

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Exelon Corporation)
) **Docket No. EC05-____-000**
Public Service Enterprise Group Incorporated)

**JOINT APPLICATION
FOR APPROVAL OF MERGER**

**PREPARED DIRECT TESTIMONY AND EXHIBITS OF
WILLIAM H. HIERONYMUS
ON BEHALF OF EXELON CORPORATION**

**DIRECT TESTIMONY OF
WILLIAM H. HIERONYMUS**

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1 **I. PURPOSE, SUMMARY OF ANALYSIS AND CONCLUSIONS**

2 **Introduction**

3 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 A. My name is William H. Hieronymus. I am a Vice President of Charles River Associates
5 Incorporated. My business address is 200 Clarendon Street, T-33, Boston, MA 02116.

6 **Q. PLEASE SUMMARIZE YOUR RELEVANT PROFESSIONAL BACKGROUND.**

7 A. For the past 30 years, the primary focus of my consulting has been on the electricity sector.
8 For the past 17 years, I have worked primarily on the restructuring of the electricity
9 industry from a fully regulated to a more competitively oriented model, both in the U.S.
10 and abroad. Much of my time has been spent on market power issues. I have developed
11 and commented on market power-related regulatory rules and Regional Transmission
12 Organization (“RTO”) (or foreign equivalent), on market power mitigation as well as on
13 issues of market structure. I have testified before the Federal Energy Regulatory
14 Commission (“Commission”) and other regulatory bodies on market power on numerous
15 occasions. This includes a number of mergers and acquisitions over the past dozen years,
16 including approximately 20 mergers among electric utilities and “convergence” mergers of
17 electric utilities and natural gas pipelines. Among these, I was the market power witness in
18 Docket No. EC00-26-000, the merger of Unicom and PECO that formed Exelon
19 Corporation. My resume is attached as Exhibit J-2.

20 **Purpose**

21 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

22 A. I have been asked by Exelon Corporation (“Exelon”) and all its jurisdictional public
23 utilities¹ to evaluate the potential competitive impact of the merger of Exelon and and

¹ These include, among others, PECO Energy Company (“PECO”), Commonwealth Edison Company (“ComEd”), and Exelon Generation Company, LLC (“Exelon Generation”).

1 Public Service Enterprise Group Incorporated (“PSEG”) and all its jurisdictional public
2 utilities² (collectively, Exelon and PSEG are referred-to as the “Applicants”) (creating
3 Exelon Electric & Gas, or “EEG”) on relevant electricity markets.³ I performed the
4 Competitive Analysis Screen described in Appendix A to the Commission’s Merger
5 Policy Statement (“Order No. 592”),⁴ as modified in the Revised Filing Requirements
6 Under Part 33 of the Commission’s Regulations.⁵ The Competitive Analysis Screen is
7 intended to comport with the Department of Justice and Federal Trade Commission
8 (“DOJ/FTC”) Horizontal Merger Guidelines (“Guidelines”). I also have analyzed other
9 electricity-related product markets (*e.g.*, ancillary services and capacity). I further
10 provide analyses to show that the proposed mitigation cures all screen failures in all
11 relevant markets.

12 The primary focus of my testimony is potential horizontal market power effects, *i.e.*,
13 those arising from the combination of the electric generating assets owned or controlled
14 by Exelon Generation and its affiliates and those owned or controlled by PSEG Power
15 and its affiliates that potentially could create or enhance the merged firm’s ability to
16 increase prices in the electricity market. I also address vertical effects concerning
17 barriers to entry that might undercut the presumption that long-run generation markets are
18 competitive and, more generally, the potential to use control over fuel supply, fuel
19 transportation facilities, or electric transmission to exert vertical market power by
20 increasing rivals’ costs.

² These include, among others, Public Service Electric and Gas Company (“PSE&G”) and PSEG Power LLC (“PSEG Power”).

³ The exhibits to the Application include a complete list of Applicants.

⁴ Order No. 592, *Inquiry Concerning the Commission’s Merger Policy Under the Federal Power Act: Policy Statement*, FERC Stats. & Regs. (Regulations Preambles) ¶ 31,044 (1996), *on reconsideration*, Order No. 592-A, 79 FERC ¶ 61,321 (1997).

⁵ Order No. 642, Final Rule in Docket No. RM98-4-000, 18 CFR Part 33, 93 FERC ¶ 61,164 (2000) (“Revised Filing Requirements”).

1 **Summary of Analysis and Conclusions**

2 **Q. DOES YOUR ANALYSIS INDICATE THAT THE MERGER RAISES**
3 **COMPETITIVE CONCERNS?**

4 A. Once the proposed mitigation is taken into account, the merger does not raise competitive
5 concerns. While the merging parties are each significant participants in energy markets
6 in PJM Interconnection, L.L.C. (“PJM”), and particularly in PJM East,⁶ where both
7 PECO and PSE&G are located, Applicants have committed to a comprehensive
8 mitigation plan that eliminates any merger-related competitive concerns that otherwise
9 would be present. Also, a combination of market and regulatory conditions, technical
10 operating constraints, and ongoing contractual commitments of the Applicants further
11 limit any ability to exercise market power. My analysis focuses on expected market
12 conditions in 2006.

13 Market and regulatory conditions. PJM operates the largest centrally dispatched,
14 competitive wholesale electricity market in the United States. The market is well-
15 functioning, and has in place comprehensive and Commission-approved market
16 monitoring and mitigation procedures that mitigate concerns about generation and
17 transmission market power. The PJM market monitor has the authority to deter, and has
18 been effective in deterring, withholding or other attempts at market manipulation.
19 Notably, the operation of PJM mitigation is essentially automatic whenever sub-areas
20 within PJM are constrained.

⁶ For purposes of my testimony and analysis, I refer to a number of variants of PJM. I use *PJM Mid-Atlantic* to refer to the original PJM, *PJM Pre-2004* to refer to original PJM members in the Mid-Atlantic Area Council (“MAAC”) plus Allegheny Energy. This is the geographic area that PJM today treats as seamless for capacity market purposes. Further, according to the State of the Market report, inclusion of APS has led to a substantial reduction in congestion between APS and the remainder of PJM, effectively moving the constraint further west. *Expanded PJM* refers to the combination of PJM Pre-2004 plus the new members, namely ComEd, AEP, Dayton Power & Light and Duquesne (all of which have integrated into PJM during 2004 and 2005), and Dominion Virginia Power (“DVP”), which is expected to integrate into PJM in 2005. The Mid-Atlantic portion of PJM, at times, has been characterized as having three submarkets reflecting the predominant west-to-east energy flow and the three high-voltage interfaces within the region: West, Central and East. These are referred to as PJM West, PJM Central and PJM East, respectively. However, West and Central are not treated as markets themselves, but are aggregated with markets to the east of them.

1 Technical operating constraints. A significant portion of Applicants' combined
2 generation portfolio in PJM consists of nuclear generation and, to a lesser extent,
3 baseload coal generation. As the Commission has recognized, the operating
4 characteristics and regulatory oversight of nuclear units make them poor choices for
5 withholding of output or other strategic bidding behavior, and the large amounts of
6 competing low-cost coal capacity in the region make the profitability of withholding coal
7 units unlikely.⁷

8 PECO and ComEd's continuing load and contractual commitments. All of PECO's retail
9 electric customers have the right to choose a generation supplier.⁸ Under the terms of a
10 settlement, PECO's distribution rates are capped through December 31, 2006, and
11 generation rates are capped through December 31, 2010. PECO meets its continuing load
12 obligations through a full-requirements, Power Purchase Agreement ("PPA") with
13 Exelon Generation. In 2003, PECO's peak load obligations were 6,531 MW, and its
14 forecast peak load requirements for 2006 are 8,033 MW.⁹ Thus, of Exelon Generation's
15 approximately 11,000 MW of generation located in the Mid-Atlantic portion of PJM
16 (prior to merger-related divestitures), the majority is committed to serving native load
17 through 2010. At least through 2010, Exelon Generation perhaps has only a few
18 thousand megawatts of "excess" generation in respect of its PECO load.

⁷ See *Ohio Edison Co.*, 94 FERC ¶ 61,291 (2001), citing *Commonwealth Edison Co.*, 91 FERC ¶ 61,036 (2000).

As we stated in *Commonwealth Edison*, 91 FERC ¶ 61,036 at 61,134 n.42 (2000), it is difficult to engage in strategic dispatch of nuclear units, given their operating characteristics and stringent regulatory oversight. Further, it is likely that the opportunity cost associated with the merged firm shutting down its coal-fired units during off-peak periods in order to drive up the market price would outweigh the potential profit. Moreover, due to the large amount of low-cost capacity in the region, Applicants would have to withhold a significant amount of capacity in order to drive up the market price during the off-peak period.

The Commission recently reiterated its view with respect to the strategic dispatch of nuclear generation in *USGen New England, Inc.*, 109 FERC ¶ 61,361 (2004).

⁸ As of January 1, 2005, approximately 7 percent of its customers (10 percent of customer load) was served by an alternative supplier. These customers continue to pay a delivery charge to PECO.
<http://www.oca.state.pa.us/cinfo/stats0105.pdf>

⁹ This peak load forecast is for PECO's load responsibility only, and does not include customers who are expected to have alternative suppliers. The high growth rate arises from the return of customers that PECO had

1 ComEd also continues to have provider of last resort (“POLR”) responsibilities that
2 continue at least to the end of 2006.¹⁰ ComEd secures generation supply to serve its
3 POLR responsibilities through a full-requirements contract with Exelon Generation.
4 ComEd’s three wholesale (full or partial) requirements customers are served under fixed-
5 price contracts that run through 2007, and its retail customers have frozen bundled rates
6 through 2006. Exelon Generation has about 15,000 MW of owned generation and
7 purchase contracts to serve ComEd’s expected approximately 18,000 MW of load in
8 2006. Thus, at least through 2006, Exelon has virtually no “excess” generation in respect
9 of its ComEd load requirements.

10 In any event, Exelon has committed to hedge a minimum of 90 percent of its generation
11 portfolio in the forward market. Moreover, for purposes of my analysis, I focus on
12 Economic Capacity, that is, I ignore load or contractual commitments.

13 PSEG Power’s load and contractual commitments. PSE&G procures resources to serve
14 its load via the New Jersey Basic Generation Service (“BGS”) auctions. Contracts have
15 been secured to serve load in rolling three-year tranches, some of which extend into 2007.
16 Affiliates of PSE&G participate as suppliers in the BGS auction, and are responsible for
17 the supply of approximately 4,200 MW for the period June 2005 to June 2006 and 1,700
18 MW for the period June 2006 to June 2007, either directly as a winner in the BGS auction
19 or indirectly as a supplier to other winners in the BGS auction. Additionally, PSE&G
20 affiliates are serving 275 MW of Duquesne POLR load through May 2006 and have sold
21 500 MW of firm energy to FirstEnergy through 2008. Given PSEG Power’s
22 approximately 12,000 MW of generation in the Mid-Atlantic portion of PJM (prior to
23 merger-related divestitures), these commitments reduce its uncommitted capacity to
24 about 7,000 to 10,000 MW in 2006. Moreover, it is likely that PSEG will secure further
25 commitments during the 2005 New Jersey BGS auction. Indeed, PSEG’s publicly-stated

auctioned off to third-party retail suppliers pursuant to decisions by the Pennsylvania Public Utility Commission (“PAPUC”).

¹⁰ In Illinois post-2006, it is expected that ComEd’s power procurement to meet its POLR obligations will be subject to a competitive auction similar to the auction that is in place in New Jersey.

1 policy is to hedge a minimum of 75 percent of its portfolio 18 to 24 months in advance.
2 As with Exelon, for purposes of my Economic Capacity analysis, I ignore PSEG's load
3 and contractual commitments.

