ATTACHMENT A

Advanced Metering Business Case Including Demand Side Management Benefits

Report for Delaware

Before The Delaware Public Service Commission – Docket No. 07-28

August 29, 2007

Executive Overview and Conclusion

Overview

The Delaware Public Service Commission (the "DPSC" or "the Commission") issued Order No. 7154 initiating this proceeding, Docket No. 07-28 on March 20, 2007. There have been several workshop meetings and discussions among the parties with the development and submission of this initial AMI business case as the next step in the process. As demonstrated in the following report, the AMI business case for Delmarva is justified by the operational benefits and the demand response benefits to the Company and our customers. Pepco Holdings, Inc. ("PHI"), the parent company of Delmarva Power & Light Company ("Delmarva" or "the Company"), Pepco and ACE has proposed their Blueprint for the Future (see February 6, 2007) that addresses two important local and national challenges: the rising cost of energy and the impact of energy use on the environment.

As regulated public utilities, we are uniquely positioned to play a leadership role in helping to meet both of these challenges. The Blueprint builds on the work we already have begun through Utility of the Future and other initiatives. In summary, Delmarva's Blueprint focuses on implementing advanced technologies and energy efficiency programs to improve service to our customers and enable them to manage their energy use and costs. If we can provide tools for our customers to control their energy use we can make a sizeable contribution to meeting the nation's energy and environmental challenges and at the same time help our customers keep their electric and natural gas bills as low as possible.

The Blueprint for the Future charts the course we believe we must follow to give our customers what they tell us they want: reasonable and stable energy costs; responsive customer service; power reliability; and environmental stewardship.

Delmarva is deploying a number of innovative technologies. Some, such as the automated distribution system, will help to improve reliability and workforce productivity, while others, including an Advanced Metering Infrastructure ("AMI"), will enable our customers to monitor and control their electricity use, reduce their energy costs and enable their participation in innovative rate options. Here are some examples of what's planned:

Demand Side Management (DSM) Programs

Delmarva plans on working closely with the SEU (Sustainable Energy Utility) to assure a portfolio of energy efficiency programs in the state that will work together to benefit our customers. Our primary focus will be on the demand response programs, as they are closely tied to the technology investments of the company. We will, however, in cooperation with the SEU develop appropriate energy efficiency programs to compliment, and supplement the SEU. A special effort with our consumer council will be taken to develop programs geared toward low-income customers who can also benefit from the advantage of this technology.

Automated Metering Infrastructure (AMI)

We will work collaboratively with the Commission to phase in the installation of an AMI system in the homes of Delmarva gas and electric customers. The AMI system will provide detailed usage data to our customers, our electricity suppliers and to the Company. The system will not only enable customers to track and modify their electric use, but it will also help us make improvements to customer reliability, outage management, and billing accuracy and timeliness.

Environmental Considerations

The deployment of an AMI System will support innovative customer rate options that help to support plug-in vehicles and small-scale renewable generators. The SEU has indicated that one of the primary benefits of this technology, to support their efforts, will be the ability to better pinpoint areas where distributed generation will provide overall system benefits. As part of PHI's multifaceted environmental initiatives, PHI is also laying the groundwork to transform its 2,000-vehicle fleet to more environmentally friendly technologies. We are already using Biodiesel at PHI fueling sites; we have replaced a number of our fleet vehicles with hybrid vehicles; and we are collaborating with the Electric Power Research Institute ("EPRI") on a project to demonstrate plug-in gasoline/electric vehicles.

In addition to these programs, the demand response efforts enabled by this technology will allow for reduced dependence on peaking sources of generation, while the technology will improve our access to greener sources of supply.

Delmarva's Blueprint for the Future Plan

Over the past several years the rising cost of energy across the nation has adversely affected Delmarva's customers, who are often left with limited ability to lower their energy use to reduce the added burden of higher energy costs. Delmarva has communicated with its customers and attempted to provide them with options to more efficiently manage their energy use. Last year PHI and Delmarva launched the "Energy Know How" campaign, which was recently re-intoduced under the name of "My Account". PHI and Delmarva invested over $1,000,000 to implement state of the art energy auditing software. This investment now enables Delmarva's residential customers to go on the internet and view data about their monthly bills to better understand how they use energy and what changes might reduce their overall costs. This was a good first step, but much more needs to be done to allow customers to further control their bills. The Blueprint is Delmarva's proposal to take Delaware customers into the future.

This filing is the next step in answering customer concerns by giving customers more robust energy efficiency tools to reduce electricity consumption and demand response programs that will help to change when customers use energy in an effort to reduce peak demands, driving total electricity costs down for the state. The data and communications capabilities inherent in the advanced metering proposal that Delmarva has set forth will provide a platform upon which to build a number of programs aimed at managing overall energy costs. Delmarva envisions that ultimately the new technology will even have customers' appliances receive and react to real time energy prices. Some of these technologies will take time and need to be tested, but many are ready to roll out immediately.

Components of Delmarva PHI AMI business case

The Business Case is comprised of four major components: Energy Delivery Benefits from AMI, Customer Savings from Reductions in Peak Loads, Cost to Deploy, and Accelerated Depreciation. The information contained in each of these components is further described below and detailed in the body of this report.

1 - Energy Delivery Benefits from AMI

Savings in operating costs captures O&M and capital savings expected to be realized once the AMI is implemented. These savings or benefits will include:

- Meter Related Benefits
- Customer Contact Benefits
- Asset Optimization Benefits
- Additional Benefits

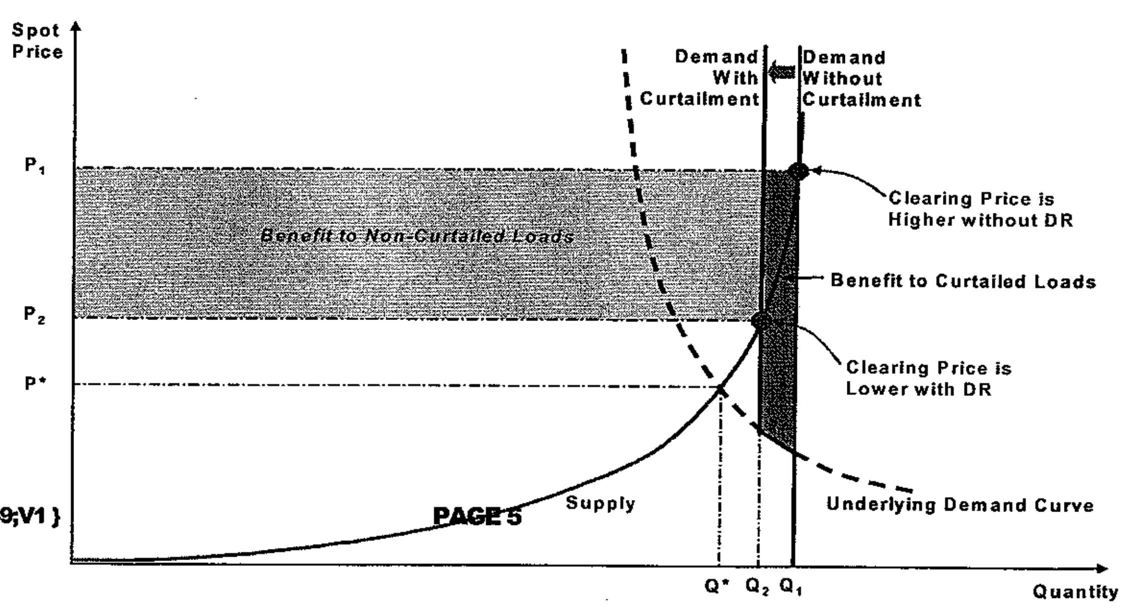
2 - Customer Savings from Reductions in Peak Loads

This analysis estimates the cost savings Delmarva's DSM programs are likely to achieve by (1) reducing the need for capacity, energy, and ancillary services (i.e., the "resource cost savings"); and (2) depressing market prices for energy and capacity by reducing demand. **The benefits are estimated consistently with the January, 2007 *Brattle* Study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), with several additional analytical elements.**

The resource cost savings reflects the fact that every MW reduction in peak load lessens the need for physical capacity, which customers pay for through the load serving entities' payments. Similarly, every MWh reduction in consumption lessens the quantity of generation that customers must buy during peak periods with very high prices.

In general, the market price impacts reflect the fact that even a small reduction in demand during tight market conditions lowers the market price for energy, thus lowering the cost of energy for all customers (not just those curtailing load), as illustrated in Figure 1. Similarly, reducing the peak demand lowers the demand for capacity and thus reduces market prices for capacity, which affects all customers.

Figure 1: The *Brattle*-PJM-MADRI Study Showed How Even Small Changes in Demand Can Lead to Large Changes in Prices and Customer Benefits



3 - Cost to Deploy

Cost to Deploy includes the cost of the capital investments associated with building out the AMI system. Deployment costs included are; meters and installation, communications network infrastructure and installation and the associated information technology systems and integration, including the meter data management system (MDMS). Also included in the Cost to Deploy are the Incremental operating cost for the AMI system. Incremental operating costs include O&M expenses associated with operating the AMI. This includes; MDMS Software, Maintenance and license fees, AMI network management software maintenance and license fees, hardware lease expense for application and storage servers and expenses related to the communications network infrastructure.

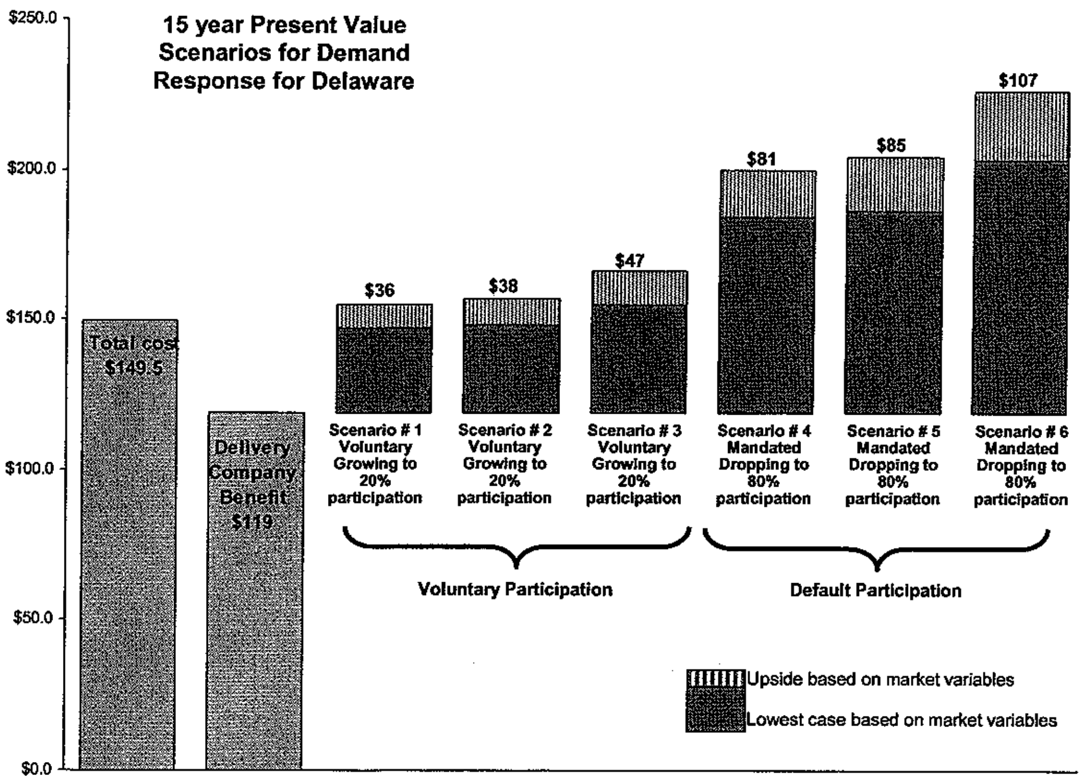
4 - Accelerated Depreciation

The deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. These impacts have been reflected in the analysis. Depreciation calculations may be updated due to pending Federal legislation.

Conclusions

The Delmarva AMI business case is justified by the operational benefits and the demand response benefits to the Company and our customers. The estimates for demand response benefits from the AMI deployment, over a 15 year period, is $36 million estimated using the most conservative of scenarios. Coupled with operational savings of $119 million, results in a positive $5.5 million Present Value Revenue Requirement (PVRR) over the same period. Using the best case for Demand Response (DR) benefits, results in a positive $76.5 PVRR.

Figure 2



In order to arrive at this conclusion, PHI contracted with the Brattle Group to develop six scenarios of customer and supplier response to AMI. Figure 2 above, shows the relationship of each of these six scenarios compared to the PVRR Cost and Benefit. The two cases, upside and low, for each scenario are the result of sensitivities associated with variations in market conditions. These conditions include possible fluctuations in fuel prices, and or high peak years (usually weather driven). Following PHI's example, if the other energy distributors in PJM deploy AMI, the benefit to Delaware customers is estimated to be as high as $393.5 million.

The results of this analysis yields two key conclusions: (1) AMI is a net positive investment even in the lowest value scenario; (2) the benefits from AMI-enabled DR will be more than twice as large if dynamic pricing is the default rate structure than if it is merely an option that customers can elect.

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Figure 3 below summarizes the PVRR for Delmarva Delaware.

Figure 3

Line	AMI System Components	Initial Deployment Costs Only $ in ('000s) Electric	Gas	Combined
1	Meters, including Installation Cost	$ 42,783	$ 9,195	$ 51,978
2	Communications Network, including Installation Cost	$ 21,616	$ -	$ 21,616
3	AMI Network Management System and Meter Data Management Sy	$ 4,417	$ 1,828	$ 6,245
4	Contingency	$ 4,680	$ 1,543	$ 6,223
	Total Capital Investment	$ 73,496	$ 12,566	$ 86,062

Line	AMI System Incremental Cost to Operate	Annual Estimated Costs After Deployment $ in ('000s) Electric	Gas	Combined
5	MDMS Software Maintenance & License Fees	$ 62	$ 26	$ 88
6	MDMS Hardware Leasing	$ 168	$ 70	$ 238
7	AMI Network Management System O&M	$ 196	$ 81	$ 277
8	Communications Network Infrastructure O&M	$ 273	$ -	$ 273
	Total Incremental Cost to Operate	$ 699	$ 177	$ 876

15 Year Revenue Requirement of Total Costs	***$149.5 million***

Line	Benefit Category	In Projected 2008 Dollars ('000s) Electric	Gas	Combined
1	Eliminate Manual Meter Reading Costs	$ 3,564	$ 1,157	$ 4,721
2	Implement Remote Turn-on/Turn-off Functionality	$ 1,592	$ -	$ 1,592
3	Improve Billing Activities	$ 484	$ 186	$ 670
4	Reduce Off-Cycle Meter Reading Labor Costs	$ 372	$ 57	$ 429
5	Asset Optimization	$ 219	$ -	$ 219
6	Reduce Expenses Related to Theft of Service	$ 88	$ 36	$ 124
7	Eliminate Hardware, Software, Maintenance and Operations Cost	$ 75	$ 30	$ 105
8	Reduce Volume of Customer Call Types Related to Metering	$ 29	$ 12	$ 41
9	Reduced Complaint Handling	$ 24	$ 10	$ 34
	Total Annual Operating Benefits	$ 6,447	$ 1,488	$ 7,935

15 Year Revenue Requirement of Operating Benefits	***$119 million***

Summary of Cost and Benefits for Delmarva Delaware

Business Case Report Details

Organization of this Report

For the preparation of this report, PHI gathered information from both internal and external subject matter experts, including IBM and the Brattle Group, as well as from other utilities across the country. While this report represents the current state of thinking for AMI deployment, information within this report is still subject to change. Therefore this report should be considered a living document that will be consistently updated as additional information becomes available. Specific points to remember are:

- AMI Capital Costs reflected in this report are estimates. Once PHI secures an AMI Vendor(s), the final Capital Cost numbers will be updated.
- This Business Case considers the deployment of an AMI system throughout all PHI jurisdictions.
- Cost and Benefit estimates are realistic yet conservative in order to assure a high probability of achievement.
- While many benefits are immediately available as the AMI System is deployed, timing of the full benefits associated with an AMI system is assumed to begin following the complete deployment.
- Business Case Financial Assumptions:
  - 15 year Present Value Revenue Requirement model, with multiple jurisdictions modeled
  - Meter Deployment assumed 100% of Delmarva DE meters in 2009:
  - Meter growth is assumed to be 1% per year
  - 3% labor and expense annual escalation rate
  - Cost of Capital
    - Delmarva-DE Elec: 6.23%
    - Delmarva-DE Gas: 6.55%
  - Tax rate 40.4% for all jurisdictions
  - Depreciation:

- New meter and meter communications equipment - 15 yrs
- Existing meter and equipment – 5 years
- IT Capital Cost - 5 years

Energy Delivery Benefits from AMI

This section of the report describes the estimated benefits[1] that could be realized by Delmarva's electric and gas delivery businesses through deployment of the advanced metering infrastructure system and the associated meter data management system. Typically, the full value realized from the benefits is expected to occur after full deployment of the AMI system. The Company proposes to use these quantified benefits to help offset the costs associated with AMI and MDMS in the proposed AMI Adjustment Mechanism as described in the Appendix to the February 6, 2007 Blueprint for the Future filing with the Delaware Public Service Commission. Figure 4 below summarizes the annualized benefits and under the Figure are more detailed descriptions of each benefit.

