PECO STATEMENT NO. 11-R

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group Incorporated with and into Exelon Corporation	)	**DOCKET NO. A-110550F0160**

REBUTTAL TESTIMONY OF

DR. JOHN R. MORRIS

ON BEHALF OF

PECO ENERGY COMPANY

July 29, 2005

ADDRESSING NATURAL GAS MARKET POWER ISSUES

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Contents

I. Introduction and Summary

A. Professional Background

Q. Please state your name, address, and position.

A. My name is John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 1200 New Hampshire Avenue, NW, Washington, DC 20036.

Q. What is your educational background and professional qualifications?

A. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting in the energy industry since joining the Federal Trade Commission ("FTC") in 1985. During my six years at the FTC, I served as the lead economist for many of the natural gas mergers reviewed by the FTC. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-rate authority, and studied market power issues in state restructuring proceedings. Some examples of mergers involving natural gas assets or natural gas and electric utility assets on which I submitted testimony include the combination of SoCalGas and San Diego Gas & Electric, El Paso's purchases of Sonat, Inc. and the Coastal Corporation, and TransCanada's acquisition of electric generation assets in New England. I have extensively studied the supply and demand conditions and company behavior during the California energy crisis of 2000 and 2001, and I testified at the Federal Energy Regulatory Commission ("FERC") concerning those issues. I have published articles on competition and energy matters. I have spoken on numerous occasions concerning competition in natural gas, electric power, and other industries before FERC, the Antitrust Division of the Department of Justice, and the FTC. I have previously been accepted as an expert witness on energy matters before FERC, state commissions, and in federal court. A complete listing of my experience, publications, and testimony is contained in my resume, presented in Exhibit No. JRM-1.

B. Case Background

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by counsel to PECO Energy Company to comment on the horizontal natural gas issues raised by Dr. Carpenter on behalf of Philadelphia Gas Works ("PGW"). Dr. Carpenter opines that the merger of Exelon Corporation ("Exelon") and Public Service Enterprise Group Incorporated ("PSEG") ("Applicants") would provide the combined entity Exelon Electric & Gas ("EEG") with the market power to raise natural gas prices in the geographic region of PJM East, which is comprised of New Jersey, Delaware, Eastern Shore of Maryland, and the portion of Pennsylvania east of the PJM Eastern Interface. I address the horizontal natural gas market issues and Dr. Hieronymus responds to criticisms of his vertical market power analysis.

Q. What is the time period for your analysis?

A. My quantitative analysis focuses on the short-run when pipeline facilities do not change significantly. This analysis is only appropriate until significant capacity is added to the northeast region of the United States and eastern Canada. Because so many Liquid Natural Gas ("LNG") terminals have been proposed, and some have received federal government approval, it is likely that entry of new capacity will occur within a few years, which would reduce the Applicants' market shares below the levels described in my quantitative analysis. A discussion of the long-run issues and their impact on the market power analysis is discussed in Section VI.D., below.

C. Summary of Conclusions

Q. Would you please summarize Dr. Carpenter's analysis?

A. Yes. Stripped of all the trappings, the gravamen of Dr. Carpenter's concern is that via its firm transportation contracts on interstate pipelines, EEG would be able to restrict gas supplies into PJM East and thereby raise natural gas prices in PJM East. Because gas demand varies from day to day, on many days EEG would have excess pipeline capacity beyond what it needs for its regulated retail and other firm contractual commitments. According to Carpenter, EEG could either fail to release unused capacity or fail to make gas sales imported into the market using this capacity so as to reduce total gas supplies to the market. He asserts that competition among competing buyers for the limited supplies would increase natural gas prices.

Q. In a nutshell, can you summarize your response?

A. Yes. EEG would not own or control any of the interstate natural gas pipelines that supply natural gas to PJM East and would not be able to restrict supplies flowing on those pipelines. EEG can do nothing to reduce the amount of pipeline capacity available to gas users in the market. Capacity that EEG does not use or resell will be made available by the interstate pipelines. FERC regulations require that the interstate pipelines make any capacity unused by EEG available to other firm shippers on the interstate pipelines. Any remaining capacity is then made available to any other potential shipper in the form of interruptible capacity. Hence, EEG would not be able to restrict supplies into PJM East and would have no ability to raise prices in PJM East.

Q. What conclusions have you reached concerning Dr. Carpenter's analysis?

A. Dr. Carpenter's analysis fails to account for the supply and demand conditions in and around PJM East. My examination of these supply and demand conditions leads me to conclude that EEG will not have market power in natural gas markets because it will not have the ability to change wholesale natural gas prices. Without an ability to change these prices, it cannot adversely change market conditions for either natural gas or electric power. More specifically, I find that:

1) Dr. Carpenter's theory is novel for a merger. His theory is that combining the firm interstate pipeline transportation capacity of PECO and PSEG would result in higher prices for natural gas. PECO and PSEG have no ownership interests in any interstate natural gas pipelines, but only contractual rights with pipeline owners to ship gas. As for his theory of vertical market power, FERC has never challenged a merger because of combined ownership of firm shipping contracts on interstate pipelines. All of FERC's challenges have been based on a change of ownership of physical pipeline assets. As for his theory of horizontal market power, the antitrust agencies have never challenged a merger of two companies based on firm shipping rights on interstate pipelines. The antitrust

agencies have only challenged changes in ownership of the interstate pipelines themselves.

2) Approximately 90 percent of the time the market is clearly broader than PJM East. Under these conditions the market is not concentrated and the merger would have no competitive effects.

3) The Herfindahl-Hirschman Index ("HHI") relied upon by Dr. Carpenter, only begins a market power analysis.[1] Even if the HHI is above 1,800, a more thorough analysis is necessary before one could conclude that any particular firm possesses market power.

4) Supply and demand conditions are such that the merged entity, Exelon Electric & Gas ("EEG"), could not raise or lower prices. Attempts to restrict gas supplies and raise prices would be met by supplies from other areas, and attempts to expand supplies to reduce prices would be met by supplies shifting to other areas. These actions would cause prices to remain at the same level that they would if the transaction did not go forward. In addition, when electric transmission facilities into PJM East are not constrained, additional energy can be imported into PJM East over the electric power transmission systems. These facilities recently have been constrained only about 3 percent of the year. These imports can provide a substitute for gas-fired generation in PJM East.

5) Both Exelon's gas distribution company, PECO Energy ("PECO") and PSEG's gas distribution company, Public Service Electric & Gas ("PSE&G"), operate under significant regulatory oversight, despite

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[1] The HHI is equal to the sum of the squares of the market shares. So a market with four suppliers with shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (= 1,600 + 900 + 400 + 100 = $40^2 + 30^2 + 20^2 + 10^2$). A market with a single seller would have an HHI of 10,000, and a market with 10 equal size sellers would have an HHI of 1,000.

PSE&G's gas merchant function being transferred to PSEG Energy Resources and Trading ("ER&T"). The Pennsylvania Public Utility Commission ("Commission") annually reviews every gas trade of PECO's. The New Jersey Board of Public Utilities ("BPU") annually reviews ER&T's gas acquisition and disposition activities and has the ability to audit these reports and examine every trade of ER&T. In addition, FERC regulation of interstate natural gas pipelines is designed to mitigate the potential market power of firm shippers like EEG, and the FERC Office of Market Oversight and Investigation ("OMOI") monitors markets both for adherence to current FERC regulations and to propose changes to mitigate market power and make energy markets more efficient. This regulatory oversight and the inherent market conditions make it very unlikely that EEG could exercise market power, even if EEG did have an ability to raise wholesale natural gas prices. The merger has no effect on this regulatory oversight.

6) The remedy proposed by Dr. Carpenter, which is the divestiture of the Applicants' natural gas operations, does not address the harm that Dr. Carpenter asserts would result from the transaction. That harm is alleged to result from the combination of the contract rights on interstate natural gas pipeline systems held by the Applicants, not from their ownership of gas distribution operations.

II. Factual Background

A. PJM East Natural Gas Facilities

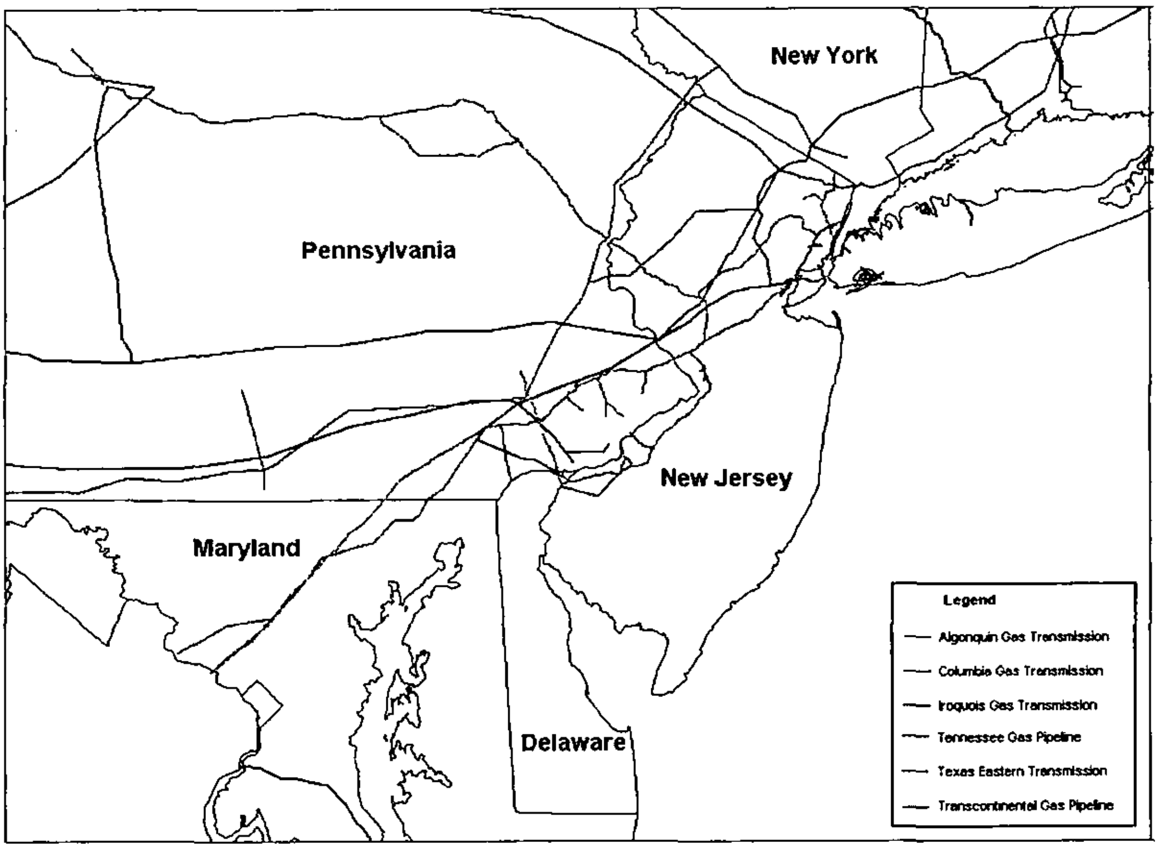
Q. Can you please generally describe the natural gas facilities located in the PJM East area?

A. PJM East is served by four interstate natural gas pipelines: (1) Columbia Gas Transmission Co. ("Columbia"); (2) Tennessee Gas Pipeline

Company ("Tennessee"); (3) Transcontinental Gas Pipeline Company ("Transco"); and (4) Texas Eastern Transmission, LP ("Texas Eastern"). They all originate in or receive gas from producing regions south and west of PJM East, run through PJM East and continue further northward to New York and, in the case of Tennessee, New England. These regions north of PJM East are referred-to as being "downstream" of PJM East because gas flows further down the pipelines from PJM East in order to reach New York and New England. The regions south and west of PJM East are referred to as being "upstream" of PJM because the gas travels through them before reaching PJM East. A map of these pipelines is shown in Figure 1 below.

In addition to the pipelines listed above, the Algonquin Gas Transmission LLC ("Algonquin") interstate natural gas pipeline commences at an interconnection with Texas Eastern in New Jersey and runs north through New York and into New England. Algonquin can also receive natural gas from Columbia, Transco, and Tennessee.

Figure 1 — Interstate Pipelines in PJM East



Q. What natural gas facilities are located in PJM East in addition to the above-mentioned pipelines?

A. There also are local gas distribution facilities owned by various local distribution companies ("LDCs") in PJM East, including PECO and PSE&G. These facilities interconnect with the various interstate natural gas pipelines mentioned above, and are used to distribute gas taken from those pipelines to retail customers located in PJM East.

Q. Are there any significant natural gas storage facilities located in PJM East?

A. No, there is no material amount of storage located in PJM East. Volumes of gas placed in storage in Appalachia must be imported into PJM East via the interstate pipelines.

Q. Do the LDCs maintain peaking facilities?

A. Yes. Many LDCs maintain Liquefied Natural Gas ("LNG") or Liquefied Propane Gas ("LPG") peaking facilities. These facilities hold small quantities of gas in a liquid form, typically in above ground tanks. These facilities are primarily designed to handle days when the LDC must deliver more gas than it is able to receive from interstate pipelines. Because of the small amount of storage, typically only a few days worth, and the need to have it available on peak days, these facilities have very limited uses and are held in reserve for when they are needed for gas supplies.

Q. Are there any constraints in pipeline capacity located in PJM East that might cause natural gas prices to separate within PJM East?

A. For the most part, there are no such constraints. However, there are constraints in on Transco (around Linden), Texas Eastern, and on Algonquin that can cause prices in Northern New Jersey, New York and New England to separate from prices in PJM East during certain times in the winter when the pipelines are running at capacity. I discuss these constraints and the time periods when prices separate in more detail below.

B. FERC Rules and Regulations

Q. What FERC regulations are relevant for evaluating competition in natural gas markets?

A. Regulations under Part 284 of the FERC regulations (18 CFR § 284) provide natural gas shippers with substantial flexibility to deliver natural gas to markets located along the physical pipeline path for which they pay demand charges. These rules were promulgated in the 1980s and substantially modified in 1992 as part of the Commission's Order No. 636 restructuring of the interstate natural gas pipeline industry.[2] Specifically, Order 636 was designed to remove the pipelines from the role of the bundled gas merchant, and to allow the pipeline customers to transport gas purchased in the production area for destinations located along the pipeline. Under these Part 284 regulations, and the pipeline tariffs filed in compliance with these regulations, there are a number of provisions that are relevant to my analysis here:

(1) In addition to the primary delivery points set forth in their pipeline transportation agreements firm shippers also are entitled to deliver natural gas to all other delivery points within their contractual transportation path on a secondary basis. In addition, these rules also permit the shipper to segment its capacity, where operationally feasible, to make more than one delivery using the same capacity. Capacity segmentation refers to the requirements in 18 C.F.R. 284.7(d) that require interstate pipelines to allow their shippers to segment their capacity. That is, the regulations require the pipelines to allow shippers to use only parts of their transportation paths and deliver to other locations on a secondary basis.

[2] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 Fed. Reg. 13,267, (1992).

Together, these rules allow shippers downstream of PJM East to make deliveries in PJM East if market conditions so dictate.

(2) Shippers are also permitted to "release" their capacity to third parties, i.e. they are allowed to assign their capacity to other shippers when they do not need it to serve their own requirements. The rate that releasing shippers can charge for their capacity may not exceed the maximum rate charged by the pipeline for the same capacity.

(3) Finally, under the same Part 284 regulations, the pipelines must make interruptible transportation ("IT") capacity available under similar flexible conditions. One of the circumstances in which IT must be made available is if a firm capacity holder does not schedule the use of its capacity. This means that if a firm capacity holder does not use its capacity or release it to others, that capacity will be made available for use by third parties on an interruptible basis. This prevents capacity from being withheld from the market.

III. The Economics of Market Power

Q. What is market power?

A. A seller is said to possess market power if it can profitably maintain prices above competitive levels for a significant period of time.[3] Market power involves both the ability and the incentive to restrict supplies and raise prices for a significant period. Some sellers have little or no ability to raise market prices, and therefore, they do not have market power. Other sellers have the ability to restrict supplies and raise market prices, but the lost profits from losing sales would outweigh the gain from higher prices on remaining sales. They too do not have market power. Only when a company has the ability both to raise prices by restricting supplies and profit from such a strategy does the company have market power.

Q. How do economists determine whether a seller has market power?

A. The essence of market power is the ability to raise market prices by making fewer sales and profit by doing this. Market prices can go up only if the sales withdrawn by one company are not replaced by sales from another. Unless total supplies to the market decline, there is no ability to raise prices. Therefore, one can directly examine the ability to prevent supplies from reaching the market and thereby raise prices. If a seller has no or very little ability to restrict total supplies to the market (as opposed to its own supplies) and raise prices, then it cannot have market power. Even if a seller can restrict total market supplies, the seller would not have market power unless the supply restriction increased its profits.

In most industries, little market evidence exists to determine whether a particular seller or group of sellers would likely have market power. For those markets, economists and policy makers have developed a screening method to assist in determining whether a seller has market power. That method is to define a relevant market and measure market shares and the HHI. In the case of vertical market power concerns, if either the upstream or downstream market HHI is less than 1,800, the analysis ends with a conclusion that vertical market power is not a concern. If both the upstream and the downstream markets have an HHI above 1,800, then additional analysis of other factors—such as regulation,

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[3] U.S. Department of Justice/Federal Trade Commission, *Horizontal Merger Guidelines*, 57 Fed. Reg. 41,552 (1992), *revised* 4 Trade Reg. Rep. ¶ 13,104, (April 7, 1997), § 0.1.

market rules, market oversight, and entry conditions—is necessary before one can conclude that a seller has vertical market power.

In the case of horizontal market power concerns, the FERC and the antitrust agencies use a sliding scale for screening purposes. Additional analysis of a transaction is necessary only if the post-transaction HHI is more than 1,000 and the increase is more than 100 or the post-transaction HHI is more than 1,800 and the increase is more than 50; otherwise, the analysis stops with a conclusion of no market power. Moreover, the antitrust agencies do not believe that the merged entity could exercise market power alone (called unilateral market power) when its market share is less than 35 percent, again with further analysis required for market shares above this level.[4] For transactions above these screening thresholds, additional structural factors—such as downstream competition, formal market rules, regulation, market oversight, and entry conditions—are examined in more detail to determine whether a seller has market power.

Q. At page 15 of his testimony, Dr. Carpenter suggests that the HHI is sufficient to establish that EEG would have market power. Is this suggestion correct?

A. No. As Dr. Carpenter acknowledge in deposition, the HHI alone is not sufficient to conclude that there is market power.[5] For the reasons explained in the testimony of Dr. Hieronymus, the proper market concentration for firm shipper capacity in PJM East is below 1,800. In its decision approving the proposed merger, FERC agreed with Dr.

4 *Horizontal Merger Guidelines*, §2.2.

5 *Carpenter Deposition Transcript*, 7/22/05, pp. 32-33. The pages of the Carpenter Deposition Transcript to which I cite are in Exhibit No. JRM-2.

Hieronymus' reasons. But even if one accepted Dr. Carpenter's calculation of the HHI for natural gas sales, the HHI would only begin a proper analysis of market power. As the Horizontal Merger Guidelines state, "market share and concentration data provide only the starting point for analyzing the competitive impact of a merger."[6] Dr. Carpenter presumes market power based upon his fallacious HHI calculation but does not provide the additional analysis that is necessary for one to conclude that a gas supplier actually possesses market power. The analysis below clearly shows that EEG will not have market power after the acquisition, regardless of the level of the HHI.

Q. What is the relevant product market for examining natural gas competition?

A. Dr. Carpenter, Dr. Hieronymus, and I are in agreement that the proper product market is delivered gas, which is also the product market accepted by FERC in examining vertical mergers.

IV. Relevant Geographic Market

Q. What economic principles are used to delineate geographic markets for short-term natural gas markets?

A. In the context of merger analysis, a geographic market for short-term natural gas is an area in which a hypothetical monopolist could profitably raise price for a substantial period. In the case of natural gas pipelines at a location on the interconnected pipeline grid, the question is what other areas would provide additional supplies to the provisional market area. If other areas would provide sufficient supplies to the provision market area,

[6] *Horizontal Merger Guidelines*, § 2.0.

then the other areas would be added to the provisional geographic market. In the case of short-term natural gas markets, like short-term electric power markets, the market boundaries tend to be set at constraint points on the pipeline grid. When the grid is unconstrained, the market can be very broad. When pipelines become constrained, the relevant geographic markets can become smaller.[7] Because of this, boundaries of geographic markets for natural gas can change over time as various factors, such as pipeline capacity constraints, affect the supply sources to any particular market. *Unlike electric power markets, natural gas can also effectively be* "imported" over electric power lines via gas-fired generation. So in areas where gas-fired generation is often economic, the ability to import power extends market areas beyond areas of constraints on the natural gas system.

Q. What standards do you use to determine the relevant geographic market?

A. To define the relevant geographic market for this case I used well-established procedures commonly used by economic experts when analyzing competition. The Department of Justice/FTC *Horizontal Merger Guidelines* generally use a five percent standard when defining relevant markets, so I used a five percent test to define prices as "similar." That is, according to the market definition paradigm of the *Horizontal Merger Guidelines*, if substitution from New York and New England into PJM East would occur in response to a five percent price increase in PJM East prices, then New England and New York are properly included in the

[7] I note that in many cases it is inconsequential that geographic markets become smaller when pipelines become constrained. The reason is that the essence of market power is that there is a restriction of supplies. When pipelines are constrained, the short-run supply is fully utilized and there is no exercise of market power in the short-run.

relevant geographic market with PJM East.[8] I have analyzed the price data from these areas and have concluded that they do indeed often show that New England and New York are in the same geographic market as PJM East. Furthermore, a price increase must be sustainable for a year or more before one would conclude that the two areas are separate geographic markets.

Q. What prices can you observe?

A. *Gas Daily* publishes daily price data for Transco Zone 6 Non-New York, Transco Zone 6 New York, and Algonquin City-gates. Transco Zone 6 Non-New York is the best measure for prices in PJM East because it excludes sales into New York and excludes sales in central Pennsylvania.[9] Transco Zone 6 New York provides a measure of New York prices. It is important to note that all but one contract for the PSEG capacity on Transco is Transco Zone 6 New York capacity because it is deliverable past the Linden constraint on the Transco system and is firm up to the New York City city-gates as well as the PSE&G city-gates in northern New Jersey.[10] Additionally Algonquin City-gates provides a measure of New England natural gas prices.

Q. Do these prices move together?

A. Yes, with the exception of very high demand days, they do. Figure 2 shows the raw Midpoint prices for Transco Zone 6 non-New York (representing PJM East), Transco Zone 6 New York (representing New

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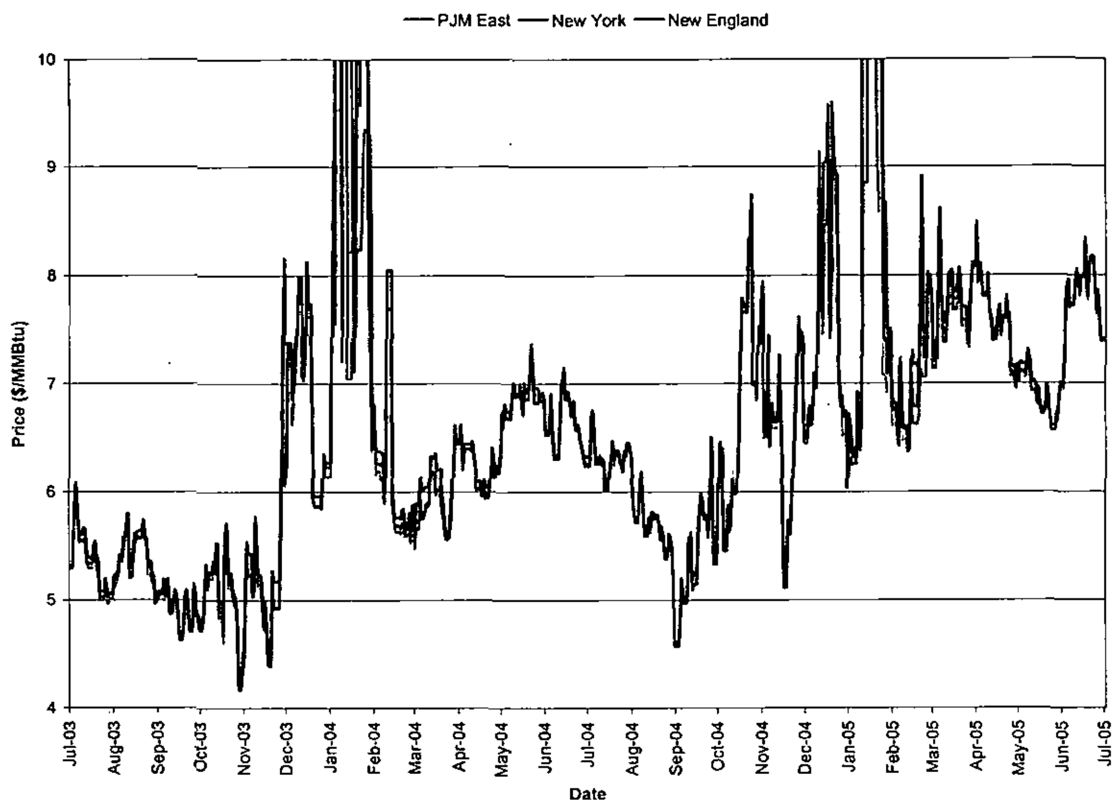
8 *Horizontal Merger Guidelines*, § 1.0. This does not imply that after the merger price could be raised five percent. Rather, this is simply a benchmark for the test used in the *Guidelines.*

9 The Texas Eastern M3 price includes sales in central Pennsylvania and sales into New York.

10 The one contract not deliverable to northern New Jersey is for 48.2 MDth/day, which compares to the total PSEG capacity on Transco of 910 MDth/d.

York City), and Algonquin City-gates (representing New England) over the two-year time period from July, 2003 to the present. It is obvious from the Figure that the three price series follow each other closely.

Figure 2 – Midpoint Gas Prices

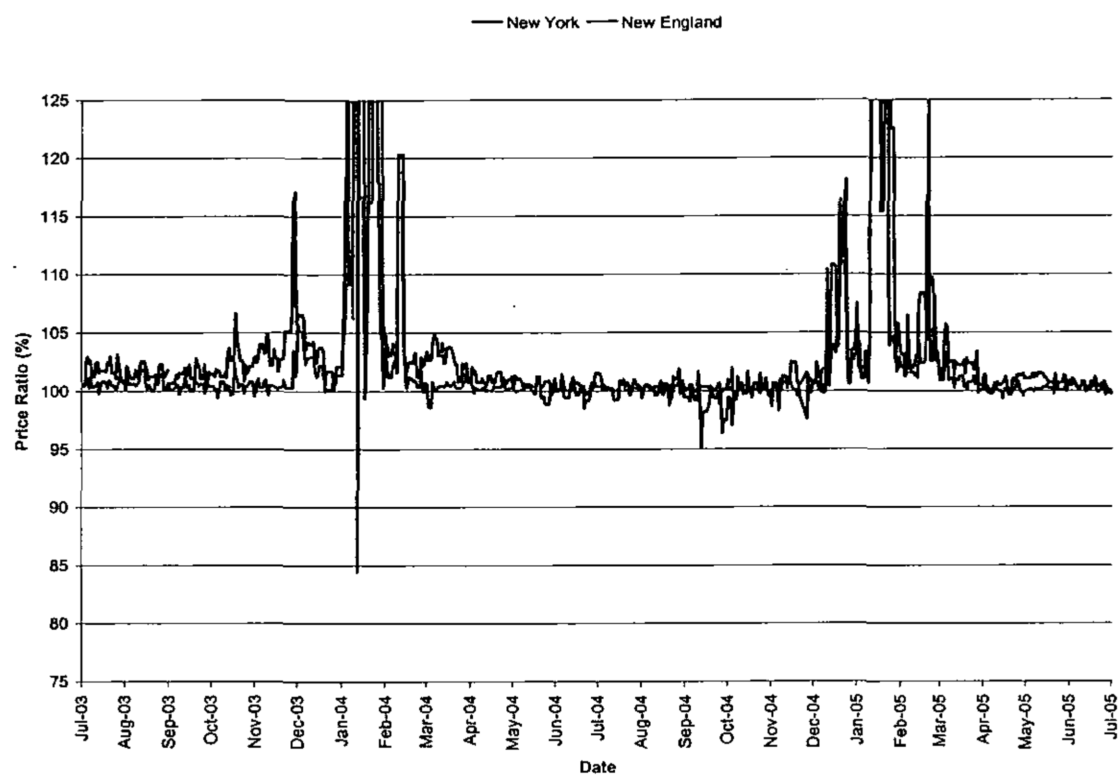


Q. Do the prices remain within 5 percent of each other?

A. During the vast majority of time, yes. Figure 3 shows the New York and the New England prices as a ratio of the PJM East price over the last two years. When one of the prices equals the PJM East price, Figure 3 will show a value of 100 percent. When the price is 5 percent above the PJM East price, Figure 3 shows a value of 105 percent. As can be seen in

Figure 3, on most days the New York and New England prices are within 5 percent of the PJM East price. Of the 725 days depicted on Figure 3, the New York price was within 5 percent of the PJM East price on 658 days, or 91 percent of the time. Similarly, the New England price was within 5 percent of the PJM East price on 651 days, or 90 percent of the time.

Figure 3 — Price of Gas in New York and New England as a Percentage of the Price of Gas in PJM East



Q. What about days when New York and New England prices rise above those in PJM East by more than 5 percent?

A. These figures show that there are some days during the year when the prices in New York and New England are not within five percent of the prices in PJM East. This happens on 10 percent of the days with regard to

New England, and on 9 percent of the days relative to New York. On these days when the prices are more than five percent apart, New York and New England temporarily separate from the PJM East geographic market. But these separations are not sustained, so a price increase in PJM East would not be sustainable.

Q. Is market power a concern when PJM East temporarily separates from New York and New England?

A. No. Although there are periods in which prices in New York and New England are significantly higher than those in PJM East, these periods typically are in winter when PJM East also has high demands. The essence of market power is restricting supplies, and on these days supplies tend to be at their maximum levels. Further, the post-acquisition HHI in PJM East on these days is below 1,800 and interruptible transportation ("IT") transportation is an economically viable substitute. Given these facts, market power in PJM East is not a concern under these conditions.

These conditions tend to increase the difference in wholesale natural gas prices between PJM East and production areas, known as the "basis differential" or just "basis," above the maximum tariff rates in interstate pipelines. Under these conditions, IT becomes an economic substitute for a firm shipper not utilizing all of its capacity. Hence, IT provides a constraint on market power when demand is high and prices justify using IT.

V. Market Concentration

Q. For the upstream natural gas HHI calculation in a vertical market power analysis, what are the implications of your analysis for the geographic markets?

A. The main implication is that FERC's decision approving the merger between Exelon and PSEG is essentially correct.[11] During most of the year the market clearly is broad. Under these conditions, all the capacity and firm shippers into PJM East should be included, including with firm shippers delivery points downstream of PJM East. Under these conditions, as shown by Dr. Hieronymus and accepted by FERC, the market concentration is below 1,800 and vertical market power should not be a concern. When the New York prices indicate that New York separates from PJM East, then it is also appropriate to exclude the PSEG capacity that is considered in the New York price zone. Under these conditions, as shown in Dr. Hieronymus' supplemental testimony and accepted by FERC, the market HHI is also less than 1,800 and vertical market power is not a concern.

Q. What are the implications for a horizontal merger analysis for the effects of the transaction in wholesale natural gas markets?

A. Although the calculations are somewhat different, the effects are basically the same as the vertical analysis. The geographic market is broader than just PJM East. Table 1 gives the market concentration for a market consisting of PJM East, southeast New York, and New England. The post-acquisition HHI is only 897. Under standards of the *Horizontal*

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[11] *Exelon Corporation and Public Service Enterprise Group, Inc.*, 112, FERC ¶61,011 (2005), at ¶¶200-203.

Merger Guidelines, the markets with a post-merger HHI of less than 1,000 are unconcentrated and no further analysis is needed to conclude that the merger is not anticompetitive.

Table 1 – Holders of Interstate Natural Gas – Pipeline Capacity in Eastern PJM, New York, and New England

Shipper Company	Capacity (MDth/d)	Share (%)
Public Service Enterprise Group Inc	1,648	16.7
Exelon Corp	385	3.9
KeySpan Corp	1,706	17.3
Consolidated Edison Inc	863	8.7
New Jersey Resources Corp	431	4.4
Energy East Corp	325	3.3
NiSource Inc	315	3.2
Northeast Utilities	305	3.1
South Jersey Industries Inc	238	2.4
Pepco Holdings Inc	220	2.2
Duke Energy Corp	210	2.1
Philadelphia Gas Works	201	2.0
NSTAR	188	1.9
Mobil Natural Gas Inc	185	1.9
El Paso Corp	175	1.8
TransCanada Corp	152	1.5
Southern Union Co	145	1.5
AES Corp (The)	130	1.3
Sempra Energy	123	1.2
Williams Companies Inc (The)	120	1.2
NUI Corp	111	1.1
Salmon Resources Ltd	100	1.0
Virginia Power Energy	100	1.0
All Other Shipper Companies	1,507	15.2
Total	**9,883**	**100.0**

	HHI
Pre-Merger	768
Change	130
Post-Merger	897

* Eastern PJM consists of the entire State of New Jersey and Bucks, Chester, Delaware, Montgomery, and Philadelphia Counties in Pennsylvania. New York includes Suffolk, Nassau, West-Chester, Rockland, and Orange Counties, as well as New York City proper. New England includes the states of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island.

Sources: Energy Velocity Index of Customers Data for Columbia Gas Transmission Corporation, Texas Eastern Transmission LP, Transcontinental Gas Pipe Line Corporation, Tennessee Gas Pipeline Company, Maritimes & Northeast Pipeline LLC, Iriquois Gas Transmission System, and Portland Natural Gas Transmission System, October 2004; Exelon Corporation; Public Service Enterprise Group Inc.

Q. What about when prices are higher in New York and New England?

A. Even when the geographic market is incorrectly defined as just PJM East excluding all the Transco Zone 6 New York capacity rights, Texas Eastern New York capacity rights, and capacity rights into Algonquin, the HHI is too low to indicate a competitive problem. In this overly narrow "market" Dr. Hieronymus reports the post-merger HHI is 1,335, which is under the 1,800 threshold level. Moreover, the EEG share of firm shipper capacity would substantially overstate the competitive position of EEG, and the HHI would overstate potential market power. When PJM East prices separate from New York and New England is when the vast majority of gas sold by EEG and other sellers would be at prices set by regulated rates and IT provides an economic alternative.

VI. Other Factors

Q. You indicated that the HHI screens start the competition analysis. If a merger violates the HHI screens, what other factors do you examine to determine whether a merger actually presents a market power problem?

A. One looks to the relevant factors affecting competition in the marketplace to determine whether the merged entity could raise prices after the transaction. These other factors include the various market rules and market oversight, the efficacy of those rules, the abilities of facilities, and the potential for entry of new capacity. All of those factors can enter into a determination of whether a merger would create or enhance market power.

A. EEG will not be able to raise prices

1. Alternative capacity is available

Q. At page 18 of his testimony, Dr. Carpenter excludes capacity bound for New York and New England in his HHI calculation because the capacity is "largely committed to serving other markets." Is this the correct standard for determining whether the capacity is available to serve the PJM East market in the event that capacity is withheld and PJM East gas prices increase?

A. No. The relevant question is whether enough supplies would shift from one of the northern markets so that prices would not increase significantly in PJM East. Even if 90 percent of the total gas supply capacity into New England would not shift to PJM East if prices in PJM East rose, the 10 percent that could be delivered into PJM East would be sufficient to counteract an attempt by EEG to restrict supplies in PJM East.

Q. In your opinion, is it proper to exclude the northern bound capacity from a market power study of PJM East?

A. No. The facts reveal that much of the northern bound capacity could be used for deliveries into PJM East. I first examine the capacity into New England and then examine the usage of that capacity.

Table 2 shows the capacity into New England based upon EIA data. The total capacity is 4,114 MMcf/d. Even accounting for Maritimes & Northeast running at 50 percent of capacity because of lack of supplies, there would still be approximately 3,900 MMcf/d of capacity into New England.

