BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

IN THE MATTER OF THE APPLICATION OF  
BALTIMORE GAS AND ELECTRIC COMPANY  
FOR ADJUSTMENTS TO ITS ELECTRIC  
AND GAS BASE RATES  

CASE NO. 9406

DISTRIBUTION INVESTMENT PLAN

June 5, 2017
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1. INTRODUCTION

By Order No. 87591 dated June 3, 2016, the Maryland Public Service Commission (the “Commission”) authorized recovery of certain costs Baltimore Gas and Electric Company (“BGE”) incurred in deploying its Advanced Metering Infrastructure (“AMI”) system. In so doing, the Commission found “compelling evidence that BGE’s AMI system is cost beneficial to its customers.”\(^1\) One of the many benefit streams considered by the Commission in its cost-benefit analysis was avoided transmission and distribution (“T&D”) capital expenditures. The method proposed by BGE for valuing avoided T&D was the marginal cost approach approved by the Commission in Case No. 9154 (EmPOWER Maryland), Order No. 87082, on July 16, 2015. The Commission accepted this methodology for valuing the AMI system-enabled avoided T&D capital expenditures, but it also required that BGE file a distribution investment plan within twelve (12) months of the date of Order No. 87591.\(^2\) With respect to the contents of the distribution investment plan, the Commission stated as follows:

The required Plan shall analyze in detail the Company’s strategy over the next five years for investing in its distribution system and shall include, among other things, specifics about how the Company’s investment in smart meters will be utilized to improve the efficiency and effectiveness of the distribution network.\(^3\)

As detailed in this Distribution Investment Plan (the “Plan”),\(^4\) BGE maintains a robust and ongoing process to identify and prioritize required investments on its distribution system. BGE considers a number of factors in determining whether to make a particular investment on the distribution system, including age of infrastructure, reliability history, forecasted load.

\(^{1}\) MDPSC Case No. 9406, Order No. 87591 at pp. 2-3 (June 3, 2016).

\(^{2}\) Id. at pp. 57-58.

\(^{3}\) Id. at p. 58.

\(^{4}\) Although this is a “distribution” investment plan, BGE has also provided certain information in this Plan about system planning processes and programs relevant to the “transmission” system.
growth, and available generation, distributed energy, energy efficiency, and demand response resources and programs. The data produced from the AMI system will increasingly enable BGE to analyze system conditions more precisely and tailor its distribution system investments accordingly.

Over the course of the next five years, BGE will pursue opportunities to use its AMI system to optimize insights into customer behavior, distribution system equipment performance, and system load growth/reduction. For example, BGE will be deploying new business intelligence/data analytics (“BIDA”) tools to manage and process the large quantities of data produced from the AMI system. Access to these BIDA tools will help BGE to better plan for and design system improvements, thus increasing the overall efficiency and effectiveness of the distribution network and the electric service that BGE provides to its customers.

In addition, BGE will continue to promote and expand its core AMI-enabled programs, BGE Smart Energy Manager® (“SEM”) and BGE Smart Energy Rewards® (“SER”), and develop additional AMI-enabled programs that will help customers monitor and control their usage. Importantly, AMI-enabled programs like SEM and SER that lead to predictable reductions in customer load may avoid certain upgrades on the distribution system that would otherwise be necessary absent the existence of such programs. Finally, BGE plans to investigate and develop additional AMI-enabled opportunities that will allow customers to better take advantage of modern technologies such as electric vehicles, energy storage, and distributed energy resources (“DER”).

2. ELECTRIC SYSTEM INVESTMENT PLANNING PROCESS

BGE undertakes a 5-year planning process to identify and prioritize required distribution system investments. The objective of this planning process is to ensure that adequate
infrastructure exists to reliably supply electric service for all customers at the lowest overall cost, consistent with goals regarding safety, reliability, quality of service, community relations, and protection of the environment. As part of this process, BGE reviews its 5-year project plan to verify the service dates of projects needed to supply customer load or address system performance issues. As system conditions change, projects may be expedited or deferred. This planning process is improved by BGE’s AMI system data. The AMI customer load information is more granular and provides a greater understanding of the impact of customer participation in AMI-enabled programs. As later described in this Plan, incorporation of this AMI data into the investment planning process will enable BGE to better prioritize its required distribution system investments and expenditures in a manner that maximizes customer reliability benefits and satisfies the capacity expansion requirements of the system.

2.1. Capital Planning Process

Fundamental to every capital planning process are the underlying studies and analyses that serve as the basis and justification for the investment decisions. To that end, the planning process at BGE includes comprehensive system studies and detailed analyses of the electric distribution and sub-transmission systems “radially” supplied from the bulk power system. Studies of the network transmission system are also conducted as part of the regional transmission system planning process. Additionally, reliability analyses are performed to identify and mitigate reliability concerns associated with changing system conditions or aging infrastructure.

These studies and analyses have the overarching objective to proactively identify potential issues that impact BGE’s ability to supply customer load. Thermal, voltage, aging infrastructure, and reliability issues are typically the drivers for projects. A thermal issue occurs
when the capacity of equipment is exceeded and begins to overheat. The overheating can quickly lead to premature failure. A voltage issue occurs when voltages are outside of prescribed limits as outlined in Code of Maryland Regulations (“COMAR”) 20.50.07.02. Customer equipment operating outside these limits can experience reduced equipment life, equipment damage, and other issues. Reliability issues may occur due to vegetation growth or the changing environment.

Many triggers exist that may create thermal or voltage issues on the electric system. Customer load growth and expansion are some of the common causes. As developments (residential, commercial, and industrial) are connected to the electric infrastructure, additional equipment utilization occurs. When the excess system capacity is exhausted, additional electric infrastructure is often needed. In addition to new customer connections, existing customers may also experience load growth as they expand their use of electricity and the infrastructure becomes insufficient to meet the peak usage. When a thermal or voltage violation is likely to occur, regulatory requirements may no longer be satisfied, thus requiring prompt response from the utility. The following Figure 1 contains the typical project threshold at BGE:

**Figure 1: Potential Project Triggers – Forecast Load of Component**

<table>
<thead>
<tr>
<th>Potential Project Triggers</th>
<th>Threshold</th>
</tr>
</thead>
<tbody>
<tr>
<td>13kV Circuit Overload</td>
<td>Forecast &gt;110% of Normal Rating</td>
</tr>
<tr>
<td>34kV Circuit Overload</td>
<td>Forecast &gt;100% of Normal Rating</td>
</tr>
<tr>
<td>34kV Circuit Contingency Overload</td>
<td>Forecast &gt;100% of Emergency Rating</td>
</tr>
<tr>
<td>Substation Transformer Overload</td>
<td>Forecast &gt;100% of Normal Rating</td>
</tr>
<tr>
<td>Substation Transformer Contingency Overload</td>
<td>Forecast &gt;100% of Emergency Rating</td>
</tr>
<tr>
<td>Firm Substation Overload</td>
<td>Forecast &gt;100% of Emergency Rating</td>
</tr>
<tr>
<td>Semi-Firm Substation Overload (block circuit transfer)</td>
<td>Forecast &gt;100% of Emergency Rating</td>
</tr>
<tr>
<td>Description</td>
<td>Threshold</td>
</tr>
<tr>
<td>---------------------------------------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>Other Operational and Reliability Issues (circuit ties, voltage issues, operability issues)</td>
<td>Program Determined</td>
</tr>
</tbody>
</table>

Other drivers for distribution investments include aging infrastructure replacement or repeat reliability issues. As equipment ages beyond its useful life, the risk for possible failure increases. Repeat reliability issues due to vegetation or the changing environment may also prompt the utility to plan corrective actions. The planning process attempts to proactively identify these issues in advance of actual need in order to allow projects sufficient time to be built and to avoid the possibility of equipment failure or customer dissatisfaction.

BGE utilizes a mix of short-term and long-term solutions in order to cost effectively resolve system issues. When larger increments of load are expected in the future, additional infrastructure will be planned to avoid issue recurrence. Transferring customer load from one circuit to another may be possible to provide a short-term, low cost solution. When load transfers are not possible, BGE investigates replacing existing infrastructure with higher capacity equipment. The addition of new circuits, substation transformers and entire new substations are all considered when determining the lowest cost solution. BGE also considers innovative alternative solutions, like DER. The following Figure 2 provides a standard timeline for the different distribution solutions commonly employed:
**Figure 2: Project Execution Time Frames**

<table>
<thead>
<tr>
<th>Local Load Control (LLC) Programs</th>
<th>Immediate</th>
<th>0-1 Year</th>
<th>1-2 years</th>
<th>2-3 years</th>
<th>3-4 years</th>
<th>4-5 years</th>
<th>5+ years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transfer Load to Another Feeder or Transformer</td>
<td>Transfer Load to Another Feeder or Transformer</td>
<td>Add Feeder Ties</td>
<td>Add Capacitors</td>
<td>Build New Feeder</td>
<td>Replace Equipment With Higher Capacity Components</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Add DA Devices</td>
<td>Add DA Devices</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replace Equipment With Higher Capacity Components</td>
<td>Replace Equipment With Higher Capacity Components</td>
<td></td>
<td></td>
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<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Retire/Rebuild Aging Infrastructure</td>
<td>Retire/Rebuild Aging Infrastructure</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 2.2. Types of BGE Project Categories

BGE uses three primary categories to group its major proactive infrastructure investments on the electric system:

1. **Capacity Expansion.** The Capacity Expansion category contains projects on the distribution and transmission systems that support load growth and increase system capacity. Projects in this category are typically infrastructure additions needed to support customer load.

2. **System Performance.** The System Performance category is made up of work to enhance system reliability through proactive equipment replacement, proactive upgrade/restoration of existing equipment, remediation of poorest performing feeders, implementation of industry recommendations, and replacement of aging infrastructure.

3. **New Business.** The New Business category is made up of work performed to connect new customers to the electric system. Projects to upgrade customers’ service equipment and relocate services are also included in this category.

### 2.3. Project Identification

BGE plans its Capacity Expansion, System Performance and New Business projects across the service territory to address load driven and system reliability needs. These projects fall into three subcategories: Major Capital Projects; Short Lead Projects; and Long Lead Projects. Projects are classified into each of the categories based on a variety of factors, including, but not limited to, execution timeline, expenditure level, and complexity of the
project. Additionally, some projects are required by a specific time in order to meet capacity requirements, accommodate changing system conditions, and/or accomplish reliability objectives. For example, BGE’s electric system typically peaks in the summer months; however, some areas of the BGE territory that lack gas service experience winter peaks due to electric heat. To ensure projects are executed before the seasonal peaking periods, the planning process will identify when the study area will peak (summer or winter) in order to correctly address system issues.

2.3.1. Major Capital Projects

Major Capital Projects are typically needed to replace existing aging infrastructure concerns on major or critical assets or address large amounts of load growth that normally come with planned development. These types of projects are identified through the long-range planning effort and ordinarily take several years to complete.

2.3.2. Short Lead Projects

Short Lead Projects are smaller in scope and typically executed in less than a year. For Capacity Expansion projects, Short Lead Projects normally consist of feeder projects that are identified by April 1st for the summer season and completed by June 1st of the following year. Winter projects are identified by September 1st and must be completed by November 15th of the following year.

2.3.3. Long Lead Projects

Long Lead Projects are medium in scope and typically executed within one to two years. For Capacity Expansion projects, Long Lead Projects normally consist of substation or 34kV projects that are identified by May 1st for summer and completed by June 1st of the second year.
after identification. Winter projects are identified by October 1st and must be completed by November 15th of the second year after identification.

2.4. Capacity Expansion – Distribution

To ensure the electric distribution system is built for the needs of BGE’s customers, a multistep analysis is conducted. Load forecasts are created and numerous system studies are conducted to prioritize the proposed projects. On an annual basis, projects are reevaluated to verify continued need. This process is designed to ensure reliability and financial objectives are met. The following Figure 3 illustrates the process flow for BGE’s distribution planning process:

Figure 3: Distribution Planning Process Flowchart

![Distribution Planning Process Flowchart](image)

2.4.1. Load Forecasting

BGE develops load forecasts on the distribution and sub-transmission transformers and feeders for both winter and summer peak conditions. The load forecast represents the best estimate of the peak loading expected on a transformer or feeder. The forecast is based on
existing customer load contribution (commonly referred to as the “reference load” or “base load”), projected load growth (new customers or existing large customer expansions), planned load transfers, and other factors that could impact loading. The load forecast is developed for the next five summer and winter seasons in order to provide sufficient information to support the 5-year workload planning effort.