Figure 4 (In $ Millions)

		In Projected 2008 Dollars			Benefit Dollars as a % of Total		
Line	Benefit Category	Delmarva DE-Elec	Delmarva DE-Gas	Delmarva Combined	Delmarva DE-Elec	Delmarva DE-Gas	Delmarva Combined
1	Eliminate Manual Meter Reading Costs	$ 3,564	$ 1,157	$ 4,721	55.3%	77.8%	59.5%
2	Implement Remote Turn-on/Turn-off Functionality	$ 1,592	$ -	$ 1,592	24.7%	0.0%	20.1%
3	Improve Billing Activities	$ 484	$ 186	$ 670	7.5%	12.5%	8.4%
4	Reduce Off-Cycle Meter Reading Labor Costs	$ 372	$ 57	$ 429	5.8%	3.8%	5.4%
5	Asset Optimization	$ 219	$ -	$ 219	3.4%	0.0%	2.8%
6	Reduce Expenses Related to Theft of Service	$ 88	$ 36	$ 124	1.4%	2.4%	1.6%
7	Eliminate Hardware, Software, Maintenance and Operations Cost	$ 75	$ 30	$ 105	1.2%	2.0%	1.3%
8	Reduce Volume of Customer Calls Related to Metering	$ 29	$ 12	$ 41	0.4%	0.8%	0.5%
9	Reduced Complaint Handling	$ 24	$ 10	$ 34	0.4%	0.7%	0.4%
10	Total	$ 6,447	$ 1,488	$ 7,935	100.0%	100.0%	100.0%

1) Eliminate Manual Meter Reading Costs

This is the largest operational benefit expected to be realized after full deployment of the AMI system. As of June 2007, Delmarva employed a total of 55 meter readers and supervisory personnel in Delaware, all of which would no longer be needed to perform their present functions with full deployment of AMI. As of the date of this report, which is prior to

[1]The quantification of these benefits will change as Delmarva conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated value of the benefits.

development of the request for proposal for the procurement of the AMI system, the Company expects to design and configure its AMI such that all Delaware customers will have meters that are reachable by the AMI's communications network infrastructure. The elimination of the need to manually read meters would result in annualized O&M expense savings of $4.7 million (expressed in projected 2008 dollars). The O&M expense savings estimate is based on the actual 2007 salaries of the 55 people with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The savings also include 2007 budgeted overtime, vehicle and miscellaneous expenses associated with the manual meter reading.

The savings were allocated between electric and gas service using a three step approach. First, the meter reading personnel working in the Delaware portions of Delmarva's New Castle and Bay regions were specifically identified with the Bay region costs assigned completely to the electric service. The New Castle region costs were then allocated between electric and gas service using the allocation factor the Company currently uses in its accounting practices to allocate the meter reading costs between electric and gas service. This allocation factor was updated in late 2006 and is presented in the Figure below. Finally, the portion of the New Castle region's expenses allocated to the electric service were added to the specifically identified Bay region expenses in order to derive the total electric savings for Delaware.

Figure 5 below is the allocation factor for New Castle region's meter reading in the Christiana operating center, which is entirely in the state of Delaware:

Figure 5

Meter Reading Analysis :

Description	Source	Number	% of Total	Gas %	Gas % of Total
Accounts read in Christiana Region	November 2006 Report BCR074 [C3]	341,757			
Combined Gas& Electric Premise	DB2 Extract from C3 November 2006	110,489	47.8%	50.0%	23.9%
Total Premises Visited	Total less combined	**231,268**			
Gas customer accounts	Monthly SAP 661 - November 2006	120,781			
Combined Gas& Electric Premise	DB2 Extract from C3 November 2006	110,489			
Gas Only Premise	Gas cust less G&E combined	10,292	4.5%	100.0%	4.5%
Electric Christiana Customer accounts	Total Accounts less Gas Accounts	220,976			
Combined Gas& Electric Premise	B. Dodge - C3 November 2006	110,489			
Electric Only Premise	Chris. Elec. Cust less G&E comb	110,487	47.8%	0.0%	0.0%
		Gas Delivery Meter Reading %			**28.3%**

The initial year was assumed to be 2008 therefore the 2007 O&M expense savings as described above were escalated three percent (3%) to account for expected wage and inflation increases. The three percent escalation factor was also used to grow the estimated annualized savings in the remaining years of the revenue requirements schedule

2) Implement Remote Turn-on/Turn-off Functionality

Delmarva's current assumption is that a switch will be available inside the meters that will permit the Company to remotely connect and disconnect 200 AMP and less electric service. This assumption is consistent with AMI recent experiences and plans of other utilities and requirements of other state public service commissions. This type of switch would not be used for the gas type of service therefore gas connections and disconnections would continue to be done using the existing work processes.

The estimated savings associated with this benefit is comprised of two components. First, there would be savings from avoiding field visits to customers' premises conducted at the customers' requests to turn-on or turn-off electric service. Based on a review of 2006 data from Delmarva's accounting system, there were approximately 12,000 labor hours used for residential turn-on and turn-off orders. This translates into approximately seven to eight (7 to 8) Full Time Equivalents (FTE). The Full Time Equivalent employee concept was used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $0.8 million (expressed in projected 2008 dollars).

The second component of the savings would come from avoiding field visits to customers' premises for collection reasons, both the initial cut/collect field visit and the reconnection field visit, if such a reconnection visit was requested by the customer. Based in a review of 2006 data from the Company's accounting system, there were approximately 10,000 labor hours used for residential field collection and reconnection visits. This translates into approximately six to seven (6 to 7) full time equivalents (FTE). Full time equivalents were used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $0.7 million (expressed in projected 2008 dollars).

Remote turn on/turn off capability will benefit all customers, especially those subject to disconnection for non-payment. Currently the Delaware tariff specifies that if a disconnected customer requests to be reconnected, then a charge of $75.00 to $175.00 is required (depending on the time of day). With AMI's remote connection and disconnection functionality, this charge could be significantly reduced (estimated in the range of $5 to $10). The reconnection could be accomplished remotely from Delmarva's offices, after the customer calls the Company to verify payment, rather than dispatching a person to the customer's premise. This reduces the financial burden on those having difficulty paying their bills. This method is also safer for employees who perform this type of work.

3) Improve Billing Activities

With the deployment of AMI, the Company expects to significantly reduce the volume of exceptions that it currently addresses in its billing department. These exceptions include such transactions as estimated bills, consecutive estimations, high/low consumption and other checks. Delmarva and Atlantic City Electric Company (ACE) operate their billing department on an integrated basis using the same customer information system (CIS). As of June 2007, Delmarva and ACE employed a total of 28 billing analyst and supervisory personnel to handle the exceptions work volume. For this benefit, Delmarva assumed 90% of the work performed by these personnel would be eliminated with full deployment of AMI which translates into the elimination of the cost of 25 full time equivalents. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees (analysts and supervisors) doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $1.9 million (expressed in projected 2008 dollars) for all of Delmarva and ACE combined. Note that if less than 90% of the exception volume is ultimately realized, then the savings estimate will be adjusted accordingly.

The savings were allocated between the Company's electric and gas types of service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor. This allocation factor is presented in the Figure below.

Figure 6

Allocation based on 2007 Budgeted Customer Counts			
ACE	543,437	47%	$ 849,577
Delmarva-DE-Electric	296,159	26%	$ 469,979
Delmarva-DE-Gas	119,403	10%	$ 180,761
Delmarva-MD	200,350	17%	$ 307,294
Combined	1,159,350	100%	$ 1,807,611

The 2007 dollars in Figure 6 above were escalated by three percent (3%) to account for 2008 estimated wage increases which increases the dollars in Figure 6 from $1.8 million to $1.9 million.

4) Reduce Off-Cycle Meter Reading Labor Costs

Delmarva typically uses meter readers, meter technicians, service persons and trouble persons to obtain meter readings outside of the normally scheduled meter reading routes for a variety of reasons. These reasons include when a customer moves out of a premise and a new customer moves in shortly thereafter and asks the billing department or the call center to check a reading in the field. With the full deployment of AMI, these "check reads" can be obtained remotely from Delmarva's offices eliminating the need for a field visit. When computing the estimated savings associated with this benefit, any costs from meter readers were excluded. Those savings are included in meter reading benefit described above.

Based on a review of 2006 data from the Company's accounting system, there were approximately 4,700 labor hours used for electric meter "check reads" and about 700 labor hours used for gas meter "check reads". This translates into approximately three to four (3 to 4) full time equivalents (FTE) for electric meters and approximately one half of a FTE for gas meters. Full time equivalents were used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit above. This portion of the savings amounted to an estimated annualized $0.4 million (expressed in projected 2008 dollars).

5) Asset Optimization

AMI deployment will improve the quality of customer outage status and hence will reduce the field restoration efforts associated with "false" power outages. Delmarva-DE experiences approximately 1000 power outage calls annually where upon arrival at the customer locations, the emergency response team finds that there is no electric service problem from Delmarva but the problem is on the customer side of the meter or in the house. Similarly, during storms, the Company responds to 500 to 600 outage requests annually which have been already restored previously but not recorded in the Company outage management system. AMI capabilities will eliminate these unproductive trips as well as reduce the number of Call Center calls and will result in estimated savings of $179,000. AMI deployment also will improve Delmarva's asset management program and will result in accurate sizing of transformers and fuses. This will result in reduced outages and is expected to reduce number of field trips by 250 annually. It will also reduce field trips associated with special load readings at substations. The savings associated with this benefit is $ 40,000 annually.

6) Reduce Expenses Related to Theft of Service

Delmarva currently uses an outside firm to analyze commercial account data to provide internal field investigators with selected accounts that may be experiencing tampering, energy diversion or some sort of metering problem. Based on discussions with MDMS vendors, it appears that with data coming from the AMI system coupled with analytical capabilities of the MDMS, Delmarva will be better equipped to conduct these types of analyses on its own and could therefore eliminate this contractual relationship. The savings were allocated between the Delmarva electric and gas service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

7) Eliminate Hardware, Software, Maintenance and Operations Cost

PHI currently pays maintenance fees on its existing hand held metering reading devices and also employs two employees to operate and maintain the devices and associated data. With the deployment of AMI, these costs would be eliminated. The O&M expense savings for the two employees is based on the actual 2007 salaries of the two people with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The costs and savings were allocated between the Delmarva's electric and gas service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

8) Reduce Volume of Call Types Related to Metering

PHI operates its call centers for Delmarva and ACE on an integrated basis using the same customer information system (CIS). In 2005 and 2006, PHI received about 40,000 customer calls related to metering. If this associated call volume were reduced after the full deployment, the call center could save two full time equivalents. The O&M expense savings for the FTEs is based on the actual salary for a customer service representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits multiplied by two FTEs. The costs and savings were allocated between Delmarva's electric and gas service in Delaware, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

9) Reduced Complaint Handling

PHI operates its complaint handling group for Delmarva and ACE on an integrated basis using the same customer information system (CIS). For this benefit, PHI is assuming the data from AMI will, over time, contribute to fewer complaints and that the company representatives may be able to more quickly resolve complaints. The current assumption is that the complaint handling group may be able to reduce one full time equivalent. The O&M expense savings for the one FTE is based on the actual salary for a company representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The costs and savings were allocated between Delmarva's electric and gas service in Delaware, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

Customer Savings from Reductions in Peak Loads

The Brattle Group was retained by PHI to estimate the value to customers of load reductions resulting from PHI's proposed investments in demand-side management (DSM) initiatives, including energy efficiency, direct load control, and deployment of advanced metering infrastructure. *Brattle*'s analysis involves two major components: first, determining the magnitude of load reductions that are likely to be achieved; and second, estimating the customer value of such load reductions.

1) Estimated Load Reductions

Load reductions associated with PHI's proposed programs involving energy efficiency and AMI-enabled direct load control are taken directly from PHI's most recent Blueprint Filing for its DSM programs. Load reductions associated with AMI-enabled critical peak pricing (CPP) programs were estimated using the PRISM model, which is based on empirical data from the California Statewide Pricing Pilot and is calibrated to the load characteristics of residential and small C&I customers in Delmarva Delaware. Assuming a CPP program similar to PEPCO DC's current CPP pilot becomes the default rate structure with 80% of eligible customers participating, the resulting load reductions would likely be quite substantial, as shown in Figure 7a. The load reductions would be less substantial if participation were voluntary, as shown in Figure 7b.

Figure 7a - Estimated Peak Load Reductions for Delaware from PHI's Initiatives, Assuming CPP is the Default Rate Structure (MW)

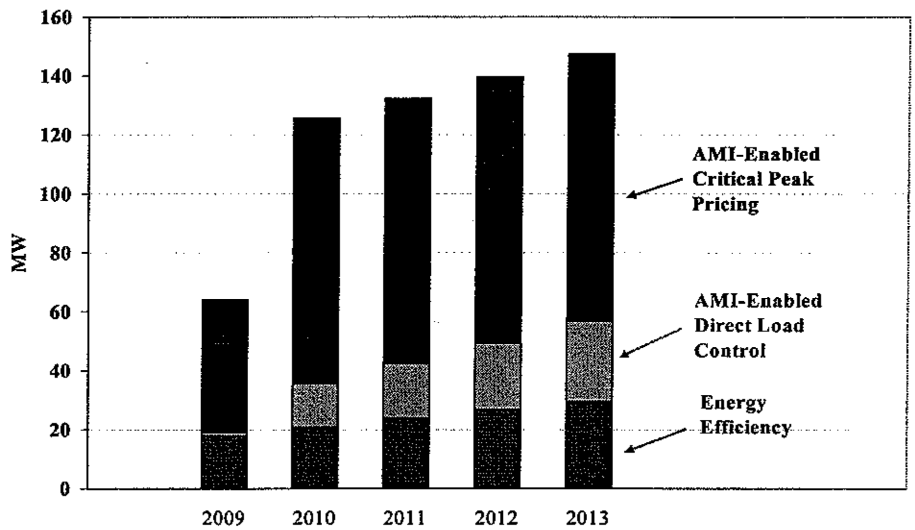
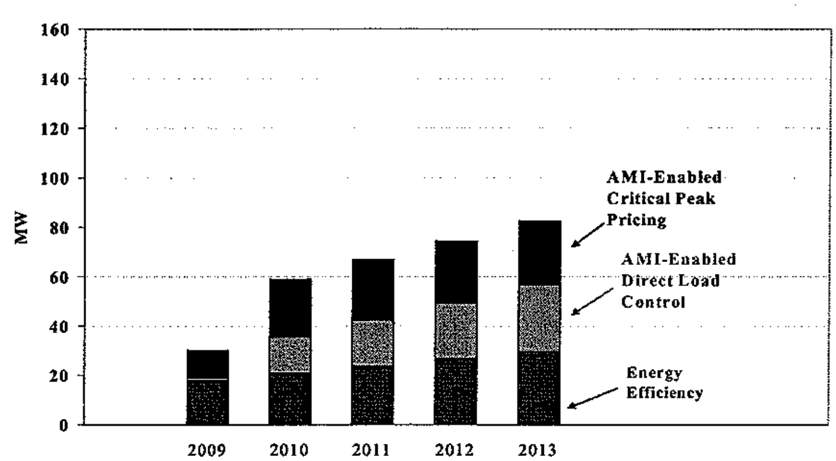


Figure 7b - Estimated Peak Load Reductions from PHI's Initiatives, Assuming CPP is a Voluntary Rate Structure (MW)



2) Analysis of Customer Benefits from Load Reductions

Savings to the customer relates to those benefits that will reduce the customer's bill, but not impact the cost of energy delivery. Most significantly, AMI-enabled innovative rate options (e.g., critical peak pricing, time of use rates, real-time pricing, etc.) will allow the customer to better manage consumption and thus reduce demand during peak periods. Reductions in peak consumption will produce savings by (1) reducing the need for supply-side capacity, energy, and ancillary services (i.e., the "resource cost savings"); (2) depressing market prices for energy and capacity by reducing demand; (3) reducing transmission losses; (4) improving reliability; (5) reducing rate volatility; (6) enhancing market competitiveness; (7) improving environmental quality or reducing energy prices by lowering the costs of environmental compliance; and (8) potentially obviating or delaying the need for investments in transmission and distribution.

The customer benefits detailed in this report focus on items one and two above. The other categories of benefits have not been quantified because the economic methodologies involved are not well developed or standardized. Therefore, the total benefits of reducing load could be substantially larger than the limited set of benefits reported in this Business Case.

The Brattle Group has estimated the benefits to Delaware customers from resource cost savings and market price impacts consistent with its January, 2007 study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), but with several additional analytical elements.

Resource Cost Savings

Capacity savings reflect the fact that DR lowers the load forecast, which lessens the amount of capacity that load-serving entities must purchase from generation suppliers through contracts or through PJM's capacity market. Alternatively, load that is controlled directly by the utility can provide capacity, thus offsetting the need for physical capacity. The value of either approach – reducing the capacity requirement or contributing capacity – can be evaluated using a projected price of capacity. *Brattle* estimated the future capacity price using the Net Cost of New Entry (Net CONE) that PJM uses in its definition of capacity market parameters. Net CONE is a conservative proxy because the capacity price has been higher than Net CONE in recent auctions for the 2007/08 and 2008/09 delivery years. Net CONE is also less than the avoided capacity cost often used in

DSM plans, which often does not net out the marginal value (i.e., operating margins) that new generation would provide by selling energy and ancillary services.

Generation savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not constructed and old capacity retired or not dispatched. The value of reduced generation is also partially offset by the value the customer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to assess and depends on whether the customer shifts load to lower-priced periods. These issues were addressed in the *Brattle*-PJM-MADRI study, in which generation savings amounted to an additional 12-36 percent on top of the capacity savings. Brattle's analysis of AMI-enabled DR in Delmarva simply adopts these figures by adding 12-36 percent of the estimated capacity savings.

Some DR could provide spinning reserves or other ancillary services (A/S), which would reduce the need for reserves from supply-side resources, the marginal value of which is given by the market price for spinning reserves. However, ancillary service value is somewhat speculative because currently none of PHI's DSM programs plan to enable ancillary services, although other DR does provide small amounts of A/S in PJM and ISO-NE[2].

Short-Term Price Impacts

Short-term energy price reductions are estimated by adapting the results of the *Brattle*-PJM-MADRI study (January, 2007) to reflect the load reductions expected from PHI's programs. As in the Brattle-PJM-MADRI study, the "benefit" is given by the product of the estimated price reduction and the load exposed to market prices. Benefits are partially offset by an associated reduction in the value of Financial Transmission Rights ("FTRs") (about a 15% offset). To the extent that PHI's load reductions differ from the load reductions simulated in the *Brattle*-PJM-MADRI study, *Brattle* linearly extrapolated the price impacts (e.g., twice the amount of load reductions would lead to twice the price impact).