4 Applicants have committed to undertake a comprehensive series of measures to address
5 market power concerns arising from this merger and to further enhance competition in
6 PJM markets. I considered three relevant geographic markets within PJM: PJM East,
7 PJM Pre-2004, and Expanded PJM.¹¹ Table 1 ~~Table 1~~ below summarizes the mitigation
8 commitment in terms of equivalent capacity (summer ratings). No additional mitigation
9 is required for Expanded PJM since the mitigation in the smaller markets also cures
10 screen failures in this market.

11 **Table 1: Mitigation Commitments (MW)**

Generation Type	PJM East	PJM Mid-Atlantic*	Total
Nuclear	2,400	200	2,600
Mid-Merit**	1,900	0	1,900
Peaking	1,000	0	1,000
Total	5,300	200	5,500

* The additional 200 MW of commitment can be delivered anywhere in PJM Mid-Atlantic, including PJM East.
** At least 550 MW of the mid-merit divestiture will include coal-fired capacity. Also, within the mid-merit category, 1,200 MW must be economic at a \$55/MWh market price.

12
13 There are two key elements of Applicants' mitigation plan: (1) divestiture of substantial
14 coal, mid-merit and peaking capacity, and (2) virtual divestiture of nuclear baseload units
15 through a combination of a) long term energy sales contracts or swaps with parties that
16 do not have significant generating assets in PJM and b) an auction of rolling three-year
17 firm contracts. To the extent nuclear baseload capacity in PJM East is divested or
18 decommissioned the virtual divestiture requirement will be reduced equivalently.
19 Applicants also have committed to mitigation measures in the PJM capacity markets.

¹¹ As discussed *infra*, there are no other relevant markets within PJM in the context of this transaction. I considered whether Northern New Jersey, or the Northern PSEG zone, is a relevant market and concluded that since Exelon owns no generation within its boundaries, it is not a relevant market.

1 Interim mitigation measures are proposed that will assure that market power potentially
2 arising from the merger will not be exercised during the period before divestiture can be
3 completed.

4 *Virtual Divestiture.* Applicants have committed to divest control over 2,600 MW of
5 nuclear capacity through a combination of three year auctions of rights to the output (the
6 Baseload Auction) and Long-Term Contracts. No single party will be eligible to
7 purchase more than half of the 2,600 MW. Details of the proposed options are discussed
8 in Mr. Cassidy's testimony. Under the Baseload Auction, Applicants will auction the
9 firm energy equivalent of 2,400 MW of nuclear baseload capacity as firm energy (24x7)
10 in 25 MW blocks delivered in PJM East (at an aggregate of Applicants' PJM East nuclear
11 generation buses) for a rolling three-year period. An additional 200 MW of equivalent
12 capacity will be subject to the Baseload Auction (or the Long-Term Contract), but may
13 be delivered at the PJM West Hub, unless seller agrees to an alternate delivery point
14 within PJM. In the initial auction, one-third of the mitigation amount will be sold for a
15 one-year term, one-third for a two-year term, and one-third for a three-year term. In
16 subsequent annual auctions, one-third of the mitigation amount will be sold for a three-
17 year term. The timing of the auction will coincide with the New Jersey BGS auction, in
18 order to facilitate competition in that auction.

19 Under the Long-Term Contract, Applicants will sell 15-year or longer entitlements to
20 PJM East baseload energy (or swap PJM East baseload energy for baseload energy in a
21 non-PJM market). Two alternative products will be available under this option. The first
22 mirrors the Baseload Auction (*i.e.*, it is a firm 7X24 product), except that the term is for a
23 minimum of 15 years following the close of the merger. The alternate product replaces
24 the firm 24X7 must-take energy product delivered at the aggregate of Applicants' PJM
25 East nuclear generation buses with a guarantee of delivery based on the performance
26 characteristics of a designated PJM East nuclear facility. Applicants will guarantee
27 delivery of an annual amount of energy based on the designated facility's historical
28 capacity factor, and the contract will be for the lesser of the term of the contract (*e.g.*, 15
29 years) or the date that the unit is decommissioned. Any permanent plant deratings will be
30 reflected in the contract terms. This alternate product will facilitate an energy swap

1 agreement, if Applicants choose that option. The amount of a contract with any single
2 party will be no more than one-half of the virtual divestiture amount. Additionally,
3 suppliers with a market share of 5 percent or more of capacity in either PJM East or
4 Expanded PJM will not be eligible for such bilateral contracts, nor will suppliers with
5 market shares between 3 and 5 percent be permitted to purchase, in aggregate, more than
6 25 percent of the capacity to be divested or sold under long-term contract.

7 Mitigation will continue subject to the condition that the virtual divestiture requirement
8 will be extinguished, megawatt for megawatt, to the extent that Applicants' PJM East
9 nuclear capacity is decommissioned, derated or sold, and to the extent that new
10 transmission capacity is constructed into PJM East that is not reflected in PJM's
11 transmission expansion plan in the PJM Regional Transmission Report that is in effect as
12 of June 2005.¹²

13 The virtual divestiture will eliminate any Competitive Analysis Screen failures during
14 off-peak periods¹³ and will eliminate any increased incentives that the merged company
15 theoretically would have to economically or physically withhold non-nuclear generation
16 arising from retained ownership of the nuclear facilities underlying the virtual divestiture.

17 There is ample Commission precedent that generation divestiture is an acceptable form of
18 mitigation. While there is no similar precedent for the virtual divestiture, virtual
19 divestiture has all of the key elements necessary to make it an adequate alternative to
20 physical divestiture. Further, while both the Commission and the antitrust agencies have
21 expressed a clear preference for mitigation in the form of a permanent structural change
22 (*e.g.*, divestiture), in this instance the virtual divestiture of baseload nuclear capacity is an
23 economic solution that achieves the same effect without undercutting the operational
24 efficiencies expected to be achieved by combined ownership of the nuclear units. Indeed,
25 increasing nuclear output will have a small but significant tendency to lower wholesale

¹² As the Commission found in *Oklahoma Gas and Electric Company and NRG McClain LLC* (Docket No. EC03-131-000), transmission enhancements that restore the amount of competing supply to pre-acquisition levels are an appropriate structural remedy for acquisitions that fail the horizontal market power screen.

¹³ The results of the Competitive Analysis Screen are discussed in detail below.

1 prices. This is because increasing the amount of energy at "the bottom of the stack" will
2 in at least some hours lower the PJM marginal cost. All else being equal, therefore, this
3 should lower LMP (*i.e.*, Locational Marginal Price) prices, particularly in PJM East.

4 From the perspective of the Competitive Analysis Screen, the generation previously
5 attributed to Applicants properly is attributed to parties winning the auction because it is
6 the buyer, not the seller, that would determine to whom and where the energy is sold.
7 The virtual divestiture – because of its firm delivery obligation – will eliminate
8 Applicants' ability to withhold this nuclear energy from the market. Further, as noted
9 earlier, the Commission already has recognized the sharply reduced ability or incentive to
10 withhold nuclear energy from the market.

11 Importantly, the virtual divestiture also eliminates Applicants' potential increase in
12 incentive to withhold other generation; that is, it eliminates Applicants' ability to benefit
13 financially through higher market prices with respect to the virtually divested capacity to
14 the same extent as if that generation had been physically divested. Therefore, the virtual
15 divestiture has the desired effect of eliminating any increase in the merged firm's ability
16 or incentive to withhold capacity from the market relating to the merging of the baseload
17 generation.

18 The Baseload Auction is likely to increase the competitiveness of the PJM energy market,
19 by making substantial amounts of baseload energy available to a number of market
20 participants in essentially atomistic quantities. The fact that the baseload auctions
21 coincide with the New Jersey BGS auction further enhances its attractiveness as
22 mitigation. Other areas in PJM East, including Pennsylvania, also can benefit by
23 increased access to competitive supplies in PJM East, both for suppliers currently serving
24 retail choice customers and in the future as PECO's rate cap period ends. The Long-
25 Term Contract, while perhaps not leading to as large a number of market participants,
26 nevertheless increases the number of potential suppliers as compared to the pre-merger
27 situation, and provides provide an opportunity for bidders for retail supply to access
28 substantial amounts of baseload energy, including through a swap with Applicants for
29 similar products in a non-PJM market.

1 *Coal, Mid-Merit and Peaking Divestiture.* Applicants have committed to divest 2,900
2 MW of coal, mid-merit, and peaking generation in PJM East. The divestiture of this
3 generation (together with the virtual divestiture of nuclear energy) will eliminate any
4 Competitive Analysis Screen failures during mid- and peak periods, and will eliminate
5 any increased ability that the merged company theoretically would have to economically
6 or physically withhold generation. No more than half of the divested capacity will be
7 sold to any single purchaser and none of the capacity will be sold to any purchaser that
8 currently owns more than 5 percent of the installed generating capacity in either PJM
9 East or Expanded PJM. Any buyers with market shares between 3 and 5 percent will not
10 be permitted to buy more than 25 percent of the divested capacity collectively (e.g., if one
11 buys 25 percent none of the others in the 3 to 5 percent range can buy any of the
12 capacity).¹⁴ Applicants are requesting a period of up to 18 months from the date of
13 closing to accomplish the divestiture, including all necessary regulatory approvals, but
14 intend to accomplish the divestiture as soon as is commercially reasonable. The proposed
15 interim mitigation gives them an incentive to do so.

16 Thus, in total Applicants intend to divest (through a combination of virtual and physical
17 divestiture) the equivalent of 5,500 MW. As the delivered price analysis will
18 demonstrate, this eliminates all of the screen failures in the PJM East market, as well as
19 in the larger geographic markets that merit analysis. [Table 2](#) below summarizes
20 the delivered price test analysis for the PJM East market, reflecting the mitigation that
21 Applicants have proposed.¹⁵ As it shows, there are no screen failures in any time period
22 and the markets remain only moderately concentrated.

¹⁴ The delivered price analysis assumes that the non-nuclear generation is divested to two parties that meet this 5 percent threshold. The analysis approximates the effect of selling to the eligible buyers. The delivered price analysis assumes that the nuclear generation is divested to two parties that do not currently own capacity in PJM.

¹⁵ The table shows the Applicants' respective market shares, market size and concentration pre-merger; their post-merger market share and HHI change pre-mitigation; the amount of nuclear and other generation to be divested (virtual or otherwise); and Applicants' market share, market concentration and HHI change post-mitigation. Finally, the table shows the MW summer-equivalent of the energy divested. Corresponding tables, included *infra*, reflect similar details for other markets.

1

Table 2: Economic Capacity Results, PJM East, Post-Mitigation

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer	
MW	Mkt Share	MW	Mkt Share	MW	Mkt Share			MW	Mkt Share								
S_SP1	\$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929	4,877	2,201	30.9%	1,329	31	5,300
S_SP2	\$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870	3,947	2,201	30.0%	1,273	55	4,300
S_P	\$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058	3,947	2,201	29.7%	1,236	(91)	4,300
S_OP	\$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015	2,201	2,201	33.4%	1,473	(4)	2,400
W_SP	\$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900	4,061	2,289	30.5%	1,291	63	4,300
W_P	\$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067	4,061	2,289	29.5%	1,222	(101)	4,300
W_OP	\$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987	2,833	2,289	30.6%	1,297	(27)	2,950
SH_SP	\$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870	3,233	1,800	28.2%	1,181	(6)	4,300
SH_P	\$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848	2,196	1,800	30.1%	1,287	30	2,950
SH_OP	\$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870	1,800	1,800	32.1%	1,389	(17)	2,400

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ICAP Mitigation. Applicants also have committed to eliminate any screen failures in PJM's capacity, *i.e.*, ICAP, market.¹⁶ The divestiture of mid-merit and peaking generation significantly mitigates any concerns in the ICAP market arising from the merger. The remaining screen failures are attributed to the combination of baseload generation, since the virtual divestiture of nuclear energy is of energy only and does not include the sale of capacity rights. Applicants are prepared to fully mitigate any screen failures in the ICAP market. However, the geographic market for ICAP and the nature of the product are being reconsidered by PJM, with material changes from the current ICAP market structure likely to be known prior to consummation of the merger.¹⁷ Applicants commit at this time to bid into the PJM annual Planning Year capacity auction at a zero price the lesser of their net ICAP position (as measured by their net Unforced Capacity Position in PJM) or 2,400 MW.¹⁸ This commitment is conservatively based on the 5,300 MW required to cure screen failures in the PJM East ICAP market as defined herein,¹⁹

¹⁶ PJM's capacity market currently is based on unforced capacity credits, *i.e.*, UCAP.

