Before the
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In the Matter of

Addressing Policy and Logistical
Challenges to Smart Grid
Implementation

Smart Grid RFI: Addressing Policy and Logistical Challenges

COMMENTS OF BALTIMORE GAS & ELECTRIC COMPANY

I. Introduction

BGE is the nation's oldest utility company. It has met the energy needs of Central Maryland for nearly 200 years. Today, it serves more than 1.2 million business and residential electric customers and approximately 650,000 gas customers in an economically diverse, 2,300-square-mile area encompassing Baltimore City and all or part of 10 central Maryland counties.

BGE already has many systems that it considers to be "smart." For example:

- One hundred percent of BGE's substations are remotely monitored and controlled and real-time data is supplied to PJM to support markets and grid reliability.
- Approximately 40 percent of BGE's distribution circuits are remotely monitored and controlled with automatic restoration functionality on many of those circuits.
- Using a 1-way VHF paging system, line capacitors are automatically controlled in order to better manage system voltage and VAR reduction.
- BGE's demand response program (PeakRewards^{SM}) is under way and has installed more than 300,000 thermostats and AC load control switches with a target of 450,000 through 2011 (including replacement of legacy devices).
- Sixty percent of BGE's customers' meters are read via drive-by vans (Automatic Meter Reading technology).
- Large commercial and industrial customers currently have access to interval consumption data.

Overview of smart grid deployment plans

BGE submitted a Smart Grid proposal to the Maryland Public Service Commission (PSC) on

July 13, 2009. The proposal outlined BGE's plan to deploy 2.1 million gas and electric AMI meters by 2014. BGE also submitted a DOE grant application for up to $200 million to offset the costs of the Smart Grid Initiative. BGE was one of six utilities to receive the full $200 million grant; and, on August 13, 2010, the Maryland PSC granted BGE approval to proceed with the initiative.

II. Comments

Interactions With and Implications for Consumers

How well do customers understand and respond to pricing options, direct load control or other opportunities to save by changing when they use power?

From BGE's perspective, customers' baseline understanding of pricing options is minimal. In BGE's territory, most customers have been on flat rates for a very long time and likely give minimal thought to when they use electricity or what pricing options may be available. We have found, however, that given appropriate education, customers will respond to pricing signals.

Direct load control, on the other hand, seems to be a concept that customers understand more generally. We have seen a very high adoption rate in our territory, with more than 300,000 devices deployed through our opt-in PeakRewards^{SM} program. From BGE's perspective, the DOE's involvement could be most impactful if focused on helping to plan and implement customer education programs on dynamic pricing concepts.

BGE has gathered insight into how well customers respond to pricing options through a series of pilots. Using advanced meters, BGE conducted pilots of dynamic pricing options in 2008 and, to test the persistence of impacts, again in 2009 and 2010. BGE specifically tested customer response to Critical Peak Pricing (CPP), Peak Time Rebates with a low rebate level (PTRL), and Peak Time Rebates with a higher rebate level (PTRH). BGE also tested the impact of different enabling technologies. During the 2008 pilot, an average peak demand reduction ranged from 22 to 37 percent, depending on the rate structure and level of technology employed. The programs without the enabling technologies yielded impacts in the range of 22 to 26 percent. The presence of an Energy Orb conclusively increased the demand response raising the range of impacts to 27 to 31 percent. The presence of both A/C switch and an Energy Orb substantially increased the impacts achieved from the rates alone and yielded impacts in the range of 32 to 37 percent.

Following the 2008 pilot, BGE decided to focus its short-term efforts on Peak Time Rebates (PTRs). By offering a strong incentive for customers to change their behavior without a punitive component, PTRs are a very attractive way to transition into dynamic pricing from BGE's perspective. Customers saved over $100 on average in the 2008 and 2009 pilots of PTR rates, with about 98 percent of pilot customers attaining some level of savings. Customer satisfaction levels were above 90 percent in each year of the pilot, and 98 percent to 99 percent of participating customers indicated they wanted to see PTRs be made available on an ongoing basis to all residential customers. Even more encouraging, the level of customer responsiveness grew substantially from the first year of the pilot to the second, suggesting that customers became more adept over time to save greater amounts on their energy bills. It should be noted that BGE selected candidates for pilot participation at random (customers had to acknowledge they knew about their enrollment however), but that customers were able to opt out. The final results of the 2010 pilot have not yet been compiled, but initial data is showing at least the same level of peak reduction as in 2008 and 2009.

Additional information on BGE's pilot results can be found in the supplemental documents included with this response.

Assessing and Allocating Costs and Benefits

How does the magnitude and certainty of the cost effectiveness of other approaches like direct load management that pay consumers to give the utility the right to temporarily turn off air conditioners or other equipment during peak demand periods compare to that of AMI or other smart grid programs?