While the *Brattle*-PJM-MADRI study assumed that all non-curtailed load was exposed to market prices, the present analysis assumes conservatively that only a fraction of load is exposed to market prices. The remainder is unaffected because it is covered by pre-existing contracts that were priced without anticipating the effects of DSM. Roughly

[2]*Brattle* assumed conservatively that AMI could eventually enable 100 MW of spinning reserves from loads that can be curtailed within less than 30 minutes of notification and stay offline for as much as 4 hours, such as electric arc furnaces or chillers in supermarkets. Hence potential ancillary service value is estimated by multiplying a conservative quantity of spinning reserves by the historical average price of spinning reserves (2004-06) of $8.5/MWh and by the number of hours in a year.

corresponding to the contract lengths and schedules by which standard offer service is procured in DC, DE, and MD and basic generation service in New Jersey, *Brattle* assumed that in any given year 50% of load-serving obligations are supplied by pre-existing wholesale contracts, and 50% are supplied by new contracts. This assumption results in discounted customer benefits relative to the *Brattle*-PJM-MADRI study – a 50% discount in the "Fast" Supply Response scenario and a 17% discount in the "Slower" scenario discussed below.

A second difference from the *Brattle*-PJM-MADRI study is the quantification of real-time DR benefits. The *Brattle*-PJM-MADRI study quantified benefits for only day-ahead DR and discussed qualitatively the potential additional value from DR that is dispatchable in real-time and thereby able to mitigate the effects of real-time surprises in supply and demand. In its present analysis of DSM in Delmarva, *Brattle* assumed that loads under direct load control were dispatchable in real time, and estimated the premium using the ratio of historical super-peak RT prices to super-peak DA prices. *Brattle* also estimated the additional value if dynamic pricing could designate peak periods on the day-of rather than day-ahead.

A third difference is that *Brattle*'s present analysis includes an estimate of the capacity price impact from DR, whereas capacity price impacts were outside the scope of the *Brattle*-PJM-MADRI. Participation of DR in capacity markets is an important element of PJM's newly instituted Reliability Pricing Model (RPM). While only the subset of load reductions, those that are under direct control (by the utility, other retail providers, curtailment service providers or the RTO), can participate as supply in capacity markets (Smart thermostat), the expected effect of dynamic pricing programs would also impact capacity prices by reducing the load forecast and thus the administratively-determined demand for capacity. Given this new market reality, *Brattle* has estimated capacity price impacts as follows: in the "Fast" and "Slower" Supply scenarios (defined below), the market was assumed to be in supply/demand balance with the expected 3-year forward capacity price set by Net CONE, irrespective of the level of load reductions achieved. Hence, the capacity price impact was conservatively set at zero in these scenarios. In the "Inadequate" Supply scenario, capacity price impacts were estimated by intersecting supply and demand curves for capacity in the Eastern MACC Locational Delivery Area both with and without DR. The demand curve was constructed using PJM's load forecast and the other parameters it uses to determine the administratively-determined demand curve. The supply curve was constructed by adding projected new supply (from the generation interconnection queue) to the supply curve available from the most recent capacity auction.

Scenario Definition

A key insight is that the resource cost savings from reducing peak loads persist over time, whereas the market price impacts can be expected to diminish as suppliers respond to depressed prices by delaying the construction of new generation or accelerating the retirement of existing plants. The magnitude and duration of the price impact depends on the rate at which suppliers respond to changes in market conditions and on the tightness of the market over the next several years. Price impacts are the largest and the longest-lasting in a scarcity situation; they are the smallest and shortest-lived in a surplus market or in a balanced market in which suppliers react quickly to DSM's successes (and associated price impacts) by delaying construction of new capacity or accelerating the retirement of existing plants. Hence, Brattle analyzed a range of plausible market conditions by constructing three supplier scenarios in which the longevity of price impacts is varied:

- In the "Fast" scenario, the market is in supply-demand equilibrium, and suppliers react quickly to changes in fundamentals. Short-term energy price impacts, as derived from the Brattle-PJM-MADRI study which used a short-term equilibrium model in which supply is static, benefits last for only one year before suppliers fully respond to DSM. One year after the introduction of new DR, suppliers have accelerated enough retirements and/or delayed enough new construction to completely offset the price impact of DR. Hence, if PHI's deployment schedule produces a 200 MW of total peak load reduction in year n and 300 MW in year n+1, then only 100 MW of load reductions has a price impact in year n+1. This scenario is consistent with the observation that suppliers in PJM's recent RPM Base Residual Capacity Auction for the 2008/09 delivery year changed their plans relative to the prior auction (in this case delaying retirements), presumably in response to high prices in the prior auction.

- The "Slower" scenario is similar to the "Fast" scenario except that short-term price impacts persist for three years before suppliers respond. The three-year response time corresponds to a three-year lead time for new construction.

- In the "Inadequate" scenario, suppliers do not build any capacity that is not currently in PJM's queue until 2015, and the market becomes very short on capacity. In such a shortage situation, suppliers are not responsive to the introduction of DR because they have no new capacity to delay and retiring existing plants early is unlikely, hence all load reductions achieved by PHI's DSM initiatives creates price impacts until 2015. This scenario reflects the possibility that suppliers are reluctant to build in the current uncertain environment with the threats of reregulation, high gas prices, climate change policies, and siting difficulties.

Finally, each supplier response scenario is analyzed assuming high rates of customer participation in dynamic pricing programs and, alternatively, low customer participation rates. Customer participation rates depend primarily on whether critical peak pricing becomes the default rate structure or merely an option that customers can elect. In the "CPP Default Rate Structure" scenario, 100% of customers would be enrolled in a critical peak pricing rate initially, and some 20% would eventually switch to a non-CPP rate structure, leaving 80% participation in year two and beyond. In the "CPP Elective" scenario, 0% of customers would sign up initially, ramping up to 20% in two years and beyond. (These rates are based on the experience from the California Statewide Pricing Pilot and other pilots.)

3) Conclusions Regarding Customer Benefits from Load Reductions

Figure 8 shows the benefits to Delaware customers (including municipal and cooperative utilities contained within the PHI zones) if Delmarva's proposed DSM programs are implemented in Delmarva-Delaware according to its proposed deployment schedule.

The following conclusions can be drawn from this analysis:

- For the Default CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM ($65-81 million for all of Delaware), but they are be much greater in the Inadequate Supply Response scenario ($84-107 million for all of Delaware).
- For the Voluntary CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM ($28-36 million for all of Delaware), but they are be much greater in the Inadequate Supply Response scenario ($36-47 million for all of Delaware).
- The short-term savings to all customers, including customers outside of PHI's zones, would be much larger than the benefits to just Delaware customers due to the fact that PHI's load reductions would have a market-wide impact on energy and capacity prices.

Figure 8. Benefits to Delaware Customers from AMI-Enabled Dynamic Pricing and Direct Load Control Programs in Delmarva Delaware for both Voluntary and Default Cases.

Benefits to Delaware Customers from AMI-Enabled CPP and DLC in Delmarva DE
Net Present Value of Benefits through 2024 (million 2007 $'s)

Rate Structure Scenario	CPP is a Voluntary Rate			CPP is the Default Rate		
Supplier Responsiveness Scenario*	Fast	Slower	Inadequate	Fast	Slower	Inadequate
RESOURCE COST SAVINGS						
Avoided Capacity Costs	$25	$25	$25	$57	$57	$57
Avoided Energy Costs	$3 - $9	$3 - $9	$3 - $9	$7 - $20	$7 - $20	$7 - $20
Avoided Ancillary Services Costs	$0.7 - $2	$0.7 - $2	$0.7 - $2	$0.9 - $2.5	$0.9 - $2.5	$0.9 - $2.5
SHORT-TERM MARKET PRICE IMPACTS						
Energy Price Benefit	$0.2 - $0.5	$0.9 - $2	$2 - $5	$0.4 - $1.1	$2 - $6	$5 - $13
Potential Additional Real-Time Benefit	$0.1 - $0.2	$0.2 - $0.4	$0.3 - $0.5	$0.3 - $0.7	$0.6 - $1.2	$0.9 - $1.5
Capacity Price Benefit	$0	$0	$6	$0	$0	$15
TOTAL QUANTIFIED BENEFITS ***	$28 - $36	$29 - $38	$36 - $47	$65 - $81	$67 - $85	$84 - $107
UNQUANTIFIED BENEFITS						
Enhanced Reliability			Large***			Very Large***
Enhanced Market Competitiveness						
Reduced Rate Volatility						
Environmental Benefits						
Reduced Transmission Losses						
Avoided Transmission and Distribution Costs						

* Fast response: short-term benefits last for 1 year; Slower response: short-term benefits last for 3 years; Inadequate response: no generic entry and short-term benefits last until 2015.
** Excludes potential real-time benefits.
*** A PHI-wide implementation of AMIand energy efficiency would increase reserve margins in Eastern MAAC from 18.1% to 18.9% in 2010, and from 11.5% to 12.9% in 2013 if CPP is the Default Rate Structure and from 18.1% to 18.6% in 2010, and from 11.5% to 12.3% in 2013 if CPP is a Voluntary Rate Structure

- The savings to Delaware customers would be as much as two times larger if all utilities in PJM-East followed PHI's lead in deploying DSM programs and achieved similar load reductions, with the aggregate load reductions creating a much greater impact on energy and capacity prices.

- The savings to Delaware customers would be less than half as large if critical peak pricing were not the default rate structure, requiring customers to take initiative in order to sign up for the program. This finding is based on the assumption that a voluntary program would achieve only 20% participation by residential and small commercial and industrial customers, whereas making CPP the default rate structure with an option to switch to a fixed rate would achieve 80% participation. (This assumption is consistent with participation rates in

California's Statewide Pricing Pilot.) However, even at a pessimistic 20% participation rate, the total benefits of AMI/DSM exceed the total costs.

- Although critical peak pricing programs typically designate peak periods on a day-ahead basis, making the programs callable on a real-time basis would enable customers to mitigate the impacts of real-time surprises in load or supply outages. This could add an additional $300,000 to $1.5 million in value.

- In the Inadequate Supply Response scenario, implementation of DSM programs like PHI's throughout PJM-East would increase reserve margins in Southwest MACC from 15.2% to 18.3% in 2010, and from 5.8% to 14.4% in 2013; in Eastern MAAC from 18.1% to 21% in 2010 and from 11.5 to 19.9% in 2013. Hence, DSM initiatives would provide substantial value as an insurance against intolerably low reserve margins.

These savings estimates do not include potential additional customer benefits from reducing transmission losses, improving reliability, reducing rate volatility, enhancing market competitiveness, improving environmental quality, reducing energy prices by lowering the costs of environmental compliance, or potentially obviating or delaying the need for investments in transmission and distribution. These categories of benefits have not been quantified because the economic methodologies involved are not as well developed or standardized. Therefore, the total customer benefits of AMI could be substantially larger than the limited set of benefits reported in this Business Case.

Additional Benefits

Customer Benefits

Delmarva utilizes a market research model developed by Market Strategies Inc ("MSI") to assist the company in identifying the key drivers of customer satisfaction. The energy delivery benefits associated with AMI related to billing, customer service, energy information and reliability contribute positively to Delmarva's customer satisfaction performance once the full Blueprint plan is implemented. Additional customer benefits include:

- Improved website capabilities which will provide interval usage data to enable customers to understand when and how they are consuming energy at their homes and businesses.

- Individual customer load profile data can be useful in enabling the utility to target specific conservation programs or messaging to those customers who would achieve the maximum benefit. Delmarva's "My Account" software has the capability to provide "Energy Grams" to customers which would offer customized energy conservation information based on how they are currently using energy.

- AMI would enable Delmarva to provide for a "point of purchase" notification or understanding by consumers. Delmarva's "My Account" software has the capability of providing AMI metered customers with "My bill to date" which enables customers to see how much they have spent so far in any given month. The "My bill to date" feature also enables the utility to perform outbound notifications to customers letting them know when energy consumption or spending has reached customer prescribed levels. These notifications will raise awareness of energy use and contribute to changing consumer behavior towards conservation and environmental stewardship.

- AMI allows Delmarva to potentially offer "On-Request" meter reading services whereby a customer could request a specific meter reading which would show consumption information for a period of time (1 hour for example). This type of reading would be able to let customers see a "before and after" view of energy use which enables them to see the benefits of conservation.

- AMI will enable Delmarva to provide on-line assistance with rate evaluations. Customers would benefit from having an Interactive Rate Comparison program available on line to examine the cost savings potential of various rate options in a manner which is customized based on their actual historic load profile. Users would select among options and calculate the energy costs for each option automatically. Users could then print out a summary of the analysis to be used for making rate decisions.

- AMI provides improved customer service due to the ability to remotely verify or determine that a particular meter is currently in service or out of service. This helps to alert the customer that the problem may be on the customer side of the meter.

- With AMI, it would be possible to offer customers an option of changing their monthly billing due date. This could conceivably provide some cash flow and payment flexibility benefit for customers.

- AMI information will benefit our Customer Contact Centers by enabling Customer Service Representatives ("CSR's") to quickly identify the time of high customer usage. This would enable the CSR to offer enhanced levels of customer educations by explaining exactly when periods of high usage are occurring at the customer's home or business.

- AMI allows the Company to be less intrusive to customers by not having meter reading personnel in or near the customer's home or business.

Theft of Service

Delmarva expects to improve the detection of lost revenue due to energy theft and other metering issues and to ultimately reduce it by using the capabilities of the AMI system. The AMI system is expected to enhance Delmarva's ability to identify and recover lost revenue in three ways. First, by visiting all of Delmarva's meter locations during the initial AMI meter deployment, we anticipate that some percentage of the meters currently affected by tampering, diversion or other problem will be found and remedied. Second, once the AMI system is installed, Delmarva anticipates that additional data will be available to indicate the status of the meter as well as provide electronic notification of possible tampering. This functionality will permit more timely identification, investigation and remediation of possible theft events. Finally, by using the interval data from the AMI system coupled with the analytical capabilities provided by the MDMS, Delmarva expects to develop the capability to analyze usage and other patterns to discern possible theft cases, particularly with commercial accounts. According to the Edison Electric Institute ("EEI"), electric utilities typically estimate approximately one to three percent of their annual revenue is lost due to energy theft. If the expected AMI capabilities enable Delmarva to improve its energy theft recovery by 0.5% of its annual kilowatt hour sales, we estimate that the recovered volume would be about 47 million kilowatt hours or about $6.5 million per year, assuming a combined residential distribution and standard offer service rate of 13.75 cents per kilowatt hour. Customers might experience a small reduction in rates due to reduced losses from the electrical system as the costs of the diverted electricity are paid for by the actual responsible parties. This benefit, however, would represent a shift in cost responsibility among customers, rather than a reduction in total revenue requirement recovered from all customers and was no included in this analysis.

Costs to Deploy

This section of the report provides the initial cost estimates for the deployment of the AMI system and the associated meter data management system ("MDMS") by Delmarva's electric and gas delivery businesses. The costs will change as the Company conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated cost values. Below is Figure 9 summarizing total capital expenditures needed for the initial deployment of the AMI system and annualized O&M costs expected in the first full year after deployment, followed by a more detailed description of each cost category.

Figure 9

Line	AMI System Components	Initial Deployment Costs Only $ in ('000s) Electric	Gas	Combined
1	Meters, including Installation Cost	$ 42,783	$ 9,195	$ 51,978
2	Communications Network, including Installation Cost	$ 21,616	$ -	$ 21,616
3	AMI Network Management System and Meter Data Management Sy	$ 4,417	$ 1,828	$ 6,245
4	Contingency	$ 4,680	$ 1,543	$ 6,223
	Total Capital Investment	$ 73,496	$ 12,566	$ 86,062
		Annual Estimated Costs After Deployment $ in ('000s) Electric	**Gas**	**Combined**
	AMI System Incremental Cost to Operate			
5	MDMS Software Maintenance & License Fees	$ 62	$ 26	$ 88
6	MDMS Hardware Leasing	$ 168	$ 70	$ 238
7	AMI Network Management System O&M	$ 196	$ 81	$ 277
8	Communications Network Infrastructure O&M	$ 273	$ -	$ 273
	Total Incremental Cost to Operate	$ 699	$ 177	$ 876

Note that the costs in the figure above exclude certain one time costs described in number 9 below.

1) Meters and Installation Labor

Costs include new AMI meters that contain certain equipment "under glass" such a remote connect/disconnect switch for certain meters, communications modules where applicable and the associated installation labor. Prices for AMI equipment are estimated using filings from other utilities as well as initial quotes from a few vendors and the calculated estimates consider differences in commercial and residential equipment requirements. A value of $85.00 is used for the AMI base cost for residential electric meters and a $194.00 value is used for commercial electric meters. Additionally 98% of residential electric meters will require a $25.00 remote connect/disconnect switch, which is not required for the commercial electric meter. All existing gas meters will be retrofitted with an AMI communications module, estimated at $60 per module. Labor cost for installations/ retrofits is estimated at $16.50 per electric meter and $20.00 per gas meter. This brings the estimated cost for meters with the associated installation labor to about $52 million for Delmarva's electric and gas customers in Delaware.

2) Communications Network Infrastructure and Installation Labor

The communications network infrastructure solution is assumed to leverage Delmarva's already existing network. There will be no separate communications network for gas meters; instead the gas meter's communication modules will utilize the communications network deployed for electric meters. The cost of this component of the AMI system is more variable than the other components (i.e., meters and the network management IT system), given the different ways AMI vendors configure and price their communications networks combined with the variability of terrain, meter density and meter locations in Delaware. For purposes of this cost estimate, $70.00 per electric meter, including installation costs, was used. The total estimated costs for communications network infrastructure and the associated installation is about $22 million for Delmarva's electric and gas customers in Delaware.

3) AMI Network Management System and Meter Data Management System

This cost category captures the estimated costs associated with software applications, systems integration and computer hardware necessary to support AMI. System costs include categories for

- MDMS – software license, servers, storage, operating system, database management system, clustering software, and system design, configuration and integration
- Customer Presentment – servers, storage, and system design, configuration and integration
- PHI Integration – CIS and other IT systems integration.

The total estimated costs for the AMI Network Management System and the Meter Data Management System are about $6 million for Delmarva's electric and gas customers in Delaware.

4) Contingency

We determined that a contingency should be applied to the start-up and installation activities as a way to help manage the current uncertainty around the AMI cost estimate. A contingency amount comprising 7% of the capital investment for Delmarva, representing an amount of about $6 million is included to cover unexpected increases in equipment costs, labor costs or materials prices.