The time horizon for the short-range forecast – referred to as the “reference forecast” – is one year. The reference forecast is used to support short-range project planning and also confirms the continued need of upcoming planned projects. To account for varying weather conditions, the reference forecast is weather adjusted and created by using a regression analysis on the hourly loads (as illustrated below in Figure 4). In some cases, actual peaks are used without weather adjustment, particularly for components not likely to be weather-sensitive such as large customer feeders and sub-transmission supplied customers.

Figure 4: Summer and Winter Regression Analysis – Weather Normalize Peak Load

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5 Local load control is an example of a program that impacts system loading. Under this program, BGE provides financial compensation in exchange for the ability to control customer load. The control is used to reduce peak loading conditions. This program was first available to large industrial and commercial customers. The program now extends to residential customers through programs like PeakRewardsSM and SER. DER also impact load forecasts, but the benefit is not as straightforward as the local load control program. DER may mask native load resulting in unexpected load increases when system failures occur, and the DER not directly controlled by the utility may be offline when needed most.
The time horizon for the long-range forecast is five years and beyond. The purpose of this forecast is to support long-range planning to identify future capacity needs. Tentative dates for major capital projects - typically substation projects - are identified through this process. The long-range load forecast allows distribution and sub-transmission transformer and feeder projects to be identified for future years.

A number of internal and external factors can influence the ultimate loading on BGE’s distribution system. To account for these factors, load projections use an incremental load growth factor, anticipated new customer additions, and planned transfers in order to develop an understanding of the system capacity needs. The primary data sources for the long-range forecast are the reference forecast, component loading history, energy conservation program estimates, demand response program estimates, additional DER, land usage reports, zoning maps, growth plans published by government agencies, and trend analysis outputs.

### 2.4.2. Contingency Analysis

In addition to planning for customer load during normal system conditions, BGE also plans for unexpected failures and negative impacts to the electric infrastructure from storms and other human or environmental impacts. BGE conducts a substation firm\textsuperscript{6}/semi-firm\textsuperscript{7} analysis annually to determine system loading following the loss of a major piece of equipment. All firm

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\textsuperscript{6} A firm substation typically serves critical load such as public safety and health, critical, and business significant customers. Firm stations have a configuration that allows the load on one transformer to be transferred to the other station transformer through what is called an “H-tie circuit breaker.” The customer load transfer will be automatic for a station supply circuit, transformer, or bus failure. If mobile transformer equipment cannot be accommodated on a site, the station will also have to follow the firm station guidelines in order to avoid long-term customer outage impacts.

\textsuperscript{7} A semi-firm substation serves non-critical load, typically residential and small industrial and commercial customers. Semi-firm stations have a configuration that allows the load on one transformer to be transferred to the other station transformer through what is called an “H-tie circuit breaker.” If equipment will be overloaded by the transfer, the circuit will not be restored following the initiating event. A semi-firm station can also accommodate a mobile transformer, allowing all customer load to be restored within 24 hours.
substations and semi-firm substations in BGE’s service territory are planned on a single contingency (N-1) condition. The objective is to have a plan in place to restore all customer load within the station following the loss of a single major component. Major components include substation buses, switches, and transformers. The station classification – firm/semi-firm/non-firm – determines the time frame for the customer load restoration.

2.4.3. Distribution Circuit Analysis

Prior to the summer and winter peak season, distribution circuits\(^8\) and sub-transmission circuits\(^9\) are analyzed to determine if any thermal equipment limitations exist. When the forecasted load on the circuits is projected to be equal to or greater than the normal rating, an issue may exist at peak.\(^{10}\) An investigation is conducted to look at transferring customer load to an adjacent circuit or building additional infrastructure to relieve any anticipated overload. The load transfers solution identified may be permanent, seasonal, or triggered during a real time system condition. Seasonal operating procedures are created when a solution is planned, which may be executed in real time to address a short-term system issue. Operating procedures allow an overload to be addressed while a long-term, permanent solution is investigated and implemented.

2.4.4. System Voltage Planning and Analysis

In addition to ensuring adequate thermal capacity of electrical supply, BGE also plans the system to meet voltage requirements, as outlined in COMAR. BGE performs a voltage and

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8 Distribution circuits include 13kV voltage level and a supply to customer load.

9 Sub-transmission circuits include 34kV voltage level and a supply to other electric substations or large commercial and industrial customers.

10 A “normal” rating defines the amount of power that can continually flow through a device or piece of equipment without creating damage or loss of equipment life. An “emergency” rating defines the amount of power that can flow through a device or piece of equipment for a short period of time and creates an acceptable amount of equipment damage or loss of life.
reactive power analysis twice a year to determine the number of capacitors and appropriate capacitor settings to ensure all voltage requirements are met for the upcoming summer and winter seasons. The analysis includes determining control scheme settings changes, non-Load Tap Change (“LTC”)\textsuperscript{11} transformer tap adjustments, and other system changes needed to support customer loads. New capacitors and setting adjustments are tracked as part of a seasonal readiness activity, which are required to be completed prior to the start of the summer and winter seasons to ensure system stability and reliability.

2.4.5. New Business and Steady State Load Growth

Load information for new customers is used to ensure that changing customer demands, requirements, and developments are accounted for in the planning process. The data is obtained by BGE from a variety of sources. For example, when large developments are in the initial planning phase, property plats showing streets and building lots are submitted to BGE as a standard practice. This information is incorporated into the planning process to ensure new customer needs can be met along with BGE system reliability criteria.

When conducting long-range planning, BGE uses a growth factor to anticipate long-term system capacity needs. BGE adjusts the projected year-by-year long-range peak load growth rate on each distribution system component to align with PJM Interconnection, LLC’s (“PJM”) long-range load forecast. The growth rate for the long-range forecast is reconciled with PJM’s long-range forecast to ensure consistency across the distribution and transmission planning process. While the distribution system is under BGE’s control, the systems need to be planned in conjunction with the regional planning effort overseen by PJM.

\textsuperscript{11} Transformers have a setting, or “tap,” that controls the output voltage of the equipment. A non-LTC transformer will require an outage to change the settings. The settings are set once a season under a planned outage. LTC transformers can have their settings adjusted in real-time with the equipment in service.
2.4.6. Demand Response Programs

Local load control devices have been deployed on BGE’s distribution circuit and sub-transmission circuits in order to help reduce peak energy demand and defer capacity expansion projects. Customer load within these programs are directly controllable by the utility and allow a direct impact on equipment loading upon program activation (see Figure 5 below). These devices include smart thermostats and load control switches. BGE customers participate in this initiative through the PeakRewards\textsuperscript{SM} and AMI-enabled BGE SER programs.