¹⁷ As of this time, PJM expects to file its new Resource Adequacy Mechanism (RAM, the ICAP replacement) proposal in March 2005, requesting Commission approval in time to begin forward auctions this fall. Based on current information, it appears that the first planning year for which locational features of the new RAM will be used is the 2007-8 planning period. If this schedule holds, the specifics of the RAM will be known well before this merger is approved. Indeed, Applicants may well have sold forward sufficient ICAP to moot any concerns about the effect of the transaction on competition in the capacity market. In the event that the structure of the new capacity markets is not known at the time of closing, Applicants commit to sell ICAP in parallel with the energy auction.

¹⁸ This commitment will be reduced *pari passu* to the extent that more than 2,900 MW are divested outright.

¹⁹ Since the market structure for ICAP is essentially identical to the market structure for energy during the summer super-peak period, any mitigation that cures screen failures in that period will also cure screen failures for

1 and will be subject to the same basis for reduction (*i.e.*, sale, closure or permanent
2 derating of the facilities or transmission expansion) as the baseload energy mitigation.
3 Applicants commit to make a compliance filing within 30 days after closing to adjust
4 their ICAP mitigation proposal to conform to any changes in the PJM ICAP program.

5 *Ancillary Services.* The Commission's regulations identify additional relevant products
6 as spinning reserves, non-spinning reserves and imbalance energy. PJM has no
7 imbalance energy market separate from the energy market. It has a quick-start non-
8 spinning reserve market that is combined with spinning reserves. Some of the capacity to
9 be divested will have significant ancillary services capability, and the mitigation of
10 energy markets also will cure screen failures in the spinning reserve market. Regulation
11 is not an enumerated product in relevant Commission Orders. Analysis of regulation is
12 difficult because what is in the market differs substantially over time, since the units that
13 are economic for providing regulation are those that are closest to the system marginal
14 price; hence, the units that provide regulation vary as the system price varies.²⁰ About
15 half of Applicants' regulation-capable generation capacity consists of pumped storage
16 units. Significantly, Applicants are far from being pivotal suppliers, and the relevant
17 market for regulation (Mid-Atlantic) has been found to be competitive. Even if
18 Applicants were to withhold all of their regulation capacity, there would be sufficient
19 capacity from non-Applicants to meet the market's regulation requirement twice over.
20 Thus, market power concerns are not present.

21 *Interim Mitigation.* The purpose of the interim mitigation is to eliminate any merger-
22 related incentive to economically or physically withhold capacity prior to implementation
23 of the long-term mitigation measures described previously. In essence, interim
24 mitigation requires that an amount of energy and other products at least equal to the
25 amount to be divested be 1) sold for periods intended to cover the pre-divestiture period,

ICAP. Thus, the maximum necessary ICAP mitigation is expected to be no more than is required for energy, and, as discussed *infra*, actually is less than the energy requirement.

²⁰ Thus, an analysis of regulation should, at least in principle, look rather like an analysis of energy in that competitive units should be those that economically compete at various price levels.

1 2) sold in amounts such that Applicants no longer have any of the product available for
2 sale in the relevant PJM market, or 3) offered into the relevant PJM market either at a
3 price of zero or at variable cost.

4 Baseload Energy. Within 90 days following the month in which the merger is
5 closed, Applicants will auction an interim product identical to the Baseload Auction
6 described above, except that 1) it will be for a shorter term, coinciding with the products
7 commonly traded in PJM and 2) delivery will be either at the PJM East nuclear
8 generation aggregate bus or at the PJM West Hub combined with a basis differential.
9 The alternative delivery arrangement reflects the fact that the PJM West Hub is more
10 liquid than PJM East, thereby facilitating the quick implementation of the interim
11 mitigation. Market participants in PJM East should be financially indifferent as between
12 the two products. Prior to the completion of the interim auction, Applicants commit to
13 bid all of their PJM East nuclear capacity into the PJM day-ahead market at a zero price.

14 Coal, Intermediate and Peaking Energy. Within 30 days following the end of the
15 month in which the merger closes, Applicants will sell the rights to 2,900 MW of energy
16 and capacity from designated units that are included as candidates for divestiture. Under
17 unit firm interim contracts, no more than half of the 2,900 MW will be sold to the same
18 party, and the contracts will be in effect for no longer than 18 months from merger
19 closing. If a designated unit is subsequently divested, the interim contract will be
20 assignable without consent to the party acquiring the designated unit. The counterparty
21 will acquire full dispatch and unit offering rights for the PJM energy and ancillary
22 services markets, and all of the Unforced Capacity associated with the particular unit.²¹
23 Until such time as the entire 2,900 MW of this capacity is committed under interim
24 mitigation contracts, Applicants will bid 2,900 into the PJM day-ahead (and, if not
25 dispatched, into the PJM real-time) market at a price not to exceed the equivalent of PJM

²¹ Because more units may be offered for sale than are required to meet screen failures, the interim mitigation requirement is limited to the maximum required divestiture quantity. Units from which unit power sales will be offered will be from a subset of the offered units that have variable cost characteristics necessary to cure screen failures in all periods.

1 cost-capped rates (*i.e.*, variable cost defined in PJM’s Cost Development Task Force
2 rules plus 10 percent).

3 Ancillary Services. The interim mitigation contracts for the sale of coal, mid-
4 merit and peaking energy are expected to mitigate the merger-related screen failures for
5 spinning reserves associated with such generation. As noted earlier, there are no market
6 power concerns relating to regulation. Nuclear generation has no ancillary services
7 capability.

8 UCAP. Prior to Applicants’ participation in the annual capacity auctions,
9 Applicants have committed to bid into the PJM monthly auction at a price of zero the
10 lesser of their ICAP mitigation amount (5,300 MW minus the amount of any capacity
11 sales or interim mitigation unit sales) or their net PJM Unforced Capacity Position. This
12 commitment is conservatively premised on the required ICAP divestiture in PJM East,
13 even though locational ICAP markets are not expected to be in effect during the period of
14 interim mitigation.²²

15 That there will be no competitive harm in wholesale markets is also important from a
16 retail perspective. Competitive retail markets rely on procurement of power from a
17 competitive wholesale market, and, thus it is important from an ultimate customer
18 perspective that the merger not increase market power in wholesale markets. Further,
19 while not directly relevant to the Commission’s approval of this transaction, it is notable
20 that the merger also will not eliminate any competitor in retail markets. Only Exelon has
21 a retail marketing affiliate, and it is not active in PJM East. PSEG has no retail marketing
22 affiliates and, thus, no retail supplier is eliminated as a result of the merger.

23 The merger raises no horizontal issues in non-PJM markets. While the merging parties
24 each own or control affiliated generation outside of PJM, the extent of the generation
25 controlled in markets where both own generation is *de minimis*.

²² The conservative nature of this commitment is illustrated by the fact that Exelon has no net ICAP in expanded PJM, the market definition applicable to the 2005-6 time period. Hence, no interim mitigation for that period should be required.

1 The merger also creates no material vertical market power issues. There are no issues
2 related either to transmission ownership and operation, or to the combination of electric
3 generation assets and fuels supplies or fuels delivery systems. The PECO, ComEd and
4 PSE&G electric transmission systems are controlled by PJM. None of the utilities owns
5 any interstate gas transmission pipelines and their intrastate systems are modest in scope.
6 PECO operates a gas distribution system in four counties that surround, but do not
7 include, the city of Philadelphia. Its gas service area includes several independent gas-
8 fired generators, all but a few of which have bypassed the distribution system. PECO
9 provides gas distribution service to only three unaffiliated electric generators totaling less
10 than 200 MW. These are primarily either industrial facilities that consume the bulk of
11 their electricity on-site or facilities that use natural gas as a secondary fuel. PECO
12 provides gas transportation services to two affiliated generators at a negotiated
13 discounted transportation rate.

14 PSE&G operates a gas distribution system in New Jersey that serves eight current or
15 former qualifying facilities (“QFs”) under contract with the utility, as well as two
16 merchant generators: the Tosco plant (172 MW) and the Williams Red Oak plant (765
17 MW). These generating facilities served by PSE&G are under long-term gas distribution
18 contracts or discounted tariffs. PSE&G also provides gas transportation services to
19 affiliated generators in its service area.

20 The mere ownership of LDC operations does not give rise to a concern that Applicants
21 will use control over their gas LDCs to favor affiliated activities. Nor do they have the
22 ability to use these systems to raise rivals’ costs or otherwise disadvantage rivals.
23 Distribution tariffs are regulated by the respective state public utility commissions, which
24 have imposed open-access distribution requirements similar to those required by this
25 Commission. Distribution tariffs are frequently constrained by bypass alternatives or
26 existing long-term (sometimes discounted) contracts. It is unlikely and unnecessary that
27 new generation would seek to be connected to an LDC as opposed to direct
28 interconnection with a pipeline system. Newly built gas-fired generating facilities could
29 readily avoid PECO’s or PSE&G’s service area or connect directly to one of the several
30 interstate pipelines serving Pennsylvania and New Jersey.

1 Both PECO and PSE&G have firm transmission rights on the gas pipelines serving PJM
2 in order to serve their gas distribution customers as well as their own gas-fired generating
3 plants.²³ PECO's firm transportation rights are fully committed to meet retail customer
4 load. Moreover, Applicants cannot withhold these transportation rights to reduce supply
5 since 1) they are held to meet the needs of retail and requirements gas customers and 2)
6 failure to use rights simply increases the amount of release and non-firm capacity
7 available to competitors. Finally, both Pennsylvania and New Jersey have in place codes
8 of conduct between gas and electric affiliates, and Applicants are in compliance with
9 FERC Order No. 2004.

10 Part 33.4 of the Commission's regulations specifies the analysis to be performed for
11 vertical mergers. The end result is that both the upstream and downstream markets need
12 to be highly concentrated in order for there to be a potential vertical market power issue.
13 Attributing gas-fired generation to the fuels transport supplier, as specified in Part 33.4,
14 changes the result only to the extent the divested gas-fired units remain attributed to
15 Applicants. After mitigation of the effects of this merger, the downstream markets in
16 PJM Pre-2004 and Expanded PJM are not highly concentrated, as shown *infra*. In PJM
17 East, this results in a highly concentrated market.²⁴ In the summer and winter periods,
18 the HHI post-mitigation is in excess of 1,800 points, but below 2,000 points.²⁵ Since the
19 downstream market for PJM East is highly concentrated under this methodology (with
20 the attribution of gas-fired generation to the supplying gas transmission system or
21 distribution company called for in Part 33.4), I also examined concentration in the

²³ With respect to PSE&G, most of the firm transmission rights are held by PSEG Energy Resources & Trading and the generation is owned by PSEG Fossil LLC. With respect to Exelon, most of the firm transmission rights are held by PECO and the generation is owned by Exelon Generation.

