages...” and “...proposing corrective steps, as appropriate.” The Work Group’s “Final Report to the Montgomery County Maryland Executive” published April 20, 2011 contained the results of online surveys of residential and commercial customers. While the survey’s results may not be scientific due to survey limitations (respondents were self-selected as opposed to randomly selected and may have responded more than once), they are presented here for purposes of comparison with the Study’s findings.

According to that report, “The median range of costs to residential customers reporting costs associated with outages [of 5 hours or more] was \$100-500, with 51.9 percent of those who experienced losses reporting this range for the magnitude of losses.”¹¹ Table 7 summarizes these results. These figures are similar in nature to the results of direct cost approach of \$363 per day as shown in Table 5.

Table 7 Summary of 2011 Montgomery County PEPCO Work Group Survey Results

Figure B8 – Summary of Survey Results related to Outage Costs (Residential)

	Under \$100	Between \$100-\$500	Between \$500-\$1,000	More than \$1,000
Number of responses	929	4,628	2,230	1,128
Cumulative	929	5,557	7,787	8,915
Cumulative (percentile)	10%	62%	87%	100%
The median (50th percentile) is between \$100-\$500				

In 2012 a survey by Bates White Economic Consulting¹² asked customers to list the “hassles” of outages that were most important to them in either short or prolonged outages. The survey showed that 75 – 80% of respondents listed “lost heat/air conditioning” and “spoiled food” as the “biggest hassles” customers face in a prolonged outage (Figure 4). Over half of respondents listed losing and/or resetting electronic devices as problematic followed closely by losing lighting. Note that the shorter the outage the more problematic the loss of electronics becomes. Perhaps this is because short outages are more common, thus the loss of electronics is less acceptable. In other words, problems are expected for a long duration outage and perhaps more frustrating for short term outages.

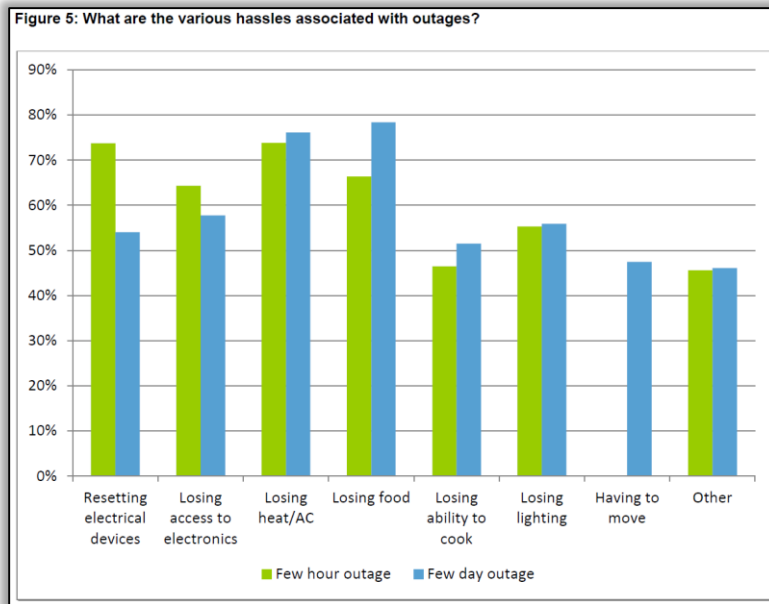
Figure 4 List of “Hassles” faced by residential customers (Bates White Economic Consulting, 2012)

¹¹ Final Report to the Montgomery County Maryland Executive, Pepco Work Group, April 20, 2011.

¹² “Willingness to Pay to Avoid Outages: Reliability Demand Survey”, Kathleen King, PhD, Principal, Bates White Economic Consulting, Washington, DC, June 2012, pp. 8-9.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective



“When asked to pick the single greatest problem, as shown in Figure 5, losing heat or air conditioning and losing food were the two biggest problems. Having to move out (for multi-day outages) and ‘other’ were the next two categories named. Compared to these problems, the other categories were cited by fewer respondents.”¹³

Research indicated that there is no direct cost of resetting electronics nor is there a direct cost of losing heat/air conditioning. The main cost of losing electronics is the loss of productivity for home based businesses or work at home professionals. Therefore, the cost of loss electronics is reflected in the lost productivity figures.

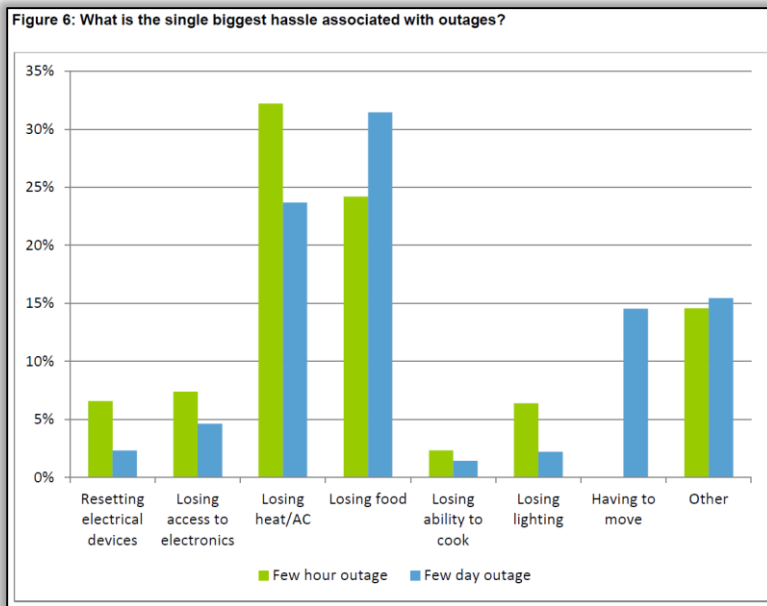
The cost of losing air conditioning may be reflected in the need to move into a hotel. It may also be reflected in the cost of installing and running backup generation. Each of these is reflected in the cost figures in the previous cost analysis tables.

Figure 5 “Biggest Hassles” of Outages (Bates White Economic Consulting, 2012)

¹³ Ibid

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective



3.2.2 Commercial Customer Hardships and Direct Costs

This section examines the direct costs for the commercial customer. Research indicated that costs include, but are not limited to:

1. Ruined food for a food service, entertainment or accommodation business
2. Being without water (if on a well and septic system for a small or rural business)
3. Operating a backup generator or micro grid
4. Relocating a home-based business employees
5. Reduction in lost productivity, wages, and revenue to businesses
6. Other costs such as those related to:
 - a. Equipment Damage
 - b. Other Restart Costs
 - c. Misc.
 - d. Backup battery supply for electronics for up to 30 minutes

There are many different types and sizes of commercial customers. This category ranges from large office buildings down to a mom and pop convenience store. In order for the reader to understand the variety and diversity of commercial customers, some facts are listed in the following tables. These tables indicate challenges faced when attempting to calculate a single direct cost of prolonged outages for the commercial customer segment.

Table 8 illustrates the impact of various types of commercial and industrial firms on Maryland's GDP. Maryland has a diverse economy with many different types of firms. Maryland ranks 15th in GDP among American states.

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A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Table 8 Maryland Commercial and Industrial GDP (<http://choosemaryland.org/factsstats/Pages/GrossDomesticProduct.aspx>)

Maryland Gross Domestic Product		
Industry	2011 GDP (\$M)	Percent Of Total
Total (Public and Private)	301,100	100.00%
Private	245,383	81.50%
Agriculture, Forestry, Fishing	737	0.20%
Mining	184	0.10%
Utilities	6,459	2.10%
Construction	13,656	4.50%
Manufacturing	19,481	6.50%
Durable Goods	9,336	3.10%
Nondurable Goods	10,145	3.40%
Wholesale Trade	13,636	4.50%
Retail Trade	16,841	5.60%
Transportation and Warehousing	5,905	2.00%
Information	11,489	3.80%
Finance and Insurance	18,269	6.10%
Real Estate	44,663	14.80%
Prof. and Technical Services	34,121	11.30%
Management of Companies	3,163	1.10%
Administrative & Waste Services	9,208	3.10%
Educational Services	4,344	1.40%
Health Care and Social Assistance	24,480	8.10%
Arts, Entertainment & Recreation	2,387	0.80%
Accommodation & Food Services	8,404	2.80%
Other Services	7,955	2.60%
Government	55,716	18.50%
Federal Civilian	N/A	N/A
Federal Military	N/A	N/A
State and Local	N/A	N/A

The varying sizes of customers in terms of employees are presented in Table 9. Employees are about evenly split between firms employing 500 or more and those employing 500 or less people.

NARUC and MDPSC

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Table 9 Maryland Companies in Terms of Number of Employees (2009 US Census)

Employment Categorized by Size Of Enterprise	Companies	Employees	Annual Payroll (\$1,000)
All firms	109,087	2,122,388	96,620,659
Fewer than 5 employees	62,872	106,825	4,283,847
5 to 9 employees	18,403	120,602	4,351,225
10 to 19 employees	11,916	158,537	6,028,792
20 to 99 employees	10,546	391,937	16,314,170
100 to 499 employees	2,704	327,330	14,676,079
500 employees or more	2,646	1,017,157	50,966,546

Table 10 illustrates the size differential of commercial customers among various utilities in Maryland in terms of MWh consumed annually. It should be noted that several studies discuss that each utility may report customer statistics in a different manner to the US Energy Information Administration. Nevertheless, the data show that commercial customers vary to a significant degree in their consumption of electricity.

Table 10 Maryland Commercial Customers Segmented by Size in Average MWh Consumed per Year (EIA 2011)

Entity	Number of Customers	Sales (MWh)	Ave. MWh/ Customer	More/Less Than Ave.
A & N Electric Cooperative	48	600	13	-37
Baltimore Gas & Electric Company	71,684	3,258,401	45	-4
Choptank Electric Coop, Inc	4,735	216,897	46	-4
Delmarva Power	17,659	554,337	31	-18
Easton Utilities Commission	2,323	151,383	65	16
Hagerstown Light Department	2,602	101,507	39	-10
Potomac Electric Power Company	28,088	1,672,060	60	10
Southern Maryland Elec Coop Inc	14,314	1,323,924	92	43
The Potomac Edison Company	20,080	724,270	36	-13
Thurmont Municipal Light Company	380	17,498	46	-3
Town of Berlin	310	3,528	11	-38
Town of Williamsport	119	2,679	23	-27
Total	162,342	8,027,084	49	

Clearly, the commercial segment is diverse in size and type, whether it is segmented by revenues, employees or electricity consumption. This significantly affects individual direct costs. E.g., an office building will have little or no food spoilage, while a restaurant may have little or no damage to electronic equipment. Additionally, each business would make its own decision about reducing or ceasing operations during a prolonged outage. E.g., backup generation may be relatively expensive to operate on a continuous 24-hour basis, enabling the business to remain open for normal business hours and

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

operations. Thus, different businesses would make differing decisions about operating generation for 24 hours at a time. However, this study attempts to list and analyze various individual direct costs of a prolonged outage.

Each of the individual costs was analyzed and is presented in the next sections.

3.2.2.1 Ruined Food for a Food Service, Entertainment or Accommodation Business

The research indicated that the costs of food for accommodations and food service establishments varied between 25% and 38% of total revenues.¹⁴ If an establishment does not have backup generation or the ability to save food with ice or dry ice, then food spoils in four hours. According to the US Census of Business, in 2011 Maryland food service establishments averaged about \$760,000 in annual revenues. Assuming an establishment is open 365 days a year, revenues per day would be a little over \$2,000 per day. Food spoilage per day would range from \$520 to \$800 per day of outage.

3.2.2.2 Being Without Water (if on a well and septic system for small or rural businesses)

Commercial customers operating on wells and septic systems are assumed to be small and rural. Therefore, the study assumes similar outage costs as those of residential customers of \$1,492 for septic system repairs.

3.2.2.3 Operating a Backup Generator or Micro grid

The average commercial customer in Maryland consumes about 49,000 kWh a year. The study calculates the cost of backup generation for larger customers. It is assumed that larger customers can more readily absorb the fixed costs of backup generation and will more likely to be in need of backup generation for critical operations. The study assumes a commercial load factor of 60% for a natural gas fueled generator and three levels of annual consumption:

- 160,000 kWh,
- 315,000 kWh, and
- 800,000 kWh.

The operating costs for prolonged outages are presented in Table 11.

¹⁴ “Common Food & Labor Cost Percentages”, Houston Chronicle, Steven Buckley, 2013.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Table 11 Operating Cost of Backup Generation for Commercial Customers

Outage Length	Natural Gas Operating Cost		
	(30 kW)	(60 kW)	(150 kW)
1 Day	\$ 136.50	\$ 238.27	\$ 568.07
2 Days	\$ 273.00	\$ 476.54	\$ 1,136.15
3 Days	\$ 409.49	\$ 714.82	\$ 1,704.22
4 Days	\$ 545.99	\$ 953.09	\$ 2,272.29
1 Week	\$ 955.49	\$ 1,667.90	\$ 3,976.51
Per hour	\$ 5.69	\$ 9.93	\$ 23.67

Does not include capacity (fixed) costs
August 2013 Natural Gas Suppliers Chart
BGE Commercial delivery rates

There are a wide range of operating scenarios for C&I customers, dependent on the type of business, the type of facility, the size of the facility, the facility's purpose, and the facility's operating characteristics. Therefore, the costs illustrated in Table 12 are based on a facility which operates 24 hours a day. Installed costs are greater than for residential customers and are derived from research into commercial backup generation vendors' technical specifications.

Table 12 Installed Costs of Backup Generation for Commercial Customers

Capacity	Installed Cost	
	Low	High
30 kW	\$10,000	\$16,000
60 kW	\$16,400	\$26,400
150 kW	\$29,000	\$44,000

3.2.2.4 Relocating Home-based Business Employees

If a company has employees working at home who are unable to continue doing so, then the company may need to provide temporary workspace for those displaced workers. As a proxy for the cost of incremental office space, the study uses the cost of weekly shared office space noted in the residential costs section. It is \$116 per week per displaced employee.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

3.2.2.5 Reduction in Lost Productivity, Wages, and Revenue to Businesses

Firms unable to conduct normal business operations are subject to lost revenues. This is truer for businesses whose sales depend on day to day operations. Other firms may not be as vulnerable, such as those firms with longer sales cycles. This is one of the cases where the diversity of firms makes it difficult to determine an accurate cost for every firm in Maryland. Therefore, presenting the business cases of firms losing daily sales would offer the most accurate example of private firms' lost revenues.

The study utilized the number of firms and private GDP figures from the MD Department of Business and Economic Development. Specific data by size/type of business were not found. The figures presented in this table are an average for all private firms in Maryland. The average Maryland firm earns about \$2.25 million a year (in 2011 \$). If this is divided by 365 days per year, then the average lost revenues per business per day is \$6,136. If it is assumed 250 working days a year for an office, then the figure may go as high as \$9,000 per day. The lower figure serves as a good measure for lost revenues.

3.2.2.6 Other Costs

Other costs such as those that follow were researched using the EPRI/primen study¹⁵ and are included in the costs to commercial customers as well as in the section on costs to industrial customers.

- Equipment damage,
- Other restart costs,
- Miscellaneous costs, and
- Backup battery supply for electronics for up to 30 minutes.

3.2.2.7 Detailed Summary of Commercial and Small Industrial Customers' Direct Costs Due to Prolonged Outages

Table 13 lists in detail the costs to commercial and small industrial customers of prolonged outages. These costs are *not* additive. For example, in the case of spoiled food, the table assumes the costs to restaurants, rather than other types of commercial customers. The backup generation is presented in three different cases for three different sizes of customers. As with the residential table, a full week is presented so the reader may view the effects of costs dependent upon weekdays versus weekend days.

¹⁵ EPRI's Consortium for Electric Infrastructure for a Digital Society: "The Cost of Power Disturbances to Industrial & Digital Economy Companies", EPRI/primen, June 29, 2001.

Table 13 Detailed List of Commercial and Small Industrial Customers' Direct Costs for Prolonged Outages

SMALL COMMERCIAL AND INDUSTRIAL CUSTOMER COSTS														
Type of Cost	Metric/Rate	One time costs regardless of outage duration		Weekend		Weekdays					4 Day Period			
		Low	High	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	1 week	2 Weekend/ 2 Weekdays	1 Weekend/ 3 Weekdays	4 Weekdays
1 Ruined food (Food service business - daily cost of food)	After 8 hours without refrigeration, food is assumed spoiled. Con Edison refunds max of \$9,000 for commercial customer food spoilage.	\$ 520	\$ 800											
2 Being without water (if on a well and septic system)		\$ -	\$ 1,492											
3 Operating a generator														
30 kW	30 kW	\$ 10,000	\$ 16,000	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 955	\$ 546	\$ 546
60 kW	60 kW	\$ 16,400	\$ 26,400	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 1,668	\$ 953	\$ 953
150 kW	150 kW	\$ 29,000	\$ 44,000	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 3,977	\$ 2,272	\$ 2,272
4 Relocating or loss of productivity of home-based business employees	Office shared space per Baltimore Sun cost \$499/month, cost per employee	\$ 116	\$ 116											
7 Lost revenues	Utilized the number of firms and private GDP figures from the MD Department of Business and Economic Development. Specific data by size/type of business were not found. The figures presented in this table are an average for all private firms in MD.			\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 43,141	\$ 24,652	\$ 24,652
8 Other (determined over the course of the study):														
Equipment Damage	Estimated (primen/EPRI study)	\$ 500	\$ 2,000											
Other Restart Costs	Estimated (primen/EPRI study)	\$ 45	\$ 1,500											
Backup battery supply for electronics for 30 minutes	Estimated (primen/EPRI study)	\$ 5	\$ 320	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 280	\$ 160	\$ 160

Notes:

- Lost revenues are calculated as total private company revenues in Maryland for 2011 divided by 365 days to arrive at an estimated \$6,163 in revenue per day per firm in Maryland.