Table 2 — Capacity into New England

Source	Delivering from State	Delivering to State	2003 Capacity (MMcf/day)
ALGONQUIN GAS TRANS CO	NY	CT	1,030
IROQUOIS	NY	CT	179
TENNESSEE	NY	CT	150
TENNESSEE	NY	MA	1,059
PORTLAND NAT GAS TRANS.	CN	NH	216
MARITIMES & NORTHEAST	NB	ME	445
EVERETT LNG TERMINAL	---	MA	1,035
TOTAL CAPACITY			4,114

Source: Energy Information Administration 'STBORDER' file, 2003 data; Everett Terminal Data: Natural Gas Intelligence, http://intelligencepress.com/features/lng/terminals/lng_terminals.html.

In comparison, New England consumption is typically substantially less than the delivery capacity into New England. Dr. Carpenter reports that average daily consumption in New England was 2,230 MMcf/d in 2004, indicating that on average about one-half of the capacity into New England is available for delivery along pipelines before the gas reaches New England.

I have also examined consumption data by month to determine whether capacity in the winter would be available for deliveries into PJM East. Table 3 shows the gas consumption by month. From the data it can be seen that even in the month with the highest average daily consumption, February, the average consumption was less than the total capacity to deliver gas into New England. To be sure, on some days most of the capacity into New England is being utilized, but on the vast majority of days a significant amount of pipeline capacity can be used to serve other areas, such as PJM East.

Table 3 — Average Daily Natural Gas Consumption in New England by Month, 2004 (MMcf/d)

Month	Consumption	Percent of Capacity
January	3,084	75
February	3,453	84
March	2,688	65
April	2,631	64
May	1,803	44
June	1,772	43
July	1,712	42
August	1,663	40
September	1,631	40
October	1,609	39
November	2,200	53
December	2,542	62

Sources: EIA, ngm19vmall.xls; Table 1

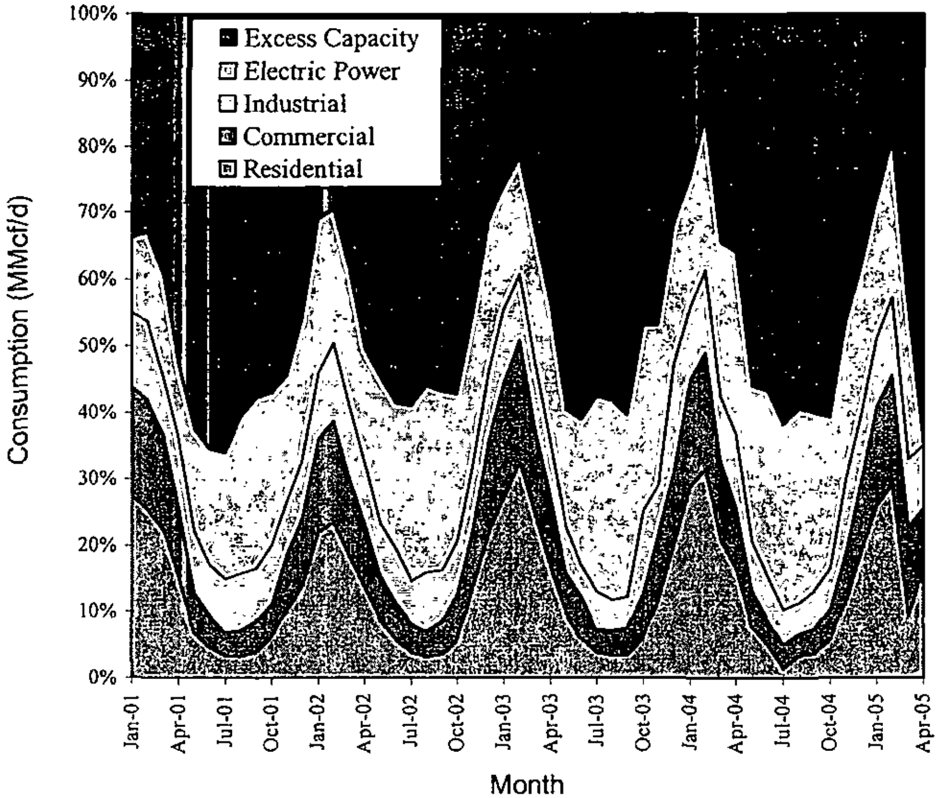
Q. Dr. Carpenter also states that the capacity is committed to other markets because it is mainly held by LDCs. Does this fact indicate that the capacity would not be used to deliver gas into PJM East?

A. No. LDC demand is seasonal, which means much of the LDC capacity is available for other uses for much of the year. LDCs' biggest need for pipeline capacity is to serve the space heating demand of residential and commercial customers. The LDC demand in the Northeast is concentrated in the winter heating season, which gives rise to the differences in monthly averages presented in Table 3, above. The capacity rights held by New England and New York LDCs are available on the capacity release market or alternatively the LDCs are able to make off-system sales of gas. Indeed, it is the ability of LDCs to make off-system sales that gives rise to Dr. Carpenter's concern. Dr. Carpenter acknowledged that New York and New England LDC commitments are no different than PECO's and PSEG's LDC commitments.[12] Therefore, there is no basis for excluding the New England LDC capacity.

This conclusion is supported by Figure 4, which shows a breakdown of the natural gas capacity into New England by customer class and excess capacity. The residential and commercial consumption provide a good proxy of the LDC commitments, and these consistently fall to less than 10 percent of capacity, one-fifth their winter levels, each year. Even in peak periods, these demands account for only about 50 percent of the capacity into New England.

12 *Carpenter Deposition Transcript*, 7/22/05, pp. 45-46.

Figure 4 — New England Natural Gas Consumption and Excess Capacity by Month, January 2001—April 2005



2. Alternative supplies place a ceiling on PJM East prices

Q. You stated that price data also indicate that EEG would not be able to raise prices. How do price data show that EEG would not be able to raise prices?

A. Consistent with the consumption data, the wholesale natural gas price data indicate that an increase in prices would typically result in gas suppliers shifting supplies to PJM East. If a firm shipper with capacity through PJM East into New England can receive a price of $6.50 in New

England and $6.60 in PJM East, the marketer will forego the sale in New England and make the more profitable sale in PJM East—a point that Dr. Carpenter accepts.[13] Hence, prices in New York and New England effectively place a ceiling on prices in PJM East. If the prices in New York and New England are very close to prices in PJM East, then natural gas suppliers in PJM East would not be able to raise prices.

Q. Can you demonstrate that EEG will not be able to raise prices?

A. Yes. Table 4 below shows the number of days that alternative supplies place a ceiling on potential price increases ranging from 1 to 10 percent. The first column gives the potential price increase. The next three columns show the percentage of days that prices have a ceiling based on *Gas Daily* midpoint (average) prices, common high prices (PJM East) and common low prices (other locations), and absolute high prices (PJM East) and absolute low prices (other locations). Based on the price data, I have labeled the columns as typical transactions (based on midpoints), some transactions (based on common transactions), and at least one transaction (based on absolute ranges). These columns give the percentage of days that the price of natural gas in New England; the price of natural gas in New York; or IT supplies effectively place a ceiling on a price increase in PJM East. The data cover a two-year period, with a total of 725 days. Table 4 shows that on virtually every day prices are such that an attempt to raise prices in PJM East would be met with a supply response from another area.

[13] *Carpenter Deposition Transcript*, 7/22/05, pp. 42-43.

Table 4 — Percentage of Days that Alternative Supplies Place a Ceiling on Anticompetitive Price Increases in PJM East

	Percentage of Days When It Would Be Profitable to Use Alternative Supplies		
Potential Price Increase (%)	**Typical Transactions**	**Some Transactions**	**At Least one Transaction**
1	85	99	100
2	93	99	100
5	99	100	100
10	100	100	100

Sources: Gas Daily: Daily Price Survey (July 5, 2003 through July 5, 2005); Algonquin Gas Transmission; Texas Eastern Transmission.

Q. What do you mean by midpoint, common, and absolute prices?

A. Natural gas prices, like most commodities, have what economists call price dispersion. That is, the prices traded on any given day at a particular location will fall within a range. For example, on June 30, 2005 the Transco Zone 6 Non-NY midpoint price was $7.795/mmBtu. But the reported trades ranged from $7.63/mmBtu to $7.89/mmBtu, and trades typically were in a range from $7.73/mmBtu to $7.86/mmBtu.

Q. Why are ranges of prices important for assessing the ability to raise prices, as opposed to looking at only the midpoint of prices?

A. Ranges of prices provide useful information because natural gas supplies will begin shifting between areas even before the midpoint prices indicate that supplies will shift. For example, when the absolute high PJM East price is more than the absolute low in a supply area such as Louisiana (plus relevant transportation costs), supplies will begin to shift from the supply area to PJM East. The process continues until the absolute low in PJM East is greater than the absolute high in the supply area (plus *transportation cost), at which point one would expect the pipelines to be* full. The important point is that supplies can begin shifting into a market area from other areas even before midpoint price data indicate that it would be profitable to shift supplies.

Q. How does Table 4 show that it would not be possible to raise prices?

A. The table indicates that no price increase would be possible because a price increase of as little as 1 percent would be sufficient to shift supplies from New England, New York, or Louisiana (via IT). Although the midpoint data suggest that minor price increases of up to one percent might be possible on as many as 15 percent of the days, the other columns indicate that even on these days gas would shift to PJM East from other locations. The reason is that on some of the specified days some trades would have been more profitable in PJM East than in New England, even when the average trade is not. As price would increase in PJM East, those marketers would begin shifting gas supplies to PJM East even before the midpoints match because some trades would be more profitable in PJM East. Given that the price data indicate that very small changes in prices would result in supplies shifting to PJM East, EEG could not raise prices.

Q. Would EEG raise prices on the days that Table 4 indicates that it might be able to raise prices?

A. No. To do this, EEG would have to make business decisions based on information available during morning trading, rather than based on the ex-post data that I can review here. Because of the price dispersion in the market, it is unlikely that EEG could selectively identify the precise days that it could raise prices 1 or 2 percent. And because on most days, even in winter, an attempted price increase would not be profitable, EEG could not develop a consistent strategy that resulted in higher prices on average and that also was profitable.

B. Efficacy of IT service

Q. On pages 22-23, Dr. Carpenter claims that IT is not a substitute for firm transportation. Please summarize his arguments.

A. Dr. Carpenter discounts the usefulness of IT service because he alleges that in winter when natural gas supplies are tight, an electric generator would not risk not having natural gas to meet commitments to generate electricity. He claims that the losses from not generating electricity on such a day can outweigh the potential gain from slightly lower natural gas prices from purchasing gas in a supply area and shipping IT instead of purchasing a daily firm gas supply from a firm shipper such as EEG.[14]

Q. How do you respond?

A. As long as the interstate pipelines make IT available and sufficient shippers are willing to use IT to fill the pipeline capacity, there are no restriction of natural gas supplies in the market and, therefore, no market power. It is important to recognize that those gas-fired generators that most need firm natural gas supplies already have term firm supply arrangements to procure their natural gas or gas transportation. Hence, the day-to-day manipulations hypothesized by Dr. Carpenter are not likely to impact generators that are otherwise the most vulnerable to such manipulations. Other generators are not as vulnerable to interruptions of natural gas transportation and can rely on IT supplies.

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[14] *Carpenter Deposition Transcript*, 7/22/05, pp. 86-89.

For example, the PECO distribution system offers back-up natural gas sales services to customers that have IT transportation contracts on its distribution system. An electric generator company that purchases this service from PECO can use IT nominations on interstate pipelines for gas supplies. If the generation company does not receive IT shipments from the interstate pipeline, then it can purchase gas from PECO at PECO's weighted average cost of gas. Other LDCs within PJM East have similar back-up service provisions. Such a service makes it impossible to withhold gas supplies to the IT customer.

Other generation units have back-up oil fuel supplies. These generators might also consider IT an acceptable substitute. Suppose, for example, the IT shipments would be curtailed one out of ten days. Under such circumstances use of IT service may make economic sense because the lower cost on nine days of purchasing natural gas in supply areas and shipping via IT instead of purchasing delivered firm gas would offset the loss from using potentially higher cost oil fuel on the one day.

Further, even if all electric generators required firm gas supplies, which many do not, IT would still be effective in limiting the exercise of market power in the natural gas market because other gas customers would be willing to use IT. Even Dr. Carpenter has acknowledged that IT would be acceptable to other customers in the marketplace.[15] As long as there is no change in the quantity of natural gas delivered to the market as a whole, natural gas prices in the market will not change and no firm shipper has market power.

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[15] *Carpenter Deposition Transcript,* 7/22/05, pp. 78-80

Q. How do you respond to the claim that IT is a poor substitute when "gas-fired power generation demands are high"?

A. As explained in the testimony of Dr. Hieronymus, the evidence is abundantly clear that substantial pipeline capacity for IT exists when demand for gas-fired generation is high, which occurs during the summer season. Although pipeline capacity is scarcer in winter, demand for gas-fired generation in PJM East is significantly lower in winter than it is in summer.

Q. How do you respond to the claim that IT is not a substitute for "episodic" withholding, as demonstrated in California in the summer of 2000?

A. Contrary to Dr. Carpenter's assertion, the evidence of IT nominations on the El Paso, PG&E, and SoCalGas systems showed that IT nominations increased whenever previously constrained paths became profitable for IT. When capacity was available, IT did flow on the California systems. At times more than 300 million cubic feet per day ("MMcf/d") of total interstate pipeline transportation capacity was nominated and over 100 MMcf/d of volume flowed using IT. This shows that IT can have a significant impact in the market. Of course, compared to the total consumption in California, IT was a relatively small share. But the nominations and actual deliveries demonstrate that a significant number of shippers will use IT sufficiently to fill pipeline capacity. As long as pipeline capacity is fully utilized, there has been no withholding of capacity and there is no exercise of market power.

C. EEG could not increase volatility

1. LPG/LNG

Q. Dr. Carpenter alleges that EEG could use LPG/LNG facilities to manipulate prices. Based upon your knowledge of the industry, does this seem plausible?

A. No. Liquid propane gas ("LPG") and liquid natural gas ("LNG") peaking facilities are designed to meet needle peak sendout volumes and typically cannot be used for daily or even episodic price manipulations. Both types of facilities are designed to supply gas for only a few days when pipeline deliveries of natural gas are not sufficient to meet the sendout requirements of the distribution system.[16] Because these facilities have relatively little storage capacity, the LPG or LNG in these facilities must be kept in storage until the design specifications are met so that they are used only when alternative supplies cannot meet system sendout requirements. Using the facilities for market manipulation would mean that not enough fuel would remain in storage to meet the sendout requirements for particularly cold days. The costs of LNG and LPG, along with the related costs of transportation and vaporization are such that the utilization of these supplies is not economic other than to satisfy the peak requirements of firm sales customers on the distribution systems. In addition, because storage is used in anticipation of cold days, which may or may not occur, utilities do not contract for constant replenishment of peaking supplies during the winter season. Consequently, the facilities

[16] Traditional LNG peaking facilities are different from the new LNG import terminals proposed throughout the country. LNG import terminals are designed to receive constant shipments of LNG on ships and constantly send out natural gas into the pipeline system. LNG peaking facilities either have low-volume liquefaction facilities that fill the storage at very slow rates or receive truck supplies of LNG. Their storage capacity is sufficient for only a few days of sendout.

are close to one-time-use-per-year facilities. Given these facts, they could not be used for market manipulations.

Q. What are the capacities of the facilities owned by PECO and PSE&G?

A. PSE&G has one LNG facility and four LPG facilities. The Burlington LNG Facility has about 350 thousand decatherms ("MDth") of storage capacity and vaporization capacity of 67.5 MDth per day ("MDth/d"), which gives it about a 5-day sendout period. PSE&G's four LPG facilities collectively have storage capacity of about 306 MDth. Three of the facilities have vaporization capacity, with collective capacity of approximately 212 MDth/d. This gives PSE&G only 1 to 2 days of LPG sendout capacity. Although the total vaporization capacity is 279.5 MDth/d, this capacity exists for less than two full days.

PECO also has one LNG facility, West Conshohocken, which has about 1,250 MDth of storage, 156 MDth/d of vaporization capacity, and an 8-day sendout period. The West Conshohocken facility has liquefaction capability of only about 6.5 MDth/d; therefore, it takes over 6 months to completely fill the facility. In addition, physical changes must be made in the facilities to change from liquefaction to vaporization. So once the withdrawal season begins, with rare exceptions, it cannot liquefy any more gas until the following spring. Hence, it is not suitable for price manipulations. The Tilghman Street Propane-Air facility in Chester, Pennsylvania has about 150 MDth of storage, 25 MDth/d of vaporization capacity, and 6-day sendout period.

2. Storage

Q. Dr. Carpenter also alleges, at pages 22-23 of his testimony, that EEG could use its underground storage capacity to manipulate prices.

Based upon your knowledge of the industry, does this seem plausible?

A. No. EEG's contractual shares of storage capacity, about 12 percent of Appalachian working storage capacity and about 10 percent of deliverability, are too small to significantly affect natural gas prices in storage areas. As discussed above, EEG would have no ability to move prices in PJM East. Hence, EEG would not be able to move market prices via its contractual rights to use others' underground storage facilities.

Operational considerations also indicate that underground storage rights are unlikely to be used to manipulate prices. There is no high deliverability storage in the market area that would allow for flexible injections and withdrawals. Rather, the storage located west of the market, has low rated deliverability, and must be moved into the market by interstate pipelines. For operators of local distribution companies, like PECO and PSE&G, storage needs to be filled by the end of the storage fill season. Because there are limits to the injection rates into storage, capacity rights holders like PECO and PSE&G cannot randomly fill storage at will. PECO, for example, seeks to have relatively constant injections during the fill season. Events in one day or period impact the ability to fill in other periods. Similarly for withdrawal rates, withdrawals in one day impact the amount of gas in storage and the ability to withdraw in other days. In addition, PECO has asset management agreements for some of its storage contracts, which give the asset manager the right to control fill-rates and withdrawals. These agreements also limit EEG's ability to manipulate storage. This is not to say that EEG would have no flexibility, in injections and withdrawals. But these operational limits reinforce the market limits discussed above.

Q. But wasn't storage manipulation and lack of storage fill one of the causes of high natural gas prices in California in 2000 and 2001?

A. No. Although elsewhere Dr. Carpenter has alleged that storage manipulation by SoCalGas and lack of storage fill contributed to the high prices in California in 2000 and 2001, the allegation has no merit for the current matter because the facts in the instant matter are substantially different from those in California. In California, SoCalGas operated the storage facilities and held by far the largest amount of storage capacity, and the underground facilities were located within the constrained pricing area. In the instant case, EEG does not own any underground storage facilities and will have no more than a 12 percent share, and the facilities are located west of the market area under examination. These facts all cut against a finding that storage usage could be used to influence prices.

3. Price Floor

Q. Dr. Carpenter claims, at page 23 of his testimony, that EEG would benefit not just from increasing natural gas prices, but from increasing price volatility. In your opinion, could EEG benefit from increasing volatility?

A. No. As discussed above, evidence on pipeline capacity, natural gas consumption, and prices indicates that EEG would not be able to raise prices. Therefore, EEG would have no ability to increase volatility by raising prices. The only other option would be for EEG to artificially lower prices in PJM East. But Dr. Carpenter does not explain how EEG would profit by artificially lowering prices below competitive levels, so it is not clear that his theory makes any sense at all. Even ignoring this fatal flaw, the natural gas price data indicate that it is very unlikely that EEG could reduce prices significantly to increase volatility. The same economic principles discussed above about price increases apply to attempts to lower price. The only difference is that prices for locations south and west of PJM East constrain PJM East prices from falling.

Q. Before continuing, what do you mean by price volatility?

A. In his deposition, Dr. Carpenter defined price volatility as prices moving up and down primarily on a day-to-day basis.[17] It is not clear how EEG would go about creating this price volatility. Most likely, it would be to significantly change the quantity of gas sold in unregulated gas sales from day-to-day even though demand conditions have not changed.

Q. How would the market likely react to such changes in sales?

A. Competing sellers would likely counteract such sales changes by EEG. As discussed above, on days when EEG attempted to raise prices, firm shippers with capacity through PJM East typically could make sales in PJM East. On days when EEG attempted to lower prices these firm shippers would simply make sales at higher prices in New York and New England, which would naturally tend to raise prices in PJM East. Similarly, if prices in PJM East are low, firm shippers with capacity in PJM East could easily forgo sales in PJM East and make sales farther south or west, place gas in storage, or withdraw less gas in storage depending upon the particular conditions. Regardless of the mechanism, it is very unlikely that EEG could significantly alter prices in PJM East on any given day.

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[17] *Carpenter Deposition Transcript*, 7/22/05, p. 90.

Q. Can you quantify the limits on price volatility?

A. Yes. As discussed above, EEG would have no ability to raise prices. Using similar methods, it is possible to count the days that prices could fall by 1, 2, 5, or 10 percent, as shown in Table 5. As with Table 4, the analysis is performed for typical transactions, some transactions, and at least one transaction. In Table 5, however, the low prices are in PJM East and the high prices are in alternative market areas, Transco Zone 5, Dominion South, and Columbia Appalachia. The table indicates that even based upon Typical Transactions, on 89 percent of the days EEG would not be able to reduce prices. The data for Some Transactions and At Least One Transaction indicate that even on most other days that prices would be unlikely to decrease significantly because marketers would sell gas south and west of PJM East instead of accepting lower prices in PJM East.

Table 5 — Percentage of Days that Alternative Supply Disposition Places a Floor on Price Decreases in PJM East

	Percentage of Days When It Would Be Profitable to Shift Supplies to Alternative Markets		
Potential Price Decrease (%)	**Typical Transactions**	**Some Transactions**	**At Least one Transaction**
1	89	97	99
2	94	97	99
5	96	98	99
10	97	99	100

Sources: Gas Daily: Daily Price Survey (July 5, 2003 through July 5, 2005); Columbia Gas Transmission Corporation; Texas Eastern Transmission, Transcontinental Gas Pipeline Corporation.

4. Option values

Q. Dr. Carpenter claims that EEG might benefit from greater volatility because of various physical and financial positions. In your opinion, is Dr. Carpenter correct?

A. No. The behavior of Exelon and PSEG reveals whether they would not likely benefit from greater volatility. Both utilities hedge their electric power positions and their natural gas positions. Hedges insulate the company from volatility, and the fact that the companies hedge their positions indicates that they do not benefit from volatility.

D. Long-term competition

Q. What do you mean by long-term competition?

A. Long-term competition refers to the competition in the market that occurs when pipeline companies can expand capacity. The HHI calculations of Dr. Carpenter, Dr. Hieronymus, and myself and the analysis above are based upon the existing pipeline capacity and firm shippers. But new capacity would change the market and make it even less likely that EEG would have market power in natural gas markets. New capacity in and around PJM East that either directly delivers new gas supplies into PJM East or allows supplies destined for other locations to be shifted into PJM East would provide new potential supplies to PJM East. For example, when Portland Natural Gas Transmission ("PNGT") entered New England, it allowed the pipelines delivering natural gas from south and west of New England to deliver more supplies to other areas such as PJM East. As FERC has stated, entry "can counteract any potential harm indicated by market share and concentration statistics."[18]

Q. What recent expansions have contributed to new supplies in and around PJM East?

A. A number of expansions in the past five years have contributed to new supplies to the region. In 2000, Maritimes & Northeastern pipeline entered New England with 440 MMcf/d of capacity. In 2001, PNGT expanded capacity by 38 MMcf/d. From 1999 through 2004, Iroquois pipeline expanded capacity approximately 286 MMcf/d. In 2002, Transco expanded capacity into PJM East by 126 MMcf/d. The Cove Point LNG terminal recommenced operation in this period, and increased its capacity by 415 MMcf/d.

Q. What proposed projects would increase capacity in the region?

A. A number of projects could effectively increase capacity to the region in the future. There are three LNG terminal projects for Canada and New England that have already received approvals and that could increase supplies in the north:

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[18] Revised Filing Requirements, 63 Fed. Reg. 20,340, 20,352 (1992)

- Canaport in Point Tupper, Nova Scotia (1,000 MMcf/d);
- Bear Head LNG in St. John, New Brunswick (1,000 MMcf/d); and
- Weaver's Cover Energy in Fall River, MA (800 MMcf/d).

The Broadwater Energy LNG terminal is in its pre-filing phase before FERC, and it would add 1,000 MMcf/d day of capacity to New York. Tennessee has a proposal to add 40,000 HP of compression, which would increase gas supplies from upstate New York to New England by 150 MMcf/d. The Millennium pipeline project will bring approximately 480 MMcf/d of capacity from Canada to Ramapo, NY where it will interconnect to the Algonquin system.[19] The Millennium project is currently scheduled to be in operation by November 1, 2007.

Directly in PJM East, Crown Landing LNG's proposal for a LNG terminal in Logan Township, NJ would increase capacity by about 1,200 MMcf/d, or about 20 percent of pipeline capacity entering PJM East. In addition, Philadelphia Gas Works ("PGW") has a proposal to place a LNG terminal in Philadelphia.

Q. What is the significance of these projects?

A. These projects total over 5,600 MMcf/d of new capacity, which is more than the total current capacity into New England and approaching the total capacity into PJM East. The market undoubtedly would not support the building of all of these projects within the next year or two. But there are many projects "in the pipeline," many of which have significantly more

[19] If an acceptable route can be found, Millennium would eventually continue directly into New York City.

capacity than that of all of PECO's interstate pipeline capacity. It is likely that most of the expansions discussed above would counteract any of the withholding hypothesized by Dr. Carpenter. This is especially true because some of the incentives discussed by Dr. Carpenter and addressed by Dr. Hieronymus deal with changes in market conditions three, five, or fifteen years in the future. Given the number of projects and the economics of LNG at current natural gas prices, significantly more supply options will be available in the future.

E. Market Oversight

Q. Dr. Carpenter states that existing regulations are not sufficient to protect against the potential for the exercise of market power by EEG. Do you agree with this assessment?

A. No. A substantial amount of regulation of natural gas markets is designed to eliminate or mitigate the potential exercise of market power. FERC regulations setting maximum tariff rates, requiring non-discriminatory service, requiring pipelines to segment firm shipper capacity, allowing secondary delivery rights and capacity release, and requiring IT service, all work to eliminate market power. State regulation of retail rates, transportation rates, balancing provisions, and back-up service, eliminate or mitigate market power of local distribution companies. Both FERC and state commissions oversee their regulations both for compliance and toward improving the efficacy of regulation. It is these regulations that lead to the consumption and price data above that lead me to conclude that EEG will not have market power.

Q. Please briefly describe how PECO is regulated and the Commission's oversight.

A. About 560 of the largest PECO customers receive gas from third-party suppliers via distribution transportation provided by PECO at regulated rates. These customers typically acquire supplies from competitive gas marketers. For the vast majority (99 percent) of PECO's customers, PECO operates as a traditional utility. It acquires interstate pipeline capacity rights, storage services, and gas supplies. It delivers gas supplies to retail customers at regulated, cost-based rates subject to prudence reviews. In annual Purchased Gas Cost (§1307(f)) proceedings, the Commission reviews PECO's gas commodity, transportation, and procurement practices. When PECO makes off-system sales or releases interstate capacity, pursuant to an existing, Commission approved sharing mechanism, approximately 75 percent of the net proceeds go as a credit to PECO's regulated gas firm sales customers and interruptible customers who have purchased firm standby service from PECO. As part of the §1307(f) proceedings, PECO reports every gas purchase and sales transaction for a year.

Q. Dr. Carpenter states that "because of the unregulated status of PSEG ER&T, the New Jersey BPU does not currently concern itself with how ER&T manages the gas assets under its control in order to meet the BGSS requirements contract ER&T holds with PSE&G. If the BPU suspected that there was a problem with the way ER&T was using the pipeline or storage capacity it controls to meet the PSE&G requirements, it would have to file a complaint at FERC" (at 23-24). Do you agree with this assessment?

A. No. I do not agree with the statement for two reasons. First, despite ER&T now handling the gas procurement functions for PSE&G via contract, the BPU has the same regulatory oversight of gas costs and acquisition practices as it did before, which is similar to the Commission's oversight of PECO. A majority of ER&T profits from off-system sales are treated as credits to Basic Gas Supply Service ("BGSS") customers that reduce the cost of holding interstate pipeline capacity for residential customers. PSEG makes annual filings on its gas acquisition costs and disposition, to set the BGSS residential rates. ER&T is obligated under the contract with PSE&G to provide the same supporting data that PSE&G provided before the contract for BGSS became effective. Although these filings are not as detailed as the PECO §1307(f) filings, they do provide detailed summaries of actual and future gas costs, along with capacity costs and projections, and the BPU has the ability to audit the filings if it desires.

Second, in my opinion Dr. Carpenter misinterprets the BPU order that he cites. His interpretation is that because ER&T is unregulated, BPU's only recourse for misuse of ER&T interstate capacity is to file a complaint at FERC. I believe a more accurate reading is that because of the filed rate doctrine, the BPU cannot review the terms of interstate transactions of

PSEG regardless of whether PSE&G or ER&T do the contracting. Regardless of whether PSE&G or ER&T provide gas transportation and gas procurement services, BPU has the ability to regulate retail rates and examine the costs filed by PSE&G that constitute those rates. In addition, the BPU regularly examines the supply demand balance that PSE&G maintains for its firm customers. Given the information available to the BPU, it is in a position to monitor the actions of PSEG and adjust rates and regulations accordingly. Because neither Dr. Carpenter nor I are qualified to give a legal interpretation of the NJBPU order that Dr. Carpenter relies upon, I have provided a copy of the order as Exhibit No. JRM-3 for the Commission's convenience.

Q. Dr. Carpenter also states that there is no equivalent to the PJM Market Monitoring Unit for natural gas markets (at 5). Is such a monitor necessary to prevent the exercise of market power in natural gas markets?

A. No. FERC has decided to regulate natural gas markets differently, with the effect that third party monitoring is not necessary. A comparison of market rules for PJM power markets and natural gas markets reveals why such monitoring is not necessary for natural gas. Consider the FERC rules requiring segmentation of capacity, secondary firm delivery points, and IT. In the electric power comparison, these rules are roughly equivalent to allowing other participants to put in contingent bids for EEG plants if the EEG bid is above market-clearing prices and the market operator always having a default bid equal to the average cost of the plant. Under such a set of market rules, the market power oversight of the Market Monitoring Unit ("MMU") would not be necessary because it is inconceivable that the capacity of the unit would be withheld. Similarly, the FERC regulation of interstate pipelines substantially reduces the amount of oversight that is necessary. Because neither Exelon nor PSEG own the interstate pipelines into PJM East, there is no issue of the merger giving a pipeline operator an incentive to evade FERC rules. Hence, there is no reason to believe that the merger would change the potential market power of any shipper.

Moreover, FERC's OMOI oversees compliance of FERC regulations and can suggest changes to regulations to make markets more efficient. OMOI monitors markets in real-time, so it can observe market activities as they happen. For example, OMOI observed that local marginal prices ("LMPs") for electric power in New England were greater than the bid of the highest-bid unit that was dispatched. OMOI investigated and found that such LMPs are consistent with an efficiently functioning LMP market. OMOI also investigated allegations that an electric generator failed to dispatch a gas-fired electric power plant even though electric power prices were significantly above the typical dispatch bid of the plant. OMOI found that it was efficient for the generator to sell its gas supply instead of producing electricity because the gas prices were high on an extremely cold day. The predecessor of OMOI alleged that El Paso Natural Gas Pipeline failed to supply all of its capacity for IT service, which led to hearings before FERC. Therefore, it is not correct to say that there is no oversight of the interstate natural gas markets.

F. Remedies

Q. Assume for a moment that Dr. Carpenter is correct that EEG would have market power due to its market share of contracted interstate pipeline capacity. Would you favor Dr. Carpenter's proposed remedy of divesting the gas operations of PECO and PSE&G?

A. No. Dr. Carpenter's concern has nothing to do with the operations of local distribution companies per se and hence the remedy (divestiture) has no nexus to the alleged problem. His concern deals with the contractual rights to use interstate pipelines. Even if his concern had merit, many less intrusive remedies exist that would allow EEG to maintain the economies of joint gas and electric utilities and to earn the economies from operating a large natural gas distribution network.

Q. What recommendations do you have for the Commission?

A. I recommend that the Commission conclude that EEG would not have market power in wholesale natural gas markets and the transaction has no material effect on retail competition in natural gas markets.

Q. Does this conclude your rebuttal testimony?

A. Yes.

EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

OVERVIEW

Dr. Morris, a recognized expert in studying competition in energy industries, currently is a Principal at Economists Incorporated. He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.

EDUCATION

Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981

PRESENT POSITION

Dr. Morris is a *Principal* at Economists Incorporated, an economic consulting firm located at 1200 New Hampshire Avenue, NW, Suite 400, Washington, DC 20036. (202-223-4700) Economists Incorporated studies competition and regulation in many industries in the United States and in other countries. It is a leading firm in studying the competitive effects of mergers and acquisitions.

