BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION

CASE NO. 9207

IN THE MATTER OF

POTOMAC ELECTRIC POWER COMPANY

AND

DELMARVA POWER AND LIGHT COMPANY

REQUEST FOR THE DEPLOYMENT OF ADVANCED METER INFRASTRUCTURE

DIRECT TESTIMONY OF J. RICHARD HORNBY

ON BEHALF OF THE

MARYLAND OFFICE OF PEOPLE'S COUNSEL

OCTOBER 20, 2009

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EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND PRESENT POSITION.

A. My name is James Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the Maryland Office of People's Counsel (OPC).

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse Energy Economics (Synapse) is a research and consulting firm specializing in energy and environmental issues, including: electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am a consultant specializing in planning, market structure, ratemaking, and gas supply/fuel procurement in the electric and gas industries. Over the past twenty years, I have presented expert testimony and provided litigation support on these issues in approximately 100 proceedings in over thirty jurisdictions in the United States and Canada. Over this period, my clients have included staff of public utility commissions, state energy offices, consumer advocate offices and marketers.

Prior to joining Synapse in 2006, I was a Principal with CRA International and, prior to that, Tabors Caramanis & Associates. From 1986 to 1998, I worked with the Tellus Institute (formerly Energy Systems Research Group), initially as Manager of the Natural Gas Program and subsequently as Director of their Energy Group. Prior to 1986, I was Assistant Deputy Minister of Energy for the Province of Nova Scotia.

I have a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT) and a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now merged with Dalhousie University. I have attached my resume to this testimony as Exhibit___(JRH-1).

Q. PLEASE SUMMARIZE YOUR EXPERIENCE WITH THE ECONOMICS OF, AND RATEMAKING FOR, ENERGY EFFICIENCY AND DEMAND RESPONSE, INCLUDING DEMAND RESPONSE ENABLED BY ADVANCED METERING INFRASTRUCTURE (AMI).

A. My experience with energy efficiency measures and policies began over thirty years ago as a project engineer responsible for identifying and pursuing opportunities to reduce energy use in a factory in Nova Scotia. Subsequently, in my graduate program at MIT I took several courses on energy technologies and policies, and prepared a thesis analyzing federal policies to promote investments in energy efficiency. After MIT, I spent several years with the government in Nova Scotia, during which time I administered a provincial program to promote energy conservation in the industrial sector and later included energy conservation in all sectors as part of energy plans developed for the province.

Since 1986, as a regulatory consultant I have helped review and prepare numerous integrated resource plans in the gas and electric industries, and testified regarding cost allocation and rate design. During the past several years I have led projects to estimate the avoided costs of electricity and natural gas in New England for a coalition of efficiency program administrators. In addition I have reviewed the economics of demand response, and of AMI proposals in New Jersey, Maine, the District of Columbia and Pennsylvania. I have testified regarding the alignment of utility financial incentives and rates with the pursuit of energy efficiency in proceedings in North Carolina, South Carolina, Indiana and Minnesota.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Potomac Electric Power Company (Pepco) and Delmarva Power And Light Company (Delmarva), collectively "the Companies," filed Direct Testimony dated September 1, 2009 in support of their request to establish a regulatory asset for the deployment of AMI. In his Direct Testimony Companies' Witness Gausman provides an overview of the application. Companies' Witness Potts provides a description of the AMI, its Business Case and operational benefits. Companies' Witness Faruqui describes the electricity supply cost benefits of dynamic prices enabled by AMI. Companies' Witness Janocha provides the Present Value Revenue requirements (PVRR) of the projected costs and benefits. Companies' Witness Bumgarner describes the proposed Dynamic Pricing rider for residential and small to medium commercial customers and the tariffs to implement Critical Peak Rebate (CPR) and Critical Peak Pricing (CPP) rate offerings. Companies' Witness Wathen describes the Companies' proposed cost recovery mechanism.

The OPC has retained three witnesses to address the Companies' two requests from the perspective of residential customers, myself, Ms. Nancy Brockway and Mr. David J. Effron.

- My testimony addresses the policy and general ratemaking implications of the Companies' request, the level of projected benefits of the AMI relative to its projected costs, as well as the uncertainty associated with those benefits, and specific ratemaking issues associated with the request. (The fact that I do not address other aspects of the Companies' filing should not be interpreted to mean I agree with those aspects.)

- OPC Witness Brockway addresses the uncertainties associated with the Companies' projections of residential customer reductions in electricity due to the AMI, the uncertainties associated with smart grid technology and consumer protection issues.
- OPC Witness Effron addresses the Companies' proposed cost recovery mechanism.

Q. WHAT DATA SOURCES DID YOU RELY UPON TO PREPARE YOUR TESTIMONY AND EXHIBITS?

A. I relied primarily on the Direct Testimony, exhibits, and workpapers of the Companies' witnesses. I also relied upon the Companies' responses to various data requests. In addition, I relied upon analyses of the PJM wholesale market for capacity and various reports on AMI and dynamic pricing.[1]

[1] The difference between dynamic pricing and traditional time-of-use (TOU) pricing is the manner in which the specific pricing periods are set. Under TOU the pricing periods are static, a utility would set them in a rate proceeding and they would then remain unchanged until the next proceeding. For example, Baltimore Gas & Electric is proposing TOU prices for a summer peak period, defined as weekdays from 2 p.m. to 7 p.m. excluding specified holidays, for a summer off-peak period and for a non-summer period. In contrast, under dynamic pricing the load serving entity (LSE) would determine the periods when its CPR and CPP would apply on a "dynamic" basis according to anticipated changes in system conditions from day to day during the summer. For example, the Companies propose to notify customers by 7 p.m. the day before an impending critical peak period during which the CPR and CPP would apply.

II. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSION AND RECOMMENDATION REGARDING ADVANCED METERING INFRASTURE PROPOSALS IN GENERAL AND THE COMPANIES'S PROPOSAL IN PARTICULAR FROM A PUBLIC POLICY PERSPECTIVE.

A. There appears to be a widespread expectation among policymakers that implementation of AMI, and dynamic pricing enabled by AMI, will produce reductions in annual electricity costs and greenhouse gas emissions that will far exceed its costs and that will justify its bill impacts. Unfortunately, that expectation is not supported by the details of utility proposals for deployment of AMI and dynamic pricing, including the Companies' proposal. Instead, analyses indicate that utilities are primarily proposing to reduce some distribution service costs and to enable reductions in energy consumption, and associated emissions in less than 100 hours per year.

My general conclusion is that utility proposals for deployment of AMI and dynamic pricing, including the Companies' proposal, are unlikely to produce large reductions in annual electricity costs or in annual greenhouse gas emissions. Based upon that conclusion, my general recommendation is that such proposals should be judged on their financial merits, with the burden of proof placed on their proponents. Since management of the Companies has chosen to propose this specific major investment, I recommend that the Commission require the Companies to bear the burden of proving that their proposed AMI deployment is reasonable.

Q. PLEASE SUMMARIZE YOUR CONCLUSION AND RECOMMENDATION REGARDING THE PROJECTED TOTAL BENEFITS AND COSTS OF THE COMPANIES'S PROPOSED AMI.

A. My first conclusion is that there is considerable uncertainty regarding the projected total benefits of the AMI as well as some uncertainty regarding projected costs. These uncertainties arise from the lack of long-term experience with the full-scale deployment of AMI and dynamic pricing such as the Companies are proposing. In particular, approximately 70% of the projected total benefits of the AMI hinge on the Companies' assumption that over 75% of residential customers will respond to its new dynamic pricing rate offerings on a sustained basis for over 15 years (2012 - 2026). Moreover, approximately 55% of that sub-set of projected benefits, representing approximately 40% of total projected benefits, hinge on the Companies' second assumption that avoiding one kW of generating capacity will be worth approximately $57 per year, in $2009, over 15 years.

My second conclusion is that a portion of this uncertainty results from the Companies' failure to specify the method they will use to monetize the reductions in peak load resulting from their dynamic pricing proposals. Dynamic pricing will not produce the maximum reductions in costs if the Companies do not actively bid those reductions into PJM wholesale markets.

These uncertainties create a financial risk, i.e., the risk that actual benefits from the AMI may prove to be substantially less the Companies' projections. This financial risk is relevant to the Commission's decision regarding approval of the Companies' request as well as to its decision regarding cost recovery.

I recommend that the Commission take these financial risks into consideration when making its decision as to whether to approve or reject the Companies' request. In particular, I recommend that the Commission not make a decision to approve or disapprove the Companies' proposed AMI until the Companies file a specific proposal for advising PJM of the reductions in peak load from that dynamic pricing and of monetizing those reductions, and all parties have had the opportunity to comment on that specific proposal.

If the Commission does approve the AMI, I recommend that it hold the Company to its projected costs as well as to its projected savings in distribution service operating and maintenance (O&M) expenses.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANIES'S PROPOSALS FOR RECOVERING THE COSTS OF AMI FROM RATEPAYERS AS WELL AS FOR CREDITING BENEFITS TO RATEPAYERS.

A. The Companies propose recovering the projected revenue requirements of AMI from all rate classes via base rates. They propose to flow the distribution service operational benefits from AMI to ratepayers through base rates and to flow the electricity supply benefits to ratepayers through four other mechanisms, i.e., CPRs to ratepayers who reduce peak load in response to that pricing, reductions in demand during critical peak periods by ratepayers who respond to CPP, reductions in annual electricity use by ratepayers who respond to usage and pricing information provided by the AMI and reductions in future rates for Standard Offer Service due to the mitigation of wholesale prices.

The Companies' illustration of the rate impact of their proposal implies that these costs will be recovered as an unavoidable monthly fixed charge in $ per meter per month. According to fundamental ratemaking principles one would expect to see the allocation of the AMI revenue requirements among rate classes, and the design of rates to recover those revenue requirements, guided by a cost-of-service (COS) study and an analysis of bill impacts. I recommend that the Commission require the Companies to present the results of COS studies and bill impact analyses to support their proposed allocations and rate designs when they file general rate cases for recovery of AMI.

III. POLICY AND RATEMAKING IMPLICATIONS OF COMPANY REQUESTS

Q. PLEASE SUMMARIZE THE COMPANIES' AMI PROPOSAL.

A. The Companies' proposal consists of an investment in AMI and the implementation of dynamic pricing enabled by AMI.

Under the AMI component the Companies would replace essentially all existing electric meters, as well as install communications equipment, an AMI network management system and a meter data management system (MDMS). The Companies expect to complete these investments between 2009 and 2011 at projected total nominal capital costs of $178.7 million, which they consider to be a significant investment (Gausman Direct, p. 7 and p. 9).

Under the AMI-enabled dynamic pricing component the Company would offer residential and small to medium commercial customers a choice of three rate designs for Standard Offer Service (SOS)[2] – CPR, CPP and flat. (These customers are currently

[2] SOS is the generation service that the Companies provide to customers who do not acquire their electricity supply from a competitive supplier. They provide this by acquiring supply from the wholesale market.

receiving SOS at a flat price). The Companies would place customers who do not make a choice on SOS with a CPR, which would be the default pricing (Bumgarner Direct, p. 4). The Companies expect 55% of residential customers will be on the CPR, 20% on CPP and 25% on SOS at a flat rate (Faruqui Direct, p. 5). Thus they expect dynamic pricing will motivate 75% of its residential customers to reduce their electricity consumption during critical peak periods, which they define as 2 p.m. to 6 p.m. on up to fifteen weekdays each year between June 1 and October 31, i.e. up to 60 hours per year (Bumgarner Direct, p. 6).

Q. DO OTHER UTILITIES HAVE LONG-TERM EXPERIENCE WITH THE PERFORMANCE AND ECONOMICS OF AMI AND DYNAMIC PRICING ON A SYSTEM-WIDE OR FULLY DEPLOYED BASIS?

A. No. Utilities have conducted a number of pilot projects testing AMI and dynamic pricing on a limited basis. However, it is only in the last few years that several United States utilities have received regulatory approval to fully deploy AMI and dynamic pricing tariffs on their systems. In fact, most of those utilities are currently in the process of completing that deployment.

The absence of robust empirical evidence regarding the performance and economics of AMI and dynamic pricing on a system-wide basis over time results in considerable uncertainty regarding both long-term technical performance and the magnitude of peak load reductions that will actually be sustained in the long-term in response to dynamic pricing approaches such as CPR or CPP. In an effort to help reduce that uncertainty, and help stimulate the economy, the recent federal stimulus bill, i.e., the American Recovery and Reinvestment Act of 2009, H.R. 1, 11th Congress (2009) (ARRA) approved appropriations to fund Smart Grid Demonstration Projects as well as a Smart Grid

Investment Matching Fund to help support full-deployment of AMI by utilities who meet the grant selection criteria.

Q. PLEASE COMMENT ON THE EXPECTATION THAT FULL DEPLOYMENT OF AMI AND DYNAMIC PRICING WILL LEAD TO REDUCTIONS IN ANNUAL ELECTRICITY BILLS AND GREENHOUSE GAS (GHG) EMISSIONS.

A. Much of the enthusiasm for AMI and dynamic pricing among policy makers appears to be based upon an expectation that full deployment of AMI and dynamic pricing will lead to material reductions in annual electricity bills and in greenhouse gas emissions. The validity of that expectation remains to be proven in terms of actual results on a sustained, system-wide basis.

The details of the actual AMI filings that I have reviewed to date, including the Companies' proposal, do not support that expectation. Instead, these filings indicate that full deployment of AMI and dynamic pricing are only likely to produce very modest reductions in annual electricity bills and greenhouse gas emissions for two main reasons.

First, the installation of AMI and associated enabling of dynamic pricing, in and of themselves, do not reduce customer electricity consumption or the emissions of greenhouse gases from the generation of electricity to supply that consumption. Instead, actual reductions in annual bills and GHG associated with that consumption, will only be achieved if individual customers actually reduce their electricity consumption in response to dynamic prices in every peak period, year after year.

Second, deployments of AMI and dynamic pricing such as the Companies' proposal primarily enable reductions in peak load rather than reductions in annual electricity consumption. Reductions in peak load are referred to as demand response (DR) while reductions in annual electricity consumption are referred to as energy conservation (EC) or energy efficiency (EE). As illustrated in Exhibit__(JRH-2), DR has very limited impacts on annual energy consumption and the annual GHG resulting from the electricity generated to supply that annual consumption.

- DR typically results in little or no material reduction in annual electricity consumption, and associated GHG, because it occurs in very few hours each year. For example, the Companies are proposing to achieve reductions in response to the PTR up to 60 hours per year, less than 1 percent of the 8,760 hours in a year. While the reduction in those peak hours tends to have a very high economic value, it still represents a relatively small portion of customer annual usage and annual bills.
- EE measures, in contrast, not only lead to reductions in electricity consumption during the 60 hours of peak demand, like DR, but also in all the other hours when electricity affected by that measure is being used.

In fact, most utilities have a strong financial incentive to deploy AMI and dynamic pricing in a manner that will enable reductions in peak load rather than reductions in annual electricity consumption. Major reductions in peak load do not result in significant reductions in the annual revenues collected by utilities, and hence do not reduce their earnings. In contrast, unless a utility has some form of revenue stabilization type mechanism such as decoupling, major reductions in annual electricity consumption do result in significant reductions in their annual revenues and their earnings.

Third, the timing and magnitude of the capacity costs avoided due to DR can be more difficult to estimate than the timing and magnitude of the electric energy costs avoided due to EE. For example, a 1 kWh reduction in electricity consumption from energy conservation or EE results in a corresponding immediate reduction in the quantity of electricity generated, after adjustments for system losses. That quantity of electricity generation is clearly avoided. In contrast, a 1 kW reduction in peak load from DR does not automatically produce a corresponding immediate reduction in the quantity of capacity being held to ensure reliable service for that load. Instead, decisions regarding the quantity of generation, transmission and distribution capacity needed for reliable service are made several years before the year in which the actual load occurs. Thus, to avoid capacity those decision makers need to be convinced that the reduction in peak load will continue over their long-term planning horizon before they will decide to approve a lower quantity of capacity. The fact that utilities and curtailment service providers have the ability to bid reductions in peak load into wholesale capacity markets in PJM and elsewhere has helped to reduce the uncertainty associated with projections of avoided wholesale generation capacity costs.

Q. HAS THE NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS (NARUC) EXPRESSED CONCERNS REGARDING THE POTENTIAL FOR ADVERSE RATE AND BILL IMPACTS FROM A RAPID TRANSITION TO FULL DEPLOYMENT OF AMI?

A. Yes. In his March 3, 2009 testimony to the United States Senate Committee on Energy and Natural Resources, New Jersey Commissioner Frederick Butler, President of NARUC, expressed a number of concerns regarding a rapid move to full deployment of Smart Grid systems. In that testimony, attached as Exhibit__ (JRH-3), President Butler makes a number of important points regarding consideration of ratepayer reaction:

> *I know the Smart Grid can change how utilities oversee their networks and improve reliability. I know that, in the end, consumers could have greater control*

over their usage and have the potential to lower their bills. I also know, however, that if we do not do this correctly, if we move too quickly and promise too much we can endanger our coming close to meeting any of those lofty aspirations.

But we do need to be careful. Right now, we are selling the Smart Grid as a means of empowering consumers to lower their usage and, correspondingly, their energy bills. While this may ultimately be the case, we must learn our lesson from the restructuring experience before heading down this path. The promise of restructuring was that consumers would save money by shopping for power….. The problem here was not restructuring per se, but it was the way it was sold to consumers. Instead of determining the best way to move forward deliberatively, we jumped right in, with the promise of lower rates to follow. Because of this approach, and because of the results, the concept of restructuring has taken a significant hit.

The concern that many of my colleagues are trying to resolve is that consumers are convinced that the Smart Grid will only raise their rates with no discernable benefits. In a high-priced environment, some or perhaps most consumers see advanced metering rollouts as just one more headache and budget buster and are particularly scared that utilities and vendors will keep raising rates as the technology changes.

We have to remember that the Smart Grid will only achieve its vast potential if consumers embrace it.

Even if there were no uncertainty associated with the projected benefits of the Smart Grid, Mr. Butler's comments indicate that it is essential to consider the impacts on ratepayers when assessing proposals for full deployment. Moreover, since there are uncertainties regarding the projected benefits of AMI and dynamic proposals such as the Companies' proposal, a rigorous assessment is even more critical.

Q. FROM AN ENERGY OR ENVIRONMENTAL POLICY PERSPECTIVE ARE THE COMPANIES OBLIGATED TO IMPLEMENT FULL DEPLOYMENT OF AMI AND/OR DYNAMIC PRICING?