Table 14 illustrates how to use the data which was presented in Table 13. Many of the costs are not cumulative, dependent on the customer’s operational characteristics, type of business and preparedness for prolonged outages. For example, a customer with backup generation may not need candles, lanterns or stoves. White sections indicate costs included in total costs. Shaded sections indicate costs which not included in bottom line costs.

Sample 1 illustrates the cost of outage to a large restaurant with:

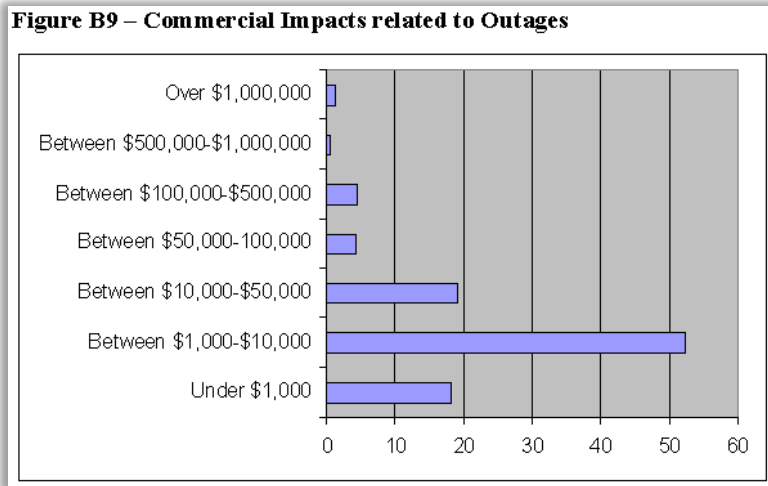
- Maximum food loss,
- Not on a well,
- With no generator,
- Revenue at the average for the state, and
- Maximum damage to equipment.

Table 14 Sample of How to Use the Commercial Cost Data

Sample of how to use data															
Sample of large restaurant with maximum food loss, not on a well, with no generator, revenue at the average for the state with maximum damage to equipment.															
Type of Cost	Metric/Rate	One time costs		Weekend		Weekdays					4 Day Period				
		Low	High	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	1 week	2 Weekend/ 2 Weekdays	1 Weekend/ 3 Weekdays	4 Weekdays	
1 Ruined food (Food service business - daily cost of food)	After 8 hours without refrigeration, food is assumed spoiled. Con Edison refunds max of \$9,000 for commercial customer food spoilage.	\$ 500	\$ 800									\$ 800	\$ 800	\$ 800	\$ 800
2 Being without water (if on a well and septic system)		\$ -	\$ 1,492												
3 Operating a generator or micro grid															
30 kW	30 kW	\$ 10,000	\$ 16,000	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 136	\$ 955	\$ 546	\$ 546	\$ 546
60 kW	60 kW	\$ 16,400	\$ 26,400	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 238	\$ 1,668	\$ 953	\$ 953	\$ 953
150 kW	150 kW	\$ 29,000	\$ 44,000	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 568	\$ 3,977	\$ 2,272	\$ 2,272	\$ 2,272
4 Relocating or loss of productivity of home-based business employees	Office shared space per Baltimore Sun cost \$499/month, cost per employee	\$ 116	\$ 116												
7 Lost revenues	Utilized the number of firms and private GDP figures from the MD Department of Business and Economic Development. Specific data by size/type of business were not found. The figures presented in this table are an average for all private firms in MD.	\$ 616	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 43,140	\$ 24,651	\$ 24,651	\$ 24,651
8 Other (determined over the course of the study):															
Equipment Damage	Estimated (primen/EPRI study)	\$ 500	\$ 2,000												
Other Restart Costs	Estimated (primen/EPRI study)	\$ 45	\$ 1,500												
Backup battery supply for electronics for 30 min.	Estimated (primen/EPRI study)	\$ 5	\$ 320	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 40	\$ 280	\$ 160	\$ 160	\$ 160
TOTAL		\$ 1,666	\$ 10,783	\$ 6,203	\$ 6,203	\$ 6,203	\$ 6,203	\$ 6,203	\$ 6,203	\$ 6,203	\$ 6,203	\$ 44,220	\$ 25,611	\$ 25,611	\$ 25,611

According to the “Montgomery County PEPCO Work Group Report”, “the median costs to commercial customers reporting costs associated with outages was \$1,000 to \$10,000, with 52.2% reporting this range as the magnitude of their losses.”¹⁶ Figure 6 summarizes these results. The example above details daily costs of \$6,200 per day. These results are comparable with the self-reported costs of survey respondents for outages lasting 5 or more hours.¹⁷

Figure 6 2011 Montgomery County PEPCO Work Group Survey Results for Commercial Customers



3.2.3 Industrial Customers Hardships and Direct Costs

The study determined that industrial customer costs include but are not limited to:

1. Being without water and waste water treatment for industrial processes
2. Operating a generator or micro grid
3. Reduction in lost productivity, wages, and revenue to businesses
4. Other such as:
 - a. Materials Loss/Spoilage
 - b. Other Restart Costs
 - c. Equipment Damage

As with the commercial customer segment, industrial customers exhibit a vast degree of diversity in terms of energy consumption (Table 15). Average customer size ranges from 66 MWh per year for BGE customers to 7,231 MWh per year for Potomac Electric customers. Utilizing a different view, BGE and Potomac Edison combined have 5,056 of 5,400 industrial customers in Maryland. These different segment sizes could be due to reporting differences as was mentioned in the previous section. These variations are also strong indicators that each industrial customer does indeed have unique characteristics affecting its direct costs of outages.

¹⁶ Final Report to the Montgomery County Maryland Executive, Pepco Work Group, April 20, 2011.

¹⁷ Ibid.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 15 Maryland Industrial Customers Segmented by Size in Average MWh Consumed per Year (EIA 2011)

Entity	Number of Customers	Sales (MWh)	Ave MWh/ Customer	More/Less Than Ave.
Baltimore Gas & Electric Company	3,259	215,536	66	-69
Choptank Electric Coop, Inc	23	91,691	3,987	3,852
Delmarva Power	122	16,496	135	0
Hagerstown Light Department	46	70,019	1,522	1,387
Potomac Electric Power Company	4	28,925	7,231	7,096
The Potomac Edison Company	1,797	260,105	145	10
Thurmont Municipal Light Company	10	26,712	2,671	2,536
Town of Berlin	110	12,385	113	-22
Town of Williamsport	29	7,427	256	121
Total	5,400	729,296	135	

An examination of the EPRI study that segments industrial customers for outage costing purposes follows next. The study was conducted on behalf of EPRI by primen in June, 2001.¹⁸ Although this is an older study, it is the most recent study discovered which surveyed industrial customer segments for actual direct costs associated with power outages. The EPRI study surveyed three segments of varying sizes (Table 16). According to the report, “These sectors were chosen in part for their sensitivity to power disruptions...” These segments are explained next.

“Three sectors of the U.S. economy are particularly sensitive to power disturbances:

- The digital economy (DE). This sector includes firms that rely heavily on data storage and retrieval, data processing, or research and development operations. Specific industries include telecommunications, data storage and retrieval services (including collocation facilities or Internet hotels), biotechnology, electronics manufacturing, and the financial industry.
- Continuous process manufacturing (CPM). This sector includes manufacturing facilities that continuously feed raw materials, often at high temperatures, through an industrial process. Specific industries include paper; chemicals; petroleum; rubber and plastic; stone, clay, and glass; and primary metals.
- Fabrication and essential services (F&ES). This sector includes all other manufacturing industries, plus utilities and transportation facilities such as railroads and mass transit, water and wastewater treatment, and gas utilities and pipelines.”¹⁹

¹⁸ EPRI’s Consortium for Electric Infrastructure for a Digital Society: “The Cost of Power Disturbances to Industrial & Digital Economy Companies” by primen/National Development Group, June 29, 2001.

¹⁹ Ibid.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 16 EPRI Industrial Customer Segments Surveyed (EPRI/primen Report Table 1-1)

	Digital Economy	Continuous Process Manufacturing (CPM)	Fabrication & Essential Services (F&ES)	Total
1 to 19 employees	179	166	159	504
20 to 249 employees	101	87	101	289
250 + employees	62	74	56	192
Total	342	327	316	985

EPRI determined that longer power outages created greater costs for businesses. The study asked respondents for costs associated with the following 4 scenarios:

- 1 second,
- Recloser,
- 3 minutes, and
- 1 hour.

A recloser event is defined as “brief outages... consisting of a one-second outage followed, a few seconds later, by another one-second outage.”²⁰

The average cost per event is presented in Figure 7. Except for recloser events, the relationship between duration of the outage and the cost of the outage appears to be directly correlated. Additionally, it is not accurate to extrapolate these costs to longer duration outages. However, they demonstrate the substantial costs of short term outages. According to the EPRI/primen study:

“Although the average cost of a one-hour outage is considerably higher at \$7,795, the difference between the cost of a one-hour outage and a one-second outage is far less than you would expect if costs accrued evenly from the beginning of an outage until its end. A one-second outage is less than 0.03 percent as long as a one-hour outage, but the cost of a one-second outage is almost 20 percent of the cost of a one-hour outage.

“Instead, the data shows that an outage of any length, even one-second, creates a substantial loss. Furthermore, the average cost of a recloser event is higher than a simple one-second outage or even a one-minute outage. The implication is that the way many utilities have designed their recloser cycles may be causing more harm than good.”²¹

²⁰ EPRI’s Consortium for Electric Infrastructure for a Digital Society: “The Cost of Power Disturbances to Industrial & Digital Economy Companies” by primen/National Development Group, June 29, 2001.

²¹ Ibid.

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Figure 7 EPRI Costs per Duration (EPRI/primen Report Table 2-1)

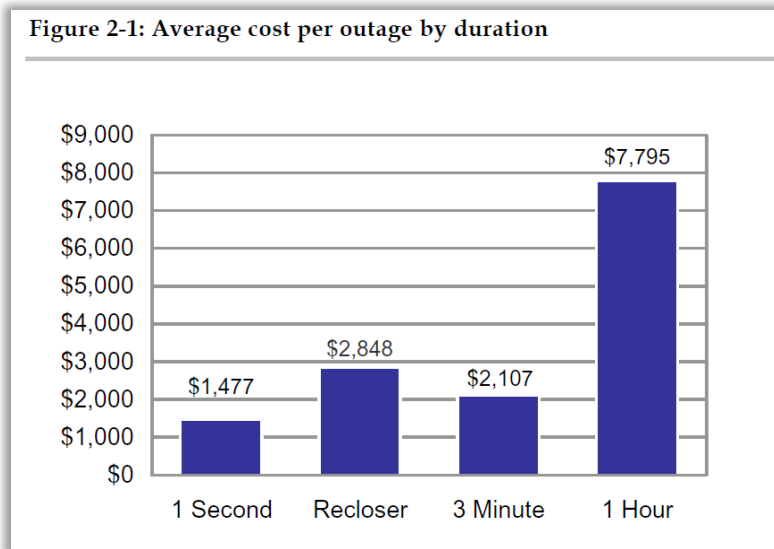


Table 17 breaks out the individual costs (and savings) of outages as provided by respondents. According to the report:

“[the report’s] Table 2-1 shows the surprisingly high average cost of recloser events. Most of the cost for a recloser event comes from damage to the customer’s equipment, presumably from the strain of stopping and restarting so quickly.

“[the report’s] Table 2-1 also reveals that the primary cost differences between a longer (one-hour) outage and a brief outage arise from lost production or sales, idled labor, and costs of restarting operations after a significant amount of downtime.

“At first glance, some of the losses in [the report’s] Table 2-1 may seem out of proportion to the length of the outage. How is it possible, for example, that a one-second outage can yield measurable losses in production? The answer is that the disruption of a business’s operations doesn’t end the instant power is restored.

“Instead, the businesses surveyed for this study indicated that a one-second outage creates, on average, almost 9 minutes of downtime for their operations (8.9 minutes). Recloser events and three-minute outages disrupt operations for almost 14 minutes (13.6 minutes and 13.7 minutes, respectively), and a one-hour outage disrupts operations for 71.6 minutes on average.”

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 17 Individual Costs per Outage (EPRI/primen Report Table 2-1)

	1 Second	Recloser	3 Minute	1 Hour
Costs	\$1,489	\$2,848	\$2,124	\$8,080
Net Lost Production ^a	\$284	\$274	\$466	\$2,922
Labor	\$433	\$263	\$590	\$1,763
Materials Loss or Spoilage	\$99	\$68	\$248	\$231
Equipment Damage	\$554	\$2,011	\$500	\$576
Backup Generation ^b	\$21	\$64	\$89	\$449
Overhead	\$33	\$49	\$101	\$364
Other Restart Costs	\$60	\$46	\$121	\$1,457
Misc.	\$5	\$73	\$9	\$318
Savings	\$12	\$0	\$17	\$285
Unused Materials	\$10	\$0	\$14	\$263
Savings on Energy Bill	\$2	\$0	\$2	\$16
Unpaid Labor	\$0	\$0	\$1	\$6
Net Cost	\$1,477	\$2,848	\$2,107	\$7,795

^aOr net lost sales
^bIncludes cost to run and/or rent backup generation

Uniquely, the EPRI/primen report calculates customer savings due to power outages. However, savings are minimal compared to costs. This table and the small savings from power outages are presented in the study merely as a point of interest. Therefore, the study does not include any savings in the customer power outage cost calculations.

Next, the study examines direct costs estimated on an individual basis.

3.2.3.1 *Being Without Water and Waste Water Treatment for Industrial Processes*

Onsite industrial water and waste water treatment is critically necessary for the following industrial processes:

- Iron and steel industry,
- Mines and quarries,
- Food industry,
- Pulp and paper industry,
- Chemicals industry, and
- Nuclear industry.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

According to Water World magazine,²² 55% of industrial facilities manage their own onsite waste water treatment facilities. There are several different types of treatment processes utilized by these industries. These vary widely in cost, size and functionality. However, when a facility's water treatment plant goes down due to an outage, it is possible that the whole plant would have to shut down. If a facility continued operations and untreated effluent entered the public waterway or reservoirs, huge local, state and federal fines would follow. Research did not turn up any single useable and easily presentable figures or statistics about the cost associate with the loss of water and waste water treatment.

3.2.3.2 *Operating a Generator or Micro Grid*

Since there are many different possible generation capacity needs for industrial customers, due to the variety of and size of industrial customers, the study presents only one example of backup generation.

Figure 8 Example of Industrial Scale Generation



There is much discussion in the electric utility industry about the future of micro grids.²³ Research indicated two micro grids in operation in Maryland. Fort Detrick operates one 8 MW micro grid and one 16 MW Micro grid. These provide 99.999% electrical reliability.²⁴ The second, recently announced micro grid, the Konterra Solar Microgrid Storage system located at Konterra's headquarters in Laurel, MD began operation in October

2013. "The 402 kW solar micro grid system, a grid-interactive energy storage system co-located with a new 1,368 panel photovoltaic (PV) canopy array, is Maryland's first commercial solar micro grid system and is also recognized as one of the first commercial solar micro grids in the nation."²⁵ Standardized cost data is not widely established for micro grids, therefore the study has not included the costs of micro grids.

An EPRI report²⁶ provided an analysis of the costs of back up generation for industrial customers. Its figures are used as a basis for the cost of backup generation for an industrial facility included in the study. None of the case studies contained generators with combined heat and power capabilities. Using EPRI's case studies and the cost of diesel fuel from EIA, the cost of a 10MW backup generation unit was calculated and is presented in Table 18.

²² <http://www.waterworld.com/articles/iww/print/volume-11/issue-1/feature-editorial/survey-examines-wastewater-treatment-costs.html>

²³ A micro grid is a group of power generation, energy storage technologies usually supplying power to a large facility or a group of facilities and or homes. It is connected to a traditional centralized grid, but can take power from the grid, sell power to the grid or disconnect itself from the grid. Engineering and constructing micro grids require complex and "smart" controls and interconnections.

²⁴ <http://www.riverviewconsultinginc.com/uncategorized/industry-update-microgrids>

²⁵ <http://www.standardsolar.com/blog/?tag=microgrid>

²⁶ "Costs of Utility Distributed Generators, 1-10 MW Twenty-Four Case Studies" EPRI, March 2003.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Table 18 Costs of Industrial Scale Backup Generation

Cost Summary for Industrial Backup Generation	
Average of 24 Case Studies	Ave
Purchase Cost	\$ 455,000
Other Costs	\$ 294,000
Total Costs Installed	<u>\$ 749,000</u>
High case from study:	\$ 3,570,000
Hourly operating cost of 10 MW Diesel Generator with diesel at \$4/gal (EIA MD Cost of Diesel Aug. 2013)	\$ 1,280.00

3.2.3.3 Reduction in Lost Productivity, Wages, and Revenue to Businesses

The study utilized the same process and figures for industrial customers as for commercial customers. The study utilized the number of firms and private GDP figures from the MD Department of Business and Economic Development. Specific data by size/type of business were not found.

3.2.3.4 Other Costs

Other costs such as those that follow were researched using the EPRI/primen study and are included in the costs table for industrial customers.

3.2.3.5 Detailed Summary of Industrial Customers' Direct Costs Due to Prolonged Outages

Table 19 lists in detail the costs to industrial customers of prolonged outages. As with commercial customers' costs, these costs are *not* additive. As with the residential and commercial tables, a full week is presented so that the reader may view the effects of costs dependent upon weekdays versus weekend days. Industrial customers' costs are highly individualized due to the large scales, and differing electricity needs. The best estimates for the cost of prolonged outages would most accurately be determined by a study or individualized analysis of each individual industrial facility (with a suggested size over 1 MW in peak demand).