PREVIOUS EXPERIENCE

Senior Vice President, Economists Incorporated, December 2001 – December 2002 • *Vice President*, Economists Incorporated, December 1995 – December 2001 • *Senior Economist*, Economists Incorporated, June 1992 – December 1995 • *Economic Tutorial Leader*, Stanford University (Stanford in Washington), April 1993 – June 1995 • *Visiting Assistant Professor*, Department of Business Economics and Public Policy, School of Business, Indiana University, September 1991 – May 1992 • *Assistant to the Director for Antitrust*, Bureau of Economics, Federal Trade Commission, November 1989 – August 1991 • *Economic Advisor*, Office of Commissioner Machol, Federal Trade Commission, December 1988 – October 1989 • *Economist*, Division of Antitrust, Bureau of Economics, Federal Trade Commission, October 1985 – December 1988

MEMBERSHIPS

Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American

Economic Association • Member, Western Economic Association International • Associate, American Bar Association

AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Affidavit, El Paso Marketing, L.P., *et al.*, ER95-428-000 (2005) • Affidavit, TransCanada Energy Ltd., *et al.*, ER95-692-000 (2005) • Affidavit, Granite Ridge Energy, LLC, ER00-1147-000, ER05-287-001 (2005) • Affidavit, TransCanada Power (Castleton) LLC, ER05-743-000 (2005) • Affidavit, Tampa Electric Company, *et al.*, ER99-2342-003 (2005) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-035 and Wisconsin Public Service Corporation, ER95-1528-010 (2005) • Affidavit, Wisconsin River Power Company, ER05-453-000 (2005) • Affidavit, Upper Peninsula Power Company, ER05-89-001 (2005) • Affidavit, Southern Indiana Gas and Electric Company, ER96-2734-003 (2004) • Affidavit, Tampa Electric Company, *et al.*, ER99-2342-003 (2004) • Affidavits, TransCanada Hydro Northeast, Inc., *et al.*, EC05-12-000, ER05-111-000 (2004) • Affidavits, Dominion Energy New England, Inc., *et al.*, EC05-4-000, ER05-34-000 (2004) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-033 and Wisconsin Public Service Corporation, ER95-1528-008 (2004) • Affidavit, NorthPoint Energy Solutions Inc. ER04-1244-000 (2004) • Affidavit, Union Power Partners, L.P., ER01-930-004 (2004) • Affidavit, Panda Gila River, L.P., ER01-931-004 (2004) • Affidavit, Dominion Energy Kewaunee, Inc., ER04-318-000 (2003) • Affidavit, TPS GP, Inc., TPG LP, Inc., Panda GS V, LLC & Panda GS VI, LLC, EC03-90-000 (2003) • Affidavit, Berkshire Power Company, L.L.C. *et al.*, ER99-3502-001 (2002) • Affidavit, El Paso Merchant Energy, L.P., ER95-428-024 (2002) • Affidavit, Tampa Electric Company, ER99-2342-001 (2002) • Affidavit, Hardee Power Partners Limited, ER99-2341-001 (2002) • Affidavit, TECO-PANDA Generating Company, L.P., ER02-1000-000 (2002) • Affidavit, Commonwealth Chesapeake Company, LLC, ER99-415-004 (2002) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-031 and Wisconsin Public Service Corporation, ER95-1528-006 (2001) • Affidavit, TPS McAdams, LLC and TPS Dell, LLC, ER02-507-000 and ER02-510-000 (2001) • Affidavits, Prepared Direct Testimony, and Hearing, CPUC v. El Paso Natural Gas Company, et al., RP00-241-000 (2000-2001), Affidavit, El Paso Energy Corporation and The Coastal Corporation, EC00-73-000, (2000) • Affidavit, El Paso Energy

Corporation and Sonat Inc., EC99-73-000 (1999) • Prepared Testimony, San Diego Gas & Electric Company and Enova Energy, Inc., EC97-12-000 (1997) • Prepared Testimony and Hearing, Wisconsin Electric Power Co., Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin), and Cenerprise, Inc., EC95-16-000 (1996)

TESTIMONY BEFORE STATE REGULATORY COMMISSIONS

Prepared Direct Testimony and Hearing, Application of Washington Gas Light Company for amendments to Rate Schedule No. 9, Firm Delivery Gas Supplier Agreement of its Gas Tariff, Docket No. PUE-2004-00085 (2005) • Prepared Direct Testimony, Application of Wisconsin Public Service Corporation for a Certificate of Public Convenience and Necessity for Construction of A Large Electric Generating Plant with Associated Facilities, known as Weston 4, at Its Existing Weston Generating Station Located in Marathon County, Docket No. 6690-CE-187, Public Service Commission of Wisconsin (2004) • Prepared Direct Testimony, Metromedia Energy, Inc. - Regarding Washington Gas Light Company's Plan to Return Customers to Sales Service Effective December 1, 2003, Docket No. PUE-2003-00536 (2004) • Report (with Mark Frankena) and Testimony, Analysis of Competitive Implications: An investigations into whether electric industry restructuring and competition in the provision of retail electric service is in the public interest, Louisiana Public Service Commission Docket No. U-21453, U-20925 (SC), U-22092 (SC) (Subdocket A) (2000) • Report and Hearing, Atlantic City Electric Company: Audit of Restructuring, New Jersey Board of Public Utilities, Docket No. EA97060395 (1998) • Prepared Testimony and Hearing, Proceeding on Motion of the Commission to Redesign Niagara Mohawk Power Corporation's Current SC-7 Service Classification and Implement a New SC-7-A Service Classification, Case 94-E-0172, New York Public Service Commission (1995)

TESTIMONY BEFORE FEDERAL COURTS

Report, Deposition, and Bench Trial, FTC v. Arch Coal, Inc., et al., Civil Action 04-0534 (JDB), U.S. Dist. Court, Dist. of Columbia (2004) • Report, Deposition and Jury Trial, Trigen v. OG&E, CIV-96-1595L, U.S. Dist. Court, Western Dist. Of Oklahoma (1998)

TESTIMONY BEFORE STATE COURTS

Affidavit, City Public Service Board of San Antonio vs. Public Utility Commission of Texas, et al., No. 97-02917, District Court of Travis County, Texas, 200th Judicial District (1997)

OTHER TESTIMONY

Report, Metromedia Energy, Inc. v. Mirant Americas Energy Marketing, RE: 18 198 Y 18484 03 (2005) • Report and Deposition, King Provision Corporation v. Burger King Corporation and Grand Metropolitan PLC, 90-05718-CA, 4th Cir., Duval Co., Florida (1992) • Deposition, West Texas Transmission L.P. v. Enron Corp. et al., SA 88 CA 0638, W.D. Texas, San Antonio Division (1988)

PUBLICATIONS

FERC MBR Screens: The Good, the Bad, and the Ugly," *Public Utilities Fortnightly* 143(7) (July 2005): 37-42 • "Finding Market Power in Power Markets," *International Journal of the Economics of Business*, 7(2) (July 2000): 167-178 • "Why Applicants Should Use Computer Simulation Models to Comply with the FERC's New Merger Policy," with Mark Frankena, *Public Utilities Fortnightly*, 135(3) (February 1, 1997): 22-26 • *Electric Utility Mergers*, with Mark Frankena and Bruce Owen, Chapters 1, 4, & 5, 1994 • "International Trade and Antitrust: Comments," *University of Cincinnati Law Review*, 61(3) (1993): 945-953 • "Upstream Vertical Integration with Automatic Price Adjustments," *Journal of Regulatory Economics* 4 (1992): 279-287 • "Should the U.S. Department of Justice deviate from the 5% price test for market definition on a case-by-case basis?" with Gale Mosteller, *International Merger Law*, April 1992 • "Defining Markets for Merger Analysis," with Gale Mosteller, *Antitrust Bulletin* 36 (Fall 1991): 599-640 • "Analyzing Agreements Among Competitors: What Does the Future Hold?" with Jim Langenfeld, *Antitrust Bulletin* 36 (Fall 1991): 651-679 • "In Defense of Antitrust," with Jim Langenfeld, *Regulation* 14(2) (Spring 1991): (Letters) 2-4 • "Enforcement of Property Rights and the Provision of Public Good Attributes," *Information Economics and Policy* 3 (1988): 91-108

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"Advertising Restrictions as Rent Increasing Costs," FTC Bureau of Economics Working Paper No. 196, May 1992 • "Rent Increasing Costs: The Antitrust Implications from a Paradox in Value Theory," FTC Bureau of Economics Working Paper No. 182, November 1990 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," FTC Bureau of Economics Working Paper No. 168, November 1988 • "Deregulation by Vertical Integration?" FTC Bureau of Economics Working Paper No. 166, November 1988

RECENT PRESENTATIONS & PROFESSIONAL ACTIVITIES

Chair, Antitrust Committee, Energy Bar Association, 2004–2005 • "Competition in the Natural Gas Industry: An Antitrust Perspective, presentation to staff of the Federal Energy Regulatory Commission," March 28, 2005 • Vice Chair, Antitrust Committee, Energy Bar Association, 2003–2004 • "Weston 4 Effect on Wholesale Competition in WUMS," submitted to the Public Service Commission of Wisconsin by Wisconsin Public Service Corporation in Docket No. 6690-CE-187, September 26, 2003 • "Computer

Models In The Electric Power Industry," presented to staff of the Federal Trade Commission, Washington, DC, June 11, 2002 • "TECO EnergySource Market Share Analysis," submitted to FERC by TECO EnergySource, Inc. in Docket No. ER96-1563-017, September 10, 2001 • "Finding Market Power in Power Markets," presented to staff of the Federal Trade Commission, Washington, DC, June 20, 2001 • "A Study of Marketing Affiliate and Other Affiliate Holdings of Firm Capacity on Interstate Natural Gas Pipelines and the Effects on Natural Gas Markets," April 30, 2001, submitted to FERC by the Interstate Natural Gas Association of America in Docket No. PL00-1-003 • "Why We Should Use Computer Models to Unveil Market Power," presented at the Sixth DOE–NARUC National Electricity Forum, Brown Convention Center, Houston, TX, September 16, 1998 • Comments, *Agency Information Collection and Dissemination Activities: Comment Request*, U.S. Department of Energy, Energy Information Administration, August 28, 1998 • Comments, *Revised filing Requirements Under Part 33 of the Commission's Regulations*, Federal Energy Regulatory Commission Docket No. RM98-4-000, August 21, 1998 • "Use of Computer Simulation Models to Unveil Market Power," presented to staff of the Federal Trade Commission, Federal Energy Regulatory Commission and U.S. Department of Justice, Federal Trade Commission, Washington, DC, April 10, 1998 • "Use of Computer Simulation Models to Unveil Market Power: The Primergy Case," presented to the Bureau of Economics, Federal Trade Commission, Washington, DC , December 8, 1997 • "Use of Computer Simulation Models to Unveil Market Power," presented at the 29th Annual Conference of the Institute of Public Utilities, Williamsburg, Virginia, December 3, 1997 • "Mergers and Market Power," presented at the National Association of State Utility Consumer Advocates Mid-Year Meeting, Charleston, South Carolina, June 9, 1997 • "Market Power Analysis: An Economic Perspective," (with Mark Frankena), presented at the Strategic Research Institute Conference on The Legal Challenges of Restructuring, Arlington, Virginia, April 16, 1997 • "Mergers and Market Power," presented at the Edison Electric Institute Workshop on FERC Merger Policy Guidelines, Arlington, Virginia, April 1, 1997 • "New Approaches to Controlling Distribution Company Market Power," presented at the New York Energy Efficiency Council Conference on Innovative Solutions to a Changing Energy Market, New York Athletic Club, February 7, 1997 • Description of the Western Power Model™, with Mark Frankena, Exhibit 8 to Prepared Testimony Before the Nevada Public Service Commission, January 31, 1997 • Reviewer, American Bar Association, Section of Antitrust Law, *Manual on the Economics of Antitrust Law, 14th Supplement*, 1995 • Referee, *Quarterly Journal of Business and Economics*, 1994—1995

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
DOCKET NO. A-110550F0160

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JOINT APPLICATION OF PECO ENERGY COMPANY AND PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE MERGER OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED WITH AND INTO EXELON CORPORATION

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DEPOSITION OF PAUL R. CARPENTER, a witness called on behalf of the Philadelphia Electric Company, taken pursuant to the Pennsylvania Rules of Civil Procedure, before Jane M. Williamson, Registered Merit Reporter and Notary Public in and for the Commonwealth of Massachusetts, at the Offices of Skadden, Arps, Slate, Meagher & Flom, One Beacon Street, Boston, Massachusetts, on Friday, July 22, 2005, commencing at 9:41 a.m.

PRESENT:

Skadden, Arps, Slate, Meagher & Flom LLP
(By Matthew W.S. Estes, Esq.)
1440 New York Avenue, N.W., Washington, D.C. 20005-2111 for Philadelphia Electric Company.

Thomas, Thomas, Armstrong & Niesen
(By Thomas T. Niesen, Esq.)
Suite 500, 212 Locust Street, P.O. Box 9500, Harrisburg, PA 17108, for Philadelphia Gas Works.

Also Present: Keya Banerjee, Lexecon
John R. Morris, Economists Incorporated
Melanie Sabo, Esq., Pennsylvania Power & Light Company (Via telephone)

Excerpts from Dr. Carpenter's Deposition Transcript

Pages 32-33

Q. Under FERC's merger policy in doing a
vertical market analysis, does FERC look at the
amount of the HHI increase?
A. My understanding is that for purposes of a
raising rivals cost type analysis, they would not
look at the size of the increase. They would look
at the level.

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What I'm suggesting here is that in these
circumstances, the size of the increase is also
material, because you've, in a sense, got a
horizontal issue with respect to gas and the merger.
Q. FERC, however, has never looked at this
type of horizontal issue as far as the combination
of natural gas contract rights in analyzing the
merger?
A. I'd have to look back, but I think this
issue came up in the Sempra merger by virtue of a
combination of San Diego's gas assets and Pacific
Enterprises' upstream gas assets. So they may have.
I'd have to go back and look.
Q. Now, under FERC's guidelines, both its
horizontal and its vertical guidelines, if these
HHIs indicate a problem, that's not the end of the
story, is it? It's not automatically concluded that
there's a market power problem; is that correct?
A. I think that's correct. I do on Page 17
quote from Order 642, in which it refers to a
particular HHI result as being a presumption that
the merger would likely create an enhanced market
power. I don't know whether you would call that the
end of the story, but certainly FERC does also

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recommend looking at other factors in these
analyses.
Q. In fact, doesn't FERC say that if you
have -- if these market power concerns are raised by

HHIs, then what they do is set the merger for hearing, to see if, in fact, the applicants can raise prices or exercise market power?

A. As I recall the language, I think what FERC says is if these HHI thresholds are exceeded, it is then the applicant's obligation to explain why it's not a problem via other factors or mitigating factors or to propose mitigation. I don't recall that that necessarily dictates whether there's a hearing or not.

Q. But the point is at that point, there's further investigation?

A. I think that's fair to say, sure. Further investigation or mitigation, I guess is a way of putting it.

Q. Right. Let's look a little bit at your Table 1. Now, I assume that this table and the calculations are done the way you understand FERC would require the analysis to be done?

A. Well, I would say that's the case, yes.

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FERC's guidelines don't provide a cookbook for how to do these kinds of calculations.

Q. So the ones that you've left blank are not necessarily largely committed to these New England markets?

A. Well, the ones that I left blank do not

Pages 42-43

Q. Just in case other people have the same problem with sense of direction as I do as to what's upstream or downstream, when we're talking about upstream here, this would be the right to deliver at other delivery points within PJM East; is that correct?

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A. Right, correct. And there's a couple of errata in my testimony where I got that flipped around. I think of down as being down -- the flow of pipe goes downhill. But unfortunately, when you live in the New England, you always think of yourself as being uphill of everything.

Q. I have that same problem. And you've caveated a bunch of your answers with the economic incentive. And I'd like to explore that a little bit. And I'd like to start off with a hypothetical.

If you assume these Algonquin shippers had no commitments to serve customers in New England -- that they were completely free contractually to do what they wanted with the gas -- do you have that as the assumption behind the hypothetical?

A. Yes.

Q. In that case, if gas prices in PJM East were higher than gas prices north of there, where they could deliver it in Algonquin, wouldn't their incentive be to deliver the gas in PJM East?

A. Yes. Of course, the key to your hypothetical is the assumption you're requiring me to make about the price differential.

Q. Could you elaborate on that.

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A. Yes. From a factual point of view, if you look at the markets downstream of PJM East, historically there is a significant price differential between those two points. To me, that suggests that the markets downstream of PJM East are in a separate geographic market. I know Dr. Hieronymus disagrees with that, but that's my opinion.

Q. Again, just for clarity of the record, by "downstream," you mean north of PJM East?

A. Yes, northeast.

Q. Again, just as a hypothetical, however, if prices were rising in PJM East as a result of the exercise in market power, isn't it the case that the incentives might be to deliver in PJM East instead of New England and New York?

A. Yes, but only if the price increase was sufficient to eliminate the differential.

Q. On Page 18 of your testimony, down at the bottom when you're talking about the delivery rights into Algonquin, you say that it's inappropriate to

include those rights in PJM East and go on to say
they are largely committed to serving other markets.
Do you see that?

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A. Yes.

Pages 45-46

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have LDC subsidiaries. That does not mean that they
might not be committed in some other sense. But
certainly one easy way to look at this capacity was
to see whether or not it was being held by
downstream LDCs. And that's what Table 2 is
designed to do.
By the way, just for the record, on Line 6
of that page, I've got "upstream," and that should
be "downstream." That's one of them. I think we'll
probably produce an errata sheet at some point for
this. There's a few other typos.
Q. Let's, if we could, compare this Table 2
with your Table 1 on 17. Now, it's the case, isn't
it, that Table 1 also has a number of LDCs on it. I
think we talked about Philadelphia Gas Works is an
LDC. And in fact, Exelon and PSEG are both LDCs; is
that correct?
A. Yes. They have elements of LDCs. They
also serve other loads as well, as we've discussed.
Q. Well, that's also the case, isn't it, for
the LDCs that you have on Table 2?
A. Potentially, sure.
Q. You're not saying that they are
substantially different in that regard, the LDCs in

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Table 2 and the ones in Table 1?
A. No, I'm not, but that's not really the
point. But I'm not making that distinction.
Q. And I think you told me when we were

talking about the companies on Table 1, there's a number of hours of the year when their contract -- they are not fully contractually committed; that they have spare capacity that's available to be delivered in the market; is that correct?
A. That's correct.
Q. And that also would be the case for these LDCs you have on Table 2; is that correct?
A. Potentially. But the one thing you also have to remember is these loads are going to be somewhat correlated from a weather point of view and also the fact that there is a pricing differential between these markets, and it's sustained. So we've observed that the Table 2 entities are operating in a separate market.
Q. You mentioned two things; one of which I understood, one of which I didn't. When you said the loads are going to be correlated, were you saying that the loads of the New York and New England LDCs are going to be correlated to the loads

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of the PJM East LDCs?
A. Yes, to some extent. So when the market starts to get tight, prices tend to be rising in both regions for weather purposes. So what that means is that at the times at which you might think that the downstream LDCs might have an incentive to sell into PJM East delivery points would be precisely the times when they as well are likely to have committed loads to meet downstream.

Pages 78-80

Q. Okay, fair enough. Now, with respect to released capacity, do you know whether it's a common

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practice for customers in PJM East markets who release their capacity to make that release subject to recall?
A. I don't know specifically.

Q. Do you know whether PECO and ER&T typically make the capacity they release subject to recall?
A. I don't know.
Q. If it is recallable, then that would give PECO and ER&T the ability to interrupt the transportation they've released and take it back; is that correct?
A. That would be correct.
Q. To the extent that the release capacity is subject to recall, then that makes it more like interruptible transportation; would you agree with that?
A. Yes, I would agree with that. Under those conditions, that makes release capacity a poor substitute for firm capacity held by capacity holders for sale at the delivery point.
Q. Now, your testimony here on the bottom of Page 22 referring to "firm transportation capacity" refers only to its utility to a generator. And I guess the question is, is it your testimony that

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interruptible transportation capacity is a poor substitute for customers other than generators?
A. I think, actually, you've misread that portion of my testimony. What it says is "...interruptible transportation is a very poor substitute for firm transportation capacity, particularly during periods when gas-fired power generator demands for gas are high" -- so during those periods -- "or for example, during the winter when the available interstate pipeline capacity is heavily utilized by firm-capacity holders."
So it's not strictly limited to just when gas-fired power generator demands are high.
Q. No, my question was, does that answer go only to generators or does it go to other types of customers. The next sentence you're referring to how it's risky for generators to use interruptible transportation, but could it be a useful product for someone who's not a generator?
A. Yes, but I would not on that basis say that it's a substitutable product. My experience with

interruptible transportation is that it gets used when pipeline conditions are slack and someone's looking for an opportunistic purchase. It is when

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market conditions are tight. It is not considered to be an equivalent substitute.

Q. You said that's your experience. Is that your experience in PJM East?

A. That's my experience worldwide, really.

Q. Have you specifically analyzed PJM East to see if that's the case there?

A. Well, again, we don't have data by customer which shows what the purchases are that would permit you to do that or that would have permitted me to do that in the time period required to prepare this testimony. You'd need third-party discovery for that.

Q. You're not claiming that this is data that PECO has withheld from you in discovery, however?

A. No. I think, actually, it would be very hard for PECO to obtain that data as well.

Q. Have you examined for the pipelines that run through PJM East how much interruptible capacity is sold by those pipelines?

A. Not for purposes of this testimony.

Q. Is that data publicly available?

A. I'm not sure. Maybe.

Q. With respect to generators and whether

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interruptible transportation is a substitute for generators for firm-released transportation -- for transportation capacity -- let's start over. I said two different things.

With respect to your testimony about generators and whether interruptible transportation is a substitute for firm transportation capacity, is it your testimony that the generators can't use interruptible transportation if it's available when firm capacity is not available?

A. My testimony is that it's risky for them to do that. And therefore, it is sufficiently less valuable that it is not a substitute for firm.

Pages 86-89

Q. Do you know whether some generators have

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backup gas service with their local distribution companies where they can purchase gas from them if their gas transportation service is interrupted?

A. I don't know.

Q. Well, assuming that the generator has that type of arrangement or has a backup oil supply, wouldn't that make interruptible transportation more attractive to that generator?

A. Well, I think we'd need to know a bit more about how easy it is to switch. I mean, IT transportation typically, you're not going to know whether you're going to get bumped until the day of gas flow and sometimes before its cycle, you know, the afternoon of gas flow.

And so if you've bid your power station in and you get interrupted on the day of gas flow, there may not be enough time for you to switch or to invoke the other arrangement that you described. So I'd need to know more about those arrangements.

But I suppose in principal, if you could eliminate the risk of interruption, you know, in principal, that might make interruptible capacity more valuable, but I would point out that those are all at costs. There are costs associated with that.

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And so the alternative of just buying gas at the delivery point firm may dominate all of those.

Q. It may, or it may have its own costs associated with buying firm; is that correct?

A. Well, you're paying a market price for firm gas. There are other weaker, poorer substitutes. And what my testimony is about is that interruptible transportation is a poor substitute. It doesn't say that it's entirely nonsubstitutable. It says it's a poor economic substitute.

Q. Now, going back to your answer at the bottom of Page 22, you say that, Interruptible transportation is a very poor substitute for firm transportation, particularly during two different circumstances. One is when gas-fired power generator demands are high; and one is during the winter, when the available interstate capacity is heavily utilized by firm capacity holders.

Would you agree that during other conditions, interruptible transportation is a better substitute? For example, if there's not a high demand either for gas-fired generation or pipeline capacity?

A. Yes.

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Q. Now, have you done any analysis as to when the time periods are when it would be a better substitute, as opposed to when it would be a poorer substitute?

A. Well, as I say here, it's a poor substitute when pipeline capacity is heavily utilized during those shoulder periods when there's a run-up to higher capacity utilization and during the periods from a gas-fired power generator point of view, when demands for power generation are high and when there's a lot at stake in terms of bearing the risk of interruptible transportation.

Q. And have you done any analysis to know how many days of the year those two conditions exist?

A. No.

Q. Let's refer to the first one; when gas-fired power generator demands for gas are high. If you're assuming this is not during the winter, why is interruptible transportation a poor substitute?

A. Well, because during those periods, it might be a better substitute for a nonpower generator, I'll grant you that. And I already said that during the summer, IT tends to flow more. But

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for a power generator, there's a lot at stake, when

gas demand is high and prices are high, of being interrupted, when power prices are high.
Q. But if there's a lot of capacity available, what is the risk of being interrupted?
A. Well, there's always a risk under interruptible transportation of being interrupted.
Q. And it's your opinion that gas generators don't want to take that risk?
A. Yes, particularly during high demand periods, when prices are high and there's a lot at stake. And particularly where the price of electricity is determined by the marginal gas-fired generator, the ability to buy market price gas and bid your plant in at that market price is valuable. So why take a chance on delivery reliability for what is a relatively small amount of profit.
MR. ESTES: It might be a good time to go to lunch. Off the record.
(Discussion off the record)
MR. NIESEN: Maybe we could move this along a little bit and work through lunch and try to get it done.
MR. ESTES: I'm willing to go through

Page 90

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lunch.
BY MR. ESTES:
Q. Let's go to the next point that you're trying to make here on Page 23, which is that the merged entity would have the ability to increase the volatility of the gas -- price of gas in addition to the price level.
Now, since you say you're referring to something other than an increase in prices, does this mean, essentially, that the actions would be taken to cause prices to decrease?
A. Well, actions could be taken to cause prices to move rapidly up and/or down, yes.
Q. And when you say "rapidly," what do you have in mind? What time frames?
A. Day-to-day, primarily.

Q. And you say on Lines 13 to 15 that this volatility would be "beneficial to Exelon and PSEG's unregulated power and gas trading arm that has physical and financial positions that profit from increased price volatility."

How exactly would the volatility benefit Exelon and PSEG in this way?

A. You actually asked me an interrogatory on

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that question that I answered. Basically every trading operation that I'm aware of in gas and power enters into financial contracts, forward contracts, swaps, different kinds of arrangements that have option features and optionality.

Optionality can come from things like being able to exercise a contract or a financial option, to close out an option at some point in the future. Whenever you take those kind of positions, the more volatile the market, the more profitable the position, the more valuable the position.

Agenda Date: 1/9/02
Agenda Item: 2D

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S PROPOSAL TO TRANSFER ITS RIGHTS AND OBLIGATIONS UNDER ITS GAS SUPPLY AND CAPACITY CONTRACTS AND OPERATING AGREEMENTS TO AN UNREGULATED AFFILIATE AND OTHER RELIEF)	ENERGY ORDER APPROVING TRANSFER OF CONTRACTS BPU DOCKET NO. GM00080564 OAL DOCKET NO. PUCOT-09734-00N

(SERVICE LIST ATTACHED)

BY THE BOARD:

PROCEDURAL HISTORY

On August 11, 2000, Public Service Electric and Gas Company ("PSE&G" or "Company") filed a petition with the Board of Public Utilities ("Board" or "BPU"), for approval to transfer its rights and obligations under its capacity contracts and operating agreements, to an unregulated affiliate ("Newco" or "Affiliate"). PSE&G proposed that it would enter into a Requirements Contract under which Newco would provide the interstate capacity, storage and gas supply needed for PSE&G to satisfy its obligation to provide Basic Gas Supply Service ("BGSS"). PSE&G also proposed to implement an optional Capacity Release Program that would ensure that Third-Party Suppliers ("TPS") would have an opportunity to obtain interstate capacity to deliver natural gas to their customers on PSE&G's system if they were unable to obtain such capacity elsewhere.

As part of its petition, PSE&G proposed to eliminate the Company's annualized commodity pricing component under its Commodity Service ("CS") rate schedules, the successor to the Levelized Gas Adjustment Clause ("LGAC"), including the elimination of the use of deferred accounting and true-up provisions. PSE&G proposed to move its firm gas customers, currently served under that levelized mechanism, to monthly, market based pricing under the Company's Market Price Gas Service ("MPGS") rate schedule.

The matter was transferred to the Office of Administrative Law ("OAL") on October 26, 2000, for hearing as a contested case and assigned to Administrative Law Judge ("ALJ") Louis G. McAfoos, III. Parties to the case included PSE&G, the Division of Ratepayer Advocate ("Advocate") and Board Staff ("Staff"). On December 19, 2000, a pre-hearing conference was conducted at the OAL, at which time a discovery and litigation schedule was established. At the December 19, 2000 pre-hearing conference, the ALJ granted intervenor status in this matter to

North Jersey Energy Associates ("NJEA"), Mid-Atlantic Power Supply Association ("MAPSA"), Independent Energy Producers of New Jersey ("IEPNJ"), the New Power Company ("New Power"), Shell Energy Services Co. ("Shell"), the Enron Corporation ("Enron") and New Jersey Business Users ("NJBUS"), (collectively "the Parties"). In a letter from PSE&G to the ALJ, dated December 21, 2000, the ALJ's oral rulings on the various interventions were summarized.

Public hearings were held in Mt. Holly, NJ, on January 29, 2001, in New Brunswick, NJ, on January 30, 2001, and in Hackensack, NJ, on February 1, 2001. Evidentiary hearings were held at the OAL on March 26, April 16, May 21, May 22, June 13, June 15, and June 22, 2001. On March 9, 2001, PSE&G amended its filing to defer transferring residential gas customers to its MPGS service for two years. The Company presented four witnesses, the Advocate presented two witnesses and Shell presented one witness in the proceeding.

On March 20, 2001, the Advocate filed a motion to dismiss PSE&G's petition, arguing that it was contrary to the policies and mandates of the Electric Discount and Energy Competition Act ("EDECA"), N.J.S.A. 48:3-49 et seq. The ALJ did not rule on the Advocate's motion. On March 22, 2001, NJBUS submitted a letter in support of the Advocate's motion to dismiss. On March 26, 2001, PSE&G filed its response to the Advocate's motion to dismiss. PSE&G also submitted a letter in opposition to NJBUS' March 22, 2001 letter in support of the Advocate's motion to dismiss. On March 29, 2001, Shell submitted a letter in opposition to the Advocate's motion. On April 2, 2001, the Advocate submitted its reply to PSE&G's and Shell's letters.

STIPULATION OF SETTLEMENT AND FIRST ADDENDUM

On April 16, 2001, a Stipulation of Settlement ("Stipulation") was executed by PSE&G, Shell, Enron and New Power, and unopposed by MAPSA, and was entered into the record. Staff and the Advocate did not sign the Stipulation of Settlement.

The Stipulation provides as follows:

1. PSE&G's rights and obligations under its Gas Transportation and Storage contracts shall be transferred to an unregulated affiliate, and valued at the current contracts costs.

2. Adjustments to the shopping incentives contained therein shall become effective on the later of 60 days after receipt of the Board's written Order approving the Stipulation or the effective date of implementation of the collection of the Gas Cost Underrecovery adjustment, pursuant to the Board's Order in Docket No. GR00070491 (LGAC proceeding).

3. An Initial FT Capacity Release Program shall be made available to Third Party Suppliers. The program shall be implemented on the effective date of the contract transfer to Newco.

4. A Citygate Storage and Redelivery Program shall be made available to TPS licensed by the Board who supply gas to customers who switch to TPS service after the effective date of the contract transfer to Newco. The program shall be implemented on the effective date of the contract transfer to Newco.

5. A Permanent Capacity Release/ Assignment Program shall be made available to TPS licensed by the Board who supply gas to customers who switch to TPS service after the effective date of the contract transfer to Newco. This program shall be implemented on the effective date of the contract transfer to Newco.

6. PSE&G and Newco shall adhere to all legal requirements regarding affiliate standards, including those approved by the Federal Energy Regulatory Commission ("FERC") and the Board.

7. Upon the effective date of the contract transfer to Newco, the Basic Gas Supply Service ("BGSS") rates for residential customers taking their delivery on rate schedule Residential Service Firm Transportation-Gas Service ("FT-RSG") will continue to be priced by PSE&G in accordance with rate schedule Commodity Service Residential Service ("CS-RSG"). The current LGAC mechanism to establish the rates for the commodity charge shall continue to include utilization of deferred accounting and monthly filings with the Board and be governed by the Board's Order in Docket No. GR00070491. Margins generated from off-system sales shall be credited to residential BGSS customers pursuant to the Board-approved sharing mechanism in effect at that time.

8. Residential customers shall be priced at market price, under the rate schedule MPGS, effective April 1, 2004. Effective April 1, 2004, Newco shall be at risk for all contract costs. The commodity charge rate mechanism shall terminate effective April 1, 2004.

   If an over/underreccovery exists at the time of implementation of MPGS to residential customers, that amount shall be collected from or credited to all FT-RSG customers over a period not to exceed two years, together with interest at the rate for the Societal Benefits Clause ("SBC") over or underrecoveries.

9. The Requirements Contract shall contain the following provisions:

   a. Newco shall provide the full requirements needed by PSE&G to render service pursuant to PSE&G's BGSS rate schedules.

   b. The initial term of the Requirements Contract ends on March 31, 2004. In the event PSE&G terminates the contract at the end of the initial term, Newco will have the option to return to PSE&G no more than 50% of each capacity and commodity contract then in effect. PSE&G may, at its option, extend the term of the Requirements Contract for three additional years. The Requirements Contract shall not be extended beyond the time that PSE&G no longer has the obligation to provide BGSS.

c. Consideration paid by PSE&G for the Requirements Contract shall include all amounts billed by PSE&G pursuant to: 1) the BGSS firm sales rates schedules, including CS-RSG and MPGS; 2) gas supply and capacity charges and/or margins under the BGSS interruptible sales rate schedules and transportation agreements (excluding Non-Firm Transportation Gas Service margins); 3) balancing charges pursuant to the FT rate schedules; 4) the Generation Affiliate Supply Arrangement [1]; and 5) non-tariff service agreements.

d. Newco shall provide monthly information regarding the rates to be charged by PSE&G for providing MPGS.

e. Newco shall provide a performance warranty whereby Newco agrees to maintain sufficient transportation and storage entitlements and sufficient natural gas supplies to enable it, in conjunction with PSE&G's Peak Shaving Facilities, to have available each day for delivery PSE&G's total requirements for natural gas.

10. The Company shall increase its Non-Gulf Coast Rate applicable to MPGS service by 2.1 cents per therm, excluding sales and use tax ("SUT"), to recover higher fixed costs under pipeline capacity contracts and an adjustment to the number of degree-days in a normal year. PSE&G's commodity cost shall be increased by 8 cents per dekatherm (excluding SUT) to reflect the higher costs of gas in inventory.

11. If one year from the effective date of a Board Order in this proceeding, the switching rate for customers switching to TPS for retail service does not achieve the 20% switching, PSE&G shall implement a 1.8 cents per therm shopping incentive for each customer class that does not achieve the 20% threshold. The following rate schedules are included: Large Volume Firm Transportation Gas Service ("FT-LV"), General Service Firm Transportation Gas Service ("FT-GS"), Street Lighting Service Firm Transportation Gas Service ("FT-SLG"), Firm Transportation Gas Service ("FT-UVNG"), Cogeneration Service Firm Transportation Service Gas ("FT-CFG") and FT-RSG.

[1] As defined in the Requirements Contract, the term "Generation Supply Arrangement" means the supply arrangement approved by the Board in Docket Nos. EO97070461, EO97070462, and EO97070463, whereby PSE&G was authorized to supply, on an as needed basis, dedicated intrastate natural gas transportation service for PSE&G's generation affiliate with respect to certain transferred generation facilities in accordance with the Stipulation approved by the Board in Docket No. ER94070293, OAL Docket No. PUC 7328-94, on May 5, 1995, or any successor to such arrangement.

12. Current Board approved gas cogeneration contracts shall remain unaffected by the Board's approval of the Stipulation.

13. The balancing charge for firm transportation customers shall remain at $0.075736 per therm ($0.080280 per therm including SUT) of balancing use pursuant to rate schedules FT-GS, FT-LV, FT-SLG, FT-UVNG, FT-CFG and FT-RSG. The current methodology for determining the rate shall remain in place.

14. The parties shall begin a collaborative process to develop a retail BGSS Pilot Program, upon the effective date of a Board Order approving the Stipulation.

Discovery conceming the Stipulation was conducted between April 16 and the resumption of hearings on May 21, 2001.

At the hearings, an Addendum to the Stipulation of Settlement ("First Addendum"), executed by PSE&G, Shell, NJEA, and IEPNJ, was entered into the record. The First Addendum adds NJEA and IEPNJ to the Stipulation and includes a revised paragraph 12 from that in the initial Stipulation. The First Addendum provides that the gas contracts transfer results in no impact to the cogeneration supply and pricing contracts. The First Addendum also provides that after fulfilling its BGSS obligation to PSE&G, and its capacity obligations to TPS, Newco shall make available surplus capacity to generation facilities, within PSE&G's service territory, that are not owned by PSE&G or its affiliates. Amendments to the proposed Requirements Contract were provided to all parties on May 14 and May 30, 2001.

INITIAL BRIEFS

On August 15, 2001, PSE&G, Staff, the Advocate and MAPSA filed Initial Briefs. Shell filed its Initial Brief on August 16, 2001. The positions of the parties were as follows:

Company Position

The Company asserts that the settlement proposals are in the public interest and should be adopted as reasonable. The Company states that the Settlement will substantially advance competition in its market area and that the Advocate's arguments are without merit and should be rejected. The Company requests that the Board enter an Order adopting the Stipulation as reasonable.

Advocate Position

In its Initial Brief, the Advocate recommends that the Board should reject both the proposed contract transfer and Requirements Contract with Newco. First, the Advocate asserts that the Company's proposal to transfer its interstate transportation and storage contracts and other gas supply resources to an unregulated affiliated is: 1) contrary to the policies of EDECA; 2) in violation of EDECA's mandates requiring full BPU regulation of BGSS; and 3) imprudent as a matter of gas supply procurement policy. Second, the Advocate asserts that PSE&G should be directed to implement measures to encourage competition while it retains control of its essential natural gas supply resources. Third, the Advocate asserts that, in accordance with the legislative directives of EDECA, the transfer should be considered only after a robust competitive natural marketplace has developed and the Board is assured that PSE&G's control of its gas supply resources is no longer needed to assure reliable and reasonably priced BGSS. The Advocate further asserts that, in order to prevent undue preference to PSE&G's affiliates, and to assure that ratepayers receive the full value of any transferred resources, any transfer should be subject to competitive bidding.

For these reasons, the Advocate argues that if PSE&G's proposed transfer is adopted, it would create inordinate risks for New Jersey's energy markets and energy consumers, while providing PSE&G affiliates with the opportunity to gain windfall profits at ratepayer expense.

Staff Position

In its Initial Brief, Staff recommends that: 1) the Board should reject PSE&G's proposal to impose binding arbitration upon the Board as it would undermine the Board's statutory authority; 2) the Requirements Contract should require that Newco be held responsible for Board approved reliability standards for its firm customers; 3) the Board should provide safeguards to ensure that the proposed BGSS pilot program requires Newco to meet PSE&G's BGSS obligations, until the Board provides further guidance through its generic BGSS proceeding; 4) in the event FERC's capacity release regulations change while PSE&G retains BGSS responsibility, the Board should permit a further review of the valuation of the contracts transferred; 5) a weather normalization adjustment using a thirty-year average should continue to be utilized; and 6) Newco, as well as PSE&G affiliates, should be bound by the Board's Affiliation Relations Standards, to ensure that there is no preferential treatment with regard to capacity and storage release between PSE&G and Newco. Staff concludes that the transfer should not be approved until these concerns are met.

Shell Energy Position

In its Initial Brief, Shell asserts that the Stipulation provides a structure for a comprehensive program that will enable PSE&G to effectuate the contract transfer, and at the same time establish a relationship between the parties that is intended and designed to result in a vibrant, competitive marketplace for natural gas in the PSE&G service territory. Shell also asserts that for the first time, PSE&G has agreed to provide transportation and storage assets required by TPS to provide reliable, cost effective service, and has also offered significant economic incentives designed to induce low-use customers to switch to alternative providers. Last, Shell asserts that the Stipulation is a significant step towards achieving EDECA's public policy goal and should facilitate the transition from traditional monopoly structure to a competitive marketplace. Accordingly, Shell recommends adoption of the Stipulation.