5 and 6) MDMS Software Maintenance, License Fees and Hardware Leasing

The MDMS will require software maintenance and license fee contracts with the system's vendor for system support, upgrades and the like. The operating costs for the hardware for the MDMS system include the hardware leasing costs for the servers, the data warehouse system and data storage capacity.

7) AMI Network Management IT System O&M

The AMI Network Management IT System has costs similar in nature to the MDMS with regard to software and hardware. Three additional FTEs are estimated to be required after AMI deployment to operate and maintain the AMI system for PHI.

8) Communication Network Infrastructure O&M

These costs include the estimated ongoing maintenance of the communications equipment needed to transmit the data back and forth between the meters on the customers' premises and the Company's offices. This cost is dependent on the mix of communication technologies Delmarva ultimately obtains through its procurement process.

9) Labor Related Costs

The reduction in certain types of work would be phased in after the 2008 deployment, with labor related costs being incurred over a three year period (2010 through 2012). These costs would include reassignment and retraining of Delmarva employees. The estimated cost of this one time expense is $1.1 million for the electric service and $0.4 million for the gas service.

Accelerated Depreciation

As stated in PHI's February 6, 2007 Blueprint for the Future filing and in the 2007 NARUC [3] Resolution to Remove Barriers to the Broad Implementation of Advanced Metering Infrastructure, the deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. To encourage the implementation of this new technology the Commission should adopt ratemaking policies that remove a utility's disincentive toward demand-side resources that reduce throughput; provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and provide depreciation lives for AMI that take into account the speed and nature of change in metering technology.

The business case reflects depreciation lives for AMI that take into the account the speed and nature of the change in metering technology. The

[3] See NARUC Resolution Attached in Appendix 2

business case reflects a recovery period of fifteen years for the AMI investment and five years for the recovery of the remaining costs associated with the existing metering system. As of December 31, 2006, Delmarva's existing electric metering system had a remaining net book value of about $26 million and the existing gas metering system's communication modules had a remaining net book value of about $3 million. At this time, Delmarva expects to be able to retrofit the existing gas meters with an AMI ready communications module and not replace the existing meters. In certain cases, Delmarva has gas meters with existing communications modules installed in customers' premises. These modules would not be compatible with the communication system needed for the AMI system and therefore accelerated recovery treatment similar to the existing electric metering system is appropriate. Depreciation calculations in the business case may need to be updated due to pending federal legislation.

[redacted]

Appendix 1

Developments in other jurisdictions

Congress with the passage of the Energy Policy Act of 2005 recognized the importance of advanced metering for growth in the development of electric demand response programs across the United States. To advance the development of such programs, Congress directed the Federal Energy Regulatory Commission ("FERC") to assess demand response resources currently in existence in the electric power industry. FERC conducted a survey where they requested information from every state on the number and uses of advanced metering, existing demand response and time-based rate programs within their state. As a result of this survey, states were required to consider the adoption of a smart metering standard for each of their state regulated utilities.

Many states took the FERC survey results and determined methods for confronting the rising energy costs within their particular states with Advanced Metering Infrastructure and Demand Response Programs. The following identifies several utilities which have obtained approval from their individual state regulatory commissions and are beginning implementation of intelligent meter technology, demand response and time-based rate programs within their operating jurisdictions. California and Texas utility companies have led the way in implementation of AMI and Demand Response Programs.

CALIFORNIA

The California Public Utilities Commission ("CPUC") in 2004, directed each of the state's regulated utilities to explore the option and feasibility of upgrading their home and small-business electric meters to digital intelligent meters, similar to the types used to measure energy usage by larger commercial customers. The CPUC's goal was for its state regulated utilities to significantly ease California's constrained energy resources by providing some form of demand response during periods of peak demand. The need for a smart metering standard was essential in California due to the increased growth in population and per-person energy use in the state. California's state energy policies require utilities to commit large amounts of resources to fund and implement energy efficiency programs.

Pacific Gas & Electric ("PG&E")

Pacific Gas & Electric in 2006 obtained approval from the CPUC for the universal deployment of an AMI system which required the installation of

5.2 million electric meters and 4.1 million gas meters throughout its operating territory. PG&E immediately began an AMI pilot program in Bakersfield, California to test the accuracy and performance of SmartMeter™ after winning approval from the CPUC. Mass deployment of PG&E's SmartMeter™ Program is expected to begin in late 2007.

Southern California Edison (SCE)

Southern California Edison obtained approval from the CPUC to replace its existing 5.1 million electric meters with "next generation" electronic intelligent meter technology beginning in 2009. Edison SmartConnect™ is Southern California Edison's AMI Program which aims to improve overall customer service by allowing customers to proactively manage their energy use and also save money through participation in programs with time-differentiated rates and demand response options. The Edison SmartConnect™ program is the first overhaul of SCE's metering system since 1949.

San Diego Gas & Electric ("SDG&E")

San Diego Gas & Electric obtained approval from the CPUC in April 2007 to begin implementation of "smart meter" technology for its estimated 1.4 million electric meters and retrofitting approximately 900,000 gas meters throughout its service territory beginning in 2008. SDG&E's approval also includes an agreement with the CPUC's Division of Ratepayer Advocates ("DRA") and the Utility Consumers' Action Network ("UCAN") to become a leader in emerging energy technologies through the use of a smarter electric distribution grid.

TEXAS

With the passage of House Bill 2129, the Texas Public Utility Commission was required to study the benefit to be derived by electric utilities in Texas from advanced metering. Because of the retail choice environment of the Texas retail market, the challenge exists for implementing advanced metering in a way that will maximize the benefits for the utility company, retail providers and customers. The Texas Commission has also initiated a separate project to evaluate potential demand response programs for the Texas utilities market.

Centerpoint Energy

Centerpoint obtained approval from the Texas Public Utility Commission in 2006 for implementation of smart meter technology for its more than three million electric and natural gas customers in the Houston area. Implementation of smart electricity meters began in November 2006 in selected areas of Houston.

TXU Electric Delivery

TXU Electric Delivery plans to have its 3 million automated meters by 2011, complementing an advanced grid intelligent enough to monitor electric service real-time. By year's end, TXU Electric Delivery expects to have 370,000 automated meters system-wide, including 10,000 BPL-enabled meters. The BPL-enabled network will serve approximately 2 million residential and commercial customers in Texas.

OTHER JURISDICTIONS

Several utility companies in other jurisdictions have either filed applications or have obtained approval for implementing advanced metering and demand response programs. A sampling of these utilities companies are outlined below.

- *Detroit Edison* ("DTE") – The Michigan Commission approved DTE's plan to replace 3 million electric meters. DTE is investing $330 million for implementation of this over the next six years. DTE has also created a Home Energy Saver audit tool on their website (mydteenergy.com) to help customers manage their energy use and obtain conservation tips.

- *Pennsylvania Power & Light Company* ("PPL") – PPL completed the installation of 1.3 million electric meters in 2004. PPL has created sections on its website dedicated to energy conservation efforts, including an energy calculator, detailed information about smart meters, safety concerns and an energy library for customers to learn more about energy usage in their homes.

- *Baltimore Gas & Electric Company* – BGE filed for approval by the Maryland Public Service Commission in early 2007 of its plan to deploy an AMI system and Demand Side Management Programs.

- *Southern Company* – Southern Company obtained Commission approval to replace 4.5 million electric meters in their four-state operating territory.

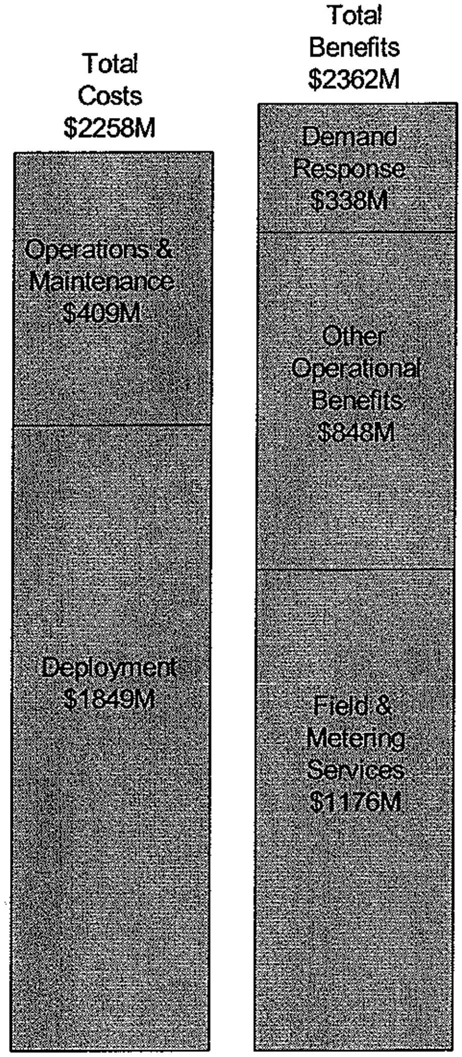
- *Portland General Electric ("PGE")* – PGE has filed an application with the Public Utility Commission of Oregon to install 843,000 smart meters for both residential and small non-residential customers throughout PGE's operating territory.

Business Case Summaries from Other Utilities

Summaries based on publicly available information from filings for PG&E Southern California Edison and San Diego Gas and Electric are included below. The summaries demonstrate the similarities in approach and results with PHI's AMI business case analysis.

Pacific Gas and Electric Company

The AMI business case filed by PG&E with the California Public Utilities Commission shows that AMI can largely be justified by the operational benefits and savings to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is $234 million on a present value revenue requirement (PVRR) basis. Adopting a benefit calculation* for Demand Response of $338 million which is more conservative than a Base Case* of $510 million still results in finding that the project is cost-effective.

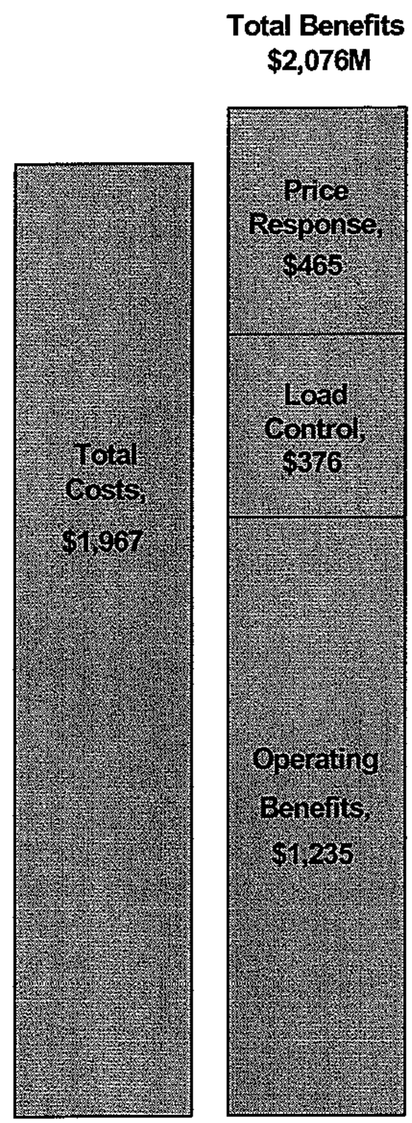


The field and metering services benefits include the reduction/elimination of the labor and non-labor costs required for regular meter reading and change of party/special reads and remote Turn-On/Shut-Off. Other operational benefits include improvement in Electric & Gas Transmission and Distribution restoration after significant outages, reduced customer calls and duration of calls related to billing and power outages, and reduced employee-related costs.

The major categories of deployment costs for AMI include meter and module equipment and installation costs, network equipment and install costs, and IT costs that include interval billing system, interface and integration costs. Operational and maintenance costs include AMI operation costs, meter operation costs, marketing and communications costs, and customer acquisition costs

Southern California Edison

The AMI business case filed by SCE with the California Public Utilities Commission shows that AMI is justified by the Operational, Load Control, and Price Response Benefits to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is $356 million on a present value revenue requirement (PVRR) basis. The new functionality of the Edison SmartConnect™ technology not only increases the ways in which customers can use demand response; it also results in SCE going from a negative $951 million Present Value Revenue Requirement (PVRR) in 2005,* to a positive $109 million PVRR in 2007 for full AMI deployment.



Through its AMI System Design and Use Case Process, SCE will integrate Edison SmartConnect™ into its operating systems to ensure that the expected benefits accrue in the areas of customer service, billing, outage management, and operations and maintenance.

Operational savings are forecast to cover approximately 63 percent of the related costs. Participation by residential and <200kW business customers in dynamic pricing and demand response programs is expected to provide sufficient additional benefits to justify the Edison SmartConnect™ project. The cost-benefit analysis is summarized in the Figure below.

* Source: EDISON SMARTCONNECT™ DEPLOYMENT

FUNDING AND COST RECOVERY

Volume 1 –Policy July 31, 2007 - Before the Public Utilities Commission of the State of California

Appendix 2 NARUC Resolution

Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure

WHEREAS, The Energy Policy Act of 2005 amended the State ratemaking provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA) to require every State regulatory commission to consider and determine whether to adopt a new standard with regard to advanced metering infrastructure (AMI); *and*

WHEREAS, Advanced metering, as defined by Federal Energy Regulatory Commission (FERC), refers to a metering system that records customer consumption hourly or more frequently and that provides daily or more frequent transmittal of measurements over a communication network to a central collection point; *and*

WHEREAS, The implementation of dynamic pricing, which is facilitated by AMI, can afford consumers the opportunity to better manage their energy consumption and electricity costs through the practice of demand response strategies; *and*

WHEREAS, Effective price-responsive demand requires not only deployment of AMI to a material portion of a utility's load, but also implementation of dynamic price structures that reveal to consumers the value of controlling their consumption at specific times; *and*

WHEREAS, AMI deployment offers numerous potential benefits to consumers, both participants and non-participants, including:

- greater customer control over consumption and electric bills;
- improved metering accuracy and customer service;
- potential for reduced prices during peak periods for all consumers;
- reduced price volatility;
- reduced outage duration; and,
- expedited service initiation and restoration; *and*

WHEREAS, The use of AMI may afford significant utility operational cost savings and other benefits, including:

- automation of meter reading;
- outage detection;
- remote connection/disconnection;
- reduced energy theft;
- improved outage restoration;
- improved load research;
- more optimal transformer sizing;
- reduced demand during times of system stress;
- decreased T&D system congestion; and,
- reduced reliance on inefficient peaking generators; *and*

WHEREAS, Sound AMI planning and deployment requires the identification and consideration of tangible and intangible costs and benefits to a utility system and its customers; *and*

WHEREAS, Cost-effective AMI may be a critical component of the intelligent grid of the future that will provide many benefits to utilities and consumers; *and*

WHEREAS, It is important that AMI allow the free and unimpeded flow and exchange of data and communications to empower the greatest range of technology and customer options to be deployed; *and*

WHEREAS, The deployment of cost-effective AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure; *and*

WHEREAS, Regulated utilities may be discouraged from pursuing demand response opportunities by the prospect of diminished sales and revenues; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its February 2007 Winter Meetings in Washington, D.C., recommends that commissions seeking to facilitate deployment of cost-effective AMI technologies consider the following regulatory options:

- pursue an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits;
- adopt ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources;
- provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and,
- provide depreciation lives for AMI that take into account the speed and nature of change in metering technology; *and be it further*

RESOLVED, That the Federal tax code with regard to depreciable lives for AMI investments should be amended to reflect the speed and nature of change in metering technology; *and be it further*

RESOLVED, That NARUC supports movement toward an appropriate level of open architecture and interoperability of AMI to enable cost-effective investments, avoid obsolescence, and increase innovations in technology products.

Sponsored by the Committee on Energy Resources and Environment
Adopted by NARUC Board of Directors February 21, 2007

ATTACHMENT B

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

RECEIVED
07 FEB -6 PM 3:04
DELAWARE P.S.C.

IN THE MATTER OF DELMARVA POWER & LIGHT COMPANY'S BLUEPRINT FOR THE FUTURE PLAN FOR DEMAND SIDE MANAGEMENT, ADVANCED METERING AND ENERGY EFFICIENCY (Opened Feb. __, 2007)	))))))	**PSC Docket No. ____** 07-28

BLUEPRINT FOR THE FUTURE
APPLICATION AND PLAN

Dated: February 6, 2007

Delmarva Power & Light Company
800 King Street, 5th Floor
P.O. Box 231
Wilmington, DE 19899-0231

I. INTRODUCTION

Delmarva Power & Light Company ("Delmarva", "Delmarva Power" or the "Company"),[1] hereby files with the Delaware Public Service Commission ("Commission" or "DPSC") the Company's comprehensive demand-side management, advanced metering and energy efficiency plan entitled the "Blueprint for the Future" Plan ("Blueprint for the Future"). With this filing Delmarva is proposing to implement the Company's Blueprint for the Future Plan, attached as Appendix A, in Delaware. Delmarva is seeking input from the Commission and interested parties on the Blueprint for the Future. Delmarva petitions the Commission to take immediate action, to the extent required by law or regulation, on the Blueprint for the Future. Specifically, Delmarva requests that the Commission:

- Issue an order giving notice of the filing and requiring publication of such notice in newspapers of general circulation;[2]

- Establish a Working Group/collaborative process to review and report on Delmarva's demand side management ("DSM") recommendations under the direction of a to-be-appointed Hearing Examiner;

- Establish a Working Group/collaborative process to review and report on Delmarva's Bill Stabilization Adjustment ("BSA") proposal; and,

- Direct the Working Group previously established in Regulation Docket No. 57 to review and report on Delmarva's AMI proposal.[3]

- Task the Working Groups and Hearing Examiner(s) to, on an expedited basis but not later than August 1, 2007, review and report to the Commission on the

[1] Delmarva is part of the Pepco Holdings, Inc. ("PHI") family of companies. Delmarva is a wholly owned subsidiary of Conectiv, a Delaware corporation, which is in turn a wholly owned subsidiary of PHI, a Delaware corporation. PHI is an energy holding company engaged in regulated utility operations and sale of competitive energy products and services to residential and commercial customers. PHI companies deliver electricity and natural gas to more than 1.8 million customers in Delaware, the District of Columbia, Maryland, New Jersey and Virginia, making it one of the largest electricity delivery companies in the mid-Atlantic region. PHI's family of energy-related businesses includes: is regulated electric utility delivering electricity to more than 725,000 customers in Washington, D.C., and its Maryland suburbs. Delmarva is a regulated utility with more than 500,000 electric delivery customers in Delaware and the Delmarva Peninsula and about 118,000 natural gas delivery customers in northern Delaware. Atlantic City Electric Company is a regulated electric utility serving more than 500,000 customers in southern New Jersey.