Table 19 Detailed List of Industrial Customers' Direct Costs for Prolonged Outages

LARGE COMMERCIAL AND INDUSTRIAL CUSTOMER COSTS														
Type of Cost	Metric/Rate	One time costs regardless of outage		Weekend		Weekdays					1 week	4 Day Period		
		Low	High	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday		2 Weekend/ 2 Weekdays	1 Weekend/ 3 Weekdays	4 Weekdays
1 Ruined food	After 8 hours without refrigeration, food is assumed spoiled. Con Edison refunds max of \$9,000 for commercial food spoilage. Used \$72 as min. bc businesses typically have refrigeration. This may vary substantially.	\$ 72	\$ 9,000											
2 Operating a generator														
Per EIA: Ave peak Demand for MD Industrial Customer at an assumed 90% load factor is 17 MW.	10 MW (diesel cost estimated at \$1,280/hour with diesel priced at \$4/gal)	\$750,000	\$3,500,000	\$30,720	\$30,720	\$30,720	\$30,720	\$ 30,720	\$30,720	\$30,720	\$215,040	\$ 122,880	\$ 122,880	\$ 122,880
3 Lost productivity per employee	Lost productivity is calculated as the average revenues per industrial employee per firm = \$85,155. (Source: US Census Bureau)			\$ 328	\$ 328	\$ 328	\$ 328	\$ 328	\$ 328	\$ 328	\$ 2,293	\$ 1,310	\$ 1,310	\$ 1,310
4 Lost revenues	Utilized the number of firms and private GDP figures from the MD Department of Business and Economic Development. Specific data by size/type of business were not found. The figures presented in this table are an average for all private firms in MD.			\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 43,141	\$ 24,652	\$ 24,652	\$ 24,652
5 Other (determined over the course of the study):														
Materials Loss/Spoilage	Estimated (primen/EPRI study)	\$ 1,000	\$ 2,000											
Other Restart Costs	Estimated (primen/EPRI study)	\$ 10,000	\$ 35,000											
Equipment Damage	Estimated (primen/EPRI study)	\$ 4,000	\$ 12,000											

Notes:

- Lost Productivity is calculated and presented as revenues per day per employee. It is derived from US Census Bureau figures. To calculate total productivity losses, the reader must multiply the daily figure times the number of employees in a firm. E.g., a firm with 500 employees would lose \$164,000 per day in lost productivity.
- Lost revenues are calculated as total private company revenues in Maryland for 2011 divided by 365 days to arrive at an estimated \$6,163 in revenue per day per firm in Maryland.

Table 20 demonstrates how to use the industrial direct cost data contained in Table 19. White areas are included in the total cost of an outage. Gray shaded areas are not included in the total bottom line cost of the sample outage. The following example is of a large Durable Goods Manufacturing facility which is:

- Not on a well,
- Has backup generation,
- Revenue at the average for the state of Maryland,
- Maximum damage to equipment, and
- Lost productivity of 500 employees unable to work on a daily basis.

Table 20 Sample of How to Use the Industrial Cost Data

Sample of how to use data														
Sample of large Durable Goods Manufacturing facility, not on a well, with generator, revenue at the average for the state with maximum damage to equipment and with lost productivity 500 employees per day.														
Type of Cost	Metric/Rate	One time costs		Weekend		Weekdays					4 Day Period			
		Low	High	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	1 week	2 Weekend/ 2 Weekdays	1 Weekend/ 3 Weekdays	4 Weekdays
1 Ruined food	After 8 hours without refrigeration, food is assumed spoiled. Con Edison refunds max of \$9,000 for commercial food spoilage. Used \$72 as min. bc businesses typically have refrigeration. This may vary substantially.	\$ 72	\$ 9,000											
2 Operating a generator														
Per EIA: Ave peak Demand for MD Industrial Customer at an assumed 90% load factor is 17 MW.	10 MW (diesel cost estimated at \$1,280/hour with diesel priced at \$4/gal)	\$750,000	\$3,500,000	\$ 30,720	\$ 30,720	\$ 30,720	\$ 30,720	\$ 30,720	\$ 30,720	\$ 30,720	\$ 215,040	\$ 122,880	\$ 122,880	\$ 122,880
3 Lost productivity per employee (500 employees)	Lost productivity is calculated as the average revenues per industrial employee per firm = \$85,155. (Source: US Cnesus Bureau)			\$163,760	\$163,760	\$163,760	\$163,760	\$ 163,760	\$163,760	\$163,760	\$1,146,323	\$ 655,042	\$ 655,042	\$ 655,042
4 Lost revenues	Utilized the number of firms and private GDP figures from the MD Department of Business and Economic Development. Specific data by size/type of business were not found. The figures presented in this table are an average for all private firms in MD.			\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 6,163	\$ 43,141	\$ 24,652	\$ 24,652	\$ 24,652
5 Other (determined over the course of the study):														
Materials Loss/Spoilage	Estimated (primen/EPRI study)	\$ 1,000	\$ 2,000								\$ -	\$ -	\$ -	\$ -
Other Restart Costs	Estimated (primen/EPRI study)	\$ 10,000	\$ 35,000								\$ -	\$ -	\$ -	\$ -
Equipment Damage	Estimated (primen/EPRI study)	\$ 4,000	\$ 12,000								\$ -	\$ -	\$ -	\$ -
TOTAL		\$765,000	\$3,549,000	\$200,643	\$200,643	\$200,643	\$200,643	\$ 200,643	\$200,643	\$200,643	\$1,404,504	\$ 802,574	\$ 802,574	\$ 802,574

3.3 VALUE OF LOST LOAD - WILLINGNESS TO ACCEPT THE COST OF AN OUTAGE

The second concept explored for valuing customer costs of prolonged outages falls under the description “Value of Lost Load” (VoLL). According to London Economics International LLC:

“VoLL is the value that represents a customer’s willingness to pay for reliable electricity service (or avoid curtailment). It is generally measured in dollars per unit of power (e.g., megawatt hour, “MWh”). Accurately estimating VoLL for a given region and a specific type of outage (as requested by ERCOT in this project) is a challenging undertaking as VoLL depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, and other specific traits of an outage.

“VoLL valuations can be marginal – the marginal value of the next unit of unserved power – or average – the average value of the unserved power. Marginal values of VoLL are often calculated for peak periods (or ‘worst case’) when customers will place the highest value on electricity. Average VoLLs are averaged over a certain period (e.g., one year) and are not differentiated over time. Average VoLLs tend to be lower than marginal VoLLs at peak times, as they average out the value customers place on electricity over, say a year, and therefore include periods during which customers place a low value on electricity.”²⁷

According to the National Regulatory Research Institute:

“Studies have shown the value of lost load (VoLL) per kilowatt-hour (kWh) for residential customers can be more than two orders of magnitude above the price of electricity; for commercial and industrial customers, the order of magnitude is far greater. VoLL reflects what economists call ‘compensating variation’ or ‘equivalent variation.’ The former measures what customers would be willing to pay to avoid a service interruption, while the latter measures what customers would be willing to accept to have a service interruption. Surveys generally have shown the latter measure to be higher.”²⁸

A generally accepted process or methodology for determining VoLLs involves surveying customers with a series of precise questions leading to a valuation. A number of these surveys have been conducted in the US and abroad over the past 20+ years. This study discusses different survey results and presents a summary of the results of these surveys standardized to Maryland in 2011 dollars.

The other methodology adopted by researchers includes literature reviews and compilation of meta data bases from previous studies. Both the EROCT 2013 study and the LBNL 2009 study utilize this methodology. The LBNL 2009 study calculated a new Customer Damage Function (CDF) based on a two stage multiple regression analysis of this meta data base. With the cooperation of Freeman, Sullivan & Company, this study presents an estimate of customer outage costs for Maryland based on this this CDF.

²⁷ “Estimating the Value of Lost Load”, London Economics International LLC, June 17, 2013.

²⁸ “Should Public Utilities Compensate Customers for Service Interruptions?”, National Regulatory Research Institute, Report No. 12–08, July 2012.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

“The Customer Damage Function (CDF) is a formula for accurately estimating customers’ economic losses as a result of reliability and power-quality problems. This idea was first suggested in 1994 by Goel and Billinton (1994). Their CDF was a simple linear equation relating average interruption cost to the duration of an interruption.”²⁹ The CDF appears to be an accurate methodology for estimating customers’ costs due to outages. Over the past 20 years, several other research teams adopted the idea of the CDF and have expanded it. This study proposes that the most accurate *current* CDF is the CDF derived by Freeman, Sullivan & Co. utilizing a two stage multiple regression methodology. Nevertheless, the CDF methodology is inaccurate when estimating the costs of extended outages as pointed out at the end of this section.

A CDF formula looks like this:

“Loss = f {interruption attributes, customer characteristics, environmental attributes}.

“Where the interruption cost (Loss) in the formula is expressed in dollars per event, per customer or per unit of power. The factors on which interruption costs depends are defined as follows:

- Interruption attributes are factors such as interruption duration, season, time of day, and day of the week during which the interruption occurs.
- Customer characteristics include factors such as: customer type, customer size, business hours, household family structure, presence of interruption-sensitive equipment, and presence of back-up equipment.
- Environmental attributes include: temperature, humidity, storm frequency, and other external/climate conditions.”³⁰

The next series of graphs are examples from different studies of the CDF. Each study’s graphs illustrate similar cost curves, thus indicating that despite different regions or nations, and sample sets, the CDF’s nature remains the same. Importantly, these studies demonstrate that on a \$/kW basis the first 6-8 hours are when costs rise at a logarithmic rate. After the first 6-8 hours, costs on a per kW basis level off, becoming primarily a function of the length of the outage. As can be seen in the following graphs this holds true for all customer segments analyzed in the studies.

²⁹ “Estimated Value of Service Reliability for Electric Utility Customers in the United States”, Freeman, Sullivan & Co., June 2009.

³⁰ Ibid.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Figure 9 Medium & Large US C&I Customer Segments CDF Curve (Lawrence Berkeley National Laboratory: "Estimated Value of Service Reliability for Electric Utility Customers in the United States", Freeman, Sullivan & Co., June 2009)

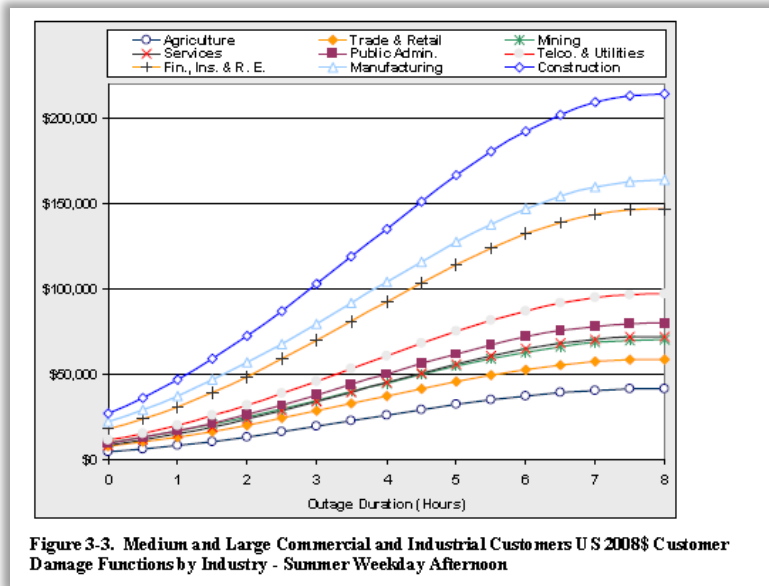
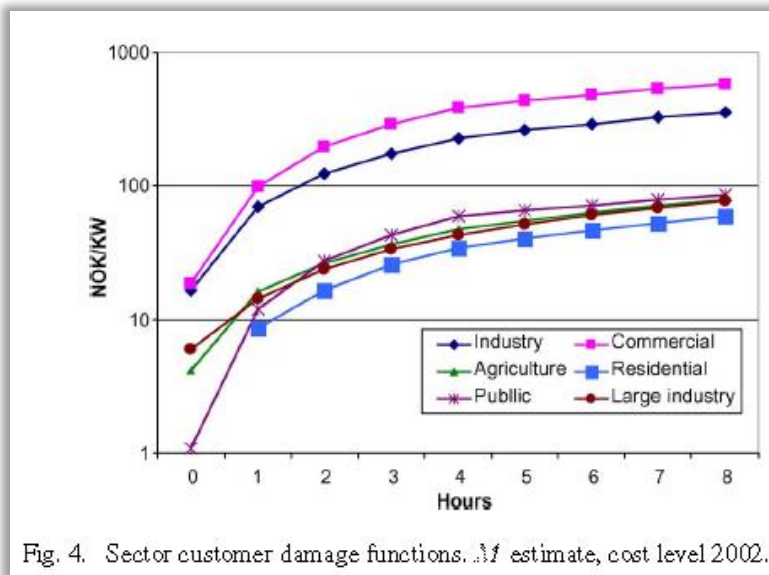


Figure 10 Norwegian CDF Curves for all Customer Segments ("Customer Costs Related to Interruptions and Voltage Problems: Methodology and Results", IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 23, NO. 3, AUGUST 2008)



The CDFs are standardized by measuring marginal costs on a \$/unit basis (kWh, MWH, kW or MW). This enables comparison across disparate sub-segments such as is shown in Figure 9. It also demonstrates that the curves' characteristics remain the same regardless of the customer segment.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

One concern that should be noted is that according to discussions with Freeman, Sullivan and Co., these curves become parabolic over extended periods of time. This means that the curves begin to arc downward turning the overall curve into a bell shape, indicating decreasing costs for extended outages. The reality is that this is obviously not the case, but it does result if the formulas are used for time periods greater than 8 hours. *Therefore, analysis indicates that a VoLL survey of customers costs of prolonged outage (e.g., greater than 8 hours) would offer much more accurate cost estimates for outages of extended duration.*

3.3.1 Residential Customers VoLL

This residential cost analysis summarizes various VoLL studies from the past ten years. Going back further in time excludes the importance of electronic devices, internet connectivity, computers, etc. that have become ubiquitous in Maryland households. Therefore, those older studies may underestimate the costs of power outages. Table 21 summarizes the results of seven VoLL studies relevant to Maryland. The results are expressed in 2011 dollars using Maryland residential customer characteristics from 2011 (the latest available data from the US Energy Information Agency). The results reflect an average use customer on an average non summer day.

As noted previously, the longest outage duration measured was 24 hours. New Zealand, Australia and Ireland exhibit the highest cost of outages, while Norwegian customers exhibited the lowest cost of outages. The outage costs for Maryland customers fall somewhere in between. By applying these other countries' survey results to Maryland customers (i.e., MD energy usage and 2011 American dollars) short outages typically would cost a Maryland customer a few dollars while an outage of 24 hours costs as much as \$81.42.

Section 3.2.1 cost examples compare at \$89 for a 24 hour weekday outage with no backup generation. This can rise to as much as \$363 (Table 5) for a customer with a 17 kW backup generator. The differences may be due to how survey questions were structured, or how customers perceive outages versus the actual costs.

Table 21 Comparison of Various Studies Customer Damage Function Results Standardized to Maryland

Cost Comparisons from Various VoLL Studies for Residential Customers. Standardized to Maryland residential customer characteristics.								
Study	Momentary	30 minutes	1 hour	2 hours	3 hours	4 hours	8 hours	24 hours
LBNL (2009 Table ES-5) Average Interruption Costs Adj. for MD Res. Customer	\$2.19	\$2.56	\$3.22			\$7.02	\$10.54	
LBNL (2004 Table 13) Residential South Atlantic	\$2.79						\$3.81	
MISO (2006 Exhibit A-3)			\$4.53	\$5.53	\$6.93			
CRA International, Australia - Victoria (2008 Table 16)			\$17.52			\$35.04	\$10.94	\$81.42
New Zealand - Auckland (2013 Table 1)							\$110.48	
Ireland (2010 Table A1 - average hour. Hourly costs range from \$0.79 - \$76.48)			\$36.87					
Norway (2008 Table IV)			\$1.29			\$4.65		\$25.42

Notes:
 All costs are adjusted to Maryland average hourly usage per the US Energy Information Agency.
 Inflation adjusted using US Department of Labor, Bureau of Labor Statistics CPI Inflation Calculator.
http://www.bls.gov/data/inflation_calculator.htm
 Currency conversion using www.bloomberg.com as of 10/15/2013

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

It should be noted that the 8 hour cost in the Australian study (\$10.91) is an outlier.

Next, the study examines an estimation of outage costs using the CDF formula developed in the Freeman, Sullivan & Co., June 2009 paper published by the Lawrence Berkeley National Laboratory (LBNL 2009). This study summarized estimates of the value of service reliability for electricity customers in the US. These estimates were obtained by analyzing the results from 28 customer value of service reliability studies conducted by 10 major US electric utilities over the 16 year period from 1989 to 2005. The datasets were combined and a two-part regression model was used to estimate customer damage functions. Analysis determined that this formula is the most accurate and most recent formula for calculating customers' costs using a CDF. The formulas for the CDF were obtained from Freeman, Sullivan & Co. Data was input to the variables based on discussions with the Maryland Public Service Commission Staff. Table 22 illustrates the results of this analysis.

The following variables comprise the inputs to the CDF:

Interruption Attributes

- Time of Day – morning, afternoon or night,
- Time of Year – summer or non-summer,
- Time of Week – weekday or weekend,
- Annual MWh per residence,

Customer Characteristics

- Residential age groupings:
 - 0-6 Years Old,
 - 7-18 Years Old,
 - 19-24 Years Old,
 - 25-49 Years Old,
 - 50-64 Years Old,
 - 65+ Years Old,
- Average Household Income,
- Medical Equipment – percent of population,
- Backup Generation – percent of population,
- Recent Prolonged Outage – percent of population,
- Detached Housing – percent of population,
- Attached Housing – percent of population,
- Apartment/Condo – percent of population,
- Mobile Home – percent of population,
- Manufactured Housing – percent of population,
- Other or Unknown Housing – percent of population.