A. No. I understand that the Companies, like other Maryland utilities, are trying to implement programs and rate designs that will enable it to meet the goals for reductions in per capita electricity demand and annual consumption that EmPOWER Maryland has established. However, from a policy perspective my understanding is that these are policy goals that the state would like to see achieved in a manner consistent with other important goals, such as controlling and stabilizing electricity bills. Moreover, my understanding is that the Companies have the flexibility to propose the particular approach, or portfolio of approaches, it considers most cost-effective to achieve those important policy goals. In other words, the Companies are not legally obligated to implement its proposal, or any other full deployment of AMI and dynamic pricing. Instead, management of the Companies has decided to propose this approach to deploying AMI from the range of possible strategies available to them. For example, there are many alternative approaches available to achieve demand reduction such as pursuing additional EE, which reduces peak load as well as annual consumption, or pursuing incremental DR from large commercial and industrial (C&I) customers. Thus, from a ratemaking perspective the Companies bear the burden of proving that their approach to deploying AMI will not only achieve these policy goals, but that it will do so in a manner that results in reasonable rates.

IV. COST EFFECTIVENESS AND UNCERTAINTIES OF PROPOSED AMI

Q. PLEASE SUMMARIZE THE BUSINESS CASE FOR THE COMPANIES' PROPOSED AMI.

A. Companies' Witness Potts summarizes the Business Case for the Companies' proposal on pages 5 to 14 of his Direct Testimony. He provides a summary table comparing the projected total costs and benefits of the AMI from a system-wide perspective, i.e., regardless of who pays for what costs and who receives which benefits (Potts Direct, p. 13). The costs and benefits are reported as the PVRR of the annual amounts projected over the period 2012 – 2026. See Schedule JFJ-1, p. 2 for example. In this section I will use the projected costs and benefits of the Pepco AMI proposal to illustrate my points.

Q. PLEASE DISCUSS THE PROJECTED COSTS OF PEPCO'S PROPOSED AMI.

A. Companies' Witness Potts estimates the projected cost of Pepco's AMI to be $180.2 million (PVRR). He states that this amount consists of four components - capital expenditures, incremental O&M expenses, costs deferred during the start up phase and the accelerated net book value of the existing meters (Potts Direct, p. 15). I have three comments regarding these projected costs, using Pepco for illustration.

First, I was unable to reconcile the aggregate cost estimate of $180.2 million with the PVRR amounts of each component as reported by Companies' Witness Janocha in Schedules JFJ-1 and JFJ-5. The values I drew from those schedules add to $190.1 million. (These are $163.5 million for capital expenditures and incremental O&M, $13.7

million for costs deferred during the start up phase and $12.9 million for the incremental costs of accelerated depreciation of the meters rendered obsolete by AMI.

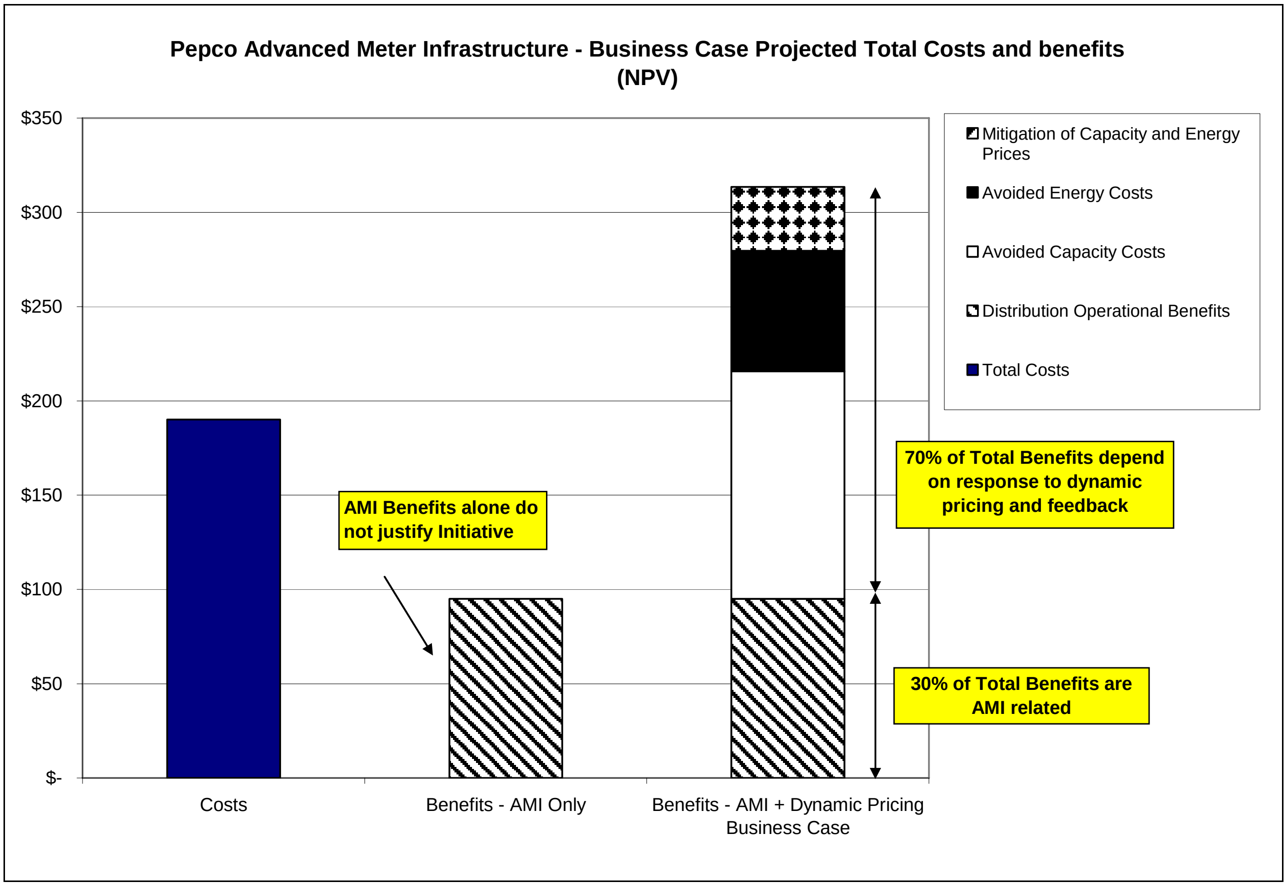
Second, the projected cost for capital and O&M are subject to some uncertainty – there is a chance that actual costs may be higher than this projection. As discussed by OPC Witness Brockway, the fact that some technical standards are still being finalized creates a risk that additional costs may be incurred if some of the technologies deployed now prove to be incompatible with the standards that are ultimately established in the future.

Third, these projected costs do not represent all of the costs that are likely to be incurred if the Pepco AMI is approved. One set of additional costs will be the amounts that ratepayers spend on in-home devices, such as smart thermostats and other controls, in order to automate their response to a CPR or a CPP. Finally, the projection does not include additional costs that the Company may propose if the AMI is approved, such as in-home displays or additional investments in distribution system controls (Response to OPC II-9).

Q. HOW DO THE BENEFITS OF THE PEPCO AMI PROJECTED IN THE BUSINESS CASE COMPARE TO ITS PROJECTED COSTS.

A. Companies' Witness Potts projects that the Pepco AMI will produce $313.5 million in benefits (PVRR) for a benefit-to-cost ratio of 1.74 (Potts Direct, p. 13). He estimates that the AMI component will produce energy delivery operating benefits worth $95 million. According to estimates develop by Companies' Witness Faruqui and quantified by Companies' Witness Janocha, the AMI-enabled dynamic pricing component will produce customer savings from reductions in peak load worth $218.5 million. These are projected savings in electricity supply costs.

These projections are summarized in the chart below, which is attached as Exhibit___(JRH-4). The projected costs are presented in the first bar. The projected benefits from AMI alone are presented in the second bar. These AMI related benefits are much less than the projected costs and would not justify the proposal. The projected benefits from AMI plus AMI-enabled dynamic pricing are presented in the third bar.



The total projected benefits in the Business Case, presented in the third bar, can be grouped into three major components, as indicated in Table 1.

Table 1 – Summary of Company projected benefits of Pepco AMI				
Projected Benefit	**Benefits bar in Exhibit___(JRH-4)**		**PVRR (million)**	**% of Total**
	Component / Block #	**Shading**		
AMI	First	Left-to-right diagonal	$95.0	30%
AMI-enabled dynamic pricing				
Avoided capacity costs	Second	White	$121	39%
Avoided energy costs	Third	Black	$64	20%
Mitigation of wholesale prices for capacity and energy	Fourth	Black and white diamond	$34	11%
Total			**$313.5**	**100%**

Q. PLEASE DISCUSS THE PROJECTED BENEFITS OF THE PEPCO PROPOSAL.

A. As noted, the Company projects two major categories of benefits, AMI and AMI-enabled dynamic pricing.

The projected benefits attributed to AMI are savings in eight types of distribution service O&M expenses (Potts Direct, p. 7). These projected operational benefits have a PVRR of $95 million, producing a benefit to cost ratio of 0.5. The projected AMI benefits would not be sufficient to justify the project, as indicated in Exhibit___(JRH-4). When added to the AMI-enabled dynamic pricing benefits, the operational benefits account for 30 percent of the overall total projected benefits.

The projected benefits attributed to AMI-enabled dynamic pricing are avoided capacity costs, avoided energy costs and price mitigation. (Companies' Witness Faruqui has also assumed reductions due to energy conservation in response to price and usage feedback, but has not distinguished those savings from the savings due to dynamic pricing.) Those three sources of savings depend upon the Companies' assumptions regarding reductions in peak load by customers who will respond to its proposed CPR and CPP. Those three sources are:

- Avoided capacity costs that the Company assumes customers who respond will receive from PJM, either directly or indirectly, as compensation for reducing the quantity of peak load that has to be met by the PJM Wholesale capacity market;
- Avoided energy costs that the Company assumes customers who respond will receive from PJM, either directly or indirectly, as compensation for reducing the quantity of electricity that has to be supplied from the PJM wholesale electric energy market during critical peak periods; and
- mitigation of prices for capacity and energy in the wholesale markets operated by PJM that the Company assumes will result from the reductions in peak demand and electricity during critical peak periods that has to be met from those wholesale markets.

These dynamic pricing related projected benefits, valued at $218.5 million, produce a benefit to cost ratio of 1.15. These dynamic-pricing projected electricity supply cost benefits, when added to the AMI related projected operational benefits, produce a total projected benefits of $313.5 with a TRC benefit to cost ratio of 1.65.

Q. DO THE MAJORITY OF THE PROJECTED BENEFITS HINGE UPON A FEW KEY ASSUMPTIONS?

A. Yes. The projected benefits of the Companies' proposal are based upon numerous assumptions. However, four assumptions underlie the majority of the projected benefits and are therefore particularly critical.

The first major assumption is that 75% of residential customers will participate in, and respond to, CPR and CPP rates on a sustained basis over fifteen years. OPC Witness

Brockway discusses those participation and persistence assumption in her Direct Testimony.

The second major assumption is that customers will receive the full value of wholesale capacity and energy during critical peak periods even if the Companies do not bid the reductions from dynamic pricing into the PJM wholesale markets. The third major assumption, related to the second, is that the value of avoided capacity in the PJM wholesale market for the zone in which the Companies are located will stabilize at a capacity value of $ 57 per kw-year (in 2009$) from 2016 onward. As noted earlier, of the 70 percent of total benefits that depend on the reductions in response to CPR and CPP, approximately 55 percent depend upon these two assumptions. I discuss this two assumptions later in my testimony.

The fourth major assumption is that residential customers will reduce their annual use by 1.5% in response to the price information they receive from the Companies' proposal. OPC Witness Brockway discusses this energy conservation assumption in her Direct Testimony.

Q. DID THE COMPANY EVALUATE THE IMPLICATIONS OF THE UNCERTAINTY ASSOCIATED WITH ITS PROJECTIONS?

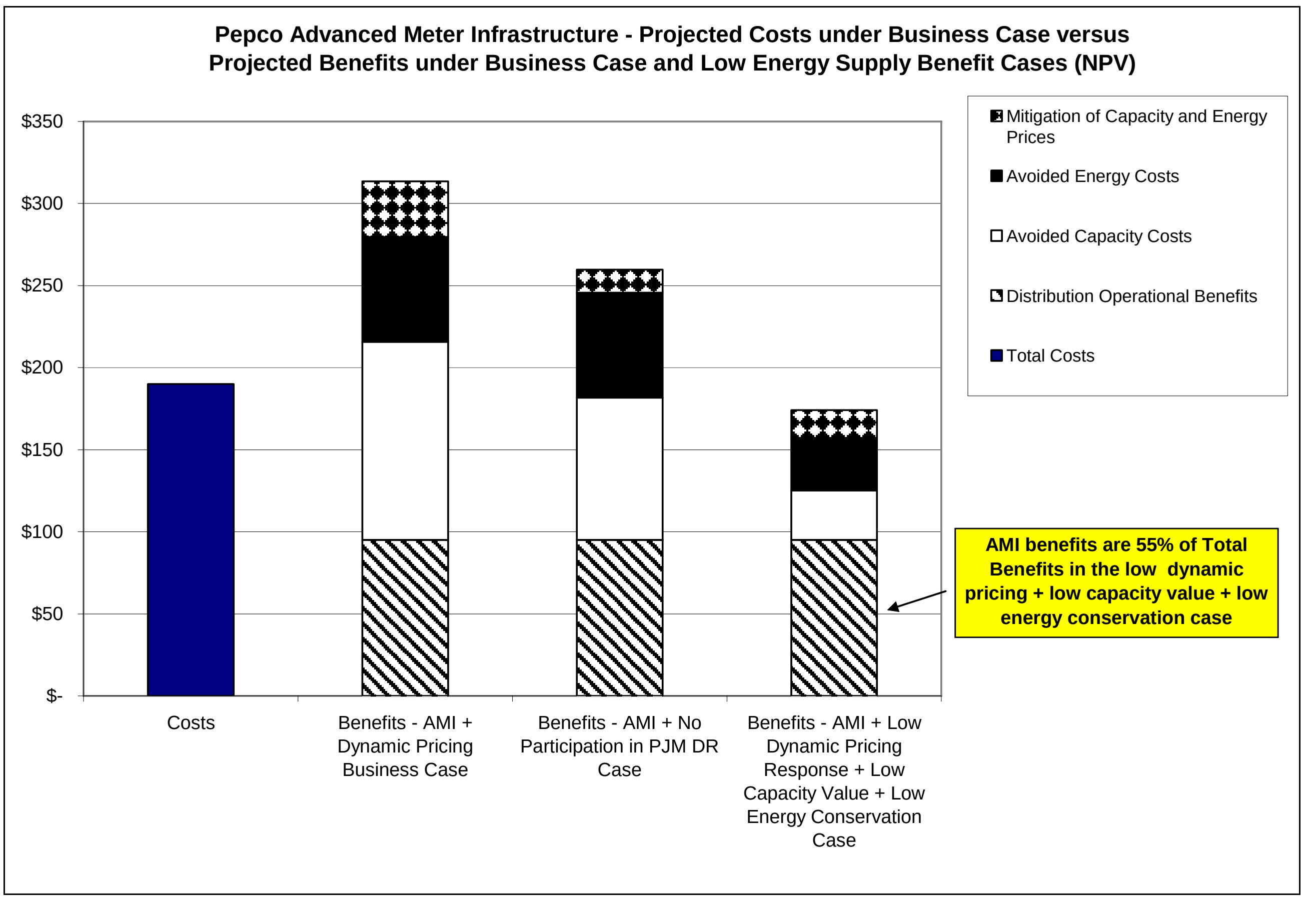
A. No.

Q. DO YOU AGREE THAT THE BUSINESS CASE IS THE MOST LIKELY SCENARIO?

A. No. My analyses, combined with those presented by OPC Witness Brockway, indicate that the future is more likely to unfold somewhere between the level of response to dynamic pricing and capacity values assumed in the Business Case and much lower levels. I have labeled one lower benefit scenario as a No Participation in PJM DR Case and the other as a Low Dynamic Pricing Response + Low Capacity Value + Low Energy Conservation Case.

Q. HOW DO THE BENEFITS OF PEPCO'S PROPOSED AMI COMPARE TO ITS COSTS UNDER YOUR TWO LOW ELECTRICITY SUPPLY BENEFITS CASES?

A. The total benefits under each of these two cases are presented in the third and fourth bars of the chart below, which is Exhibit___JRH-5.



The "No Participation in PJM DR Case" assumes that Pepco does not bid any reductions in peak load into any of the PJM Demand Response programs or into the PJM wholesale capacity market. Under this Case there is a four year delay between the year in which a reduction in peak load occurs and the year in which PJM recognizes that reduction by reducing the capacity obligation for the Pepco service territory. Under this Case Pepco's AMI has a benefit to cost ratio of 1.4.

The "Low Dynamic Pricing Response + Low Capacity Value + Low Energy Conservation Case" assumes reductions in peak load and annual use are 50% of those assumed by Pepco in its Business Case and that capacity values are also 50% of those assumed by Pepco in its Business Case. Under this case Pepco's AMI has a benefit to cost ratio of 0.9.

Q. BEFORE PROVIDING THE BASIS FOR EXPECTING ONE OF THESE LOWER BENEFIT CASES, PLEASE EXPLAIN WHY THE POSSIBILITY OF A LOWER BENEFIT CASE IS RELEVANT TO THE COMPANY REQUESTS IN THIS PROCEEDING.

A. The possibility of a lower benefit case is relevant to the Company's requests in this proceeding for two reasons. First, the Companies are proposing to recover their AMI costs in base rates, which should require them to bear a portion of the financial risk that its actual AMI-related benefits are less than its projections. However, the Company will make the same AMI investment and earn the same return on that investment regardless of the amount of dynamic pricing related benefits ratepayers actually receive. Second, there are different possible approaches to deploying AMI. The Companies have the burden of demonstrating to the Commission that their proposed approach is the most cost-effective out of the range of possible alternative approaches available to them.

Q. PLEASE EXPLAIN WHY AVOIDED CAPACITY COSTS ARE LIKELY TO BE LOWER IN THE "NO PARTICIPATION IN PJM DR CASE" THAN THOSE PROJECTED IN THE BUSINESS CASE.