BGE believes that both direct load control and Advanced Metering Infrastructure (AMI) offer compelling business cases. Based on BGE's initial estimates, the benefit-to-cost ratio for its Smart Grid Initiative (AMI and PTRs) is 3.2 to 1 while the ratio for its PeakRewards℠ direct load control program is 7 to 1. While both programs depend significantly on marketing and customer education efforts, most would consider the benefits associated with the direct load control program as somewhat more certain since they do not depend on customers to take action when notified of critical peak periods. Unlike a direct load control program, BGE's smart grid initiative's primary focus will be to educate customers. It will be up to the customer to "turn off the lights." While this does introduce some uncertainty, BGE has been very encouraged by its pilot results and strongly believes that its PTR program will drive significant benefits for its customers. Through BGE's three years of pilots, customers have demonstrated significant and reliable demand response capability when offered a meaningful incentive. It is also important to note that direct load control programs are typically offered only to customers with central air conditioning systems.

How does the notion that only some customers might opt in to consumer facing smart grid programs affect the costs and benefits of AMI deployments?

The notion that only some customers might opt in to customer-facing smart grid programs must be mitigated to realize the full potential of smart grid. This is one of the reasons that BGE plans to make PTR pricing available to all residential customers. To take advantage of the program, all a customer will have to do is reduce his/her usage during peak events (i.e., no sign-up required). If a customer chooses to continue to use energy as he/she has in the past, his/her bill will be unchanged, as he/she will receive neither a rebate nor a penalty. If in a given month a customer does elect to modify his/her usage to a level below his/her baseline, he/she will receive a rebate.

Furthermore, BGE plans to provide energy usage feedback to customers by default. This is closely related to a privacy consideration related to sharing of usage data. BGE is fully committed to protecting the privacy of its customers and believes that customers should generally have control over whether or not their usage data is shared with third parties. As regulators and legislators determine how to address privacy concerns related to interval usage data, we think it is important for them to consider that many utilities are currently or are considering partnering with third parties to operate portions of their business processes, including providing feedback to customers on their energy use and ways to save. These types of services, which may, for example, provide feedback to a customer through a website, a paper report or a phone call, may be able to drive significant energy conservation and are dependent on customers' data. We believe that the effectiveness of this type of program is significantly enhanced when not explicitly requiring a customer to opt in because of the low current level of awareness of smart grid and related benefits. We believe it is important to proactively "push" information to customers initially. Over time, as their understanding and interest grows, we expect customers to begin to seek information themselves and utilize self-service tools. To support this evolution, we suggest that policy makers do not necessarily require proactive customer consent for this type of program. Instead, in situations where utilities establish contractual privacy protections with business partners, policy should support data being provided to such energy efficiency service providers by default.

Utilities, Device Manufacturers and Energy Management Firms

How can federal and state regulators work together to better coordinate wholesale and retail power markets and remove barriers to an effective smart grid (e.g. regional transmission organization require that all loads buy ''capacity'' to ensure the availability of power for them during peak demand periods, which makes sense for price insensitive loads but requires price sensitive loads to pay to ensure the availability of power they would never buy)?

The business case for BGE's smart grid Initiative contains a significant level of benefits related to peak demand reductions anticipated from its planned Peak Time Rebate program. For utilities like BGE operating in regions with organized wholesale markets, it has been and will continue to be important for there to be effective market structures and product options through which to monetize automated and price-responsive demand reduction. These dollars extracted from the market are directly used to offset the cost of the smart grid infrastructure, and give participating customers significant bill credits.

To support the proliferation of large-scale retail price-responsive demand programs, such as BGE's Peak Time Rebate program, it would be helpful for markets to support demand response resources as either supply-side or demand-side resources. While the two approaches should theoretically yield similar results, there are potential perception and timing issues with a demand-side only approach. From a perception standpoint, regulators and other stakeholders may be more comfortable—especially during a transition period—with utilities receiving revenue for demand response capability as allowed for by a supply-side approach. This is because it allows for a more straight-forward connection to be made between the value of the load reductions and the benefits flowing to customers through rebates or otherwise. From a timing standpoint, if load serving entities (LSEs) are not able to reduce the amount of capacity that they purchase by the forecasted amount of demand response, a lag could be introduced in the realization of benefits for customers. That is because LSEs would likely need to continue to buy capacity that they do not expect to need until after demand reductions are realized. This could result in a benefit lag of several years relative to a supply-side approach (or a demand-side approach that allows LSEs to reduce their capacity purchases by their anticipated price-responsive demand response capability).

As demand response (DR) capability continues to grow and to be committed as capacity in wholesale markets, some stakeholders have expressed concern about potential impacts to system reliability. Unlike most generation units, DR resources typically have limits on when and how often they can be dispatched. In PJM, for example, DR resources must only reduce their load up to a maximum of 10 times in a year and only during summer months. One option being considered to mitigate reliability risks is for the ISO/RTO to set limits on DR saturation in the capacity market. While BGE fully supports actions required to ensure system reliability, the benefits of more widely available DR can significantly reduce short- and long-term costs to end-use customers. BGE encourages the DOE to advocate for market structures that promote further investment in DR, while having controls in place to ensure reliability.

Commenters should feel free to describe current and planned deployments of advanced distribution automation equipment, architectures, and consumer-facing programs in order to illustrate marketplace trends, successes, and challenges. And they should feel free to identify any major policy changes they feel would encourage appropriate deployment of these technologies.