Table 22 Cost of Prolonged Outages for Maryland Residential Customers Based on the LBNL 2009 CDF

LBNL METHOD: RESIDENTIAL								
Cost Per Day of Outage								
Outage Description	Sat	Sun	Mon	Tue	Wed	Thu	Fri	1 Week
Average Summer Occurrence for all Customers	\$ 47.26	\$ 47.26	\$ 40.28	\$ 40.28	\$ 40.28	\$ 40.28	\$ 40.28	\$ 295.90
Average Summer Occurrence for a Customer with Backup Generation	\$ 57.68	\$ 57.68	\$ 49.12	\$ 49.12	\$ 49.12	\$ 49.12	\$ 49.12	\$ 360.97
Average Non Summer Occurrence for all Customers	\$ 39.27	\$ 39.27	\$ 33.40	\$ 33.40	\$ 33.40	\$ 33.40	\$ 33.40	\$ 245.56
Average Non Summer Occurrence for a Customer with Backup Generation	\$ 45.51	\$ 45.51	\$ 38.67	\$ 38.67	\$ 38.67	\$ 38.67	\$ 38.67	\$ 284.36

Note: Regression model discussed with Freeman, Sullivan & Co. and with London Economics International.
 Both said that there is no data nor are there any studies for outages lasting longer than 8 hours.
 Both also stated that the regression is only accurate up to 8-9 hours.
 Therefore, we ran the model for 8 hours and then multiplied by 3 to get an approximation of the effects of a 24-hour outage.
 Average MD residential customer used 12,271 kWh in 2011 per EIA

It was confirmed with the authors of the LBNL 2009 paper that an approximate 24 hour outage cost could be determined by multiplying an 8 hour outage by 3. Differences between Table 21 and Table 22 figures are due to the delineation of weekend and weekdays in Table 22, while Table 21 is an average of weekdays and weekend days. Also, Table 21 is an average of all summer and non-summer days. Finally, Table 21 assumes a mix of backup generation, while Table 22 assumes customers either have or do not have backup generation.

As would be expected, weekend outages are more costly to customers since they are more likely to be at home on weekends rather than at work and school. Backup generation appears to be about 20% more costly. This may be due to customer perceptions. It may also be that the added costs of purchasing, maintaining and operating generation outweigh the savings (e.g. the one-time cost for spoiled food of around \$70 (Table 4) versus the daily cost of backup generation ranging from \$39 to \$222).

The estimates presented in Table 22 indicate that the cost of a one-week outage for Maryland's residential customers ranges from \$250 to \$360. Those estimates compare with an estimate of \$2,543 for the cost of a one-week outage shown in Table 5 (which includes an estimates for lost wages and the operating cost of backup generation) and with an estimate of \$567 presented in Table 6, which assumes no lost wages and no backup generation. This range of estimates applies to different scenarios and could reflect other factors such as:

- Differences in perception by customers of outage costs,
- Customers may underestimate costs when surveyed,
- Survey questions asked did not cover all the costs detailed in the direct cost approach (Section 3.2), or
- Overestimation of costs of study Section 3.2.

The study concludes that daily outage costs for residential customers can range from a low of \$33 (Table 22) to a high of \$363 (Table 5). Many factors discussed in the report explain this differential. Among these factors include time of year, weekday versus weekend day, methodologies, and customer perceptions. Additionally, analysis indicates that a new study resulting in a long term CDF would be the most accurate method for estimating customer costs due to prolonged outages as it is an accepted analytical method. No long-term outage CDF function has been derived since the 1990s. Residential customer behavior characteristic have changed in the intervening 20 years due in part to the ubiquity of electronics and the internet.

3.3.2 Commercial Customers VoLL

As with the residential VoLL analysis, this analysis is limited to a review of studies conducted in the past 10 years. This section first discusses the results of the LNBL survey meta-dataset for commercial customers and a summary of the results in the ERCOT study. It is followed by a comparison of studies found from the past 10 years and finally with the use of the LBNL 2009 CDF model standardized to Maryland customer characteristics.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

The following is a summary of the results taken from the report for Lawrence Berkeley National Laboratory: "Estimated Value of Service Reliability for Electric Utility Customers in the United States" by Freeman, Sullivan & Co., June 2009:

"The small commercial and industrial dataset is built from 12 studies conducted by 9 companies and includes approximately 4,636 respondents. Overall, there were approximately 20,673 total responses available for the analysis.

"The results indicate that interruption costs for construction are significantly higher than those of any other business activity in the small customer class. The costs are roughly 50% more than those experienced by the next highest sector, mining. Costs for construction and mining are significantly higher than those of other businesses because they depend heavily on electricity to directly support production. Costs for other business types are relatively close to those of retail trade – though the differences among them are statistically significant. Interruption costs for winter interruptions are significantly higher than those experienced in summer and interruption costs during the night and on weekends are significantly lower as expected.

"A summary of a few results of note:

- The longer the interruption, the higher the interruption cost.
- Weekday interruptions are more costly than weekend interruptions, but summer interruptions cost less than non-summer interruptions.
- Larger customers (in terms of annual MWh usage) incur larger costs for similar interruptions.
- The construction and mining industries incur larger costs for a similar interruption than other industries.
- Time of day does not impact the magnitude of interruption costs."³¹

In the London Economics LLC study for ERCOT (2013), a range of commercial costs was reported. Small C&I customer VoLLs were wide-ranging with the service sector generally having the lowest cost per MWh of outage. These costs ranged from \$3,302 - \$42,000 per MWh of outage. "...small C/I customers have the highest VoLLs. Small C/I customers are more labor and capital intensive than residential customers and are less likely to prepare for operational risks such as outages by using interruptible contracts and back-up generation as hedges against outages than large C/I customers, leading to generally higher VoLLs."³²

Table 23 presents a summary analysis of several scenarios utilizing the LBNL 2009 CDF model. The figures have been standardized to an average Maryland commercial customer (EIA estimate of average annual 49,995 kWh per year). Additionally, all cost figures were normalized to 2011, since this was the latest year available for EIA energy consumption figures. The table's results are the product of \$/MWh of power outage (from each study's CDF) and the Maryland specific hourly average of 5.644 kWh/hour (49.995 kWh ÷ 8,760 hours/year = 5.644 kWh in an hour). After discussing the model with Freeman,

³¹ "Estimated Value of Service Reliability for Electric Utility Customers in the United States" by Freeman, Sullivan & Co., June 2009.

³² "Estimating the Value of Lost Load", London Economic International LLC, 2013.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Sullivan & Co., it was determined that an 8 hour outage would substitute for a 24 hour outage. Most businesses operate on an 8-12 hour cycle. As such, it was decided that an 8-hour outage does not vary much in cost from a 24-hour outage. The exception to this would be facilities that operate 24 hours, like some retail firms and possibly mining firms.

The following variables comprise the inputs to the CDF:

- Interruption Attributes:
 - Time of Day – morning, afternoon or night,
 - Time of Year – summer or non-summer,
 - Time of Week – weekday or weekend,
- Customer Characteristics
 - Annual MWh per commercial customer,
 - Advanced Warning – yes or no,
 - Annual MWh – according to the EIA, average Maryland annual MWh for 2011 were 49.445,
 - Agriculture, Forestry and Fishing – percent of respondents in this industry,
 - Mining – percent of respondents in this industry,
 - Construction – percent of respondents in this industry,
 - Manufacturing – percent of respondents in this industry,
 - Transportation, Communication & Utilities – percent of respondents in this industry,
 - Wholesale & Retail Trade – percent of respondents in this industry,
 - Finance, Insurance & Real Estate – percent of respondents in this industry,
 - Services – percent of respondents in this industry,
 - Public Administration – percent of respondents in this industry,
 - Unknown – percent of respondents in this industry,
 - None or Unknown Backup Equipment – percent of respondents utilizing this equipment,
 - Backup generation or Power conditioning – percent of respondents utilizing this equipment,
and
 - Backup generation and Power conditioning – percent of respondents utilizing this
equipment.

Daily costs range from \$4,114 for a Public Administration customer on a weekend to \$19,694 for a Construction customer on a weekday. For all segments, weekday outages cost on average 40.5% more than weekend outages. Construction and Mining outage costs were much larger than other segments. Construction outages cost 98% more than the average of all other segments (except Mining). Mining was 84% more expensive than all other segments (except Construction). Backup generation added about \$15,000 to the weekly cost of outages or about \$2,100 per day.

Table 23 Estimate of Maryland Commercial Costs Using the 2009 LBNL CDF

LBNL METHOD: SMALL COMMERCIAL AND INDUSTRIAL								
Cost Per Day of Outage								
Outage Description	Sat	Sun	Mon	Tue	Wed	Thu	Fri	1 Week
Average Small C&I Customer	\$ 6,341	\$ 6,341	\$ 8,897	\$ 8,897	\$ 8,897	\$ 8,897	\$ 8,897	\$ 57,167
Average Small C&I Customer with NO backup generation or power conditioning	\$ 5,817	\$ 5,817	\$ 8,180	\$ 8,180	\$ 8,180	\$ 8,180	\$ 8,180	\$ 52,535
Average Small C&I Customer with backup generation or power conditioning	\$ 7,526	\$ 7,526	\$ 10,532	\$ 10,532	\$ 10,532	\$ 10,532	\$ 10,532	\$ 67,713
Average Small C&I Customer with backup generation and power conditioning	\$ 9,891	\$ 9,891	\$ 13,608	\$ 13,608	\$ 13,608	\$ 13,608	\$ 13,608	\$ 87,821
Agriculture, Forestry and Fishing	\$ 6,082	\$ 6,082	\$ 8,970	\$ 8,970	\$ 8,970	\$ 8,970	\$ 8,970	\$ 57,011
Mining	\$ 12,705	\$ 12,705	\$ 17,694	\$ 17,694	\$ 17,694	\$ 17,694	\$ 17,694	\$ 113,879
Construction	\$ 13,741	\$ 13,741	\$ 19,048	\$ 19,048	\$ 19,048	\$ 19,048	\$ 19,048	\$ 122,722
Manufacturing	\$ 8,231	\$ 8,231	\$ 11,455	\$ 11,455	\$ 11,455	\$ 11,455	\$ 11,455	\$ 73,738
Transportation, Communication & Utilities	\$ 8,369	\$ 8,369	\$ 11,732	\$ 11,732	\$ 11,732	\$ 11,732	\$ 11,732	\$ 75,400
Wholesale & Retail Trade	\$ 5,574	\$ 5,574	\$ 7,741	\$ 7,741	\$ 7,741	\$ 7,741	\$ 7,741	\$ 49,854
Finance, Insurance & Real Estate	\$ 8,670	\$ 8,670	\$ 12,174	\$ 12,174	\$ 12,174	\$ 12,174	\$ 12,174	\$ 78,210
Services	\$ 4,896	\$ 4,896	\$ 6,885	\$ 6,885	\$ 6,885	\$ 6,885	\$ 6,885	\$ 44,215
Public Administration	\$ 4,114	\$ 4,114	\$ 5,939	\$ 5,939	\$ 5,939	\$ 5,939	\$ 5,939	\$ 37,924

Notes:

Regression discussed model with Freeman, Sullivan & Co. and with London Economics International.

Both said that there is no data nor are there any studies for outages lasting longer than 8 hours.

Both also stated that the regression is only accurate up to 8-9 hours.

Therefore, model was run for 8 hours and assumed an 8 hour workday or 8 hours open for business or operations.

Non summer outages only.

Average Small C&I Customer assumes customer characteristics of:

Proportion of customers with backup generation or power conditioning: 26.23%

Proportion of customers with backup generation and power conditioning: 3.38%

Average MD Commercial Customer used 49,445 kWh in 2011 per EIA

Cost comparisons using the various models from past years' studies could not be standardized to Maryland. This was due to lack of detailed data in those studies, which could be used to convert to Maryland figures. e.g., segment information in the MISO study did not offer enough information to transform peak \$/kW of outage to \$/kWh of outage.

The underlying small commercial and industrial segment data varies greatly in accuracy, measurement and public reporting. To accurately apply a CDF to commercial data would require much deeper investigation than was in the scope of this study. In particular it would require some primary survey research into individual segments and substantial time would need to be spent with the authors of the several other studies.

All recent CDF studies measure outage costs for outages lasting for 24 hours or less. All recent US studies only study outages lasting 8 hours or less. It is recommended that in order to get an accurate long term outage CDF function, a customer study be performed that investigates long term outages using the methodologies outlined in the CDF reports, including primary research and surveys of customers within all small commercial customer segments.

3.3.3 Industrial Customers VoLL

Industrial customers' VoLL is explained in this section. Several VoLL studies from the past ten years were reviewed (Table 24). As part of this review, the results of several sub-segments of industrial customers were also analyzed. Maryland industrial customer's energy usage figures vary substantially as shown in Table 15. The average Maryland industrial customer consumed 135 MWh in 2011 according to the EIA. This is substantially smaller than what is traditionally accepted as a large C&I customer. A traditionally accepted standard for the US electric utility industry is that large customers have annual peak demands of greater than 1 MW. Large industrial customers also have high load factors. Some examples of C&I customers with 1 MW of peak demand follows:

- At a 90% load factor, annual energy consumption would be 7,884 MWh,
- At an 80% load factor, annual energy consumption would be 7,008 MWh, and
- At a 70% load factor, annual energy consumption would be 6,132 MWh.

An annual energy consumption figure of 7,140 MWh per customer as a standard for comparison purposes was used across all studies examined. This figure is derived from the LBNL 2009 study.

The study then presents the results of the LBNL 2009 CDF model using standardized Maryland figures for 2011, including the smaller 135 MWh average size for industrial customers (Table 25). The purpose of this table is to illustrate the VoLL for Maryland-specific industrial customers. As such the smaller Maryland-specific consumption figure was used. As with the small commercial segment, the underlying segment data varies significantly in accuracy, measurement and public reporting. To accurately determine and apply a CDF to commercial and industrial data would require much deeper investigation than was in the scope of this study. In particular it would require some primary survey research into individual segments and substantial time would need to be spent with the authors of the several other studies.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

All recent CDF studies measure outage costs for outages lasting for 24 hours or less. All recent US studies only study outages lasting 8 hours or less. In order to get an accurate long-term outage CDF function, a customer study should be performed that investigates long term outages using the methodologies outlined in the CDF reports, including primary research and surveys of customers within all small commercial customer segments.

Table 24 summarizes the comparison of several VoLL studies from the past 10 years. The table also includes the 2001 primen/EPRI results for large (> 5,000 MWh) customers for comparison purposes. All numbers are expressed in \$ 2011. Australian costs are the highest with Irish costs the lowest. It should be noted that as in the smaller C&I comparison, the mining segment has high costs of outages. However, unlike the smaller study, the manufacturing segment is much higher than the construction segment.

Table 24 Comparison of Industrial Customer VoLL Results Standardized to \$ 2011 and 7,140 MWh/Customer

Cost Comparisons from Various VoLL Studies for Large C&I Customers. Standardized to 7,140 MWh/customer								
Study	Momentary	30 minutes (20 for Australia)	1 hour	2 hours	3 hours	4 hours	8 hours	24 hours
LBNL Medium and Large C&I - All Industries (2009 Table ES-5)	\$ 6,852	\$ 9,630	\$ 13,046			\$ 44,408	\$ 72,385	
LBNL Commercial South Atlantic Annual - Usage Unknown - (LBNL 2004 Table 13)	\$ 819						\$ 1,455	
CRA International, Australia - Victoria (2008 Table 18)		\$ 25,703	\$ 36,039	\$ 51,632		\$ 89,232	\$ 202,959	
New Zealand - Auckland (2013 Table 1)							\$ 57,631	
Ireland (2010 Table A1)			\$ 5,216	\$ 10,433	\$ 15,648	\$ 20,864	\$ 41,728	\$ 125,185
Norway (2008 Table IV)	\$ 19,454		\$ 43,328			\$ 45,096		\$ 18,127
EPRI/primen Overall US for customers with 5+ GWh annual usage (EPRI/primen 2001 Figure 2-4)	\$ 40,644		\$ 74,937					
MISO Direct Costs (2006 Exhibit A-2) Agriculture			\$ 11,276	\$ 18,210	\$ 27,579			
MISO Direct Costs (2006 Exhibit A-2) Mining			\$ 36,279	\$ 31,110	\$ 88,769			
MISO Direct Costs (2006 Exhibit A-2) Construction			\$ 11,276	\$ 18,210	\$ 27,579			
MISO Direct Costs (2006 Exhibit A-2) Manufacturing			\$ 19,280	\$ 31,110	\$ 47,153			
MISO Direct Costs (2006 Exhibit A-2) Transportation/Communication			\$ 11,276	\$ 18,210	\$ 27,579			
MISO Direct Costs (2006 Exhibit A-2) Wholesale/Retail			\$ 11,276	\$ 18,210	\$ 27,579			
Notes:								
Maryland average hourly usage per the US Energy Information Agency varies greatly. The average of 135,000 kWh per customer was considered to be too small. Therefore the Consultants used the 2009 LBNL stated US average of 7,140 MWh per customer for 2011.								
Inflation adjusted using US Department of Labor, Bureau of Labor Statistics CPI Inflation Calculator. http://www.bls.gov/data/inflation_calculator.htm								
Currency conversion using www.bloomberg.com as of 10/15/2013								

Next, the study examines the LBNL 2009 CDF results standardized for the 135 MWh usage level of Maryland industrial customers and presented in 2011 dollars (Table 25). A few pertinent observations from the LBNL 2009 study include:

- “Afternoon interruption costs are significantly more likely to incur positive costs than any other time of day, weekday interruptions are more likely to produce positive interruption costs than weekends, and summer interruptions are more likely to incur costs than non- summer interruptions.
- “Weekday interruptions are more costly than weekend interruptions, but summer interruptions cost less than non-summer interruptions.
- “The construction and mining industries incur larger costs for a similar interruption than other industries.
- “Time of day does not impact the magnitude of interruption costs.”³³

The following variables comprise the inputs to the CDF:

- Interruption Attributes
 - Time of Day – morning, afternoon or night,
 - Time of Year – summer or non-summer,
 - Time of Week – weekday or weekend,
- Customer Characteristics
 - Annual MWh per residence,
 - Advanced Warning – yes or no,
 - Annual MWh – according to the EIA, average Maryland annual MWh for 2011 were 49.445,
 - Agriculture, Forestry and Fishing – percent of respondents in this industry,
 - Mining – percent of respondents in this industry,
 - Construction – percent of respondents in this industry,
 - Manufacturing – percent of respondents in this industry,
 - Transportation, Communication & Utilities – percent of respondents in this industry,
 - Wholesale & Retail Trade – percent of respondents in this industry,
 - Finance, Insurance & Real Estate – percent of respondents in this industry,
 - Services – percent of respondents in this industry,
 - Public Administration – percent of respondents in this industry,
 - Unknown – percent of respondents in this industry,
 - None or Unknown Backup Equipment – percent of respondents utilizing this equipment,
 - Backup generation or Power conditioning – percent of respondents utilizing this equipment, and
 - Backup generation and Power conditioning – percent of respondents utilizing this equipment.