[2] A proposed Order and Notice is attached as Appendix B, Draft Order and Notice.

[3] In the Matter of the Commission's Combined Consideration of the Utilization of Advanced Metering Technologies Under 26 Del. C. §1008(b)(1)b and the Implementation of the Federal Standards for Time Based Metering and time Based Rate Schedules Under 16 U.S.C. §2621(d)(14) and 2625(i) (Opened May 9, 2006). PSC Regulation Docket No. 57.

three key components of Delmarva's Blueprint for the Future: DSM; AMI; and, BSA.

- Issue a final order not later than September 1, 2007, approving all cost recovery mechanisms proposed, approving the proposed Net Energy Metering Tariff and approving the BSA with an effective date of November 1, 2007.

The Blueprint for the Future, which ultimately will be rolled out across all PHI utilities and their jurisdictions, is the PHI vision for the future that is designed, among other things, to better enable customers to mange their energy bills through energy efficiency programs and the ability to see and react to price signals in the market, placing significant downward pressure on regional electricity wholesale capacity and energy prices. The purpose of this Blueprint for the Future is to set forth Delmarva Power's comprehensive vision of the future and for taking Delmarva and Delmarva's Delaware customers forward into that future – a future where DSM programs, both energy efficiency and demand response, are enabled by new technology investments to best meet Delmarva's Delaware customer energy needs. A recent study, prepared by The Brattle Group and sponsored by the five Mid-Atlantic public utility commissions and PJM Interconnection, has found that a modest reduction in electricity use during peak hours would reduce energy prices by at least $57 million to $182 million annually in the Mid-Atlantic region. The study examined the effects of reducing electricity use by three percent during the highest use hours for five utility areas. It notes that, "[m]ore widespread participation and deeper curtailments would result in even greater price impacts." This study also shows the importance of demand response to a state like Delaware and further supports the Company's recent IRP filing and the need for the Commission to support this filing.[4]

For the past decade, the State of Delaware's energy future has been the focus of Executive Task Forces, Legislative Committees and regulatory action collectively and individually by the Governor, the Legislature, U.S. Senator Carper, the Sustainable Energy Utility ("SEU"), Commission, Delaware's Colleges and Universities, and citizens. Many concerned and interested parties have attempted to study, develop and promote energy efficiency and demand side response programs, including: the State of Delaware with the State Climate Change Action Plan; the Governor's Energy Task Force; SEU Task Force; University of Delaware Center for Energy and Environmental Policy; Delaware Department of Natural Resources; the Delaware House and Senate,[5] and Delmarva. Additionally, the Delaware Public Service Commission, in response to legislation and/or legislative directives has established

[4] See Bratton Report, Quantifying Demand Response Benefits in PJM (January 29, 2007).

[5] See Renewable Energy Portfolio Standards Act, 26 Del. C. C. 351 – 363. See Also, The Electric Utility Retail Customer Supply Act of 2006. 26 Del. C. § 1007. The Electric Utility Retail Customer Supply Act of 2006 ("EURSA" or the "Act"), passed by the Delaware General Assembly in the Spring of 2006, mandated that the Company prepare an Integrated Resource Plan ("IRP") and evaluate various procurement strategies for Standard Offer Service ("SOS") energy supply. EURSA required Delmarva to conduct a competitive request for proposal ("RFP") process to consider long term commitments with third party resource suppliers.

proceedings on Renewable Energy Portfolio Standards,[6] Advanced Metering,[7] and Integrated Resources Planning[8] – which includes a highly controversial RFP proposal which, if adopted, would force Delmarva to procure 400 MWs of new generating capacity to serve SOS customers.[9]

Delmarva Power, in this Blueprint for the Future, is proposing to the Commission and the customers of Delaware a full and comprehensive complement of energy efficiency and demand side management programs. Each program is specifically set forth in the Blueprint for the Future outlined in Appendix A.

1. Applicant

Delmarva, the Applicant in this matter, is located at:

Delmarva Power & Light Company,
800 King Street, P.O. Box 231,
Wilmington, Delaware 19899

[6] In the Matter of the Adoption of Rules and Procedures to Implement the Renewable Energy Portfolio standards Act, 26 Del. C. § 351-363 As Applied to Retail Electricity Suppliers (Opened August 23, 2005). PSC Regulation Docket No. 56,

[7] In the Matter of the Commission's Combined Consideration of the Utilization of Advanced Metering Technologies Under 26 Del. C. § 1008(b)(1)b and the Implementation of the Federal Standards for Time Based Metering and time Based Rate Schedules Under 16 U.S.C. 2621(d)(14) and 2625(i) (Opened May 9, 2006). PSC Regulation Docket No. 57.

[8] In the Matter of the Integrated Resources Planning for the Provision of Standard Offer Supply Service By Delmarva Power & Light Under 26 Del. C. § 1007(c) and (d): Review of Initial Resource Plan Submitted December 1, 2006 (Opened January 23, 2007). PSC Docket No. 07-20.

[9] In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service Supply by Delmarva Power & Light Company Under 26 Del. C. § 1007(c) and (d): Review and Approval of the Request for Proposals for the Construction of New Generation Under 26 Del C. § 1007(d) (Opened July 25, 2006). PSC Docket No. 06-241.

2. Communications

All communications and notices with respect to this application should be made to:

Gary Cohen Mgr, Regulatory Affairs Delmarva Power & Light Company Regulatory Affairs P.O. Box 9239 Newark, DE 19714	Anthony C. Wilson Associate General Counsel Delmarva Power & Light Company Legal Services Group 800 King Street, 5th Floor P.O. Box 231 Wilmington, DE 19899
With a copy to:	With a copy to:
Glenn Moore, Vice President Delmarva Power Region Delmarva Power & Light Company Regulatory Affairs P.O. Box 9239 Newark, DE 19714	Steven Sunderhauf Regulatory Affairs Pepco Holdings, Inc. 701 9th Street, NW Washington, DC 20068

II. OVERVIEW AND SUMMARY

1. Energy Efficiency To Assist Customers In Managing The Rising Cost Of Energy

Over the past several years the rising cost of energy across the nation has hurt Delmarva's customers, who are often left with limited ability to lessen their energy use to reduce the added burden of higher energy costs. The Company has talked with its customers and attempted to provide them with options to more efficiently manage their energy use. Last year PHI and Delmarva launched the "Energy Know How" campaign. PHI and Delmarva invested over $1,000,000 to implement state of the art energy auditing software. This investment now enables all of Delmarva's customers to go on the internet and view data about their monthly bills and better understand how they use energy and what changes might reduce their overall costs. This was a good first step, but much more needs to be done to allow customers to further control their bills. The Blueprint is Delmarva's proposal to take Delaware customers into the future.

This filing is the next step in answering customer concerns by giving customers more robust energy efficiency tools to reduce electricity consumption and demand response programs that will help to change when customers use energy in an effort to reduce peak demands, driving total electricity costs down for the state. The data and communications capabilities inherent in the advanced metering proposal that the Company has set forth will give each customer a platform upon which to build a number of programs aimed at managing overall energy costs. Delmarva envisions that some day the new technology will even have customers' appliances receive and react to real time energy prices. Some of these technologies will take time and need to be tested, but many are ready to roll out immediately.

Collaborative efforts have served Delmarva's customers well through the many working group processes that the Company, Public Service Commission, Department of the Public Advocates office and other interested parties have worked on through the years. As the Company looks at the key components of this filing: advanced metering, energy efficiency and demand response, bill stabilization proposals, and renewable resources, each will require key stakeholders across the state and at times across the region to come together and work collaboratively.

The Company is of the view that this same kind of joint effort will be important when implementing statewide energy efficiency and demand response programs. Working with partners like the SEU (which was recently established and supported by key legislators in the state) will help us identify best practices in the energy efficiency and conservation services arena. Certainly the Delaware Energy Office will be a valuable partner when working on the design of the DSM and the energy efficiency programs. The customer's experiences in administering programs such as the Delaware Energy Answers Program, the Delaware Green Energy Program, the Delaware Energy star program, and other energy related programs, will be invaluable when establishing new programs. A collaborative effort for Company programs will aid the state in developing other energy efficiency programs for other fuel sources. The Company proposes a Working Group including Staff, the Public Advocate, representatives from SEU, and the State Energy Office, to move ahead on the energy efficiency efforts. This group should begin meeting in March, using the details of this filing as a starting point. Not only will the group verify the proposed programs suggested by the Company are the right ones, but they can also work to align the efforts of each group to provide a comprehensive statewide effort. PHI is also joining the National Action Plan on Energy Efficiency Coalition, a broad-based group of utilities, environmental advocacy groups, state utility commissions and others working together on environmental issues.

This filing is a natural next step from Delmarva's recently filed detailed Integrated Resource Plan. It is meant to move forward the implementation of many of the ideas coming out of the planning process. It is also in step with the Company's vision of the future, as articulated in recent "State of the Company" presentations where the Company referred to the "Utility of the Future." Across PHI the corporation is employing a large amount of resources to take the Company forward in this vision of the future, and it will be one of the most significant initiatives we have had in many years. Delmarva believes this effort will take the Company and the states PHI serves into the forefront in enabling customers, specifically Delmarva's customers, to control energy costs, improve environmental conditions and also provide the Company with additional tools to make dramatic advances in reliability and customer service.

2. Delmarva's Blueprint For The Future

Delmarva's vision of the future involves a substantial investment in new technologies such as advanced meter infrastructure, distribution automation, smart thermostats linked to the AMI system, and an improved communications network. This vision will be met by designing and implementing these technologies and processes across the regions Delmarva serves. In Appendix A, the Company provides details on the components of this plan. Below is a summary of proposed programs.

A. Demand Side Management and Renewable Resources

1. DSM Programs

In addition to the many technology platforms outlined in the Blueprint, the Company has proposed a number of programs for Delmarva's customers. These programs will be refined and possibly expanded through Delmarva's proposed collaborative working groups. Delmarva has programs that fall into three categories: Energy Efficiency, Demand Response and Renewable Energy. Below is a snapshot of the residential and commercial programs the Company is proposing.

Energy Efficiency	Demand Response	Renewable Energy
Home Performance	Smart Thermostat	Renewable Portfolio
HVAC	Critical Peak Pricing	Green Choice
Lighting	Internet Demand Response	Net Energy Metering
Building Commissioning		
Prescriptive Audits		
Custom Audits		

These programs, coupled with the technology investments listed, will provide the tools Delmarva's customers and Delmarva needs to move into the future.

2. Renewable Resources

Delmarva's IRP clearly pointed to the need for a moderate amount of renewable resources in Delmarva's portfolio over the next 10 years. As the Company moves forward in its efforts to secure needed renewable resources for Delmarva's customers, the Company sees an opportunity to help promote and gain support from Delmarva's customers for these often more costly energy sources. The Company believes that potential modifications to Delmarva's renewable portfolio legislation, the existing standard offer service bid process, and/or the implementation of green choice programs, where customers make the choice to support renewable energy supplies for the customer's needs, are a few ways to meet Delmarva's needs. Working with the Delaware Energy Office, the SEU group, Energy Suppliers, the Public

Advocate and the PSC, the Company can discuss options and ideas to encourage renewable generation resources.

B. Advanced Metering and Related Technology

1. AMI Infrastructure

AMI will provide customers and the utility with more detailed and timely information on energy use. The Company will replace approximately 430,000 existing gas and electric meters[10] with new computer imbedded intelligent meters. These intelligent meters will ultimately allow the Company to collect and transmit customer information such as billing data, usage patterns, voltage levels and outage information, and ultimately send information to Delmarva's computer systems, where the Company can process it and use it to better serve customers. This system could also be used to communicate directly to customers' thermostats and appliances and control the operation of this equipment based on energy prices. In the future, this same system will allow Delmarva to send information to customers, via a display in the customer's homes or to an internet site, the price of electricity – either real time prices or day ahead pricing. Eventually appliances will be in homes and businesses that are able to directly respond to energy prices.

Most recently, the Company participated in a working group in Docket No. 57 and worked collaboratively with the Division of the Public Advocate and the Commission Staff to prepare a report on Advance Metering, which was submitted to the Commission on November 15, 2006. Much of this joint report will be critical to helping establish the framework for the Advance Metering Infrastructure system. The Company proposes that a working group, comprised of the same stakeholders, work with Delmarva to develop the implementation plan for full scale AMI implementation. Timelines for starting work were laid out in Docket 57, and the Company proposes to maintain this timeline going forward to plan the implementation of a full scale roll out.

In addition to the direct customer benefits, the Company expect several operating efficiencies resulting from AMI technology, such as the ability to remotely turn customers on/off (an advantage in areas with high seasonal occupancy), theft detection and, as the Company will be able to monitor (as opposed to estimate) actual load, more accurate transformer and circuit wire sizing. Customer restoration will be improved due to more detailed information around the number and location of customers out of service coming from the advanced meters. Not only will this allow us to quickly respond, but it will also help us better pinpoint the location of the problem. Delmarva will share with the working group with a more detailed business case upon full scale implementation.

2. Smart Thermostat Technology

Another optional technology the Company is recommending is the implementation of Smart Thermostats for residential and commercial customers. These will not only have the obvious benefit of allowing customers to precisely control their heating and air conditioning use,

[10] 303,000 electric meters, 126,000 gas meters.

but also will provide a link back to the utility, so that during peak times the Company will be able to control the largest energy using devices in homes. This is an evolution of the "Energy for Tomorrow" program currently in place in Delaware.

3. Customer Information Systems Enhancements

Within PHI there are two CIS systems and a variety of meter data management systems. Two new PHI-wide systems, one for meter management and a second for customer information, will allow us to better use the greatly increased information coming from the automated meter reading system and new automated field devices. Although the Company is not proposing in this filing that it embark on the updating of Delmarva's CIS, the Company does recognize that, eventually, the Company will be limited in the use of some technology, such as advanced metering, by the current capabilities of the system. The Company does plan on implementing a new meter management system as part of this effort.

4. AMI Related Communications Network Upgrades

Delmarva will improve the Company's communications network to handle the increased flow of customer and distribution system data to/from Delmarva's operational centers. The Company is of the view that a fixed communications network provides the most robust and secure communications platform for AMI and DA. This network would take information to Delmarva's substations; from there it would travel over a fiber network to Delmarva's main offices. While many of Delmarva's transmission substations are served by fiber, the Company has plans to install fiber at select Delmarva distribution substations. It is important to leverage this network across all of Delmarva's technology investments, as it will greatly improve the business case for all applications if they share a common communications network.

5. Distribution Automation

Distributed Automation ("DA") is a technology designed to lower the number and length of electric system outages. The Company will install a number of intelligent relay devices, circuit switching devices, advanced protective devices and computer programs to more accurately detect and determine where problems exist on the network. In many cases, once problems are identified and located, a new technology will automatically isolate the problem areas and reconfigure the network to provide electric service to customers not impacted within the problem area. This will result in fewer outages, faster restoration and, other operating efficiencies. Although not part of this filing, because of the linkage to the proposed technology changes, we plan on following up with a distribution automation filing in the near future as it is very interrelated to the advanced meters and enhanced communications network.

C. Electric Vehicle and Distributed Generation

1. Electric Vehicles

Delmarva Power anticipates a surge in growth of electric powered vehicles in Delaware in the near term, as a result of General Motors, Toyota and other vehicle manufacturers bringing plug-in hybrids and electric drive vehicles to the market.

Delaware Customers will be able to recharge their vehicles via power metered through a second meter installed for the Customer that limits recharging to the hours between midnight and 6:00 a.m. The Company anticipates offering a new Electric Vehicle tariff with rates similar to the rates currently available in the Residential Time-of-Use, Super-Off-Peak tariff; the Customer charge is $11.32 per month and the cost per kWh equates to less than 5 cents per kWh.

The proposed tariff, which is not included with this filing, would be implemented once advanced metering was completed to enable the time of use component of this application.

2. Net Energy Metering

Net Energy Metering is used by the Company to enable customer sited generation on our system. It is a good tool to enable renewable energy resources for our customers. We believe that our advanced metering will enhance our ability to encourage Net Energy Metering customers to provide added generation during peak periods, and receive larger credits as a result.

Senate Bill No. 8 is currently pending Legislative approval. This Bill suggests enhancements to the Net Energy Metering tariff for all Delaware Electric Power Customers. Delmarva Power feels the increased maximum system size moving from 25 kW to 2 MWs is a step in the right direction to encourage more Delmarva Power Customers to adopt renewable generation systems including wind, photovoltaic solar or hydro power.

Red-line and revised versions of Leaf Nos. 102 and 104 are included in Appendix A. These proposed changes move towards a more progressive tariff that enables additional renewable on-site generation to be built in Delaware.

D. Cost Recovery Proposals

The deployment of AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure and to encourage the implementation of this new technology the Commission should adopt ratemaking policies that remove a utility's disincentive toward demand-side resources that reduce throughput; provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and provide depreciation lives for AMI that take into account the speed and nature of change in metering technology.[11]

1. Bill Stabilization Mechanism

The Company is proposing a BSA, a billing adjustment to be applied on a quarterly basis for all customers. The initial and most visible benefit of the BSA is to reduce the volatility in the distribution charge on customer bills. In severe weather in which customers face sharply higher bills, the BSA will reduce the payments that would otherwise be due. Conversely under the BSA, customers will pay more for delivery in mild weather than they would otherwise, but their overall bills will still be lower compared to what they would be with normal weather. In short, customers' electric distribution bill variability will decrease somewhat.

The BSA is intended to stabilize revenues fluctuations resulting from unanticipated changes in usage, and ensures that the Company only recovers the Commission-approved level of distribution costs. In essence, the BSA provides for decreases in delivery rates if actual revenues per customer are above the Commission approved level, and it provides for increases in delivery rates if actual revenues per customer are below the Commission approved level.