REPLY BRIEFS

On September 14, 2001, PSE&G and Staff filed Reply Briefs. On September 17, 2001, the Advocate filed its Reply Brief. The positions of the parties were as follows:

Company Position

PSE&G agrees to modify its proposals in the Stipulation to satisfy all of Staff's concerns as expressed in Staff's Initial Brief. PSE&G also argues that the Advocate's arguments should be rejected as without merit, especially in view of Company's willingness to modify its Stipulation to accept Staff's position, as set forth in its Initial Brief.

Advocate Position

The Advocate asserts that: 1) the Stipulation fails to address the fundamental issue of market power; 2) the Stipulation is in violation of EDECA'S mandate for continued Board oversight of BGSS, specifically as it relates to reliability and BGSS pricing; 3) the Stipulation would appropriate ratepayer-funded assets without proper compensation; and 4) Staff's proposed remedial measures are inadequate to remedy serious flaws in the Stipulation with respect to the issues of continued Board oversight of BGSS, reasonably priced BGSS, continued Board ratemaking authority, valuation and undue preference.

The Advocate recommends that the Stipulation should be rejected as inconsistent with the policies and mandates of EDECA, and that the Board adopt the recommendations set forth in its Initial Brief.

Staff Position

Staff relies upon the position presented in its Initial Brief.

FURTHER PROCEDURAL DEVELOPMENTS

On October 1, 2001, the parties were advised that the ALJ would be departing State service prior to completion of the case. Due to his imminent departure, the ALJ convened a conference call with the parties on October 3. Rather than transfer the case to a new ALJ, the ALJ recommended to the parties that the Board should, in accordance with the provisions of N.J.A.C. 1:1-3.3(a), recall this matter. All parties concurred with the recommendation. During the conference call, the ALJ established a schedule for closing the record. That schedule was as follows: signatories to the Stipulation of Settlement and Addendum thereto had until October 17 to file a Second Addendum thereto, with the Parties' responses due by October 31, 2001, which was after the date of the ALJ's departure.

At its agenda meeting of October 12, 2001, the Board determined to recall the Gas Contract Transfer case from the OAL. On October 15, 2001, the Board's Secretary sent a letter to the OAL requesting that this case be returned the Board on November 1, 2001, after the close of the record.

SECOND ADDENDUM TO THE STIPULATION

On October 26, 2001, PSE&G filed a Second Addendum ("Second Addendum") to the Stipulation. In addition to PSE&G, signatories to the Second Addendum included Shell, NJEA, New Power, Enron and IEPNJ. Staff and the Advocate did not sign the Second Addendum. The Second Addendum addresses five concerns as presented by Board Staff in its Initial Brief. The Second Addendum provides that the signatories agree to the Stipulation and First Addendum with modifications, including the following:

1. Paragraph 11.2 of the Requirements Contracts, entitled Regulatory Risk, is deleted. Additionally, Article 18, including paragraph 18.1, of the Requirements Contract is also deleted, with a substitution providing that except to the extent that jurisdiction is conferred upon FERC under the Natural Gas Act or other applicable federal law, jurisdiction to resolve disputes arising under the Requirements Contract shall reside exclusively in the Superior Court of New Jersey and be governed by the laws of New Jersey.

2. The Requirements Contract will be modified to reflect that Newco is obligated to abide by any Board approved reliability standards applicable to PSE&G's gas operations with respect to wholesale gas supplies, including capacity, for the period in which PSE&G is obligated to provide BGSS. Newco shall be entitled to participate as a party in any proceeding before the Board pertaining to the establishment of reliability standards.

3. Consistent with Staff's recommendations in its Initial Brief, the parties agree that:

   a. A weather normalization adjustment using a thirty-year average will be utilized;

   b. Newco is obligated to provide service to PSE&G to fulfill its BGSS service. The Requirements Contract shall be modified to reflect such continuing obligations, and

   c. PSE&G shall provide written notice to all industrial and commercial customers, currently served under rate schedules CS-V and CS-GS, of the change in service to MPGS within thirty days of the Board's Order approving the transfer.

4. To maintain the Non-Gulf Coast Cost component at $1.26/Dth, PSE&G shall remove from the Non-Gulf Coast Cost component contributions for off-system sales margins for industrial and commercial customers only. Margin sharing for residential customers shall not be affected. Residential gas customers shall continue to receive margins from off-system sales pursuant to the applicable Board Order addressing those margins.

5. In the event FERC removes the rate ceiling applicable to valuation of the contracts, within five years of any action by the Board authorizing the proposed transfer, the Board maintains the right to review the valuation of the transferred contracts.

6. PSE&G agrees that the Requirements Contract shall be modified to reflect that Newco agrees not to provide any undue preferences to retail gas supplier affiliates with respect to the sale of commodity, release or assignment of interstate pipeline transportation and storage capacity.

7. Paragraph 8 of the Stipulation is modified so as to provide that residential customers shall not be priced under rate schedule MPGS prior to April 1, 2004. At least one year prior to April 1, 2004, PSE&G shall file for Board approval to implement rate schedule MPGS pricing for residential customers.

8. A revised Requirements Contract, including the changes described above, shall be submitted to the Board for approval.

SUPPLEMENTAL BRIEFS

On October 31, 2001, the Advocate filed its Supplemental Brief in response to the Second Addendum. The Advocate's Supplemental Brief reiterates issues, which were raised in varying degrees by the Advocate in its earlier filings. First, the Advocate claims that approval of the PSE&G proposal would result in the Board losing regulatory oversight of BGSS. The Advocate indicates that the modifications included in the Second Addendum do nothing to assure the

Board's continuing authority over matters affecting the reliability and pricing of BGSS. Advocate Supplemental Brief at 3. The Advocate continues that the Second Addendum fails to address its concerns because it places reliability obligations on Newco, does not specify long term pricing terms and is effectuated through contractual obligations that are outside the Board's jurisdiction. The Advocate concludes that even with the Addenda, the PSE&G proposal would cause the Board to lose its ability to oversee gas procurement and its ability to assure reliable and reasonably priced BGSS.

DISCUSSION AND FINDINGS

The Board has carefully reviewed the record in this proceeding, including the arguments raised by the Advocate. The Board recognizes that the Advocate has raised significant issues with respect to the proposed Stipulation and Addenda. The gas contracts transfer would mean that the Board would not have the ability to delve into the gas procurement practices of Newco. Nor will it have the ability to alter the pricing agreements between PSE&G and Newco or any other contractual terms of the PSE&G/Newco agreement. However this is no different than the current situation under which PSE&G provides BGSS service. PSE&G enters into wholesale arrangements for gas supply and enters into pipeline obligations that are under FERC control. Currently, the Board does not have the authority to look behind the wholesale gas agreements or to alter FERC mandated pricing and operational terms and conditions. What the Board has now and would have in the future is the ability to hold PSE&G responsible for BGSS service and to regulate the terms and conditions of that service. N.J.S.A. 48:3-58(r). The Board will determine appropriate terms and conditions for BGSS service consistent with EDECA and PSE&G will be held responsible for meeting those terms and conditions. Currently, PSE&G enters into contractual obligations for capacity, commodity and storage, which are reviewed through Levelized Gas Adjustment Clause proceedings for prudence and possible disallowance. Any obligations that are found to be impudent, or costs which are disallowed, become the responsibility of PSE&G. Similarly, it does not matter that the Board does not have jurisdiction over the parties with which PSE&G has contracted. The Board currently sets and in the future will continue to set the BGSS rates, terms and obligations.

The Advocate raises a concern over the value at which the assets are being transferred. PSE&G's supply, capacity and storage rights have fixed durations and contractual terms and conditions determined by FERC. PSE&G has obtained these rights to serve its firm customer load. To suggest that there is a flourishing market for long-term capacity and storage by other than those with an obligation to serve customers overlooks the reality of the current marketplace. The Advocate cites PSE&G witness Wohlfarth's testimony that during the winter of 2000/01 gas delivered to New Jersey peaked at $25 per dekatherm, which was above FERC tariff rates, to indicate that, as a bundled transaction, the total value is greater than the sum of the parts. Advocate Supplemental Brief at 7-8. This may be true on a short-term basis, for a limited amount of capacity. As the Advocate points out, its example is for a $25 transaction for the 2000/01 winter. The Advocate does not provide similar evidence for summer periods or for any other period of time. Also, as indicated in this example, commodity prices at that time were around $10 per dekatherm. During the current winter, commodity prices are below $3 per dekatherm. It is not clear that bundled transactions would be similarly priced or whether a lower commodity price suggests a lower demand for commodity and capacity. The Advocate's *argument in this regard is unpersuasive and unsupported. Further, the Advocate's argument* is based on transactions for incremental amounts of supply and capacity. It is not clear that if the entire PSE&G supply/capacity portfolio were mixed in with the amount cited by the Advocate that the $25 transaction would not move to or below FERC-tariffed rates, and that on a year-round basis the average transaction for this larger volume would not be well below FERC-tariffed rates. The year-round value of the PSE&G supply and capacity portfolio is only addressed in the record by PSE&G witness Makholm who concludes that the cost of the contracts in question are $170 million above their market value. The Board believes that there is sufficient evidence to conclude that the PSE&G proposal as amended through the Addenda is providing fair value to the ratepayers through a reallocation of supply risks, enhanced supplier services, which may spur the competitive gas market, and market-based pricing for C&I customers.

The Advocate also indicates that the Proposal imposes a $.16 per dekatherm rate increase on commercial and industrial ("C&I") customers which has not been properly noticed and which the Ratepayer Advocate has not had the opportunity to review. Id. at 6. On or about November 2, 2000 PSE&G published a Notice of Filing in Docket No. GM00080564 that indicates in part:

> Because the Company's gas prices would be market priced monthly pursuant to its MPGS rate schedule, the Company's proposal may result in either higher or lower natural gas prices than exist currently.
>
> [PSE&G-1.]

The Advocate has been a party to this proceeding from the outset and has engaged in discovery and cross-examination of witnesses. The Board emphatically rejects the Advocate's argument that the change in rates has not been properly noticed and that it has not had the opportunity to review the proposed C&I pricing mechanism.

The Advocate also alleges that the market-based pricing proposal for C&I customers results in prices which would be based on neither actual costs nor on the results of a bid. Advocate Supplemental Brief at 6. The Advocate claims that the market-based pricing proposal is based on PSE&G's MPGS rate schedule and was originally designed as an unfavorable rate so that customers returning to BGSS would not create increased costs for existing BGSS customers. Advocate Initial Brief at 16. The Advocate's argument that the market-based pricing proposal is not based on actual costs is incorrect. As the Advocate notes in its Initial Brief, there is a formula for setting the floor and ceiling for this service based on the cost of interstate transportation and storage and short-term commodity indices or the highest cost of gas during the month. Id.at 16-17. Therefore, the proposal prices C&I BGSS customers based on actual procurement costs.

Contrary to the Advocate's assertions, MPGS was never designed as an unfavorable rate, but rather, as the Advocate notes, it was designed to recover the incremental cost of providing supply service to returning customers and to avoid creating additional supply costs for existing customers. Id.at 16. This, by definition, is cost-based service. The Board notes that currently the incremental cost of providing supply service could be higher or lower than the PSE&G tariff supply rate. MPGS was created with a floor price to satisfy a supplier concern that PSE&G tariff rates could be set to undercut suppliers in order to keep customers on sales service. At the same time, there was a concern about the MPGS price having no upper limit. An upper limit was established using the \$.181/therm margin that has been in the Emergency Sales Service since C&I rates were first unbundled in 1994. MPGS was intended to put the Company's sales service to C&I customers on the exact same footing as that of competitive suppliers. This element of the Settlement Proposal, namely, pricing customers in a comparable way as competitive suppliers, is the key to competition in the C&I customer classes. Under the Settlement Proposal, Newco and suppliers are both at risk for the recovery of the fixed cost obligations under the pipeline contracts held to service their customers. This is true for Newco since there will no longer be a straight cost pass through via an LGAC-type mechanism for C&I customer classes. Therefore, both Newco and the competitive suppliers are at risk for weather and loss of load from customers leaving, in addition to incurring the added cost of the financial products needed to try to protect against these risks. There is no floor or ceiling on the price the third party supplier can charge. Competitive suppliers would not place themselves at risk for these significant costs without having the flexibility to price at competitive prices. In other words, competitive suppliers would not participate in the retail marketplace if the Board tried to regulate their prices, and in a competitive environment, it is appropriate that PSE&G be accorded similar flexibility for MPGS.

We further note that the MPGS price is very transparent. It is filed with the Board every month for all to see. In this manner, competitive suppliers have a known benchmark against which to compete. The possibility that PSE&G could charge any price it wants up to the ceiling would place it, and therefore Newco, at risk for total C&I migration to competitive suppliers. The Board FINDS that the MPGS pricing mechanism for C&I customers was duly noticed, is cost based, and is appropriate to encourage gas competition in these rate classes.

Concerning the C&I pricing proposal, the Advocate criticizes the removal of the \$.05/therm credit for C&I off-system sales. Advocate Supplemental Brief at 6. Margins from off-system sales are returned to firm customers because, as firm customers, they are responsible, through the LGAC, for all reasonable and prudent costs incurred to provide the commodity to the customer. This would include FERC-tariffed pipeline capacity charges even when the capacity is not being 100% utilized. Therefore, to the extent the utility could re-sell unused pipeline capacity and/or package it with a commodity sale whereby the sale was above the cost of the commodity, the utility and thereby the ratepayers would be better served than having capacity sitting idle. This is only true where the customer is paying, such as through the LGAC, the full cost of reserving capacity and commodity to meet any variations in customer service requirements. When the customer is only paying for the pipeline capacity and commodity on an "as needed" basis, and some third-party is responsible for fluctuations in demand, then it is the third-party that is at risk for unused capacity and commodity and it is the third-party that should receive the benefits from such sales. In the current proposal, MPGS pricing will put Newco, not PSE&G customers, at risk for the capacity and commodity to provide service to C&I customers and therefore, it is appropriate that the margin sharing formula developed under an LGAC-based process be discontinued for these customer classes. Margin sharing would continue for residential customers, since they would still be subject to LGAC-type pricing.

The Advocate further claims that there is the potential for undue preference inherent in the PSE&G proposal, first in transferring resources to Newco without competitive bid and second in permitting Newco to potentially provide undue preference to its generation affiliate. Id. at 9. The Board has previously discussed the value of the asset transfer and found that the terms and conditions of the transfer of assets is fair to ratepayers. The proposal to transfer these assets is conceptually similar to the transfer of generation assets, which was approved in conjunction with PSE&G's rate unbundling, stranded cost and restructuring settlement, by Board Order dated August 24, 1999 (Docket Nos. EO97070461, EO97070462 and EO97070463). As with the transfer of the generation assets, the Board needs to review the transfer of natural gas assets in the context of the entire Stipulation before it. The Board is not considering the transfer of PSE&G's natural gas assets in isolation. The proposal before the Board provides additional features such as capacity and storage services for licensed gas marketers and new tariff provisions for certain ratepayer classes which are desirable to this Board which would not likely be included in a proposal that was strictly a divestiture. As for the potential for undue preference to the PSE&G generation affiliate, the First Addendum provides that during the term of the Requirements Contract, after Newco has satisfied its PSE&G BGSS obligations and its obligations to release capacity to licensed gas suppliers, Newco will make any excess capacity available to New Jersey unaffiliated generators under comparable terms and conditions as it does to its affiliated generation. PS-7 at 2. This provision obviates the Advocate's concerns in this area.

The Advocate raises a concern about potential market power in terms of both the natural gas and electric markets in New Jersey. Advocate Initial Brief at 37-48. The Advocate maintains that a California type situation could occur as the result of Newco controlling significant gas resources in New Jersey. As indicated by PSE&G, the relatively small percentage of gas fired generation in the PJM region argues against the ability of any gas supplier to affect PJM electric markets. Given that Newco would be only one gas supplier in the PJM region and for that matter in New Jersey, the argument for Newco to exercise electric market power is weak. PSE&G Reply Brief at 11. As for the ability for Newco to unduly influence the natural gas market, in making such an argument one would have to assume, as the Advocate argues, that the significant pipeline and storage assets which would belong to Newco could be withheld from those requiring the use of those assets in order for market power to exist. This is simply not the case. Newco is committed to provide the BGSS requirements of PSE&G and to make capacity available to those licensed suppliers desiring to use it to serve PSE&G customers as well as to New Jersey generators, when excess capacity exists. Therefore the capacity and storage assets left for Newco to use at its discretion to unduly influence prices in the PSE&G service territory, and certainly in New Jersey as a whole, is a small portion of the overall portfolio and considerably less than the Advocate would suggest. Should the Board have reason to believe that undue market power was developing, in either the electric or natural gas arenas, the Board has the authority to investigate such allegations and take such actions, including filing a complaint with FERC, or other regulatory authority, as may be warranted to remedy the situation.

Finally, the Advocate indicates that the Settlement Proposal would subject ratepayers to high and unstable rates, uncertain reliability, and diminished consumer protections, while recognizing the incentive in the Proposal to promote competition and the transfer of pipeline risk from consumers to Newco. Advocate Initial Brief at 60-61. The Settlement Proposal does provide the two benefits to ratepayers identified by the Advocate. The Advocate has previously been vocal in its support of the need for additional incentives to increase competition in the energy markets. The Board has heard numerous comments since the implementation of EDECA for natural gas in 2000 that market-based pricing is the primary element necessary in order for gas competition to develop. This proposal will move all non-residential customers to market-based pricing and provide the opportunity no sooner than 2004, after experience with the non-residential classes, to investigate and possibly consider similar pricing structures for residential customers. As for the Advocate's concerns about unstable rates, reliability and consumer protections, we have previously indicated our belief and intention that BGSS is a fully regulated service subject to Board oversight in each of the areas identified by the Advocate.

The Board has carefully reviewed the record in this matter, the Stipulation of Settlement and the First and Second Addenda thereto, the revised Requirements Contract, as well as the Initial Briefs, Reply Briefs and Supplemental Briefs of the parties. Based upon the foregoing discussion, the Board FINDS that the Company's proposal to transfer its interstate capacity, storage and supply contracts to Newco and to enter into the revised Requirements Contract with Newco is reasonable.

The Board HEREBY APPROVES the Stipulation of Settlement as amended by the First and Second Addenda, and attached hereto and DENIES the Ratepayer Advocate's motion to dismiss the petition. The Board emphasizes that it will continue to exercise its jurisdiction to regulate BGSS rates, terms and conditions as required by EDECA. The Board DIRECTS PSE&G to file revised tariffs consistent with this Order within ten business days of the date of this Order and to inform the Board within five business days of the completion of the asset transfer with a full and detailed accounting of the specific assets transferred to Newco. The Board also notes that since the final documents were filed in this proceeding, a PSE&G base rate case was concluded (Docket No. GR01050328) which resulted in modifications to certain rate class designations. As part of the compliance filing, the Board DIRECTS PSE&G to file a list showing how the prior rate classes referenced in the current Stipulation and Addenda relate to current rate class designations and to file, where necessary, a revised Stipulation of Settlement, the First and Second Addenda thereto, and the revised Requirements Contract, *using the current* customer rate class designations.

DATED: April 17, 2002

BOARD OF PUBLIC UTILITIES
BY:

(SIGNED)

CONNIE O. HUGHES
COMMISIONER

(SIGNED)

FREDERICK F. BUTLER
COMMISSIONER

(SIGNED)

CAROL J. MURPHY
COMMISSIONER

ATTEST: (SIGNED)
KRISTI IZZO
SECRETARY

Agenda Date: 1/9/02
Agenda Item: 2D

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S PROPOSAL TO TRANSFER ITS RIGHTS AND OBLIGATIONS UNDER ITS GAS SUPPLY AND CAPACITY CONTRACTS AND OPERATING AGREEMENTS TO AN UNREGULATED AFFILIATE AND OTHER RELIEF

ENERGY

ORDER APPROVING TRANSFER OF CONTRACTS

BPU DOCKET NO. GM00080564
OAL DOCKET NO. PUCOT-09734-00N

(SERVICE LIST ATTACHED)

BY THE BOARD:

PROCEDURAL HISTORY

On August 11, 2000, Public Service Electric and Gas Company ("PSE&G" or "Company") filed a petition with the Board of Public Utilities ("Board" or "BPU"), for approval to transfer its rights and obligations under its capacity contracts and operating agreements, to an unregulated affiliate ("Newco" or "Affiliate"). PSE&G proposed that it would enter into a Requirements Contract under which Newco would provide the interstate capacity, storage and gas supply needed for PSE&G to satisfy its obligation to provide Basic Gas Supply Service ("BGSS"). PSE&G also proposed to implement an optional Capacity Release Program that would ensure that Third-Party Suppliers ("TPS") would have an opportunity to obtain interstate capacity to deliver natural gas to their customers on PSE&G's system, if they were unable to obtain such capacity elsewhere.

As part of its petition, PSE&G proposed to eliminate the Company's annualized commodity pricing component under its Commodity Service ("CS") rate schedules, the successor to the Levelized Gas Adjustment Clause ("LGAC"), including the elimination of the use of deferred accounting and true-up provisions. PSE&G proposed to move its firm gas customers, currently served under that levelized mechanism, to monthly, market based pricing under the Company's Market Price Gas Service ("MPGS") rate schedule.

The matter was transferred to the Office of Administrative Law ("OAL") on October 26, 2000, for hearing as a contested case and assigned to Administrative Law Judge ("ALJ") Louis G. McAfoos, III. Parties to the case included PSE&G, the Division of Ratepayer Advocate ("Advocate") and Board Staff ("Staff"). On December 19, 2000, a pre-hearing conference was conducted at the OAL, at which time a discovery and litigation schedule was established. At the December 19, 2000 pre-hearing conference, the ALJ granted intervenor status in this matter to

North Jersey Energy Associates ("NJEA"), Mid-Atlantic Power Supply Association ("MAPSA"), Independent Energy Producers of New Jersey ("IEPNJ"), the New Power Company ("New Power"), Shell Energy Services Co. ("Shell"), the Enron Corporation ("Enron") and New Jersey Business Users ("NJBUS"), (collectively "the Parties"). In a letter from PSE&G to the ALJ dated December 21, 2000, the ALJ's oral rulings on the various interventions were summarized.

Public hearings were held in Mt. Holly, NJ, on January 29, 2001, in New Brunswick, NJ, on January 30, 2001, and in Hackensack, NJ, on February 1, 2001. Evidentiary hearings were held at the OAL on March 26, April 16, May 21, May 22, June 13, June 15, and June 22, 2001. On March 9, 2001, PSE&G amended its filing to defer transferring residential gas customers to its MPGS service for two years. The Company presented four witnesses, the Advocate presented two witnesses and Shell presented one witness in the proceeding.

On March 20, 2001, the Advocate filed a motion to dismiss PSE&G's petition, arguing that it was contrary to the policies and mandates of the Electric Discount and Energy Competition Act ("EDECA"), N.J.S.A. 48:3-49 et seq. The ALJ did not rule on the Advocate's motion. On March 22, 2001, NJBUS submitted a letter in support of the Advocate's motion to dismiss. On March 26, 2001, PSE&G filed its response to the Advocate's motion to dismiss. PSE&G also submitted a letter in opposition to NJBUS' March 22, 2001 letter in support of the Advocate's motion to dismiss. On March 29, 2001, Shell submitted a letter in opposition to the Advocate's motion. On April 2, 2001, the Advocate submitted its reply to PSE&G's and Shell's letters.

STIPULATION OF SETTLEMENT AND FIRST ADDENDUM

On April 16, 2001, a Stipulation of Settlement ("Stipulation") was executed by PSE&G, Shell, Enron and New Power, and unopposed by MAPSA, and was entered into the record. Staff and the Advocate did not sign the Stipulation of Settlement.

The Stipulation provides as follows:

1. PSE&G's rights and obligations under its Gas Transportation and Storage contracts shall be transferred to an unregulated affiliate, and valued at the current contracts costs.

2. Adjustments to the shopping incentives contained therein shall become effective on the later of 60 days after receipt of the Board's written Order approving the Stipulation or the effective date of implementation of the collection of the Gas Cost Underrecovery adjustment, pursuant to the Board's Order in Docket No. GR00070491 (LGAC proceeding).

3. An Initial FT Capacity Release Program shall be made available to Third Party Suppliers. The program shall be implemented on the effective date of the contract transfer to Newco.

4. A Citygate Storage and Redelivery Program shall be made available to TPS licensed by the Board who supply gas to customers who switch to TPS service after the effective date of the contract transfer to Newco. The program shall be implemented on the effective date of the contract transfer to Newco.

5. A Permanent Capacity Release/ Assignment Program shall be made available to TPS licensed by the Board who supply gas to customers who switch to TPS service after the effective date of the contract transfer to Newco. This program shall be implemented on the effective date of the contract transfer to Newco.

6. PSE&G and Newco shall adhere to all legal requirements regarding affiliate standards, including those approved by the Federal Energy Regulatory Commission ("FERC") and the Board.

7. Upon the effective date of the contract transfer to Newco, the Basic Gas Supply Service ("BGSS") rates for residential customers taking their delivery on rate schedule Residential Service Firm Transportation-Gas Service ("FT-RSG") will continue to be priced by PSE&G in accordance with rate schedule Commodity Service Residential Service ("CS-RSG"). The current LGAC mechanism to establish the rates for the commodity charge shall continue to include utilization of deferred accounting and monthly filings with the Board and be governed by the Board's Order in Docket No. GR00070491. Margins generated from off-system sales shall be credited to residential BGSS customers pursuant to the Board-approved sharing mechanism in effect at that time.

8. Residential customers shall be priced at market price, under the rate schedule MPGS, effective April 1, 2004. Effective April 1, 2004, Newco shall be at risk for all contract costs. The commodity charge rate mechanism shall terminate effective April 1, 2004.

   If an over/underreccovery exists at the time of implementation of MPGS to residential customers, that amount shall be collected from or credited to all FT-RSG customers over a period not to exceed two years, together with interest at the rate for the Societal Benefits Clause ("SBC") over or underrecoveries.

9. The Requirements Contract shall contain the following provisions:

   a. Newco shall provide the full requirements needed by PSE&G to render service pursuant to PSE&G's BGSS rate schedules.

   b. The initial term of the Requirements Contract ends on March 31, 2004. In the event PSE&G terminates the contract at the end of the initial term, Newco will have the option to return to PSE&G no more than 50% of each capacity and commodity contract then in effect. PSE&G may, at its option, extend the term of the Requirements Contract for three additional years. The Requirements Contract shall not be extended beyond the time that PSE&G no longer has the obligation to provide BGSS.

c. Consideration paid by PSE&G for the Requirements Contract shall include all amounts billed by PSE&G pursuant to: 1) the BGSS firm sales rates schedules, including CS-RSG and MPGS; 2) gas supply and capacity charges and/or margins under the BGSS interruptible sales rate schedules and transportation agreements (excluding Non-Firm Transportation Gas Service margins); 3) balancing charges pursuant to the FT rate schedules; 4) the Generation Affiliate Supply Arrangement [1]; and 5) non-tariff service agreements.

d. Newco shall provide monthly information regarding the rates to be charged by PSE&G for providing MPGS.

e. Newco shall provide a performance warranty whereby Newco agrees to maintain sufficient transportation and storage entitlements and sufficient natural gas supplies to enable it, in conjunction with PSE&G's Peak Shaving Facilities, to have available each day for delivery PSE&G's total requirements for natural gas.

10. The Company shall increase its Non-Gulf Coast Rate applicable to MPGS service by 2.1 cents per therm, excluding sales and use tax ("SUT"), to recover higher fixed costs under pipeline capacity contracts and an adjustment to the number of degree-days in a normal year. PSE&G's commodity cost shall be increased by 8 cents per dekatherm (excluding SUT) to reflect the higher costs of gas in inventory.

11. If one year from the effective date of a Board Order in this proceeding, the switching rate for customers switching to TPS for retail service does not achieve the 20% switching, PSE&G shall implement a 1.8 cents per therm shopping incentive for each customer class that does not achieve the 20% threshold. The following rate schedules are included: Large Volume Firm Transportation Gas Service ("FT-LV"), General Service Firm Transportation Gas Service ("FT-GS"), Street Lighting Service Firm Transportation Gas Service ("FT-SLG"), Firm Transportation Gas Service ("FT-UVNG"), Cogeneration Service Firm Transportation Service Gas ("FT-CFG") and FT-RSG.

[1] As defined in the Requirements Contract, the term "Generation Supply Arrangement" means the supply arrangement approved by the Board in Docket Nos. EO97070461, EO97070462, and EO97070463, whereby PSE&G was authorized to supply, on an as needed basis, dedicated intrastate natural gas transportation service for PSE&G's generation affiliate with respect to certain transferred generation facilities in accordance with the Stipulation approved by the Board in Docket No. ER94070293, OAL Docket No. PUC 7328-94, on May 5, 1995, or any successor to such arrangement.

12. Current Board approved gas cogeneration contracts shall remain unaffected by the Board's approval of the Stipulation.

13. The balancing charge for firm transportation customers shall remain at $0.075736 per therm ($0.080280 per therm including SUT) of balancing use pursuant to rate schedules FT-GS, FT-LV, FT-SLG, FT-UVNG, FT-CFG and FT-RSG. The current methodology for determining the rate shall remain in place.

14. The parties shall begin a collaborative process to develop a retail BGSS Pilot Program, upon the effective date of a Board Order approving the Stipulation.

Discovery concerning the Stipulation was conducted between April 16, and the resumption of hearings on May 21, 2001.

At the hearings, an Addendum to the Stipulation of Settlement ("First Addendum"), executed by PSE&G, Shell, NJEA, and IEPNJ, was entered into the record. The First Addendum adds NJEA and IEPNJ to the Stipulation and includes a revised paragraph 12 from that in the initial Stipulation. The First Addendum provides that the gas contracts transfer results in no impact to the cogeneration supply and pricing contracts. The First Addendum also provides that after fulfilling its BGSS obligation to PSE&G, and its capacity obligations to TPS, Newco shall make available surplus capacity to generation facilities, within PSE&G's service territory, that are not owned by PSE&G or its affiliates. Amendments to the proposed Requirements Contract were provided to all parties on May 14 and May 30, 2001.

INITIAL BRIEFS

On August 15, 2001, PSE&G, Staff, the Advocate and MAPSA filed Initial Briefs. Shell filed its Initial Brief on August 16, 2001. The positions of the parties were as follows:

Company Position

The Company asserts that the settlement proposals are in the public interest and should be adopted as reasonable. The Company states that the Settlement will substantially advance competition in its market area and that the Advocate's arguments are without merit and should be rejected. The Company requests that the Board enter an Order adopting the Stipulation as reasonable.

Advocate Position

In its Initial Brief, the Advocate recommends that the Board should reject both the proposed contract transfer and Requirements Contract with Newco. First, the Advocate asserts that the Company's proposal to transfer its interstate transportation and storage contracts and other gas supply resources to an unregulated affiliated is: 1) contrary to the policies of EDECA; 2) in violation of EDECA's mandates requiring full BPU regulation of BGSS; and 3) imprudent as a matter of gas supply procurement policy. Second, the Advocate asserts that PSE&G should be directed to implement measures to encourage competition while it retains control of its essential natural gas supply resources. Third, the Advocate asserts that, in accordance with the legislative directives of EDECA, the transfer should be considered only after a robust competitive natural marketplace has developed and the Board is assured that PSE&G's control of its gas supply resources is no longer needed to assure reliable and reasonably priced BGSS. The Advocate further asserts that, in order to prevent undue preference to PSE&G's affiliates, and to assure that ratepayers receive the full value of any transferred resources, any transfer should be subject to competitive bidding.

For these reasons, the Advocate argues that if PSE&G's proposed transfer is adopted, it would create inordinate risks for New Jersey's energy markets and energy consumers, while providing PSE&G affiliates with the opportunity to gain windfall profits at ratepayer expense.

Staff Position

In its Initial Brief, Staff recommends that: 1) the Board should reject PSE&G's proposal to impose binding arbitration upon the Board as it would undermine the Board's statutory authority; 2) the Requirements Contract should require that Newco be held responsible for Board approved reliability standards for its firm customers; 3) the Board should provide safeguards to ensure that the proposed BGSS pilot program requires Newco to meet PSE&G's BGSS obligations, until the Board provides further guidance through its generic BGSS proceeding; 4) in the event FERC's capacity release regulations change while PSE&G retains BGSS responsibility, the Board should permit a further review of the valuation of the contracts transferred; 5) a weather normalization adjustment using a thirty-year average should continue to be utilized; and 6) Newco, as well as PSE&G affiliates, should be bound by the Board's Affiliation Relations Standards, to ensure that there is no preferential treatment with regard to capacity and storage release between PSE&G and Newco. Staff concludes that the transfer should not be approved until these concerns are met.

Shell Energy Position

In its Initial Brief, Shell asserts that the Stipulation provides a structure for a comprehensive program that will enable PSE&G to effectuate the contract transfer, and at the same time establish a relationship between the parties that is intended and designed to result in a vibrant, competitive marketplace for natural gas in the PSE&G service territory. Shell also asserts that for the first time, PSE&G has agreed to provide transportation and storage assets required by TPS to provide reliable, cost effective service, and has also offered significant economic incentives designed to induce low-use customers to switch to alternative providers. Last, Shell asserts that the Stipulation is a significant step towards achieving EDECA's public policy goal and should facilitate the transition from traditional monopoly structure to a competitive marketplace. Accordingly, Shell recommends adoption of the Stipulation.

REPLY BRIEFS

On September 14, 2001, PSE&G and Staff filed Reply Briefs. On September 17, 2001, the Advocate filed its Reply Brief. The positions of the parties were as follows:

Company Position

PSE&G agrees to modify its proposals in the Stipulation to satisfy all of Staff's concerns as expressed in Staff's Initial Brief. PSE&G also argues that the Advocate's arguments should be rejected as without merit, especially in view of Company's willingness to modify its Stipulation to accept Staff's position, as set forth in its Initial Brief.

Advocate Position

The Advocate asserts that: 1) the Stipulation fails to address the fundamental issue of market power; 2) the Stipulation is in violation of EDECA'S mandate for continued Board oversight of BGSS, specifically as it relates to reliability and BGSS pricing; 3) the Stipulation would appropriate ratepayer-funded assets without proper compensation; and 4) Staff's proposed remedial measures are inadequate to remedy serious flaws in the Stipulation with respect to the issues of continued Board oversight of BGSS, reasonably priced BGSS, continued Board ratemaking authority, valuation and undue preference.

The Advocate recommends that the Stipulation should be rejected as inconsistent with the policies and mandates of EDECA, and that the Board adopt the recommendations set forth in its Initial Brief.

Staff Position

Staff relies upon the position presented in its Initial Brief.

FURTHER PROCEDURAL DEVELOPMENTS

On October 1, 2001, the parties were advised that the ALJ would be departing State service prior to completion of the case. Due to his imminent departure, the ALJ convened a conference call with the parties on October 3. Rather than transfer the case to a new ALJ, the ALJ recommended to the parties that the Board should, in accordance with the provisions of N.J.A.C. 1:1-3.3(a), recall this matter. All parties concurred with the recommendation. During the conference call, the ALJ established a schedule for closing the record. That schedule was as follows: *signatories* to the Stipulation of Settlement and Addendum thereto had until October 17 to file a Second Addendum thereto, with the *Parties' responses* due by October 31, 2001, which was after the date of the ALJ's departure.

At its agenda meeting of October 12, 2001, the Board determined to recall the Gas Contract Transfer case from the OAL. On October 15, 2001, the Board's Secretary sent a letter to the OAL requesting that this case be returned the Board on November 1, 2001, after the close of the record.

SECOND ADDENDUM TO THE STIPULATION

On October 26, 2001, PSE&G filed a Second Addendum ("Second Addendum") to the Stipulation. In addition to PSE&G, signatories to the Second Addendum included Shell, NJEA, New Power, Enron and IEPNJ. Staff and the Advocate did not sign the Second Addendum. The Second Addendum addresses five concerns as presented by Board Staff in its Initial Brief. The Second Addendum provides that the signatories agree to the Stipulation and First Addendum with modifications, including the following:

1. Paragraph 11.2 of the Requirements Contracts, entitled Regulatory Risk, is deleted. Additionally, Article 18, including paragraph 18.1, of the Requirements Contract is also deleted, with a substitution providing that except to the extent that jurisdiction is conferred upon FERC under the Natural Gas Act or other applicable federal law, jurisdiction to resolve disputes arising under the Requirements Contract shall reside exclusively in the Superior Court of New Jersey and be governed by the laws of New Jersey.