³³ "Estimated Value of Service Reliability for Electric Utility Customers in the United States" by Freeman, Sullivan & Co., June 2009

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

As expected, weekday cost of outages is higher than weekend cost of outages. Costs are lowest for the “Agriculture, Forestry and Fishing” segment and highest for “Construction”. Perhaps indicative of the diversity of large customers is that each of the analyses ranks segments differently in terms of the cost of power outages. For example, the 2009 LBNL results indicate that “Mining” costs of outages are not substantially higher or lower than the average. Yet, some of the other CDF studies have the “Mining” segment at a higher cost for outages. This may be due in part to reporting differences in the raw data (e.g., this is easily seen in the differences in EIA consumption data in Table 15). It is also true that each of the other studies normalized the data using slightly different processes.

Table 25 Cost of Prolonged Outages for Maryland Industrial Customers Standardized to \$ 2011 and 135 MWh/Customer

LBNL METHOD: MED-LARGE COMMERCIAL AND INDUSTRIAL								
Cost Per Day of Outage								
Outage Description	Sat	Sun	Mon	Tue	Wed	Thu	Fri	1 Week
Average Med - Large C&I Customer	\$15,113	\$15,113	\$19,937	\$19,937	\$19,937	\$19,937	\$19,937	\$129,909
Average Med - Large C&I Customer with NO backup generation or power conditionin	\$14,424	\$14,424	\$19,052	\$19,052	\$19,052	\$19,052	\$19,052	\$124,109
Average Med - Large C&I Customer with backup generation or power conditioning	\$15,710	\$15,710	\$20,729	\$20,729	\$20,729	\$20,729	\$20,729	\$135,066
Average Med - Large C&I Customer with backup generation and power conditioning	\$17,084	\$17,084	\$22,359	\$22,359	\$22,359	\$22,359	\$22,359	\$145,965
Agriculture, Forestry and Fishing	\$6,516	\$6,516	\$8,741	\$8,741	\$8,741	\$8,741	\$8,741	\$56,736
Mining	\$11,446	\$11,446	\$14,943	\$14,943	\$14,943	\$14,943	\$14,943	\$97,606
Construction	\$34,574	\$34,574	\$45,581	\$45,581	\$45,581	\$45,581	\$45,581	\$297,054
Manufacturing	\$26,606	\$26,606	\$34,860	\$34,860	\$34,860	\$34,860	\$34,860	\$227,513
Transportation, Communication & Utilities	\$15,460	\$15,460	\$20,548	\$20,548	\$20,548	\$20,548	\$20,548	\$133,659
Wholesale & Retail Trade	\$9,485	\$9,485	\$12,468	\$12,468	\$12,468	\$12,468	\$12,468	\$81,311
Finance, Insurance & Real Estate	\$23,554	\$23,554	\$31,240	\$31,240	\$31,240	\$31,240	\$31,240	\$203,309
Services	\$11,480	\$11,480	\$15,272	\$15,272	\$15,272	\$15,272	\$15,272	\$99,320
Public Administration	\$12,751	\$12,751	\$16,930	\$16,930	\$16,930	\$16,930	\$16,930	\$110,153

Notes:

Regression model was discussed with Freeman, Sullivan & Co. and with London Economics International.

Both said that there is no data nor are there any studies for outages lasting longer than 8 hours.

Both also stated that the regression is only accurate up to 8-9 hours.

Therefore, model was run for 8 hours and assumed an 8 hour workday or 8 hours open for business or operations.

Summer outages only.

Average Med- Large C&I Customer assumes customer characteristics of:

Proportion of customers with backup generation or power conditioning: 37.2%

Proportion of customers with backup generation and power conditioning: 8.4%

Average MD Industrial Customer used 135,055 kWh in 2011 per EIA.

3.4 A SURVEY OF COMPENSATION/REFUNDS TO CUSTOMERS FOR OUTAGES

In July 2012, the National Regulatory Research Institute published a report³⁴ which contained the results of a review of public utility commission and utility company compensation programs for outages. Whether or not utility companies should compensate customers for outages is a topic of interest to regulators, customers and utilities in the light of several prolonged outages caused by natural disaster over the past 3-5 years. Additionally, the amounts that Consolidated Edison in New York compensates residential, commercial, and industrial customers for spoiled food were used in this analysis. This was detailed in the cost tables.

The primary question asked in recent times is “Should utilities compensate customers for weather related prolonged outages?” According to NRRI:

“Electric utilities seldom compensate their customers for outages, regardless of the outages’ duration. The utility is typically not liable for causes of interruptions beyond its control (e.g., those that are weather-related). Tariffs frequently hold a utility liable only for willful or gross neglect or other extreme conditions, which commissions seem to determine rarely. Important issues for the industry and regulators include (1) the definition of willful or gross neglect, and (2) the specific utility actions that constitute neglect.”³⁵

A summary of compensations schemes is presented in Table 26. There are few compensation schemes in the US and those that do exist vary in size, scope terms and conditions. Some have limitations such as in Michigan which limits compensation to \$25 or the monthly charge whichever is larger. Other states, such as Illinois allow for recovery of full damages, but with exceptions such as:

- Unpreventable damage due to weather events (e.g., lightning) or other conditions (e.g., uprooted trees);
- Customer tampering;
- Unpreventable damage due to civil or international unrest or animals; and
- Damage to utility equipment or other actions by a party other than the utility, its employees, or its contractors.

Some allow for small claims court appeals if claims are disallowed by the utility. In summary, there are few compensation schemes in the US and those that do exist differ in their scope and compensation processes.

³⁴ “Should Public Utilities Compensate Customers for Service Interruptions?”, Ken Costello, Principal Researcher, National Regulatory Research Institute, July 2012.

³⁵ Ibid.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 26 Summary of Outage Compensation Schemes across the US

State	Utility	Compensation Program
California	Southern California Edison "Service Guarantee Program"	SCE guarantees that electrical service will be restored within 24 hours of a power outage. SCE guarantees to notify you of a planned outage at least three (3) calendar days prior to the event. Notification may be made by mail, phone, door-to-door, in person, or by e-mail. Southern California Edison reviews all claims. If claim is denied SCE explains why. If the customer is not satisfied, he/she can file a civil action, including a small-claims action.
	Pacific Gas & Electric "Safety Net Program"	A residential customer having gone without power for at least 48 hours due to severe storm conditions may qualify for a payment. Payment levels are based on the length of the customer's outage: 48 to 72 hours \$25, 72 to 96 hours \$50, 96 to 120 hours \$75, 120 hours or more \$100. Claims processed within 60-120 days of filing.
Illinois	Ameren Commonwealth Edison	If more than 30,000 customers are subject to an interruption exceeding 4 hours. All damages suffered as a result of power interruption. Customer files claim with utility. Commission or small claims court. Exceptions: unpreventable damage due to weather events (e.g., lightning) or other conditions (e.g., uprooted trees); customer tampering; unpreventable damage due to civil or international unrest or animals; and damage to utility equipment or other actions by a party other than the utility, its employees, or its contractors.
Michigan	All utilities	Utility (a) fails to restore service within 120 hours of an outage during a catastrophic condition (i.e., when 10 percent or more customers face service interruption or a state of emergency occurs); (b) fails to restore service within 16 hours of an outage during normal conditions (e.g., less than catastrophic conditions, or when not more than 10 percent of customers are without service); or (c) has seven or more interruptions in a 12-month period. The greater of \$25 or the monthly customer charge for each instance.
Minnesota	Xcel	Xcel Energy tariffs contain provisions that require compensation to customers who receive service quality below some predetermined standard. (a) \$50 in annual compensation for individual customers experiencing at least six interruptions, (b) \$50 in compensation for individual customers per interruption lasting 24 hours or more and (c) \$200 in compensation to municipal pumping customers per interruption of any duration.
New York	Con Edison	Con Edison Reimbursement Tariff: reimbursement to residential customers for loss of refrigeration of up to \$450 per customer (\$200 without proof of loss) for spoiled food, and for actual losses for perishable prescription medications. Non-residential customers may be reimbursed for loss of perishable merchandise up to \$9,000 per customer. Electric utilities must make dry ice available at centralized locations to customers when utilities anticipate a widespread outage lasting longer than 48 hours. Con Ed "Total liability is limited to \$15 million per incident, and claims are pro-rated if this amount is exceeded. Liability is limited to outages on distribution circuits (33 kV or less) exceeding 12 hours, when not due to deficiencies in generation or transmission, NYISO directives, customer-owned meters, or conditions beyond the Company's control, such as storms, floods, vandalism, strikes, or fires or accidents.

3.5 TEMPLATE TO REPLICATE IN OTHER JURISDICTIONS

The template to apply the study methodology used in this report to other jurisdictions is provided in the Cost/Benefit Analysis deliverable which was provided in Microsoft Excel. The tables from that section are in this report and labeled Table 4 Detailed List of Residential Direct Costs for Prolonged Outages, Table 13 Detailed List of Commercial and Small Industrial Customers' Direct Costs for Prolonged Outages, and Table 19 Detailed List of Industrial Customers' Direct Costs for Prolonged Outages. Various examples of how to use the data are also provided.

4 MITIGATION MEASURES TO ADDRESS ELECTRICAL OUTAGES

4.1 INTRODUCTION TO MITIGATION MEASURES

The mitigation measures are the areas, departments, activities, policies, procedures, etc. at the utility company that can be implemented, changed or improved in order to avoid, eliminate, or reduce the occurrence and duration of outages. The gains in mitigation measures help reduce the cost to the utility and direct costs incurred by customers during outages while improving reliability and time to restore power. Such measures also improve safety to utility and emergency response personnel during maintenance and outages. In this section, the types of mitigation measures addressed by utilities in Maryland will be discussed, as well as the benefits they provide. The cost of the mitigation measures will be categorized as capital or operating and maintenance (O&M) in order to add clarity as to the type of expense being incurred by utility companies.

The types of mitigation measures discussed below include:

- Vegetation management
- Undergrounding of distribution system
- Delivering System Improvements
 - Transmission and Area Distribution
 - Local Distribution or Micro Grid Improvements
 - Local Substation Automation
 - Circuit Loops with Small Switches
 - Undergrounding Local Cables (Lower Voltage)
- End-Use Investments
 - Smart Meters
 - Home Automation
- Replacement of Feeders
- Call Center Improvement
- Utility Work Force
 - Staffing Levels to Respond to Outages
 - Training Availability
- Outage Process Improvements

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

- Facilities that Require Backup Generation
- Maryland Energy Assurance Plan
- Protecting Medically Vulnerable Citizens

4.2 VEGETATION MANAGEMENT

Vegetation management mostly refers to the activities required to keep trees and plants cleared from transmission and distribution lines. The activities typically require tree and shrub pruning and removal of the branches. However, it includes the clearing of vegetation around all buildings, equipment and assets in the production, transportation, and delivery of power. This includes power plants, substations, transformers, poles, access paths (easements, right of way) as well as any other land or assets that are part of the production and delivery process for ensuring reliable energy.

Vegetation management is critical because broken branches and downed trees are strong enough to cause enough damage to the grid to interrupt power. Also, during an outage vegetation problems can inhibit the work necessary to restore power. Therefore, standards are set for managing vegetation during regular operations that target controlling the growth in order to minimize likelihood the vegetation can cause an outage and to maximize the safe access to assets workers have during an outage to restore power.

The Grid Resiliency Task Force reported in its Weathering the Storm Report that there was consistent agreement among roundtable participants that appropriate vegetation management is one of the most effective ways to improve the resiliency of the grid. Various sources confirm that when there are fewer trees that are likely to fall on lines, the more likely the system is to weather the storm.

Other aspects of managing vegetation include educating the public about the importance of notifying the utility company if anyone identifies vegetation that could cause a problem with power, what to do and who to call when there is a downed tree or debris that is a hazard, and why the utility company must do continuous maintenance.

However, vegetation management is complicated because of the complex issues involved in gaining appropriate approval for clearing areas that can affect power lines.

Because utility companies do not own all the land surrounding its assets, it is important that vegetation management practices comply with state and local laws governing ownership, rights, and protection of wildlife. In fact the RM43 Working Group reported that 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 properties. Government regulations and laws lean toward protecting vegetation. There may be heavy penalties assessed for violations.

Utilities must be diligent to keep up a comprehensive plan and aggressive proactive approach while avoiding delays and penalty assessments during regular operations to avoid issues when responding to emergency situations. Some examples of compliance activities provided in the Weathering the Storm report include:

- Obtaining consent of property owners to allow vegetation management work.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

- Obtaining adjacent property owner’s consent in order to perform vegetation management on trees that grow on private property that is adjacent to a utility’s right of way.
- Complying with that other State, county or municipal regulations that may impose additional obligations and restrictions on vegetation management even if landowner consent is obtained, as noted by RM43 Working Group.
- Obtaining any permits that may be required from Federal, State, County, or City agencies when land is public or is on government property.
- Managing multiple regulating entities when roads cross city, county, and state borders.
- Complying with Maryland’s Roadside Tree Law 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. 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.³⁶
 - 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.³⁷ 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.”³⁸ The Maryland department of Natural Resources 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.”³⁹
 - 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.⁴⁰
 - Underground Facilities – The regulations protect roadside trees and tree roots during excavation, including excavation for installation and maintenance of electric cable or conduits.⁴¹

In Weathering the Storm, the Grid Resiliency Task force described the statutory and regulatory framework which affects Maryland’s trees:

³⁶ Md. Code, NR 5-406; COMAR 08.07.02.03.

³⁷ See COMAR 08.07.02.07.

³⁸ Id.

³⁹ Id.

⁴⁰ Id.

⁴¹ Id.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

“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.”⁴²

The Grid Resiliency Task Force recommended the formation of a new group consisting of representations from the Department of Natural Resources, the PSC, and the Maryland Energy Administration, in collaboration with the Attorney General’s Office, 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.

This new task force would address two main areas of concern. According to the Task force Report, the regulations affecting vegetation management are so complex, interconnected and possibly overlapping that there needs to be clarity for utilities. Second, there are danger trees located off the right of way that have the potential to contact an electric power line. These danger trees are outside the jurisdiction of the utilities, but either their branches reach to the power lines or if the trees are downed they are close enough to fall on the power lines and cause outages.

The Maryland Public Service Commission’s Ten-Year Plan (2012-2021) of Electric Companies provided the new standards defined by COMAR 20.50.12 for vegetation management during regular operations. There are minimum standards for the following areas:

- tree pruning and removal;
- cultural control practices;
- vegetation management around energized electric plants;
- vegetation management along rights-of-way;
- public education and
- debris management.

Improvements in these areas should increase reliability by reducing the proximity of vegetation that could cause service interruptions if downed by storms, wind, or other inclement weather conditions. Additionally, managing vegetation with more aggressive standards reduced hazards that impede response to service interruptions and improve time to restore service.

With RM43, the PSC recently adopted vegetation management regulations (COMAR 20.50.12) that became effective on May 28, 2012. These regulations establish, for the first time in Maryland, vegetation management standards for distribution and transmission lines not regulated by FERC.⁴³ In response to the requirements of COMAR 20.50.12, the utilities developed vegetation management plans

⁴² Weathering the Storm: Report of the Grid Resiliency Task Force, September 24, 2012, p. 53.

⁴³ Weathering the Storm: Report of the Grid Resiliency Task Force, September 24, 2012, p. 54.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

outlining how they will meet the standards set for each of the categories. For example, the utilities can adopt a four or five year schedule for pruning or, alternatively, can adopt a minimum distance vegetation management plan.

The Grid Resiliency Task Force summarized the new vegetation management regulations in the following areas:

- 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.”⁴⁴
- 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.
- 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. Utilities are also required 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

⁴⁴ Weathering the Storm: Report of the Grid Resiliency Task Force, September 24, 2012, p. 54.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

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.

The Grid Resiliency Task Force held various roundtable forums in preparation for its final report. During the 2nd Electric Feedback Forum about Undergrounding, the cost of tree trimming for 12 utilities in Texas and Florida from 2008 were included in the report from the meeting. The combined total of more than 180,000 miles of tree trimming showed an average of about \$6,000 per mile.

In order to determine an accurate cost of vegetation management the utilities in Maryland should track and report the number of miles trimmed per year and the cost in either an average per mile or a total cost for all the miles. Additionally, the utilities should track and report the cost incurred for planning, managing schedules, efforts required to adhere to state and local regulations (obtaining permits), and overseeing any activities that are outsourced. All of these costs would be O&M costs.

However, there is some information available about the total number of miles of lines and the percent that are underground in Maryland. Therefore, the number of miles above ground can be deducted. Assuming vegetation management is necessary for all above ground miles, the average per mile vegetation management cost from Texas and Florida can be applied to estimate the cost for Maryland.