The BSA will facilitate the Company's promotion demand side management measures. In this filing, the Company is proposing development of electric energy efficiency measures and demand response services for all Delmarva electric distribution customers, as part of an overall response to the recent increases in supply prices. Demand-side management programs reduce sales and, consequently, revenues and fixed cost recovery decline. This creates a disincentive for the utility to consider demand-side resources. The existing rate structure provides strong incentives for utilities to sell as much electricity as possible in order to maximize profit. The BSA removes the incentive for the Company to maximize its sales in order to benefit shareholders. Without the BSA, the Company's shareholders benefit from each additional kWh delivered. With the BSA, the link between increased sales and profits is broken. The Company's interest in helping its customers use energy wisely and efficiently is no longer at seeming odds with the interests of shareholders. By decoupling the Company's revenues from changes in the volume of electricity delivered to customers, the adoption of the BSA aligns the Company's interests with the interests of the customer. The adoption of the BSA mechanism is a

[11] See NARUC Proposed Resolution supporting this approach.

critical component of the Company's overall proposal to institute conservation programs to help customers meet the challenges of the current high costs of energy, without conflicting with the interests of shareholders.

In Delmarva's natural gas base rate case, the Company proposed a bill stabilization plan for Delmarva's gas customers.[12] With this filing The Company has proposed the same for Delmarva's electric customers. Delmarva has made a similar proposal in its Maryland electric distribution base rate case filing. Based upon input to date in Delmarva's gas filing, the Company understands that there is an interest in working this issue collaboratively with the other gas utility in the state; therefore, the Company proposes to develop the final the gas and electric proposals together in conjunction with Chesapeake Utilities. In this manner, all of the regulated Delaware electric and gas distribution entities will move forward together on this effort, with common philosophies.

2. DSM Surcharge Proposal

Delmarva requests the Commission establish a DSM electric distribution surcharge mechanism that would recover all DSM expenditures, other than smart thermostat related costs, over a five year period. Program costs would be allocated to each rate class eligible to participate in each implemented program. This surcharge mechanism would be similar to the DSM surcharge mechanism that existed in the 1990s for Delmarva in Maryland. Delmarva's annual carrying cost of any unrecovered expenditures would equal the Company's approved rate of return.

The surcharge amount would be established by an annual Delmarva DSM surcharge adjustment filing, subject to Commission approval, based upon the forecast level of expenditures for the next program year and any required "true-up" adjustments for over or under collections from the prior year. If Delmarva's recommended DSM programs were implemented, the estimated maximum monthly surcharge for residential customers would be $0.001149 per kWh and $0.000395 per kWh for nonresidential customers.

3. AMI Adjustment Mechanism

Delmarva requests that a base rate electric and gas adjustment mechanism ("AMI Adjustment Mechanism") be adopted to recover the capital costs associated with the installation of smart thermostats and the AMI on a timely basis between base distribution rate cases. Specifically the AMI Adjustment Mechanism would be set annually on the basis of total project expenditures during the previous 12 month period. Delmarva proposes to net any utility cost savings resulting from AMI deployment from the cost recovery sought each year. Similar to other utility investments, the amortization period would be identical to expected equipment life -- for these expenditures the recommended recovery period is 15 years, due the accelerating obsolescence rate of new technology.

[12] In the Matter of the Application of Delmarva Power & Light Company for a Change in Natural Gas Base Rates, PSC Docket No. 06-284 (Filed August 31, 2006).

Delmarva requests that the cost of retiring all existing meters and fully amortizing those costs be recovered through the AMI Adjustment Mechanism on an accelerated basis, not to exceed three to five years. Delmarva's annual cost of any unrecovered expenditures would equal the Company approved rate of return. The amount of the AMI Adjustment Mechanism would vary by customer class, reflecting any AMI or smart thermostat cost differences. If the Commission approves the AMI Adjustment Mechanism, the monthly bill impact on customers after full AMI deployment is estimated to be $6.00 for each electric and gas customer. These costs will be offset by energy cost reductions, utility cost reductions and service quality improvements.

An alternative utility cost recovery approach could be obtained through electric base rate case filings; however, this mechanism has the significant disadvantage of delaying the timing of Delmarva's cost recovery for a significant capital cost project and having a potentially adverse impact upon the Company's cost of capital.

E. Regional Consistency

Today's filing represents a significant resource commitment and the Company is confident that the initiatives will yield many benefits for Delmarva's customers. In order to best move forward with these initiatives, the Company feels that it is essential to proceed in a collaborative fashion with many of the key stakeholders. From the beginning the Company has indicated that the energy issues in the State cannot be solved by any one group, or any one proceeding alone, but will require all stakeholders to work together on a solution.

The Company proposes that a regional group led by a Company Executive and a Commissioner, and made up of high level representation from each of the state commissions where PHI operates, should be formed to ensure the programs developed to support advance metering, energy efficiency, demand response and renewable energy best meet the needs of Delmarva's consumers throughout the Company's service territory. The Working Group can do this by working toward consistent design and guiding principles as programs such as these are laid out. The Company hopes this group will be able to bring together regulatory and state agency representatives from across the region with a commitment to work together for the benefit of all customers served by PHI utilities.

III. CONCLUSION

The Company requests the Commission issue an order requiring publication of notice announcing Delmarva's filing. In addition, we request the Commission assign this to a Hearing Examiner, who will use a series of working groups to review the components of this bundled package. We believe it is important that, despite the need to have several working groups address the separate components of the filing, a single joint working group coordinate the various teams to assure continued linkage of the components.

Delmarva has packaged the various components of this filing together for a reason: we believe they are all critical components which, for the most part, should be considered as a package for implementation. It is our hope that although we do not expect any pre-approval of the substantial investments we are about to make, that the Commission rules in support of moving the Company forward in this direction. In addition, the various cost recovery mechanisms and stabilization components would need to be approved prior to moving forward.

The Working Groups are requested to complete their review and make recommendations to the Commission by August 1, 2007. Delmarva requests that the Commission issue a final order not later than September 1, 2007. Thereafter, Delmarva would begin working towards implementation in the same collaborative manner as the review was conducted, keeping all stakeholders engaged along the way.

Finally, Delmarva requests that the Commission grant such other relief as necessary to effectively implement the Blueprint for the Future Plan.

Respectfully submitted,

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ATTACHMENT C

42 CPUC 2d 645, 130 P.U.R.4th 97, 1991 WL 501681 (Cal.P.U.C.)

Re Southern California Edison Company

Decision 91-12-076
Application 90-12-018
Interim Orders 89-12-025, 91-02-079

California Public Utilities Commission

December 20, 1991

INTERIM OPINION authorizing base rate revenue requirement for an electric utility in Phase I of a general rate case. Commission approves an authorized level of base rate revenues of $4.012 billion, or an increase of 1.3% over current revenues. The approved increase will result in an increase to overall rates of 0.7%. Commission also adopts marginal costs for the utility for use in Phase 2 of the proceeding to consider revenue allocation and rate design issues. The utility is directed to share with ratepayers any savings experienced under a cost containment program, as well as to institute a shared savings incentive program for demand-side management activities. Commission finds that the utility had failed to meet established standards for the provision of information regarding affiliated qualifying cogeneration facilities (QFs), but declines to impose a rate-of-return penalty. It rules, however, that in future cases on the utility's energy adjustment clause, it might allow recovery of only the lowest available replacement power costs if the utility should continue to offer incomplete information on its QF affiliates.

P.U.R. Headnote and Classification
1. REVENUES
s2 - Estimates for the future - Effect of bypass by customers - Drought - Electric utility.

Ca.P.U.C. 1991
An electric utility's test-year sales were projected without special adjustments for customer bypass or drought conditions, since bypass effects were already included in historical data trends and drought conditions were not expected to persist.
Re Southern California Edison Company

P.U.R. Headnote and Classification
2. EXPENSES
s95 - Salaries and wages - Comparisons with other firms - Electric utility.

Ca.P.U.C. 1991
Although doubting that an electric utility's level of employee compensation higher than market averages was necessary for assuring safe and reliable service, the commission declined to disallow the compensation level and did not require the utility to institute compensation based on total market parity.
Re Southern California Edison Company

P.U.R. Headnote and Classification
3. EXPENSES
s9 - Ascertainment - Adjustments to test-year figures - Escalation of costs - Controllable and uncontrollable expenses - Productivity and cost containment - Electric utility.

Ca.P.U.C. 1991
Under an electric utility's cost containment program, expenses are classified as controllable or uncontrollable, with controllable expenses subject to a containment goal of the rate of inflation less 1.5%, and with the 1.5% savings shared equally between ratepayers and shareholders; examples of uncontrollable expenses include fuel, demand-side management, research, franchise fees, uncollectibles, and employee health plan costs.

6.2.4.1 Materials and Supplies

Edison estimated its 1992 materials and supplies inventory by escalating the recorded 1990 end-of-year balance to 1992 at 5% per year. DRA noticed that the 1990 balance was more than 16% higher than the 1989 balance. Therefore, DRA estimated the 1992 inventory level by escalating the 1989 balance forward, using the same 5% per year. After month-by-month weighting, the amount in dispute is $4.323 million in rate base.

We agree with DRA that the 1989 end-of-year inventory is an appropriate basis for test year inventories. We will adopt DRA'S rate base reduction.

6.2.4.2 Working Cash

[44] Working cash itself has eight operational cash elements which are derived from account records, plus a cash requirement based on a lead-lag study of estimated utility cash flows. DRA has disputed several parts of this construction. DRA and Edison agree that working cash should be calculated using adopted expenses, escalation rates, and sales forecasts. Although working cash disputes seem overly detailed at first glance, for Edison a change of one day in cash flow could result in a $10 million change in rate base.

DRA recommended a reduction in recorded account balances for 'other accounts receivable,' due to nonrecurring charges of $4.0 million for earthquake damage claims and $1.4 million for reimbursable fire damage at Edison's office building. Edison did not respond to DRA's recommendation, either in rebuttal testimony or in briefs. We accept DRA's reduction.

The lead-lag calculation considers the timing of both Edison payments and customer revenues. On the payment side, DRA recommends increasing the average time for purchased power payments from 39.65 days to 42.28 days, to exclude payments to Kern River Cogeneration Company (KRCC), an Edison affiliate. DRA determined that payments to KRCC are made in 12.5 days, unfairly decreasing the average lag between receipt of the power and payment by Edison. Edison did not respond to DRA's recommendation, and we will not adopt it. Early payments to utility affiliates and subsidiaries should not be considered in working cash calculations.

On the customer revenue side, DRA disputed Edison's estimate of the impacts of Edison's planned late payment charge. Edison's recorded revenue lags during 1989 for commercial, industrial, and agricultural customers were 43.55, 45.53, and 44.36 days, respectively. Edison used 40 days to estimate test year working cash, reflecting the effects of the late payment charge on customer behavior. DRA recommended a further reduction of 2.2 days.

The forecasts of customer behavior are no more than educated guesses. We will adopt Edison's forecast, but with a note of concern about application of the late payment charge. During hearings Edison announced that it plans a six to eight day grace period in application of the late payment charge, which would tend to increase revenue lag days. We remind Edison that if its late payment charge is eventually approved, it should enforce the charges fairly and uniformly, in accordance with filed tariffs.

In its comments on the ALJ's Proposed Decision, the California Department of General Services pointed out that late payment charges to governmental facilities are limited by the California Governmental Code. We assume that Edison's lag day estimates have considered this constraint.

6.2.5 Amorphous Core Transformers

Although the parties do not mention this issue in their briefs, the joint comparison exhibit shows a dispute over inclusion of amorphous ***704** core transformers in rate base, in the amount of $1.272 million. Amorphous core transformers cost more than

ATTACHMENT D

1992 WL 402072 (Nev.P.S.C.)
PUR Slip Copy

Re Central Telephone Company-Nevada

Docket Nos. 91-5054 and 91-7026

Nevada Public Service Commission

January 7, 1992

ORDER addressing applications by a local exchange telephone carrier (LEC) for approval of revised depreciation rates and for authorization to be regulated under General Order No. 60 (GO 60), to adjust certain intrastate rates and charges and to recover revenue under General Order No. 42. A stipulation in the consolidated dockets is approved to resolve issues relating to GO 60 requirements for quality-of-service standards and accounting reports. The order also requires imputation of directory revenues for rate-making purposes, because the LEC's filed revenues were not supported by substantial evidence, and Touch Four service is discontinued. With regard to the calculation of depreciation rates, the order rejects use of the equal life group procedure, as well as the use of a reallocation of reserves.

APPEARANCES: For the Commission: Rose Mckinney-James, Commissioner, and Presiding Officer, Thomas Stephens, Chairman, Stephen Wiel, Commissioner, Jo Ann Kelly, Commissioner, Michael A. Pitlock, Commissioner, C. Kirby Lampley, Deputy Commissioner, Leslie T. Miller, Esq., General Counsel, Gemma Greene, Esq., Administrative Attorney, Helen H. Aberle, Esq., Administrative Attorney, Micheal Greedy, Technical Advisor, Steven Tullis, Technical Advisor, Frank McRae, Technical Advisor.

For the Commission Staff: Kelly Jackson, Esq., Staff Counsel, Lawrence J. Stratman, II, Esq., Assistant Staff Counsel.

For the Applicant Central Telephone of Nevada: LIONEL, SAWYER & COLLINS, by Kristin Burt McMillan, Esq., Todd M. Touton, Esq., and Paul Larson, Esq., in association with CENTRAL TELEPHONE COMPANY, by Loreli Fritz Cohn, Esq., Vice-President for Legal Affairs.

For the Attorney General's, Office of Advocate for Customers, of Public Utilities: LAW OFFICES OF STEVEN F. BUS, by Steven F. Bus, Esq.

For Nevada Bell: Margaret E. Garber, Esq., General Counsel.

For MCI Communications: CROWELL, SUSICH, OWEN & TACKES, LTD., by Steven E. Tackes, Esq.

For AT&T Communications, of Nevada: MCDONALD CARANO, WILSON, MCCUNE, BERGIN, FRANCOVICH. & HICKS, by John Francovich , Esq., in association with AT&T COMMUNICATIONS, INC., by William A. Ettinger, Esq., Senior Attorney.

For Nevada State Press, Association: KILPATRICK, JOHNSTON & ADLER, by Ernest Adler, Esq., and Andrea Engleman, Executive Director.

BY THE COMMISSION:

OPINION

I. INTRODUCTION

***1** A. Procedural History

improper mismatch. By the nature of the annualization, a full year's effect based on the certification level of revenue, expenses and investment is recognized. Therefore, we reject the OCA's adjustment. [51]

iv. 1992 Shift (GO 42)

In the previous discussion and denial of the OCA's Motion to Dismiss (see, supra), the Commission accepted the inclusion in rates of the shift in allocation from interstate to intrastate that will take place on January 1, 1992. Therefore, we reject OCA witness Silva's proposal to reverse the Applicant's certification adjustment for GO 42. As noted above, the Commission was able to calculate the interstate shift only with the assistance of information presented in Staff's exhibits. The Commission's Calculation of the 1992 shift to Nevada intrastate is shown on Attachment 4. As portrayed on this schedule, the Commission arrives at an increased revenue requirement of $4,924,504 using a rate of return of 10.50 percent compared to the Applicant's $5,233,887 using a rate of return of 12.35 percent, which represents a reduction of $309,383. Most differences are insignificant, but a notable exception is the shift in Reserve for Leasehold Improvements. It appears that the Applicant used the same factor as the Reserve for Capital Leases, but it is clear from Workpaper N-1 and the schedule of ratios attached to GO 42 that this is not the correct factor. It should be noted that the gross-up factor used to calculate the increased revenue requirement is 1.515152 rather than the 1.540903 used in the general rate case portion of the filing to be consistent with the Applicant's presentation. [52]

V. GENERAL RATE CASE AND REVENUE REQUIREMENT

*55 Revenue Requirements

A. Pension and Other Postretirement Benefit Expense

Jeffrey Galloway, witness for Staff, proposed an adjustment to the Applicant's pension expense based on an accelerated amortization of the "transition asset" calculated under Statement of Financial Accounting Standards ("SFAS") No. 87 over a period of five years. (Ex. 65a at JWG-2) Except for the five year period, this is basically the same adjustment that Staff has proposed in prior cases. (Tr. at 1827) The proposed adjustment would result in a decrease of expense to the Applicant of $775,034 (intrastate). (Ex. 65a at JWG-2)

Mr. Galloway also proposed an adjustment to the Applicant's expense for other postretirement benefits ("PRB"). This adjustment is based on Staff's objection to the calculation of PRB by the Applicant pursuant to SFAS No. 106. (Ex. 65 at 4) According to Staff, implementation of SFAS No. 106 is not required until December 1992 and, therefore, calculation of expense under this standard should not be allowed for ratemaking purposes. (Ex. 65 at 5) Mr. Galloway proposed a reduction to expense of $876,031 (intrastate), which also reflects a Staff adjustment for discontinued operations and utilizes Staff's separation ratios. (Ex. 65a at JWG-3) According to Mr. Galloway, this adjustment allows the Applicant to accrue PRB expenses in accordance with Docket 87-1249 which settled only the period of amortization relating to PRB. *(Id.)*

Mr. Robert Silva, witness for the OCA, proposed an adjustment to PRB expense but not to pension expense. Mr. Silva based his proposal on the fact that the Applicant adopted SFAS No. 106 earlier than required by the Financial Accounting Standards Board ("FASB") and the fact that the Applicant had already initiated calculation of PRB expense based on accrual accounting. (Ex. 61 at 16-17) Since 1985, the Applicant has been amortizing PRB expense over the average remaining service life of employees in accordance with the Stipulation in Docket Nos. 87-1131, 87-1249, and 87-1072. *(Id.)* The essence of Mr. Silva's adjustment is that the Applicant, under SFAS No. 106, amortizes prior service cost on a straight-line basis which results in a higher expense than under the method the Applicant has been using since 1985. *(Id.)* Mr. Silva believes that the fact that SFAS No. 106 encourages early implementation relates more to the transition from a cash basis to an accrual basis of accounting, which would not apply to the Applicant since it is already on an accrual basis. (Ex. 61 at 18) Mr. Silva's adjustment is $1,452,706 (intrastate). (Ex. 61 at 16)

Mr. Thomas De Ward, also a witness for the OCA, proposed two rate base adjustments relating to pensions and PRB. Mr. De Ward recommended that the deferred pension cost be removed from rate base. Since this asset was the result of a book entry and required no cash outlay from the Applicant, according to Mr. De Ward, the Applicant is not entitled to earn a return on it. (Ex. 62 at 9) This adjustment is a $10,357,354 (intrastate) reduction to rate base. (Ex. 62a at TCD-1, Sched. 1)

***56** Mr. De Ward also proposed an adjustment to rate base relating to PRB. According to Mr. De Ward, the Applicant is not currently funding PRB expense, and, therefore, the book accrual representing a liability should not be allowed in rate base. (Ex. 61 at 10) Mr. De Ward's adjustment is a $7,253,343 increase to rate base (intrastate). (Ex. 61a at TCD-1, Sched. 1)

i. Commission Discussion

In past dockets, the Commission has accepted adjustments to accelerate the gain resulting from adoption of SFAS No. 87 relating to pensions. In these prior cases, however, accounting for postretirement benefits under SFAS No. 106 was not an issue. In the instant case the Applicant has chosen to adopt SFAS No. 106 during the certification period, although it was not required to do this. Whether the Applicant adopted SFAS No. 106 during the certification or not, the Applicant would have to adopt this accounting procedure for its fiscal year beginning after December 15, 1992, within the GO 60 option period. The Commission believes that the real issue is whether or not to recognize acceleration of the transition gain for pensions on the one hand, while not recognizing acceleration of the postretirement benefit liability resulting from SFAS No. 106, on the other.