**Figure 5: Impact of Demand Response (LLC) on BGE Zone Load**

![BGE Zone Load Impact From LLC (7/25/16)](image)

BGE considers the impacts of its demand response programs during the forecasting and project planning process. Demand response that is controllable by the utility is able to be used to defer capital projects. Voluntary demand response programs, like SER, create a gradual change in customer usage behavior. Such programs can have a sustainable impact on customer usage behaviors over time, which could result in reduced seasonal system load forecasts. As the
system load is affected by usage reductions due to customer behavior changes, the need for additional system capacity may reduce or diminish. Equipment typically experiences peak load for only a small number of hours throughout the year.

By controlling and reducing the peak loading conditions, project deferral can potentially be achieved. An example includes the deferral of a reconductoring project two 34kV circuits supplied out of Lippins Corner. The project was deferred by two years to 2016 from its initial service date of 2014 based on the impact of BGE’s demand response programs. Another example is a large substation, distribution, and transmission project in the Loch Raven area. The project is currently being considered for deferral from 2021 to 2022 due to the impact of demand response. The following Figure 6 depicts an example of impacts due to LCC on the project service date:

**Figure 6: Example Project Load Table Showing Project Deferral Due to LLC**

<table>
<thead>
<tr>
<th>Project ID:</th>
<th>Project Name:</th>
<th>Service Date: 6-01-2016</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>37.8</td>
<td>51.3</td>
<td>No</td>
<td>24.36</td>
<td>24.87</td>
</tr>
<tr>
<td>32.6</td>
<td>46.2</td>
<td>Yes</td>
<td>24.86</td>
<td>25.06</td>
</tr>
<tr>
<td>25.8</td>
<td>30.9</td>
<td>No</td>
<td>20.90</td>
<td>20.96</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Rating</th>
<th>LLC Applies</th>
<th>Act. Peak Load</th>
<th>Ref. Load</th>
<th>Forecasted Summer Loads Before Project - Normal Weather (LCC)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

2.4.7. Distribution Planning Process Data and Future Impacts of AMI

AMI is transforming the way BGE forecasts. The load values currently used in the planning process are measured and recorded by BGE’s supervisory control and data acquisition (“SCADA”) system, which generally gathers data at the substations/transformer level. Customer
monthly consumption data is used to estimate the amount of load the line equipment will see during a given time period. Aggregate data at the substation will show the feeder loading throughout the day. Models and the monthly customer consumption data is then used to predict the line equipment loading near the customer. With real time metering only at the substation level or along the circuit at key devices, the estimated load flow may not match actual loading. A method to identify loading conditions and actual overloads on unmetered line equipment is needed.

This load allocation process works for the current planning process, but a margin of error exists. Integrating AMI customer data with the SCADA data can allow feeder or specific equipment load curves to be created and analyzed. Opportunities for additional deferral of summer and winter projects may be possible with more detailed time series load information. With the addition of advanced system modeling and planning tools, AMI data will allow the system to be modeled closer to actual conditions, resulting in improved issue identification. Improved analysis may also allow current planning margins to be reduced allowing projects to be built closer to the time of actual need.

2.5. Capacity Expansion – Transmission

The PJM Regional Transmission Expansion Plan (“RTEP”) process assesses the transmission system to ensure system reliability, market efficiency, and operational performance throughout the PJM region, which includes BGE’s service territory. PJM studies the region both for near-term (years one through five) and long-term (years six through fifteen) system impacts due to customer load. The RTEP analysis ensures that all North American Electric Reliability Corporation (“NERC”), PJM, and local reliability standards are met. When PJM identifies a

12 “Time series” data is real time data, time stamped, and recorded throughout the period.
reliability or market efficiency issue, various parties are able to submit proposed solutions to the issue. PJM will then select a solution and that party becomes obligated to fund and construct the project by the service date established by PJM.

The PJM load forecasting and analysis process is explained in PJM Manual 19. This includes the process to create the 15-year monthly peak forecasts for the entire PJM region. The load forecast serves as the input to the transmission planning studies. The forecasts are produced every year and released around January. With forecast data incorporated, the PJM study process takes into account a number of additional factors when determining project needs. These factors include: expected demand response; expected transfers; generation additions/retirements; reactive resource capability; expected service dates of new or modified transmission facilities; and duration or timing of known transmission outages. Projects will be identified due to capacity needs as well as for market efficiency reasons. Market efficiency projects consider energy forecasts, fuel and emissions costs, and various other sensitivities.

2.5.1. Transmission Planning Impacts from AMI

Reductions associated with AMI system-enabled programs are one factor among many factors that affects hourly metered load data. As customers take advantage of demand response programs and support reducing peak demand, the need for new transmission projects may be altered. There are many additional factors, however, which determine the need for a transmission project. For example, system voltage, thermal, stability, load deliverability, generation deliverability, and congestion analyses criteria are all considered when determining project needs. In addition, demand response resources that participate in PJM base residual and incremental auctions are included in various power flow studies and can mitigate or delay the need for transmission upgrades.
2.6. System Performance

BGE is continually monitoring the electric grid to deliver safe and reliable electricity to all customers. In addition to responding to day-to-day operational conditions such as loading concerns and outages, BGE invests significant capital to maintain and improve the reliability of the electric distribution system. Within the distribution level voltages (4kV – 34kV), capital investments in infrastructure to improve reliability are included in the System Performance category, which consists of a wide range of programs to meet increasingly robust reliability goals. The purpose and scope of these programs can include reconfiguring the electric system, selectively undergrounding overhead circuits, upgrading aging infrastructure, and leveraging current technologies to enhance system performance.

2.6.1. AMI Impact on System Performance

AMI positively impacts the System Performance category. For example, before AMI, BGE would traditionally only become aware of customer voltage issues when contacted directly by the customers. However, with the inception of the Low Voltage Mitigation program within the System Performance category, BGE is able to leverage AMI to obtain meter data and proactively identify customers experiencing low voltage issues on the BGE distribution system. Remediation solutions are then engineered, designed, and constructed to address the identified issues.