A. The "No Participation in PJM DR Case" assumes that Pepco does not bid any reductions in peak load into any of the PJM Demand Response programs or into the PJM wholesale capacity market. Companies' Witness Faruqui has identified this as one of two approaches the Companies' are evaluating for capturing the value of avoided capacity costs for ratepayers who reduce their loads in response to dynamic pricing (Faruqui Direct, p. 21). The other approach is to bid those reductions into the PJM DR programs and wholesale capacity market.

I characterize these as taking either a "passive" or an "active approach" to advising PJM of reductions in peak load. Under the passive approach" customers simply reduce their peak load in year one and Companies' Witness Faruqui assumes PJM will recognize that reduction by reducing their capacity obligation in year two and thereafter. Under the "active approach" the Companies would bid the anticipated reductions in peak load into the PJM wholesale market and its demand response programs, and PJM would compensate them for the reductions. Unlike Baltimore Gas and Electric, which is proposing an "active approach," Companies' Witness Faruqui states that the Companies have not finalized the approach they propose to follow.

The actual levels of avoided capacity costs that Pepco customers will receive under the "No Participation in PJM DR Case" will be less than those projected in the Business Case. Contrary to Companies' Witness Faruqui's assertion, if customers reduce their peak load in year one PJM will not recognize that reduction by reducing their capacity obligation in year two. Instead there is a time lag of up to four years between the year in which the reduction occurs and the year in which PJM recognizes that reduction in the form of a reduction in capacity obligation. This time lag, which is noted in Response to

OPC II-20 and described in a Brattle report of July 2008,[3] is due to the fact that PJM makes its decision regarding the quantity of capacity it will acquire for a delivery year three years in advance of the delivery year.

Q. PLEASE EXPLAIN WHY ACTUAL AVOIDED ELECTRICITY SUPPLY BENEFITS ARE LIKELY TO BE LOWER THAN THOSE PROJECTED IN THE BUSINESS CASE.

A. Actual reductions in peak load are likely to be at levels somewhere between those projected in the Business Case and those in the "Low Dynamic Pricing Response + Low Capacity Value + Low Energy Conservation Case."

My expectation regarding a low dynamic pricing response is based upon the analyses presented the testimony of OPC Witness Brockway. She provides several reasons why the actual quantity of residential peak load reductions achieved each year for fifteen years is likely to be lower than the level projected in the Business Case. She also explains why the Company's projection of a 1.5% reduction in annual consumption from EE is not the most likely estimate.

My expectation of a future with lower than projected capacity revenues is based upon an analysis of capacity market fundamentals presented in Exhibit____ (JRH-6).

Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN THE COMPANIES' PROJECTIONS OF AVOIDED CAPACITY COSTS AND THEIR ASSUMPTIONS REGARDING THE FUTURE VALUE OF WHOLESALE CAPACITY.

A. The projections of avoided capacity costs in the Business Cases are directly related to the Companies' assumptions regarding the future value of wholesale capacity. These

[3] Pfeifenberger, Johannes et al, *Review of PJM's Reliability Pricing Model (RPM)*, The Brattle Group, June 30, 2008, p. 116.

assumptions reflect the zone in which the Companies are located, i.e. SWMAAC. If these assumptions are unrealistically high, and the actual market value of capacity is lower than forecast, the actual value of avoided capacity costs will be correspondingly lower than the Companies have projected in their Business Cases.

Companies' Witness Faruqui is responsible for the assumptions regarding the future value of capacity in the wholesale market operated by PJM over the planning period. These assumptions are based upon an analysis of the PJM wholesale capacity and energy markets that the Brattle Group prepared for the Companies in 2007 (2007 Brattle Analysis).[4] The 2007 Brattle Analysis assumed that that the wholesale capacity market would reach equilibrium in 2016 and that a new gas-fired combustion turbine (CT) would be the marginal source of new capacity in that market. The analysis estimated the net cost of bringing such a unit into service, which is referred to as the net cost of new entry or "net CONE," to be $57 per kw-yr if expressed in $2009 (Response to OPC IV-20).

The Business Case calculations of avoided capacity costs from the 2007 Brattle Analysis projected values are likely to be unrealistically high for two reasons. First, the 2007 Brattle Analysis did not simulate the operation of the PJM energy and capacity markets over the fifteen year planning period being used in this proceeding. For example, it did not consider the possibility that load might grow much more slowly in the future than in the past, particularly in light of the current recession, nor did it consider the impact of major new transmission projects over that planning horizon which may reduce constraints during critical peak periods. Further the 2007 Brattle Analysis did not consider the impact of capacity from new renewable resources coming into service to meet Renewable Portfolio Standards (RPS), i.e. independent of the wholesale market. For those reasons,

[4] Response OPC IV – 1.

which I discuss below and in Exhibit____(JRH-6), the capacity market may not reach equilibrium until several years after 2016 and/or the marginal unit may not be a gas-fired CT. Second, the Companies have apparently prepared their analyses in nominal dollars assuming an inflation rate of 2% or more.[5] It is not clear that the market value of capacity will escalate at inflation.

Q. WHAT MARKET FUNDAMENTALS MAY CAUSE THE MARKET PRICE OF WHOLESALE CAPACITY TO BE MUCH LESS THAN THE VALUE THE COMPANY HAS ASSUMED IN THE BUSINESS CASE?

A. The market fundamentals that may cause the market price of wholesale capacity to be much less than net CONE of a gas-fired CT are low load growth, increased utilization of existing capacity due to reduction in transmission constraints and capacity additions from renewable resources driven by Renewable Portfolio Standards (RPS). I discuss each of those market fundamentals in Exhibit____(JRH-6). Those factors could combine to delay the need for additional new gas-fired CT capacity, or other conventional capacity by several years. Hence, those market fundamentals, and that delay, will tend to keep market prices for wholesale capacity below net CONE of a gas-fired CT over the planning period.

On the demand side, peak load in PJM is likely to grow more slowly in the future than it has in the past, even after the economy rebounds. Increased spending on energy efficiency and demand response, prior to any impacts of AMI investments, will contribute to lower growth in peak demand. On the supply side, new transmission projects will tend to reduce the constraints that currently limit the ability to access capacity located outside SWMAAC. Finally, new renewable energy resources are

[5] The Companies did not provide the detailed inputs used in their calculations as requested in OPC Data Request IV – 20 b.

projected to come on-line in response to the renewable portfolio standards of various states. Based upon those various factors it is reasonable to expect that market prices for wholesale capacity in PJM could be less than the Companies' assumed value.

Q. HAVE YOU EXAMINED UTILITY PROJECTIONS OF THE MARKET VALUE OF AVOIDED CAPACITY IN OTHER AMI OR DEMAND RESPONSE FILINGS?

A. No. In other proceedings I have analyzed the projected timing and magnitude of capacity benefits that utilities expect from DR enabled by AMI. However, this is the first proceeding in which I have examined a utility's projection of the market value of avoided generating capacity it expects to receive for its peak load reductions. My decision to examine the projections of the market value of capacity was sparked by two events.

In May, the base residual auction (BRA) for planning year 2012/2013 set the market value of capacity in the rest of PJM at $16 per Mw-day, equivalent to $6 per kw-yr. This is about 10 percent of the $57 per kW-yr that the Companies assume for 2016 onward. I realize that the current demand and supply conditions in SWMAAC are different from the rest of PJM, but it does indicate the potential for market fundamentals to drive prices down.

In August, a Synapse project team I managed completed a long-term projection of avoided capacity and energy costs in New England. That report projects that wholesale capacity costs in New England, which have been approximately $30 per kw-year, will be approximately $18 per kw-yr. That low long-term projected value is attributable to an over-supply of existing capacity, a projection of low load growth and a projection of substantial new renewable capacity driven by renewable portfolio standards. Again, I realize that the current demand and supply conditions in SWMAAC are different from those in New England, but our projection for New England does indicate the potential for market fundamentals to drive prices down.

Q. WHAT IS THE IMPLICATION OF THIS LOW ELECTRICITY SUPPLY BENEFITS SCENARIO FOR THE COMPANY?

A. As noted earlier, this lower benefits scenario would not have any particular adverse implication for the Companies. The Company would make the same AMI investment and earn the same return on that investment as it would under the Business Case.

Q. WHAT IS THE IMPLICATION OF A LOW ELECTRICITY SUPPLY BENEFITS CASE FOR RATEPAYERS?

A. A low electricity supply benefits case has adverse implications for ratepayers. Ratepayers would have to rely heavily upon the Commission to ensure that the Company actually produced the projected benefits attributed to AMI and flowed those benefits through in its rates. As illustrated in Exhibit___JRH-5, under this scenario AMI related benefits represent approximately 55% of the total benefits and are therefore much more important than under the Business Case.

Q. IS THE POSSIBILITY THAT ACTUAL BENEFITS MAY BE LESS THAN IN THE BUSINESS CASE OFFSET BY BENEFITS THAT THE COMPANY HAS NOT QUANTIFED?

A. No. Companies' Witness Gausman and Companies' Witness Faruqui each refer to several categories of benefits from AMI that the Company has not quantified (Gausman Direct, pp. 28 - 34 and Faruqui Direct, pp. 24 - 27). These categories include environmental benefits, support for renewable energy, support for electric vehicles and increased energy conservation. The reference to these benefits implies that, if quantified, they would be material. However, until the Company actually quantifies each of these benefits in some manner, in physical terms if not in monetary terms, I recommend that the Commission not give them any weight.

The Company could have quantified the environmental benefits of the reductions in peak load and annual electricity consumption it is projecting. For example it is relatively straightforward to estimate the annual reduction in tons of carbon dioxide emissions reduced by applying a carbon emission co-efficient, e.g. tons of carbon per kWh, to the quantity of kWh reduced. The carbon emission coefficient can be estimated based on assumptions regarding the type and fuel of the generating units that are "on the margin" in peak and off-peak hours.

The ability of AMI to support significant expansion of renewable energy and development of electric vehicles are both also routinely highlighted. However, the Company needs to provide an analysis of whether similar support can be provided at less cost through other approaches.

Q. PLEASE SUMMARIZE YOUR CONCLUSION AND RECOMMENDATION REGARDING THE PROJECTED TOTAL BENEFITS AND COSTS OF THE COMPANIES'S PROPOSAL.

A. My first conclusion is that there is considerable uncertainty regarding the projected total benefits of the AMI as well as some uncertainty regarding projected costs. These uncertainties arise from the lack of long-term experience with the full-scale deployment of AMI and dynamic pricing such as the Companies are proposing. In particular, approximately 70% of the projected total benefits of the AMI hinge on the Companies' assumption that over 75% of residential customers will respond to its new dynamic pricing rate offerings on a sustained basis for over 15 years, 2012 to 2026. Moreover, approximately 55% of that sub-set of projected benefits, representing approximately 40%

of total projected benefits, hinge on the Companies' second assumption that avoiding one kW of generating capacity will be worth approximately $57 per year, in $2009, over 15 years.

My second conclusion is that a portion of this uncertainty results from the Companies' failure to specify the method they will use to monetize the reductions in peak load resulting from their dynamic pricing proposals. Dynamic pricing will not produce the maximum reductions in costs if the Companies do not actively bid those reductions into PJM wholesale markets.

These uncertainties create a financial risk, i.e., the risk that actual benefits from the AMI may prove to be substantially less the Companies' projections. This financial risk is relevant to the Commission's decision regarding approval of the Companies' request as well as to its decision regarding cost recovery.

I recommend that the Commission take these financial risks into consideration when making its decision as to whether to approve or reject the Companies' request. In particular, I recommend that the Commission not make a decision to approve or disapprove the Companies' proposed AMI until the Companies file a specific proposal for advising PJM of the reductions in peak load from that dynamic pricing and of monetizing those reductions, and all parties have had the opportunity to comment on that specific proposal.

If the Commission does approve the AMI, I recommend that it hold the Company to its projected costs as well as to its projected savings in distribution service O&M expenses.

Q. DOES YOUR RECOMMENDATION APPLY EVEN IF THE COMPANIES RECEIVE A DOE GRANT TO OFFSET THE PROJECTED COST OF THE PROPOSAL?

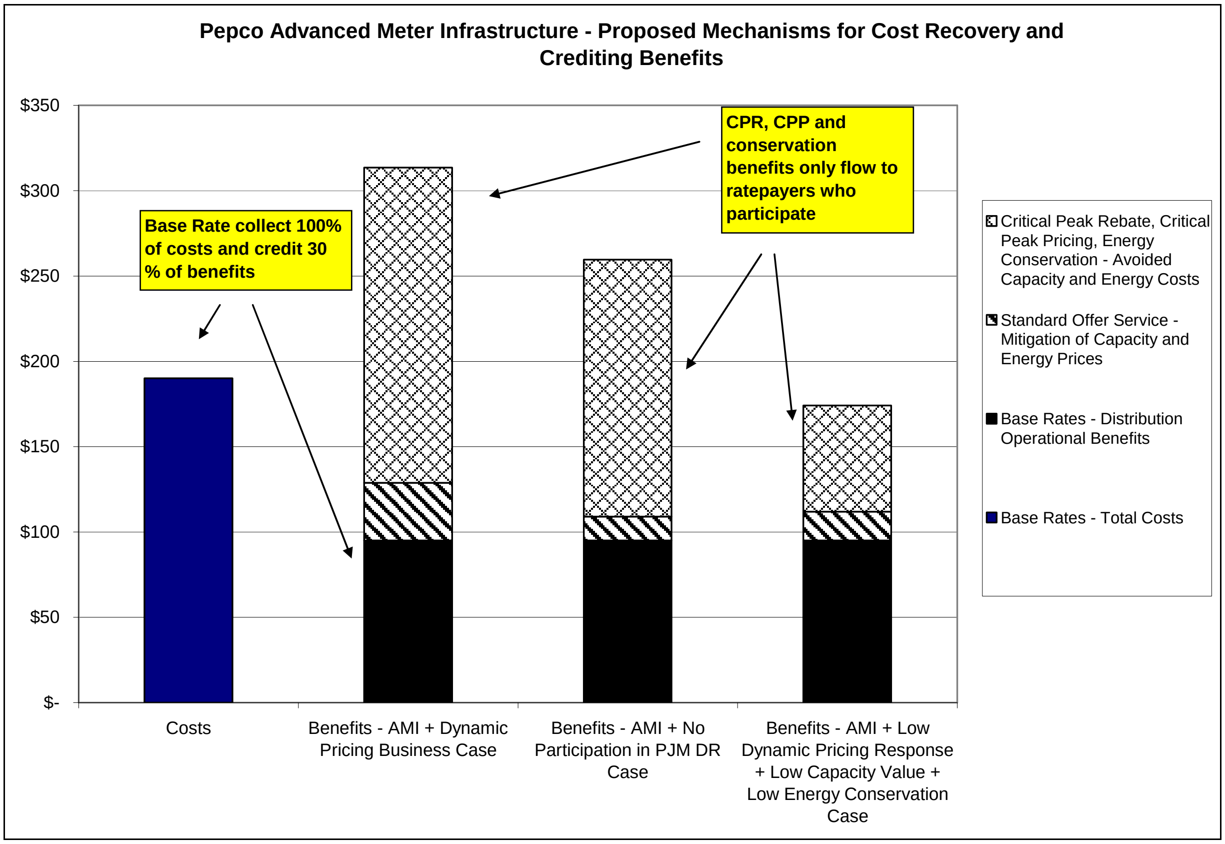
A. Yes. Even if the Companies receive a DOE grant, there will still be a risk that actual benefits may prove to be substantially less the Companies' projections. That risk will be lower, but a risk will still exist. The nature and amount of financial risk is relevant to the Commission's decision regarding approval of the Companies' request as well as to its decision regarding cost recovery.

V. RATEMAKING ISSUES

Q. PLEASE SUMMARIZE THE COMPANIES' PROPOSAL FOR RECOVERING THE COSTS OF THE PROPOSAL FROM RATEPAYERS AS WELL AS FOR CREDITING BENEFITS TO RATEPAYERS.

A. The Companies propose recovering the projected revenue requirements of AMI from all rate classes via base rates. They propose to flow the distribution service operational benefits from AMI to ratepayers through base rates and to flow the electricity supply benefits to ratepayers through four other mechanisms, i.e., CPRs to ratepayers who reduce peak load in response to that pricing, reductions in demand during critical peak periods by ratepayers who respond to CPP, reductions in annual electricity use by ratepayers who respond to usage and pricing information provided by the AMI and reductions in future rates for Standard Offer Service due to the mitigation of wholesale prices.

The amounts that the Company proposes to recover via base rates and to return to ratepayers via base rates, as the amount of benefits from the Business Case it expects will flow through each mechanism are presented in the chart below, which corresponds to the total costs and benefits presented in Exhibit___(JRH-5). The chart also shows how benefits will flow to ratepayers under a low benefits scenario. This chart is attached as Exhibit___(JRH-7).



As indicated in the first column of the chart, the Companies are proposing to recover the costs of AMI through base rates and to flow the distribution service benefits, representing approximately 30% of the total projected benefits, through base rates. They expect the benefits of mitigating wholesale capacity and energy prices, approximately 11% of total projected benefits will flow through to ratepayers via future changes in their rates for Standard Offer Service or supply from other load serving entities. Finally, avoided capacity and energy costs will flow to ratepayers who reduce peak load in response to CPR, CPP and or feedback on price and usage.

Q. PLEASE COMMENT ON THE COMPANIES' ILLUSTRATION OF THE RATE IMPACT OF THEIR PROPOSAL.

A. Companies' Witness Gausman provides an illustration of the impact of their proposal on system-wide average bills (Gausman Direct, p. 15) in his Schedule WGC-3 which I have re-created as Exhibit___(JRH-8). That illustration is misleading in several respects.

First, it does not give an accurate picture of the impacts of AMI by rate class, and particularly for the residential rate class. For low usage customers in the residential class increases of a few dollars per month are serious increases. This is particularly true for low usage customers who will not be able to save serious money by responding to CPR or CPP pricing. For example, in Exhibit___(JRH-8) I plot a dashed line labeled "total operational + Existing Meters and Price Mitigation Only." That dashed line shows the net increase in monthly bills of customers who can not or do not respond to CPR, CPP or feedback on their usage. Those customers will see a net increase in their monthly bills from AMI through 2023. In contrast, the sub set of customers who do respond to dynamic pricing should experience lower monthly bills, if the Company can monetize all of the projected energy supply savings and flow them back to those customers.