The Applicant has exercised its prerogative to adopt the new accounting rule, as it was encouraged to do by the FASB. (See SFAS No. 106 at 36) The Applicant has indicated that it had sufficient data to make this implementation, based on its experience since 1985. (Ex. 94 at 14) Although the OCA would hold the Applicant to an expense level determined by a accrual method used since 1985, the Commission believes that adoption of SFAS No. 106 necessitates a new expense calculation. The Commission further notes that while the pension plan is overfunded by approximately $12 million, other postretirement benefits are underfunded by approximately $24 million. (Ex. 94 at 3) An equitable determination would require the Commission to consider an accelerated recognition of the underfunded portion of other postretirement benefits if it decided that it was appropriate to accelerate recognition of the pension plan transition asset. The two issues must be considered together. In conclusion, the Commission believes that expense levels calculated pursuant to SFAS Nos. 87 and 106, when pensions and other postretirement benefits are considered together, are appropriate and will make no adjustment to these expenses. [53]

With regard to the rate base adjustments proposed by Mr. De Ward, Mr. Bailor, for the Applicant, responded that investors were the source of the prepaid pension asset and that the corresponding reduction to expense that gave rise to the asset resulted in a reduction of revenue requirement and, hence, cash flow. (Ex. 94 at 48) This reduction in cash flow must be compensated for from other sources. *(Id.)* Mr. Bailor concluded that the reduction in pension expense and revenue requirement was supported by investors and, therefore, was entitled to a return. (Ex. 94 at 47)

***57** The Commission believes it is illogical to conclude that investors should receive a return on a book entry that reduces expense. Investors are entitled to a return only on funds that are actually provided and not on assets that accrue as a result of accounting procedures. Additionally, if the Applicant believed that this accounting methodology resulted in cash flow problems, the Applicant should have proposed an addition to rate base for Cash Working Capital. Since no such proposal was made, the Commission concludes that the Applicant felt it was being made whole with regard to cash flow. The Commission also believes that Mr. De Ward's proposed adjustment to rate base properly reflects the fact that the Applicant has made no contributions and, therefore, should earn no return on rate base relating to pensions. [54]

Likewise, the liability for PRB should also be removed from rate base. The net effect of these adjustments is a reduction to rate base of $10,357,354 - $7,253,343, or $3,104,011 (intrastate). Additionally, the Commission accepts the related reduction to Accumulated Deferred Federal Income Tax of $1,194,084 corresponding to these adjustments proposed by OCA witness De Ward. (Ex. 62 at 10; Ex. 62a at TCD-1, Sched. 1) This results in an increase to rate base of $1,194,084. The net change in rate base is a reduction of $3,104,011 minus $1,194,084, or $1,909,927. [55]

ATTACHMENT E

19 Tex. P.U.C. Bull. 929, 1993 WL 595464 (Tex.P.U.C.)
PUR Slip Copy

Re Central Telephone Company of Texas

Docket No. 9981

Texas Public Utility Commission

September 08, 1993

Before Gee, chairman, and Greytok and Rabago, commissioners.

BY THE COMMISSION:

*1 Commission approved $18.073 million annual rate reduction for local exchange carrier. Third motions for rehearing denied by operation of law November 22, 1993.

[1] RATEMAKING - INVESTED CAPITAL - CAPITALIZED EXPENSE ITEMS

Fully funded prepaid pension fund not included in utility's invested capital because permitting utility to earn return on fund would effectively charge ratepayers again an amount already paid through rates. (Page 956)

[2] PROCEDURE - PURA § 43 RATE CASES - RATE FILING PACKAGE PROCEDURE - PURA § 42 RATE INQUIRIES - RATE FILING PACKAGE

Failure to challenge sufficiency of rate filing package does not estop party from later challenging sufficiency of utility's evidence to support specific ratemaking treatment. (Page 961)

[3] RATEMAKING - COST OF SERVICE - AFFILIATE TRANSACTIONS

Utility's failure to offer specific proof evidencing that unit price it paid to supplying affiliate was no higher than unit price charged other affiliates justified exclusion of affiliate-related expenses; utility witness's 'understanding' that affiliate charged affiliated local exchange carriers for units at cost and marked up prices for same units in transactions with non-telecommunications affiliates does not suffice to meet utility's burden of proof under PURA § 41(c)(1). (Page 1058)

[4]

Utility's use of proposed allocation methodology, as opposed to actual allocation methodology used during test year, to prove that its affiliate did not charge it a higher price in comparison to other affiliates does not meet standard of proof required by PURA § 41(c)(1). (Page 1060)

[5] RATEMAKING - COST OF CAPITAL - RATE OF RETURN - OTHER

Nothing in PURA § 39(a) permits Commission to establish earnings monitoring zone separate from utility's reasonable return on invested capital. (Page 1087)

[6] RATEMAKING - RATE DESIGN - TELEPHONE - PRICING CONCEPTS - GENERAL CONCEPTS - UNIVERSAL SERVICE

The examiner further agrees that it is proper to reduce CENTEL's rate base by $1,077,586 for accrued post-retirement benefits other than pensions. The examiner concurs with General Counsel that accrued post-retirement benefits other than pensions should be adjusted by an additional ($589,348) to reflect attendant impacts to CENTEL's proposed implementation of SFAS 106. CENTEL argues that inclusion of the ($589,348) assumes the implementation of SFAS 106 in 1991. The examiner disagrees. CENTEL has not yet adopted SFAS 106. P.U.C. SUBST. R. 23.21(a) states, in part, that rates are based upon a utility's cost of service during a historical test-year. Post-test-year adjustments for known and measurable changes must identify, quantify, and match attendant impacts. Because CENTEL proposes adoption of SFAS 106 after the test-year, it is considered a post-test-year adjustment which requires identification, quantification, and matching of attendant impacts. General Counsel witness Ms. Stark properly included an adjustment of ($589,348) to accrued post-retirement benefits other than pensions.

The examiner rejects CENTEL's assertion that General Counsel's adjustment creates a mismatch with other rate base components by moving only one component of invested capital to a December 31, 1991 date. As pointed out by General Counsel, many rate base items in this case have been adjusted to 1991 levels. The examiner recommends accrued post-retirement benefits other than pensions in the amount shown in Schedule VI, to reflect CENTEL's use of cost-free capital. Further, the examiner recommends an increase of $476,380 to CENTEL's cost of service to reflect CENTEL's adoption of SFAS No. 106.

C. Pensions

***11** CENTEL proposes to include in its calculation of invested capital a prepaid pension asset in the amount of $2,079,022. [16] CENTEL witness John P. Meyer testified that CENTEL's pension fund is fully funded and has been since 1985, because of favorable investment experience and reductions in benefit levels. According to Mr. Meyer, ratepayers are receiving a negative pension expense which is used to reduce the cost of service in Texas. The reduction in pension expense and the attendant revenue requirement reduction is supported by investors. Mr. Meyer gave the following example to illustrate his position that a reduced revenue requirement resulted in the need for investor-supplied funds.

First, assume CENTEL incurred and paid allowable operating costs of $10 million (without considering the negative pension expense). The Commission would presumably set rates to permit recovery of $10 million from the ratepayers. The ratepayers would be providing revenues sufficient for CENTEL to pay all of the operating costs and no external cash flow would be necessary. Now consider the effects on revenue requirements and outside financing requirements caused by negative pension expense. Note that when the $1 million negative pension expense is recorded by a non-cash credit to the income statement, the revenue requirement is reduced to $9 million. This $9 million of revenue will be used to pay $9 million of the $10 million of allowable operating costs (excluding pension), and a $1 million shortfall results. External financing is needed to pay the shortfall. Thus, Ms. Blumenthal's suggestion that investors are not the source of the prepaid pension asset recorded on CENTEL's books is incorrect because it fails to take into account the resulting cash shortfall caused by the passing on of the over-funded pension trust assets to Texas ratepayers, in the form of negative pension expense.

OPC witness Ellen Blumenthal disagreed with CENTEL's proposal. [17] According to Ms. Blumenthal, CENTEL has made no contributions to its pension fund and the pension asset on which the Company proposes to earn a return was established with ratepayer funds. Pension expense has been historically recovered through rates on a pay-as-you-go basis. Because investors did not supply any funds for pension costs, and the funds were all provided by ratepayers, Ms Blumenthal recommended that the prepaid pension asset that CENTEL included in rate base be removed.

Further, Ms. Blumenthal recommended that no pension expense be included in rates, because the Company is making no contributions to its pension fund. Ms. Blumenthal testified that by including the prepaid pension asset in rate base, CENTEL, in effect, charges ratepayers again for amounts they have already overpaid.

General Counsel concurred with CENTEL that the correct amount of prepaid pension costs to be included in rate base is $2,079,022. However, General Counsel provided no credible testimony to support its concurrence with CENTEL's proposal.

***12** The prepaid pension asset proposed by CENTEL to be included in rate base caused the examiner great consternation. CENTEL witness Mr. Meyer provided an eloquent discussion to support his proposal that CENTEL earn a return on the prepaid pension asset. However, the examiner finds that the evidence in the record does not support CENTEL's proposal.

If we revisit Mr. Meyer's example, in which CENTEL would incur and pay operating costs of $10 million, Mr. Meyer is correct that the Commission would set rates to permit recovery of the $10 million from ratepayers. The examiner disagrees with Mr. Meyer's next contention, however, that when the $1 million negative pension expense is recorded by a non-cash credit to the income statement, revenue is reduced to $9 million, resulting in a $1 million shortfall. If CENTEL were allowed $10 million in operating costs, the $1 million negative pension expense would have already been deleted from the revenue requirement and there would be no shortfall. The $1 million negative pension expense is simply a non-cash journal entry CENTEL must record on its books.

CENTEL's argument is beguiling at first glance. However, upon further consideration, CENTEL's argument to include a return on the prepaid pension asset is specious. CENTEL argues that the negative pension expense is deducted from the cost of service for the benefit of the ratepayer, and that if CENTEL does not recover the negative pension expense from the ratepayers, then the Company must obtain the cash from another source and pay a return to investors. However, the characterization of the reduction in cost of service as a negative pension expense is a misnomer. The negative pension expense simply means that CENTEL has no revenue requirement for pension expense in its cost of service. There is no cash credit to ratepayers by CENTEL. There is simply a non-cash journal entry made by CENTEL on its books to reduce the amount of the overfunding, much the same way that a financial obligation is amortized over a period of time.

Mr. Meyer admitted at the hearing that the pension asset was funded by ratepayers and that the credit is a non-cash journal entry. [18] However, he subsequently attempted to characterize this non-cash entry as investor-supplied cash that must be included in rate base. The examiner disagrees that CENTEL must go to investors to make up the amount of the negative pension expense. If CENTEL's pension fund does not require additional funding and CENTEL's revenue requirement is reduced as a result, there is no cash for CENTEL's investors to make up. Section 39 of PURA allows CENTEL to earn a reasonable return on invested capital, over and above reasonable and necessary operating expenses. If CENTEL's pension fund is fully funded, then there should be no pension expense included in rates as a reasonable and necessary expense. CENTEL should not earn a return on the credit it must make on its books to reduce the overfunding.

In its brief, CENTEL argues that the excess portion of the pension fund should be treated as an investor-supplied asset because investor monies fund the pension plan in the sense that the funds were earned through authorized rates and are monies that belong to the Company that could either have been used as internal capital or distributed to shareholders. This argument, however, is not credible. CENTEL collected, through its rates, enough money from ratepayers to fund its pension plan. Because CENTEL did not accurately predict that its pension fund would experience favorable investment results and that there would be reductions in benefit levels, the pension fund was subsequently overfunded. If CENTEL had predicted these events in advance, CENTEL's revenue requirement would have been reduced, the ratepayers would not have paid in as much, and CENTEL's pension plan would not be overfunded as it presently is. Therefore, CENTEL's argument that the Company or investors would have had use of the additional money in the pension fund is without merit. [1] The examiner is not convinced, and the credible evidence does not show, that it is reasonable for CENTEL's investors to earn a return on the prepaid pension asset because the pension fund is overfunded. The examiner agrees with OPC that to include the prepaid pension asset in rate base would have the effect of charging ratepayers again for amounts they have already paid. Accordingly, the examiner recommends that CENTEL's proposal to include $2,079,022 as a prepaid pension cost be rejected. The examiner's recommended offsetting adjustment of ($2,079,022) is shown on Schedule VI attached to this Report.

5. As of December 31, 1991, CENTEL served approximately 136,539 access lines in 48 central offices.

6. CENTEL is a wholly-owned subsidiary of Centel-Texas, Inc., which in turn is a wholly-owned subsidiary of Centel Corporation.

7. Interventions were granted to the Office of Public Utility Counsel (OPC), MCI Telecommunications Corporation (MCI), AT&T Communications of the Southwest, Inc. (AT&T), the General Services Commission (GSC), the Advisory Commission on State Emergency Communications (ACSEC), and to the Texas Association of Long Distance Telephone Companies (TEXALTEL).

8. Notice was provided by CENTEL to each customer by bill insert. The Company also published notice for four consecutive weeks in newspapers of general circulation in all service areas wherein affected customers reside.

9. The hearing on the merits convened on January 21, 1992, and adjourned on May 21, 1992.

10. The amount of invested capital reflected in Schedule VI is reasonable.

11. The amount of plant-in-service as set forth in Schedule VI is reasonable.

12. CENTEL's requested adjustments to plant-in-service to reflect one-party upgrades were not disputed by any party in this proceeding and are reasonable.

13. The amount of expense related to telephone plant under construction (TPUC), which was placed in service by December 31, 1990, is reasonable and should be included in plant-in service. TPUC which was actually placed in service after December 31, 1990, should not be included in plant in service for the reasons discussed in Section III of this Report.

14. The disallowance of plant-in-service attributable to affiliate allocations is reasonable for the reasons stated in Section III of this Report.

15. CENTEL presently funds its post-retirement benefits other than pensions on a pay-as-you-go basis and does not set aside funds to meet these obligations.

16. It is reasonable for CENTEL to accrue the costs of post-retirement benefits other than pensions over the service life of the employee. The benefits are being earned now and the liability for those benefits should be paid as they are earned. The obligation for benefits presently incurred should be paid by present, not future, ratepayers. However, FASB Rule 106 applies.

17. The adjustment discussed in the finding of fact above does not create a mismatch with other rate base components by moving only one component of invested capital to a December 31, 1991, date. Many rate base items in this case have been adjusted to 1991 levels.

***136** 18. It is reasonable to adjust CENTEL's rate base to reflect CENTEL's use of this cost-free capital, as reflected on Schedule VI.

19. It is reasonable to adjust CENTEL's rate base by an additional amount to reflect attendant impacts of this post-test-year adjustment.

20. CENTEL's argument to include a return on the prepaid pension asset is specious.

21. Investors are not required to make up the amount of negative pension expense. If CENTEL's pension fund does not require additional funding and CENTEL's revenue requirement is reduced as a result, there is no cash for CENTEL's investors to make up.

22. If CENTEL's pension fund is fully funded, then there should be no pension expense included in rates as a reasonable and necessary expense. CENTEL should not earn a return on the credit it must make on its books to reduce the overfunding.

23. The credible evidence does not show that it is reasonable to compensate investors through a return on the prepaid pension asset because the pension fund is overfunded. To include the prepaid pension asset in rate base would have the effect of charging ratepayers again for amounts they have already paid.

24. The examiner's adjustment disallowing this expense is reflected on Schedule VI.

25. CENTEL's proposal to include prepaid pension costs in rate base should be rejected.

26. OPC's proposed one-half-year convention adjustment to accumulated depreciation should be rejected. There is no credible evidence in the record to support this adjustment.

27. CENTEL's requested accumulated depreciation should be adjusted to reflect General Counsel's proposed alternative treatment of affiliate transactions allocated to CENTEL by the Nevada/Texas Regional Headquarters.

28. Accumulated depreciation as reflected on Schedule VI is reasonable.

29. Lead-lag studies provide support for cash working capital allowance for telephone companies. Telephone companies usually have negative cash working capital requirements because they bill in advance for local service.

30. Local service revenues constitute approximately 50 percent of CENTEL's total operating revenues.

31. If CENTEL had done a lead-lag study, it most likely would have resulted in a negative cash working capital allowance which would have lowered the Company's revenue requirement.

32. A lead-lag study was prepared in 1989 by Central Telephone Company in Iowa in connection with a filing before the Iowa Public Utility Commission. It is appropriate to apply the leads and lags from the Iowa study to CENTEL's revenues and expenses. Although it is a less than ideal way to compute CENTEL's cash working capital requirements, the Iowa study is the best choice available under the circumstances, because CENTEL failed to file a lead-lag study.

33. Regardless of whether or not SUBST. R. 23.21(c)(2)(B)(III) requires a lead-lag study to be filed by CENTEL in this case, the study would have supported or refuted CENTEL's request. Without the study CENTEL has no support for a request for a zero working cash capital allowance.

***137** 34. Using the methodology proposed by OPC to calculate working cash capital using the leads and lags of CENTEL's former Iowa affiliate, as modified by the examiner, to determine CENTEL's working cash capital allowance is reasonable for the reasons stated in Section III of this Report.