The circuit miles and percent underground for transmission lines, substation supply lines, and distribution lines for BGE, Pepco, and Potomac Edison were provided in the Weathering the Storm report. The table below takes that information and provides the number of miles underground. The total number of miles underground is 22,914. When applying the average per mile cost of the Florida and Texas utilities to these three Maryland utilities’ overhead lines, the cost of complying with the vegetation management standards set forth in COMAR 20.50.50 is about \$137.5 million.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 27 Estimate of Maryland Miles and Cost for Vegetation Management

Maryland Vegetation Management Miles and Cost				
	BGE	Pepco	Potomac Edison	Total
System Components				
Transmission Lines	143	121	42	
Circuit Miles	1,288	1,009	627	
Underground	8%	16%	0%	
Miles Above Ground	1,185	848	627	2,660
Substation Supply Lines	253	97	65	
Circuit Miles	1,428	1,827	494	
Underground	24%	9%	0%	
Miles Above Ground	1085	1663	494	3,242
Distribution Lines	1,295	693	323	
Circuit Miles	23,568	8,399	8,581	
Underground	65%	59%	38%	
Miles Above Ground	8,249	3,444	5,320	17,013
Total Miles Above Ground				22,914
Ave Cost/Mile for Veg Mgmt				\$ 6,000
Total Cost for Veg Mgmt				\$ 137,483,880

The vegetation management activities are done entirely in-house at some utilities while partially or fully outsourced at other. If the field activities for vegetation management are outsourced, then the costs are also O&M. However, if any or all field activities are done by utility personnel, then the equipment, vehicles, machinery, and tools purchased by the utility would be capital costs.

CONSULTANT RECOMMENDATIONS

Information for vegetation management from each utility in Maryland should be collected regarding:

- **O&M Costs**
 - Cost to plan, schedule, and implement vegetation management programs
 - Outsourcing costs
 - Average cost per mile, total miles, and total cost for vegetation management
 - Cost to dispose of debris
 - Cost of public education and outreach programs
- **Capital Costs**
 - Cost and lifecycle of vehicles purchased by the utilities that are used for vegetation management
 - Cost and lifecycle of machinery, equipment, and tools purchased by the utilities that are used for vegetation management
 - Cost for permits to comply with State and local regulations
 - Legal fees

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

- Development of software

This will provide the information needed to understand the type of cost and total cost of vegetation management. The data from other states is helpful, but each state is different in demographics, type and density of vegetation, labor rates, weather conditions and state and local restrictions that can affect when certain activities can be conducted, etc. Therefore, the cost data presented above is a general indicator only.

4.3 UNDERGROUNDING OF DISTRIBUTION SYSTEM

Undergrounding of the distribution system is moving from the above ground on utility poles scheme to below ground in roughly the same path. This has proven to be an effective way to significantly reduce the number of outages and therefore, increase reliability of power supplies. The distribution systems are extensive and complex, making undergrounding expensive and daunting to move all lines. Therefore, utilities prioritize the undergrounding in order to get the most benefits by using selective criteria.

The most common selection criteria involves ranking feeders based on historical data of outages to determine the sequence for performing this work. The outage data provides two critical measurements for determining undergrounding priorities:

- SAIDI – System Average Interruption Duration Index. Average time customers are interrupted. Mathematically equal to the sum of customer interruption hours divided by total number of customers served.
- SAIFI – System Average Interruption Frequency Index. Average frequency of sustained interruptions per customer. Mathematically equal to the sum of number of customer interruptions divided by total number of customers served.

Once the most appropriate feeders to provide the greatest reliability improvements are identified utilities can factor in other criteria to help prioritize undergrounding projects. Some criteria include:

- Cost to underground
- Time to complete
- Customer benefits
- Reliability improvements
- Impact on the community
- Cost-benefit to partial undergrounding
- Benefits to be gained before work completed

Utility companies are not the only ones undergrounding. Communication companies that share the same poles are also moving to an underground system. Phone and cable companies experience the same issues of interruptions in service that power utilities do and are turning to undergrounding to solve the issue.

The highest line sometimes provides protection to the others. If the power line is the highest and a tree branch falls on it during a storm, then that line may be strong enough to hold the branch and protect the communication lines from being affected. Therefore, utilities consider the effects of

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

undergrounding on other companies sharing the pole and how lines might be more vulnerable or cause the others to be more vulnerable when undergrounded and factor this into its plans and prioritization. Sometimes all the lines are undergrounded and sometimes the communication lines are not included.

The Grid Resiliency Task Force reported that Maryland has benefited significantly during storms by undergrounding. The benefits include:

- The more circuits underground, the less frequent outages are on that line during a storm.
- Underground lines require significantly less vegetation management.
- Better aesthetics by delivering power without crowding airspace or obstructing the views.
- Improved real estate values.
- Increased protection from falling trees, ice, wind, and other storm damage.
- Reduced vulnerability to vandalism.
- Elimination of damage due to vehicular collisions.
- Ability to optimize capital spending previously dedicated to reliability improvement efforts to offset the cost of undergrounding.
- Improved customer relations regarding tree trimming & fewer outages.

Future construction methods and technology will allow for faster restoration time compared to past design due to greater system interconnection flexibility.

As pointed out in the Task force Report and other experts, undergrounding lines has disadvantages as well. Those disadvantages include but are not limited to:

- Poles would still be visible to carry other utilities, unless all were also undergrounded.
- 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.
- Increased time to locate and repair damage to underground lines.
- Installation difficulties related to excavation and other actions necessary to place assets underground.
- More complex switching and control requirements.
- Underground equipment may not last as long as overhead facilities due to environmental conditions.
- Other facilities such as feeder cables and substations are still above ground and therefore are susceptible to damage from storms or other weather related events.
- Can still be damaged by tree-root intrusion, which can physically damage conduits, trenches, and ducts, as well as allowing water ingress.
- Generally higher replacement costs than overhead lines.

Maryland has required most new distribution lines to be underground since 1969.⁴⁵ However, the state does not require existing overhead lines to be moved underground.

⁴⁵ COMAR 20.85.03.01.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Undergrounding costs are significantly higher than overhead lines. The Weathering the Storm report cited estimates by the Edison Electric Institute (“EEI”) that it can cost five to ten times more than to underground new or convert overhead. Since Maryland has been undergrounding new lines for almost 45 years, it is difficult to determine exactly how much more it has cost the ratepayers.

The Grid Resiliency Task Force Report discussed in detail the factors that affect estimating costs in rural, urban and suburban areas and demonstrated ranges in costs for new underground and converting to underground. However, without the total lines in each category for the state provided by each utility company, it is difficult to determine total costs.

However this report provides an estimate of undergrounding costs by following these three steps:

- Step 1 - Compare Maryland projects to other states’ projects for converting overhead lines to underground lines in order to confirm that cost data from other utilities can be used to estimate Maryland utilities’ costs.
- Step 2 - Use the District of Columbia’s (DC) cost per customer and apply it to Maryland’s customers.
- Step 3 - Use a typical distribution of costs to determine the capital and O&M costs.

In order to accomplish step 1, the projects listed in a table provided by the Task Force’s Electric Feedback Forum Roundtable #2 were manipulated to separate Maryland projects from the others. Additionally, the other projects were separate between estimated and actual costs. The comparison showed that Maryland projects and the other projects are similar in costs. All projects average about \$1 million. Unfortunately, the number of miles were not included, therefore the cost per mile could not be determined from this data.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 28 Project Costs to Underground

Year	State	Cost		Estimated	Actual	MD Only	Project Info.
1996	FL	\$ 917,532	Actual		\$ 917,532		Sand Key
1999	MD	\$ 350,000	Est.				Min. cost
1999	MD	\$ 2,000,000	Est.				Max. cost
2000	MD	\$ 952,066	Est.	\$ 952,066		\$ 952,066	BGE
2000	MD	\$ 1,826,415	Est.	\$ 1,826,415		\$1,826,415	PEPCO
2000	MD	\$ 728,190	Est.	\$ 728,190		\$ 728,190	Conectiv
2000	MD	\$ 764,655	Est.	\$ 764,655		\$ 764,655	Alleghany Power
2000	FL	\$ 414,802	Actual		\$ 414,802		Allison Island
2003	NC	\$ 3,000,000	Est.				Max. cost
2003	NC	\$ 151,000	Est.				Min. cost
2003	MD	\$ 450,000	Est.			\$ 450,000	
2005	VA	\$ 1,195,000	Est.	\$ 1,195,000			Av. cost
2006	DC	\$ 3,500,000	Est.	\$ 3,500,000			Extrapolated from 1 feeder
2006	mult.	\$ 1,006,491	Est.	\$ 1,006,491			Av. cost
2006	FL	\$ 814,929	Est.	\$ 814,929			State of Florida
2006	NY	\$ 1,578,976	Est.	\$ 1,578,976			LIPA
2006	CA	\$ 1,191,176	Est.	\$ 1,191,176			Tahoe-Donner
2006	VA	\$ 950,000	Est.	\$ 950,000			Virginia Power
2006	CA	\$ 500,000	Est.	\$ 500,000			State of California
2006	FL	\$ 840,000	Est.	\$ 840,000			Florida Power & Light
2006	GA	\$ 950,400	Est.	\$ 950,400			Georgia Power
2006	WA	\$ 1,100,000	Est.	\$ 1,100,000			Puget Sound Energy
2006	FL	\$ 883,470	Actual		\$ 883,470		County Road 30A
2006	FL	\$ 1,686,275	Actual		\$1,686,275		Pensacola Beach
2008	OK	\$ 1,500,000	Est.	\$ 1,500,000			Av. main lines
2008	OK	\$ 500,000	Est.	\$ 500,000			Av. lateral lines
AVERAGE				\$ 1,170,488	\$ 975,520	\$ 944,265	

In order to use DC's cost per customer and apply it to Maryland's customers, the data was collected by the Grid Resilience Task Force from the DC Mayor's Power Line Undergrounding Task Force Findings and Recommendations (via Shaw Consulting International). DC looked at the cost for 3 options, which include undergrounding everything, only mainline primary and laterals, and only mainline primary. The table below provides the data applicable to DC.

Table 29 DC Cost for Undergrounding

DC Cost for Undergrounding					
Option	Est Cost to UG (\$2006)/ Billion	Customers Affected (2008 data)	OH Customer Outages Avoided	Incremental Cost per Customer Affected	Relative Benefits
Undergrounding Mainline Primary (Option 3)	\$ 1.1	73,384	65%	\$14,990	Significant reliability improvement; least road-work needed to implement
Undergrounding Mainline Primary and Laterals (Option 2)	\$ 2.3	97,650	87%	\$49,452	Additional reliability benefits, almost equal to those of Option 1; addresses 87% of customer outages
Undergrounding All Existing Assets (Option 1)	\$ 5.8	112,345	100%	\$238,176	Slightly increased reliability over Option 2; maximum aesthetic benefits

Next, the table below provides Maryland's customer count.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 30 Maryland Customer Count by Utility

Entity	No. of Consumers	No. of Commercial	No. of Industrial	Total Customers
A & N Electric Coop	275	48	0	323
Baltimore Gas & Electric Co	883,917	71684	3259	958,860
Choptank Electric Coop, Inc	47,255	4735	23	52,013
Delmarva Power	158,249	17659	122	176,030
Easton Utilities Comm	8,218	2323	0	10,541
Hagerstown Light Department	14,811	2602	46	17,459
Potomac Electric Power Co	402,528	28088	4	430,620
Southern Maryland Elec Coop Inc	137,357	14314	0	151,671
The Potomac Edison Company	206,761	20080	1797	228,638
Thurmont Municipal Light Co	2,452	380	10	2,842
Town of Berlin - (MD)	1,946	310	110	2,366
Town of Williamsport	854	119	29	1,002
Maryland Total	1,864,623	162,342	5,400	2,032,365

The DC costs per customer and percentage of customers affected for undergrounding were then applied to the 2 million customers in Maryland to determine an estimated cost for each of the options considered for DC undergrounding.

Table 31 Maryland Cost Estimates for Undergrounding

Maryland Cost Estimates for Undergrounding				
Option	Est Cost to UG/ Billion	Customer Outages Avoided	Customers Affected	Cost per Customer Affected
Undergrounding Mainline Primary (Option 3)	\$19.8	65%	1,321,037	\$14,990
Undergrounding Mainline Primary and Laterals (Option 2)	\$87.4	87%	1,768,158	\$49,452
Undergrounding All Existing Assets (Option 1)	\$484.1	100%	2,032,365	\$238,176

It should be noted that cost for undergrounding are not driven by number of customers. Therefore, it would be more accurate to capture costs by project and number of miles undergrounded in order to estimate and project costs. The calculation of costs based on per customer was used because the data was readily available. However, it is recommended for Maryland to collect data from the utilities that will allow for the costs to be captured by per mile for use in future studies.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Step 3, to break this down further between capital and O&M costs, a typical allocation of costs for undergrounding projects was applied to each Option. With the estimates below, capital and O&M costs can be identified in a typical project.

Table 32 Estimated Cost Structure for Maryland Undergrounding

Estimated Cost Structure for Maryland Undergrounding				
Typical Cost Allocation		Allocation Per Option in Billions		
Cost Item	% of Total	Option 1 \$484.1 B	Option 2 \$87.4 B	Option 3 \$19.8 B
Materials	34%	\$ 164.6	\$ 29.7	\$ 6.7
Contractor Labor & Equipment	29%	\$ 140.4	\$ 25.3	\$ 5.7
General & Administration Overheads	21%	\$ 101.7	\$ 18.4	\$ 4.2
Company Labor	8%	\$ 38.7	\$ 7.0	\$ 1.6
Other	8%	\$ 38.7	\$ 7.0	\$ 1.6

The expenses for materials and contractor labor and equipment are capital costs. General and administration overheads, company labor, and expenses in the “other” category are O&M costs. When cost estimates per customer for only mainland primary undergrounding in DC (Option 3) are applied to Maryland, the capital costs (materials + contractor labor and equipment) would be around \$12.5 billion and O&M would be around \$7.3 billion. For undergrounding mainland primary and laterals (Option 2) the capital costs would be around \$55.1 billion and O&M would be about \$32.3 billion. And if everything was undergrounded (Option 1), capital costs would come in at \$305 billion, leaving O&M cost around \$179.1 billion.

It should be noted that in addition to the capital and O&M costs to utilities, undergrounding causes indirect and intangible costs that are difficult to track and quantify.

Indirect costs are incurred expenses by customers, government entities, and other companies sharing the poles (phone, cable, etc.) that are not covered by the undergrounding project but are a result of it. Obvious examples include adapting facilities to accept underground service, damage or destruction of landscaping, and weakened or killed trees affected by damaged roots or had to be removed. Examples of less obvious indirect costs include the effect of construction work to businesses, increased fuel costs required because of detours or delays in traffic flow, interruption in power service required during the conversion, and the cost of time or efficiency lost to businesses and individuals working around the construction.

Some examples of intangible costs resulting from the public affected by construction for undergrounding include frustration, inconvenience, changing schedules, altering plans, obstructed views, loss of aesthetics, and increased risk of hazards.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

CONSULTANT RECOMMENDATIONS

The cost for undergrounding would be more accurately estimated if each utility in Maryland provided the number of miles underground and number of miles of overhead lines. For each of the projects to underground, the utilities should provide the number of miles included and number of customers affected in addition to the estimated and/or actual costs. This will allow an analysis to be done for Maryland that provides the cost per customer and to more accurately project cost for similar options that DC is considering.

The total costs for projects should be broken out by utilities by capital and O&M expenses. This will allow Maryland to have its own project cost profile that can be used in budgeting, planning, and projecting costs in various scenarios of undergrounding efforts. The generic one applied in this analysis is significantly different than the profile for DC. Therefore, not all areas have the same percentages of expenses in capital and O&M costs. However, within the state the projects should align with similar profiles and that can be used for projections and analysis.

4.4 DELIVERY SYSTEM IMPROVEMENTS

Many of the investments and improvements in the power delivery system can be considered mitigating measures because they improve reliability along with increases in efficiency and reductions in costs to end users. LBNL⁴⁶ reported that the bulk of power interruptions are caused by problems in the local distribution system. As a result, a larger portion of investment will be required at the local distribution system (local substations and circuits to customers).

The Perfect Power Institute provided a significant amount of information in a comprehensive report titled "Investing in Grid Modernization."⁴⁷ According to the report, the analysis below indicates that, for large utilities, about 90% of the smart grid spending should be allocated to the local distribution systems. Additionally, focus on local distribution systems could reduce interruptions significantly by the following:

- 1) The deployment of innovative technologies that allow substations to automatically isolate faults, restore service and re-route power. Today, many utilities rely on manual switches that open on a fault and must wait for utility crews to install a new one. This manual process results in an outage for all customers served by the substation. With smart switches only a few hundred are out of service for a shorter duration, and power to the rest of the residents is automatically restored;
- 2) The use of circuit looping with smart switches dispersed along looped circuits. Looping provides residents with power from two directions and smart switches sense and isolate faults to a very small area. Instead of entire neighborhoods being in the dark due to a tree falling on a line, only a few customers are impacted;

⁴⁶ Lawrence Berkeley National Laboratory: "Understanding the Cost of Power Interruptions to U.S. Electricity Customers", Kristina Hamachi LaCommare and Joseph H. Eto, September 2004.