2. The Requirements Contract will be modified to reflect that Newco is obligated to abide by any Board approved reliability standards applicable to PSE&G's gas operations with respect to wholesale gas supplies, including capacity, for the period in which PSE&G is obligated to provide BGSS. Newco shall be entitled to participate as a party in any proceeding before the Board pertaining to the establishment of reliability standards.

3. Consistent with Staff's recommendations in its Initial Brief, the parties agree that:

   a. A weather normalization adjustment using a thirty-year average will be utilized;

   b. Newco is obligated to provide service to PSE&G to fulfill its BGSS service. The Requirements Contract shall be modified to reflect such continuing obligations; and

   c. PSE&G shall provide written notice to all industrial and commercial customers, currently served under rate schedules CS-V and CS-GS, of the change in service to MPGS within thirty days of the Board's Order approving the transfer.

4. To maintain the Non-Gulf Coast Cost component at $1.26/Dth, PSE&G shall remove from the Non-Gulf Coast Cost component contributions for off-system sales margins for industrial and commercial customers only. Margin sharing for residential customers shall not be affected. Residential gas customers shall continue to receive margins from off-system sales pursuant to the applicable Board Order addressing those margins.

5. In the event FERC removes the rate ceiling applicable to valuation of the contracts, within five years of any action by the Board authorizing the proposed transfer, the Board maintains the right to review the valuation of the transferred contracts.

6. PSE&G agrees that the Requirements Contract shall be modified to reflect that Newco agrees not to provide any undue preferences to retail gas supplier affiliates with respect to the sale of commodity, release or assignment of interstate pipeline transportation and storage capacity.

7. Paragraph 8 of the Stipulation is modified so as to provide that residential customers shall not be priced under rate schedule MPGS prior to April 1, 2004. At least one year prior to April 1, 2004, PSE&G shall file for Board approval to implement rate schedule MPGS pricing for residential customers.

8. A revised Requirements Contract, including the changes described above, shall be submitted to the Board for approval.

<u>SUPPLEMENTAL BRIEFS</u>

On October 31, 2001, the Advocate filed its Supplemental Brief in response to the Second Addendum. The Advocate's Supplemental Brief reiterates issues, which were raised in varying degrees by the Advocate in its earlier filings. First, the Advocate claims that approval of the PSE&G proposal would result in the Board losing regulatory oversight of BGSS. The Advocate indicates that the modifications included in the Second Addendum do nothing to assure the

Board's continuing authority over matters affecting the reliability and pricing of BGSS. Advocate Supplemental Brief at 3. The Advocate continues that the Second Addendum fails to address its concerns because it places reliability obligations on Newco, does not specify long term pricing terms and is effectuated through contractual obligations that are outside the Board's jurisdiction. The Advocate concludes that even with the Addenda, the PSE&G proposal would cause the Board to lose its ability to oversee gas procurement and its ability to assure reliable and reasonably priced BGSS.

DISCUSSION AND FINDINGS

The Board has carefully reviewed the record in this proceeding, including the arguments raised by the Advocate. The Board recognizes that the Advocate has raised significant issues with respect to the proposed Stipulation and Addenda. The gas contracts transfer would mean that the Board would not have the ability to delve into the gas procurement practices of Newco. Nor will it have the ability to alter the pricing agreements between PSE&G and Newco or any other contractual terms of the PSE&G/Newco agreement. However this is no different than the current situation under which PSE&G provides BGSS service. PSE&G enters into wholesale arrangements for gas supply and enters into pipeline obligations that are under FERC control. Currently, the Board does not have the authority to look behind the wholesale gas agreements or to alter FERC mandated pricing and operational terms and conditions. What the Board has now and would have in the future is the ability to hold PSE&G responsible for BGSS service and to regulate the terms and conditions of that service. N.J.S.A. 48:3-58(r). The Board will determine appropriate terms and conditions for BGSS service consistent with EDECA and PSE&G will be held responsible for meeting those terms and conditions. Currently, PSE&G enters into contractual obligations for capacity, commodity and storage, which are reviewed through Levelized Gas Adjustment Clause proceedings for prudence and possible disallowance. Any obligations that are found to be impudent, or costs which are disallowed, become the responsibility of PSE&G. Similarly, it does not matter that the Board does not have jurisdiction over the parties with which PSE&G has contracted. The Board currently sets and in the future will continue to set the BGSS rates, terms and obligations.

The Advocate raises a concern over the value at which the assets are being transferred. PSE&G's supply, capacity and storage rights have fixed durations and contractual terms and conditions determined by FERC. PSE&G has obtained these rights to serve its firm customer load. To suggest that there is a flourishing market for long-term capacity and storage by other than those with an obligation to serve customers overlooks the reality of the current marketplace. The Advocate cites PSE&G witness Wohlfarth's testimony that during the winter of 2000/01 gas delivered to New Jersey peaked at $25 per dekatherm, which was above FERC tariff rates, to indicate that, as a bundled transaction, the total value is greater than the sum of the parts. Advocate Supplemental Brief at 7-8. This may be true on a short-term basis, for a limited amount of capacity. As the Advocate points out, its example is for a $25 transaction for the 2000/01 winter. The Advocate does not provide similar evidence for summer periods or for any other period of time. Also, as indicated in this example, commodity prices at that time were around $10 per dekatherm. During the current winter, commodity prices are below $3 per dekatherm. It is not clear that bundled transactions would be similarly priced or whether a lower commodity price suggests a lower demand for commodity and capacity. The Advocate's argument in this regard is unpersuasive and unsupported. Further, the Advocate's argument is based on transactions for incremental amounts of supply and capacity. It is not clear that if the entire PSE&G supply/capacity portfolio were mixed in with the amount cited by the Advocate that the $25 transaction would not move to or below FERC-tariffed rates, and that on a year-round basis the average transaction for this larger volume would not be well below FERC-tariffed rates. The year-round value of the PSE&G supply and capacity portfolio is only addressed in the record by PSE&G witness Makholm who concludes that the cost of the contracts in question are $170 million above their market value. The Board believes that there is sufficient evidence to conclude that the PSE&G proposal as amended through the Addenda is providing fair value to the ratepayers through a reallocation of supply risks, enhanced supplier services, which may spur the competitive gas market, and market-based pricing for C&I customers.

The Advocate also indicates that the Proposal imposes a $.16 per dekatherm rate increase on commercial and industrial ("C&I") customers which has not been properly noticed and which the Ratepayer Advocate has not had the opportunity to review. Id. at 6. On or about November 2, 2000 PSE&G published a Notice of Filing in Docket No. GM00080564 that indicates in part:

> Because the Company's gas prices would be market priced monthly pursuant to its MPGS rate schedule, the Company's proposal may result in either higher or lower natural gas prices than exist currently.
>
> [PSE&G-1.]

The Advocate has been a party to this proceeding from the outset and has engaged in discovery and cross-examination of witnesses. The Board emphatically rejects the Advocate's argument that the change in rates has not been properly noticed and that it has not had the opportunity to review the proposed C&I pricing mechanism.

The Advocate also alleges that the market-based pricing proposal for C&I customers results in prices which would be based on neither actual costs nor on the results of a bid. Advocate Supplemental Brief at 6. The Advocate claims that the market-based pricing proposal is based on PSE&G's MPGS rate schedule and was originally designed as an unfavorable rate so that customers returning to BGSS would not create increased costs for existing BGSS customers. Advocate Initial Brief at 16. The Advocate's argument that the market-based pricing proposal is not based on actual costs is incorrect. As the Advocate notes in its Initial Brief, there is a formula for setting the floor and ceiling for this service based on the cost of interstate transportation and storage and short-term commodity indices or the highest cost of gas during the month. Id at 16-17. Therefore, the proposal prices C&I BGSS customers based on actual procurement costs.

Contrary to the Advocate's assertions, MPGS was never designed as an unfavorable rate, but rather, as the Advocate notes, it was designed to recover the incremental cost of providing supply service to returning customers and to avoid creating additional supply costs for existing customers. Id at 16. This, by definition, is cost-based service. The Board notes that currently the incremental cost of providing supply service could be higher or lower than the PSE&G tariff supply rate. MPGS was created with a floor price to satisfy a supplier concern that PSE&G tariff rates could be set to undercut suppliers in order to keep customers on sales service. At the same time, there was a concern about the MPGS price having no upper limit. An upper limit was established using the $.181/therm margin that has been in the Emergency Sales Service since C&I rates were first unbundled in 1994. MPGS was intended to put the Company's sales service to C&I customers on the exact same footing as that of competitive suppliers. This element of the Settlement Proposal, namely, pricing customers in a comparable way as competitive suppliers, is the key to competition in the C&I customer classes. Under the Settlement Proposal, Newco and suppliers are both at risk for the recovery of the fixed cost obligations under the pipeline contracts held to service their customers. This is true for Newco since there will no longer be a straight cost pass through via an LGAC-type mechanism for C&I customer classes. Therefore, both Newco and the competitive suppliers are at risk for weather and loss of load from customers leaving, in addition to incurring the added cost of the financial products needed to try to protect against these risks. There is no floor or ceiling on the price the third party supplier can charge. Competitive suppliers would not place themselves at risk for these significant costs without having the flexibility to price at competitive prices. In other words, competitive suppliers would not participate in the retail marketplace if the Board tried to regulate their prices, and in a competitive environment, it is appropriate that PSE&G be accorded similar flexibility for MPGS.

We further note that the MPGS price is very transparent. It is filed with the Board every month for all to see. In this manner, competitive suppliers have a known benchmark against which to compete. The possibility that PSE&G could charge any price it wants up to the ceiling would place it, and therefore Newco, at risk for total C&I migration to competitive suppliers. The Board FINDS that the MPGS pricing mechanism for C&I customers was duly noticed, is cost based, and is appropriate to encourage gas competition in these rate classes.

Concerning the C&I pricing proposal, the Advocate criticizes the removal of the $.05/therm credit for C&I off-system sales. Advocate Supplemental Brief at 6. Margins from off-system sales are returned to firm customers because, as firm customers, they are responsible, through the LGAC, for all reasonable and prudent costs incurred to provide the commodity to the customer. This would include FERC-tariffed pipeline capacity charges even when the capacity is not being 100% utilized. Therefore, to the extent the utility could re-sell unused pipeline capacity and/or package it with a commodity sale whereby the sale was above the cost of the commodity, the utility and thereby the ratepayers would be better served than having capacity sitting idle. This is only true where the customer is paying, such as through the LGAC, the full cost of reserving capacity and commodity to meet any variations in customer service requirements. When the customer is only paying for the pipeline capacity and commodity on an "as needed" basis, and some third-party is responsible for fluctuations in demand, then it is the third-party that is at risk for unused capacity and commodity and it is the third-party that should receive the benefits from such sales. In the current proposal, MPGS pricing will put Newco, not PSE&G customers, at risk for the capacity and commodity to provide service to C&I customers and therefore, it is appropriate that the margin sharing formula developed under an LGAC-based process be discontinued for these customer classes. Margin sharing would continue for residential customers, since they would still be subject to LGAC-type pricing.

The Advocate further claims that there is the potential for undue preference inherent in the PSE&G proposal, first in transferring resources to Newco without competitive bid and second in permitting Newco to potentially provide undue preference to its generation affiliate. Id. at 9. The Board has previously discussed the value of the asset transfer and found that the terms and conditions of the transfer of assets is fair to ratepayers. The proposal to transfer these assets is conceptually similar to the transfer of generation assets, which was approved in conjunction with PSE&G's rate unbundling, stranded cost and restructuring settlement, by Board Order dated August 24, 1999 (Docket Nos. EO97070461, EO97070462 and EO97070463). As with the transfer of the generation assets, the Board needs to review the transfer of natural gas assets in the context of the entire Stipulation before it. The Board is not considering the transfer of PSE&G's natural gas assets in isolation. The proposal before the Board provides additional features such as capacity and storage services for licensed gas marketers and new tariff provisions for certain ratepayer classes which are desirable to this Board which would not likely be included in a proposal that was strictly a divestiture. As for the potential for undue preference to the PSE&G generation affiliate, the First Addendum provides that during the term of the Requirements Contract, after Newco has satisfied its PSE&G BGSS obligations and its obligations to release capacity to licensed gas suppliers, Newco will make any excess capacity available to New Jersey unaffiliated generators under comparable terms and conditions as it does to its affiliated generation. PS-7 at 2. This provision obviates the Advocate's concerns in this area.

The Advocate raises a concern about potential market power in terms of both the natural gas and electric markets in New Jersey. Advocate Initial Brief at 37-48. The Advocate maintains that a California type situation could occur as the result of Newco controlling significant gas resources in New Jersey. As indicated by PSE&G, the relatively small percentage of gas fired generation in the PJM region argues against the ability of any gas supplier to affect PJM electric markets. Given that Newco would be only one gas supplier in the PJM region and for that matter in New Jersey, the argument for Newco to exercise electric market power is weak. PSE&G Reply Brief at 11. As for the ability for Newco to unduly influence the natural gas market, in making such an argument one would have to assume, as the Advocate argues, that the significant pipeline and storage assets which would belong to Newco could be withheld from those requiring the use of those assets in order for market power to exist. This is simply not the case. Newco is committed to provide the BGSS requirements of PSE&G and to make capacity available to those licensed suppliers desiring to use it to serve PSE&G customers as well as to New Jersey generators, when excess capacity exists. Therefore the capacity and storage assets left for Newco to use at its discretion to unduly influence prices in the PSE&G service territory, and certainly in New Jersey as a whole, is a small portion of the overall portfolio and considerably less than the Advocate would suggest. Should the Board have reason to believe that undue market power was developing, in either the electric or natural gas arenas, the Board has the authority to investigate such allegations and take such actions, including filing a complaint with FERC, or other regulatory authority, as may be warranted to remedy the situation.

Finally, the Advocate indicates that the Settlement Proposal would subject ratepayers to high and unstable rates, uncertain reliability, and diminished consumer protections, while recognizing the incentive in the Proposal to promote competition and the transfer of pipeline risk from consumers to Newco. Advocate Initial Brief at 60-61. The Settlement Proposal does provide the two benefits to ratepayers identified by the Advocate. The Advocate has previously been vocal in its support of the need for additional incentives to increase competition in the energy markets. The Board has heard numerous comments since the implementation of EDECA for natural gas in 2000 that market-based pricing is the primary element necessary in order for gas competition to develop. This proposal will move all non-residential customers to market-based pricing and provide the opportunity no sooner than 2004, after experience with the non-residential classes, to investigate and possibly consider similar pricing structures for residential customers. As for the Advocate's concerns about unstable rates, reliability and consumer protections, we have previously indicated our belief and intention that BGSS is a fully regulated service subject to Board oversight in each of the areas identified by the Advocate.

The Board has carefully reviewed the record in this matter, the Stipulation of Settlement and the First and Second Addenda thereto, the revised Requirements Contract, as well as the Initial Briefs, Reply Briefs and Supplemental Briefs of the parties. Based upon the foregoing discussion, the Board FINDS that the Company's proposal to transfer its interstate capacity, storage and supply contracts to Newco and to enter into the revised Requirements Contract with Newco is reasonable.

The Board HEREBY APPROVES the Stipulation of Settlement as amended by the First and Second Addenda, and attached hereto and DENIES the Ratepayer Advocate's motion to dismiss the petition. The Board emphasizes that it will continue to exercise its jurisdiction to regulate BGSS rates, terms and conditions as required by EDECA. The Board DIRECTS PSE&G to file revised tariffs consistent with this Order within ten business days of the date of this Order and to inform the Board within five business days of the completion of the asset transfer with a full and detailed accounting of the specific assets transferred to Newco. The Board also notes that since the final documents were filed in this proceeding, a PSE&G base rate case was concluded (Docket No. GR01050328) which resulted in modifications to certain rate class designations. As part of the compliance filing, the Board DIRECTS PSE&G to file a list showing how the prior rate classes referenced in the current Stipulation and Addenda relate to current rate class designations and to file, where necessary, a revised Stipulation of Settlement, the First and Second Addenda thereto, and the revised Requirements Contract, using the current customer rate class designations.

DATED: April 17, 2002

BOARD OF PUBLIC UTILITIES
BY:

(SIGNED)

CONNIE O. HUGHES
COMMISIONER

(SIGNED)

FREDERICK F. BUTLER
COMMISSIONER

(SIGNED)

CAROL J. MURPHY
COMMISSIONER

ATTEST: (SIGNED)
KRISTI IZZO
SECRETARY

PECO STATEMENT NO. 12-R

(REVISED)

9K
9-22-05
Phila

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JOINT APPLICATION OF PECO	:	
ENERGY COMPANY AND PUBLIC	:	
SERVICE ELECTRIC AND GAS	:	
COMPANY FOR APPROVAL OF	:	Docket No. A-110550F0160
THE MERGER OF PUBLIC	:	
SERVICE ENTERPRISE GROUP	:	
INCORPORATED WITH AND	:	
INTO EXELON CORPORATION	:	

REBUTTAL TESTIMONY
OF
J. GREGORY SIDAK

Concerning the Appropriation Of Non-Regulated,
Generation-Related Merger Synergies
And Asset Sale Proceeds
To Fund Rate Reductions By PECO Energy Company

Date: July 29, 2005

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PECO STATEMENT NO. 12-R

REBUTTAL TESTIMONY
OF
J. GREGORY SIDAK

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and business address.

A. My name is J. Gregory Sidak. My business addresses are Georgetown University Law Center, 6018 Hotung International Law Building, 600 New Jersey Avenue, N.W., Washington, D.C. 20001 and Criterion Economics, LLC, 1620 Eye Street, N.W., Suite 800, Washington, D.C. 20006.

Q. Where, and in what capacity, are you employed?

A. I am a Visiting Professor of Law at Georgetown University Law Center.

Q. What is your educational background?

A. I received a law degree and a master's degree in economics from Stanford University in 1981. I received a bachelor's degree in economics from Stanford University in 1977.

Q. Please state your professional qualifications.

A. My professional qualifications are summarized in Appendix A.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Joint Applicants, PECO Energy Company (PECO) and Public Service Electric & Gas Company (PSE&G). The views that I present are my own and not those of Georgetown University Law Center, which does not take institutional positions on specific legislative, regulatory, adjudicatory, or executive matters.

Q. Have you ever testified previously on behalf of PECO?

A. Yes, I have. In 1997, I submitted prefiled direct, rebuttal and rejoinder testimony in the proceedings on PECO's application for approval of its electric restructuring plan and Enron's Choice Plan (Docket Nos. R-00973953 and P-00971265). I also submitted testimony on PECO's behalf in *Omnipoint Corporation v. PECO Energy Corporation* (Docket No. PA 97B002), a pole attachment proceeding filed before the Federal Communications Commission in 1998.

Q. Have you ever testified before this Commission in other matters besides those concerning PECO?

A. Yes. On several occasions in 1996, I submitted testimony before this Commission on behalf of GTE North Inc. (now part of Verizon) in connection with the implementation of the unbundling provisions of the Telecommunications Act of 1996.

II. PURPOSE OF TESTIMONY AND SUMMARY OF CONCLUSIONS

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to respond to the direct testimony of Richard La Capra on behalf of the Office of Consumer Advocate (OCA), David Keim, Kevan Deardorff [redacted] on behalf of the Office of Trial Staff (OTS) and Brian Kalcic on behalf of the Office of Small Business Advocate (OSBA). Specifically, I will address proposals by Messrs. LaCapra, Keim and Kalcic to appropriate a portion of merger-related savings that will be created within the non-regulated generation subsidiaries of

Exelon Corporation (Exelon) and Public Service Enterprise Group (PSEG) to fund rate reductions by PECO. [redacted]

Q. How is your testimony organized?

A. Messrs. La Capra and Kalcic contend that their proposals to appropriate non-regulated merger synergies are consistent with the terms of the Electricity Generation Customer Choice and Competition Act (Competition Act), and they offer their own interpretations of specific provisions of the Act to support their positions (OCA St. 1, p. 8; OSBA St. 1, pp. 10-11).[1] Thus, the entire framework of electric industry restructuring created by the Competition Act is brought into question by the arguments opposing party witnesses make to try to justify proposals that, in essence, seek to selectively re-regulate generation assets owned and operated by a non-regulated subsidiary of Exelon. Accordingly, the first portion of my testimony examines the Competition Act and relevant Commission Orders to explain how the Act fundamentally changed the division between utility customers and shareholders of the risks and rewards of generation ownership such that, prospectively, customers bear none of the market or operational risks attending generation assets and, correspondingly, have no claim on the rewards from increases in market value or operational efficiency. As part of this analysis, I will also discuss the Commission's orders approving the settlements of PECO's restructuring proceeding (the

[1] While OTS witness[redacted] Keim [redacted] does not discuss the Competition Act to the same extent as Messrs. La Capra and Kalcic, his testimony clearly implies that the Competition Act supports – or at least does not bar – his proposal. This is evidenced by the OTS witness' reference to PECO's recovery of stranded costs as the alleged justification for requiring Exelon's non-regulated generation subsidiaries to transfer a portion of their merger-related synergies [redacted] (OTS St. 1, pp. 10-11[redacted]).

Restructuring Settlement) and the PECO-Unicom merger proceeding, which created Exelon (the PECO-Unicom Merger Settlement). In the former, the Commission expressly approved the transfer of PECO's formerly regulated generation assets to an unregulated affiliate and relinquished jurisdiction over those assets.

In the second part of my testimony, I apply the principles embodied in the Competition Act to critically analyze the opposing parties' positions and show that they are not sustainable. In addition, I examine the three other electric mergers the Commission ruled upon since the Competition Act was passed, namely, Allegheny-Duquesne, PECO-Unicom and FirstEnergy-GPU. The Commission orders in those cases lend no support to the opposing parties' argument and, in fact, the Commission's Order deciding Duquesne's restructuring proceeding, which was a companion case to the Allegheny-Duquesne merger, flatly contradicts those arguments.

In the third part of my testimony, I examine the opposing parties' positions within the broader context of (1) United States Supreme Court precedent, which prohibits the use of profits from a company's non-regulated business lines to support or subsidize its regulated business; and (2) economic theory, which shows that the kind of wealth transfer the opposing parties propose would discourage reasonable business behavior that leads to overall productivity gains.

Q. **Please summarize your conclusions.**

A. I have reached three main conclusions. First, the Competition Act established four fundamental principles: (1) following restructuring, generation assets would no longer be subject to regulation, irrespective of whether those assets were transferred to an unregulated affiliate of the utility or to an unaffiliated third party; (2) stranded costs for all Pennsylvania electric utilities would be finally and permanently determined as of the end of 1998, and such determination would fully account for all future contingencies; (3) utilities would recover their finally determined stranded costs according to a Commission-approved schedule and methodology; and (4) as the *quid pro quo* for paying a CTC/ITC to their utility, customers would be guaranteed the right to obtain POLR generation service at capped rates so long as CTCs/ITCs were being paid. With the Commission's prior approval, PECO has "unbundled" its rates, separated its generation assets from its transmission and distribution assets and transferred its generation assets to an unregulated subsidiary of Exelon. In addition, by its Order approving the Restructuring Settlement, the Commission made a final determination of PECO's stranded costs and established capped rates for POLR service. As a consequence, PECO's transfer of generation assets to a subsidiary of Exelon should not be treated any differently than if it had transferred those assets to an unaffiliated third party. Following that transfer, the prospective risks and rewards of the transferred generation assets are borne entirely by the generation owner, Exelon Generation Company LLC (Exelon Generation or ExGen).

Second, the proposals to capture, for the benefit of PECO's customers, the merger synergies [redacted] that belong to Exelon Generation, as advocated by Messrs. La Capra, Kalcic, and Keim [redacted], are an attempt to reopen the Commission's Order approving the Restructuring Settlement and unilaterally change its terms. Such a result would be inconsistent with the Competition Act and Commission precedent. As explained in detail hereafter, the Commission has previously held, at the urging of the OCA, among others, that stranded costs must be determined with finality as of December 31, 1998, as part of the Commission's approval of an electric utility's restructuring plan. The Competition Act and the orders implementing it afford utility customers significant rights and protections during the transition period and beyond. Specifically, so long as CTCs/ITCs are being collected, customers have a right to POLR service at capped rates, which is equivalent to a call option on fixed generation rates through 2010. PECO's POLR rates are backed by a full-requirements contract between PECO and Exelon Generation, such that the latter bears the risk of assuring that generation is available to meet PECO customers' need at the capped POLR rate. While the Competition Act grants customers a right to obtain POLR service at capped rates it clearly does not give them a direct claim on the unregulated generation assets that may be used to furnish that service. Similarly, beyond 2010 customers have a right to default generation service to be furnished pursuant to regulations being promulgated by the Commission under Section 2807(e)(2) of the Competition Act. However, that right also does not extend to any particular set of assets that may be used to generate the electricity furnished to default customers. As Mr. La Capra notes, Section 2802 (7) of the Competition Act expresses the legislature's finding that the Act will benefit electric utility customers. However, it is equally clear from the substantive terms of the Act that the legislature did not authorize continued regulation of generation assets in any form to accomplish that end. To the contrary, the expressly stated intent is that such benefits would flow from de-regulating generation.

Third, the opposing parties' positions are contrary to due process and would harm economic welfare. The Supreme Court of the United States has determined that a regulatory body cannot appropriate the profits from the unregulated operations of a firm to support the firm's regulated operations. Were this Commission to follow the recommendations of the opposing party witnesses it would engage in the same regulatory conduct that the Court held violates due process. Furthermore, the Commission should follow sound economic principles that define when a utility's customers have a claim on the proceeds from the sale of an asset. Customers have no claim on any portion of the proceeds from the sale of an asset that the utility transferred to an unregulated entity pursuant to a "no strings attached" approval of its regulator. That is precisely the case here. Finally, this Commission would harm economic welfare if it were to engage in short-term "rent extraction" by appropriating for PECO's customers the net proceeds from the sale of ExGen's generation assets or the efficiency gains that the merger will create for ExGen's unregulated business. Current economic welfare would not improve because the Commission would be taxing and redistributing income—not creating economic value. Future economic welfare would be harmed because this form of regulatory rent extraction would discourage efforts to increase the efficiency and productivity of generating assets through business or asset combinations. In other words, it would discourage the kind of efficiency and productivity gains the Competition Act sought to foster by de-regulating generating assets.

III. THE COMPETITION ACT

Q. Please elaborate on your first conclusion.

A. The Competition Act comprehensively restructured the regulatory contract between Pennsylvania electric utilities and their customers and, as part of that restructuring, provided for the recovery of stranded costs on the terms set forth in Section 2803. The Competition Act was interpreted by the Commission in a series of Orders, beginning in

1997, approving the restructuring of PECO and other Pennsylvania electric utilities. I will describe the four main principles of the Competition Act's plan for industry restructuring that are important to this case.

Q. Please describe the first principle.

A. The first principle is that the generation of electricity *per se* was no longer regulated. Sections 2802(14) and 2806(a) provide that "[t]he generation of electricity will no longer be regulated as a public utility function except as otherwise provided for in this chapter." Section 2809 of the Competition Act specifies the requirements for Electric Generation Suppliers (EGSs) but the generation assets themselves were to be deregulated as part of industry restructuring. To complete the deregulation would require the legal transfer of the generation assets pursuant to a Certificate of Public Convenience granted under Chapter 11 of the Code, as the Commission recognized in its December 23, 1997 Order approving the PECO restructuring (p. 126). With the Commission's prior approval, PECO, PPL Electric Utilities and West Penn Power Company transferred their generating assets to unregulated affiliates following an administrative determination of the market value and stranded costs of those assets as part of the utilities' restructuring proceedings. The GPU companies and Duquesne Light Company sold their generation to unaffiliated third parties.

Q. Did the Commission affirm that it no longer regulated electricity generation?

A. Yes, it did. Paragraph 28 of PECO's Restructuring Settlement expressly authorized PECO to transfer its generating assets and liabilities to either an affiliate or non-affiliate "at their book value at the date of transfer" and, if the transfer was to an affiliate, specified that the transferee would not be subject to PUC regulation unless it made retail sales and, even in that event, it would be regulated only as an EGS. In addition, the Restructuring Settlement makes it clear that the Commission did not reserve any right or authority to reassert jurisdiction over the transferee or any aspect of the transfer:

> PECO hereby requests, and the effectiveness of this Settlement is conditioned upon, the Commission's approval, without addition, condition or modification, of all aspects of PECO's transfer of its generation assets and liabilities and wholesale power contracts under this settlement and the Commission's issuance of such orders and certificates of public convenience as are necessary to implement those transfers. The Commission's approval includes, but is not limited to, approval under Chapters 5, 11, 19, 21 and 28 of the Public Utility Code (66 Pa. C.S.)

PECO transferred its generating assets and liabilities to ExGen pursuant to the authority granted in the Restructuring Settlement and one or more certificates of public convenience issued by the Commission to evidence approval under Section 1102(a) of the Public Utility Code. Consequently, the asset transfers terminated any possibility of continuing jurisdiction by the Commission over either the transferred assets, any subsequent transfer of those assets by ExGen, or the disposition by ExGen of the proceeds of any subsequent transfer. The transfer approval reinforces the conclusion that the Restructuring Settlement established PECO's stranded costs with finality and does not permit the issue to be revisited based on subsequent market transactions by the entity to which PECO transferred its generating assets.

Q. Please describe the second principle.

A. The second principle is that the amount of recoverable stranded costs was to be determined "once and for all" as of a date certain. In its December 23, 1997 Order in PECO's restructuring proceeding, the Commission stated: "The recoverable stranded costs amount must be identified on a 'present value' basis as of the date competition begins, January 1, 1999." The December 23, 1997 Order determined PECO's generation stranded costs by comparing the book value of PECO's generating assets at the end of 1998 with the Commission's administrative determination of their future market value. That Order became the subject of several appeals and other state and federal legal challenges, which were resolved by the Restructuring Settlement. The Restructuring Settlement altered the recoverable amount of stranded costs, but the "amount and date certain" principle was upheld.

The other Pennsylvania electric utilities each had their stranded costs determined on a "once and for all" basis as of the end of 1998, pursuant to the orders in their respective restructuring proceedings or subsequent settlements. The methodology varied, but the principle did not. In all cases the determinations were final and included current estimates of the consequences of future events, such as the life extension of certain units and other opportunities to mitigate stranded costs.

Q. Was the finality principle affirmed by the Commission and appellate courts?

A. Yes, it was. As described in more detail in Section IV of my testimony, the Commission decisively rejected the "wait and see" approach to determining stranded costs originally proposed by Duquesne and West Penn in their respective restructuring proceedings as contrary to "the assumptions, definitions and directives of the [Competition] Act that stranded costs are to be determined in this proceeding as a net present value as of December 31, 1998." Significantly, the Commission's holding in Duquesne accepted the interpretation of the Competition Act advocated by, among other parties in that case, the OCA. The finality principle was affirmed by the Commonwealth Court in *ARIPPA v. Pa. P.U.C.*, 792 A.2d 636 (Pa. Commw. 2002), which reviewed a Commission Order granting GPU's request to recoup the cost it incurred to provide POLR electric generation service above its generation rate cap. The Commission's order allowed GPU to recover that excess cost through its CTC as an addition to its stranded costs. The Commonwealth Court held that the Commission did not have authority to alter its earlier stranded cost determination:

> Pursuant to 66 Pa. C.S. § 2803, *stranded costs were to be fixed forever as part of the utility's restructuring plan.* In its restructuring plan, GPU Energy was paid for all of its costs associated with the change to a non-regulated environment. The Competition Act froze rates until December 31, 2004, in return for utilities receiving their stranded costs fixed in the restructuring plan, and the only relief from those rates set forth in the Competition Act was a rate increase.

See ARIPPA at 667-68 (emphasis added).

The *ARIPPA* decision makes it clear that the Competition Act does not permit the Commission to re-visit the stranded cost determination it made in approving PECO's Restructuring Settlement.

Q. Is the finality principle breached or compromised because the Commission authorized PECO to recover decommissioning costs for its nuclear units?

A. No, it is not. Nuclear decommissioning expenses are simply another element of stranded costs, and they are specifically identified as such in Section 2808(c)(1) of the Competition Act. The Restructuring Settlement provided for recovery of the actual cost of decommissioning by creating a mechanism to account for increases or decreases in the cost to decommission the nuclear units. It is a balanced approach that recognizes the public health and safety implications of providing reasonable assurance that funding is available so that decommissioning will actually occur while also assuring that customers receive the benefit if decommissioning costs go down in the future. Perhaps even more important, this recovery method mitigated the cost borne by customers by assuring favorable tax treatment for the amounts paid into decommissioning trust funds.

Q. Please describe the third principle.

A. The third principle is that the present value of stranded costs, finally determined as of the end of 1998, was to be recovered according to a Commission-approved schedule and methodology. True-ups in the approved methodologies were not intended to reset the recoverable amount of stranded cost. To the contrary, true-ups are to assure that the CTCs/ITCs recover neither more nor less than the finally determined amount of stranded costs. In its December 23, 1997 Order, the Commission approved PECO's recovery of $5.024 billion of stranded costs over 8.5 years through a levelized CTC charge. The Restructuring Settlement provided for recovery of $5.26 billion of stranded costs, but extended the recovery period through 2010. As a result, the generation rate cap will remain in effect until stranded cost recovery is completed in 2010.

While the orders and approved settlements in other cases provided for different recovery schedules and methodologies, they adhered to the principle that the stranded costs determined as of December 31, 1998 would be recovered in accordance with the Commission-approved schedule and methodology. True-ups were limited to adjustments necessary to recover the approved amount of stranded costs.

Q. Please describe the fourth principle.

The fourth principle was that ratepayers would have the option to buy generation service from their electric distribution company at capped rates during the period stranded costs were being recovered. Because the regulatory contract was being rewritten and generation would be unregulated beginning in 1999, customers' price to purchase generation service would no longer be tied to the Commission's administrative determination of the generation assets' "cost of service" plus an assured return. However, as a *quid pro quo* for paying CTC/ITC charges, customers would be guaranteed the right to purchase POLR generation service at capped rates. These generation rates took the form of a "shopping credit" representing the amount of the total rate a customer could avoid if it purchased its generation from a competitive supplier. Again, the size of the "shopping credits" varied by utility and by year, and the source for backstop power varied as well. In the case of PECO, the POLR option is backed by PECO's full-requirements contract with ExGen.[2]

The POLR provisions give customers the flexibility to shop for competitive generation supplies that beat the "shopping credit" while at the same time having the option to return to POLR service during the transition period at a guaranteed generation rate if market prices rise above the shopping credit.

Q. What conclusions do you draw from your examination of the four principles of restructuring described above?

A. With respect to the issues in this case, these four principles lead to the following conclusions:

1. PECO's stranded costs were determined with finality by the Commission's Order approving the Restructuring Settlement. That determination cannot be revisited or revised either directly or indirectly.

2. Following its administrative determination of PECO's stranded costs, the Commission approved, without qualifications, the transfer of PECO's generating assets to an affiliated or unaffiliated third party and relinquished jurisdiction over those assets.

[2] The full-requirements generation supply contract between PECO and ExGen was approved under the affiliated interest provisions of Chapter 21 of the Public Utility Code as part of the PECO-Unicom Merger Settlement.

3. Exelon Generation, as the transferee of PECO's generating assets, bears the risks and rewards of generation ownership. This is the result that the de-regulation of generation was intended to accomplish.

4. Because cost of service regulation of generation has been terminated, customers no longer bear the risks that attend utility ownership of generation assets. Correspondingly, they do not have a claim on any post-restructuring increases in the value of those assets that may occur. Instead, customers have been given the right to obtain POLR generation service at fixed rates for the duration of the CTC/ITC collection period as a *quid pro quo* for paying those charges.

My overall conclusion is that the opposing parties' proposals represent an attempt to re-examine and revise the Commission's prior stranded cost determination by ignoring the corporate separateness of ExGen and selectively re-regulating generation assets, in order to capture possible increases in the productivity and market value of those assets, while continuing to shield PECO's customers from the risks of utility ownership of generation.