²⁴ In other words, I only counted the divestiture of nuclear or coal units in my post-merger calculation. Of course, if some of the divested units are oil-fired, they too represent a reduction in Applicants' market share and would likely reduce concentration below 1800.

²⁵ The fact that mitigation cures screen failures in the horizontal energy market analysis but not in the downstream vertical analysis (which also is the energy market) is because divested gas-fired generation still is attributed to Applicants in the latter analysis.

1 upstream market and determined that it, indeed, was not highly concentrated.²⁶ For the
2 remaining relevant markets, PJM Pre-2004 and Expanded PJM, I did not perform an
3 upstream analysis. However, based on my experience in performing upstream analyses,
4 it is highly unlikely that these other upstream markets are highly concentrated because,
5 particularly in markets with gas retail access, the ownership of firm transportation rights
6 tends to be fragmented and mostly unconcentrated or, at worst, moderately concentrated.
7 In any event, competitive conditions in the relevant PJM markets I examined are not
8 conducive to a successful strategy of foreclosure or raising rivals' costs.

9 There are no other barriers to entry that raise concerns: Applicants do not have dominant
10 control over generating sites and there has been substantial entry into relevant markets.

11 In short, none of the vertical concerns that the Commission focused upon in prior vertical
12 mergers exist in this merger and the transaction does not create or enhance vertical
13 market power.

14 For all these reasons, I recommend that the Commission find that the transaction, as
15 proposed, will not adversely affect competition and approve the merger.

²⁶ The Commission approved the El Paso-Coastal merger on the basis, among other things, of an analysis by the merging parties that demonstrated the upstream market for gas in PJM East was not highly concentrated. The analysis submitted in that docket showed the delivered gas market for PJM was moderately concentrated. *El Paso Energy Corporation and The Coastal Corporation* 92 FERC ¶ 61,076 (2000) . Any larger geographic market definition in PJM likely would result in an unconcentrated market.

1 An affiliate of Exelon recently completed the sale to Dynegy, Inc. of its 50 percent
2 indirect ownership interest in Sithe Energies, Inc. (“Sithe”), which owns generation assets
3 located primarily in New York and mid-Atlantic markets.²⁸

4 **Q. PLEASE DESCRIBE EXELON’S ENERGY DELIVERY BUSINESS.**

5 A. Exelon's energy delivery business consists of the regulated sale of electricity and
6 distribution services by ComEd in northern Illinois and PECO in southeastern
7 Pennsylvania (Philadelphia). It also is the passive owner of transmission assets
8 controlled by PJM and regulated under the PJM tariff. In addition, PECO is involved in
9 the regulated sale of natural gas and distribution services in the Pennsylvania counties
10 surrounding Philadelphia.

11 Neither PECO nor ComEd owns generation, and each serves its customers’ capacity and
12 energy needs through PPAs with Exelon Generation. PECO currently has no
13 requirements customers. ComEd has three partial or full requirements wholesale
14 customers within its control area served under fixed price contracts through May 31,
15 2007: the cities of Naperville (full requirements), Batavia and St. Charles.²⁹

16 The states of Pennsylvania and Illinois have retail access for electricity customers, and
17 both PECO’s and ComEd’s customers have the right to choose competitive energy
18 suppliers. The majority of retail customers in PECO’s service territory continue to be
19 served by PECO at distribution rates that are capped through December 31, 2006, and
20 generation rates that are capped through December 31, 2010. The majority of retail
21 customers in the ComEd service territory continue to be served by ComEd at bundled
22 retail rates that are frozen through 2006.

²⁸ This sale has been approved by the Commission. *Sithe Energies, Inc., Dynegy New York Holdings et al.*, 110 FERC ¶ 62,027 (2005).

²⁹ A fourth municipal utility, City of Rochelle, is supplied by ComEd’s retail affiliate, Exelon Energy. In addition, there are three municipal customers within ComEd’s service territory who obtain their requirements from other suppliers.

1 The Illinois Electric Service Customer Choice and Rate Relief Law of 1997
2 (“Restructuring Act”) initiated the state’s restructuring initiative. The law provided
3 Illinois customers with the ability to choose their electricity supplier, mandated a 20
4 percent rate reduction for residential customers, imposed a rate freeze,³⁰ and defined the
5 utility’s residual POLR service obligation.

6 Illinois is facing the end of the Restructuring Act’s transition period. The Illinois
7 Commerce Commission (“ICC”) has hosted a series of workshops to examine the future
8 of the electric market in Illinois and to develop a proposal for the ICC to consider. The
9 post-2006 framework proposal developed by the stakeholders and the ICC staff, and
10 endorsed by the ICC, is a vertical tranche auction, which is similar in many respects to
11 the New Jersey BGS auction. Exelon has endorsed the ICC’s recommendations and is
12 working to implement the recommendation.

13 **Q. PLEASE DESCRIBE EXELON’S RETAIL COMPETITIVE ENERGY SUPPLY**
14 **BUSINESS.**

15 A. Exelon Energy Inc. (“Exelon Energy”) is authorized to provide retail electric and gas
16 services as an unregulated retail energy supplier in Illinois, Massachusetts, Michigan,
17 New Jersey, Ohio, Pennsylvania and other areas in the Midwest and Northeast United
18 States. However, Exelon Energy is primarily active in the Midwest, with virtually no
19 activity in PJM East.³¹

20 **PSEG, PSE&G and PSEG Power**

21 **Q. PLEASE DESCRIBE PSEG.**

22 A. PSEG is an exempt public utility holding company under PUHCA with four principal
23 direct wholly-owned subsidiaries: PSE&G, PSEG Power, PSEG Energy Holdings LLC
24 (“PSEG Energy Holdings”) and PSEG Services Corporation. The principal operating

³⁰ The initial rate freeze was through December 31, 2004; it was extended in 2004 through Dec. 31, 2006.

³¹ A gas retail affiliate, AllEnergy, was active in the east, but its operations are being wound down.

1 subsidiaries of PSEG Power are PSEG Fossil, PSEG Nuclear LLC (“PSEG Nuclear”) and
2 PSEG ER&T. The principal operating subsidiaries of PSEG Energy Holdings are PSEG
3 Global LLC and PSEG Resources L.L.C.

4 PSEG Global is an independent power producer and distributor, which develops, owns
5 and operates electric generation, transmission and distribution facilities in selected
6 domestic and international markets. PSEG Resources is a passive investor in a number of
7 leveraged leases in the generation business.³² Since these are merely passive investments
8 and involve no form of operational control (nor any beneficial interest), I have not
9 considered these investments as relevant to my analysis.

10 **Q. PLEASE DESCRIBE PSE&G.**

11 A. PSE&G is a transmission and distribution utility for electricity and gas service in New
12 Jersey, covering approximately 2,600 square miles running diagonally across New Jersey
13 from Bergen County in the northeast to an area below the city of Camden in the
14 southwest.

15 All electric and gas customers in New Jersey have the ability to choose an electric energy
16 and/or gas supplier. PSE&G serves as the supplier of last resort for electric and gas
17 customers within its service territory through the provision of Basic Generation Service
18 (“BGS”). New Jersey's Electric Distribution Companies (“EDCs”), including PSE&G,
19 began providing two types of BGS in August 2003: BGS-FP provides for smaller
20 commercial and residential customers at seasonally-adjusted fixed prices. BGS-CIEP
21 provides supply for larger customers at hourly market prices for a term of 12 months.
22 The New Jersey Board of Public Utilities has approved auctions held by the EDCs each
23 February to determine who will supply BGS to New Jersey's EDCs. PSE&G's BGS-FP-
24 eligible load is approximately 8,500 MW.

³² These investments are described in the Application. In addition, PSEG Power has a minority ownership interest in Merrill Creek Reservoir, which is jointly owned by several generation owners that rely on water from the facility. As with the leveraged leases, this ownership interest is not relevant to my analysis.

1 With respect to its gas distribution business, PSE&G has entered into a full requirements
2 contract with PSEG ER&T its gas supply through 2007, with evergreen rights.

3 **Q. PLEASE DESCRIBE PSEG POWER.**

4 A. PSEG Power integrates its generating asset operations with its wholesale energy, fuel
5 supply, energy trading and marketing and risk management function through its wholly-
6 owned subsidiaries: PSEG Nuclear, which owns and operates nuclear generating
7 stations; PSEG Fossil, which develops, owns and operates domestic fossil generating
8 stations; and PSEG ER&T, which markets the capacity and production of its affiliated
9 generating stations and manages the commodity price risks and market risks related to
10 generation.

11 PSEG Power, through its subsidiaries, along with PSEG Global, owns or controls
12 approximately 18,000 MW of North American generation, primarily in PJM (14,000
13 MW), as well some capacity in ISO-NE, in the New York ISO Independent System
14 Operator (“NYISO”), in ERCOT and in the Western Electric Coordinating System
15 (“WECC”), under the control of the California Independent System Operator
16 (“CAISO”).³³ See Exhibit J-3.

³³ This includes generation expected to be on-line by 2006. Generation under construction includes a 761 MW combined cycle plant in the NYISO and the 1,220 MW Linden combined-cycle plant in PJM. Both of these facilities replace existing generation at the respective sites.

1 supply the products produced by the merging parties and whose ability to do so
2 diminishes the ability of the merging parties to increase prices. Hence, determining the
3 scope of a market is fundamentally an analysis of the potential for competitors to respond
4 to an attempted price increase. Typically, markets are defined in two dimensions:
5 geographic and product. Thus, the relevant market is composed of companies that can
6 supply a given product (or its close substitute) to customers in a given geographic area.

7 **Horizontal Market Power Issues**

8 **Q. HOW HAS THE COMMISSION TYPICALLY EXAMINED PROPOSED** 9 **MERGERS INVOLVING ELECTRIC UTILITIES?**

10 A. In December 1996, the Commission issued Order No. 592,³⁴ the “Merger Policy
11 Statement,” which provides a detailed analytic framework for assessing the horizontal
12 market power arising from electric utility mergers. This analytic framework is organized
13 around a market concentration analysis. The Commission adopted the DOJ/FTC
14 *Horizontal Merger Guidelines* for measuring market concentration levels by the
15 Herfindahl-Hirschman Index (“HHI”).³⁵ On November 15, 2000, the Commission issued
16 its Revised Filing Requirements Under Part 33 of the Commission’s Regulations,³⁶ which
17 affirmed the screening approach to mergers consistent with the Appendix A analysis set

³⁴ Order No. 592, FERC Stats and Regs. ¶ 31,044 (1996).

³⁵ To determine whether a proposed merger requires further investigation because of a potential for a significant anti-competitive impact, the DOJ and FTC consider the level of the HHI after the merger (the post-merger HHI) and the change in the HHI that results from the combination of the market shares of the merging entities. Markets with a post-merger HHI of less than 1000 are considered “unconcentrated.” The DOJ and FTC generally consider mergers in such markets to have no anti-competitive impact. Markets with post-merger HHIs of 1000 to 1800 are considered “moderately concentrated.” In those markets, mergers that result in an HHI change of 100 points or fewer are considered unlikely to have anti-competitive effects. Finally, post-merger HHIs of more than 1800 are considered to indicate “highly concentrated” markets. The *Guidelines* suggest that in these markets, mergers that increase the HHI by 50 points or fewer are unlikely to have a significant anti-competitive impact, while mergers that increase the HHI by more than 100 points are considered likely to reduce market competitiveness. (See U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, 1992 [amended 1997].)

³⁶ Order No. 642, Final Rule in Docket No. RM98-4-000, 18 CFR Part 33, 93 FERC ¶ 61,164 (2000) (“Revised Filing Requirements”).