Additionally, the System Performance category programs currently require routine analysis to identify and prioritize each program’s annual work plan. While necessary and altogether beneficial, the analysis can be time consuming. With the implementation of AMI, BGE will be able to leverage the associated reliability data through its BIDA initiatives. With
the additional reliability data, BGE will be able to more swiftly and effectively optimize each program’s annual work plan.

3. USE OF THE AMI SYSTEM TO FURTHER IMPROVE THE EFFICIENCY AND EFFECTIVENESS OF THE DISTRIBUTION NETWORK

An AMI system is the backbone infrastructure required to support many modern technologies designed to improve the efficiency and effectiveness of the distribution network. BGE completed its deployment of an AMI system in September 2015 and has already deployed a number of programs that utilize the AMI system technology to drive efficiencies, increase productivity, and improve services for customers. Over the next five years, BGE will investigate, develop, and deploy a variety of additional technologies that depend upon the AMI system in an effort to further improve the level of service for customers. This section of the Plan discusses these existing and ongoing efforts of BGE.

3.1. BGE PeakRewards℠ Enhancement Program

The BGE PeakRewards℠ program initiated an enhancement project in November of 2015 to evaluate the working condition and functionality of demand response hardware installed on customers’ air conditioning equipment. Under this enhancement project, BGE identifies potential non-operable devices and schedules inspections by analyzing AMI data. Field inspectors check demand response equipment for correct wiring, firmware, physical damage, tampering, age, condition, and overall functionality. Any device issues are corrected or the customer is removed from the PeakRewards℠ program. Through this enhancement program, BGE better ensures that the credits paid to participating customers will produce the expected demand reduction when the program is activated. The PeakRewards℠ Enhancement program, enabled by AMI, allows BGE to be confident in the amount of load that can be controlled during
a demand response event. This allows more effective project deferral decisions, due to local load control, to be made.

Of the 13,056 inspections completed to date in the enhancement program on PeakRewardsSM air conditioning switches, the program vendor has provided an assessment based upon devices inspected: 60% pass inspection with no observable malfunctions or installation issues. Additionally, the program vendor has concluded that 27% have been observed “tampered,” meaning that the PeakRewardsSM device has been disconnected, 4.6% of devices have been observed disconnected or missing due to installation of new HVAC equipment, and the remaining 8% which fail inspection are due to physical damage, incorrect wiring, equipment malfunctioning, or the consumer actually requests to be removed from the program at time of the inspection. The inspection of potential non-operable devices allows BGE to identify and correct equipment malfunction. This ensures the PeakRewardsSM program is able to deliver the expected demand response levels.

3.2. Remote Meter Reading and Remote Connection

The AMI system enables BGE to read and process meter usage data remotely, which reduces labor, vehicle, and IT costs. Such capability also helps reduce the number of estimated bills issued to customers.

Another benefit of the AMI system is the ability to remotely connect/disconnect electric service, which reduces time and expense by eliminating otherwise required truck rolls. Further, as a result of the technology, BGE can more efficiently respond to customer requests to initiate or disconnect electric service.

3.3. Outage Management System – AMI System Integration

The outage management system (“OMS”) is the tool used by operating personnel at BGE to identify customer outages and coordinate day-to-day operation of the distribution system. The
system provides operating personnel with a model of the system as it currently exists in the field. Having a current system model allows accurate and efficient operating decisions to be made during outage events and other adverse operational conditions.

Historically, OMS would predict service outages using only customer outage calls. The system would then take the calls associated with certain customers and determine the most likely protective device that operated. With the OMS and AMI system integration, the ability to identify outages from real-time data better enables significant operational improvements.

As a result of the AMI system, some outages can be detected before a call is even received. This capability enables BGE to proactively respond to outages sooner than otherwise possible, and this effectively reduces the outage restoration time. In addition, the AMI data provides more information from which the cause of an outage can be predicted. This allows BGE personnel to more accurately respond to outages. Customers also benefit as the outage restoration time is reduced.

3.3.1. Restoration Verification

OMS automatically pings AMI meters to verify restoration times. Unsolicited power-on responses received from the AMI meters can also be processed. The Restoration Verification functionality allows power-on communications from individual AMI meters to appear as a condition in the OMS viewer. By enabling OMS to automatically communicate with meters to verify that the meter is working, BGE can verify that no nested outages exist, ultimately saving customer outage minutes and unnecessary crew time.\(^\text{13}\)

\(^{13}\) A nested outage is when two protective devices in series operate. The service operator is sent to the upstream device to restore power and then when power is restored, the event is closed but the customers downstream of the second device that operated are still left without power. Normally, another event is started and another service operator would need to mitigate the second device outage resulting in longer outages times for the downstream customers.
3.3.2. Automatic Restore Time Adjustment and Predicted Service Outage Verification

With the increased functionality and connectivity of the AMI network, the OMS system is able to automatically adjust the restoration time to the time when AMI indicates the power has been restored. The field crews currently input the restoration time manually, and this input method can be subject to human error. Having the outage and restoration times validated against the AMI data allows outage durations to be accurate, resulting in a reduction of the amount of outage correction effort that is needed following a storm event.

In addition to adjusting restoration times, OMS is also able to automatically ping “single no light” jobs to verify the status of the meter and determine if the outage is due to BGE or customer equipment.\(^14\) If the automatic ping results in a response, OMS is able to remotely detect that the meter is functioning and determine that the cause of the outage is on the customer side of the meter. This additional information through the AMI system allows the dispatcher to quickly review and close the job and dedicate resources to appropriate outage jobs. Automatically verifying the status of single no light jobs avoids the need for additional resources to investigate the outage, most likely through a field call to the customer’s premise.

3.3.3. OMS Functionality Currently Being Tested

In addition to the above functionalities being leveraged by BGE to improve the OMS and response to customer outages, BGE is testing enhancements to its predicted device outage verification capability. By being able to better pinpoint the predicted device outage, the outage restoration effort can be conducted more efficiently. Repair crews are more likely to be

\(^{14}\) A “single no light” job is a single customer outage. This type of outage occurs due to damage on the secondary loop or bus supplying the customer premise. Repair crews attempt to identify and correct all damage during the initial restoration effort. The possibility for a customer to inadvertently be left out of service due to secondary damage following repairs to the primary system is possible. It is more effective to identify and correct these issues while the crew is still in the area conducting restoration efforts.
dispatched to investigate the direct source of the problem. Another feature of AMI that is being tested is for OMS to detect the AMI meter’s last gasp message following a power outage. Receiving the last gasp can help create a predicted outage map that can be used for restoration planning efforts.