Second, the illustration implies that the AMI costs will be recovered as an unavoidable monthly fixed charge in $ per meter per month. According to fundamental ratemaking principles one would expect to see the allocation of the AMI revenue requirements among rate classes, and the design of rates to recover those revenue requirements, guided by a COS study and an analysis of bill impacts. The starting point for determining the portion of revenue requirements by class to be recovered via a customer charge should be the portion identified in the COS as customer-related. Then, one needs to consider the amount by which the customer charge should be allowed to increase in a given time period consistent with the ratemaking principle of continuity and gradualism. This is particularly important because customer charges are unavoidable and will have a disproportionate impact on low use customers within the residential rate classes.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE RATEMAKING ISSUES REGARDING THE COMPANIES' COST RECOVERY PROPOSALS.

A. Companies propose recovering the projected revenue requirements of AMI from all rate classes via base rates. They propose to flow the distribution service operational benefits from AMI to ratepayers through base rates and to flow the electricity supply benefits to ratepayers through four other mechanisms, i.e., CPRs to ratepayers who reduce peak load in response to that pricing, reductions in demand during critical peak periods by ratepayers who respond to CPP, reductions in annual electricity use by ratepayers who respond to usage and pricing information provided by the AMI and reductions in future rates for Standard Offer Service due to the mitigation of wholesale prices.

The Companies' illustration of the rate impact of their proposal implies that these costs will be recovered as an unavoidable monthly fixed charge in $ per meter per month. According to fundamental ratemaking principles one would expect to see the allocation of the AMI revenue requirements among rate classes, and the design of rates to recover those revenue requirements, guided by a COS study and an analysis of bill impacts. I recommend that the Commission require the Companies to present the results of COS studies and bill impact analyses to support their proposed allocations and rate designs when they file general rate cases for recovery of AMI.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

LIST OF EXHIBITS

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Consultant*, 2006 to present.
Analysis and expert testimony regarding planning, market structure, ratemaking and contracting issues in the electricity and natural gas industries.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006.
Senior Consultant, 1998-2004.
Provided expert testimony and litigation support in several energy contract price arbitration proceedings, as well as in electric and gas utility ratemaking proceedings in Ontario, New York, Nova Scotia and New Jersey. Managed a major productivity improvement and planning project for two electric distribution companies within the Abu Dhabi Water and Electricity Authority. Analyzed a range of market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Presented expert testimony on rates for unbundled retail services in restructured retail markets and analyzed the options for purchasing electricity and gas in those markets.
Manager of Natural Gas Program, 1986–1997.
Prepared testimony and reports on a range of gas industry issues including market structure, unbundled services, ratemaking, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada; 1981–1986
Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986
Member of a federal-provincial board responsible for regulating petroleum industry exploration and development activity offshore Nova Scotia.

Assistant Deputy Minister of Energy 1983–1986
Responsible for analysis and implementation of provincial energy policies and programs, as well as for Energy Division budget and staff. Directed preparation of comprehensive energy plan emphasizing energy efficiency and use of provincial energy resources. Senior technical advisor on provincial team responsible for negotiating and implementing a federal/provincial fiscal, regulatory, and legislative regime to govern offshore oil and gas. Directed analyses of proposals to develop and market natural gas, coal, and tidal power resources. Also served as Director of Energy Resources (1982-1983) and Assistant to the Deputy Minister (1981-1982.

Nova Scotia Research Foundation, Dartmouth, Canada, Consultant, 1978–1981
Edited Nova Scotia's first comprehensive energy plan. Administered government-funded industrial energy conservation program—audits, feasibility studies, and investment grants.

Canadian Keyes Fibre, Hantsport, Canada, Project Engineer, 1975–1977

Imperial Group Limited, Bristol, England, Management Consultant, 1973–1975

EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
Thesis: "An Assessment of Government Policies to Promote Investments in Energy Conserving Technologies"

B.Eng. Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973

EXPERT TESTIMONY AND LITIGATION SUPPORT (1987 to present)

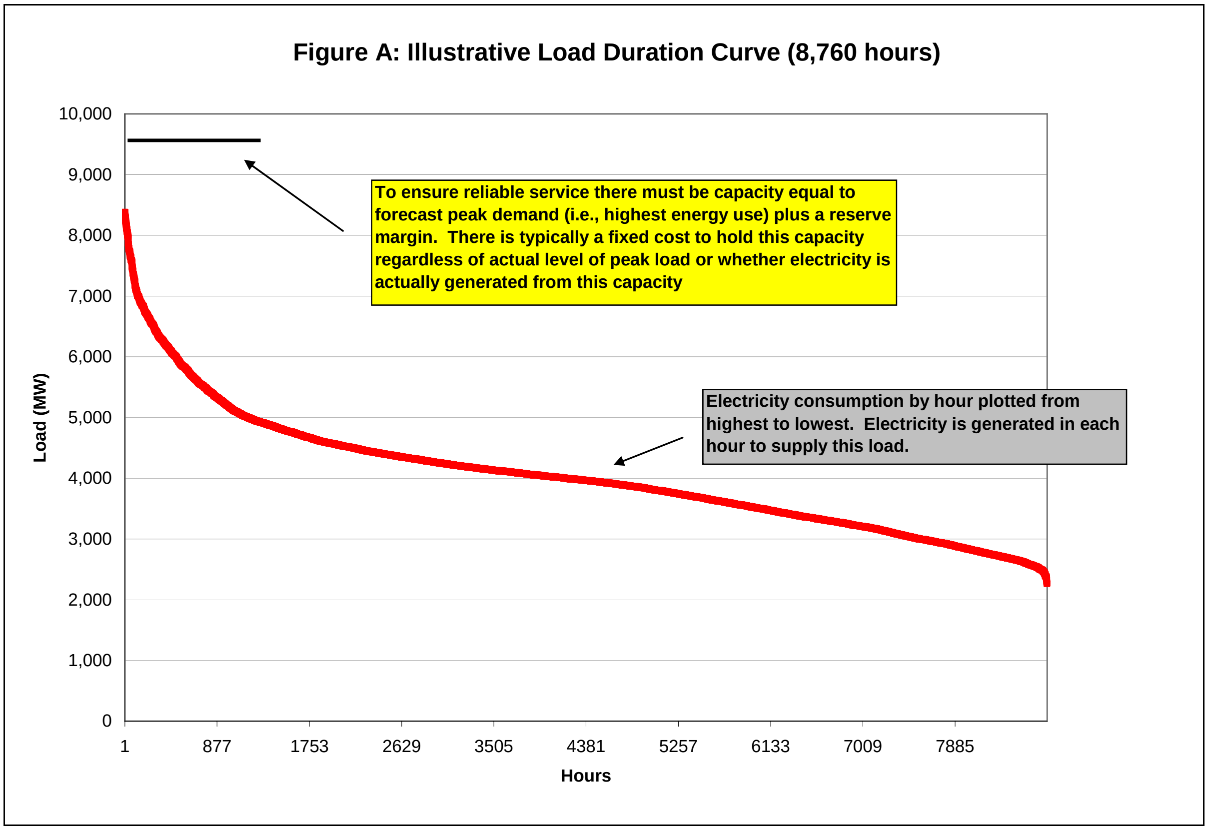
Provided expert testimony and/or litigation support on planning, market structure, ratemaking and gas supply/fuel procurement in the electric and gas industries in approximately 100 proceedings in over thirty jurisdictions in the United States and Canada. List of proceedings available upon request.

DEMAND RESPONSE (DR) PRODUCES MUCH LESS REDUCTION IN ANNUAL ENERGY CONSUMPTION AND ASSOCIATED CARBON DIOXIDE EMISSIONS THAN ENERGY EFFICIENCY (EE)

The deployment of smart meters will enable DR, including new price-driven DR by residential and small commercial customers, referred to as mass market customers. The reductions in peak load from that DR, as well as from energy efficiency (EE), will produce savings in wholesale generation capacity costs as well as in wholesale electric energy costs in peak hours. However, as this exhibit explains, that DR will produce much less reduction in annual energy consumption and associated annual air emissions such as carbon dioxide than EE.

1. Annual electricity supply costs and associated annual air emissions are a function of electricity consumption in all hours of the year

To appreciate the differences between DR and EE it is useful to begin with a review of the fundamental characteristics of annual electricity consumption and how those characteristics drive annual electricity supply costs and annual air emissions associated with annual electricity consumption. Those fundamental characteristics include the peak load, the annual load and the shape of that annual load. Those characteristics are illustrated in Figure A. This chart, referred to as a load duration curve, plots the total electric energy consumed by customers of a representative electric utility in each hour of a year. That consumption is plotted in decreasing quantity from the hour with highest use to the hour with lowest use.



The two major components of annual electricity supply costs are annual electric energy costs and annual electric capacity costs. Annual electric energy costs are driven by several key variables. The primary driver of those annual costs is the quantity of electric energy, in MWh, consumed in each hour of the year. In Figure A that consumption, plotted in the solid line which begins at over 8,000 MWh in critical peak hours and declines to approximately 2,500 MWh in off-peak hours. In retail markets whose supply costs are based upon market-based prices, the other important drivers are the type of unit that is on the margin, or sets the wholesale market price, in each hour such as natural gas units in peak hours and coal units in off-peak hours.

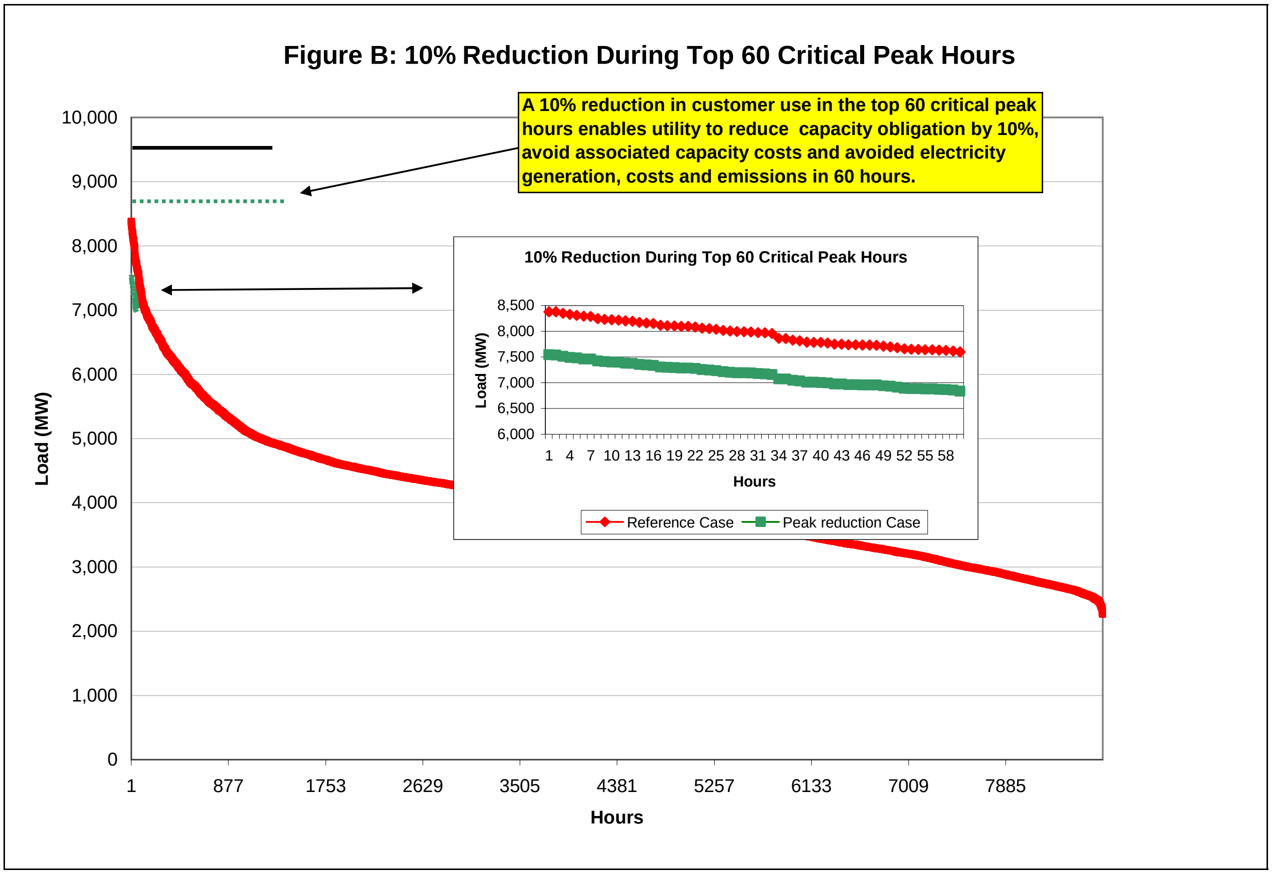
Annual electric capacity costs are driven by the quantity of electricity use during the hours of highest system-wide electricity use, or critical peak periods. (The critical peak periods of most utilities typically occurs in less than 100 hours each year. In the U.S. Northeast those critical peak periods typically occur during afternoons in July, August and September.) Electric industry planners determine the quantity of capacity needed in any given year to ensure reliable service by forecasting the quantity of retail peak load (MW) under extreme conditions and then adding allowances for line losses and for a target reserve margin. In Figure A the capacity required to ensure reliable service is approximately 9,600 MW, plotted in the solid horizontal line.

The annual air emissions associated with electricity consumption are driven by many of the same variables that drive annual electric energy costs. The primary driver of those emissions is the quantity of electric energy consumed in each hour of the year. Other important drivers are the quantity of electricity generated from each type of unit in each hour, e.g. nuclear, coal, natural gas and the air emissions per MWh generated by each of those units.

2. DR reduces load in critical peak hours whereas EE reduces load in most hours of the year, including critical peak hours

DR refers to the reduction of electricity use during the hours of highest system-wide electricity use, or critical peak hours. A common DR measure is to reduce central air conditioning ('cac') electricity use during critical peak periods by increasing the room temperature setting or by cycling the operation of the unit.

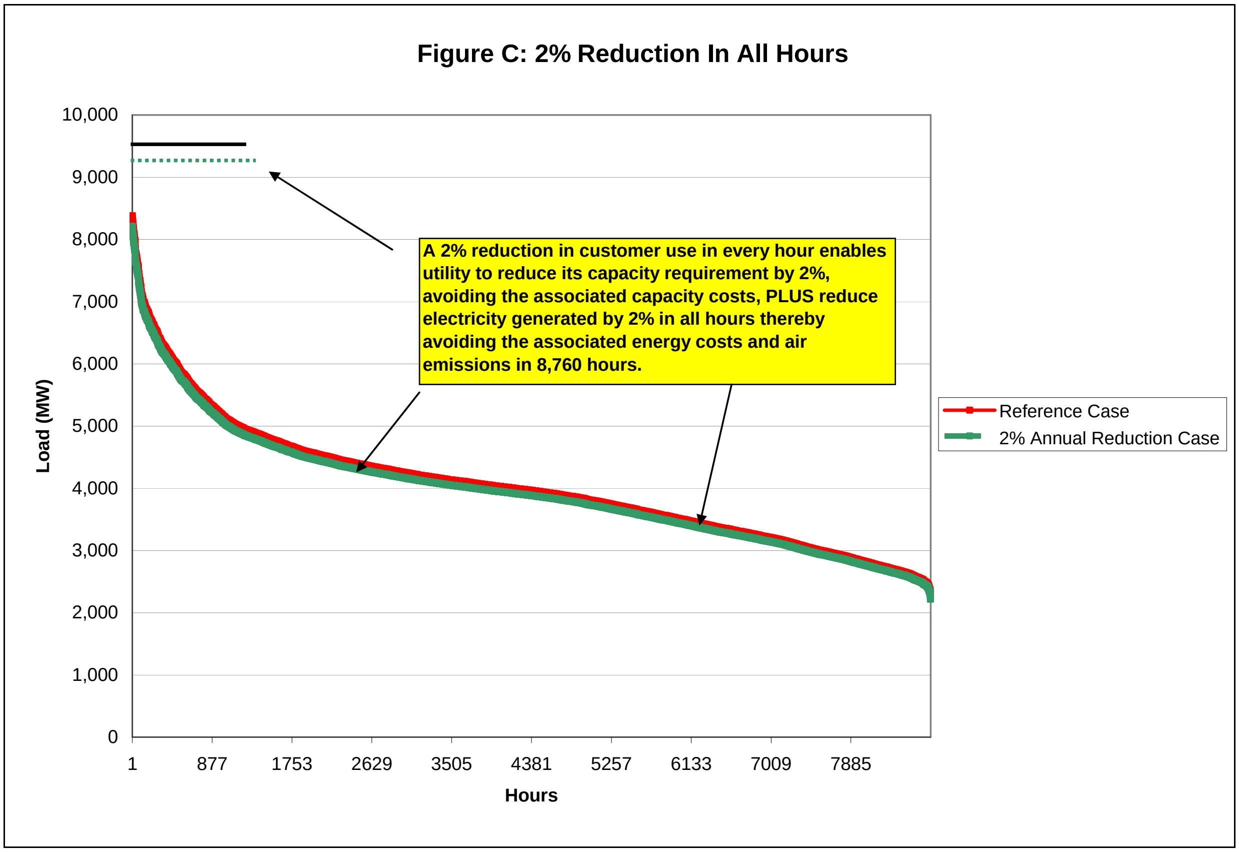
The impact of DR on the fundamental characteristics of the illustrative utility from Figure A is shown in Figure B. This chart illustrates the impact of DR that reduces load by 10 % in the top 60 critical peak hours



That illustrative reduction from DR would enable the utility to reduce the quantity of capacity by 10%, and to avoid the associated capacity costs. It would also enable the utility to reduce the quantity of energy it acquired in those 60 hours by 10%, and avoid the cost of that energy. Finally, the utility would avoid the air emissions associated with that 10% reduction in electricity use in those 60 hours.

EE refers to measures that reduce electricity use in all hours of the year affected by the EE measure. EE measures reduce electricity use during critical peak periods, like DR, as well as in all other hours of the year during which the application affected by the EE measure operates. For example, an EE measure such as insulating a home will reduce the air conditioning load of the home in all hours. That EE measure will reduce air conditioning electricity use during critical peak

The impact of EE on the fundamental characteristics of the illustrative utility from Figure A is shown in Figure C. This chart illustrates the impact of EE that reduces load by 2 % in all 8,760 hours of the year.