1 forth in the Merger Policy Statement, and codified the need to file a screen analysis and
2 the exceptions therefrom.

3 Appendix A of the Merger Policy Statement, the Competitive Analysis Screen, specifies
4 a “delivered price” screening test to measure Economic Capacity, defined as energy that
5 can be delivered into a destination market at a delivered cost less than 105 percent of the
6 destination market price. The screening test also provides for an analysis of Available
7 Economic Capacity, defined as energy over and above that required to meet native load
8 and other long-term obligations that meets the delivered price test.

9 If a proposed merger raises no market power concerns (*i.e.*, passes the Appendix A
10 screen), the inquiry generally is terminated. Both the Merger Policy Statement and the
11 Revised Filing Requirements accept that merger applications involving no overlap in
12 relevant geographic markets do not require a screen analysis or filing of the data needed
13 for the screen analysis.³⁷

14 **Q. WHAT PRODUCTS HAS THE COMMISSION GENERALLY CONSIDERED?**

15 A. The Commission generally has been concerned with three relevant product markets: non-
16 firm energy, short-term capacity (firm energy) and long-term capacity.³⁸ Both Economic

³⁷ Order No. 592 (at 30,113) states: “...it will not be necessary for the merger applicants to perform the screen analysis or file the data needed for the screen analysis in cases where the merging firms do not have facilities or sell relevant products in common geographic markets. In these cases, the proposed merger will not have an adverse competitive impact (*i.e.*, there can be no increase in the applicants' market power unless they are selling relevant products in the same geographic markets) so there is no need for a detailed data analysis.”

The Revised Filing Requirements state that an analysis need not be filed if the applicant “demonstrates that the merging entities do not currently conduct business in the same geographic markets or that the extent of the business transactions in the same geographic markets is *de minimis*.”

³⁸ The market for long-term capacity generally does not need to be analyzed since the Commission has concluded as a generic matter that the potential for entry ensures that the long-term capacity market is competitive. See *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Statutes and Regulations, ¶ 31,036 - 31,657 (1996). The presumption that long-term capacity markets are competitive can be overcome if the applicants have dominant control over power plant sites or fuels supplies and delivery systems. This exception is addressed below.

1 Capacity and Available Economic Capacity³⁹ are used as measures of energy. The
2 Commission's current policy does not specify required analyses of capacity markets as
3 such, likely because competitive conditions in the energy market in peak periods closely
4 correlate with conditions in capacity markets. Nevertheless, I have analyzed the PJM
5 Unforced Capacity Credit ("UCAP") market.

6 Under the Economic Capacity and Available Economic Capacity measures, capacity that
7 is attributed to a market participant is that capacity controlled by it that can reach the
8 destination market, taking transmission constraints and costs into account, at a price no
9 higher than 105 percent of the destination market price. As described above, the two
10 measures differ as to the treatment of capacity used to meet native load requirements.
11 The Commission has determined that long-term capacity markets are presumed to be
12 competitive, unless special factors exist that limit the ability of new generation to be sited
13 or receive fuel.

14 Order No. 642 directs Applicants to analyze relevant ancillary services markets
15 (specifically, reserves and imbalance energy⁴⁰) "when the necessary data are available."
16 As discussed below, I analyzed relevant ancillary services markets within the limits of the
17 quantitative data available.

18 **Q. HOW HAS THE COMMISSION ANALYZED GEOGRAPHIC MARKETS?**

19 A. Traditionally, the Commission has defined the relevant geographic markets as centered
20 on the applicants and on utilities directly interconnected with the applicants, referred to as
21 first-tier utilities. Both Order No. 592 and the Revised Filing Requirements continue to

³⁹ I note that evaluating Available Economic Capacity is quite difficult in the context of this merger, given the state of retail access in Pennsylvania, New Jersey and Illinois. While identifying Applicants' load commitments is relatively straightforward, it is virtually impossible to match generation and load commitments for most PJM utilities. Notwithstanding these difficulties, which are discussed in more detail below, I analyzed Available Economic Capacity.

⁴⁰ Because PJM does not require balanced schedules, it has no imbalance market separate and distinct from spot energy markets.

1 define the relevant geographic market in terms of first-tier destination markets.⁴¹ Further,
2 in a merger context, the Commission considers as potential additional destination markets
3 other utilities that historically have been customers of the applicants.

4 This test is intended to be a conservative screen to determine whether further analysis of
5 market power is necessary. If the Appendix A analysis shows that a company will not be
6 able to exercise market power in its first-tier destination markets, it generally follows that
7 the applicants will not have market power in more broadly defined and more
8 geographically remote markets. The screen is the first step in determining whether there
9 is a need for further investigation. If the screening test is not passed, leaving open the
10 issue of whether the merger will create market power, the Commission invites applicants
11 to propose mitigation remedies targeted to reduce potential anti-competitive effects to
12 safe harbor levels. In the alternative, the Commission will undertake a proceeding to
13 determine whether unmitigated market power concerns mean that the merger is contrary
14 to the public interest.

15 While destination markets typically are defined as individual control areas, the
16 Commission's practice has been to aggregate customers that have the same supply
17 alternatives into a single destination market. This approach has been accepted in a
18 number of merger filings in New York, PJM, and New England.

19 To simplify the analysis, customers that have the same supply alternatives,
20 as identified in the competitive analysis screen, can be aggregated into a
21 single destination market. The Commission has accepted this approach in
22 a number of merger filings. For example, in Atlantic City/Delmarva, the
23 Commission found acceptable the treatment of PJM as a single destination
24 market since customers in PJM trade largely with the same set of
25 suppliers. The same is true of mergers occurring within the New England
26 and New York ISOs (e.g., ConEd/NU and CMP/NYSEG).⁴² [footnote
27 omitted]

⁴¹ Order No. 592 at 30,119.

⁴² Revised Filing Requirements, ¶ 31,311 at 31,844-5, citing *Atlantic City Electric Company and Delmarva Power & Light Company*, 80 FERC ¶ 61,126 (1997); *Consolidated Edison Co., Inc. and Northeast Utilities* 91 FERC ¶ 61,225 (2000). To the extent there are internal transmission constraints within these markets, the Commission has considered smaller markets within these single control areas as potentially relevant.

1 As discussed below, in the context of this merger, the appropriate focus of the
2 competitive analysis is on PJM, both overall and relevant sub-markets within PJM. As I
3 will describe, the overlap of generation ownership in other geographic markets is *de*
4 *minimis* and does not require a screen analysis.

5 **Vertical Market Power Issues**

6 **Q. WHAT ARE THE POTENTIALLY RELEVANT VERTICAL MARKET POWER**
7 **ISSUES?**

8 A. In the Revised Filing Requirements, the Commission set out several vertical issues
9 potentially arising from mergers with input suppliers. The principal issue identified is
10 whether the merger may create or enhance the ability of the merged firm to exercise
11 market power in downstream electricity markets by control over the supply of inputs used
12 by rival producers of electricity. Three potential abuses have been identified: the
13 upstream firm acts to raise rivals' costs or foreclose them from the market in order to
14 increase prices received by the downstream affiliate; the upstream firm acts to facilitate
15 collusion among downstream firms; or transactions between vertical affiliates are used to
16 frustrate regulatory oversight of the cost/price relationship of prices charged by the
17 downstream electricity supplier. The downstream products to be analyzed in a vertical
18 analysis are the same as in the horizontal analysis.

19 With respect to the vertical analysis, the Commission proposes defining the downstream
20 market in the same manner as in the horizontal analysis. For upstream markets, the
21 relevant geographic market has not been defined by the Commission. In concept, it
22 should include the area in which suppliers to generators competing in the downstream
23 market are located. The Commission suggests in *Dominion*⁴³ that the market includes
24 sellers that can provide competitive alternatives, such as those that can provide
25 transportation capacity on terms comparable to those offered by the merging firm.

⁴³ *Dominion Resources, Inc. and Consolidated Natural Gas Company*, 89 FERC ¶ 61,162 (1999).

1 **Q. HOW DOES THE FRAMEWORK FOR ASSESSING VERTICAL MARKET**
2 **POWER DIFFER FROM THE HORIZONTAL ANALYSIS FRAMEWORK?**

3 A. For the vertical market power screen, the Commission's focus is on the structural
4 competitiveness of downstream or upstream product markets, as measured by HHIs. The
5 main difference from the horizontal analysis is that in the vertical analysis, the focus is
6 not on the change in HHIs resulting from the merger, but on the structure of those
7 markets where one merging party sells upstream products in a geographic market in
8 which the other merging party sells downstream products.

9 **Q. WHAT ARE THE VERTICAL ISSUES THAT THE COMMISSION HAS FOUND**
10 **REQUIRE INVESTIGATION IN THE CONTEXT OF MERGERS BETWEEN**
11 **ELECTRIC UTILITIES AND GAS TRANSPORTATION PROVIDERS?**

12 A. The Commission has indicated that under some circumstances such mergers could give
13 rise to vertical concerns. The Commission has expressed its concern in decisions
14 addressing "convergence mergers" and in Order No. 642, that vertical mergers "may
15 create or enhance the incentive and/or ability for the merged firm to adversely affect
16 prices and output in the downstream electricity market and to discourage entry by new
17 generators."⁴⁴ Potential market power arising from a merger between an electric utility
18 and a gas pipeline is discussed by the Commission principally in Order No. 642 and
19 Section 33.4 of the Revised Filing Requirements, and in its orders in *Enova*, *Dominion*,
20 *Brooklyn Union Gas* and *Energy East*.⁴⁵

21 As already noted, the main areas of Commission concern are: (1) the creation of
22 incentives for the gas-related upstream activities to raise costs for rivals of the electricity
23 generation affiliate; (2) the enhanced ability to facilitate coordination of pricing in
24 upstream or downstream markets; and (3) the enhanced ability to evade regulation,

⁴⁴ III FERC Stats. & Regs. Regs. Preambles, ¶31,111 at 31,904.

⁴⁵ See *Enova Corporation and Pacific Enterprises*, 79 FERC ¶ 61,372 (1997) ("Enova"); *Dominion*; *Long Island Lighting Company*, 80 FERC ¶ 61,035 (1997) ("Brooklyn Union Gas"); and *Energy East Corporation and RGS Energy Group, Inc.*, 96 FERC ¶ 61, 322 (2001) ("Energy East").

1 primarily through self-dealing.⁴⁶ The Commission also has expressed concerns that (a)
2 convergence mergers involving an upstream gas supplier serving the downstream merger
3 partner, as well as competitors of that partner, could result in preferential terms of
4 service; and (b) a pipeline serving electric generation could provide commercially
5 valuable information to newly affiliated electricity generating or marketing operations.
6 My analysis considers each of these concerns, however, I note that these concerns
7 typically are far less substantial for mergers involving LDCs than for mergers involving
8 ownership of an interstate pipeline.

9 **Q. PLEASE ELABORATE ON WHAT IS MEANT BY RAISING RIVALS' COSTS.**

10 A. Foreclosure, or raising rivals' costs, refers to a situation in which a vertically integrated
11 firm withholds inputs produced in its upstream operations (*e.g.*, delivered gas) from rivals
12 in the downstream (*e.g.*, electric generation) market in order to increase the costs of
13 downstream rivals, thereby increasing downstream market prices and creating an
14 opportunity for the integrated firm to achieve increased profits from its downstream
15 operations. It also may refer to a situation in which the price charged to rivals can be
16 profitably increased as a result of a merger with additional generating facilities (*e.g.*, the
17 economics of discounted service are changed by the merger).