AMI Cost Recovery

While the Maryland Public Service Commission authorized BGE to establish a regulatory asset to facilitate cost recovery, not a tracker surcharge mechanism as requested, BGE continues to believe that trackers offer numerous benefits for both customers and investors. As the public debate over appropriate cost recovery for AMI projects continues, BGE suggests that the following items be considered:

- Trackers minimize carrying costs. In its application for rehearing filed with the PSC, BGE estimated that a tracker would lower costs to customers for its Smart Grid Initiative by approximately $100 million or 12 percent relative to a regulatory asset.

- Relative to regulatory assets, trackers are credit supportive. Regulatory assets can cause a meaningful deterioration in the credit metrics assessed by rating agencies, as they reduce cash flow, funds from operations and, absent specific measures, net income. A tracker is credit supportive, which is beneficial to companies and customers, because credit ratings and borrowing costs are a function of such metrics.

- While meters are typically considered classic utility infrastructure, AMI initiatives are extraordinary projects that require significant investments over a compressed time period. The extraordinary nature of such projects and the savings that they enable make alternative cost recovery approaches (e.g., trackers) appropriate.

Several utilities have established tracker surcharge mechanisms for cost recovery. During BGE research in mid-2010, 11 utilities were identified nationwide with surcharge cost recovery for AMI.

Depreciation

Adoption of reduced useful lives for book depreciation of AMI assets reduces the risk of technological obsolescence prior to the conclusion of cost recovery. It can also reduce financing charges and lower the nominal cost to customers. For these reasons, BGE has been supportive of a 10-year depreciable life for AMI assets, a shorter life than meters currently in BGE's rate base.

BGE believes that it is essential for unrecovered legacy meter costs to be recoverable. While BGE is supportive of regulators handling this issue in separate depreciation proceedings, regulators should provide some assurance up-front that prudently incurred legacy assets displaced by AMI investment will ultimately be recoverable from customers. Utilities adopting AMI should not be penalized for a willingness to innovate by being forced to absorb large write-off adjustments for stranded meter investments.

A related opportunity to speed adoption of smart grid systems would be to allow accelerated depreciation for tax purposes. This would provide further incentive for utilities to invest in smart grid assets in that tax benefits would at least mitigate significant initial investments.

Utility Use of Consumer-Specific Energy-Usage Data

As mentioned previously, BGE is fully committed to protecting the privacy of its customers. BGE also agrees with the DOE's finding in its *Data Access and Privacy Issues Related to Smart Grid Technologies* report that "utilities should continue to have access to [consumer-specific energy-usage data] and to be able to use that data for utility-related business purposes like managing their networks, coordinating with transmission and distribution-system operators, billing for services, and compiling it into anonymized and aggregated energy-usage data for purposes like reporting jurisdictional load profiles."

Reliability and Cyber-Security

What is the role of federal, state, and local governments in assuring smart grid technologies are optimized, implemented, and maintained in a manner that ensures cyber security? How should the Federal and State entities coordinate with one another as well as with the private and nonprofit sector to fulfill this objective?

BGE is committed to designing, building, and operating its smart grid system in a way that protects the privacy of its customers and supports the reliable operation of the electric system as a whole. To this end, BGE has remained focused on cyber security and has been monitoring ongoing cyber security and electric reliability standards development. In particular, BGE is closely monitoring the updates to the NERC Critical Infrastructure Protection (CIP) standards as well as the NIST Smart Grid Cyber Security Guidelines.

There is some uncertainty in the industry about the future applicability of NERC CIP to Advanced Metering Infrastructure (AMI) systems. As the DOE is likely aware, much of the uncertainty in this area stems from the criterion in the draft CIP-002 Version 4 standard that categorizes “common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes” as critical assets. Many AMI systems will theoretically be capable of shedding load in excess of 300 megawatts although protections have been incorporated to prevent this type of event. Therefore, many AMI systems may be classified as critical assets and be subject to the CIP standards. BGE understands that the NERC CIP standard drafting committee is attempting to establish “bright lines” between assets to which NERC CIP applies and those to which it does not. BGE will suggest that the committee further clarify the term “automatic load shedding” to clearly state whether this could apply to a system that requires human intervention. BGE also encourages the DOE to facilitate clarification on this point.

Regardless of whether its AMI system is determined to be a critical asset under NERC CIP, BGE will be incorporating strong cyber security protections into its system and management processes. In fact, security was the most highly weighted criterion in BGE’s AMI vendor evaluation. BGE is concerned, however, that uncertainty related to NERC CIP and the potential for significant financial penalties will slow innovation in the industry even where security concerns have already been mitigated.

III. Conclusion

The Department of Energy is in a unique position to provide informed guidance and best-practice information for the benefit of energy utilities and their customers, regulators and legislators. The policy and logistical challenges surrounding smart grid are significant and evolving. If BGE can provide additional information or detail with respect to this Request for Information, please let us know. Thank you for the opportunity to provide our perspective and input on this most important topic.

Respectfully submitted,

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