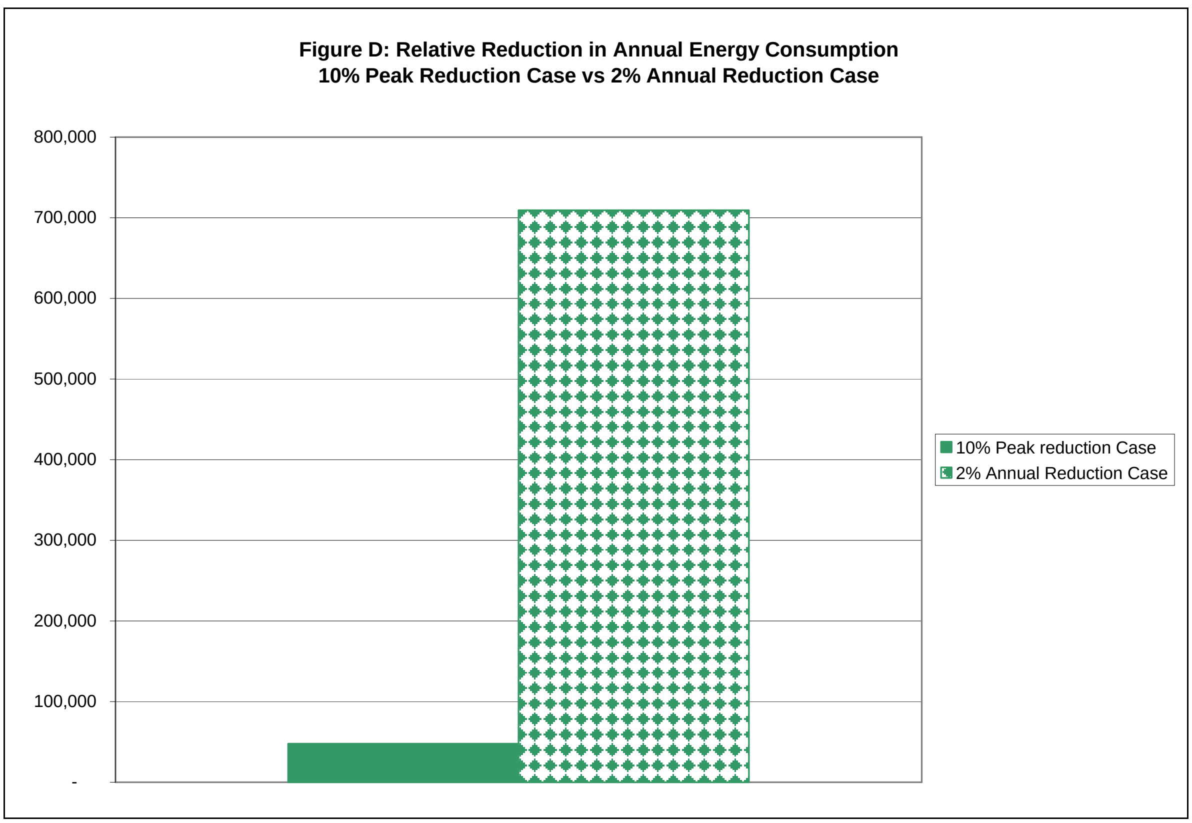


That illustrative reduction from EE would enable the utility to reduce the quantity of capacity by 2%, and to avoid the associated capacity costs. It would also enable the utility to reduce the quantity of energy it acquired in all 8,760 hours by 2%, and avoid the cost of that energy. Finally, the utility would avoid the air emissions associated with that 2% reduction in electricity use in those 8,760 hours.

3. DR Produces Much Less Reduction In Annual Energy Consumption And Associated Carbon Dioxide Emissions Than EE

Reductions in peak load from DR are valuable in terms of avoiding capacity costs and the costs of energy in critical peak periods. For example, a 10% reduction in peak load will certainly avoid more capacity costs, and peak hour energy costs, than a 1% reduction in peak load. However, DR produces much less reduction in annual energy consumption and associated carbon dioxide emissions than EE because DR reductions occur in less than 100 hours, or 1%, of the year. In contrast, EE causes reductions in both critical peak hours and in many additional hours of the year.

For example, the illustrations in Figures B and C indicate that, all else equal, an EE measure that reduces energy use by 2% in every hour would produce a reduction in annual energy consumption about 15 greater than a 10% reduction in critical peak hours from DR. Those relative reductions are presented in Figure D.



Some DR measures are designed to encourage customers to shift their consumption from peak hours, in which electric energy prices are higher, to off-peak hours in which electricity prices are lower. That load shifting may be valuable in terms of reducing the cost of energy, by acquiring the same annual quantity from lower cost sources of generation. However, since shifting load from peak hours to off-peak hours does not reduce the quantity of electricity actually consumed, detailed analyses are required to determine whether that load shifting will produce a material reduction in annual air emissions, such as carbon dioxide. In order for such a reduction to occur the emissions per MWh from units on the margin in off-peak hours would have to be less than the emissions per MWh from the units on the margin during on-peak hours.

**BEFORE THE
UNITED STATES SENATE**

COMMITTEE ON ENERGY AND NATURAL RESOURCES

**TESTIMONY OF THE HONORABLE FREDERICK F. BUTLER
COMMISSIONER, NEW JERSEY BOARD OF PUBLIC UTILITIES**

**ON BEHALF OF THE
NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS**

ON

"Smart Grid"

March 3, 2009

**National Association of
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Good morning Chairman Bingaman, Ranking Member Murkowski, and Members of the Committee:

My name is Frederick F. Butler, and I am a member of the New Jersey Board of Public Utilities (NJBPU). I also serve as President of the National Association of Regulatory Utility Commissioners (NARUC), on whose behalf I am testifying here today. I am honored to have the opportunity to appear before you this morning and offer a State perspective on "Smart Grid".

NARUC is a quasi-governmental, non-profit organization founded in 1889. Our membership includes the State public utility commissions serving all States and territories. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Our members regulate the retail rates and services of electric, gas, water, and telephone utilities. We are obligated under the laws of our respective States to ensure the establishment and maintenance of such utility services as may be required by the public convenience and necessity and to ensure that such services are provided under rates and subject to terms and conditions of service that are just, reasonable, and non-discriminatory.

There's a worn-out cliché that goes something like this: Don't put the cart before the horse. In an industry as old as the electric utility sector, this saying aptly describes the situation we face in dealing with the modern Smart Grid and future demand growth.

As a State regulator in New Jersey and co-chair of a national board analyzing Smart Grid issues, I am absolutely convinced of the Smart Grid's potential to revolutionize how energy is delivered and consumed. I know the Smart Grid can change how utilities oversee their networks and improve reliability. I know that, in the end, consumers could have greater control over their usage and have the potential to lower their bills. I also know, however, that if we do not do this correctly, if we move too quickly and promise too much we can endanger our coming close to meeting any of those lofty aspirations.

That is why it is important to remember that old cliché and not put the cart before the horse. The benefits of the Smart Grid are obvious, and we must be sure that we move deliberately and in stages so that the costs of rolling out the necessary infrastructure are borne by those who will benefit. If we expect the horse—i.e. the consumers—to push the cart before it is ready, we many never get the Smart Grid off the ground. This means that we should not focus immediately on the end user and demand response; rather, we must start with the backbone—the transmission and distribution systems—while proceeding carefully to go inside consumers' homes.

Achieving the ultimate goal of reliable service at a fair and reasonable price is becoming harder and harder in this era of rising costs. There is a high probability that within the next three to ten years all electricity consumers will be facing higher costs because of rising fuel and commodity prices, as well as the initial sticker shock of federal and State initiatives to increase renewable generation and the anticipated costs associated with climate change legislation. These costs are and will continue to hit energy companies hard, and State regulators are faced with having to approve rate increases that a growing number of consumers may not be able to afford. Should the potentially substantial price tag of Smart Grid be suddenly thrust upon them, not withstanding the federal funding increase in the stimulus law, ratepayers will not be happy.

The utility industry is facing tremendous challenges, and we all need to welcome new technologies that could help this country become more efficient while bolstering the existing transmission grid. The Smart Grid has this potential, but only if embraced by utilities and, most importantly, consumers. Without getting the consumers on board, the Smart Grid may just be another good intention.

Before going too much further, it must be stated that our nation's energy woes will not be slain by a single silver bullet, but rather by what has been referred to as silver buckshot, a whole array of various and new revolutionary energy programs. This includes building some new transmission, encouraging renewable energy resources, promoting energy efficiency, resolving the nuclear-waste storage problem, and developing new technologies. The easiest and cheapest of this list is, of course, energy efficiency, but we must consider the role new technologies can play in helping us fix our current situation.

Here is where the Smart Grid comes into play. With the right investment and incentives, modernizing the nation's transmission system could revolutionize how and when we use electricity. If done correctly, utilities can streamline their operations and have more control over their networks. The more efficient we get, the less electricity will be lost on the transmission grid. Consumers, meanwhile, can reduce their usage across the board, and especially during peak times. This can actually lead to reduced electricity bills. From an operational, business, environmental and economic standpoint, the Smart Grid, if implemented properly, can be a major win-win.

But we do need to be careful. Right now, we are selling the Smart Grid as a means of empowering consumers to lower their usage and, correspondingly, their energy bills. While this may ultimately be the case, we must learn our lesson from the restructuring experience before heading down this path. The promise of restructuring was that consumers would save money by shopping for power. Nearly half the States introduced some kind of restructuring legislation in the mid- and late-1990s. Congress also considered mandating a national restructuring scheme during the late 1980s and early 1990s. In many States, rates were cut and/or frozen for a set number of years, so at the outset, restructuring seemed to be a success.

The 2000-2001 Western Energy Crisis prompted many to rethink this approach. Instead of lower prices, consumers saw their rates skyrocket as utilities were forced to buy electricity through the volatile spot-market costs which, we later found out, were being manipulated. Along the East Coast, starting in 2006, when rate caps expired in Maryland, ratepayers and politicians led a mutiny that nearly resulted in the demise of the State's Public Service Commission. Cooler heads prevailed and the massive rate increases were phased in over time, but many consumers still feel burned. Delaware and

Illinois have had similar experiences. We have not had these kinds of problems in New Jersey, but the sting in many States is being felt across the country.

The problem here was not restructuring per se, but it was the way it was sold to consumers. Instead of determining the best way to move forward deliberatively, we jumped right in, with the promise of lower rates to follow. Because of this approach, and because of the results, the concept of restructuring has taken a significant hit. Indeed, we put the cart before the horse.

We cannot make this same mistake with the Smart Grid if we want it to succeed. There is no doubt that the Smart Grid will bring consumers significant benefits. However, if we want to make the biggest impact, we should consider a different approach and concentrate first on the operational side while we educate consumers and deploy smart meters very strategically. Many utilities, engineers, and vendors have extolled the virtues of how an updated, modernized transmission system will give grid operators a much better view of their transmission and distribution network. New technologies can be installed on distribution poles and on the lines themselves to give advanced warning of a power surge. A modernized grid can help utilities lower costs by reducing the need for sending out trucks to read meters or restore power. Business operations can be streamlined, reliability can be improved, and money—real money—can be saved.

For instance, phasor measurement and backscatter sensors on the transmission grid, along with video sagometers and wireless mesh sensors, can use radio-frequency identification (RFID) technology to give utilities real-time information on the status of specific lines. These sensors can detect problems on the grid as they develop and that are relayed back to the utility for resolution before they escalate into a massive blackout. Instead of relying on costly and time-consuming manual visits from work crews, utilities will have up-to-date information on their system and can act accordingly. These reasons alone will make the Smart Grid a safe and worthwhile investment for utilities, whether or not end-users choose to get on board later.

From my perspective as a State regulator, it seems to make the most sense that if we're going to begin investing in a Smart Grid, we should start here. If we start with the backbone – if we update and improve the delivery system first – we will see the utility company side benefits of the Smart Grid. The question of who pays is important—and with consumers already challenged because of rising rates and the economic downturn, we must be careful before putting more on their plate. In this case, starting with the backbone means the initial investments would be paid for by the utilities themselves, as they will be the initial beneficiaries, and not immediately by ratepayers. While we all would like to see end users enjoy the benefits of Advanced Metering Infrastructure, the Smart Grid can still make an immediate and long-lasting improvement for the industry by making the delivery system more efficient. This alone will result in considerable savings and fewer outages. Meanwhile, advanced meters and the applications they enable can at the same time be deployed strategically in pilot and demonstration projects thus demonstrating the benefits to end-use customers. Moreover, these backbone investments are necessary at some point during the transition to the Smart Grid. So let's ready the cart to be pulled before asking the horse—or consumers—to pull it.

The second part of Smart Grid should be developed and implemented in an effort coordinated by State and local officials. In my experience as a Commissioner I have found that a key component for an initiative such as Smart Grid is public outreach. We should use some federal resources to explain to the consumers that a new Smart Grid program is worthwhile. Most State commissioners understand the benefits of Advanced Metering Infrastructure and time-of-use rates, but most consumers do not. Because these new programs will need new rate structures that will be disruptive to habits of paying energy that have been in place for over 120 years, we must proceed carefully to avoid public backlash. Time-of-use rates are being welcomed by some sectors of society and feared by others. States must be sure that consumers will embrace the technology and tolerate the initial investment. So far, this is only occurring in a few States. In California, for example, the Public Utilities Commission is committed to rolling out the Smart Grid to their consumers. The State has taken a number of steps laying out the initial foundation, including a decision in September 2008 approving a smart-metering program for Southern California Edison, one of the State's three investor-owned utilities.

Still, my colleague on the California PUC, Commissioner Dian Grueneich, said that despite the commission's conclusion on the benefits, key California consumer groups remain unconvinced that the Smart Grid will deliver. The advanced metering infrastructure deployment for Southern California Edison will cost about $1.63 billion, with estimated benefits ranging from $9 million and $304 million for consumers. Speaking in September 2008 at the Grid Week forum in Washington, D.C., Commissioner Grueneich said the PUC moved forward despite the strong opposition from some consumers. "Very significant costs have been authorized and put into rates," she said. "Our consumer groups are not comfortable" with this.

The concern that many of my colleagues are trying to resolve is that consumers are convinced that the Smart Grid will only raise their rates with no discernable benefits. In a high-priced environment, some or perhaps most consumers see advanced metering rollouts as just one more headache and budget buster and are particularly scared that utilities and vendors will keep raising rates as the technology changes.

California will be launching a major education, marketing, and outreach campaign next year. This will need as much support as possible from all parties so the program can succeed and perhaps reduce the sting on ratepayers. Once they see the benefits, they should also see how they can turn this into savings.

As this experience demonstrates, the way a Smart-Grid program is structured and rolled out is absolutely key to its success, and regulators and industry must be flexible to ensure that consumers will not feel inundated or overwhelmed. Depending on how a Smart-Grid program is structured and rolled out will be the key to its success, and Congress, regulators, and industry must be flexible to ensure that consumers will not feel inundated or overwhelmed. As a State regulator, here's how I think we should proceed.

A good place to look is at the work we're doing with the NARUC-Federal Energy Regulatory Commission (FERC) Smart Grid Collaborative, which I co-chair with FERC Commissioner Suedeen Kelly. As this is an issue that cuts across both wholesale and retail energy markets, the dialogues we are initiating through this process will help us all as we move forward. The Collaborative brings together a diverse group of State and federal regulators, consumer groups, and industry experts and allows us to talk in a public setting about these issues.

The Collaborative has met three times since its February 2008 inception, most recently at the NARUC Winter Committee Meetings last month. We have discussed issues such as cost allocation, specific technologies, interoperability, and pilot programs with consumers and industry executives who are promoting Smart-grid technologies.

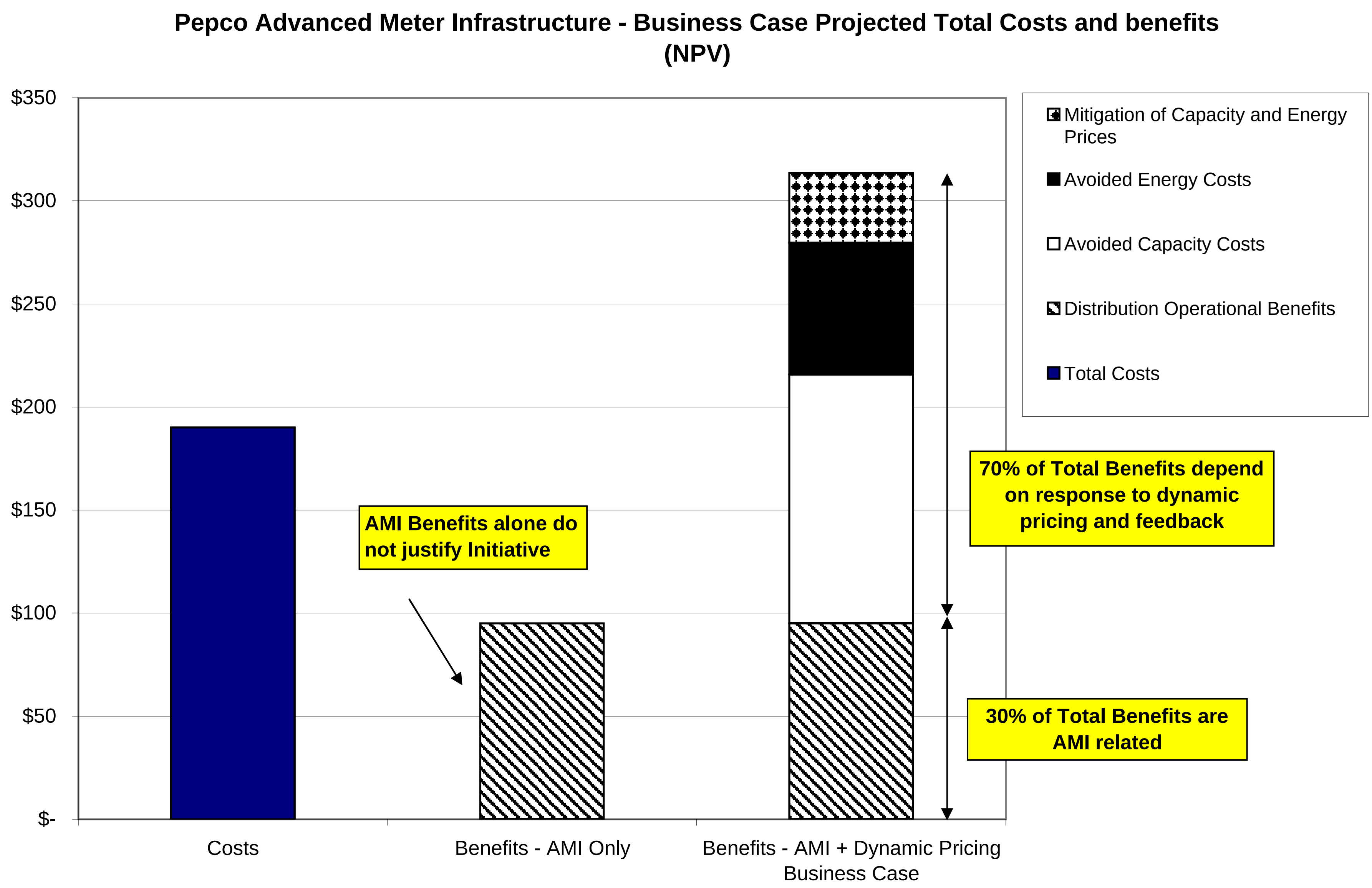
In my role as co-chair of this Collaborative, I have spent a considerable amount of time getting up to speed on the different technologies and pilot programs throughout the country. I am, as is the entire Smart-Grid industry, very interested in the pilot program in Boulder, Colorado, which is aiming to become the nation's first "Smart Grid City." I have discussed the many different pilots with my regulatory colleagues and am convinced that we must take a deliberate approach to introducing these new technologies to end-use consumers. As described above, consumers have yet to "buy into" the concept of the Smart Grid, and when they see any associated rate increases, they are more than likely not going to be pleased. Smart meters are expensive—right now we're talking about approximately $150 - $200 per meter—so we must be very careful in forcing anyone to upgrade if they are not willing. Pilot programs must be carefully structured in such a way that creates a "buzz" and excitement, not a ratepayer revolt.