IV. THE OPPOSING PARTIES' PROPOSALS ARE CONTRARY TO THE PRINCIPLES OF RESTRUCTURING EMBODIED IN THE COMPETITION ACT

Q. What arguments do the opposing parties advance for trying to capture non-regulated synergies and asset sale proceeds for the benefit of customers receiving regulated service from PECO?

A. Messrs. La Capra, Keim, and Kalcic each allude to PECO's recovery of stranded costs and nuclear decommissioning expense as the alleged rationale for extending the Commission's jurisdiction to encompass merger-related synergies experienced within ExGen. [redacted] Mr. La Capra attempts a theoretical defense of his position based upon his interpretation of Section 2802(7) of the Competition Act. Mr. Kalcic contends that the "mitigation" language of Section 2808(c)(4) also supports his position.

Q. How does Mr. La Capra interpret Section 2802(7)?

A. Section 2802(7) is part of the "Declaration of Policy" for the Competition Act and states, in its entirety, as follows:

> This Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs.

Mr. La Capra contends that the phrase "to benefit all classes of customers" embodies "expectations" that the "benefits from industry restructuring" would inure to "all Pennsylvania ratepayers" (OCA St. 1, p. 8). Mr. La Capra assumes a broad definition of "benefits" that includes merger-related cost savings that may occur in the non-regulated subsidiaries of Exelon. Mr. La Capra assumes further that the only way customers of PECO could benefit from merger-related efficiency gains at ExGen is to appropriate those savings to fund reductions in PECO's regulated distribution rates.

Q. What are the flaws in Mr. La Capra's argument?

A. Mr. La Capra tries to leverage a single phrase in the Declaration of Policy into an argument for ignoring the substantive provisions of the Competition Act that removed generation from public utility regulation and, thereby, shielded utility customers from the potential consequences – favorable and unfavorable – of generation ownership. In short, Mr. La Capra contends that the "benefits" phrase in Section 2802(7) provides all the authority necessary to override the four overarching principles incorporated in substantive provisions of the Competition Act that I explained earlier in my testimony. By his expansive and unsupported interpretation of Section 2802(7), Mr. La Capra attempts to justify a collateral attack on the Commission's final determination of PECO's stranded costs that, in effect, would subject generation assets owned by a non-jurisdictional entity to selective re-regulation designed to capture a portion of the current and future value of those assets for PECO's customers.

In addition, Mr. La Capra errs in assuming that customers can obtain the benefits of electric restructuring only by reducing PECO's regulated distribution rates. To the contrary, the Competition Act makes it clear that competition in the market for generation would both foster efficiency gains, like those that ExGen will experience from the synergies of the proposed Exelon-PSEG merger, and provide the means – market pricing of generation – for customers to benefit from those efficiency gains. As stated in Section 2802(5) of the Competition Act: "Competitive forces are more effective than economic regulation in controlling the cost of generating electricity."

Q. Mr. La Capra also contends that the distinction between "regulated" and "unregulated" merger savings is an "artificial" one that "mechanistically" divides savings and costs into "categories that the applicants have defined" (OCA St. 1, p. 20). How do you respond?

A. The distinction between "regulated" operations, which are within the jurisdiction of the Commission, and "unregulated" operations, which are not, is hardly "artificial." To the contrary, that distinction is central to the Commission's role as a regulator and, in fact, reflects categories that regulatory commissions and appellate courts have long recognized. In fact, the distinction between regulated and unregulated operations and the significance of that distinction for state utility ratemaking was established by the United States Supreme Court's 1920 decision in *Brooks-Scanlon Co. v. Railroad Commission of Louisiana* which is discussed in detail later in my testimony. Furthermore, Mr. La Capra concedes the reality and importance of the distinction between regulated and unregulated operations in his own testimony, as evidenced by his recommendation that the Commission reaffirm commitments to maintain the financial separation of PECO's regulated business from the unregulated businesses conducted by other subsidiaries of Exelon (OCA St. 1, p. 28). The importance of that distinction was echoed in the testimony of OTS witnesses Keim (OTS St. 1, p. 16) and Deardorff (OTS St. 3 P.S.) recommending various conditions intended to isolate PECO and its customers from the possible direct and indirect effects of businesses conducted by Exelon's other subsidiaries.

Q. Mr. Kalcic relies upon *Section 2808(c)(4)* and an alleged duty to mitigate stranded costs as authority for his proposal to capture non-regulated merger synergies to fund rate reductions for PECO's regulated distribution service (OSBA St. 1, p. 11). How do you respond?

A. Section 2808(c) deals with the determination of stranded costs. Subsection (4) provides that, during the transition period, "electric utilities" have a "duty to mitigate generation-related transition or stranded costs to the extent practicable" and that the Commission "shall consider the extent to which the electric utility has undertaken efforts to mitigate generation-related transition or stranded costs" in its stranded cost determination. In other words, when stranded costs were determined by the Commission, both past and future opportunities to mitigate stranded costs were to be taken into account as the Commission deemed appropriate. Such future mitigation was included in the determination of stranded costs through assumptions such as life extensions and productivity improvements. Section 2808(c)(4) does not authorize the periodic reopening of the Commission's final stranded cost determination for the purpose of adjusting the level of stranded costs to reflect future "mitigation." The OSBA's attempt to use Section 2808(c)(4) in that fashion is not supported by anything in the Competition Act. In fact, in Duquesne's restructuring proceeding, Duquesne proposed deferring the final determination of stranded costs so that, among other reasons, post-restructuring mitigation could explicitly be considered. The Commission rejected that proposal stating:

> Once deregulated, the owners of generation assets will, as a result of market pressures, seek ways of controlling costs and improving productivity on an ongoing basis ... Also, we reject the Company's reliance on post-restructuring mitigation as the sole indicator of the efficiencies and productivity gains that inure to the new competitive regime.

Similarly, the "duty to mitigate" provision does not leave the Commission's stranded cost determination open-ended for the duration of the transition period. Furthermore, once PECO, with the Commission's prior approval, transferred its generating assets to another entity, it ceased to have a "practicable" means to achieve further mitigation of stranded costs.

Q. Do the post-restructuring electric company mergers lend any support to the opposing parties' position that non-regulated merger savings should be "shared" with customers of the regulated utilities?

A. The PECO-Unicom merger and the FirstEnergy-GPU merger were completed after the electric industry had been restructured pursuant to the Competition Act. Neither case supports the opposing parties' position in this proceeding.

Q. What happened in the PECO-Unicom merger?

A. In the PECO-Unicom proceeding, PECO submitted a synergy study that identified net regulated merger savings that were likely to be achieved from 2001 through 2005. Unregulated merger savings were not identified or quantified. The parties to that case reached a settlement, which was approved by the Commission. As Mr. La Capra recounts in his testimony (OCA St. 1, pp. 22-23), the parties agreed that PECO would implement rate reductions to provide customers $200 million of the estimated merger-related savings and would extend the distribution rate cap through December 31, 2006. While the settlement contained certain additional conditions and commitments, the merger savings "shared" with customers was within the level of regulated merger savings PECO estimated for the extended rate cap period. Nothing in the Commission's Order or the Joint Petition for Settlement of the PECO-Unicom proceeding suggests that non-regulated merger savings were to be "shared" with PECO's customers.

Q. What happened in the FirstEnergy-GPU merger?

A. The applicants in that case did not prepare a synergy study. Evidence was presented explaining that electric company mergers typically produce "a reduction of five to fifteen percent of non-generation operating and maintenance costs." The applicants assumed a five percent reduction in non-generation O&M expenses for purposes of their merger. In its Order approving the merger, the Commission did not quantify possible merger savings, opting instead to send that issue to a "collaborative" that would also address the GPU companies' request for an exception to their rate caps in order to recover the costs of purchasing electric generation to meet their POLR obligations. The collaborative produced a non-unanimous settlement that created a mechanism for the GPU companies to recover their excess POLR costs and recognized the applicants' non-generation merger savings by freezing the distribution rates of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company through December 31, 2007. The Commission's Order approving the non-unanimous settlement was appealed to the Pennsylvania Commonwealth Court, which overturned the Order because it found that the POLR cost recovery mechanism amounted to an unauthorized rate cap exception. Because the Order approving the non-unanimous settlement was overturned, the Court remanded to the Commission all of the issues covered by the "collaborative" including the determination of the amount of merger savings and the allocation of those savings 792 A.2d at 669. A decision on the remand has not been issued. While the final disposition of merger savings is yet to be decided, it is clear that the estimates presented in the merger proceeding consisted of only non-generation merger savings.

Q. Please address the Allegheny-Duquesne merger.

A. The Allegheny-Duquesne merger was a singular case for three reasons. First, the merger was filed along with the restructuring applications of West Penn and Duquesne. Therefore, each utility was required to calculate stranded costs two ways: (1) assuming the merger was completed and (2) in the alternative, assuming the merger was not completed. Second, both utilities proposed to defer the determination of stranded costs beyond 1998 for reasons that I will explain later. Third, although the Commission issued a final order conditionally approving the merger, Duquesne terminated the merger agreement before the merger was completed.

Q. What distinguished Allegheny-Duquesne from the other mergers you discussed?

A. The Allegheny-Duquesne merger was proposed before restructuring of the electric industry had occurred. In fact, West Penn and Duquesne filed their application for merger approval and their respective restructuring plans with the Commission on the same day (August 1, 1997). At that time, they were still vertically integrated utilities, owned their generation, and all of their operations, including their generation assets, were subject to economic regulation by this Commission. Most importantly, a determination of their stranded costs had not been made. As a consequence, in their respective restructuring proceedings, the effects of the merger on the future operating costs of West Penn's and Duquesne's generating plants would have to be considered in determining whether or how much of the investment in those plants was "stranded." Calculations were made separately for the merger partners' distribution-related merger savings and generation-related merger savings. In the merger proceeding, the Commission recognized distribution-related merger savings, which it determined should be reflected by an appropriate reduction in distribution rates. However, it directed that the effects of the merger on the companies' generation operating costs should be taken into account in determining stranded costs in their restructuring proceedings.[3]

Q. What happened in the restructuring proceedings?

A. The Commission determined that, if a completed merger were assumed, then generation-related effects of the merger should be taken into account to reduce the companies' "stand alone" stranded costs.

Q. Is that result inconsistent with your conclusion concerning the treatment of generation-related savings in this case?

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3 Duquesne and the OCA presented competing estimates of the generation-related merger savings. The Commission accepted the OCA's calculation, which, for Duquesne, was $152 million on an after-tax, present value basis.

A. No, not at all. In fact, it supports my conclusion. In Allegheny-Duquesne, the Commission considered generation-related merger savings in the context of the utilities' restructuring proceedings as part of the original stranded cost determination for each company. Nothing in the Allegheny-Duquesne case suggests that the stranded cost determination, once made, would be subject to reopening and revision even if the benefits of the merger were more or less than estimated or other post-restructuring contingencies affected the valuation of the generating assets.

Q. Do the West Penn and Duquesne cases support the "once and done" nature of stranded cost determinations?

A. Yes, they do, as evidenced by the Commission's rejection of the utilities' proposals to leave stranded cost determinations open-ended until the 2003-2005 time frame. Duquesne and West Penn made similar proposals, but for simplicity, I will discuss Duquesne's. In essence, it proposed to continue charging customers its "embedded" generation rates for seven years, from 1999 through 2005. The shopping credit would be determined annually through an auction, and the remainder of the embedded generation rate would become the CTC and would be used to amortize the book value of Duquesne's generation investment. However, unlike other methodologies that would produce an administrative determination of stranded costs as of December 31, 1998, the Duquesne proposal would have deferred the stranded cost calculation to 2003, with the final determination to be made as of the end of 2005. Duquesne had proposed to take generation-related merger savings into account as part of that later determination. Duquesne contended that a "wait and see" approach was desirable because more actual information relevant to the valuation of generating assets in a de-regulated generation market would be available beginning in 2003, after the wholesale market had time to develop.

Q. What was the response to the "wait and see" proposal?

A. It was strenuously opposed by several parties, including the OCA, which argued that the proposal was contrary to the terms of the Competition Act that called for a "one-time determination of stranded costs" in the restructuring proceeding. The OCA elaborated on this argument in its Main Brief (p. 15):

> The first problem with Duquesne's approach is a legal one. OCA submits that the Act requires that stranded costs be determined in this restructuring proceeding. Thus, a future valuation of stranded costs is inconsistent with the Act. This is made plain in the definitional section of the Act where "Transition or stranded costs" are defined as the utility's net electric generation-related costs "determined on a net present value basis ... as part of its restructuring plan." 66 Pa. C.S. §2803. OCA submits that the requirement in the Act for a determination of stranded costs in the restructuring plan on a net present value basis is a clear requirement for a one-time determination of stranded costs in this proceeding.

The Commission agreed with those that opposed the "wait and see" proposal, finding that it was contrary to the Competition Act's requirement for a final determination of stranded costs as of December 31, 1998:

> Duquesne's proposals ignore the assumptions, definitions, and directives of the Act that stranded costs are to be determined in this proceeding at a net present value as of December 31, 1998. Section 2808(a) authorizes the collection of stranded costs through a CTC only following the determination of just and reasonable recoverable stranded costs by the Commission pursuant to 2808(c).

Q. What was the final disposition of the Allegheny-Duquesne merger?

A. The merger was ultimately terminated by Duquesne. Duquesne subsequently auctioned its generating assets and used the auction-derived market value to determine its stranded costs. Allegheny entered into a settlement with its intervenors that made a final determination of stranded costs according to the methodology developed in its stand-alone restructuring case. The West Penn generation assets were subsequently transferred to an unregulated generation affiliate. No generation-related merger savings were ultimately reflected in either case.

Q. What conclusions do you draw from the three merger proceedings that the Commission has considered since the Competition Act?

A. In none of those cases has the Commission considered generation-related merger savings as part of its merger approval process. In PECO-Unicom, the rate reductions and other terms and conditions were within the Company's estimate of merger savings from the regulated transmission and distribution portions of the combined businesses. In FirstEnergy-GPU only non-generation merger savings were at issue. In Allegheny-Duquesne, generation-related merger savings were considered in the respective parties' restructuring proceedings because, at that time, they were still fully regulated, vertically integrated utilities and final determinations of their stranded costs had not yet been made. None of those cases supports the opposing parties' proposals to extend the Commission's jurisdiction to non-regulated operations of other Exelon subsidiaries and, thereby, capture non-regulated merger savings [redacted] for the benefit of PECO's customers.

Q. [redacted]

[redacted]

Q. Do PECO's customers have a claim on any portion of the current market value of ExGen's generating plants?

A. No, they do not. As I previously explained, the rights and obligations of customers of regulated electric distribution service were reset as of January 1, 1999 by isolating them from the prospective risks and rewards that go along with utility ownership of generating assets. In exchange, customers were given a call option on POLR generation service at fixed rates as a *quid pro quo* for paying CTCs and ITCs.

These principles, which are embodied in the framework of restructuring established by the Competition Act, were reinforced by the Commission's approval of the Restructuring Settlement, as Paragraph 28 thereof makes clear:

> PECO hereby requests, and the effectiveness of this Settlement is conditioned upon, the Commission's approval, without addition, condition or modification, of all aspects of PECO's transfer of its generation assets and liabilities and wholesale power contracts under this settlement and the Commission's issuance of such orders and certificates of public convenience as are necessary to implement those transfers.

The Commission did not reserve any jurisdiction over the generation assets transferred by PECO to its unregulated generation affiliate or over the transferee. [redacted] The proposals of Messrs. La Capra, Keim and Kalcic directly conflict with the Commission-approved terms of that transfer.

V. ANALYSIS OF THE OPPOSING PARTY PROPOSALS IN LIGHT OF BROADER ECONOMIC AND LEGAL PRINCIPLES

Q. Please outline the broader economic and legal principles that are applicable here.

A. Economic theory holds that, because market forces govern the profitability of a regulated firm's unregulated assets, the firm (not the customers of its regulated operations) bears the losses and retains the profits from the operation or sale of the firm's unregulated assets. Applicable legal principles follow economic theory in this regard. Beginning with *Brooks-Scanlon v. Railroad Commission of Louisiana*, 251 U.S. 396 (1920), and continuing through recent appellate decisions, courts have adhered to the principle that a regulator cannot appropriate benefits from the unregulated operations of a firm or its affiliate to subsidize that firm's regulated operations.

Furthermore, were a regulator to appropriate profits from the unregulated operations of the firm, it would impede future economic growth by discouraging business combinations or asset transfers that would increase the efficiency and productivity of generation assets or other non-regulated business assets.

Q. Has any of your academic research and writing focused on the allocation between a utility's shareholders and customers of the proceeds from asset sales?

A. Yes, it has. I co-authored with Professor Paul W. MacAvoy of Yale University "The Efficient Allocation of Proceeds from a Utility's Sale of Assets," which was published in 2001 in the *Energy Law Journal*. That article addressed the economic framework for determining how to divide the proceeds when a utility sold assets that it owned and used to provide regulated service to its customers. The book that I co-authored with Professor Daniel F. Spulber of the Kellogg School of Management at Northwestern University, *Deregulatory Takings and Regulatory Contract: The Competitive Transformation of Network Industries in the United States* (Cambridge University Press 1997), addresses the appropriate division of the proceeds from a sale of a firm's regulated and unregulated assets.

Q. The opposing parties' proposals in this case all involve capturing increases in the value of assets that are not owned by the regulated utility but by a non-regulated affiliate. Do the economic principles addressed in your prior research and writings offer any guidance on the issues raised by those proposals?

A. Yes, they do. Cost of service regulation allocates to customers of regulated service a range of benefits and burdens associated with the regulated entity's ownership of assets used to furnish regulated service. My prior writings addressed how those benefits and burdens should be allocated between the utility and its customers when a utility asset is sold. Broadly stated, the fundamental factor defining that allocation is who bore the risk of negative returns from that asset. While there are further distinctions that need to be drawn when utility assets are being sold, the overarching principle is that rewards should follow risks.

Q. How does that principle apply to the unregulated generation assets that are the source of the merger savings and sale proceeds the opposing parties seek to allocate to PECO's customers?

A. Simply stated, ExGen bears the operational and market risk associated with the generation assets. Consequently, increases or decreases in the value of those assets – either from gains or losses in efficiency or as a result of market forces – are ExGen's alone.

Q. Does it make any difference that the generation assets formerly belonged to PECO and its customers are paying stranded costs?

A. No, it does not. Although the generation assets had been owned by PECO and had been subject to cost of service regulation, a new bargain was struck between utility customers and shareholders in furtherance of the objectives of the Competition Act when the Commission approved the Restructuring Settlement. By that time, the Pennsylvania legislature had considered and balanced the competing interests of the various stakeholders, and this Commission had resolved the details necessary to implement that new statutory framework as it pertained to PECO. As I stated above, by approving Paragraph 28 of the Restructuring Settlement, the Commission gave unconditional approval to "all aspects of PECO's transfer of its generation assets and liabilities and wholesale power contracts." Therefore, pursuant to the Competition Act and as clearly expressed in the Commission's Order approving the Restructuring Settlement, shareholders would henceforth bear the consequences of the success or failure of unregulated affiliated generation. It was certainly foreseeable that future, unanticipated market developments would affect the value of those affiliated generation assets, either positively or negatively. If, to the contrary, those developments could have been clearly anticipated, they would have influenced the terms of the compromise reached under the Competition Act and the Restructuring Settlement, only a part of which addressed the recovery of stranded costs.

Q. Page 253 of your article with Professor MacAvoy refers to ratepayers' entitlement to the proceeds above book value where a utility sells a "stranded asset." Is that statement inconsistent with the principles you discussed above?

A. No, it is not. The entire passage reads as follows:

> When systems of regulation change, the ratepayer is at risk for utility losses when the opportunity is eliminated for capital recovery under the old tariff and rate schedule. Any change in regulations that causes costs to be stranded renders ratepayers liable, over time, to pay. The ratepayer is thus entitled to any net returns, over remaining book value, that accrue as a result of the sale of stranded assets.

My previously published views are entirely consistent with my opinion in this proceeding because the "sale" referred to in the quote above is the disposition of a stranded asset by the regulated utility itself. The transfer of generation assets from PECO to Exelon Generation yielded no "net returns" to PECO because the facilities were transferred at book value, in accordance with the terms of the Commission-approved Restructuring Settlement and the subsequent PECO-Unicom Merger Settlement. From that point forward, customers did not bear any further risk of fluctuations in the value of the generation assets that ExGen acquired. Instead, ExGen shareholders began to bear all of that risk. This concept was reinforced by the various controls and safeguards implemented for the express purpose of insulating regulated customers from any of those risks. This is evidenced by Paragraph 59 of the PECO-Unicom Merger Settlement, which states: "Such controls and procedures will be designed to provide reasonable assurance that PECO does not bear costs associated with the business activities of affiliated companies, which are not regulated by the Commission."

Q. Is your research with Professor Spulber consistent with your opinion that this Commission should not attribute profits from ExGen's unregulated operations to PECO's regulated business operations for the purposes of setting rates?

A. Yes. On pages 314 and 315 of *Deregulatory Takings and the Regulatory Contract,* Professor Spulber and I conclude that, according to legal precedent, the regulator cannot use the regulated division of a firm as the foothold to control the unregulated operations of the firm or to expropriate the revenue or profit of those unregulated operations so as to reduce rates to customers of regulated services.

Q. To what legal precedent are you referring?

A. I am referring to *Brooks-Scanlon Co. v Railroad Commission of Louisiana*, 251 U.S. 396 (1920). The Supreme Court of the United States determined that the regulator (the Railroad Commission of Louisiana) could not appropriate the profits from Brooks-Scanlon's unregulated operations, which included a sawmill and lumber business, to support the operations of its regulated railroad business. In delivering the opinion of the Court, Justice Holmes wrote, at 251 U.S. 399:

> The plaintiff may be making money from its sawmill and lumber business but it no more can be compelled to spend that than it can be compelled to

> spend any other money to maintain a railroad for the benefit of others who do *not* care to pay for it.

Consequently, the Court decided that the reasonableness of rates charged by the firm's regulated business must be determined without regard to the profitability of the unregulated operations of the firm. No component of the profits earned on the unregulated segment of the firm can be applied toward the firm's regulated business so as to drive down regulated rates.

Q. Does this decision still have merit today?

A. Yes. *Brooks-Scanlon* was a landmark decision that is still relied upon to bar a regulator's attempt to subsidize a firm's regulated operations with profits from unregulated operations. For example, in *Michigan Bell Telephone Company v. Engler*, 257 F.3d 587 (6th Cir. 2001), the Sixth Circuit relied upon *Brooks-Scanlon* as the basis for invalidating portions of the 2000 Michigan Telecommunications Act. At dispute in that case was the treatment of regulated and unregulated telecommunications rates. The 2000 Michigan Act called for regulated rates to be subsidized by rates on unregulated telecommunications service. However, the Sixth Circuit, citing *Brooks-Scanlon*, found this pricing structure to be unlawful:

> [A]lthough the plaintiffs have other unregulated income streams, they are not required to subsidize their regulated income services with income from rates either deemed to be competitive, or with revenues generated from unregulated services. 257 F.3d at 594.

The Supreme Court has not overruled *Brooks-Scanlon,* and this decision remains relevant to current regulatory and judicial proceedings, including this one.

Q. Do you see any internal inconsistencies in the recommendations of witnesses La Capra, Keim, [redacted] and Kalcic?

A. Perhaps, because it does not appear that these witnesses would apply their proposed rule symmetrically. Suppose, for example, that ExGen incurred operating losses in its generation business or had to write down the value of investments that it made in unregulated generation assets. Would these witnesses then conclude that PECO deserves a rate increase on its regulated services, so as to offset ExGen's losses? I doubt the witnesses would support that result, even though it would logically flow from a symmetrical application of their proposed rule. In that regard, it is notable that the PECO-Unicom Merger Settlement contains provisions designed to protect regulated customers from risks of the unregulated businesses of Exelon and, as I previously explained, OTS witnesses Keim and Deardorff propose further conditions along those lines in this case.

Q. You have explained why using a regulatory bootstrap to transfer value from ExGen's unregulated operations to PECO's regulated operations would violate legal precedent. Is there a corresponding economic rationale against taking such action?

A. Yes, such a wealth transfer is what economists call a short-run "rent extraction." That kind of regulatory action would extract value from Exelon's unregulated assets and operations and grant a windfall to customers of PECO's regulated service. That process would shift economic benefits, but would not create any net increase in economic welfare. In fact, by discouraging reasonable business combinations and asset transfers, economic welfare would be harmed. A principal goal of the Competition Act was to reduce electric costs by subjecting generation to market forces and thereby driving efficiency and productivity gains that would be reflected in competitive pricing. Economies of scale and scope and the introduction of standardized processes are some of the benefits that accrue when businesses are combined through mergers or acquisitions. And those benefits are translated into efficiency and productivity gains - - lower costs and greater output. Similar gains can accrue when generating assets are transferred to more efficient operators. Those are the types of changes the Competition Act was designed to promote. However, a regulatory policy that appropriated those efficiency gains and value increases to reduce regulated distribution rates would discourage the very conduct the Act tries to promote, would create obstacles to the operation of the competitive wholesale market and would deprive customers of the benefits that competitive generation was intended to produce.

VI. SUMMARY AND CONCLUSION

Q. Please summarize your response to the opposing parties' proposals.

A. The Competition Act provides for the deregulation of generation assets, a final determination of stranded costs, recovery of stranded costs pursuant to approved CTCs/ITCs and, as a *quid pro quo,* POLR generation service at capped rates during the CTC/ITC recovery period. In approving the Restructuring Settlement, the Commission authorized PECO's transfer of its generation assets to its unregulated generation affiliate and relinquished jurisdiction over those assets. Accordingly, PECO should be treated no differently than if it had divested its generation assets to an unaffiliated third party. The risks and rewards of the transferred generation (including any gain or loss on the sale of those assets) are now borne by ExGen.

Intervenor "sharing" proposals are simply attempts to unilaterally change the Restructuring Settlement and are inconsistent with the Competition Act and broader legal and economic principles. Such proposals represent efforts to continue back-door regulation of what are today unregulated generation assets owned by ExGen. Such proposals should, therefore, be rejected.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

PROFESSIONAL QUALIFICATIONS
OF
J. GREGORY SIDAK

Q. Other than your current professorship at Georgetown University Law Center, have you held any academic positions?

A. Yes. I previously held the F.K. Weyerhaeuser Chair in Law and Economics at the American Enterprise Institute for Public Policy Research, where I was a resident scholar from 1992 until 2005. Between 1993 and 1999, I also held the position of Senior Lecturer at the Yale School of Management, where I taught a graduate course with Dean Paul W. MacAvoy on regulation and competitive strategy in the telecommunications industry.

Q. Have you ever served in state of federal government?

A. Yes. I was Deputy General Counsel of the Federal Communications Commission from 1987 until 1989. I was the agency's second-highest attorney and oversaw a department of roughly fifty attorneys. From 1986 until 1987, I was Senior Counsel and Economist at the Counsel of Economic Advisers in the Executive Office of the President. There, my portfolio included economic policy issues concerning antitrust and the deregulation of network industries, such as evaluation of the efficacy of the AT&T divestiture decree three years after its imposition. From 1981 to 1982, I served as Law Clerk to Judge Richard A. Posner of the U.S. Court of Appeals for the Seventh Circuit.

Q. What did you do between your time at the FCC and your time at the American Enterprise Institute?

A. I was in private law practice with Covington & Burling in Washington, D.C.

Q. What was the nature of your practice?

A. I worked on antitrust cases and federal administrative, legislative, and appellate matters concerning regulated network industries.

Q. Do you serve on any corporate boards?

A. Yes. Since 2002, I have been a member of the U.S. Advisory Board for NTT DoCoMo, Japan's largest wireless telecommunications company.

Q. As a member of that advisory board, what do your responsibilities entail?

A. I meet twice annually with DoCoMo's chairman and senior management to brief them on global developments in telecommunications regulation and to discuss with them how best to modify DoCoMo's competitive strategy to respond to emerging regulatory risks.

Q. Have you ever submitted expert testimony?

A. Yes.

Q. Before which courts or regulatory bodies in the United States have you submitted expert testimony?

A. I have given live expert testimony before this Commission and before state public utilities commissions in Indiana, Iowa, Kentucky, Minnesota, New Mexico, Ohio, and Texas. I have given live expert testimony before the Federal Energy Regulatory Commission, and I have submitted numerous declarations and affidavits to the Federal Communications Commission. I have testified or submitted expert reports in several U.S. district courts and in the U.S. Court of Federal Claims. I have submitted expert reports in state trial courts in New York and California. I have also submitted an expert report to the Presidential Commission on the United States Postal Service.

Q. Have you ever submitted expert testimony to foreign courts or regulatory bodies?

A. Yes. I have filed testimony or expert reports with the Australian Competition and Consumer Commission, the Canadian Radio-Television and Telecommunications Commission, the Competition Bureau (Canada), the Commission for Communications Regulation (Ireland), the Competition Directorate of the European Commission, the Court of First Instance of the High Court of the Hong Kong Special Administrative Region, the High Court of the Republic of Ireland, the Office of the Director of Telecommunications Regulation (Ireland), and the Office of Telecommunications Authority (Hong Kong). I have submitted an expert report (under seal) before the London Court of International Arbitration. In addition to submitting testimony to these courts or regulatory bodies, I have submitted an opinion of law to the Australian Parliament; an expert economic report to the Australian Minister for Communications, the Information Economy, and the Arts; and an economic report to the Canada Post Corporation Mandate Review Committee.

Q. Have you ever testified before the U.S. Congress?

A. Yes. I have testified before committees of the U.S. Senate and House of Representatives on regulatory and constitutional law matters.

Q. Have you published scholarly articles on regulated network industries?

A. I have published several dozen scholarly articles, in both law reviews and economics journals, on regulated network industries. Journals in which my articles have appeared include the *American Economic Association Papers and Proceedings*, *Antitrust Law Journal*, *Columbia Law Review*, *Energy Law Journal*, *Journal of Competition Law & Economics*, *Journal of Political Economy*, *New York University Law Review*, *Stanford Law Review*, *University of Chicago Law Review*, *Yale Journal on Regulation*, and *Yale Law Journal*.

Q. Have you written books on the subject of regulated network industries?

A. Yes. I have written six books on regulated network industries. In chronological order, they are *Toward Competition in Local Telephony* (MIT Press 1994), co-authored with William J. Baumol; *Transmission Pricing and Stranded Costs in the Electric Power Industry* (AEI Press 1995), co-authored with William J. Baumol; *Protecting Competition from the Postal Monopoly* (AEI Press 1996), co-authored with Daniel F. Spulber; *Deregulatory Takings and the Regulatory Contract: The Competitive Transformation of Network Industries in the United States* (Cambridge University Press 1997), co-authored with Daniel F. Spulber; *Foreign Investment in American Telecommunications* (University of Chicago Press 1997); *Broadband in Europe: How Brussels Can Wire the Information Society* (forthcoming Kluwer/Springer 2005), co-authored with Dan Maldoom, Richard Marsden, and Hal J. Singer. I am currently completing a seventh book, with Professor Jerry A. Hausman of the MIT: *The Failure of Good Intentions: Is Regulation or Competition the Future of American Telecommunications?* (forthcoming Cambridge University Press 2006). In addition, with Judges Richard A. Posner and Frank H. Easterbrook, I am writing a third edition of *Antitrust Law: Cases and Materials* (forthcoming West Publishing 2006).

Q. Do any of your books discuss the 1996 Pennsylvania Electric Generation Customer Choice and Competition Act?

A. Yes, Professor Spulber and I discussed some of the Act's stranded cost provisions in *Deregulatory Takings and the Regulatory Contract.*

Q. Have any courts or regulatory commissions or similar bodies relied upon your scholarly writing in published decisions?

A. Yes. My writings have been cited by the Supreme Court of the United States, the lower federal and state supreme courts, state and federal regulatory commissions, and the European Commission. For example, in *Verizon Communications Inc. v. FCC*, decided by the Supreme Court in May 2002, both the majority and dissenting opinions quoted several of my writings on mandatory unbundling. In *United States v. Microsoft Corporation*, decided in June 2001, my article "Antitrust Divestiture in Network Industries" was quoted several times in the *en banc* decision by the U.S. Court of Appeals for the District of Columbia Circuit. In *State of New Mexico ex rel. Sandel v. New Mexico Public Utilities Commission*, decided in March 1999, the New Mexico Supreme Court adopted the definition of stranded costs that Professor William J. Baumol and I presented in an article in the *Harvard Journal of Law and Public Policy*. In *Case COMP/35.141—Deutsche Post AG*, decided in March 2001, the European Commission quoted my writings with Professors Baumol and Spulber on the relevance of common costs and universal service obligations to the proper calculation of a predatory pricing floor for a regulated multiproduct firm.

Q. Do you edit any scholarly journals?

A. Yes. I am the founding U.S. editor of the *Journal of Competition Law & Economics*, an international, peer-reviewed academic journal published by the Oxford University Press.

Q. Does this conclude your statement of qualifications?

A. Yes, it does.

PECO STATEMENT NO. 1-DQ

JK
9-22-05
Phila

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JOINT APPLICATION OF PECO ENERGY COMPANY AND PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE MERGER OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED WITH AND INTO EXELON CORPORATION	:	Docket No. A-110550F0160

SUPPLEMENTAL TESTIMONY
OF
DENIS P. O'BRIEN

Responding To The Directed Questions of
Vice Chairman Cawley and Commissioner Shane

Date: August 26, 2005

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SUPPLEMENTAL TESTIMONY OF DENIS P. O'BRIEN

I. INTRODUCTION

Q. Please state your name and business address.

A. Denis P. O'Brien, 2301 Market Street, Philadelphia, Pennsylvania 19103.

Q. Have you previously participated in this proceeding?

A. Yes. I submitted direct testimony (PECO Statement No. 1) with the Joint Applicants' February 4, 2005 filing and Rebuttal Testimony on July 29, 2005 (PECO Statement No. 1-R). A statement of my qualifications is contained in my direct testimony.

II. PURPOSE OF TESTIMONY AND SUMMARY OF CONCLUSIONS

Q. What is the purpose of this testimony?

A. By Secretarial Letter dated July 15, 2005, the parties to this proceeding were directed to respond to a series of questions (the "Directed Questions") posed by Vice Chairman James H. Cawley and Commissioner Bill Shane. The first four questions inquire into whether the synergies to be unlocked by the proposed merger of Exelon and PSEG could be harnessed to enhance economic development, and they specifically raise the issue of a set aside of "virtually" divested generation to be dedicated to that purpose. Question No. 5 asks the parties to consider the viability of combining the natural gas operations of PECO, PSE&G and the Philadelphia Gas Works ("PGW"). In Section III of this testimony, I describe PECO's existing economic development programs; provide an overview of certain programs in neighboring states; and respond to Directed Questions

Nos. 1 through 4. In Section IV, I discuss the hypothetical consolidation of gas operations (Directed Question No. 5).

Q. Please summarize your conclusions.

A. PECO fully supports the economic development goals articulated by Vice Chairman Cawley and Commissioner Shane. At the same time, we oppose the hypothetical set aside of power because PECO no longer owns or operates any generating facilities and because, as Mr. Sidak explains (PECO Statement No. 12-DQ), any such requirement would be inconsistent with the legislature's goal of promoting the development of competitive wholesale and retail electric markets.

In my rebuttal testimony (PECO Statement No. 1-R), I expressed PECO's willingness to consider a modest extension of the current distribution and transmission rate cap coupled with an appropriate sharing of regulated merger savings. I firmly believe that any rate-related benefits along these lines which are directed to business customers will improve the economic environment in PECO's service territory, limit rate volatility and strengthen the region's ability to remain competitive. Alternatively, if the Commission were to conclude that a more direct approach was preferable, some portion of the regulated merger savings quantified by Mr. Arndt that might otherwise be directed to rate reductions could be utilized to expand PECO's existing economic development programs. If, however, the Commission envisions a larger long-term economic development program, then what may be called for is a legislatively authorized statewide program. PECO would support such an initiative.

With regard to Directed Question No. 5, I conclude, based largely on Mr. Arndt's rebuttal testimony (PECO Statement No. 2-R) and the testimony being submitted herewith by Mr. Jirovec (PECO Statement No. 13–DQ), that a spin-off of the natural gas operations of PECO and PSE&G is not in the public interest and, in fact, would likely increase the cost of service and customer rates. It further appears that any synergies that might be produced by the merger of that newly-created entity with PGW would not come close to offsetting the diseconomies of spinning off the Joint Applicants' gas operations. What is less clear is whether an acquisition of PGW by Exelon and its consolidation with the PECO and PSE&G gas systems would make sense. That determination clearly cannot be made without extensive further investigation; an understanding of the transactional terms and conditions upon which Exelon and PGW would agree; and the regulatory treatment that would be accorded a host of difficult issues. That having been said, PECO would be willing to participate in a separate fact-finding proceeding, to take place after the consummation of the Exelon/PSEG merger, in which such issues could be explored.