35. The record evidence in this proceeding supports a negative cash working capital allowance for CENTEL as reflected in Schedule VIII.

36. CENTEL Uniform Billing System (CUBS) is CENTEL's centralized billing system which was implemented in early 1989.

ATTACHMENT F

83 Pa.P.U.C. 17, 1994 WL 843040 (Pa.P.U.C.)

Pennsylvania Public Utility Commission

v.

UGI Utilities, Inc. - Electric Division

R-00932862

Pennsylvania Public Utility Commission

September 22, 1994
entered September 23, 1994

PETITION for reconsideration of an order entered in this matter July 27, 1994, relative to incentive compensation plans; denied, where no new or novel arguments had been raised. Commission affirms its disallowance of the utility's proposed incentive compensation package as not having been shown to have a direct impact on cost reductions or rate control efforts. For the earlier order, see 82 Pa PUC 488.

P.U.R. Headnote and Classification
1. PROCEDURE
s33

Pa.P.U.C. 1994
[PA.] Rehearing and reconsideration - Grounds for granting - Raising of new or novel arguments - No previous consideration of such arguments.
Pennsylvania Public Utility Commission v UGI Utilities, Inc. - Electric Division

P.U.R. Headnote and Classification
2. PROCEDURE
s36

Pa.P.U.C. 1994
[PA.] Principle of stare decisis - Not binding on the commission - Discretion of commission to change course - Necessity of explaining new position.
Pennsylvania Public Utility Commission v UGI Utilities, Inc. - Electric Division

P.U.R. Headnote and Classification
3. EXPENSES
s105

Pa.P.U.C. 1994
[PA.] Salaries and wages - Incentive compensation plans - Good idea in the abstract - Factors affecting actual approval - Promotion of operational improvements - Factual nexus to operational cost savings.
Pennsylvania Public Utility Commission v UGI Utilities, Inc. - Electric Division

P.U.R. Headnote and Classification
4. EXPENSES
s105

Pa.P.U.C. 1994
[PA.] Salaries and wages - Incentive compensation plans - Reasons for disallowance - No direct bearing on cost reduction or rate control efforts - Affirmation - Electric utility.

Pennsylvania Public Utility Commission v UGI Utilities, Inc. - Electric Division

David W. Rolka, Chairman, Joseph Rhodes, Jr., Vice-Chairman, John M. Quain, Dissenting, Lisa Crutchfield, John Hanger

BY THE COMMISSION:

OPINION AND ORDER

Before us for consideration is a *Petition for Reconsideration* [1] ('Petition ') filed by UGI Utilities, Inc., ('UGI' or 'Company') on August 16, 1994, relative to the above-captioned proceeding. The Office of Trial Staff ('OTS ') and the Office of Consumer Advocate filed responses to UGI's Petition on August 26, 1994.

HISTORY OF THE PROCEEDING

On November 1, 1993, UGI filed with the Pennsylvania Public Utility Commission Supplement No. 37 to its Tariff Electric-Pa. P.U.C. No. 4, requesting an increase in total annual electric operating revenues of approximately $4.2 million, or approximately 6.7% over the level of revenues anticipated for the future test year ending June 30, 1994.

By Order entered December 3, 1993, the Commission instituted a formal investigation at Docket No. R-00932862 to determine the lawfulness, justness and reasonableness of the *18 Company's rates. Supplement No. 37 was thereby suspended by operation of law for a period of up to seven months, or until July 31, 1994.

The OTS entered an appearance and actively participated in this proceeding. Additionally, the Office of Consumer Advocate ('OCA'), the Office of Small Business Advocate ('OSBA') and Sandra A. Conway, a residential customer, filed Formal Complaints against the proposed rates, all of which were consolidated with the Commission's investigation for purposes of hearing and disposition.

Prehearing conferences were held before Administrative Law Judge ('ALJ ') Morris J. Solomon on January 5 and 19, 1994. In response to the written request of Complainant Sandra A. Conway, the ALJ, per a Preliminary Order, determined that she was an inactive participant in the proceeding. Public Input Hearings were held in Kingston on March 1, 1994. Evidentiary hearings were held in Harrisburg on January 25, 26, and 27, March 1, 8, 9, 23 and 24, 1994.

By letter dated March 11, 1994, UGI, the OTS, the OCA, and the OSBA filed a *Stipulation Concerning Fair Rate of Return, Post-Retirement Benefits Other than Pensions, and Construction Work in Progress*. The Parties agreed, for purposes of this rate proceeding, that the overall cost of capital for UGI would be 9.56%. The Parties further stipulated, subject to the outcome of certain appellate proceedings, that the Company's ratemaking claim for post-retirement benefits other than pensions, or OPEBs, will be determined in accordance with the provisions of Statement of Financial Accounting Standards No. 106, and stipulated to the appropriate level of the Company's OPEBs claim. Finally, the Parties agreed on the appropriate treatment of UGI's rate base claim to recover its investment in certain environmental improvement project at Conemaugh.

By letter dated April 29, 1994, UGI, the OTS and the OCA stipulated that UGI's claim for the bulldozer lease is for the actual expense of $63,189, that its fuel reserve claim is limited to $3.55 million and that certain wording in the Company's Reply Brief relating to its advertising expense would be replaced by the specified text. The record consists of 810 pages of transcribed testimony, voluminous prepared testimony and numerous exhibits. On April 14, 1994, UGI, the OTS, the OSBA, and the OCA filed their individual Main Briefs. Reply Briefs were filed by the Parties.

On May 27, 1994, Administrative Law Judge ('ALJ') Morris J. Solomon issued his Recommended Decision ('R.D.') recommending that the Commission find that UGI has shown the need for $61,294,000 in annual operating revenues, an increase of $1,202,000. On June 10, 1994, UGI, the OSBA, the OTS, and the OCA filed Exceptions to the Recommended Decision.

Reply Exceptions were filed on June 17, 1994 by OTS, UGI, and OCA. On June 18, 1994, the OSBA filed a letter advising the Commission that it would not be filing Reply Exceptions.

Per Opinion and Order entered on July 27, 1994, the Commission disposed of the Exceptions, as filed, and authorized an increase in annual operating revenues of $1.324 million. Whereupon, UGI filed the instant *Petition for Reconsideration* on August 16, 1994.

DISCUSSION

[1] Section 5.572(a) of our Rules of Administrative Practice and Procedure, 52 Pa. Code § 5.572(a) provides that:

(a) Petitions for rehearing, reargument, reconsideration, clarification, rescission, amendment, supersedeas or the like shall be in writing and shall specify, in numbered paragraphs, the findings or orders involved, and the points relied upon by petitioner, with appropriate record references and specific requests for the findings or orders desired.

We note that the standards for determining whether we should exercise our discretion to grant a petition for reconsideration under the provisions of 66 Pa. C.S. § 703(g) was articulated in the *Philip Duick Case*[2] as follows:

A Petition for Reconsideration, under the provisions of 66 Pa. C.S. § 703(g), may properly raise any matters designed to ***19** convince the Commission that it should exercise its discretion under this code section to rescind or amend a prior order in whole or in part.

In this regard, we agree with the court in the *Pennsylvania Railroad Company* case, wherein it was said that:

Parties ...cannot be permitted by a second motion to review and reconsider, to raise the same questions which were specifically considered and decided against them.

The recent Commonwealth Court case *AR&T v. Pa. P.U.C.*, 130 Pa. Commonwealth 595; 568 A.2d 1362, (1990) further elucidated the standards for rehearing, reconsideration, revision or rescission.

In its Petition UGI contends, *inter alia*, as follows:

1. The Commission's July 27, 1994 Order overlooks or disregards a long line of PUC Decisions approving Rate Recovery of Incentive Compensation Plans.

2. The standard the Commission applied in this case to assess the reasonableness of UGI's Incentive Compensation Claim is inconsistent with the standard it has applied in prior proceedings.

3. UGI's annual bonus and SODEP plans are not comparable to the Incentive Compensation Plan rejected by the Commission in Roaring Creek II.

4. Even assuming the Commission's new standard was properly applied in this case, UGI presented sufficient evidence to meet the new standard.

We shall address the foregoing arguments of UGI *seriatim*.

First, UGI contends that the Commission, the ALJ and all Parties to this proceeding appear to agree that, as a general proposition, incentive compensation programs are appropriate and desirable and should be encouraged. Accordingly, UGI asserts that because we have permitted rate recognition of certain incentive compensation plans in part, we must recognize the costs of UGI's incentive compensation plan in UGI's rates.

In support of its contention, UGI cites to and relies on several cases [3] wherein we recognized the value of incentive compensation programs. UGI rejoins that in our July 27, 1994 Order, we failed to distinguish or explain our decision to depart from this long line of uniform precedent and, therefore, we should revisit the issue of incentive compensation programs.

[2] We recognize that as an administrative agency we are not bound by the strict principles of *stare decisis*. We note, that we do have an obligation to render consistent opinions and either follow, distinguish or overrule our own precedent. *Lehigh Valley Family v. Brock*, 640 F. Sup. 1992, aff'd 829 F.rd Aug. (1986) *Standard Fire Inc., Co. v. Insurance Dept.*, 148 Pa. Commonwealth Ct. 350, 611 A.2d 356, 359 (1992). However, it is well settled that as an administrative agency we are entitled to change course, and as long as we adequately explain our new position, that view will be accorded deference. *Butler County Memorial Hospital v. Heckler*, 780 F.2d 352 (1985).

[3, 4] Our review of the record in this proceeding indicates that all of the cases cited by UGI were discussed in the Briefs of the Parties as well as in our final Opinion and Order entered July 27, 1994, relative to the subject proceeding. UGI's argument that we failed to explain or distinguish our decision to disallow incentive compensation costs claimed in rates in this proceeding is misplaced. In our final Order we fully explained the reasons for our disallowance of incentive compensation costs in the subject proceeding. At page 40 of our Opinion and Order we stated, in pertinent part, as follows:

Incentive compensation plans are a good idea and they should be utilized to stimulate innovative operational improvements to create a better performing company. In order to be passed on to ratepayers, however, there must be an adequate factual basis for the Commission to conclude that the Company seeks to maximize more than just shareholder value. Even if no specific cost savings can be shown to result from the incentive ***20** compensation plan, at a minimum the plan must be shown to have a direct bearing on cost reduction and rate control efforts. In this case, the Company has unfortunately made no such showing.

Therefore, it is evident that we have already fully considered and properly disregarded the arguments proffered by UGI relative to its Incentive Compensation programs.

Second, UGI contends that we have in prior decisions provided guidance as to how the reasonableness of incentive compensation plans should be assessed (Petition p. 6). At page 7 of its Petition, UGI retorts that:

The standard the Commission has adopted in this case - that the incentive compensation plan 'be shown to have a *direct bearing* on cost reduction and rate control efforts' - is totally inconsistent with the Commission's earlier acknowledgment that it is 'well nigh impossible' to demonstrate a direct benefit to ratepayers from the adoption of an incentive compensation plan.

(Emphasis in Original)

As a result, UGI argues that our final Order announces a new standard without providing any explanation as to why such a change is appropriate or necessary. Accordingly, UGI asserts that our action is arbitrary and capricious and constitutes an abuse of discretion. (Petition p. 9). The OCA points out in its Response that UGI asserted in its Petition that we espoused the same position in *Duquesne* and *Roaring Creek* cited *supra*, and we concluded that the reasonableness of the overall level of compensation is dispositive (OCA Response p. 7).

The OTS in its response to UGI's Petition rejoins as follows:

The magnitude of an expense category cannot justify the expense if the expense bears no relation to the provision of utility service (OTS' Response p. 3).

We note that the arguments proffered by UGI have already been raised and rejected by us, and form no basis for the relief requested. We note further that we adopted the ALJ's discussion, relative to the issue of incentive compensation, in our final Opinion and Order. We believe that it will be instructive to quote hereinbelow the pertinent section of the ALJ's discussion, as stated at pages 34-35 of our July 27, 1994 Order, wherein he observed that:

It will not do for UGI simply to contend that its overall compensation levels are reasonable and such is dispositive of the issue. The only matter before us is the reasonableness of the Company's two incentive compensation programs as a charge to ratepayers.

The Commission's most recent consideration of this matter is set forth in *Roaring Creek* [Docket No. R-00932655 (Order entered February 3, 1994)]. In that case, we found that the utility's incentive compensation program was not aimed at enhancing the productivity and efficiency of the utility and we excluded the program cost from operating expenses. (Slip op. at 27-28). In adopting our reasoning and recommendation, the Commission observed:

The Company's Exceptions failed to allay our concern that the focus of the criteria being used is the [parent company's] profitability rather than criteria focusing on the operation of Roaring Creek .... (W)e are disturbed by the Company's errant focus on profitability over operational effectiveness.

Roaring Creek, slip op. at 30. With those concerns in mind, we will proceed to examine UGI's Annual Bonus Plan and SODEP program.

In the Form 10-K filed with the United States Securities and Exchange Commission, UGI Utilities, Inc., under 'Item 11 Executive Compensation', on page 37, stated as follows:

The Annual Bonus Plan is based on the achievement of pre-determined business and/or financial performance objectives which support business plans and goals.

***21** We think the clear meaning of these words is that a reward may be given for employee performance contributing to the profitability of the parent corporation. Our interpretation of the bonus plan's focus is reinforced by the fact that the overwhelming majority of the persons eligible for the bonuses are holding company employees.

As for the Stock Option and Dividend Equivalent Plan, we again find UGI's Form 10-K to be instructive. At page 38 we are informed that the award of this incentive compensation is

subject to UGI's achievement of long-term performance as compared to a group of peer companies ('Peer Group') over a five-year period .... Performance criteria for that five-year period will encompass both changes in the per share market prime of UGI Common Stock and dividend paid on that stock ....

Plainly, the operational effectiveness of the Company is of no moment. The SODEP compensation is payable on the basis of comparative measurements of the profitability of UGI Corporation, the Company's parent. Again, we take note of the fact that nearly all of the persons eligible for SODEP compensation are holding company employees.

Our concern here is the same as it was in *Roaring Creek*. It is possible that deserving performance on the part of a UGI employee may not result in the receipt of incentive compensation because the parent company and other subsidiaries failed to meet their financial and business goals. In the same vein, the Company's personnel could receive incentive compensation simply because the holding company's profitability was enhanced at the expense of needed service improvements. Beyond this, we must say that our suspicions are always heightened when an effort is made to pay bonuses at the expense of ratepayers to those employees not proximately responsible for serving those same customers.

Accordingly, we note that consistent with our decision in *Roaring Creek*, cited *supra*, we disallowed rate relief for UGI's incentive compensation plan. Therefore, it is evident that the arguments posed by UGI in its Petition have been duly considered and rejected by us.

Third, UGI contends that in determining that the costs of both the Annual Bonus and the Stock Option and Dividend Equivalent Plans ('SODEP') should be disallowed in their entirety, we did not rely on any of the numerous decisions cited by UGI, but instead relied exclusively on our decision in *Roaring Creek II*. (Petition p. 11). UGI asserts that its incentive compensation plan is sufficiently dissimilar to Roaring Creek's plan as to justify and otherwise warrant a dissimilar ratemaking treatment. UGI rejoins that neither the Annual Bonus Plan or the SODEP plan is comparable to the incentive compensation plan at issue in the Roaring Creek proceeding.

We note that the arguments proffered by UGI relative to its Annual Bonus and SODEP plans were raised in UGI's Initial and Reply Briefs as well as in the Company's Exceptions. Accordingly, we conclude that UGI is not presenting any 'new and novel' arguments for our review. Indeed, in our final Order of July 27, 1994, we determined that there exists an important similarity between UGI and Roaring Creek and, therefore, we dismissed the same arguments which UGI has proffered in its Petition.

Fourth, UGI contends that it has demonstrated in the record that its incentive compensation plans have a sufficiently direct bearing on cost reduction and rate control efforts to justify rate recognition. UGI argues that we erroneously determined that the Company failed to show that its incentive compensation programs had 'a direct bearing on …rate control efforts' (Final Order p. 40) without referencing the evidence presented by UGI (Petition p. 15).

We note that we have already considered and rejected this argument of UGI as well. The OTS at page 6 of its Response to UGI's Petition points out very succinctly that:

OTS noted in its main brief at p. 45 that there is simply no definitive evidence of record that the Annual Bonus Plan and SODEP have ***22** resulted in savings to ratepayers of even 1 cent. The principal criteria for awarding bonuses and the determinate for the level of bonuses under the Annual Bonus Plan is the Company's financial performance. Similarly, the payment of dividend equivalents under the SODEP is dependent upon UGI's stock performance in comparison to a peer group. UGI's claim that its incentive compensation plans support goals like reducing expenses and improving operating efficiencies is simply not supported by the record.

Accordingly, we conclude that the arguments raised by UGI in its *Petition for Reconsideration*, have already been presented in Briefs, Reply Briefs and Exceptions and have been rejected by the presiding ALJ and by this Commission. We further conclude that UGI has failed to present any 'new and novel' arguments, not previously heard or considerations which we may have overlooked or not addressed; THEREFORE,

IT IS ORDERED:

That the *Petition for Reconsideration* filed by UGI Utilities, Inc., - Electric Division on August 18, 1994, be, and hereby is, denied.

FOOTNOTES

EDITOR'S APPENDIX

Citations in Text

Footnotes

1 UGI files its *Petition for Reconsideration* pursuant to 66 Pa. c.s. § 703(g), and 52 Pa. Code § 5.572.

2 *Duick v. Pennsylvania Gas & Water Company*, 56 Pa. P.U.C. 553 (December 17, 1982).

3 *Pa. P.U.C. v. Roaring Creek Water Co.*, Docket No. R-00932665 (Entered February 3, 1994); *Pa. P.U.C. v. Metropolitan Edison Co.*, 141 PUR 4th 336, 387 (1993); *Pa. P.U.C. v. Duquesne Light Co.*, 63 Pa. P.U.C. 337 (1987); *Pa. P.U.C. v. UGI Corp. - Luzerne Electric Division*, Docket No. R-78030572 (Entered December 29, 1978)

PA Pennsylvania Pub. Utility Comm'n v. Roaring Creek Water Co., R-00932665 et al., 81 Pa PUC 285, 150 PUR4th 449, Feb. 3, 1994.

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