18 If the vertically integrated firm exercises market power in the upstream market after the
19 merger, the costs to rivals in the downstream market could increase. However, if
20 competitors in the downstream market have adequate alternatives to the upstream
21 product, the merged firms cannot exercise market power. Moreover, if conditions in the
22 upstream market are not conducive to the exercise of market power (*i.e.*, the upstream
23 market is competitive), an attempt to raise rivals' cost will be unsuccessful. Similarly, if
24 the upstream or downstream markets are sufficiently competitive, there should be no
25 issue of anti-competitive coordination.

⁴⁶ Because none of the Applicants own regulated assets that take service from the other Applicant's LDC, the regulatory evasion concern is not present and I do not discuss it further.

1 **Q. ARE THERE ANY OTHER RELEVANT PARAMETERS IN CONSIDERING**
2 **VERTICAL ISSUES?**

3 A. The Commission has stated that a necessary condition for a convergence merger to cause
4 a vertical concern is that both the upstream and downstream markets are highly
5 concentrated.⁴⁷ In other words, the screen is passed if the downstream (or upstream)
6 market is not highly concentrated, irrespective of the degree of concentration of the
7 upstream (or downstream) market. A proper analysis of the upstream market requires
8 that the structure of control of transportation capacity be examined, which requires that
9 control of the transportation capacity be allocated to holders of firm capacity rights on the
10 relevant pipelines with any unsubscribed capacity allocated to the pipeline owner. In my
11 experience, this allocation has invariably resulted in a not highly concentrated market. In
12 the context of this merger, which does not involve ownership of natural gas pipelines *per*
13 *se*, but merely control over shares of delivery capacity, the relevant focus is on
14 Applicants' contractual rights to use the interstate pipeline delivery system into the
15 relevant markets.

⁴⁷ “[H]ighly concentrated upstream and downstream markets are necessary, but not sufficient, conditions for a vertical foreclosure strategy to be effective” Revised Filing Requirements, ¶ 31,311 at 31,911. “A vertical merger can create or enhance the incentive and ability of the merged firm to adversely affect electricity prices or output in the downstream market by raising rivals’ input costs if market power could be exercised in both the upstream and downstream geographic markets.” Order No. 642, *slip op.* at 79. This was confirmed in *Energy East*. (“Applicants correctly conclude that because they have shown that the downstream markets are not highly concentrated, there is no concern about foreclosure or raising rivals’ costs in this case.”) *Energy East, op. cit.*

1

IV. DESCRIPTION OF METHODOLOGY

2 **Q. PLEASE SUMMARIZE THE METHODOLOGY THAT YOU USED TO**
3 **ANALYZE THE COMPETITIVE EFFECTS OF THE MERGER.**

4 A. I evaluated the competitive effects of the merger using the delivered price test outlined in
5 Appendix A and the Revised Filing Requirements. I implemented this analysis using a
6 proprietary CRA model called the “Competitive Analysis Screening Model” (“CASm”).
7 The source and methodology for the data required to conduct the delivered price test in
8 CASm are described in Exhibit J-4. A technical description of CASm is provided in
9 Exhibit J-5.

10 **Q. WHAT DESTINATION MARKETS DID YOU CONSIDER?**

11 A. Consistent with the instructions in the Revised Filing Requirements, I identified the
12 destination markets that could potentially be impacted by the merger. First, I will discuss
13 relevant PJM markets. In analyzing the PJM market, the Commission historically has
14 taken into consideration the predominant west-to-east energy flow and defined markets
15 by the three high-voltage interfaces within PJM: West, Central and East.⁴⁸ See Exhibit
16 J-6. The location of Applicants’ generation in PJM is summarized in [Table 3](#)~~Table 3~~
17 below:

18

Table 3: Applicants’ Generation in PJM

	<u>Exelon</u>	<u>PSEG</u>
	(MW)	(MW)
PJM East	7,180	10,121
PJM Central	3,108	1,120
PJM West and Far West	714	776
PJM (ECAR)	-	1,946
PJM (MAIN)	15,340	-
Total PJM	26,341	13,963

⁴⁸ The PJM regions and related transmission limits are discussed in the Commission’s Order in Docket No. ER97-3729-000, 86 FERC ¶ 61,248 (1999), and have been considered as relevant markets in a number of orders. The PJM sub-markets have included PJM East; PJM Central plus East; and PJM West plus Central plus East. PJM Central and PJM West are not typically considered as relevant markets.

1 I considered PJM East as the smallest relevant geographic market, for a number of
2 reasons, including historical precedent, location of Applicants' generation, transmission
3 constraints, and price separation. The Commission has, on numerous occasions
4 examined PJM East as a relevant geographic market. As shown in the table above, the
5 majority of PSEG's generation (approximately 10,000 MW) and a significant portion of
6 Exelon's generation (approximately 7,000 MW) is located inside of the Eastern Interface
7 of PJM. The PJM Market Monitoring Unit has studied constraints within PJM and
8 identified 51 hours in 2002 and 203 hours in 2003 that were "congestion-event hours."⁴⁹
9 In 2004, the number of hours when the Eastern Interface was constrained increased to
10 275 hours.⁵⁰

11 This is the smallest relevant market for an analysis of this transaction: although local
12 congestion within the Eastern Interface may occur, for example within the PECO zone or
13 within the PSE&G zone, only one of the merging parties owns generation within these
14 smaller constrained areas.⁵¹ Similarly, I have determined that it is not necessary to
15 analyze other submarkets within PJM Pre-2004. PJM Central, PJM West and PJM Far
16 West have not been considered separate markets; these are markets that separate from
17 each other and from PJM East only when constraints in a west-to-east direction separate
18 the markets. Moreover, the West and Central interfaces are congested substantially less
19 frequently than the East interface.⁵²

20 If, for example, the Northern PSEG zone were deemed a relevant market, Exelon owns
21 no generation within that market and the only market share it would receive would be an
22 allocation of the limited interface into the Northern PSEG zone. Since Applicants' plan

⁴⁹ *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, page 164. In this analysis, "[t]he constrained hour data...use the convention that if congestion occurs for 20 minutes or more in an hour, the hour is considered congested."

⁵⁰ Based on data from the PJM website. I note that the number of hours when prices separate between interfaces or even within the Eastern constraint can be substantially greater than the reported hours of constraint.

⁵¹ The exception is the joint ownership of nuclear plants.

⁵² In 2004, PJM Central had only 63 congestion event hours, and PJM West only 78 hours.

1 to divest or auction a significant amount of generation in PJM East, including from the
2 jointly owned nuclear units, any concerns in individual sub-zones are similarly mitigated.

3 I also considered PJM Pre-2004 (that is, the portion of PJM consisting of the original
4 PJM members in MAAC plus Allegheny Energy) as a relevant market in the absence of
5 internal constraints, for example, when PJM East is not binding. This, again, is
6 consistent with historical precedent and with PJM studies that show significant
7 constraints between this area and the rest of Expanded PJM.

8 I also considered Expanded PJM as a relevant geographic market, consistent with the fact
9 that there is now a single energy market across PJM. While I am not aware that the
10 Commission has analyzed an Expanded PJM market in the context of a merger or other
11 Section 203 application, the Commission has considered (and accepted) this market
12 definition in the context of Section 205 applications for market-based rates.⁵³ As a
13 pragmatic matter, I have analyzed this market in anticipation of concerns that Exelon's
14 generation in Northern Illinois, despite its remoteness from PSEG's generation, should be
15 considered in assessing this merger. Further, Expanded PJM is a relevant market in the
16 absence of significant internal constraints within PJM. As I noted earlier, I considered
17 Dominion Virginia Power to be included in Expanded PJM, in anticipation of its
18 integration well before 2006.

19 I analyzed each of these markets – PJM East, PJM Pre-2004 and Expanded PJM – to
20 evaluate the impact of the merger on competition. I did not analyze any of PJM's first-
21 tier markets (other than those in which Applicants own generation), because such an
22 analysis will not provide any further insight into the impact of this merger. As is self-
23 evident, the effect of the merger on more remote geographic markets necessarily will be
24 less than its effect on the markets I have analyzed.

25 Finally, I considered whether there were any destination markets outside of PJM that
26 were potentially relevant, given the location of other Applicant-affiliated generation. As

⁵³ *Virginia Electric and Power Company*, 108 FERC ¶ 61,242 (2004); *Dayton Power & Light Company et al.*, 109 FERC ¶ 61,268 (2004).

1 shown in ~~Table 4~~ Table 4 below, Applicants each own generation in the ISO-NE and
 2 ERCOT markets; analysis of other markets in which one or the other Applicant controls
 3 no generation is unnecessary. As I discuss later in my testimony, in these markets the
 4 extent of overlapping operations is sufficiently *de minimis* that a complete Competitive
 5 Analysis Screen is not necessary to conclude that there are no competitive concerns
 6 resulting from the merger.

7 **Table 4: Applicants' Generation Outside of PJM**

NERC	RTO	Exelon (MW)	PSEG (MW)
NPCC	ISO-NE	630	967
NPCC	NYISO	-	761
WECC	CAISO	-	443
SPP	SPP	795	-
ERCOT	ERCOT	3,651	2,026
SERC		1,755	-
MAIN	MISO	713	-
Total, Non-PJM		6,714	4,197

Note: Exelon's total is adjusted to account for double-counting of a unit connected to both ERCOT and SERC.

8
 9 **Q. WHAT TIME PERIODS DID YOU ANALYZE?**

10 A. For each relevant market, I examined ten time periods for both the Economic Capacity
 11 and Available Economic Capacity measures, selected to reflect a broad range of system
 12 conditions. Broadly, I evaluated hourly load data to aggregate similar hours. I defined
 13 periods within three seasons (Summer, Winter and Shoulder) to reflect the differences in
 14 unit availability, load and transmission capacity. Hours were first separated into seasons
 15 to reflect differences in generating availability and then further differentiated by load
 16 levels during each season.⁵⁴ For each season, hours were segmented into peak- and off-

⁵⁴ Appendix A requires applicants to evaluate the merger's impact on competition under different system conditions. For example, aggregating summer peak and shoulder peak conditions may mask important differences in unit availability and, therefore, a merger could potentially affect competition differently in these seasons. Thus, applicants are directed to evaluate enough sufficiently different conditions to show the merger's

1 peak periods.⁵⁵ The periods evaluated (and the designations used to refer to these periods
2 in exhibits) are:

3 **SUMMER** (June-July-August)

4 Super Peak 1 (S_SP1):	Top load hour
5 Super Peak 2 (S_SP2):	Top 10% of peak load hours
6 Peak (S_P):	Remaining peak hours
7 Off-peak (S_OP):	All off-peak hours

8 **WINTER** (December-January-February)

9 Super Peak (W_SP):	Top 10% of peak load hours
10 Peak (W_P):	Remaining peak hours
11 Off-peak (W_OP):	All off-peak hours

12 **SHOULDER** (March-April-May-September-October-November)

13 Super Peak (SH_SP):	Top 10% of peak load hours
14 Peak (SH_P):	Remaining peak hours
15 Off-peak (SH_OP):	All off-peak hours

16 **Q. WHAT “COMPETITIVE” PRICE LEVELS DID YOU ANALYZE?**

17 A. For each destination market, I evaluated conditions assuming destination market prices
18 ranging from \$20/MWh in the Shoulder Off-Peak periods to \$250/MWh in the Summer
19 Super Peak period. In PJM, the effect of these prices is that during the lowest-priced off-
20 peak periods in summer and winter, only nuclear generation passes the delivered price
21 test. However, I note that during off-peak, overnight periods, coal is operated at
22 minimum generation to ensure availability for the next day’s peak hours. Often, coal is
23 bid during these periods at below its marginal cost (or even zero) to ensure operation.

impact across a range of system conditions. On the other hand, the DOJ/FTC *Horizontal Merger Guidelines* discuss the ability to “sustain” a price increase, and a finding that a structural test (like the HHI statistic) violates the safe harbor for some small subset of hours during the year may not be indicative of any market power problems.