III. DIRECTED QUESTIONS NOS. 1-4 (ECONOMIC DEVELOPMENT)

1. Neighboring states have availed themselves of opportunities to enhance their economic competitiveness through access to economical energy resources. What opportunities exist from this proposed merger in terms of economic development for Pennsylvania? Specifically, does this proposed merger present us with an opportunity to strengthen the State's ability to remain competitive during periods of economic recession and volatile energy pricing?

2. The innovative and controversial nuclear "virtual divestiture" component of the FERC decision appears to present intriguing opportunities for the Commonwealth. Does the proposed merger present this Commission with an opportunity to create an additional economic development program designed to improve Pennsylvania's business climate by creating strategic partnerships with

the public and private sector that support product development and the use of energy-efficient technologies?

3. **Would it be possible to set aside 10% or some relatively small share of the "virtually" divested generation to augment economic development and economic competition within the Commonwealth? For example, could the parties consider and comment on creating a pool of energy and capacity of at least 260 MWs which could be used at the discretion of the Secretary of the Department of Community and Economic Development to attract and retain business in the Commonwealth?**

4. **Could the Commonwealth through one of its agencies and/or in conjunction with a licensed Electric Generation Supplier facilitate the use of the output of this generation?**

A. PECO's Existing Economic Development Programs

Q. Mr. O'Brien, please describe PECO's existing economic development programs.

A. PECO is a recognized, national leader in the area of economic development. We maintain a full-time staff dedicated to promoting the Greater Philadelphia region as a desirable business location for new and expanding businesses. We also provide rate incentives to existing and prospective customers that commit to creating jobs and/or investing capital.

Q. Please summarize the principal activities of PECO's Economic Development Department.

A. The staff expedites the flow of information essential to the site location process; facilitates access to key political, civic and business leaders; and coordinates customized site location tours. The economic development team also works directly with the region's business leaders, real estate professionals, site location consultants, as well as county and state economic development agencies, to bring and expand business to the Philadelphia region. The department participates in professional conferences and trade shows, with exhibit space showcasing the benefits of doing business in the Greater Philadelphia area, and partners with the Greater Philadelphia Chamber of Commerce's regional marketing initiative, Select Greater Philadelphia, to promote the Philadelphia region nationally and internationally. In my rebuttal testimony (PECO Statement No. 1-R), I described a few of the major economic projects that PECO has been instrumental in bringing to this region and I also identified some of the recognition that PECO has received for its economic development efforts.

Q. **You previously mentioned discounted rates. Please describe the discounted rate programs that PECO offers to spur economic development.**

A. PECO offers discounted rates through the Employment and Economic Recovery Rider (E2R2) and the Keystone Opportunity Zone Rider (KOZR) programs. The E2R2 program is targeted to increasing manufacturing in PECO's service territory. The electric rate discounts are available to new manufacturing load and existing manufacturing activities where the customer can demonstrate increased levels of employment and/or investments. In the case of existing manufacturing activities, the E2R2 provides for increases in electric rate discounts as the customer expands the level of employment and capital investment. Effective in 2002, the KOZR provides electric rate discounts to customers who establish business in a Keystone Opportunity Zone or an Expanded Keystone Opportunity Zone, as those zones are defined by statute (Act 92 of 1998).

In addition to these programs, PECO offers discounted rate opportunities to incentivize companies to stay in the region or to locate in our service territory. These include: (1) Economic Efficiency Rider (EER) and Tariff Rule 4.6 Contracts, which provide negotiated electric rate discounts to customers using over 1,000 kW who have a viable competitive alternative, and (2) the Incremental Process Rider (IPR), which offers electric rate discounts to customers who install qualifying equipment that increases electric process load by at least 50 kW.

Q. **Have PECO's rate discount programs been successful in retaining and attracting business customers?**

A. Yes. Approximately 325 customers, representing over 1500 MW of new or incremental load, currently receive service under PECO's economic development rate programs.

Q. **Will these programs remain in place after the proposed Exelon/PSEG merger is consummated?**

A. Yes, they will.

B. Economic Development Programs In Neighboring States

Q. **Directed Question No. 1 states that "[n]eighboring states have availed themselves of opportunities to enhance their economic competitiveness through access to economical energy resources." Please comment.**

A. Although we do not know what specific initiatives Vice Chairman Cawley and Commissioner Shane may have had in mind, my staff was able to gather some information on programs in place in New Jersey, New York and Ohio. Of those, the New York programs seem to be the most analogous.

Q. Please describe the New York programs.

A. In New York, there are two programs administered by the New York Power Authority ("NYPA") and the New York Economic Development Power Allocation Board ("EDPAB") which are intended to target businesses facing expansion opportunities or threatening to leave the State due to high electricity costs - - the "Economic Development Power" and the "Power for Jobs" programs.[1] Although these programs were initiated with the intention to provide electricity from sources priced below-market, in their current form the programs provide a discount from the regulated delivery rates charged by the transmission-owning utilities. The utilities are given a state tax credit to recoup the revenues lost from the discount.

Q. How do the Economic Development Power and Power for Jobs programs operate?

A. The amount of power available under these programs and the protocols for obtaining it have changed over the years and continue to be revised by the New York legislature. However, in broad terms, awards are made by the EDPAB which entitle successful

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1 Additional programs apply to customers in areas historically served by NYPA's hydroelectric projects. However, it is my understanding that those are not strictly speaking economic development programs.

applicants to purchase power from NYPA (a state agency) and to have the power delivered by the recipients' host electric utilities at reduced delivery rates. The power supplied under these programs formerly came from a combination of NYPA's Fitzpatrick nuclear plant and purchases made by NYPA from external market sources. The Fitzpatrick plant was divested by NYPA in 1999, and a purchase power contract with the new owner that supported these programs terminated at the end of 2004. All of the energy supporting these programs now comes from market sources acquired in bulk by NYPA.

Q. What price do successful applicants pay for energy awarded under the Economic Development Power and Power for Jobs programs?

A. New York's investor-owned utilities deliver the electricity to the award recipients pursuant to delivery tariff schedules that exclude the utilities' stranded cost charges. This reduction in delivery charges is the primary – if not the exclusive – benefit to program participants. (There may be some additional benefit realized by having NYPA purchase all the power for these programs in bulk.) The utilities are held economically harmless against the loss of delivery revenues by means of a tax credit. The tax credit is equal to the loss in net revenues caused by a customer switching from the normal delivery service (with stranded cost charges) to the special NYPA-related delivery service (without stranded cost charges).

Q. You noted previously that your staff had also become aware of certain programs in New Jersey and Ohio. Please elaborate.

A. The New Jersey Board of Public Utilities (NJBPU) and the New Jersey Economic Development Authority (EDA) administer New Jersey's "Clean Energy Program," which makes available grants and low interest rate financing for energy efficiency and renewable energy projects in New Jersey. As noted by PennFuture witness Tuffey (Statement No. 1), this program is funded, in whole or substantial part, by a Societal Benefits Charge (SBC) assessed on all utility customers.

The Office of Energy Efficiency (OEE), which is housed in Ohio's Department of Development, administers an "Energy Loan Fund," which makes available low interest rate financing to individuals and businesses for investments in products, technologies or services that will conserve energy and/or increase the use of renewable resources. The Energy Loan Fund was established as part of Ohio's 1999 electric restructuring legislation (Ohio Revised Code, Sections 4928.61-4928.63) and is financed through a surcharge on the bills of Ohio's five investor-owned electric utilities. According to information on the OEE's web-site, the surcharge approximates 9 cents per month for the typical residential customer and is expected to remain in place until 2011, by which time the Fund is projected to reach $100 million.

Unlike the situation in New York, the programs in New Jersey and Ohio do not specifically target economic development, but instead seem designed primarily to promote energy efficiency and the increased use of renewable forms of energy.

Q. Do the programs in New Jersey, New York and Ohio have any common features?

A. Yes. First, our research reveals that the programs in question were implemented on a statewide basis pursuant to legislative (New York and Ohio) or commission (New Jersey) mandate. In other words, they apply equally to all jurisdictional utilities. Second, they all appear to be funded by consumers, either through surcharges to their utility bills or through tax credits granted the utilities themselves. As a corollary, I am unaware of any program, in Pennsylvania or elsewhere, that requires utility shareholders to subsidize state-sponsored economic development efforts.

C. Response To Directed Questions Nos. 1 – 4

Q. Before responding to the Directed Questions themselves, do you have any general comments regarding the goals articulated by Vice Chairman Cawley and Commissioner Shane?

A. Yes. As I mentioned earlier, PECO has long been and continues to be a leading advocate of economic development. I believe that PECO's track record in that regard speaks for itself. Notably, our commitment to economic development will be strengthened by the proposed merger for the reasons discussed in my rebuttal testimony (PECO Statement No. 1-R at pp. 23-24). In addition, we would enthusiastically lend our support to a properly structured, statewide economic development program in which all stakeholder groups would participate and, presumably, would benefit. However, I question whether the Commonwealth's economic development objectives should be pursued in the context of the current merger proceeding.

Q. How do you construe the economic development program envisioned by the Directed Questions?

A. Directed Questions Nos. 2 and 3 speak to a set aside of a portion of the generation to be "virtually" divested in compliance with the FERC's July 1, 2005 Order approving the merger. Directed Question No. 4, in turn, inquires into the possible role of a Commonwealth agency or a licensed Electric Generation Supplier (EGS) to "facilitate the use of the output of this generation." I therefore conclude that the Directed Questions anticipate the Commonwealth or its designee/agent serving a function akin to that of New York's Power Authority and the EDPAB, i.e. procuring energy and making it available to qualified applicants at discounted rates.

Q. Do the Directed Questions shed any light on how these rate discounts would be funded?

A. No, they do not. However, as described by Mr. Sidak (PECO Statement No. 12-DQ), the suggested set aside conceptually could take one of three forms: (1) a Commonwealth-funded set aside; (2) an Exelon-funded set aside; and (3) a set aside subsidized by some portion of PECO's estimated net regulated merger savings.

Q. You testified previously that you oppose a set aside of "virtually" divested generation. Why?

A. There are several reasons. First, the term "set aside" implies that a portion of the 2600 MW of power would be removed from the "virtual" divestiture process and, in effect, dedicated for use by the Commonwealth or its designee to serve new or expanded load. Initially, I am advised that the market value of a 10% (i.e. 260 MW) set aside would exceed $100 million per year. Furthermore, and as Dr. Hieronymus observes (PECO Statement No. 3-DQ), any set aside would have to be carefully structured in order to be consistent with the mitigation plan adopted by the FERC and, in any event, would need to be reviewed and approved by the FERC.

Second, and as Mr. Sidak explains (PECO Statement No. 12-DQ), PECO - - or, in this instance, its nonregulated affiliate, Exelon Generation Company - - could not be forced to make the power available to the Commonwealth at discounted (i.e., below market) prices without raising significant "takings" and perhaps Commerce Clause issues. Mr. Sidak further suggests that such an appropriation of value might be considered a form of unauthorized taxation in violation of state law.

Third, and as Mr. Sidak also points out, the proposed set aside program would seem to be contrary to the legislative principles at the core of the Electric Competition Act because it would have state government intrude in the operation of the competitive wholesale market and, in a sense, put the Commission back into the business of regulating the price of generation for at least one segment of the customer base.

Finally, I would note that, as Dr. Hieronymus testifies, any set aside would have to be acquired on a 24 hour/7 days a week basis in order to comply with the FERC-approved mitigation plan. Dr. Hieronymus further points out that, to the extent that program participants do not consume the power in that fashion, the Commonwealth, at a minimum, would have to market the excess energy during hours when the entire amount of power is not needed by the program participants, thereby subjecting itself to the market risk that the price of the energy is higher than the market price of energy at the time it is resold, as well as various credit and other protocols imposed by the PJM.

Q. Would you object if the Commission were to adopt the third set aside scenario you described, namely to use a portion of PECO's regulated merger savings to fund purchases of power by the Commonwealth on the open market?

A. That would depend on the reasonableness of the value appropriated from PECO. Nonetheless, I believe that a comprehensive long-term solution to the Commonwealth's economic development aspirations is what is needed. I would therefore urge the Commission to recommend to the legislature that it authorize, and fund as necessary, a statewide program that would enable the Commonwealth to more effectively leverage its energy and financial resources. PECO would be pleased to work with the Commission to develop the framework of such an initiative.

IV. DIRECTED QUESTION NO. 5 (CONSOLIDATION OF PECO, PSE&G AND PGW GAS OPERATIONS)

5. Would the combination of the PSE&G gas division with the PECO gas division and the Philadelphia Gas Works provide critical mass for a viable, profitable, shareholder owned, public utility, assuming a revenue stream from off system sales from an LNG facility, and separate resolution of the problem of a billion dollar debt?

Q. Directed Question No. 5 anticipates the consolidation of the PECO, PSE&G and PGW natural gas operations into "a viable, profitable, shareholder owned public utility." Would such an entity be independent of Exelon or would it remain under the Exelon corporate umbrella?

A. The Directed Questions are unclear on this point and, consequently, we asked Mr. Jirovec to address both scenarios in his testimony (PECO Statement No. 13-DQ).

Q. Does it matter to PECO which scenario is assumed?

A. Yes, it does. Exelon has no intention of spinning off its natural gas operations and would vigorously contest any such directive. Moreover, Messrs. Arndt and Jirovec have established, to my satisfaction, that (1) the divestiture of the PECO and PSE&G gas systems would substantially increase the overall cost of service and (2) the synergies achievable by merging PGW's operations into the newly-formed corporate entity would not offset those increased costs. In short, the spin-off scenario is a non-starter.

Q. Would the acquisition by Exelon of the PGW system yield similar diseconomies?

A. There is no way of knowing based on the information currently available and, for that reason, I cannot rule out the acquisition scenario at this time. Exelon is interested in any transaction that brings value to its customers, shareholders and employees. However, many questions would have to be answered in order to determine whether such a combination made sense. This, in turn, would require extensive due diligence and the careful analysis of a host of critical issues, including, but not limited to, the following:

- The physical status of the PGW system and, in particular, the condition of approximately 1660 miles of aging cast iron mains that remain in service.
- The effects of de-municipalization caused by the sale of PGW's assets.
- The financial integrity of PGW's business operations.
- PGW's environmental compliance record and potential exposure to future environmental liabilities.
- PGW's existing labor commitments, including the cost of accrued health and retirement benefits.
- Outstanding litigation and claims.
- Supplier and support services contracts.
- The terms, conditions and effects of converting PGW's outstanding indebtedness.
- The status and future prospects of the "LNG facility" alluded to by the Directed Questions.
- Opportunities to achieve acquisition-related synergies.

Q. Assuming that Exelon were provided all of the information it required, would it then be willing to pursue the acquisition of PGW?

A. Not necessarily. The results of due diligence would enable Exelon to make a preliminary assessment of the feasibility of such an acquisition under certain assumed terms and conditions. However, there is no guarantee that those terms and conditions would be acceptable to PGW - - or, for that matter, Exelon - - or that a deal could be negotiated. Moreover, I cannot imagine that we would be willing to move forward without having first resolved with the Commission the future treatment of various rate issues - - e.g., the valuation of the acquisition for rate base purposes (especially given that PGW's rates are not presently set on a "rate base, rate of return" basis that would be needed to attract private equity investment); the design of rates and impacts on different classes of customers (including whether PGW's rates should be aligned with PECO's and whether PGW's senior citizen discounts should be continued); billing and collection matters (including its low-income customer assistance programs).

Q. What regulatory approvals would need to be obtained in order to consolidate the PECO, PSE&G and PGW systems?

A. Depending on how it is structured, the transaction would need to be reviewed and approved by both the Commission and the New Jersey Board of Public Utilities. In addition, I am advised that the Department of Justice and the Securities and Exchange Commission would review the deal.

Q. Do you believe that the foregoing issues should be addressed in this proceeding?

A. No, I do not.

Q. Is PECO willing to participate in a separate proceeding to examine the feasibility of Exelon acquiring PGW's gas operations?

A. Yes, it is. We believe that a separate proceeding, to commence following consummation of the Exelon/PSEG merger, could serve a valuable function in terms of identifying issues and gathering the information needed to determine whether such a combination would be in the public interest. We are willing to work with the Commission and all interested parties to define the scope and anticipated timeline of such an investigation.

Q. Does that conclude your supplemental testimony?

A. Yes, it does.

PECO STATEMENT NO. 3-DQ

JK
9-22-05
Phila

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JOINT APPLICATION OF PECO ENERGY COMPANY AND PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE MERGER OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED WITH AND INTO EXELON CORPORATION	:	DOCKET NO. A-110550F0160

SUPPLEMENTAL TESTIMONY

OF

WILLIAM H. HIERONYMUS

Concerning Directed Questions 1 Through 4
From Vice-Chairman Cawley and Commissioner Shane

Date: August 26, 2005

P245255

I. INTRODUCTION

Q. What is the purpose of your Supplemental testimony?

A. I have been asked by PECO and PSE&G to address Directed Questions No. 1-4 that were posed by Vice-Chairman Cawley and Commissioner Shane. In particular, I address the question of whether 245 or more MW of energy from the virtually divested capacity[1] could be set aside for use at the discretion of the Secretary of the Department of Community and Economic Development in attracting and/or retaining business in Pennsylvania and without violating the mitigation commitments made to the FERC. This capacity is owned and operated by Exelon Generation, LLC and PSEG Generation, not by PECO and PSE&G, and will be owned by Exelon Generation after the merger is consummated.

Q. What is your conclusion in that regard?

A. My conclusion is that it would be possible to establish such a program in such a way that is consistent with the mitigation commitments. However, in order to achieve this result, the program would have to be implemented in a fashion that could diminish its usefulness as a program, and could expose the Commonwealth or its designated competitive electric generation supplier (EGS) to market risks. Any such program would necessarily be different from what FERC approved in

[1] The Directed Questions refer to a set-aside of 10% of the proposed virtual divestiture of 2,600 MW of nuclear capacity. Exelon's and PSEG's' proposal in the FERC proceeding involves taking outages of capacity into account to determine the amount of energy that must be sold, and works out to sales of 2,450 MW of blocks of energy. 10% of this amount equals 245 MW of set-aside for the Pennsylvania program.

its Merger Order. As a result, FERC would need to review and approve the program as constituting acceptable mitigation. Finally, any set-aside of power properly should be priced at the market price paid to Exelon Generation that is established for virtually divested power.

II. CONDITIONS UNDER WHICH VIRTUALLY DIVESTED CAPACITY COULD BE MADE AVAILABLE TO A COMMONWEALTH AGENCY FOR BUSINESS ATTRACTION AND RETENTION

Q. In order to provide the necessary background, could you briefly summarize Exelon's and PSEG's virtual divestiture proposal?

A. The virtual divestiture proposal is described at length in my other testimony that has been filed in this proceeding, including my FERC testimony that was filed in this proceeding. The purpose of the virtual divestiture proposal is to mitigate any increase in market power that otherwise could result from the combination of Exelon Generations and PSEG's nuclear generation fleets. The virtual divestiture proposal achieves this by selling 25 MW blocks of energy for a term of three-years in a competitive auction process. Alternatively, the power may be sold under 15-year or longer contracts.

There are three important aspects of the proposal for market power purposes: (1) the contracts must require Exelon Generation to sell, and the purchaser to take, the energy on a firm "24/7" basis, i.e. twenty-four hours a day, seven days a week, for the entire term of the contract; (2) the price of the contracts must be fixed at the time they are entered into and cannot vary during the term of the contract as market prices change; and (3) all but 200 MW of the energy sold must be delivered in PJM East – the remaining 200 MW can be delivered anywhere in PJM Pre-2004, including PJM East.

Q. Why are these aspects of the proposal important for purposes of mitigating any increases in market power resulting from combining Exelon Generation's and PSEG's nuclear generation fleets?

A. The requirement that deliveries be firm on a 24/7 basis is necessary to ensure that the energy cannot be withheld from the market, which is how market power is exercised. Because the energy is delivered on a 24/7 basis, it is always in the market and never can be withheld.[2]

The requirement that the price be fixed at the time the contract is entered into and not vary with the market price is necessary to ensure that Exelon Generation does not have any merger-related incentive to attempt to increase market prices through the use of its remaining generation. Because the contract price does not vary with market prices, Exelon Generation cannot reap the benefits of a withholding strategy involving their other units.

The requirement that most of the energy be delivered in PJM East and the rest in PJM Pre-2004 results from the fact that these are the relevant geographic markets

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[2] Under the 15-year contract option, the virtual divestiture proposal requires either that (i) power be delivered on a 24/7 basis or (ii) delivered based on the availability of a specific unit with a guaranteed minimum deliverability. With respect to this second option, energy must be taken by the purchaser in all hours that it is required to be delivered, and thus cannot be withheld.

in which Exelon Generation's nuclear generation is located, and in which the transaction creates a potential market power problem. In order to mitigate these market power concerns, the virtual divestiture must take place in the same relevant geographic markets as the increased concentration of nuclear generation.

Q. In order for a virtual divestiture set aside program to mitigate market power, what attributes would it need to have?

A. In order to act as mitigation, the set aside program would need to retain the above three features of the virtual divestiture proposal. Assuming a set aside of 245 MW of energy, (1) 245 MW of energy would have to be delivered by Exelon Generation and taken under the program on a 24/7 basis beginning at the effective date of the first auction; (2) the price for the 245 MW of energy would have to be fixed at the time the contract is entered into; and (3) most, if not all, of the energy would have to be delivered in PJM East.

Q. You mentioned earlier that these requirements could diminish the usefulness of the set aside program. Why is that?

A. The primary problem is that the full amount of energy must be taken on a 24/7 basis beginning at the first auction date and continuing thereafter. This raises a "start-up" problem, in that the industrial development customers that the Commonwealth would like to offer the power to will not, in the main, be in a position to receive it beginning on that date. This means that the Commonwealth would need to dispose of the power that customers are not yet ready to take.

Beyond this near-term problem, as a continuing matter it is unlikely that any business or combination of businesses in Pennsylvania would take exactly 245 MW (or whatever the set aside amount may be) on a 24/7 basis. Depending on the size of the business load served under the program, the load may be higher than 245 MW in some hours and less than 245 MW in other hours.

As a consequence, the Commonwealth would have to resell energy in those hours when the full 245 MW is not needed by the program's business customers and, depending upon the size and the nature of the program, it could also have to purchase energy in those hours when more than 245 MW is needed. This would require that the Commonwealth become a market participant in PJM (directly or indirectly) in order to meet its obligations under the program. This would entail creating an agency that would have to register as a market participant in PJM (meeting all of the PJM membership criteria includingcredit requirements) and employ personnel to manage the program on a 24/7 basis (or hire an agent to do so), selling energy into and buying energy from PJM as needed.

The need to buy top-up power or dispose of excess power would put the Commonwealth at risk for market fluctuations in the price of electricity. Because the contract price must be fixed at the time the contract is entered into, the Commonwealth would lose money in every hour that it resells energy at a price below what it pays Exelon Generation for that power. To the extent that this requires the sale of energy in the off-peak hours when energy market prices are at their lowest, there is a very real possibility that the Commonwealth would lose money on its resale of excess power. Furthermore, to the extent that the Commonwealth obligates itself under its program to supply more than 245 MW of energy at a fixed price, then it will incur losses to the extent that it purchases energy at a higher price than the price at which it provides energy under its program. To the extent that this occurs during peak hours when the market price of energy tends to be higher, the Commonwealth again would sell at a loss.

The essential point is that the Commonwealth would be taking on the market risk that the fixed price at which it purchases power will be higher than the market price in hours when the Commonwealth has excess energy and that the fixed purchase price will be lower than the market price in hours in which the Commonwealth needs to purchase additional energy.

Q. Couldn't this problem be solved by allowing the Commonwealth to sell the energy back to Exelon Generation (or not take it) in those hours that the Commonwealth does not need 245 MW and purchase additional energy in those hours when it needs more than 245 MW?

A. There are serious problems with both aspects of this suggestion. With respect to the option to sell power back to Exelon Generation when it is not needed, such an option would either allow Exelon Generation to opt not to generate the energy being sold back or, if it is still obligated to generate the energy, to resell it at market prices. Either outcome would violate either the FERC mitigation requirement that Exelon Generation deliver the full 245MW on a 24/7 basis or the requirement that it not be able to sell the energy at spot market prices. In other words, allowing the Commonwealth to sell the energy back to Exelon Generation when it is not needed would eliminate the market power mitigation associated with that energy.

Imposing an obligation on Exelon Generation to sell additional energy in hours when it is needed would not raise market power mitigation concerns, but would involve its own set of problems. To the extent that Exelon Generation sells the additional energy to the Commonwealth at market prices, the risk of the Commonwealth incurring a loss when market prices are higher than the resale price has not been diminished. To the extent that the Exelon Generation would be obligated to sell the additional energy at the same fixed rate that applies to the 245 MW block of energy, that simply would transfer to Exelon Generation the obligation to sell power at a loss when the market price is above the fixed rate applicable to the 245 MW block of energy.

Q. **Directed Question No. 4 suggests that the program could be implemented in conjunction with a licensed Electric Generation Supplier ("EGS"). Could the problems that you describe above be resolved by having the EGS purchase the energy from Exelon Generation and resell that power to Pennsylvania businesses at the direction of the Secretary of the Department of Community and Economic Development?**

A. Not really. Intermediation of an EGS does not in any way affect the requirement for consistency with the mitigation commitments. With respect to the risks that would be borne by the Commonwealth, these risks do not go away because an

EGS is used. The EGS would not bear these risks for free, but would require that it be compensated, directly or through a fixed fee sufficient to compensate for the risks. The risk-related compensation (over and above the other compensation required to compensate the EGS function) paid to the EGS will either have to be borne by taxpayers or, if added to the energy price charged to the Pennsylvania businesses, will reduce the benefits of the program to those businesses.

Since an EGS would not be willing to accept the market risk that I described above associated with reselling energy in hours when it is not needed or in purchasing energy in hours when it is needed, at least without significant compensation for doing so, the cost associated with these risks remains with the Commonwealth. Either the Commonwealth would have to retain that market risk itself, or else it would have to pay a significant additional compensation to the EGS or some other entity to hedge the risk.

Q. Could the set aside have an impact on the price of the energy sold in the virtual divestiture auction?

A. The set aside would, of course, reduce the amount of energy sold in the virtual divestiture. All things being equal a reduction in the amount of energy sold at the auction could increase the price at which the auction clears, thereby increasing the price of energy sold at the auction.[3]

[3] On its face, one could argue that selling energy to the targeted businesses would reduce demand for the energy sold at the auction by an amount corresponding to the decrease in supply. However, my understanding is that the set aside program may be targeted for incremental load that otherwise would leave the system or

Q. Assuming that the Commonwealth nevertheless wishes to go forward with the proposal outlined in the Directed Questions, what price to you think should be paid to Exelon Generation for the power that is purchased under such a program?

A. In my opinion, the price paid to Exelon Generation should be the auction price that results from the auction of the other energy being sold under the virtual divestiture proposal. This represents the true economic cost of the energy being sold by Exelon Generation.

Q. What would your opinion be of a proposal to sell the energy at a price below the virtual divestiture auction price?

A. I would have several problems with such a proposal.

First, forcing Exelon Generation to sell power to Pennsylvania businesses at below market prices represents nothing more than an involuntary transfer of money from Exelon Generation to those businesses. As I have described above, the proposed program for accomplishing this would involve administrative burdens and inefficiencies that would result in the Pennsylvania businesses receiving less in benefits than the losses incurred by Exelon Generation, and likely would require the expenditure of tax revenues by the Commonwealth as well. Moreover, it is well-known by economists that "in-kind" subsidies are less efficient than cash subsidies since they distort resource decisions. If the

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locate in another region. Therefore, demand should not be reduced as a result of sales to the Commonwealth under the program.

Commonwealth believes that there are good policy reasons for subsidizing certain businesses, it would be much more efficient if the Commonwealth were to just make direct payments to those businesses.

Second, as I explain above, it is almost certain that the Commonwealth or the EGS working under the Commonwealth's direction would have to resell energy purchased from Exelon Generation in those hours when it is not needed under the proposed program. Even if it were appropriate for Exelon Generation to sell power to the businesses served under the proposed program at below market rates, I do not believe that it would be appropriate to allow the Commonwealth, a subsidized customer or an EGS to profit from reselling power in the market that it purchased from Exelon Generation at below-market rates.

Third, I do not believe that it would be appropriate as a policy matter to compel one business, in this case Exelon Generation, to subsidize Pennsylvania businesses at the expense of its shareholders. In this regard, I understand that Dr. Sidak is presenting testimony regarding the constitutional problems raised by requiring Exelon Generation to make sales at below-market rates.

Q. **Are there any other issues that you wish to bring to the Commission's attention regarding the proposed set aside program?**

A. Yes. I have explained above the conditions under which, in my opinion, the program could be conducted and still mitigate market power. I would note, however, that even if those conditions are met, the proposed program still would be somewhat different from the program that was approved by FERC. Therefore, to the extent that the Commission decides to require the implementation of such a program, I believe that the program first would have to be presented to FERC for its determination that the program does adequately mitigate market power.

III. CONCLUSION

Q. Does this complete your supplemental testimony?

A. Yes.

PECO STATEMENT NO. 12-DQ

JK
9-22-05
Phila

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JOINT APPLICATION OF PECO ENERGY COMPANY AND PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE MERGER OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED WITH AND INTO EXELON CORPORATION	:	Docket No. A-110550F0160

SUPPLEMENTAL TESTIMONY
OF
J. GREGORY SIDAK

Concerning Directed Questions 1 Through 4
From Vice-Chairman Cawley and Commissioner Shane

Date: August 26, 2005

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SUPPLEMENTAL TESTIMONY
OF
J. GREGORY SIDAK

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is J. Gregory Sidak. My business addresses are Georgetown University Law Center, 6018 Hotung International Law Building, 600 New Jersey Avenue, N.W., Washington, D.C. 20001 and Criterion Economics, LLC, 1620 Eye Street, N.W., Suite 800, Washington, D.C. 20006.

Q. Have you provided testimony previously in this proceeding?

A. Yes, I submitted PECO Statement No. 12-R, which was served on the other parties on July 29, 2005. My qualifications are set forth in that statement.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Joint Applicants, PECO Energy Company (PECO) and Public Service Electric & Gas Company (PSE&G). The views that I present are my own and not those of Georgetown University Law Center, which does not take institutional positions on specific legislative, regulatory, adjudicatory, or executive matters.

II. PURPOSE OF TESTIMONY AND SUMMARY OF CONCLUSIONS

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to analyze the economic and policy implications of the conceptual economic development program offered for comment by Directed Questions 1 through 4 issued by Vice-Chairman Cawley and Commissioner Shane. In so doing, I will address the "takings" and Commerce Clause issues raised by the proposed program and discuss whether such a program would comport with the policy and principles underlying electric restructuring and the competitive wholesale and retail markets for electric generation.

Q. Please summarize your conclusions.

A. Directed Questions 1 through 4 outline a broad concept for a state economic development program but do not explain how such a program could be structured, implemented or funded. In order to analyze that concept, one must consider its possible structure and possible scenarios for implementation of which there are three, as described subsequently in this testimony.

The concept outlined in Directed Questions 1 through 4 raises significant "takings," Commerce Clause, statutory and regulatory policy issues. Appropriating the value of generation owned by Exelon Generation Company LLC (Exelon Generation or ExGen), a non-regulated subsidiary of Exelon Electric & Gas Corporation (EEG),[1] as the proposal posited in Directed Questions 1 through 4 may contemplate, is an unlawful taking. Also, the Commerce Clause of the United States Constitution could be violated if the effect of the proposal is to employ state action to appropriate generation for the benefit of Pennsylvania customers in a manner that raises the cost of the remaining generation supply for other customers, including those in other states. In addition, under each of the possible implementation scenarios, the generation "set-aside" program posited by

[1] Following the merger, Exelon Corporation (Exelon) will change its name to "Exelon Electric & Gas Corporation."

Directed Questions 3 and 4 would likely exceed the bounds of traditional ratemaking authority and constitute a form of taxation and appropriation that requires – but does not have – express legislative authorization. Finally, the kind of economic development program contemplated by Directed Questions 1 through 4 would be inconsistent with the policy and principles of electric industry restructuring in Pennsylvania, which introduced competition in electric generation as the best way to foster economic growth and keep Pennsylvania competitive in attracting industry and jobs to the State.

III. THE DIRECTED QUESTIONS

Q. What is the principal proposal that Directed Questions 1 through 4 ask the parties to address?

A. Questions 1 through 4 ask the parties to this proceeding to address whether the proposed merger of Exelon and Public Service Enterprise Group (PSEG), the parent companies of the Joint Applicants, presents opportunities to improve Pennsylvania's "business climate" and strengthen the State's ability to "remain competitive during periods of economic recession and volatile energy pricing." Questions 1 through 4 provide increasing levels of specificity and culminate in a proposal that envisions a "set aside" of approximately ten percent[2] of the nuclear generation being "virtually divested" by Exelon Generation as part of the generation market mitigation plan required by the Federal Energy Regulatory Commission (FERC) in approving the merger under Section 203(a) of the Federal Power Act. Specifically, Questions 3 and 4 propose creating a "pool of energy and capacity" to

[2] As explained by Dr. Hieronymus (PECO Statement No. 3-DQ), 10% of the generation to be "virtually divested" – the measure referenced in Directed Question 3 – actually equates to 245 MW, not 260 MW, as the question apparently assumes. Consequently, in the balance of this statement, I will use 245 MW, not 260 MW, as the illustrative "set aside."

be used at the discretion of a state agency, such as Pennsylvania's Department of Commerce and Economic Development (DCED), "to attract and retain business in the Commonwealth." Although not stated explicitly, the questions imply that energy and capacity from the "pool" would be provided to selected business customers in Pennsylvania at below-market prices.

Q. How would such a program actually operate?

A. That is unclear. Directed Questions 1 through 4 simply outline a broad concept for a state economic development program. The questions do not explain how the program could be structured, implemented or funded. It is beyond the scope of this testimony to try to fill in those gaps. However, in order to analyze the proposal, it is necessary to consider, at a general and theoretical level, several alternative structures and implementation scenarios.

Q. Before describing the general structural/implementation scenarios you considered, please identify any relevant facts that the Directed Questions may have omitted.

A. The context provided by two facts is essential to understanding the obstacles to implementing the concept outlined in the Directed Questions.

First, neither PECO nor PSE&G, the Joint Applicants in this proceeding, own any generation. As I explained in Statement No. 12-R, as part of the settlement of PECO's restructuring proceeding, the Commission approved, without qualification or condition, PECO's transfer of all of its generation to an affiliated or unaffiliated third-party at book cost. Subsequently, the Commission granted PECO a certificate of public convenience to transfer its generation to ExGen pursuant to that prior approval. Similarly, with the prior approval of the New Jersey Board of Public Utilities, PSE&G transferred its generation to subsidiaries of PSEG Power LLC (PSEG Power) in furtherance of the restructuring of the electric power industry in New Jersey initiated by its Electric Discount and Energy Competition Act. Accordingly, the generation to be divested, which Directed Questions 1 through 4 assume will be the basis for the proposed "set aside," is the property of ExGen and PSEG Power, which are subsidiaries of Exelon and PSEG, are not regulated by this Commission and are not parties to this proceeding.

Second, within the PJM Interconnection LLC (PJM),[3] there is a competitive market for wholesale purchases and sales of electric power. Electric power, whatever the source of its generation, is bought and sold at prices determined by the market. Consequently, the economic value of a generation "set aside" obtained from ExGen would be its market-determined price, regardless of whether the generation originated from units that have a low operating cost or units that have a higher operating cost.