In addition, there should be large-scale "demonstration projects" that cover a larger geographic area. We are all watching the Boulder, Colorado effort and that project's success is instrumental to the future of the Smart Grid. These kinds of projects must cover a significant demographic area that reflects a microcosm of the country at large, including different incomes and education levels. While the pilot programs are useful, these larger projects will give us a glimpse as to how a larger pool of consumers will react to the Smart Grid. The project doesn't have to be huge, but it must be an accurate representation of the society.

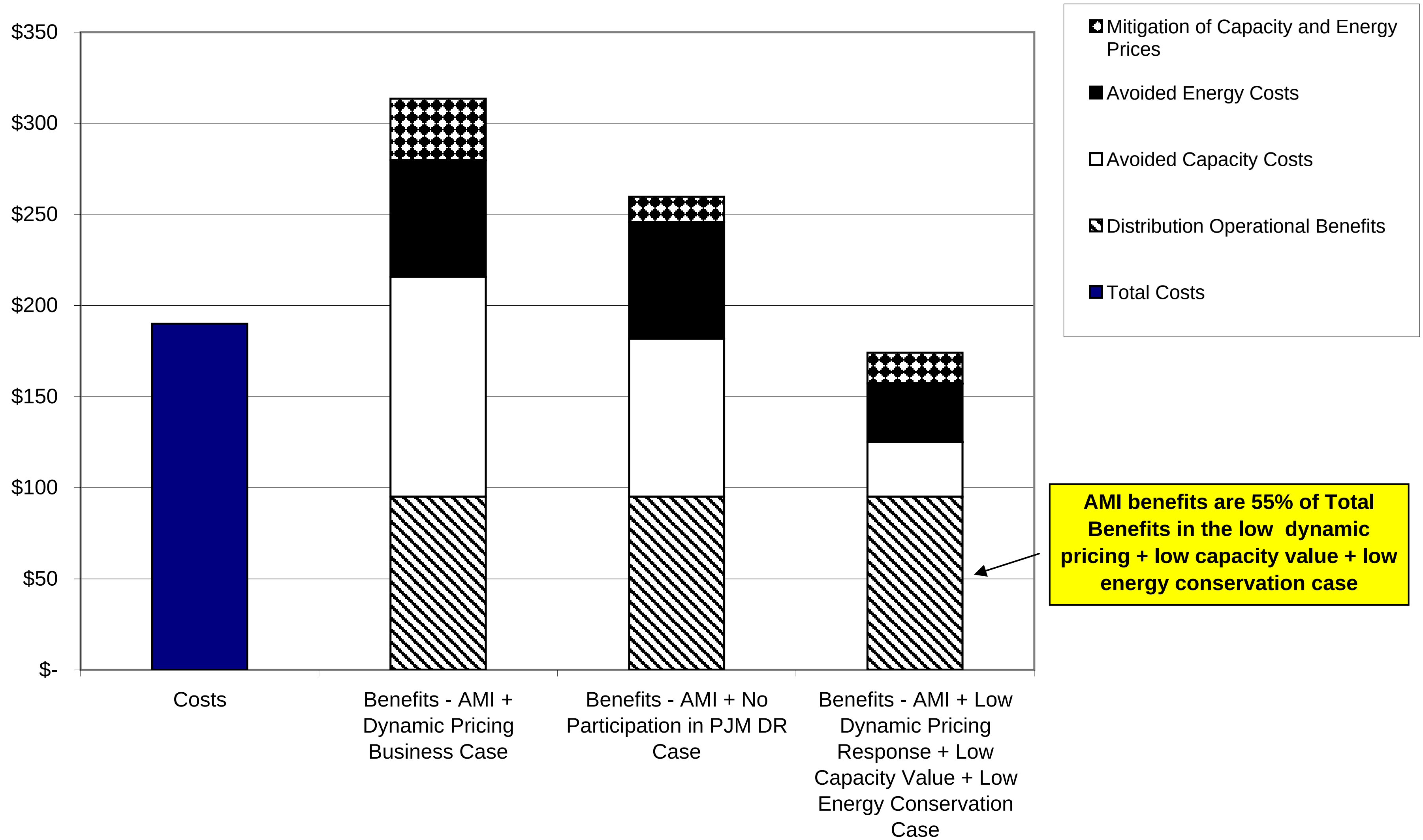
This approach lets consumers take part by building interest and selling the product amongst themselves, rather than having Congress, utilities, or regulators do it for them. The consumers who want the meters will get the meters, and through word-of-mouth, others will find out how valuable this new system can be, and will be more willing to endure a slight rate increase to pay for it. What concerns me is that under some proposals, millions of people will get these smart meters whether they want them or not. They will be getting a rate increase and new gadgets that they do not know how to use installed in their homes. I am not sure if this will breed anything but hostility among a rate class that is already facing challenging economic times.

Smart Grid can be successful provided we have federal and State governments working in concert with one another as partners; not working in contrast to one another as adversaries. The challenge before us is great, the technology and potential benefits exciting. The federal government has resources that the States do not; the States have expertise in the development and implementation of programs that the federal government does not have. Therefore, this challenge calls for a true partnership between the States and FERC that we are already developing through the NARUC-FERC Smart Grid Collaborative.

We have to remember that the Smart Grid will only achieve its vast potential if consumers embrace it. While we can certainly see major improvements in efficiencies and reliability by upgrading the transmission and distribution backbone, we will not change consumers' habits and consumption if we are unable to convince them of its promise. I respectfully request that this Committee and this Senate recognize and respect our unique roles so that we can work towards a truly 21st Century electricity delivery system.


Pepco Advanced Meter Infrastructure - Business Case Projected Total Costs and benefits (NPV)
$350
$300
$250
$200
$150
$100
$50
$-
Mitigation of Capacity and Energy Prices
Avoided Energy Costs
Avoided Capacity Costs
Distribution Operational Benefits
Total Costs
AMI Benefits alone do not justify Initiative
70% of Total Benefits depend on response to dynamic pricing and feedback
30% of Total Benefits are AMI related
Costs
Benefits - AMI Only
Benefits - AMI + Dynamic Pricing Business Case

Pepco Advanced Meter Infrastructure - Projected Costs under Business Case versus Projected Benefits under Business Case and Low Energy Supply Benefit Cases (NPV)



Pepco AMI - Summary of Projected Total Costs and Benefits

Business Case and Low Electricity Supply Benefit Cases

Case		Business Case (1)		No Participation in PJM DR Case (1)		Low Dynamic Pricing Response + low Capacity Value + low Energy Conservation Case (1)	
$'s in Millions		PVRR millions	% of Benefits	PVRR millions	% of Benefits	PVRR millions	% of Benefits
Costs	**Category**						
	Capital and O&M	$ 163.5		$ 163.5		$ 163.5	
	Deferred Cost recovery	$ 13.7		$ 13.7		$ 13.7	
	Existing Meter recovery	$ 12.9		$ 12.9		$ 12.9	
	Total Costs	$ 190.1		$ 190.1		$ 190.1	
BENEFITS							
Primary Driver	**Category**						
AMI	**Distribution Operational Benefits**	$ 95		$ 95.0		$ 95.0	
	Sub-total AMI	**$ 95**	**30%**	**$ 95**	**37%**	**$ 95**	**55%**
Dynamic Pricing	**Energy Conservation**	$ -	**0%**		**0%**	$ -	**0%**
	Avoided Capacity Costs	$ 121	**39%**	$ 87		$ 30	
	Avoided Energy Costs	$ 64	**20%**	$ 64		$ 32	
	Mitigation of Capacity and Energy Prices	$ 34	**11%**	$ 14		$ 17	
	Sub-total from Peak Reduction	$ 219	**70%**	$ 165	**63%**	$ 79	**45%**
	Sub-total SEP	**$ 218.5**	**70%**	**$ 164.6**	**63%**	**$ 79.1**	**45%**
Total Benefits - AMI + Dynamic Pricing		$ 313.5	100%	$ 259.6		$ 174.1	100%
Benefit / Cost Ratio							
	AMI Benefit/ Cost Ratio	0.50		0.50		0.50	
	Dynamic Pricing Benefit/ Cost Ratio	1.15		0.87		0.42	
	Total	**1.65**		**1.37**		**0.92**	

Sources:

1 Workbook A to Exhibits___JRH-4, 5 and 7

MARKET FUNDAMENTALS AFFECTING FUTURE VALUE OF WHOLESALE GENERATING CAPACITY IN PJM

The prices for capacity in the wholesale market operated by PJM, referred to as the Reliability Pricing Model ('RPM'), set the value for wholesale generating capacity as well as for reductions in peak load. This exhibit discusses major demand and supply factors that will delay the need for new conventional capacity and thereby place downward pressure on the future prices for capacity in the RPM. The exhibit is based upon a high-level review of these factors prepared by Synapse Energy Economics as of September 2009.

1. PJM Interconnection

PJM Interconnection (PJM) is a regional transmission organization (RTO) which coordinates the movement of wholesale electricity in all or parts of thirteen states[1]. It also operates wholesale markets for electric energy, electric capacity as well as ancillary services.[2] The prices for energy vary by hour throughout the year[3] while the price of capacity varies by planning year[4]. The prices of both energy and capacity also vary by location or Load Delivery Area ('LDA'). Prices vary by location due to factors such as line losses and constraints on the quantity of transmission capacity available during periods of peak electricity consumption.

The utilities who participate in these markets, grouped according to their location or LDA as defined by PJM, are presented in Table 1 to this Exhibit.

2. Purpose and Operation of Wholesale Capacity Market (RPM)

A. Purpose of RPM

PJM is responsible for ensuring reliable service. One activity through which it accomplishes that goal is operation of the RPM. In operating the RPM PJM begins by

[1] www.pjm.org.

[2] Synchronized Reserve and Regulation

[3] on-peak periods are weekdays, except NERC holidays, from hour ending 0800 until hour ending 2300

[4] PJM planning year is June 1 through May 31

setting the level of demand for which capacity and/or demand response (DR) resources must be available to ensure adequate service each year, referred to as a capacity obligation. PJM then acquires those resources through a series of auctions. Because of the lead time required to bring new conventional peaking capacity into service, PJM sets the capacity obligation three years in advance of the actual delivery or power year, also referred to as the planning year.

PJM sets the minimum capacity obligation for each delivery year equal to its projection of retail peak load (MW) under extreme conditions plus an allowance for line losses and a target reserve margin, referred to as Installed Reserve Margin ('IRM'). The target IRM is typically in the order of 115% of peak load. PJM sets this minimum capacity obligation for each LDA.

PJM acquires the resources through a series of auctions. The primary auction is the Base Residual Auction (BRA) which is held three years in advance. For example the BRA for the 2012 planning year was held in May 2009. PJM holds several subsequent, Interim Auctions between the BRA and the start of the delivery year. One of the major purposes of the RPM is to provide suppliers of existing capacity and DR sufficient compensation to assure their continued participation and, if new capacity is required, to provide prospective providers sufficient compensation to invest in that new capacity.[5]

The actual capacity obligation established for a delivery year is the quantity of capacity that clears in the RPM auction for that delivery year. The load serving entities ('LSEs')[6] in each LDA are obliged to control, and pay for, capacity based on their specific capacity obligation. The price for capacity established by the RPM auction for any given delivery year is the market value of capacity in that delivery year.

B. Establishment of Market Clearing Price in RPM

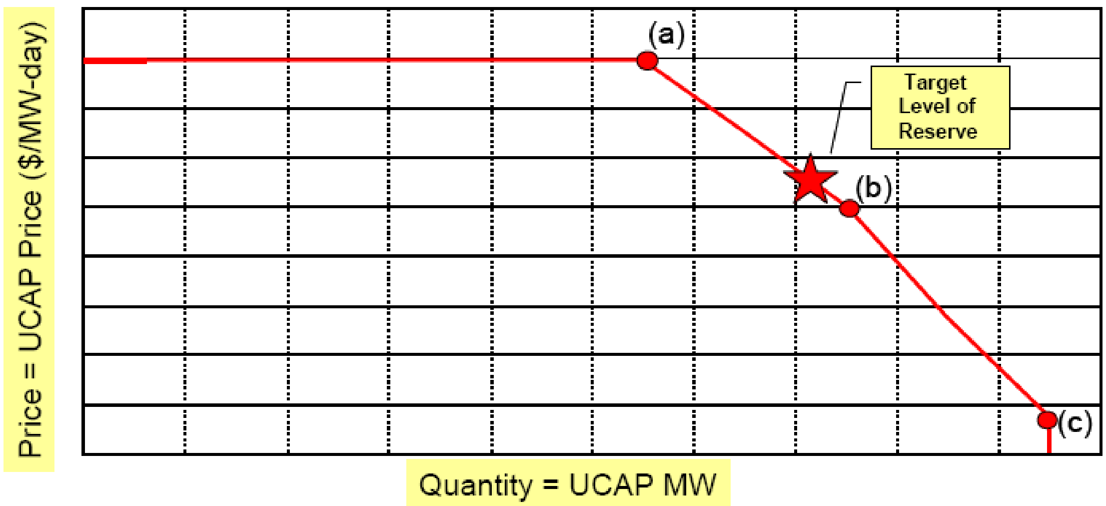
PJM sets the quantity of capacity to be acquired in a given year, and the market clearing price for that capacity, based on the intersection of the supply curve for that year and PJM's administratively determined demand curve. The supply curve reflects the quantity and price bids submitted by generators and demand resources in the BRA. PJM has

[5] PJM, "Reliability Pricing Model," http://pjm.com/markets-and-operations/rpm.aspx (downloaded September 24, 2009).
[6] LSEs provide electricity supply service to retail customers.

determined the demand curve, referred to as the Variable Resource Requirement ("VRR") curve, administratively.[7] These curves are plotted as price, on the y axis, versus quantity, on the x axis.

Figure 1 is an illustrative example of PJM's VRR curve.[8]

Figure 1



The administrative VRR curve consists of the following three key points:

- Point A is equal to a y axis value of 1.5 times the Net Cost of New Entry ('CONE') and an x axis quantity equal to 3% less than the target IRM;
- Point B is net CONE at the target IRM plus 1%; and
- Point C is 20% of net CONE at a supply 5% greater than the target Installed Reserve Margin.

PJM's current calculation of Net CONE is based on its assumption that the marginal source of new capacity is a gas-fired combustion turbine (CT). The value of net CONE is PJM's estimate of the cost and expected market revenues of a gas-fired CT. Net Cone is the difference between the cost of building and operating such a plant and the amount of energy and ancillary service revenue PJM estimates that it would receive under average

[7] Levitan & Associates for the Maryland Public Service Commission, "An Analysis of Resource and Policy Options for Maryland's Energy Future," December 1, 2008, section 2.2

[8] PJM Capacity Market Operations, Manual 18: PJM Capacity Market, Revision 7, August 18, 2009, Exhibit 1 (available at http://pjm.com/documents/~/media/documents/manuals/m18.ashx)

market conditions. In other words net CONE is an estimate of the compensation, in excess of energy and ancillary service revenues, that a developer of a gas-fired unit would require from the capacity market in order to bring it online. Thus the RPM is currently explicitly designed to provide a capacity price that would support new entry of a gas-fired CT, if and when new capacity is required.

As of September 2009, PJM has conducted six BRAs. The first three were transitional and hence not representative. In this analysis we focus on the most three auctions, for planning years 2010 through 2012 respectively. Table 2 shows the net CONE values set for each BRA. Table 3 shows the resource clearing prices in the six BRAs and Table 4 shows the market prices as a percent of net Cone each year.

A review of the three most recent auctions indicates that, except for DPL south, the market prices in all LDAs have, on average, cleared at prices below net CONE. For example, in MAAC, one of the constrained LDAs, net Cone in the past three auctions has averaged $160 per Mw-day. This amount is equivalent to $59 per kw-year.[9] In contrast, the market price in MAAC averaged $139 per MW-day ($51 per kw-yr). Some LDAs have experienced much lower average market prices. For example market prices in the APS LDA in western Pennsylvania averaged $100 per Mw-day or $36 per kw-year. Those prices were about 50% of net CONE for that LDA.

3. Market Fundamentals Expected To Place Downward Pressure on Future Prices for Capacity in RPM

The key assumptions underlying the current RPM approach are that peak load will grow, new capacity will have to be built to meet the new load and gas-fired CTs will be the least cost sources of that new capacity. All of those assumptions are open to question.

Several demand and supply factors are likely to combine to delay the need for new conventional peak capacity and thereby place downward pressure on the future prices for capacity in the RPM. Those market fundamentals are likely to result in market prices for capacity below current values of net CONE for a gas fired CT over the

[9] $162 per MW-day * 365 days per year * 1 MW per 1,000 kw

planning period. For example, the most recent two BRAs, for the 2011 and 2012 planning years, produced market prices about 60% to 65% of net CONE in most LDAs. Our review of market fundamentals indicates that future market prices could remain in this range, e.g. $110 to $133 per Mw-day ($40 to $46 per kw-yr) or lower rather than the $171 to $176 per Mw-day ($60 to $64 per kw-yr) suggested by net CONE .