⁴⁷ Perfect Power Institute: "Investing in Grid Modernization: The Business Case for Empowering Customers, Communities and Utilities", March 2012.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

- 3) Undergrounding cables improve reliability and power quality, reduce repair costs, reduce tree-trimming costs and improve esthetics. Today's electricity system, for the most part, is exposed on overhead lines and poles. Very often when a storm rolls through a city, the power is knocked out. The typical response is to cut down all of the trees that threaten the power lines. Unfortunately, as cities try to become greener, they are planting more trees, resulting in a futile cycle of residents planting trees and utilities cutting them down. Therefore, the electricity sector should develop and implement more economical ways of moving the grid underground or to ground level;
- 4) The optimization of tap settings that reduce transformer efficiency losses. The savings can be reinvested into reliability or advanced meter upgrades; and
- 5) Advanced software, automation and control systems that can coordinate market pricing with end-use devices and utility system conditions to optimize reliability, power quality, efficiency and asset utilization.

4.4.1 Transmission and Area Distribution

In a 2011 smart grid cost benefit report,⁴⁸ the Electric Power Research Institute (EPRI) identified the following investment categories and costs for the transmission and area substation systems. The EPRI study also allocated about 40 percent of these costs to the residential sector. The total nationwide cost is \$55 billion or \$12 per residential customer, based on amortizing the costs over 15 years.

⁴⁸ Electric Power Research Institute: "Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid", 2011.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 33 Transmission and Area Distribution Investments

Transmission and Area Distribution Investments		
INVESTMENT CATEGORY	AVERAGE ESTIMATED COST, MILLIONS \$	COMMENT
Dynamic thermal circuit rating	\$170	Dynamic ratings increase the capacity of existing transmission lines by providing real-time ratings to system operators. This is accomplished by monitoring actual conductor tension and environmental factors.
Sensors	\$2,250	Smart sensors in transmission corridors and substations will be able to monitor conditions in real time. That capability has many applications including safety, maintenance, asset management and risk assessment.
Short circuit current limiters	\$580	This technology limits the magnitude of high-level fault currents to a level that can be managed by the infrastructure's existing protection systems.
Storage	\$0	The initiative removed this cost that will be borne by the private sector and paid for through market savings, not as an additional cost, \$8 billion.
Flexible transmission	\$4,600	"Flexible transmission" describes a wide range of technologies designed to give greater control over the transmission system in terms of power flow control, load sharing and many other possibilities.
PMU	\$156	Phasor measurement units (PMU) draw in data about the transmission system's performance (such as voltage and current) at a speed of 30 times per second. These real-time measurements will allow for comprehensive monitoring and management of the electric system.
Communications to substations	\$700	With the multitude of new evaluative technologies along the electric grid, there will have to be an upgrade to the information infrastructure leading to the substation to allow for the transmission of this data.
Communications for substations	\$2,900	As the amount of data about the operations and performance of the electric system increases exponentially, substations will also need to be upgraded to process and use this information.
Relays and sensors IED	\$6,050	Intelligent electronic devices (IED) refer to a number of technologies that are used to monitor and control various aspects of the grid, such as transformers and circuit breakers.
Cyber security	\$3,700	Though the major benefits of a smart grid include automation, information collecting and widespread control, these features also make the system ripe for cyber attacks. Naturally, an enhanced method of security would be a must.
Back office enterprise software	\$32,000	As with many other areas of the electric system, the increased amount of information and operations of a smart grid would require updates to the software utilities use to manage their operations.
ISO upgrades	\$2,400	Just as utilities need to upgrade computers and communication devices to accommodate the added functionality of a smart grid, independent system operators (ISO) will also need to update their infrastructure.
Maintenance increase	\$0	The initiative removed this cost based on an assumption that this would be offset by operational savings from automation, \$15 billion
TOTAL	\$55,506	This equates to about \$12 per residential customer per year.

Source: Gellings, C. (2011). *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid.*

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

4.4.2 Local Distribution System or Microgrid Improvements

The EPRI study also identified the investment categories and costs for the local distribution systems as outlined in Table 34. Based on Perfect Power prototyping done by the Galvin Electricity Initiative, additional costs associated with local substation automation, circuit looping, smart switches, and moving circuits underground/to ground level were identified. These additional cost estimates are based on actual cost data from the IIT Perfect Power prototype.⁴⁹ EPRI also allocated about 40 percent of these costs to the residential sector. The total nationwide cost is estimated to be about \$630 billion, or \$150 per residential customer, based on amortizing the costs over 15 years.

⁴⁹ Illinois Institute of Technology. (2010). Perfect Power at IIT. Retrieved from http://www.iit.edu/perfect_power

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Table 34 Distribution Improvement Costs

Distribution Improvement Costs		
INVESTMENT CATEGORY	AVERAGE ESTIMATED COST, MILLIONS \$	COMMENTS
EPRI Local Distribution Automation and Communications Costs		
Communications	\$4,400	Communications allow the updated components of the smart grid to pass information back and forth, thus enabling the true potential of the system.
Current limiters	\$2,300	Advanced current limiters can reduce the number of interruptions while at the same time securing a more steady and reliable flow of power.
Volt/Var control	\$40,500	Voltage variation control is crucial for reducing loss and power quality events.
Remote control switch	\$1,500	Remote control switches decentralize the manipulation of key components of the grid, cutting down on interruptions and increasing recovery time.
Direct load control	\$1,800	Direct load control would enable the utilities to decrease non-essential electrical demand during peak hours to avoid the risk of overloading the system.
ElectriNet controller	\$3,500	The ElectriNet controller allows the operator to coordinate electrical needs to work in concert with the smart grid for maximum efficiency and cost savings.
Operations and maintenance	\$0	EPRI estimated an additional \$8 billion in maintenance costs, which were assumed to be offset by operational and maintenance savings.
EPRI Subtotal	~\$54,000	This equates to about \$12 per residential customer per year.
EPRI Local Smart Switch Costs		
Head-end recloser	\$16,000	Intelligent head-end reclosers allow for a more flexible, efficient power system by enabling instantaneous and timeovercurrent protection, better coordination with other devices and the ability for self-diagnosis. Assumed 70% penetration on circuits at \$50,000 each.
Smart switch	\$79,000	Smart switches automatically adjust to isolate problems on the grid and instantly react with other smart technologies to reconfigure and adapt to changing needs. Assumed 55% penetration on circuits at \$310,000 each.
Intelligent recloser	\$14,500	Like many automated components of the smart grid, intelligent reclosers can seal off problems before they can spread system-wide and cause larger interruptions. Assumed 25% penetration on circuits at \$125,000 each.
EPRI Subtotal	~\$109,500	This equates to about \$25 per residential customer per year.
IIT Prototype Improvements (See Sections 5.2.2.1 to 5.2.2.3)		
Substation automation	\$116,000	This assumes \$2,000,000 per substation based on the IIT prototype actual costs. This equates to about \$25 per residential customer per year.
Looping	\$46,500	EPRI estimated that there were 464,200 circuits nationwide at an estimated average cost of \$100,000 to connect circuits in a looping or redundant configuration. This equates to about \$10 per residential customer per year.
Smart switches	\$70,000	This assumes adding two additional switches per circuit (\$75,000 each) to the already budgeted reclosers and smart switch costs estimated by EPRI. This equates to about \$15 per residential customer per year.
Underground cables	\$232,000	This assumes \$1 million per circuit and undergrounding half of the total estimated circuits. This equates to about \$50 per residential customer per year.
IIT Subtotal	~\$464,000	This equates to about \$25 per residential customer per year.
Total	~\$630,000	This equates to about \$150 per residential customer per year.

Source: Illinois Institute of Technology. (2010). *Perfect Power at IIT*.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

4.4.3 Local Substation Automation

Local substation automation includes automated breakers and switches in the substation so that the substation bus can be supplied power from multiple feeds. The cost for substation automation is estimated at \$2 million per substation. EPRI estimates about 58,000 substations total, or a cost of \$25 per resident per year.

4.4.4 Circuit Loops with Smart Switches

Circuit loops provide customers with power from two directions while sectionalizing smart switches sense and isolate faults to a smaller set of customers, reducing interruptions and outage duration. Costs include the expenses for additional conductors required to build loops out of radial feeds. Most likely some, but not all, of the existing conductors would have to be replaced. The exact cost depends on the ratings and projected loads on the existing conductors.

The following assumptions were used to estimate additional costs for:

- Two additional intelligent reclosers or smart switches for each circuit at a cost of \$75,000 for each of the estimated 460,000 circuits, or \$15 per resident per year; and
- An estimated \$100,000 per loop with an estimated 230,000 loops or \$10 per resident per year (one for every two circuits).

4.4.5 Undergrounding Local Cables (Lower Voltage)

The cost for undergrounding cables was estimated by EPRI to be \$1,000,000 per local circuit for 50 percent of their estimated 460,000 circuits. Based on a 15-year rollout, this would cost each household about \$50 per residential customer per year.

The Delivery System Improvements section covered costs for:

- Transmission and Area Distribution
- Local Distribution System or Microgrid Improvements
- Local Substation Automation
- Circuit Loops with Smart Switches
- Undergrounding Local Cables (Lower Voltage)

Consistent with GAAP, the items listed that are hardware, software, and development costs are capital expenses. Once deployed, day-to-day activities to use equipment and utilize software associated with the new technology would be O&M costs.

4.5 END-USE INVESTMENTS

End-use investments are important because customers and innovators respond to affordable dynamic pricing programs, ancillary services, net metering, and the new ability to easily interconnect and participate in electricity markets. This introduces a variety of new technology and software solutions to the customer marketplace. The economic benefits of technology and software that creates energy savings and generates revenue, including through ancillary services, ensures there will be continued investments. Advanced software will learn and adjust home operations to minimize costs, energy use and associated emissions automatically. Therefore, the “apps” and “intelligent software” allow

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

customers to not have to take action to produce savings. The two main areas of investment that provide the new functionality and services are smart meters and home automation.

4.5.1 Smart Meters

Many utilities invest in smart meters if approved by the state public utility commission. If a utility company does not invest in smart meters its customers may invest in them as part of a services solution that enables savings from participating in market pricing and conservation. EPRI estimated the cost of residential smart meters and support infrastructure at about \$150 per residential customer. The total cost if financed over an assumed life of 8 years is \$20 per household.

4.5.2 Home Automation

Home-automation packages are typically designed for conservation by targeting large loads in the home. The packages include programmable and controllable thermostats, Web-enabled energy management tools, controllers for switching off large loads, controllable dimmable lighting and intelligent apps or software that automates the optimization of energy use and cost. The estimated cost is \$800 per home for half of the meters in the subject area. The annual cost to customers based on an assumed life of 8 years is about \$100 per household.

The End-Use Investments section covered costs for smart meters and home automation. Consistent with GAAP, the items listed that are hardware, software, and development costs are capital expenses. Once deployed, day-to-day activities to use equipment and utilize software associated with the new technology would be O&M costs.

CONSULTANT RECOMMENDATIONS

Maryland utilities should include the purchase and use of any of the delivery system improvements and end-use investments as mitigating measures for outages and, track and report this information to be included in discussions, consideration, and analysis.

4.6 REPLACEMENT OF FEEDERS

Replacing poor performing feeders is another way utilities manage the reliability of the distribution system. In Maryland, reliability and operations standards in COMAR 20.50.12 require each qualifying utility to report annually on system performance measured against objective standards for reliability, poorest performing feeders, device activation, downed wires, and customer communication as each of these relate to outages.

The utilities must track the SAIFI and the SAIDI. Each utility has a baseline against which improvements in scoring must be made in order to track improvements in frequency and duration of outages.

COMAR requires that the utilities list the poorest performing 3% of system feeders. These poorest performing feeders are identified by each utility using a formula outlined in its annual plan, which is approved by the Commission. Once the poorest performing feeders have been identified, the respective utility is allotted time to make necessary corrections. Identification and remediation of the

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

poorest performing feeders is an annual process; however, once a feeder has been identified for this list, it cannot be relisted in future years.

If a protective device is activated more than five times and causes loss of service to more than ten customers, it must be reported in the annual report to the Commission. Furthermore, the cause of these activations must be explained as part of the report.

The Grid Resiliency Task Force looked at the benefits and costs associated with increasing the percentage of reportable poorest performing feeders. There are clear reliability benefits to increasing the percent of poor performers that are replaced or rehabilitated and this program should be retained and perhaps expanded in the future.

4.7 CALL CENTER IMPROVEMENTS

Call center improvements have been a main focus in smart grid initiatives. Technology and availability of information have made it possible for utilities to communicate more quickly and effectively with customers during regular operations and during emergency and outage situations. With the use of social media, customers can communicate more easily with utilities to report outages. Many new functions and services are still in planning and development stages, but the existing functionality can be improved more easily.

In Maryland, new regulations to improve customer safety and reliability require that utilities respond to at least 90 % of all downed wire calls within four hours of notice.⁵⁰

Finally, in order to improve communication between the utilities and their customers, calls are required to be answered within 30 seconds at least 75 % of the time and, similar to downed wires, failure to achieve this rate will require the filing of a corrective action plan for the subsequent year.⁵¹ To provide granularity on customer communication, the Commission has required, as part of the annual reports, that the following metrics be clearly explained:

- percentage of calls answered within 30 seconds;
- percentage of abandoned calls; and
- average speed of answer.⁵²

The improvements required by the Commission may require additional associates in the Call Center. The additional labor would be O&M costs. However, if additional technology is used as a result of smart grid initiatives or upgrades to the Call Center then the software and development would be capital costs.

⁵⁰ MD PSC Ten-Year Plan (2012-2021) of Electric Companies, p. 31.

⁵¹ Id.

⁵² Id.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

4.8 UTILITY WORK FORCE

4.8.1 Staffing Levels to Respond to Outages

The Grid Resiliency 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.

The utilities should have sufficient personnel available to conduct restoration efforts during extended outages. Because utilities increase and decrease staff over the years, the task force needed to look at historic staffing levels to gain an understanding of the appropriate number of technicians per customer that should be available. The Task Force asked the utilities to provide information about historic staffing levels.

To help compare staffing levels across utilities, the Task Force determined the number of “network technicians.” This included 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 group. 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.

The Task Force then obtained utility customer counts to develop a standard metric of network technicians per 100,000 customers. This helped to remove the impact of relative scale between the utilities and permitted utility-specific trends to be identified.

The Task Force also collected information about the distribution assets for BGE, Pepco, and PE. The data was normalized for each point. Normalization allowed comparisons across utilities and across system components.

The comparison revealed where improvements need to be made to ensure staffing levels are adequate. Although useful for comparative purposes, caution must be taken when trying to extrapolate these results to direct impacts on system reliability. The Task Force views this staffing data as one of many pieces of information that informed its recommendations.

4.8.2 Training Availability

Utilities in Maryland have made investments in training and training facilities. A BGE training facility opened last year. According to the company, BGE 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 Line worker or 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.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

4.8.3 Preparing for an Aging Workforce

The Grid Resiliency Task Force found that the average age of utility field crews is unusually high, with many of the most senior crew chiefs and field managers nearing or past retirement age. Because of the significant lead time for utility crew training (up to 7 years) utilities may find they are unable to replace their retiring crew members. BGE specifically acknowledged this as an issue and recently opened a training center for new personnel in White Marsh to address this issue. Both the North American Electric Reliability Corporation (NERC) and the Department of Labor (DOL) have expressed concerns about these staffing trends. 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, many companies will need to replace a huge portion of their workforce.”⁵³

4.9 OUTAGE PROCESS IMPROVEMENTS

The Grid Resiliency 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.

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.⁵⁴

Maryland is currently determining the best way to prioritize facilities for energy assurance and emergency generation. This is being accomplished by the joint efforts of and cooperation between State and local government, the private sector, and the utilities. 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 was expected to be completed by the end of 2012.⁵⁵

Many investments are being made 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 installed over 200 uninterrupted power supply systems at key traffic intersections to provide up to 8 hours of continuous services and has plans to install hundreds more. The State’s Public Safety Intranet provides backup communications,

⁵³ 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

⁵⁴ The Maryland Energy Assurance Plan may be found online here: <http://energy.maryland.gov/energyassurance/documents/MarylandEnergyAssurancePlan.pdf>

⁵⁵ Id.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

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.⁵⁶

4.10 FACILITIES THAT REQUIRE BACKUP GENERATION

A matrix of federal and State statutes and regulations require various facilities to have back-up generation. Generally, these include hospitals, nursing homes, assisted living facilities, facilities with medically fragile children, and buildings with more than 25 people in occupancy and over four stories. The requirement to have back-up generation protects critical facilities from being vulnerable to a power outage.

4.11 MARYLAND ENERGY ASSURANCE PLAN

Maryland released its Energy Assurance plan in 2012. The document was developed by the Maryland Energy Administration (“MEA”), Maryland Emergency Management Agency (“MEMA”), and the PSC. The intent of the program is to assist with the creation of “a more resilient energy infrastructure that recovers quickly from disruption.”⁵⁷ The plan provides an overview of the existing energy assurance initiatives and 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. Maryland’s Energy assurance Plan also helps in the development of the list of critical infrastructure that are part of the State’s Core Capacities.

4.12 PROTECTING MEDICALLY VULNERABLE CITIZENS

COMAR 20.31.03.01 established 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. This list of medically vulnerable citizens is important information that helps emergency managers to prioritize the electrical restoration and ensure the well-being of medically at-risk people during extended outages.

In the aftermath of the Derecho Storm in Maryland in early summer, 2012, the Commission initiated a proceeding to review the Major Storm Reports required to be filed by the utilities following such a storm. An outcome of that proceeding was the initiation of a work group to examine procedures followed by the utilities and local medical emergency management personnel to identify and protect persons and facilities which house vulnerable citizens. The Maryland General Assembly passed HB 1159 and identified new work for the work group to undertake. The report of this work group is due to be filed with the Commission on November 18, 2013.

⁵⁶ The Maryland Energy Assurance Plan may be found online here:
<http://energy.maryland.gov/energyassurance/documents/MarylandEnergyAssurancePlan.pdf>

⁵⁷ Id.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

5 CRITICAL INFORMATION FOR INFORMED DECISION-MAKING

This section presents information necessary to inform decision-making and improve the quality of life for ratepayers frequently impacted by these outages. The basis for this section will be the research and findings of sections 2 and 3.