Q. **In your rebuttal testimony, you discuss four fundamental principles inherent in the framework of electric industry restructuring created by the Electricity Generation Customer Choice and Competition Act (Competition Act). Are those principles relevant to the analysis of the "set aside" proposal offered in Directed Questions 3 and 4?**

A. Yes, they are. Therefore, I have analyzed the "set aside" proposal in light of those principles, which are identified and discussed in depth in PECO Statement 12-R at pages 4 through 14. In summary, the restructuring of the electric industry removed generation assets from state regulation, and the rights and obligations of the customers of regulated

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3 PJM is a regional transmission organization that operates over a broad, multi-state area.

electric distribution service were reset as of January 1, 1999, by isolating those customers from the prospective risks and rewards that attend the ownership of generation. In exchange, those customers were given a call option on POLR generation service at fixed rates as a *quid pro quo* for paying Competitive Transition Charges (CTCs) and Intangible Transition Charges (ITCs). Because of that reordering of customer rights and obligations, after January 1, 1999, the market and operational risks and rewards of owning and operating the formerly regulated generation assets are borne entirely by shareholders regardless of whether market or operational factors increase or decrease the value of those assets. Within the context of this case, that means that any synergies the proposed merger would produce within the non-regulated generation subsidiaries of Exelon and PSEG cannot lawfully be appropriated for the benefit of customers of PECO's regulated electric distribution service.

Q. What structural/implementation scenarios did you consider in analyzing Directed Questions 1 through 4?

A. The scenarios I considered fall into three broad categories, which differ based upon what it means to "set aside" a "pool of energy and capacity" and how the creation of that pool would be funded. These scenarios consist of: (1) a Commonwealth-funded set aside; (2) an ExGen-funded set aside; and (3) a set aside subsidized by estimated net merger synergies that PECO will generate within its regulated operations.

Q. Please describe the Commonwealth-funded scenario.

A. Under this scenario, instead of auctioning all of the virtually divested generation as contemplated by the mitigation plan, up to 245 MW would be "set aside" for future bi-lateral sales, either directly to a Commonwealth agency or to an electric generation supplier (EGS) serving as its designee. The Commonwealth or its designee would purchase energy and capacity from the 245 MW "pool" at the virtual divestiture auction-determined price and offer it to selected businesses at below-market prices as an incentive to locate in PECO's service area (or, perhaps, in Pennsylvania, generally), remain in PECO's service area (or, perhaps, Pennsylvania, generally), or expand their existing operations.

Q. Please describe the ExGen-funded scenario.

A. Under this scenario, ExGen would be expected to provide 245 MW of energy and capacity from the sources subject to "virtual divestiture" to a Commonwealth agency or its EGS designee at no cost or at a substantial discount to market prices. Energy and capacity from the "pool" thus created would be offered by the Commonwealth or its designee at below-market prices to selected businesses as an incentive to come to Pennsylvania, remain here, or expand their existing operations within the State.

Q. Please describe the scenario that would involve subsidizing the set-aside from PECO's allocable share of synergies from regulated operations.

A. The third full paragraph on the second page of Secretary McNulty's letter suggests that the "set-aside" proposal may be intended to capture a portion of the synergies that the merger will create. That paragraph states as follows:

> What synergies could result from the proposed merger and how can these synergies be harnessed for ordinary Pennsylvanians? Could the proposed merger enhance economic development? Does the divestiture of generation, especially the nuclear "virtual divestiture," present any opportunities?

The Joint Applicants have submitted a study that identifies and quantifies the net merger savings projected to be achieved by the regulated utility subsidiaries of the merger partners. The results of that study are described in the direct testimony of Mr. Arndt (PECO Statement No. 2). Under the third possible scenario, a portion of PECO's allocable share of the "regulated" merger synergies identified in Mr. Arndt's study would provide the funds needed to subsidize the acquisition of up to 245 MW of energy and capacity at the virtual divestiture auction-determined price by the Commonwealth or its designee, who would resell that power to selected business customers at below-market prices. To illustrate, if energy were purchased for $50 per MWH and sold to business customers at $45 per MWH, the difference of $5 per MWH would be subsidized by a portion of PECO's allocable share of "regulated" merger synergies.

Q. Are there obstacles to actually implementing a program like those outlined in each of the three scenarios?

A. Yes, there are. Other witnesses will address specific implementation issues, such as the need to assure that any sale, whether to the Commonwealth or its designee, would be within the terms of the FERC-approved mitigation plan. Additionally, I understand that specific legal issues concerning, for example, the Commission's jurisdiction and authority to establish a "set-aside" program, the authority of a department of the Commonwealth to purchase and sell electric power, possible conflicts with FERC's jurisdiction over wholesale sales of electricity and federal preemption, would be addressed in the Joint Applicants' brief. My testimony analyzes the proposal in light of broader principles of law and economics, including those discussed in detail in my rebuttal statement.

Q. Please provide an overview of your analysis of the three alternative scenarios.

A. My analysis identified four major issues that need to be addressed in connection with the proposal outlined in Directed Questions 3 and 4:

1. Does the proposal seek to capture, without compensation, a portion of the value of generating assets that belong to ExGen and, thereby, effect an unlawful taking of private property or a due process violation?
2. Does the proposal seek to benefit Pennsylvania preferentially by restraining the interstate purchase and sale of electricity in a manner that may violate the Commerce Clause of the United States Constitution?
3. Does the proposal to establish a "set-aside" program funded by ExGen or PECO represent a valid exercise of the Commission's regulatory powers, or is it a form of taxation and appropriation, which can be lawfully accomplished only with legislative authorization?
4. Does the kind of economic development proposal contemplated by Directed Questions 1 through 4 comport with the policy underlying, and the principles embodied in, the Competition Act or does it represent an unlawful effort to return, at least in part, to an era of state regulation of electric generation?

Q. Please address how the first issue may be implicated in each of the three scenarios.

A. The issue of unlawful taking is not presented by the Commonwealth-funded scenario because that alternative would involve a purchase and sale of capacity and energy at the virtual divestiture auction-determined price. By definition, ExGen would be compensated for the full economic value of the product it sells to the Commonwealth or its designee.

The ExGen-funded scenario would constitute an unlawful taking and due process violation because it would appropriate the value of a non-regulated enterprise to support the operation of a regulated business. That conduct is the same kind of regulatory action invalidated by the Supreme Court of the United States in *Brooks-Scanlon Co. v. Railroad*

Commission of Louisiana, 251 U.S. 396 (1920), which is discussed in my rebuttal testimony (pages 30-31).

As also discussed in my rebuttal testimony (pages 4-14, 26-32), the Competition Act restructured the rights and obligations of customers of regulated electric distribution service and the utilities that provide that service. Cost of service regulation of generation was terminated, and, since January 1, 1999, the risks and rewards of generation ownership are borne by shareholders. This realignment was confirmed by a corporate structural change. Specifically, the Commission granted express, unconditional approval for PECO to transfer its generating assets to ExGen and explicitly acknowledged that ExGen would not be subject to Commission regulation unless it made retail sales of electricity and, even then, it could be regulated only as an EGS.[4] Because the generation assets and the risks and rewards that attend their ownership were transferred to an entity the Commission does not regulate, the Commission cannot, consistent with due process, appropriate increases in the value of those assets whether those increases result from market forces or the "synergies" created by a merger.

The third possible alternative, subsidizing the proposed set-aside from a portion of PECO's allocable share of "regulated" synergies, may raise a "taking" or due process issue. Whether the issue is presented or not depends upon the reasonableness of appropriating some – or any – of the value generated by the merger in the regulated operations of PECO. Such a reasonableness determination necessarily involves the Commission's authority and discretion to set just and reasonable rates. If the appropriation of regulated synergies would prevent PECO from being able to earn a fair

[4] As the Commission is aware, ExGen has not made any retail sales of electricity.

return on its assets dedicated to public service, then the Commission's action would not be reasonable and might rise to the level of a "taking" or due process violation.

Q. Is a Commerce Clause issue implicated by any of the three scenarios?

A. It may be, because the stated purpose and possible effect of the set-aside proposal is to use state action to retain electricity for the exclusive benefit of customers located in Pennsylvania. As a consequence, that action may restrain trade in the interstate market for the purchase and sale of wholesale electric power depending upon how the hypothetical set-aside program would be structured.

Article I, Section 8, clause 3, of the United States Constitution grants the Congress of the United States the power "to regulate Commerce with foreign Nations, and among the several States." The Commerce Clause has been interpreted to imply a negative or "dormant" power prohibiting state action that, as described by the United State Supreme Court, "discriminates against or unduly burdens interstate commerce and, thereby, 'impedes free private trade in the national market place.' " *General Motors Corp. v. Tracy*, 519 U.S. 278 (1997) (quoting *Reeves, Inc. v. Stake,* 447 U.S. 429, 437 (1980)).

The ExGen-funded scenario would raise serious Commerce Clause concerns if it were to appropriate generation for the benefit of Pennsylvania customers to the detriment of the interstate market place for wholesale generation. Electricity generation is traded in an interstate market based on matching bids and offers. The exercise of state action to appropriate a slice of generation for use exclusively within Pennsylvania removes that power from the supply offered to all bidders in the market. One possible consequence of such a program is to drive up the average price of power to all other bidders, which include purchasers in states other than Pennsylvania. In that event, the overall effect would be to impede the operation of market forces and, by regulatory fiat, dictate an outcome beneficial to Pennsylvania and potentially detrimental to customers in other states that might not otherwise occur. That kind of state action is analogous to what the United States Supreme Court invalidated in *New England Power Co. v. New Hampshire*, 455 U.S. 331 (1982), where it held that New Hampshire's attempt to require a state-regulated utility to target hydroelectric power to in-state customers violated the dormant aspect of the Commerce Clause.

The Commonwealth-funded and PECO-subsidized scenarios would not raise Commerce Clause concerns if they were to simply make the Commonwealth or its designee a bidder, like any other, for the purchase of electric power up to 245 MW. However, if, in their implementation, these scenarios operated as a regulatory "thumb on the scale" to divert 245 MW of power to Pennsylvania that otherwise would be part of the overall supply available to all bidders in the interstate wholesale market, a Commerce Clause issue may arise.

Q. Would a program funded by ExGen or PECO be a valid exercise of regulatory power or is it a form of taxation and appropriation?

A. Such a program resembles the latter more than the former because the explicit purpose of such a program would be to appropriate value from ExGen or create a fund from merger synergies to be produced within PECO in order for the Commonwealth or its designee to obtain electric generation and provide it at below-market prices to selected business customers. This kind of program is qualitatively different from establishing special rates for "load retention" or to allow utilities to meet competitive alternatives, as the Commission did when the "bundled" rates of fully integrated electric utilities were subject to the Commission's ratemaking authority. In contrast to the authority exercised by the Commission before the enactment of the Competition Act, generation is no longer subject to cost-of-service regulation and, under the proposed economic development program, electric power would be obtained and distributed by arms of the State (or a non-governmental designee) other than the Commission. The establishment of such a program would appear not to be an exercise of ratemaking power. In any event, the Commission does not have regulatory jurisdiction or authority over ExGen or over wholesale generation pricing. In fact, ExGen is not even a party to this proceeding. Rather, it is an attempt to create a funding source for a program that the Commission believes may promote economic development within the State. The Pennsylvania Supreme Court disapproved similar action by the Commission in *Process Gas Consumers Group v. Pa. P.U.C.*, 511 Pa. 88, 511 A.2d 1315 (1986), where it held that revenue from surcharges on natural gas used as boiler fuel had to be accounted for through a reduction in the regulated rates of the natural gas utilities that imposed those surcharges and could not be appropriated for a state-wide conservation plan. The Court held that the Public Utility Code "does not empower the PUC to create funds or to mandate programs to utilize those funds." Notably, the Commonwealth-funded scenario would require the State to raise and appropriate funds to acquire capacity and energy for the program. The ExGen-funded and PECO-subsidized scenarios employ a formal device to try to evade that substantive requirement. *Process Gas Consumers* prohibits the Commission from doing indirectly what it cannot do directly, namely, appropriate funds for State programs without the required legislative approval.

Q. Does the economic development program outlined by Directed Questions 1 through 4 comport with the policy and principles of the Competition Act?

A. I do not believe so. Initially, it is important to examine what the Competition Act itself says about economic development. In the Declaration of Policy (Section 2801), the Act addresses the issues of economic development and the ability of the Commonwealth to "compete" for "industry and jobs:"

> (5) Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity.
>
> (6) The cost of electricity is an important factor in decisions made by businesses concerning locating, expanding and retaining facilities in this Commonwealth.
>
> (7) This Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs.

From the Declaration of Policy, it is clear that the introduction of competition in the electricity generation market was viewed by the Legislature as the primary tool for encouraging economic development and assuring that Pennsylvania could compete with other locales to attract and retain industry and jobs. The Legislature determined that the cost of electricity was significant to business decisions and that the best way to assure that the price of electricity in Pennsylvania would be competitive with other states was to "unbundle" electric rates, permit retail access to incumbent utilities' wires, remove generation from cost-of-service regulation, and, thereby, introduce competition in the retail market for electric generation. Stated differently, the deregulation of electricity generation and the creation of a competitive market was, itself, an economic development program that lay at the heart of the Competition Act.

The program for economic development proposed in Directed Questions 1 through 4 is not consistent with the policy and principles embodied in the Competition Act. The proposal would put the Commission – indirectly, if not directly – back into the business of regulating the price of generation for at least one segment of the customer base. The program would conflict with the state policy of the Competition Act because it would direct the Commonwealth to intrude in the operation of the competitive wholesale market for generation either as another purchaser or as the recipient of electricity generation (through a coerced transfer) at no cost or at below-market prices.

Nothing in the Competition Act suggests that the Legislature, in enacting the Competition Act, contemplated that the State would become an active player in the competitive market for the purchase and sale of generation. A reassertion of authority over the generation function, which the proposed program would entail, is so completely at odds with the policy and principles of the Competition Act that it should not be undertaken without clear legislative approval. In that regard, as explained by Mr. O'Brien (PECO Statement No. 1-DQ), it is noteworthy that the only neighboring state programs that, in any way, resemble the concept outlined in Directed Questions 3 and 4 are the Economic Development Power and Power For Jobs programs in New York. The New York programs are conducted by a state authority under specific enabling legislation. In addition, these programs employ energy and capacity purchased by the Power Authority of the State of New York at prevailing market prices, not power appropriated from private owners. Moreover, utilities are provided tax credits that fully compensate them for reductions in regulated delivery rates offered as part of these programs. Obviously, the legislatively authorized New York programs are much different from the regulatory construct proposed in the Directed Questions 1 through 4.

Q. Viewed in broader economic terms, would the generation "set-aside" program outlined in Directed Questions 3 and 4 yield net benefits for Pennsylvania?

A. In order for the set-aside program to yield a net benefit for Pennsylvania, the gains to the targeted constituency must exceed the losses to other identifiable groups in Pennsylvania. Otherwise, the set-aside would reduce economic welfare on an overall net basis for Pennsylvania and could not be justified under a public interest standard. The targeted constituency would consist of businesses that are (1) considering moving to Pennsylvania; (2) at risk of leaving; or (3) contemplating an expansion and would decline to locate or expand within the State or decide to leave unless they have the incentive provided by the set-aside program. At a minimum, the other affected groups in Pennsylvania would consist of:

1. All other electric customers, including other business customers in the state, who would conceivably pay more for electricity because a block of power was removed from the available supply;
2. Businesses in the State that compete with the favored constituency, who would be put at a competitive disadvantage because their competitor(s) received a non-market-determined price advantage for an essential service;
3. Marketers of retail electricity, because they would face the Commonwealth as a competitor for supplying retail electricity to businesses under circumstances where the Commonwealth can use the coercive power of government to obtain electric generation at lower cost than they can and potentially raise the price of the remaining available supply.

There is no evidentiary basis for assessing the relative magnitudes of the positive and negative effects, and there is no reason to assume that the benefits to the favored constituency would exceed the negative impacts to the other affected groups within

Pennsylvania. However, because the set-aside program would represent governmental intrusion in the operation of the free market for generation, it could inhibit the growth and vitality of the competitive market for retail generation in Pennsylvania. That likely effect is contrary to the legislatively determined policy underlying the Competition Act and, therefore, would have a net negative impact on Pennsylvania.

IV. CONCLUSION

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

PECO STATEMENT NO. 13-DQ

gk
9-22-05
Phila

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JOINT APPLICATION OF PECO ENERGY COMPANY AND PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE MERGER OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED WITH AND INTO EXELON CORPORATION	:	Docket No. A-110550F0160

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SUPPLEMENTAL TESTIMONY
OF
TODD J. JIROVEC

Concerning Directed Question No. 5
From Vice-Chairman Cawley and Commissioner Shane

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Date: August 26, 2005

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SUPPLEMENTAL TESTIMONY
OF
TODD J. JIROVEC

I. INTRODUCTION

Q. Please state your name, title and by whom you are employed.

A. My name is Todd J. Jirovec, and I am a Vice President with Booz Allen Hamilton. My business address is 901 Main Street, Suite 6500, Dallas, Texas 75202.

Q. Would you briefly summarize your academic and professional background?

A. I graduated from Arizona State University with a B.S. degree in Accounting and immediately joined Deloitte, Haskins & Sells, where I began my career as an auditor. Subsequently, I worked for Deloitte & Touche (formed by the merger of Touche Ross and Deloitte, Haskins & Sells in 1989). After working five years as a Certified Public Accountant, I obtained an M.B.A. from the Wharton School at the University of Pennsylvania and joined Deloitte Consulting in 1993 where I began my consulting career specializing in the utility industry. From 1998 to 1999 I was Vice President of Franchise Development for Koch Energy before rejoining Deloitte Consulting and then Booz Allen Hamilton (Booz Allen) as a Vice President.

Over the course of my consulting career, I have performed a variety of assignments that involved assisting managements of a number of electric and/or gas utilities in identifying merger and acquisition benefits and costs. This work has included screening analysis, review of corporate restructuring alternatives, assessment of merger-related cost reduction opportunities, development of regulatory strategies, planning and execution of merger integration, and assignment and allocation of costs and benefits related to mergers and acquisitions. My current resume is attached as Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to Directed Question No. 5 issued by Vice-Chairman Cawley and Commissioner Shane. Booz Allen has assisted PECO Energy Company (PECO), Public Service Electric and Gas Company (PSE&G) (the Joint Applicants) and their respective parent companies, Exelon Corporation (Exelon) and Public Service Electric and Gas Incorporated (PSEG), in analyzing the potential diseconomies that would occur from implementing the structural and ownership changes in the gas operations of the Joint Applicants and the Philadelphia Gas Works (PGW) proposed in Directed Question No. 5.

Q. How is your testimony organized?

A. Section I provides a brief summary of the conclusions reached from analyzing the changes in non-fuel costs that would result under two possible deal structures suggested by Directed Question No. 5, namely, a spin-off of the combined gas operations of PGW, PECO and PSE&G or an acquisition of PGW's gas business by Exelon Electric & Gas Company (EEG), the post-merger parent of PECO and PSE&G.

Section II explains the general approach used to analyze changes in non-fuel costs associated with the structural and ownership changes proposed in Directed Question No. 5. Section III discusses the cost changes identified and quantified for the spin-off scenario. Section IV discusses the possible cost changes that may result from the acquisition scenario and explains why a quantitative analysis could not be performed. Section V discusses other factors that would have to be taken into account in analyzing the consequences of each scenario.

Q. Please explain further the difference between the spin-off and acquisition scenarios that you identified previously.

A. Directed Question No. 5 states as follows:

> Would the combination of the PSE&G gas division and the PECO gas division with the Philadelphia Gas Works (PGW) provide critical mass for a viable, profitable, shareholder owned utility assuming a revenue stream from off system sales from an LNG facility, and separate resolution of the problem of a billion dollar debt?

Because Directed Question No. 5 did not indicate whether the "shareholder owned utility" would be an existing or new company, I considered two possible scenarios. Under the spin-off scenario, EEG would spin-off the PSEG and PECO gas divisions to create a stand-alone gas company (GasCo), the common stock of which would be held by the public. GasCo would then acquire PGW and integrate it with GasCo's comparable gas operations and corporate and administrative functions. Under the acquisition scenario, EEG would acquire PGW, integrate PGW's gas operations with the gas divisions of PSEG and PECO and integrate PGW's corporate and administrative functions with EEG's comparable functions.

II. SUMMARY OF CONCLUSIONS

Q. What conclusions have you reached concerning a combination of the PECO/PSE&G gas divisions with PGW under each alternative scenario?

A. Under the spin-off alternative, the corporate separation of the Joint Applicants' gas operations and the need to establish a stand-alone business organization would result in lost economies of approximately $250 million per year. While modest scale economies could be achieved by combining the gas operations of PGW with those of the Joint Applicants, they would be negligible in comparison to approximately $250 million of diseconomies that would result from carving out the Joint Applicant's gas operations from their existing corporate structures.

An acquisition of PGW's gas assets and business by EEG would produce savings through standardizing and integrating processes and eliminating the resulting duplication and redundancy. These savings would be offset by costs-to-achieve and by increased costs resulting from the de-municipalization of PGW, which would include the end of exemptions from federal and state taxes and the loss of the ability to raise capital by issuing debt for which the interest is not subject to federal or Pennsylvania income tax. As a consequence, it is difficult to discern whether net savings would result and, if so, whether they would be material. A quantitative analysis of net merger savings has not been presented because a synergy analysis similar to the one conducted for the Exelon-

PSEG merger requires a cooperative working relationship between the likely merger partners with access to information that is not generally available from public sources. Neither of those conditions was present here.

Finally, there are cost factors in addition to lost economies and possible merger-related savings that would need to be considered. These include differences in rates, PGW's bad debt exposure, PGW's significant capital investment needs and salary and wage differentials. All of these factors would erode shareholder value and increase customer costs for the combined entity under either scenario.

III. APPROACH TO ANALYSIS

Q. **Please describe generally the approach used to evaluate each scenario?**

A. I was able to use existing analyses as reference points for assessing the two scenarios. The synergy analysis of the Exelon-PSEG merger discussed in Mr. Arndt's testimony (PECO Statement No. 2) provided information on the baseline staffing and cost structures for those companies on both a pre-merger and post-merger basis. Booz Allen assisted in preparing the synergy study, and, therefore, I am familiar with the methodology and data employed in that analysis.

As the principal basis for assessing the spin-off scenario, I employed a recently completed gas separation analysis prepared to meet the requirements of the Public Utility Holding Company Act (PUHCA) for Securities and Exchange Commission (SEC) approval of the proposed merger. The separation analysis quantifies the cost impacts of separating the PECO and PSE&G gas divisions into a separate, stand-alone gas company. Booz Allen was primarily responsible for the preparation of the gas separation analysis, and, therefore, I am familiar with the methodology and data it employed and the results it produced.

As I previously explained, a quantitative analysis of the acquisition scenario has not been presented because it would entail a close working relationship between the managements of the merger partners, access to personnel within PGW that have detailed operational knowledge of its business, and the use of non-public information that is not available to PECO. The non-quantitative assessment that is discussed later in my testimony is based on publicly-available information such as PGW's annual reports, press releases and Pennsylvania Public Utility Commission (PUC) filings and reports.

IV. SPIN-OFF SCENARIO

Q. Briefly describe how you approached your analysis of the spin-off scenario.

A. Under the spin-off scenario, the gas operations of PSE&G and PECO would be transferred to GasCo, and the common stock of GasCo would be distributed to the shareholders of EEG or sold in a public offering. The newly-formed GasCo would then acquire the assets and business of PGW. The analysis of this transaction considered the effects on annual operating costs of disaggregating the gas divisions from the existing integrated utilities of which they are a part. As explained below, the diseconomies of such a separation are substantial. I also considered the fact that the combination of PGW with GasCo would produce savings as compared to PGW's existing status as an independent gas utility. However, I did not conduct a quantitative analysis of such savings, which was not possible for all of the same reasons discussed in Sections II and V in connection with the acquisition scenario.

Q. What is the economic effect of transferring the Joint Applicants' gas businesses to GasCo?

A. Spinning-off the Joint Applicants' gas businesses into GasCo would create significant diseconomies and cause operating costs to increase relative to the current organizational and cost structures. The gas operations of PSE&G and PECO would lose the labor and non-labor benefits they currently receive from being part of a much larger organization and the benefits of being able to participate in an efficient shared-services business model with the Joint Applicants' other business lines. Furthermore, the gas operations of PECO and PSE&G have service territories that overlap with their respective electric service areas. This common customer base allows PECO and PSE&G to achieve economies of scale in the areas of customer service, meter reading, bill processing, and field operations. In addition to increased operating costs, the creation of GasCo and related mergers and/or asset transfers would generate considerable transaction costs.

Q. Have the diseconomies resulting from a spin-off scenario been quantified?

A. Yes, they have. The separation study that Exelon and PSEG are filing with the SEC to satisfy PUHCA requirements analyzes the economic consequences of disaggregating the PECO and PSE&G gas divisions and operating them as a separate, stand-alone business. That analysis shows that, as compared to their existing, pre-merger costs, the revenue requirement of the stand-alone business would increase by approximately $250 million per year. To put that figure in perspective, it represents approximately 23% of the current combined non-fuel revenue requirement of PSE&G's and PECO's gas divisions. Moreover, comparing the stand-alone scenario to current revenue requirements does not take into account the reduction in current gas division costs that the savings from the merger of Exelon and PSEG will produce, which would make the diseconomies of divestiture even greater.

In addition, the separation of the gas divisions would also have an adverse effect on the cost of providing electric service because PECO's and PSE&G's electric divisions would also lose the economies that result from sharing a common customer base with their corresponding gas operations. The diseconomies that would be experienced by PECO's and PSE&G's electric divisions as a consequence of a gas divestiture were also identified and quantified in the gas separation analysis and consist of an increase in annual operating expenses of approximately $160 million.

Q. Would the diseconomies created by separating the PECO and PSE&G gas divisions be offset by economies created by combining PGW with GasCo?

A. No. The business structure that would have to be established by GasCo to accommodate the PECO and PSE&G gas divisions would be large enough so that, if PGW were rolled into GasCo, savings could be achieved. The combination would produce duplication and redundancies that could be eliminated, with resulting cost savings. However, for the reasons previously discussed, it was not possible to quantify those savings. In any event, the potential savings would be far less than the $250 million of gas utility diseconomies and $160 million of electric utility diseconomies identified and quantified in the gas separation study. PGW's current non-fuel operating and maintenance expenses total approximately $240 million. Consequently, even if the combination of PGW and GasCo could eliminate PGW's non-fuel operating and maintenance expenses in their entirety – a clearly impossible result – the transaction overall would have a net negative outcome.

V. ACQUISITION SCENARIO

Q. Briefly describe how you approached your analysis of the acquisition scenario.

A. Under the acquisition scenario, EEG would acquire the assets and business of PGW. EEG would absorb PGW into its post-merger management structure, which would result in adding only those incremental costs required to operate the combined businesses. Because their service areas are contiguous, PECO and the former PGW gas business would consolidate the management of their utility support functions and consolidate field operations where possible. Additionally, the corporate and administrative functions of PGW would be incorporated into EEG's corporate and shared services organizations.

Q. Would the acquisition be likely to produce savings as compared to PGW's existing cost structure?

A. Yes, it would. Because of EEG's post-merger size and scale, less than all of PGW's current staffing and costs would be required to effectively operate and manage PGW's gas business as part of the combined enterprise.

Q. In what areas could savings be expected?

A. Cost savings could be expected in corporate and utility support staffing, corporate programs, information technology (IT), supply chain and non-labor utility support.

Q. What savings are included in these areas?

A. **Corporate And Utility Support Staffing**. Reductions in corporate and utility support staffing would be achieved by eliminating positions that perform duplicative functions. At the corporate level, likely candidates for the consolidation of functions and resulting staff reductions would be in the areas of executive management, legal, finance, regulatory affairs, human resources, IT, communications, procurement and general administration. At the utility level, likely candidates for the consolidation of functions and staff reductions would be in the areas of customer service, gas operations, customer billing and similar back-office functions. In the utility support category, the areas of likely consolidation and reduction would include system planning, engineering and gas procurement.

Corporate Programs. Corporate program costs consist of non-labor costs in areas such as corporate governance, corporate facilities, insurance, auditing and consulting services. Savings in this area could be achieved by eliminating redundancies and capturing economies of scale.

IT. Savings in IT costs may be achieved by creating a single IT organization and standardizing platforms and applications, thereby reducing licensing, maintenance and consulting costs.

Supply Chain. Supply chain savings would likely be available by eliminating duplicative services, adopting best procurement practices and increasing purchasing power.

Non-Labor Utility Support. In non-labor utility support, potential savings opportunities would include consolidating service buildings and warehouses, consolidating vehicle fleets and standardizing metering technology.

Q. Are there possible constraints on achieving savings in one or more of the areas you outlined?

A. Yes. The principal limiting factor would be an inability to reduce positions that are covered by collective bargaining agreements. Because a large proportion (in excess of 75%) of PGW's employees are represented by collective bargaining units, restrictions on employee terminations would limit the level of savings that could be achieved. I have not had the opportunity to review PGW's collective bargaining agreements to determine if any such restrictions are currently in place. If those types of restrictions do exist, they would significantly reduce potential synergies because, in our experience, staffing savings traditionally account for approximately 50% of overall merger/acquisition – related savings.

Q. Would EEG incur costs to achieve the savings you outlined?

A. Yes, for each of the areas I discussed, it would be reasonable to expect that significant costs to achieve would be incurred. Costs-to-achieve would be incurred for, among other things, employee severance, IT standardization, customer education programs and legal, regulatory and financial transaction costs.

Q. Did you quantify either the likely savings or costs-to-achieve for an acquisition of PGW by EEG?

A. No, I did not. The process of identifying and quantifying such savings and costs requires management personnel of both the acquiror and acquired businesses to work closely together to identify baseline staffing and cost levels, analyze processes and determine how the post-acquisition business will be staffed and operated. It also requires access to substantial amounts of non-public information that a business may be unwilling to reveal until both sides are committed to a process that is likely to lead to an agreement. None of that is present here and, therefore, it is not possible to perform a synergy study like the one presented by Mr. Arndt for the Exelon-PSEG transaction. The assessment of the acquisition scenario discussed above was done at a high level using only publicly available information.

Q. In addition to the possible savings and costs-to-achieve that you previously discussed, are there other factors that could impact, and offset, the net savings potential of the acquisition scenario?

A. Yes, there are other impacts and costs, which are common to both the acquisition and spin-off scenarios, that would erode the savings potential of the acquisition scenario and add to the costs of the spin-off. These are discussed below.

VI. OTHER IMPACTS AND COSTS

Q. Please discuss the other factors that could increase the costs of GasCo or EEG if either were to acquire PGW?

A. One very significant factor derives from the fact that PGW is a municipally owned and operated utility system. As such, it is not subject to federal income tax, taxes imposed by Pennsylvania on comparable businesses conducted by for-profit enterprises (capital stock tax, corporate net income tax and Public Utility Realty Tax), or various municipal taxes. In addition, PGW currently has the ability to issue debt the interest on which, when received by a taxpaying individual or entity, is not subject to federal or Pennsylvania income tax. Typically, the coupon rate on tax-free debt is appreciably less than the coupon rate on taxable debt of comparable duration.

Q. Are there other factors that could affect post-acquisition costs?

A. Yes. These fall into three major areas: capital structure, salary and wage differentials, and capital expenditures.

Q. Please explain how capital structure could affect costs.

A. Currently, PGW's capital structure consists of 85% long-term debt. PGW's assets and business, if held by a private for-profit company, would require a substantially higher equity component. Since equity typically bears a higher pre-tax cost than debt, this factor would tend to make post-acquisition capital costs higher.

Q. How would salary and wage differentials affect costs?

A. Based on my review of publicly available information, it appears that PGW's salary and wage scale across comparable positions is lower than PECO's or PSE&G's. This disparity would impede the integration of PGW and would have to be reduced, and eventually eliminated, over a reasonable timeframe. The net impact would be an increase in costs that would erode the savings of the acquisition alternative and increase the net cost of the spin-off scenario.

Q. Why would capital expenditures increase?

A. PECO, PSE&G and PGW have cast iron mains that need to be replaced with mains of modern material. Each entity has a main replacement program in place. However, approximately 55% of PGW's mains are cast iron, while the corresponding figures for PECO and PSE&G are approximately 14% and 29% respectively. Given that disparity, the PGW program may have to be adjusted to increase capital expenditures over current levels.

Q. Are there other aspects of an acquisition by GasCo or EEG that would have to be considered?

A. Yes, there are. The non-fuel portions of PGW's rates are significantly higher than those of PECO or PSE&G. While these rate differentials reflect possible differences in a number of cost areas, the most significant cost difference appears to be in uncollectible accounts. PGW's uncollectible accounts expense is currently running at 9% of billed revenue. Even its stated goal of reducing uncollectibles to 7-8% of billed revenue is far above that of other gas utilities. In contrast, uncollectible accounts expense for PECO's and PSE&G's gas divisions is approximately 1.0% of billed revenue. The disparity in rates and the significant difference in uncollectible accounts expense would make it difficult to migrate Pennsylvania jurisdictional customers to a common set of rates, if consolidation of the PECO and PGW rate structures were contemplated. On the other hand, if the PGW system were to be operated as a separate subsidiary or separate rate zone, some of the potential savings of combining PGW with either EEG or GasCo would be lost.

Q. Are there risks and uncertainties that would have to be considered and addressed in either a GasCo or EEG acquisition?

A. Yes, there would be. These would include the range of risk factors that the acquisition due diligence process is designed to identify and assess, such as environmental risks and risks associated with the age and condition of existing gas infrastructure. These additional risk factors are discussed by Mr. O'Brien in his testimony on the Directed Questions (PECO Statement No. 1-DQ).

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

RESUME
OF
TODD J. JIROVEC

TODD J. JIROVEC

Mr. Jirovec is a Vice President of Booz Allen Hamilton's Energy & Utilities Practice, based in the Firm's Dallas, Texas office. Mr. Jirovec has more than 10 years of consulting experience in assisting clients in the Energy Industry. He has directed numerous engagements in the areas of strategy development, corporate growth, organizational restructuring, operational improvement, financial management and regulatory strategy and assistance.

He has been involved in the many of the power and gas mergers in the United States having led or participated in ten publicly announced transactions. He has also worked with a number of private equity participants on the assessment, modeling and operations transfer of acquisitions related to generation, transmission and distribution assets or segments.

Representative Consulting Experience:

Booz Allen Hamilton Oct. 2004 – Present
Deloitte Consulting 1993 – 1997; Apr 1999 – Sept. 2004

Mergers and Acquisitions: Directed over 100 merger, acquisition, carve-out, spin, and sell-side assistance projects related to mergers of equals, unsolicited tenders, buy-side investment assistance, joint ventures and alliances. The related scope of activities included identification of potential targets, quantification of operational cost synergies, development of revenue enhancement opportunities, financial modeling, development of potential regulatory alternatives, evaluation of customer and shareholder impacts, bid assistance and development of negotiation strategies.

Merger Integration Planning: Directed numerous post-merger integration planning assignments, including developing the strategic framework, defining the integration process, managing integration teams, establishing the governance processes, capturing or meeting revenue targets, managing boundary issues across function and processes, and guidance through the regulatory approval process.

Business Transformation: Led business transformation initiative focused on identifying process and performance improvement opportunities for transmission and distribution, shared services, human resources, and information technology business units. Scope included development of end to end process framework, governance structure, program methodology, and center of excellence creation. Activities included operational improvement, process redesign and alignment, program management assistance, and executive alignment.

Corporate Strategy: Directed multiple corporate strategy projects focused on identifying growth strategies and opportunities consistent with existing portfolio businesses and client capabilities and competencies. Analysis has included evaluation of target segments, assessment of business model requirements, financial feasibility, shareholder value impacts, and implementation strategies.

Performance Improvement: Led multiple assignments related to identifying, quantifying, and realizing benefits from performance improvement and cost reduction within utility companies. These projects have focused on organizational modeling, cost and staffing benchmarking, performance target establishment, and implementation planning.

Prior Experience

Koch Energy - 1998 – 1999
Vice President of Franchise Development
Responsible for midstream gas acquisitions, asset trading, and acquisition integration. Led teams in the identification, evaluation, due diligence, and structuring of potential acquisitions and asset trades. Assisted in development of growth strategies for midstream gas business.

Deloitte & Touche - 1986 – 1991
Audit Manager
Led teams in design and execution of financial audits. Experience primarily in public utilities, savings and loan institutions and real estate companies. Supervised audit engagements including one of the Firm's ten largest financial institution and public utility clients. Determined asset valuation for a financial institution using discounted cash flow analysis to estimate properties' net realizable value. Assisted a financial institution client with financial transactions including securitization of manufactured housing loans, branch network sales, and debt and equity issues.

Education

M.B.A. Wharton School, University of Pennsylvania, 1993

B.S. Accounting, Arizona State University, 1986

Certified Public Accountant, Arizona