A. No Guarantee That RPM Prices Will Approximate Net CONE of A Gas-Fired CT Indefinitely

PJM currently assumes that net CONE based upon a gas-fired CT is a realistic proxy for the marginal source and cost of new capacity. However, that net Cone is only a planning parameter in setting the VRR curve. Moreover, there is no guarantee that the RPM clearing price will approximate that particular net CONE over any given time period.

The RPM clearing price is likely to average a level equal to that particular net CONE over time only if certain key assumptions regarding the demand for and supply of, capacity in the wholesale market hold true. Those key assumptions, which are embedded in the computer model of RPM developed by its consultant, are as follows:

- The market is generally in equilibrium, meaning that essentially the same amount of compensation is required to entice all types of resources to participate, i.e. existing capacity, existing DR, new conventional capacity, new DR, new renewable capacity and new transmission projects that relieve constraints;
- Peak load will continue to increase over time, creating a need for new resources;
- New resources of all types (new conventional capacity, new DR, new renewable capacity, new transmission projects that relieve constraints) will be built *if and only if* they receive a sufficient capacity payment;
- A capacity payment commitment for one year approved three years in advance of the delivery year / in-service date, will be sufficient to entice investments in all types of new resources; and

- Some existing generating capacity will retire solely because they do not receive a capacity payment commitment for one year approved three years in advance of the delivery year.

If some, or all, of those underlying assumptions are inconsistent with actual market conditions in the future, it is unlikely that PJM will continue to set net Cone according to its current methodology and assumptions. Thus, while the RPM may well continue to be designed to produce market prices that average around Net CONE, the value set for net CONE may be much lower than its current level.

Our analyses of market fundamentals suggests that actual market conditions over the coming decade are likely to be different than most of these underlying assumptions, and thus that capacity prices are likely to be considerably lower than net CONE based on a gas-fired CT. In addition, if BRAs for several planning years consistently clear at prices corresponding to an excess of capacity while there is net growth in resources, the value of CONE could be reduced automatically.[10] PJM could also at any time propose and file with the FERC a new value of Cone based upon a different calculation method and/or proxy unit. In fact, PJM is required it to review the calculation of CONE every three years. [11].

B. Load may grow slowly

PJM determines the quantity of capacity that has to be acquired in the BRA for each planning year by forecasting the capacity obligation. That capacity obligation, combined with the quantity of existing capacity and DR willing to bid into the BRA, in turn determines the quantity of new capacity that will have to be developed to satisfy the capacity obligation.

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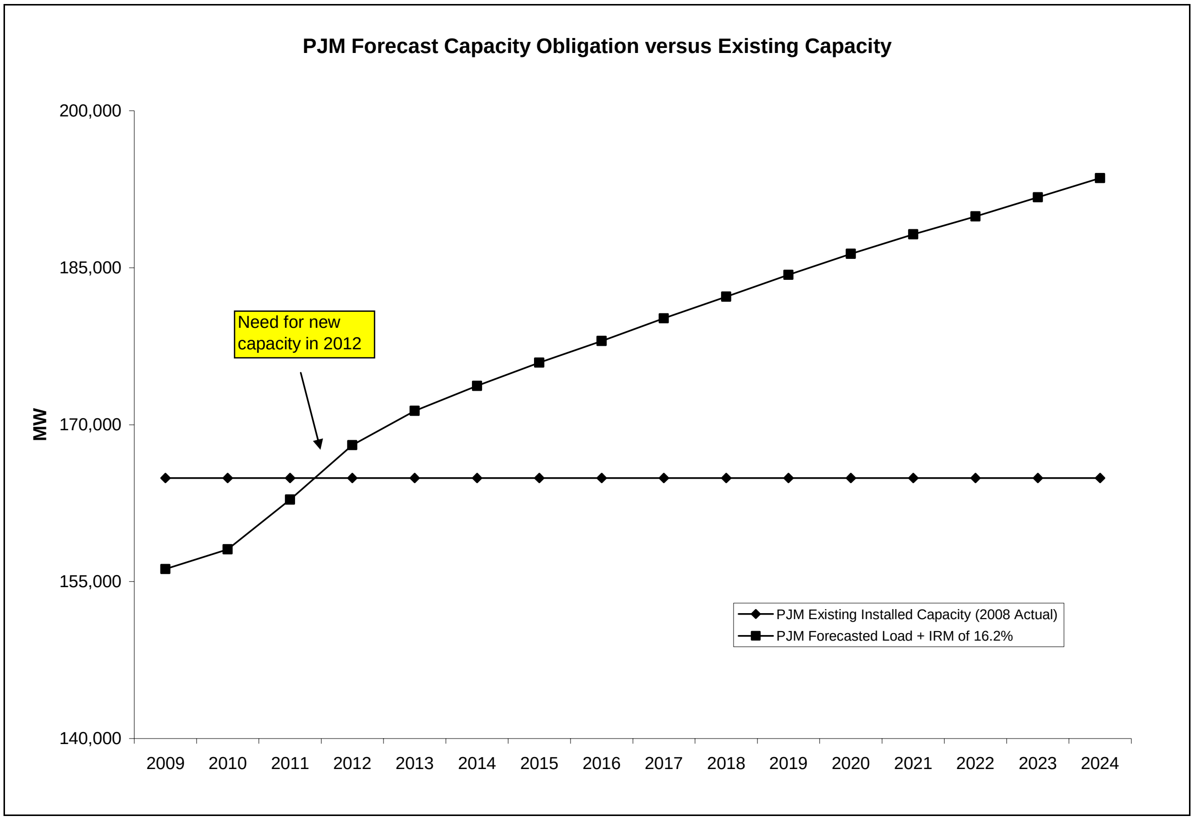
[10] PJM OATT, substitute Third Revised Sheet No. 586 as of September 18, 2009.
[11] 126 FERC ¶61,275, Order Accepting Tariff Provisions in Part, Rejecting Tariff Provisions in Part, Accepting Report, and Required Compliance Filings, March 26, 2009.

Our high level review indicates that, according to PJM's most recent long-term forecast[12], the capacity obligation will exceed existing capacity starting in 2012, as shown in Figure 2. Those estimates indicate that new capacity would be needed from that point onward.

Figure 2



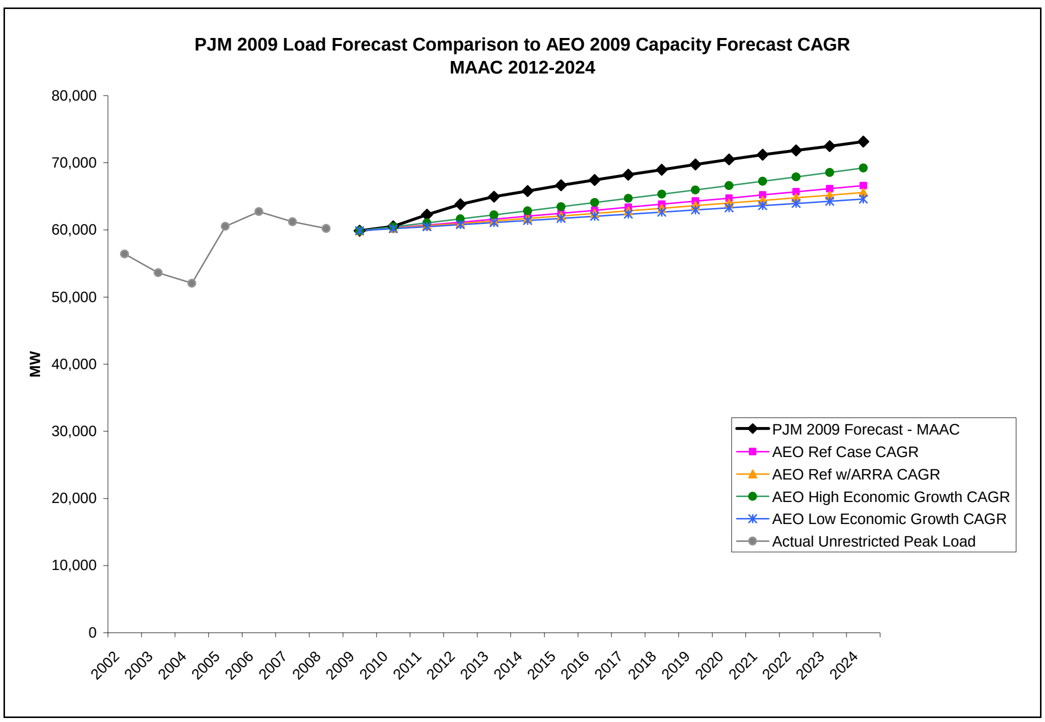
However, it is likely that peak load will grow more slowly than PJM has forecast due to a slow recovery from the current recession and the increased emphasis being placed upon energy efficiency and DR. Those factors could cause load to remain relatively flat or increase only slightly during the next decade. With no or low growth in peak load the need for new capacity could be delayed several years.

[12] PJM Manual 21, Revision 7, Appendix B

PJM currently projects that peak load will increase at a compound annual rate (CAGR) of 1.35% between 2009 and 2024.[13] However, this forecast is not consistent with other recent load forecasts from public sources. For example, EIA provides a capacity forecast for the Mid-Atlantic Area Council (MAAC) Electricity Market Module (EMM) in its Annual Energy Outlook Report (AEO).[14] The 2009 AEO updated reference case, which considers the American Recovery and Reinvestment Act of 2009 (ARRA), shows annual capacity growth of only .61% from 2009-2024.

Figure 3 compares PJM's forecast load growth for the MAAC sub-region to the growth in capacity forecast in several AEO 2009 scenarios.

Figure 3



[13] *See* PJM, 2009 Load Forecast Report, January 2009, p. 28, available at http://pjm.com/documents/~/media/documents/reports/2009-pjm-load-report.ashx (downloaded September 24, 2009).

[14] EIA, Annual Energy Outlook 2009, Supplemental Table 74, Electric Power Projections for EMM Region Mid-Atlantic Area Council, available at http://www.eia.doe.gov/oiaf/aeo/index.html (downloaded September 24, 2009).

As shown in Figure 1, the PJM load forecast CAGR is higher than all EIA forecasts. Even the CAGR in the AEO 2009 high economic growth case is lower than the PJM forecast.[15]

In fact, intervenors protesting PJM's proposed tariff changes of February 2009 argued that the macroeconomic forecast underlying the PJM load forecast greatly overestimated economic growth for the 2012 delivery year.[16] For example, James F. Wilson of LECG argued that the macroeconomic forecast used by PJM for 2012 is much higher than Aspen Publisher's Consensus of Blue Chip Financial Forecasts.[17] He noted that the PJM forecast is also higher than the average of the ten highest macroeconomic forecasts included in that consensus. Mr. Wilson found that inserting the consensus forecast into PJM's load model would reduce the forecasted load for 2012 by 3,000 MW or 2%.[18]

In the same affidavit, Mr. Wilson argued that recent PJM load forecasts have failed to capture a trend toward slowing load growth in the region that has been developing since 2005. Mr. Wilson compared the contemporaneous AEO forecast of electricity demand for the MAAC EMM to the PJM load forecast and found that the difference in growth rates translates into over 6,000 MW of peak load in 2012.[19]

In addition to macroeconomic conditions, slowing load growth is attributable to increased energy efficiency initiatives and demand response programs. The PJM load forecast only includes energy efficiency and demand resources to the extent that they have already cleared in previous RPM auctions—the impacts are not taken out of forecasted load until the program is in place and is reflected in metered load.[20] However, recent federal and state initiatives to boost investment in energy efficiency and other

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[15] The AEO 2009 high economic growth case incorporates higher population, labor force and productivity growth rates than the reference case. Due to the higher productivity gains, inflation and interest rates are lower compared to the reference case. Investment, disposable income, and industrial production are increased. Economic output is projected to increase by 3.0 percent per year between 2007 and 2030 (EIA, Assumptions to the Annual Energy Outlook, Macroeconomic Activity Module, http://www.eia.doe.gov/oiaf/aeo/assumption/macroeconomic.html).

[16] Protest Regarding Load Forecast to be used in May 2009 RPM Auction, and Affidavit of James F. Wilson, January 5, 2009, Docket Nos. ER09-412-000, EL05-1414-000, and EL05-148-000 before the Federal Energy Regulatory Commission.

[17] Aspen Publishers, Blue Chip Financial Forecasts, December 2008, and Blue Chip Economic Indicators, December 2008.

[18] Wilson Affidavit at Par. 6.

[19] Wilson Affidavit, Attachment A at Par. 7.

[20] PJM 2009 Load Forecast, Executive Summary, available at http://pjm.com/documents/reports.aspx.

conservation and demand-side measures have the potential to reduce future load below the level assumed in the RPM auction parameters.

On the federal level, the Energy Policy Acts of 2005 and 2007 set equipment and appliance efficiency standards and provided federal tax incentives for energy efficiency.[21] The American Recovery and Reinvestment Act of 2009 provided $16.8 billion for energy efficiency and renewable energy programs, including $3.2 billion in energy efficiency and conservation block grants, $5 billion in weatherization assistance, $3.1 billion to state energy plans, and $4.4 to modernize the electric grid with, among other things, demand response equipment.[22] The American Clean Energy and Security Act of 2009 (ACES), currently before the Senate, includes a combined efficiency and renewable electricity standard, support for state energy efficiency programs, smart grid advancement (including peak demand reduction goals),[23] building energy efficiency programs, lighting and appliances efficiency programs, and industrial energy efficiency programs.[24]

In addition to federal efficiency programs, all states within the PJM region have energy efficiency programs in place, including both regulations and incentive-based voluntary programs.[25] PJM states are also setting new targets for energy savings and peak demand reductions, and requiring they be met by law. For example, in Pennsylvania, Act 129 of 2008 requires all electric and gas utilities to participate in an energy efficiency and conservation program.[26] By May 2011, each electric distribution company (EDC) must reduce consumption by a minimum of 1% below the PUC's 2009-2012 peak load forecast and reduce peak demand by 4.5% of annual system peak in the 100 highest hours of demand measured against its 2007-2008 forecast. By May 2013, consumption must be decreased by 3% of the 2009-2010 forecast, and incremental increases to the peak load reduction target will be made if savings from the 2011 reduction are greater than the costs.[27] In New Jersey, the Energy Master Plan (EMP) calls for a reduction in peak load

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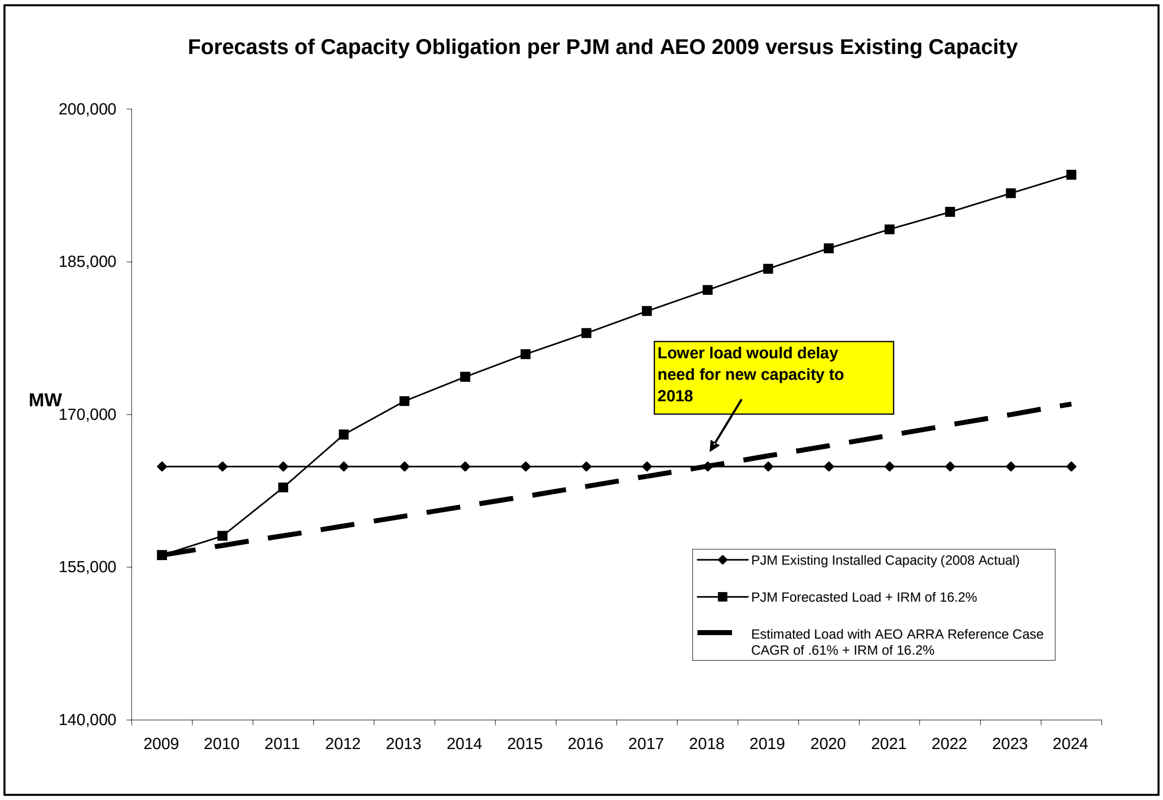
[21] *See* ACEEE, "Energy Policy Act of 2005," http://www.aceee.org/energy/national/legsttus.htm, and "2007 Federal Energy Legislation," http://www.aceee.org/energy/national/07nrgleg.htm (downloaded September 24, 2009).
[22] American Recovery and Reinvestment Act of 2009, Division A, Title IV, Energy and Water Development.
[23] American Clean Energy and Security Act of 2009, Title I.
[24] American Clean Energy and Security Act of 2009, Title II.
[25] *See* Database of State Incentives for Renewables and Efficiency (DSIRE), http://dsireusa.org/.
[26] General Assembly of Pennsylvania, House Bill No. 2200 and Act 129 of 2008, Section 1.2, available at http://www.puc.state.pa.us/electric/pdf/Act129/HB2200-Act129_Bill.pdf (downloaded September 25, 2009).
[27] *Ibid*.

of 20% below current levels and a reduction in electricity demand of 5,700 MWh by 2020.[28]

Returning to PJM's long-term forecast shown earlier in Figure 2. If peak load grows according to the AEO 2009 Updated Reference Case capacity forecast[29], rather than the PJM forecast, no new capacity of any type will be required until 2018. This delay is illustrated in Figure 4.

Figure 4



C. Transmission upgrades may enable greater utilization of existing capacity

Transmission constraints affect wholesale capacity prices by limiting the ability for surplus capacity in one LDA to be used to meet the capacity obligation in a neighboring

28 New Jersey Energy Master Plan, October 2008, available at http://www.state.nj.us/emp/ (downloaded September 25, 2009).