⁵⁵ Peak and off-peak hours were defined according to NERC’s definition, except that I did not consider Saturdays to be peak days. See ftp://www.nerc.com/pub/sys/all_updl/oc/opman/apdx1f.doc.

1 While the delivered price analysis does not reflect the coal units as economic during off-
2 peak periods, the effect on the overall results of the Competitive Screen Analysis is not
3 material, as the price levels reflect the full range of market conditions.⁵⁶

4 In Order No. 642, the Commission indicated that sub-periods should be determined by
5 load levels rather than by time periods. As discussed below, I analyzed each market at
6 prices that range from the levels that would apply at the lowest load levels to those
7 consistent with the highest load levels. These prices analyzed were selected based on a
8 review of PJM market prices. I considered the frequency and distribution of market
9 prices, irrespective of season, as well as the distribution of market prices based on the
10 seasonal definitions used for modeling purposes. I took into consideration actual prices
11 in relevant PJM markets during 2004,⁵⁷ fuel prices in 2004 and forecast fuel prices for the
12 reference year of my analysis, 2006. This broad range of prices, in combination with the
13 time periods, should be reflective of a sufficient range of system conditions such that a
14 full effect of the merger is captured in the analysis.

15 **Q. PLEASE DESCRIBE THE BASIC MODEL ARCHITECTURE YOU USED IN**
16 **ANALYZING THIS MERGER.**

17 A. I used CRA's proprietary model, CASm, to perform the analysis. CASm is a linear
18 programming model developed specifically to perform the calculations required in
19 undertaking the delivered price test. The model includes each potential supplier as a
20 distinct "node" or area that is connected via a transportation (or "pipes") representation of
21 the transmission network. Each link in the network has its own non-simultaneous limit
22 and cost. Potential suppliers are allowed to use all economically and physically feasible
23 links or paths to reach the destination market. In instances where more generation meets

⁵⁶ However, failing to reflect the actual bidding behavior of owners of coal-fired generation does significantly overstate Applicants' share of generation in these off-peak periods, particularly in the PJM Pre-2004 and Expanded PJM markets. Applicants have a disproportionately high share of nuclear generation and a disproportionately low share of coal-fired generation.

⁵⁷ Although locational prices are obviously different throughout Expanded PJM, I nevertheless used a single set of prices for my analysis of all the relevant markets, since the prices cover a full range of possible price conditions, from \$20/MWh to \$250/MWh.

1 the economic element of the delivered price test (e.g., 105 percent of the market price)
2 than can actually be delivered on the transmission network, scarce transmission capacity
3 is allocated based on the relative amount of economic generation that each party controls
4 at a constrained interface.

5 **Q. HOW DID YOU ALLOCATE LIMITED TRANSMISSION CAPACITY?**

6 A. Appendix A notes that there are various methods for allocating transmission, and that
7 applicants should support the method used.⁵⁸ I allocated transmission based on a prorata,
8 “squeeze down” method based on relative ownership shares of capacity at a transmission
9 interface, rather than on the basis of economics, which would allocate limited
10 transmission first to the least expensive generation. The prorata “squeeze-down” method,
11 so-named because it seeks to prorate capacity at each node, is the closest approximation
12 to what the Commission applied in *FirstEnergy*⁵⁹ that is computationally feasible. Under
13 this method, shares of available transmission are allocated at each interface, diluting the
14 importance of distant capacity as it gets closer to the destination market. When there is
15 economic supply (i.e., having a delivered cost less than 105 percent of the destination
16 market price) competing to get through a constrained transmission interface into a control
17 area, the transmission capability is allocated to the suppliers in proportion to the amount
18 of economic supply each supplier has outside the interface.

19 Shares on each transmission path are based on the shares of deliverable energy at the
20 source node for the particular path being analyzed. The calculations start at the outside of
21 a network, defined with the destination market as its center, and end at the destination
22 market itself. A series of decision rules are required to accomplish this proration. The

⁵⁸ See Order No. 592, ¶ 31,044 at 30,133: “In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated among the potential suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used.”

⁵⁹ *Ohio Edison Company, et al.*, 80 FERC ¶ 61,039 at 61,107: “When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface.”

1 purpose of these decision rules is limited to assigning a unique power flow direction to
2 each link for any given destination market analysis. Once the links are given a direction,
3 the complex network can be solved. CASm implements a series of rules to determine the
4 direction of the path. The first rule (and the one expected to be applied most frequently)
5 is based on the direction of the flow under an economic allocation of transmission
6 capacity. Other options take into consideration the predominant flow on the line based
7 on desired volume (the amount of economic capacity seeking to reach the destination
8 market, the number of participants seeking to use a path in a particular direction, and the
9 path direction that points toward the destination market).

10 The model proceeds to assign suppliers at each node a share equal to their maximum
11 supply capability. At each node, “new” suppliers (those located at the node outside of the
12 next interface) are given a share equal to their supply capability, and the shares of more
13 distant suppliers (those who have had to pass through interfaces more remote from the
14 destination market in order to reach the node) are scaled down to match the line capacity
15 into the node. Ultimately, the shares at the destination market represent the prorated
16 shares of Economic Capacity (or Available Economic Capacity) that is economically and
17 physically feasible.

18 This is the same modeling architecture that I have used to analyze numerous previous
19 mergers in testimony relied upon by the Commission. A summary of the transmission
20 architecture used in analyzing the relevant PJM markets is included in Exhibit J-6. In my
21 analysis, I treated MISO as a single exporting control area. However, I note that this
22 treatment of MISO has no material effect on the results of the analysis because any such
23 assumption is overridden by the simultaneous import limits.

24 **Q. WHAT ASSUMPTIONS DID YOU MAKE ABOUT SIMULTANEOUS IMPORT**
25 **CAPABILITY?**

26 A. Analyzing each of the relevant PJM markets requires an assumption about simultaneous
27 import limit (“SIL”). As shown in Exhibit J-6, for imports into PJM East, I assumed a
28 SIL of 7,300 MW, based on a study conducted by PSEG’s transmission engineering

1 group.⁶⁰ When I analyzed the PJM East market, I assumed that generation in the rest of
2 PJM Pre-2004 competed for the limited transmission. In other words, I did not “squeeze”
3 generation from Far West to West to Central. This is consistent with the assumption that,
4 although PJM East is a sometimes-constrained market, the remaining interfaces in PJM
5 Pre-2004 are not often constrained or constrained at the same time as PJM East.

6 For imports into PJM Pre-2004, I used an SIL of 4,600 MW. No transmission study was
7 conducted for this purpose. Instead, I based the 4,600 MW on the maximum level of
8 imports in 2003 for the capacity market.⁶¹ I presume the actual SIL for energy imports
9 would be even greater, and hence this is a conservative measure of import capability into
10 PJM Pre-2004. When analyzing the PJM East market, I used the 4,600 MW SIL to limit
11 flows into PJM Pre-2004, and the 7,300 MW SIL to limit flows into PJM East.

12 Finally, for imports into Expanded PJM, I used an SIL of 7,500 MW. PJM studied
13 simultaneous import capability into PJM for 2004 conditions that included the integration
14 of all the new PJM members, including Dominion.⁶² When analyzing the PJM East
15 market, I assumed the 7,500 MW SIL limited flows into Expanded PJM, the 4,600 MW
16 SIL limited flows into PJM Pre-2004, and the 7,300 MW SIL limited flows into PJM
17 East. When analyzing the PJM Pre-2004 market, I assumed the 7,500 MW SIL was
18 applied to flows into Expanded PJM, and then the 4,600 MW SIL was applied to flows
19 into PJM Pre-2004.

⁶⁰ This study was conducted using PJM’s transmission models for summer 2006. Thus, these models are intended to reflect any transmission upgrades that PJM assumes will be in effect by the summer of 2006. The workpapers for this study are included in my workpapers, filed as Critical Energy Infrastructure Information (“CEII”).

⁶¹ *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, pages 123. “An average of 3,819 MW of capacity resources was imported into the PJM and an average of 1,664 MW was exported (delisted) for an average net import of 2,155 MW of capacity resources during the period. The maximum export (delist) was 2,457 MW, while the maximum import was 4,638 MW.”

⁶² “Simultaneous PJM Import Capability”, Document prepared by System Operations Division – Transmission, September 8, 2004, and posted on OASIS.
<http://www.pjm.com/markets/market-integration/downloads/documentation/20040909-simultaneous-pjm-import-capability.pdf>

1 **Q. WHAT YEAR DID YOUR ANALYSIS COVER?**

2 A. I analyze 2006 market conditions, consistent with the Order No. 642 requirement that the
3 analysis be forward looking.

4 Even though my analysis approximates 2006 market conditions, the primary source of
5 data on generation and transmission is current and recent historical data. Where
6 appropriate, I adjusted relevant data to approximate 2006 conditions. As described in
7 Exhibit J-4, this includes load and generation dispatch (*i.e.*, fuel) costs. With respect to
8 new generation, I only included generation already under construction and expected to be
9 on-line by 2006; I did not include any additional planned generation not yet under
10 construction. With respect to retirements, I included only units already retired or already
11 approved by PJM for retirement prior to 2006.

12 **Q. HOW DO YOU ACCOUNT FOR LONG-TERM PURCHASES AND SALES?**

13 A. In the past, I have treated long-term power arrangements as resulting in a transfer of
14 ownership and control to the purchaser. Order No. 642 discusses two criteria for
15 determining control: operational control (*i.e.*, “the party that has the authority to decide
16 when generating resources are available for operation”),⁶³ and economic or beneficial
17 interest (*i.e.*, “the party for whose economic benefit the...unit is operated”).⁶⁴ In the

⁶³ *Revised Filing Requirements*, Section 33.3(c)(4)(i)(A).

Economic capacity means the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. Prior to applying the delivered price test, the generating capacity meeting this definition must be adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts (*i.e.*, contracts with a remaining commitment of more than one year). The capacity associated with any such adjustments must be attributed to the party that has authority to decide when generating resources are available for operation. Other generating capacity may also be attributed to another supplier based on operational control criteria as deemed necessary, but the applicant must explain the reasons for doing so. (emphasis added)

⁶⁴ *Order No. 642*, footnote 39.

The starting point for calculating economic capacity is the supplier's own generation capacity with low enough variable costs that energy can be delivered to a market (after paying all necessary transmission and ancillary service costs, including losses) at a price that is five percent or less above the pre-merger market price. Capacity must be decreased to reflect any portion committed

1 Revised Filing Requirements and in subsequent orders concerning market rate authority,
2 the Commission has emphasized the first of these criteria.⁶⁵ For most purchases and
3 sales, I am unable to determine whether the seller or buyer has control⁶⁶ and in those
4 cases I assigned control to the buyer. I note, however, that the treatment of purchases and
5 sales is inconsequential in terms of the results of my analysis, except with respect to
6 Applicants' contracts.