3.4. Energy Theft Program

The energy theft program improves safety for employees, customers, and the general public as well as helps ensure that those who receive service from BGE are financially responsible. Prior to the deployment of the AMI system, many instances of meter tampering and theft went undetected. With the AMI system, BGE is now able to detect, investigate, and respond to potential theft circumstances in a more timely fashion. This is achieved through the implementation of a data analytics tool that is able to identify non-operating meters and network equipment. As a result of the analytics produced through the BIDA initiative, BGE is able to use information from AMI meters to identify and address potential meter tampering and theft. Theft detection reduces the amount of energy stolen, helps make system conditions safer, and has a positive effect on the equitably distributing cost of electric service.

3.5. Distribution Automation

Distribution Automation (“DA”) is an advanced centralized control system used to minimize the impact of faults that occur on the distribution system. The DA system consists of electronic automatic reclosers installed in the field. The DA head-end control system, along with a communication system, enables an automatic restoration scheme to be implemented. The DA system improves the customer experience by reducing the number of transient faults that become sustained outages (e.g., falling tree limbs on overhead lines that burn clear). The DA system also reduces the number of customers impacted from an event by sectionalizing the system into
smaller segments. Following an outage, electronic reclosers automatically isolate the fault, and the DA system then coordinates recloser operations to quickly reconfigure the circuit and restore unaffected sections to minimize the number of customers impacted by the outage. BGE’s DA system operates on a single phase basis, limiting the interruption to customers on only the faulted phases. There are approximately 3,000 automatic reclosers currently in service on the BGE system. In 2016, the DA system saved approximately 2.6 million customer interruptions.

3.5.1. DA Communication System – Leveraging the AMI Provider System

The existing DA wireless communication network relies on 900MHz point-to-point radio communication from master stations across the BGE territory to radios integrated into individual recloser controllers. BGE plans to leverage its Smart Grid AMI Network Provider for the deployment of its next-generation DA network. BGE also plans to leverage the AMI network for the management of the DA radio devices. The new DA network will utilize wireless mesh technology and will feature modern, multi-layer security features. BGE is starting the deployment of the new DA network in 2017 and plans to complete the deployment in 2021.

In the future, BGE is likely to consider leveraging the new DA network to handle the wireless communications of additional devices such as automated remote fault indicators, secondary voltage regulating devices, and DER. As additional line sensing devices are installed and communicate back to a central system, additional customer benefits will be achieved. For example, the addition of fault indicators with communications capability will allow BGE to improve outage identification and dispatch, reducing Customer Average Interruption Duration Index (“CAIDI”). The new communications network may also allow monitoring and control of secondary line voltage regulating devices and customer DER which may help further improve reliability.
3.6. Conservation Voltage Reduction

Conservation Voltage Reduction ("CVR") is a technique for improving the efficiency of the electric distribution system by optimizing voltage levels, within the limits prescribed by COMAR 20.50.07.02, on the circuits that run from substations to homes and businesses. Lower voltage levels result in customers using less energy, which leads to lower customer bills. By reducing the need to generate additional energy at power plants, CVR also helps to reduce carbon emissions.

The AMI system is one of the enablers for the effective implementation of BGE’s industry-leading CVR program. More specifically, the AMI system provides customer voltage data that can be used to optimize voltage levels in a manner that maximizes customer savings while ensuring voltages are maintained within the COMAR limits.

During the next five years, BGE will continue to investigate opportunities to further enhance its CVR program. For example, one promising application is the further use of data obtained from CVR and AMI systems and development of voltage analytics to dynamically adjust CVR voltage targets based on system conditions. Further, BGE is looking to incorporate newly available data to improve its planning process for the addition of reactive power resources.

3.7. Business Intelligence and Data Analytics

Over the next five years, BGE will focus on translating accumulated data into solutions that improve the efficiency and effectiveness of the distribution network. The following subsections highlight the various applications being investigated and implemented by BGE over the next five years.
3.7.1. Transformer and Line Equipment Sizing

The availability of AMI data will assist BGE in determining the optimal sizing of transformer and line equipment in the future. Consistent with other utilities across the nation, BGE does not meter customer service transformers. In order to estimate transformer utilization, BGE currently leverages a legacy system that utilizes a correlation between customer kWh consumption and peak demand to estimate the peak kVA demand on the customer service transformer. This information is used to estimate available transformer capacity before adding new customers to the system. Knowing the actual peak kVA demand on a transformer by aggregating meter data from AMI, however, may allow more load to be added to an existing transformer. In the past, another transformer or upsizing the existing transformer may have been required if the equipment was estimated to be fully utilized.

AMI information also helps to model the placement of load across the distribution circuits. Because a variety of customer types and load shapes exist across the BGE service territory, the accuracy of the predicted component loading obtained using the legacy system can be fairly limited in certain circumstances. AMI data includes the kWh demand and time of use information for all customers. By leveraging AMI data, the peak hourly demand for each customer service transformer could be calculated based upon the connected customer meters and used in the project prioritization process.

The AMI data will also allow a review of customer load estimation assumptions further allowing for improved equipment sizing. Having the correct size transformer initially installed avoids follow-up work and potential system issues. A better understanding of the load profiles on the equipment can also lead to improved health monitoring. As equipment becomes overloaded, proactive measures can be taken to address the overload. Equipment can be
upgraded to avoid premature failure. It may also be possible to reconfigure the system to shift load to equipment that does have the necessary capacity. Ultimately, AMI can allow better utilization of existing infrastructure to be achieved and potentially allow project deferment.

3.7.2. Power Quality Assessment

BGE’s current process is to reactively respond to customer power quality (“PQ”) complaints. After a customer opens a PQ case with BGE, PQ meters can be installed for a limited time at a customer’s meter or service transformer. The installed monitoring device will capture and record data on any PQ events for additional analysis. A method to proactively identify issues did not previously exist before the AMI system was deployed. AMI meters monitor voltage and capture average voltage data as well as certain voltage sag/swell events. Recorded PQ information can then be reported back to the utility.

Additional information from the AMI system may allow customer issues to be proactively addressed. Reports can be run to identify customers experiencing sustained low or high voltages. These issues can be further investigated and addressed before the customer experiences any noticeable power quality issues. Similar reports can be created to identify customers experiencing large numbers of momentary outages or sag/swell events in an effort to proactively identify and remediate poor performing areas of the system.