29 EIA, Annual Energy Outlook 2009, Updated Reference Case, Supplemental Table 74;.

LDA. In other words, they can limit the quantity of existing capacity that can bid into a BRA for a particular LDA.

According to the PJM Regional Transmission Expansion Planning (RTEP) report, major transmission upgrades are expected to be completed over the next three to four years. To the extent that these upgrades reduce various existing transmission constraints they could affect clearing prices in future BRAs by increasing the quantity of surplus capacity in one LDA that can bid into the BRAs for a neighboring LDA or LDAs.

D. New Renewable Capacity Will Be Developed To Comply With Renewable Portfolio Standards (RPS)

RPS requirements in PJM states will increase the amount of capacity additions required by law each year over the next decade. Special renewable energy fund provisions and cost recovery mechanisms as well as financial and operational penalties suggest that suppliers are likely to comply with program targets. The continuing new additions to capacity supply from RPS requirements would therefore be expected to put increasingly more downward pressure on capacity prices over the next ten to 15 years.

All states with utilities participating in the PJM capacity market, except for West Virginia and Indiana, currently have RPS. New Jersey's RPS, which is one of the most aggressive in the country, requires that of 12% electricity sales be generated from qualifying renewable sources by 2015, increasing to 22.5% by 2021.[30] In Maryland, 18% of electricity sales must be from tier 1 resources[31] plus an additional 2% from solar resources by 2022. The solar set-aside alone is projected to result in 1,500 MW of new capacity. Overall, PJM has 1,500 MW of new wind capacity under construction, and another 42,000 MW in its transmission queue.[32]

If load grows according to the AEO 2009 forecast, the capacity from renewable resources developed to comply with RPS could further delay the need for new

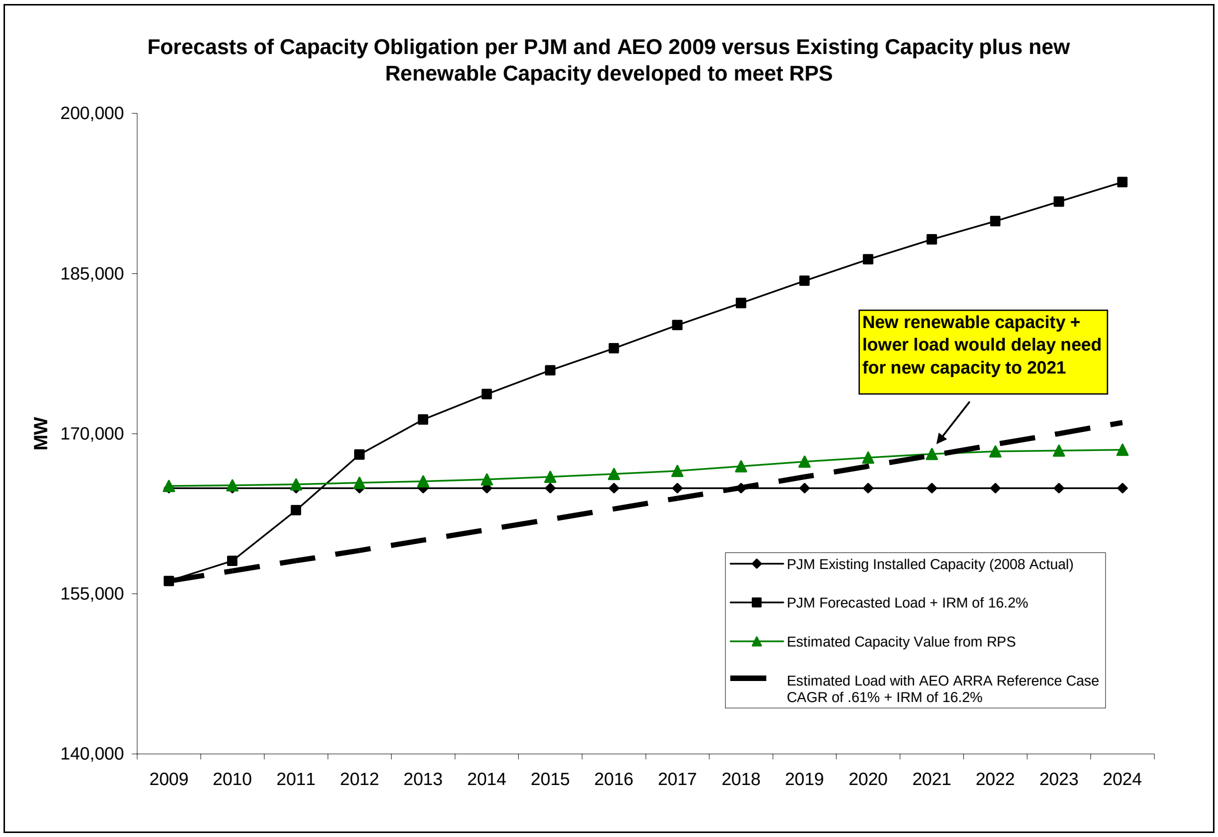
[30] Database of State Incentives for Renewables and Efficiency (DSIRE), "New Jersey," http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=1&ee=1 (downloaded September 25, 2009).

[31] Tier 1 resources include solar, wind, qualifying biomass, methane from the anaerobic decomposition of organic materials in a landfill or a waste water treatment plant, geothermal, ocean fuel cells powered by methane or biomass, and small hydroelectric plants (DSIRE, "Maryland," http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=MD05R&re=1&ee=1).

[32] PJM, Regional Transmission Expansion Plan Report (RTEP), February 27, 2009, section 2.2.4, available at http://pjm.com/documents/reports/rtep-report.aspx (downloaded September 25, 2009).

conventional capacity until 2021. The potential impact of new renewable resource capacity developed to comply with RPS requirements in states served by PJM is illustrated in Figure 5.

Figure 5



Synapse estimated the quantity of new renewable capacity developed to comply with RPS that PJM would recognize in a BRA in three steps. First we calculated the annual energy (MWh) required from new renewables in order to meet the RPS of each state each year by type of resource[33]. Then, we calculated the implied quantity of installed capacity of new renewable resources as annual energy from renewables (MWh) divided by 8,760 hours per year times the typical capacity factor for the type of resource. We assumed 30% for wind, 13% for solar and 85% for biomass. Finally, we calculated the quantity of new renewable capacity that PJM would recognize in a BRA by multiplying the installed capacity from step two by the "intermittent resource capacity

[33] Database of State Incentives for Renewables and Efficiency (DSIRE), https://dsireusa.org

factors" that PJM has established for capacity planning purposes[34]. The intermittent resource capacity factors for wind and solar resources are 13% and 38% respectively. Over this period, the estimated quantity of capacity from RPS resources grows at a CAGR of 19%.

Our analyses indicate that substantial new RPS capacity will be available in PJM, even if the RPM market continues to clear at a low price, because capacity from renewables is driven by RPS requirements rather than compensation from the RPM. All of the PJM state RPS policies include cost recovery mechanisms and special funding to cover the costs of compliance. Each of the PJM RPS programs include penalty-supported funds including Alternative Compliance Payments (ACP) and Solar Alternative Compliance Payments (SACP) that also serve as de facto cost caps. Each of the states also has special public benefits funds in place to support development of renewable energy sources. These funds are generally supported by surcharges on customer's electricity rates.[35] In Maryland, if an electricity supplier purchases solar renewable energy credits (REC) directly from a renewable on-site generator to meet the solar set-aside requirement, the duration of the contract term for the solar RECs may not be less than 15 years.[36]

In all states ACPs and SACPs serve as both cost caps and penalties for non-compliance with the RPS. Other penalties include suspension or revocation of the electric power supplier's license, disallowance of cost recovery, and prohibition of accepting new customers (as in New Jersey and Delaware).[37] In Maryland, shortfall payments are reduced on a sliding scale through 2023. These penalties, along with cost recovery mechanisms and special funding programs, help ensure that RPS targets will be met and that capacity growth from renewable resources in PJM will be sustained through the next decade.

[34] PJM 2009 Load Forecast Report; PJM Manual 21, Revision 7, Appendix B.
[35] Union of Concerned Scientists, Renewable Electricity Standards Toolkit, available at http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?template=main (downloaded September 25, 2009).
[36] *Ibid.*
[37] *Ibid.*

4. Conclusion

Wholesale capacity prices will only approximate net CONE of a gas-fired CT if specific conditions are met. These conditions are that peak load will grow, new capacity will have to be built to meet the new load and that gas-fired CTs will be the least cost sources of that new capacity. Our analyses of market fundamentals suggests that actual market conditions over the coming decade are likely to be different than most of these underlying assumptions due to a combination of low load growth, transmission projects that reduce constraints on greater utilization of existing capacity increases supply and new renewable capacity developed to comply with RPS requirements. Therefore, capacity prices are likely to be considerably lower than net CONE based on a gas-fired CT. Future market prices could remain in the range of BRA results for 2011 and 2012, e.g. $110 to $133 per Mw-day ($40 to $46 per kw-yr) or lower rather than the $171 to $176 per Mw-day ($60 to $64 per kw-yr) suggested by net CONE.

Table 1. Utility service territories by PJM LDA

Local Deliverability Area (LDA)[2]	Utility Zone Acronym	Utility Zone Full NAME[1]	State(s)[1]
EMAAC	AE	Atlantic Electric (part of PEPCO Holdings, Inc.)	NJ
	DPL	Delmarva Power & Light	DE, MD, VA
	JCPL	Jersey Central Power & Light	NJ
	PECO	PECO Energy	PA
	PS	Public Service Electric & Gas	NJ
	RECO	Rockland Electric (East)	NJ
SWMAAC	BGE	Baltimore Gas & Electric	MD
	PEPCO	Potomac Electric Power (part of Pepco Holdings, Inc.)	MD
WMAAC	METED	Metropolitan Edison	PA
	PENLC	Pennsylvania Electric	PA
	PL (incl. UGI)	PPL Electric Utilities (subzone of PLGroup)	PA
DPL South	DPL	Delmarva Power & Light	DE, MD, VA
Dominion	DOM	Dominion	VA, NC
PSNORTH	PSNORTH	Public Service Electric & Gas	NJ
Western PJM	AEP (incl. Non-Zone Load)	American Electric Power	KY (KP) WV (APP) OH (CSP, OP) IN, MI (INM)
	APS	Allegheny Power	PA, OH (West Penn, Potomac Edison) WV (Monongahela, Potomac Edison) MD (Potomac Edison) VA (Potomac Edison, Monongahela)
	COMED	Commonwealth Edison	IL
	DAYTON	Dayton Power & Light	OH
	DLCO/DQE	Duquesne Lighting Company	PA

Table 2. Net CONE from BRA auctions for Planning Years 2007 - 2012[38]

LDA	Planning Period						AVERAGE - 2010 to 2012	
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	$/MW-day	$/kw-yr
RTO	171.87	172.25	172.27	174.29	171.40	276.09	207.26	75.65
APS	171.87	172.25	139.69	174.29	171.40	276.09	207.26	75.65
MAAC	**171.87**	**172.25**	**148.81**	**131.87**	**171.40**	**176.44**	**159.90**	**58.36**
EMAAC	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
SWMAAC	158.68	159.02	159.04	112.77	171.40	176.44	153.54	56.04
DPL South	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
DPL	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
PS North	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
PS	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75

38 BRA Planning Parameters and Results from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item07 (downloaded September 25, 2009).

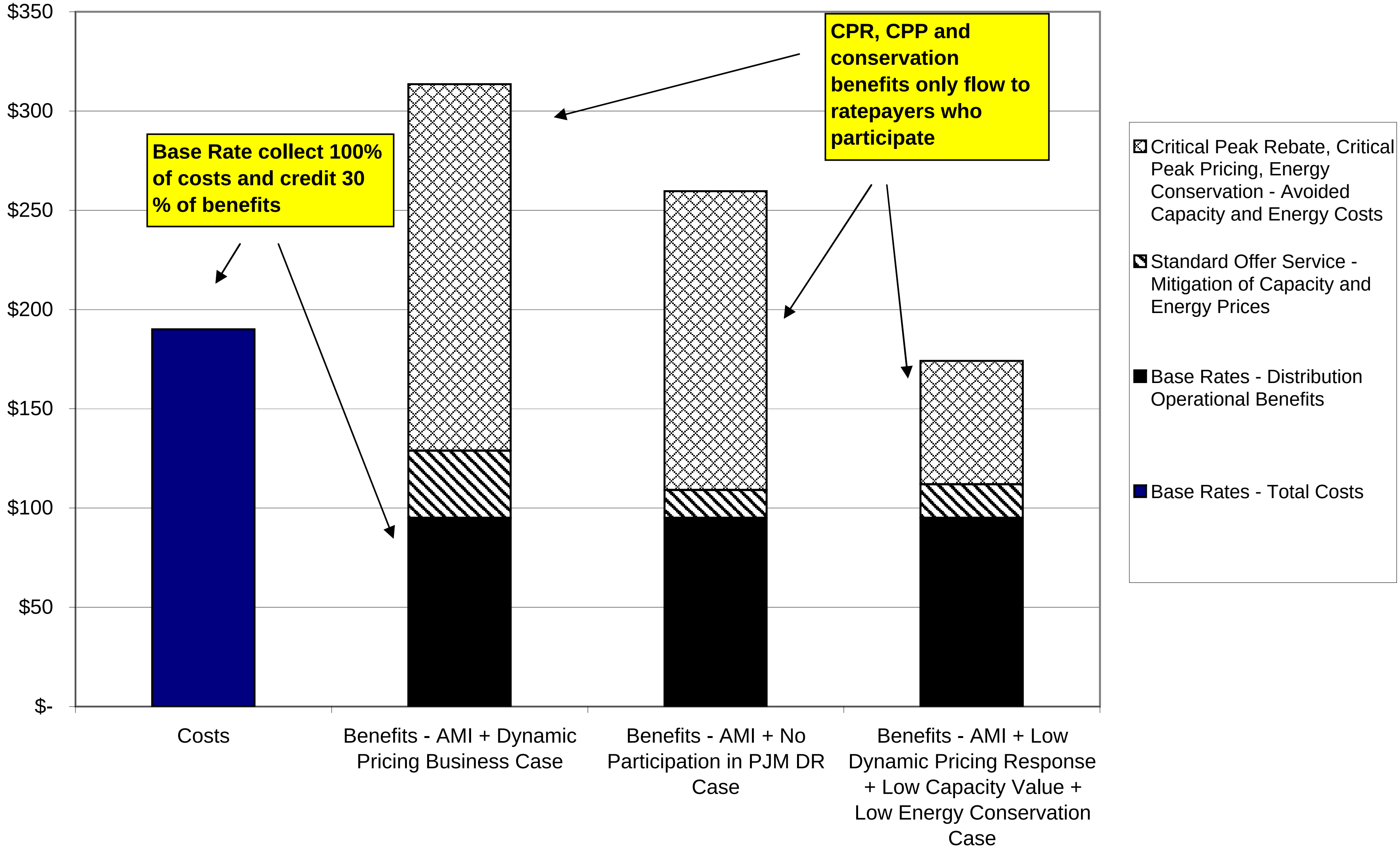
Table 3. Market Prices from BRA auctions for Planning Years 2007 - 2012

LDA	Planning Period						AVERAGE - 2010 to 2012		
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	$/MW-day	$/kw-yr	% net CONE
RTO	40.80	40.80	102.04	174.29	110.00	16.46	100.25	36.59	48%
APS	40.80	40.80	191.32	174.29	110.00	16.46	100.25	36.59	48%
MAAC	**40.80**	**40.80**	**191.32**	**174.29**	**110.00**	**133.37**	**139.22**	**50.82**	**87%**
EMAAC	197.67	197.67	191.32	174.29	110.00	139.73	141.34	51.59	82%
SWMAAC	188.54	188.54	237.33	174.29	110.00	133.37	139.22	50.82	91%
DPL South	197.67	197.67	191.32	186.12	110.00	222.3	172.81	63.07	101%
DPL	197.67	197.67	191.32	186.12	110.00	139.73	145.28	53.03	85%
PS North	197.67	197.67	191.32	174.29	110.00	185.00	156.43	57.10	91%
PS	197.67	197.67	191.32	174.29	110.00	139.73	141.34	51.59	82%

Table 4. Market Prices as % of Net Cone from BRA auctions for Planning Years 2007 - 2012

LDA	Planning Period						AVERAGE - 2010 to 2012
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	
RTO	24%	24%	59%	100%	64%	6%	48%
APS	24%	24%	137%	100%	64%	6%	48%
MAAC	**24%**	**24%**	**129%**	**132%**	**64%**	**76%**	**87%**
EMAAC	133%	133%	129%	132%	64%	66%	82%
SWMAAC	119%	119%	149%	155%	64%	76%	91%
DPL South	133%	133%	129%	141%	64%	105%	101%
DPL	133%	133%	129%	141%	64%	66%	85%
PS North	133%	133%	129%	132%	64%	87%	91%
PS	133%	133%	129%	132%	64%	66%	82%

Pepco Advanced Meter Infrastructure - Proposed Mechanisms for Cost Recovery and Crediting Benefits



Pepco AMI - Summary of Projected Total Costs and Benefits

Business Case and Low Electricity Supply Benefit Cases

Costs and Benefits	Proposed Mechanism	Categories of Costs and Benefits	Business Case (1)			No Participation in PJM DR Case (2)			Low Dynamic Pricing Response + low Capacity Value + low Energy Conservation Case (2)		
				PVRR millions	% of Benefits		PVRR millions	% of Benefits		PVRR millions	% of Benefits
Costs	**Base Rates**	**Total Costs**	$	190		$	190		$	190	
Benefits											
	Base Rates	**Distribution Operational Benefits**		95			95			95	
		Sub-total Base rates	$	95	30%				$	95	55%
	Standard Offer Service	**Mitigation of Capacity and Energy Prices**	$	34		$	14		$	17	
		Sub-total SOS	$	34	11%	$	14	9%	$	17	10%
	Critical Peak Rebate, Critical Peak Pricing, Energy Conservation	**Avoided Capacity Costs**	$	121		$	87		$	30	
		Avoided Energy Costs	$	64		$	64		$	32	
		Sub-total PTR	$	185	59%	$	151	91%	$	62	36%
			$	-	0%	$	-		$	-	0%
		Total Benefits		314	100%		165	100%		174	100%

Source: Workbook A to Exhibits___JRH-4, 5 and 7

Exhibit___(JRH-8)