5.1 COMPARISON OF VARIOUS STUDIES

More than 75 reports and analyses were used to gather information, compare methodologies, identify consistencies in results to help verify accuracy, and to determine recommendations for future studies in Maryland and to replicate in other states.

Of note, many studies available use each other as sources. This creates duplicate information, but also provides some common approaches that are helpful. Unfortunately, this also means there is a shortage of new data being collected. Most studies are working with the same initial raw data. Most of the recommendations are to gather new data that will allow the analysis to be more detailed and accurate. But the recommendations also fill obvious gaps where data is needed in order to provide more accuracy and details.

5.2 COST/BENEFIT ANALYSIS

The spreadsheet provided separately can be used to estimate costs to customers of outages during catastrophic events. This information can now be incorporated into the decision-making process in considering investments in more mitigating measures.

6 CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSIONS

This study is the first of its kind. No other recent publically available study determines the cost to customers of outages with durations more than 8 hours.

Although a lot of data is available, there is a lot more that can help make the analysis more accurate and detailed. This study has provided a roadmap for additional analysis in Maryland and for replicating the analysis in other states.

The analysis reveals the tremendous costs, inconveniences, and other effects of outages to customers during catastrophic events.

The Study concludes that daily outage costs for residential customers can range from a low of \$33 to a high of \$363. Many factors discussed in the report explain this variation. Among these factors include time of year, weekday versus weekend day, methodologies, and customer perceptions. No long term outage CDF function has been derived since the 1990s. Residential customer behavior characteristic

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

have changed in the intervening 20 years due in part to the ubiquity of electronics and the internet. For this reason, the Consultants recommend a study resulting in a long term CDF would be the most accurate method for estimation customer costs due to prolonged outages as it is an accepted analytical method.

6.2 RECOMMENDATIONS

For small and large commercial segments, the underlying segment data varies significantly in accuracy, measurement and public reporting. To accurately determine and apply a CDF to commercial and industrial data would require much deeper investigation than was in the scope of this study. In particular it would require some primary survey research into individual segments and substantial time would need to be spent with the authors of the several other studies.

All recent CDF studies measure outage costs for outages lasting for 24 hours or less. All recent US studies only study outages lasting 8 hours or less. It is recommended that in order to get an accurate long term outage CDF function, a customer study be performed that investigates long term outages using the methodologies outlined in the CDF reports, including primary research and surveys of customers within all small commercial customer segments.

Therefore, the Consultants believe that a VoLL survey and study of extended outage costs would offer much more accurate cost estimates.

Information for vegetation management from each utility in Maryland should be collected regarding:

- O&M Costs
 - Cost to plan, schedule, and implement vegetation management programs
 - Outsourcing costs
 - Average cost per mile, total miles, and total cost for vegetation management
 - Cost to dispose of debris
 - Cost of public education and outreach programs
- Capital Costs
 - Cost and lifecycle of vehicles purchased by the utilities that are used for vegetation management
 - Cost and lifecycle of machinery, equipment, and tools purchased by the utilities that are used for vegetation management
 - Cost for permits to comply with State and local regulations
 - Legal fees
 - Development of software

Collection of this data will provide the information needed to understand the type of cost and total cost of vegetation management. The data from other states is helpful, but each state is different in demographics, type and density of vegetation, labor rates, weather conditions that can affect when certain activities can be conducted, etc. Therefore, the cost data is most helpful and applicable from within the state.

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

The cost for undergrounding would be more accurately estimated if each utility in Maryland provided the number of miles underground and number of miles of overhead lines. For each of the projects for which undergrounding is proposed, the utilities should provide the number of miles included and number of customers affected in addition to the estimated and/or actual costs. This will allow an analysis to be done for Maryland that provides the cost per customer and to more accurately project cost for similar options that DC is considering.

The total costs for proposed undergrounding projects should be broken out by capital and O&M expenses by each utility. This will allow Maryland to have its own project cost profile that can be used in budgeting, planning, and projecting costs in various scenarios of undergrounding efforts. The generic cost profile applied in this analysis is significantly different than the profile for DC. Therefore, not all areas have the same percentages of expenses in capital and O&M costs. However, within the state, the projects should align with similar profiles and that can be used for projections and analysis.

Maryland utilities should include the purchase and use of any of the delivery system improvements and end-use investments as mitigating measures for outages and therefore, track and report this information to be included in discussions, consideration, and analysis.

7 APPENDICES

7.1 NATURAL GAS TARIFF

Schedule D is shown for illustrative purposes. Deliver costs also include the Riders listed at the bottom of the Schedule. These Riders were included in the Study's cost calculations. For the purposes of brevity, the Riders are not included in this section.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

RESIDENTIAL SERVICE – GAS

SCHEDULE D

1. AVAILABILITY:

- (a) For use for the domestic requirements of:
 - 1. A single private dwelling.
 - 2. An individually metered dwelling unit in a multiple dwelling building.
 - 3. One combination of two dwelling units within a building, if served through a single meter.
 - 4. A dwelling occupied as the dwelling place of a church divine or of religious associates engaged in church duties.
 - 5. A single dwelling within a building where the occupant has not more than 10 bedrooms to let or not more than 10 table boarders, or a combination of not more than ten.
- (b) For use, if on one property and served through a single meter, of a combination of the occupant's domestic requirements in a dwelling and his nondomestic requirements, provided that more than 50 percent of the connected load is for domestic purposes.
- (c) For use, if served through a separate meter, by appliances used in common by the occupants of not more than two dwelling units within a building.

2. RATE TABLE:

Customer Charge	\$ 13.00 per month, plus
Delivery Price (For all gas used)	\$0.3544 per therm

- 3. DELIVERY SERVICE:** Firm service transportation of gas through the Company's distribution system for all customers served under this Schedule.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Schedule D continued

4. GAS COMMODITY SERVICE: The sale of gas under one of the two options below:

4.1 BGE Gas Commodity Service:

The sale of gas by BGE is provided under the provisions of Rider 2 – Gas Commodity Price.

4.2 Supplier Gas Commodity Service: The Customer may elect to obtain Gas Commodity Service from a third party gas supplier subject to the following Terms and Conditions.

4.21 Terms and Conditions: Supplier Gas Commodity Service is available where:

- (a) the Customer arranges for the transport and delivery of gas into the Company's distribution system at its interstate pipeline gate station(s); and
- (b) the Customer may only contract with a gas supplier that has obtained a license from the Public Service Commission of Maryland and has separately contracted with the Company under the Gas Supplier Tariff. Supplier Gas Commodity Service under this Schedule is provided only so long as the Customer's gas supplier remains a qualified gas supplier under the Gas Supplier Tariff. In the event that the Customer's gas supplier becomes disqualified, the Customer's Supplier Gas Commodity Service is terminated; and
- (c) the Customer shall select only one gas supplier for any time period; and
- (d) the Customer takes title to the gas at or before the Company's City Gate; and
- (e) the transported gas is for the Customer's burner tip use and shall not be resold; and
- (f) the Customer shall be responsible for the payment of any tax or assessment levied by any jurisdiction related to the acquisition, transportation or use of gas under the Supplier Gas Commodity Service; and
- (g) when a Customer changes residence within the Company's gas service territory, the Customer may elect to continue to receive Supplier Gas Commodity Service, provided that the new residence has gas service and the arrangement between the Customer and the supplier permits.

NARUC and MDPSC
A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects
From the End Users' Perspective

Schedule D continued

5. GENERAL TERMS

- | | |
|---------------------------------------|---|
| 5.1 Minimum Charge: | Customer Charge |
| 5.2 Late Payment Charge: | Standard (Part 2, Sec. 7.5) |
| 5.3 Payment Terms: | Standard (Part 2, Sec. 7) |
| 5.4 Term of Contract with BGE: | The Customer's initial term of contract with BGE for Delivery Service is 1 year, and thereafter until terminated by at least 30 days notice from the Customer to BGE. |

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

1. Gas Efficiency Charge
2. Gas Commodity Price
4. Budget Billing
7. Gas Choice and Reliability Charges
8. Monthly Rate Adjustment
10. Billing in Event of Service Interruption
11. Unaccounted – For Gas Factor
12. Gas Administrative Charge
14. Exelon Rate Credit
15. Sparrows Point (SP) Revenue Stabilization Rate

7.2 LIST OF SOURCES

The following documents and individuals (interviews) were consulted in establishing the baseline of information for the analysis.

Consultants interviewed over the telephone and by email Josh Schellenberg of Freeman, Sullivan & Co., who co-authored the 2009 Lawrence Berkeley Laboratory Report titled "Estimated Value of Service Reliability for Electric Utility Customers in the United States", and

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

Consultants interviewed in person and by email Julia Frayer of London Economics International LLC, who was the lead author of the 2013 Electric Reliability Council of Texas report titled "Estimating the Value of Lost Load" for the Power Line Undergrounding Task Force

Literature read and reviewed:

"Mayor's Power Line Undergrounding Task Force Findings & Recommendations", Washington DC, May 2013

"Mayor's Power Line Undergrounding Task Force Washington", DC 20005, August 23, 2012

Power Line Undergrounding Task Force - <http://oca.dc.gov/page/power-line-undergrounding-task-force>

"Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia – Formal Case No. 1026", Shaw Consultants International, Inc., prepared for the Public Service Commission of the District of Columbia, July 1, 2010

"ABOUT DERECHOS" Subsection CASUALTY AND DAMAGE RISKS -
<http://www.spc.noaa.gov/misc/AbtDerechos/derechofacts.htm#risks>

"A Review of Power Outages and Restoration Following the June 2012 Derecho, Infrastructure Security and Energy Restoration", Office of Electricity Delivery and Energy Reliability U.S. Department of Energy, August 2012

"Estimated Value of Service Reliability for Electric Utility Customers in the United States", prepared for Lawrence Berkeley National Laboratory by Michael J. Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A, Freeman, Sullivan & Co., June 2009

"Understanding the Cost of Power Interruptions to U.S. Electricity Customers", prepared for Lawrence Berkeley National Laboratory by Kristina Hamachi LaCommare and Joseph H. Eto, September 2004

"Before and After the Storm: A Compilation of recent studies, programs and policies related to storm hardening and resiliency", Edison Electric Institute: January 2013

"Out of Sight, Out of Mind: An Updated Study on Undergrounding of Overhead Power Lines", prepared for Edison Electric Institute by Kenneth Hall, P.E. Hall Energy Consulting, Inc., December 2009

"Methods to Consider Customer Interruption Costs in Power Systems Analysis", CIGRE, June 2012

"Should Public Utilities Compensate Customers for Service Interruptions?" Ken Costello, Principal Researcher, National Regulatory Research Institute, July 2012

"Investing in Grid Modernization", Perfect Power Institute, March 2012

"PPI Investing in Grid Modernization", Perfect Power Institute, March 2013

"Willingness to Pay to Avoid Outages: Reliability Demand Survey", Kathleen King, PhD, Bates White Economic Consulting, Washington, DC, June 2012

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

"An Analysis of the Direct and Indirect Costs of Utility and Right-of-Way Conflicts on Construction Roadway Project", Paul Goodrum, et al., Lexington, Kentucky: University of Kentucky, College of Engineering. Prepared for the Kentucky Transportation Center. August 2006

MD PSC Rule Making 43 (RM 43)

- Item 34 Working Group Report (cost estimate beginning on p 73)
- Item 44 BGE Comments (cost estimate beginning on p 29)
- Items 69 - 76

"The Maryland Energy Assurance Plan", Maryland Energy Administration, Maryland Emergency Management Agency, and the Maryland Public Service Commission

Electric Feedback Forum, Office of Governor Martin O'Malley, Improving Maryland's Electric Distribution System, Roundtable Discussion #1: Introduction to the Topic, August 21 2012

- Roundtable Discussion #2: Undergrounding, August 27, 2012
- Roundtable Discussion #3: What investments should customers be encouraged to make (or not to make) to increase their reliability?, August 28, 2012
- Roundtable Discussion #4: How will the "smart grid" impact reliability and resiliency of the grid?, September 4, 2012
- Roundtable Discussion #5: Other Investments on the Utility Side of the Met?, September 6, 2012
- Roundtable Discussion #6: Energy Assurance: How can emergency planning/infrastructure planning help with resiliency?, September 7, 2012
- Roundtable Discussion #7: Human Infrastructure, September 10, 2012
- Roundtable Discussion #8: Cost Recovery, September 11, 2012

"UTILITY 2.0 Piloting a Better Future for Maryland's Electric Utilities and their Customers", by the Energy Future Coalition, submitted to Governor Martin O'Malley, March 15, 2013

MD PSC Case # 9291: Item 32: Staff Comments (cost of undergrounding at pp 18-20)

MD PSC Case # 9291: Item 36: BGE's Comments on Staff Report (Exhibit C - cost of undergrounding)

MD PSC Case # 9291: Item 37: Howard County response to Staff

MD PSC Case # 9298: Derecho Multi-State Outage and Restoration Report

MD PSC Case # 9298: Item 71: BGE

MD PSC Case # 9298: Item 74: Pepco and DPL

MD PSC Case # 9298: Item 80: Choptank

MD PSC Case # 9298: Item 76: SMECO

MD PSC Case #9298: Item 72: Potomac Electric

MD PSC Case 9311: Pepco rate case Item #1 Volume I of II (Gausman Direct at pp. 134-288) Order to be issued by MD PSC July 12, 2013

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

MD PSC Case 9323: BGE rate case Item #1 (Woerner Direct, Vahos Direct) Order to be issued by MD PSC on December 13, 2013

MD PSC Case# 9317: DPL rate case Item #1 (Gausman Direct at pp. 131-162) Order to be issued by Law Judge September 6, 2013

MD PSC Electric Choice Monthly Enrollment Choice Reports

MD PSC Ten-Year Plan (2012-2021) of Electric Companies

Report of the "Task Force to Study Moving Overhead Utility Lines Underground" to the Maryland Legislature, December 2003

"Weathering the Storm: Report of the Grid Resiliency Task Force", submitted to Governor Martin O'Malley, September 24, 2012

"The Feasibility of Placing Electric Distribution Facilities Underground", Public Staff of the North Carolina Utilities Commission, Raleigh, North Carolina. November 2003

"Customer Costs Related to Interruptions and Voltage Problems: Methodology and Results", IEEE Transactions On Power Systems, Vol. 23, No. 3, August 2008

"ERCOT VoLL Literature Review and Macroeconomic Analysis: Estimating the Value off Lost Load", Julia Frayer et al, London Economics International LLC, June 17, 2013

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"An Examination of Transmission and Regional Electricity Planning and Communication as it Relates to Reliability", prepared for NARUC by Mot McDonald, December 2012

"The Cost of Power Disturbances to Industrial & Digital Economy Companies" prepared for EPRI's Consortium for Electric Infrastructure for a Digital Society: by primen/National Development Group, June 29, 2001

"New Focus for Weathering Storms: Customer Resilience", Brent Barker, EPRI, Spring 2013

"The Power to Change the Face of America: Converting Overhead Utilities to Underground", published by Underground 2020, 2009

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NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

"Weather-Related Power Outages and Electric System Resiliency", Richard J. Campbell Specialist in Energy Policy, Congressional Research Group, August 28, 2012

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"Keep Your Food Safe During Emergencies: Power Outages, Floods & Fires", USDA

"GIS Verification of Perishable Refrigerator Contents in New York City", Julie McCormick and Larry Anderson PhD, Ipsos-NPD, 2000

"How Much Does it Cost to Repair a Septic Tank?" <http://www.homeadvisor.com/cost/plumbing/repair-a-septic-tank/>

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"Should You Buy a Standby Generator?", David Agrell, Popular Mechanics, January 25, 2013

"Final Report of Montgomery County Maryland PEPCO WORK GROUP", April 20, 2011

August 2013 Natural Gas Supplier Prices and addresses,
<http://www.opc.state.md.us/LinkClick.aspx?fileticket=Qft7EvDx0MM%3d&tabid=136>

Gas schedules - BGE residential and commercial natural gas delivery rates:

<http://www.bge.com/myaccount/billsrates/ratestariffs/gasservice/gas%20rates%20and%20tariffs%20documents/gasscheduled.pdf>

<http://www.bge.com/myaccount/billsrates/ratestariffs/gasservice/gas%20rates%20and%20tariffs%20documents/gasscheduled.pdf>

"Costs of Utility Distributed Generators, 1-10 MW Twenty-Four Case Studies", D. Thimsen, EPRI Technical Update, Cosponsors: Cooperative Research Network and National Rural Electric Cooperative Association, March 2003

Texas Transportation Institute at Texas A&M University, September 2011.

"Common Food & Labor Cost Percentages", Houston Chronicle, Steven Buckley, 2013 (<http://smallbusiness.chron.com/common-food-labor-cost-percentages-14700.html>)

NARUC and MDPSC

A Cost-Benefit Analysis of Various Electric Reliability Improvement Projects From the End Users' Perspective

The Consultants contacted U.S. public utility commissions (PUCs) by telephone and email to inquire if any had knowledge of publicly available studies that would be of assistance and provide information for this study. PUCs for which similar work was found are listed in the previous section of this Appendix. The following PUCs responded with none having knowledge of any similar studies, reports, dockets, rate cases, etc.:

- Alabama Public Service Commission
- Arizona Corporation Commission
- Arkansas Public Service Commission
- California Public Utilities Commission
- Colorado Public Utilities Commission
- Idaho Public Utilities Commission
- Illinois Commerce Commission
- Iowa Utilities Board
- Kansas Corporation Commission
- Louisiana Public Service Commission
- Minnesota Public Utilities Commission
- Mississippi Public Service Commission
- Missouri Public Service Commission
- Nebraska Power Review Board
- New Mexico Public Regulation Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- South Dakota Public Utilities Commission
- Tennessee Regulatory Authority
- Public Utility Commission of Texas
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Public Service Commission of Wisconsin
- Wyoming Public Service Commission