3.7.3. Network Connectivity

BGE maintains an electrical network connectivity model down to the individual customer, which includes the meter to transformer and transformer to phase relationship. As with any data set, there is occasionally inaccurate or incomplete data. Examples of these inaccuracies would be meters mapped to the wrong transformer, meters not mapped to any transformer, or transformers mapped to the wrong phase on the feeder. These inaccuracies
become issues during outage detection and restoration response. In addition, a complete and accurate network connectivity model is necessary to perform advanced analytics on the grid. Without accurate data, it would be difficult to conduct high value analytics and produce meaningful conclusions.

Before AMI, it was not feasible to detect and correct network connectivity errors from readily available information. Meter to transformer relationship errors would have often gone undiagnosed. With the additional data provided by the AMI, however, a number of different methods to determine inaccuracies and recommend corrections now exist.

The first is geospatial analysis, analyzing the physical proximity of the meter to the transformer. Distances that are exceptionally long might indicate an error. Another method is to analyze outage data from multiple meters on a single transformer. This analysis would compare outage and restoration event timestamps from the smart meters mapped to the transformer and determine if there are any abnormalities (i.e., one of several meters does not show an outage at the same time as the other meters). The final method is to compare the voltage profile data for all meters on a transformer and determine if there is one that is dissimilar to the others. A combination of these methods can be used to identify inaccuracies and suggest corrections.

A direct operational benefit from the improved network connectivity case is enhanced storm response. As outage information comes to the outage management system (via smart meter alerts or customer reports) single outage events can be analyzed with the connectivity model and other grid sensors to determine the size and scope of the outage. When a large area is restored and damage still exists on the downstream system, those customers still out will be immediately identified and restored while the crews are still in the area.
3.7.4. Load Forecasting

BGE currently uses a top down model of load forecasting for the individual feeders on the distribution system. By leveraging circuit metering at the substation (head of feeder), future new customer loads, and a weather normalization algorithm, BGE forecasts the load for each feeder for the next several years. These forecasts currently lack granular detail of loading along the feeder and an in depth understanding of each customer’s contribution to the feeder peak load.

Through AMI data, BGE can forecast load down to a more granular level along the feeder, as opposed to just at the head of the feeder. This leads to greater understanding of loading along each segment, the drivers for yearly load increases/decreases, and prediction of potential thermal overloads. The individual customer loads would be able to be aggregated to their segment along the feeder to understand the loading. In addition, the AMI data allows the analytics to layer in customers with DER. The additional transparency and understanding of how the customer DER affects the loading along the feeder can greatly improve the identification of true loads and the projects needed to support system reliability.

Through enhanced load forecasting, BGE has a better understanding of the scope and timing of potential thermal overloads. Better understanding allows tighter project planning criteria. For example, without AMI data, forecasted overloads may require significant reconductoring of a feeder, a new feeder or a new substation. With a more granular understanding of the loads along the feeder, and the potential overloads, a more surgical solution may be possible for addressing issues. Reconductoring a specific section of the circuit, transferring a specific set of customers to adjacent feeders, or strategic placement of battery storage along the feeder may be possible. In addition, the increased accuracy of when these overloads are predicted to occur allows BGE to deploy solutions closer to when they are needed.
3.7.5. Overloaded Equipment Transparency

All equipment on the electric system is sized to fit the voltage and loading requirements of the customers supplied. A buffer is normally applied to equipment sizing because the needed data is provided by the customer and typically only accounts for their current needs at the time of initial installation. If a residential community gets developed or a commercial customer adds additional machines, load could increase beyond the initial load usage data. Properly sizing equipment for ultimate needs may be more cost effective and prevent premature equipment failure due to overload.

AMI data, along with future advanced analytic tools, will allow BGE to aggregate energy usage to the upstream equipment to determine if a device is overloaded or if a new customer provided improper load information. BGE would then be able to proactively develop a plan to address the concern. It is ideal to proactively replace overloaded equipment or to move load before an outage is experienced due to equipment failure. Reconfiguring the electric infrastructure is an effective means to maximize existing infrastructure and defer the cost of upgrading equipment while still providing safe and reliable electricity.

3.7.6. Momentary Data Analysis

BGE focuses a majority of its reliability resources to address areas that experience sustained outages, responding to issues as they occur retroactively. With AMI and advanced analytics, BGE will have the ability to effectively leverage momentary outages and identify areas that are becoming at risk for future sustained outages. A momentary outage or transient fault is any fault that clears itself given a small amount of time. Examples include a tree branch brushing the lines due to high winds or wildlife making contact and falling clear of the equipment.
Before the AMI system, the only way BGE would be aware of a protective device reclosing due to a transient fault would be either a customer complaint of excessive momentary outages or a reclosing device with communication capabilities reporting the event. Analyzing momentary outage data provided by the AMI network will enable BGE to identify areas showing signs of potential reliability concerns. An inspection or other proactive measures can then be taken to prevent possible future sustained outages. Targeted tree trimming, equipment integrity inspections, and system redesigns are all options available to BGE. The overall customer experience would be improved by addressing momentary outage issues, as issues causing momentary outage may turn into a sustained outage down the road if not addressed.

### 3.7.7. Voltage Var Optimization

AMI voltage data can be used to evaluate the performance of the CVR/Voltage Var Optimization (“VVO”) algorithm and to identify opportunities for further refinement of CVR operating parameters. Examples include calculation of optimal voltage set points for each circuit, identification of extensive device operations in search of an optimal operating point, and identification of devices that are not operating as expected. AMI data can also be used to optimize the operation of the CVR algorithm and assure operation within the prescribed voltage limits.

In addition, AMI data can be used to recommend optimal size and location for placement of new devices that could further optimize the operation of the CVR algorithm, and for calculation of optimal tap positions for Non-LTC transformers.

### 4. USE OF THE AMI SYSTEM TO FURTHER IMPROVE THE EFFICIENCY AND EFFECTIVENESS OF DISTRIBUTED ENERGY RESOURCES INTERCONNECTED TO THE DISTRIBUTION NETWORK

DER, including solar, wind, and battery storage systems, have become more cost effective in recent years. Many customers are taking advantage of state and federal incentives to
The new DER systems are able to offset a portion of the customer energy usage, but most systems do not produce a significant offset at the time of the system peak. The following Figure 7 provides an overview of the volume of DER systems installed on the BGE electric distribution system:

**Figure 7: Volume of DER Systems Installed on the BGE Electric System**

![DER System Annual Net Meter Installations - March 2017](image)

The effects of DER can be challenging for utilities. The electric grid was originally designed for uni-directional power flow, and DERs have the potential to create bi-directional power flow. Regardless of the challenges, the utility can help to maximize benefits from DER installations when they are incorporated into their distribution planning efforts.

The AMI system helps the utility to manage the impacts of DER on the electric grid by providing a wealth of data that can be used for operating and planning purposes. Having more metered locations throughout the electric system, with data available in near real-time, allows the utility to better assess and monitor the system conditions. The effects of DER to the grid cannot
be fully determined without having good system performance data at the customer level. AMI is able to provide some of the needed customer data to help monitor the impacts of DER.

4.1. DER System Impact Challenges

There are practical challenges the utility must address when integrating DER systems. DERs must be operated in a safe and reliable manner without compromising the existing infrastructure or quality of service to nearby customers. Utilities must design, construct, operate, maintain, and upgrade the distribution system to be able to supply the full requirements of the connected customers at any time, whether or not the local DER is available. DER systems are typically intermittent resources and may contribute to the complexities of operating and maintaining the electric system. A classic example is the peak loads the utility might see during the overnight hours on a bitter cold February night. While significant solar capability exists on that feeder, those DER resources are not available in the absence of sunlight. Without DER systems operating reliably at the required time periods, system capacity must still exist to meet peak loads and ensure key operating measures like voltage and frequency are within operating limits.

When evaluating the impact of DER, it is important to consider the true potential load on the distribution system to ensure proper design and operation of the grid. The true load on a circuit may be masked by the DER. Most DER is not monitored or managed by the utility and may become disconnected at any time. AMI data can be used to calculate true loads by combining customer load curves and estimated DER load curves. Impact of DER, during critical time periods, on customer loads and voltage can also be more easily identified with AMI data. The need for system enhancements or project deferrals can be verified by considering true equipment loading.
4.2. Benefits of DER

The installation of DER technology has the potential to generate many benefits to BGE customers and stakeholders. Line losses may be reduced because generation will be closer to the load. DER can also be designed to separate from the grid in times of emergencies in order to run critical customer load.\textsuperscript{15} Energy storage DER systems can store off-peak energy and deliver the stored energy to the grid at peak.\textsuperscript{16} The AMI system has the potential to allow improved DER system modeling which may allow increased penetration of DER devices and reduced system planning criteria margins.

4.3. Smart Inverters

Smart inverters provide advanced functions that support grid reliability. A smart inverter uses digital architecture, bidirectional communications, and robust software infrastructure to provide dynamic reactive and real power support. Advanced functions like frequency ride-through, ramp rate control, and communication allow the utility to better integrate DER. These functions can be used to mitigate issues related to high penetration levels of DER on the distribution system. Customers may be able to install larger systems while maintaining reliable voltage levels. Having better control of the DER system output can allow grid operations to better manage system reliability. In the future, with two-way communications with the customer, the utility will be able to coordinate operations with the smart inverters, possibly through the AMI network. This coordination will allow DER penetration to increase further, which may further improve grid reliability.

\textsuperscript{15} Solar PV is an exception to this for most installations as national codes and standards require the PV system to separate from the grid and stop production on loss of the utility supply, for safety and the protection of the local installation and adjacent customer equipment.

\textsuperscript{16} Energy storage systems can take advantage of off-peak energy rates. At peak the stored energy can be released, resulting in a reduced customer demand. These systems are typically applied on large industrial and commercial customers, as demand charge savings can be substantial.
4.4. Energy Storage

Energy storage technologies include batteries, flywheel, compressed air, thermal storage, and pumped hydropower. Storage can be used to provide power to the electric grid when needed, which increases reliability and resiliency. The use of battery storage has been a topic of particular interest recently because of improved technology and reduced costs. Having energy storage available throughout the system creates the ability to shift peak loads and participate in the wholesale markets. As regulations allow, storage may be used to integrate more DER, especially solar and wind, onto the electric grid and reduce the issues of intermitted energy resources.

4.5. Benefits of AMI for DER

The amount of DER that can be safely and reliably installed on the distribution system is referred to as the hosting capacity. Utilities determine the hosting capacity of a circuit or substation by analyzing the effects of the DER on the circuit at various locations. The DER has the potential to negatively impact load, voltage, or the protection systems on a circuit and hosting capacity tries to create a high level view of what can be theoretically interconnected.

Advanced computer models, using AMI data, will allow BGE to predict the combined impact of aggregated DER to feeders, transformers, and other grid components. AMI allows improved data and data models. Modeling the type, location, and time based characteristics of DER and customer load, allows the utility to analyze distribution components and determine if a problem exists or could be expected. For example, by monitoring voltages at the customer level, BGE can verify the effects of adding DER to the system. If a localized area is currently experiencing borderline high voltage, a DER installation may exacerbate the issue, and therefore be denied.
Future BIDA systems can use AMI data to locate unaccounted for DER interconnections. The system models can be verified and improved by comparing model results with customer real-time data. Costly electric system infrastructure issues can occur with a poorly coordinated rollout of DER systems. Using AMI data can allow customer satisfaction to be maximized as system issues will be avoided or identified quickly for correction.

Interconnection studies may also be improved by AMI. Some DER interconnections can be approved during the screening process while others require a detailed study. AMI provides time series customer data that can be used to enhance the screening process. Future tools may be able to automatically study the impact of the proposed DER, and AMI will be a key data input. With advanced tools, suspect DER applications can be flagged for additional review. Border line voltage levels or operational concerns may trigger additional analysis. For example, the AMI data can be used to flag customers currently operating near the upper limits of the voltage bandwidth. Installing DER near these customers may potentially exacerbate or create customer voltage issues.

5. CONCLUSION

BGE’s investment in an AMI system has laid the foundation for the deployment of modern technologies – some of which have yet to even be imagined – that will improve system reliability, enhance the customer experience, and afford customers additional opportunities to save money on their utility bills. As part of the Company’s strategy for the next five years, BGE will continue to investigate innovative ways to serve its customers and take advantage of the AMI system backbone infrastructure. In so doing, however, BGE must always remain committed to its core obligation to provide safe and reliable electric and gas service to its customers. Accordingly, the Company must continue to take a measured and balanced approach to distribution system planning to ensure that its core obligations are not compromised.