7 Exelon Generation has several long-term (more than one-year) contracts of relevance for
8 the output of various plants located in the former ComEd control area. Through mid-
9 2011, Exelon Generation has contracts with affiliates of Dominion to purchase the output
10 of two coal-fired plants (Kincaid and State Line) formerly owned by ComEd. In my
11 analysis, I treated the entire output of these units as available to (and controlled by)
12 Exelon Generation when economic. Exelon Generation also has a series of long-term
13 PPAs for approximately 3,600 MW of supply from merchant generation, mostly peakers,
14 located in the former ComEd control area.⁶⁷ Again, in my analysis, I treated these PPAs
15 as if Exelon Generation controls the units.

to long-term firm sales; and it must be increased to reflect any portion acquired by long-term firm purchases. In addition, any capacity under the operational control of a party other than the owner must be attributed to the party for whose economic benefit the related unit is operated. The result of these calculations is the supplier's "economic capacity." (Emphasis added)

⁶⁵ In the context of the Commission's new, interim generation market power analysis in connection with market-based rates, the Commission focuses on operational control ("if an applicant has control over certain capacity such that the applicant can affect the ability of that capacity to reach the relevant market, then that capacity should be attributed to the applicant when performing the screens."). *AEP Power Marketing, Inc. et al.*, Order on Rehearing, 108 FERC ¶ 61,026 (2004), P 65.

⁶⁶ This uncertainty arises both from ambiguity in the Commission's guidance and a lack of access to contract terms. A common example is a unit contingent contract (tolling or otherwise) in which the buyer has the right to nominate output from the unit. However, the seller controls whether the unit is made available (typically subject to penalties for non-availability). Moreover, if the buyer does not nominate the output, the seller frequently has the right to dispatch the plant for its own account. Given this mixture of circumstances, it is not wholly clear which party has "control" in the sense relevant to the Commission's market power tests.

⁶⁷ Exelon Generation also has PPAs or tolling agreements for the output of generation outside of PJM that I considered under its control as well. See Exhibit J-3.

1 Additionally Exelon Generation has a long-term contract with Illinois Power to sell 400
2 MW of the output of the Clinton nuclear unit located in the Illinois Power control area
3 through 2006, which I reflected in my analysis as under the control of the buyer.

4 With respect to purchases from QFs or non-utility generators (“NUGs”), I included as
5 Exelon-affiliated generation purchases totaling less than 200 MW from several NUGs,
6 and treated them as must-take, non-dispatchable. However, because of regulatory
7 treatment, PSE&G does not control its NUGs. PSE&G sells the energy delivered and
8 capacity provided under NUG contracts to PJM. PSE&G has no financial interest in the
9 price received for this power. Thus, PSE&G does not have either operational control of
10 or beneficial interest in these NUGs. These NUGS were treated in my modeling as must-
11 take, non-dispatchable units, but unaffiliated with Applicants.

12 PSEG has sold a substantial amount of energy (as well as capacity) in the New Jersey
13 BGS auction, as well as through long-term bilateral sales. I conservatively have not
14 taken these into account in my analysis of Economic Capacity, but have reflected them in
15 my analysis of Available Economic Capacity.

16 Finally, both Exelon Generation and PSEG ER&T have contracts to sell capacity
17 (ICAP/UCAP) in the PJM market. I have not taken these into account in either my
18 energy or capacity analyses.

19 **Q. PLEASE DESCRIBE YOUR BASE, PRE-MERGER CASE WITH RESPECT TO**
20 **EXELON.**

21 A. As shown in [Table 5](#) below, Exelon Generation’s owned and contracted resources
22 in PJM Pre-2004 total 11,002 MW, mostly located in PJM East,⁶⁸ which is equivalent to
23 Exelon’s Economic Capacity within the PJM Pre-2004 market at the highest-priced time
24 period, before adjustment for outages (and before consideration of imports).

⁶⁸ This tabulation reflects energy only, and does not include purchases or sales of capacity. Also, these figures will differ slightly from those used in my capacity analysis, primarily because of differences in the treatment of NUGs and other generation that does not typically qualify as capacity.

1 PECO’s forecasted load requirement for 2006 is 8,033 MW. Thus, Exelon’s “excess”
 2 supply in PJM Pre-2004 (before consideration of reserves) is less than 3,000 MW, which
 3 is equivalent to Exelon’s Available Economic Capacity within the PJM Pre-2004 market
 4 at times of peak (again, before adjustment for outages). In analyzing Available
 5 Economic Capacity, I assume that PECO’s load in the East was served by its generation
 6 in both PJM East and the rest of PJM Pre-2004. Consistent with Order No. 592, I
 7 assumed that the “lowest running cost units are used to serve native load.”⁶⁹

8 ComEd will continue to have POLR load obligations through 2006, and, indeed is
 9 currently capacity-short with respect to these obligations, as shown in Table 5 below.

Table 5: Exelon Generation and Load in PJM

Exelon Generation and Load (in megawatts)	PJM East	Rest of PJM Pre- 2004	PJM Pre- 2004	Rest of Expanded PJM
<i>Economic Capacity</i> Exelon Generation Owned and Contracted-For Resources	7,180	3,822	11,002	15,340
Peak Load, 2006	8,033	0	8,033	18,000
<i>Available Economic Capacity</i>	NA	NA	2,969	(2,660)

11
 12 ~~Table 6~~ below reflects Exelon’s net position in the ICAP market in 2006.
 13 However, the ICAP analysis I undertake later is based on Exelon’s gross, rather than net,
 14 ICAP position.

⁶⁹ Order No. 592, *slip op*, page 70. I note that this section continues, and states: “As competition develops, this presumption may not be valid.” The following footnote is included: “For example, in a market with full retail access and a bid-based power exchange, all generation units would be in the market.” However, in the specific circumstances for PECO, even in a full retail access environment and a bid-based power exchange, PECO has the obligation to serve its native load customers through 2010.

1

Table 6: Exelon ICAP Position

Exelon Generation and Load (in megawatts)	PJM Pre- 2004	Rest of Expanded PJM
Starting ICAP Position (see Table 5)	2,969	(2,660)
Plus Purchases, Jun '05-May '06	0	1,700
Minus Sales, Jun '05-May '06	0	1,000
Net ICAP Position, Jun '05-May '06		(1,960)
Plus Purchases, Jun '06-May '07	0	500
Minus Sales, Jun '06-May '07	0	1,000
Net ICAP Position, Jun '06-May '07	2,969	(3,160)

2

3 **Q. PLEASE DESCRIBE YOUR BASE CASE ASSUMPTIONS WITH RESPECT TO**
4 **PSEG.**

5 A. As shown in [Table 7](#) below, PSEG's owned and contracted resources in PJM Pre-
6 2004 total 12,017 MW, mostly located in PJM East. PSE&G has no POLR load
7 obligations as such, since its POLR responsibilities are met through the New Jersey BGS
8 auction.

9

Table 7: PSEG Generation and Load

PSEG Generation and Load (in megawatts)	PJM East	Rest of PJM Pre-2004	PJM Pre- 2004	Rest of Expanded PJM
<i>Economic Capacity</i> PSEG Generation Owned and Contracted-For Resources	10,121	1,896	12,017	1,946
PSE&G Load Responsibility, 2006	0	0	0	0
Load Commitments, Jun '05-May '06			4,975	0
<i>Available Economic Capacity, Jun '05-May '06</i>			7,042	1,946
Load Commitments, Jun '06-May '07			2,200	
<i>Available Economic Capacity, Jun '06-May '07</i>			9,817	1,946

10

11 However, PSEG is a supplier into the BGS auction, and provides the supply for 42
12 tranches for the period June 2005 through May 2006 and 17 tranches for the period June
13 2006 through May 2007. Each tranche entails the requirement to supply approximately

1 100 MW of peak load obligation (capacity, energy and ancillary services), with the
 2 delivery requirement following the shape of the 100 MW of peak load. The peak load
 3 could be slightly higher or lower depending on customer migration and load growth.
 4 PSEG also has a commitment to serve 275 MW of Duquesne POLR obligations
 5 (capacity, energy and ancillary services) through May 2006, and a commitment to
 6 provide 500 MW of firm energy to FirstEnergy for delivery at PJM West through 2008.
 7 For purposes of analyzing Available Economic Capacity, I reflect PSEG's commitment
 8 to serve 4,975 MW of load through May 2006 (4,200 MW BGS, plus 275 MW
 9 Duquesne, plus 500 MW FirstEnergy) and 2,200 MW of load for the remainder of 2006
 10 (1,700 MW BGS plus 500 MW FirstEnergy), as shown in [Table 7](#) ~~Table-7~~ above.⁷⁰

11 [Table 8](#) ~~Table-8~~ below reflects PSEG's net position in the ICAP market. As with Exelon,
 12 the ICAP analysis I undertake later is based on PSEG's gross, rather than net, ICAP
 13 position.

14 **Table 8: PSEG ICAP Position**

PSEG Generation and Load (in megawatts)	PJM Pre- 2004	Rest of Expanded PJM
Starting ICAP Position (see Table 7 Table-7) Jun '05-May '06	7,042	1,946
Plus Purchases, Jun '05-May '06	0	0
Minus Sales, Jun '05-May '06	2,400	0
Net ICAP Position, Jun '05-May '06	4,642	1,946
Starting ICAP Position (see Table 7 Table-7) Jun '06-May '07	9,817	1,946
Plus Purchases, Jun '06-May '07	0	0
Minus Sales, Jun '06-May '07	2,100	0
Net ICAP Position, Jun '06-May '07	7,717	1,946

15
16

70 PSEG also has commitments to provide approximately 150 MW to retail aggregators. I conservatively did not

1 **V. IMPACT OF THE MERGER ON COMPETITION**

2 **Q. WHAT SPECIFIC ANALYSES DID YOU CONDUCT TO EVALUATE THE**
3 **POTENTIAL COMPETITIVE EFFECTS ARISING FROM THE COMBINATION**
4 **OF GENERATION ASSETS?**

5 A. Consistent with the guidance in the *Merger Policy Statement*, I analyzed Economic
6 Capacity and Available Economic Capacity, and ancillary services markets. I also
7 analyzed the PJM market for capacity. As discussed earlier, I examined PJM East, PJM
8 Pre-2004, and Expanded PJM as relevant destination markets. I also considered other
9 geographic markets in which Applicants own generation outside of PJM.

10 In the sections below, I first look at each of the PJM markets for Economic Capacity.
11 Second, I consider the relevant Available Economic Capacity analyses. Third, I evaluate
12 any other relevant geographic markets. Fourth, I evaluate capacity and ancillary services
13 markets in PJM. Finally, I present the results of the analysis of mitigation and the effect
14 on the Competitive Analysis Screen.

15 **PJM Markets: Economic Capacity**

16 **Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN PJM**
17 **EAST?**

18 A. The Economic Capacity analysis reflects the substantial overlap of generation owned by
19 the Applicants in PJM East.⁷¹ In this market, the Competitive Analysis Screen is failed in
20 all time periods, as shown below in [Table 9Table-9](#) and in Exhibit J-7. Pre-Merger,
21 Exelon's market share ranges from 18 to 31 percent, and PSEG's from 14 to 25 percent.
22 The market is highly concentrated post-merger, with a combined market share as high as
23 47 percent and HHI changes in excess of 1,000 points.

include this in my analysis.

⁷¹ The analyses also reflect the allocation of a portion of the interface into PJM East to Applicants' generation located in the rest of PJM.

1

Table 9: Economic Capacity, PJM East

Period	Price	Pre-Merger						Post-Merger			
		Exelon		PSEG		Mkt Size	HHI	EEG			HHI Chg
		MW	Mkt Share	MW	Mkt Share			MW	Mkt Share	HHI	
S_SP1	\$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929
S_SP2	\$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870
S_P	\$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058
S_OP	\$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015
W_SP	\$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900
W_P	\$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067
W_OP	\$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987
SH_SP	\$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870
SH_P	\$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848
SH_OP	\$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870

2

3 **Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN PJM**
4 **PRE-2004?**

5 A. Market shares and HHI changes are significantly lower in PJM Pre-2004, but the
6 Competitive Analysis Screen still is failed in all time periods, as shown below in [Table](#)
7 [10Table 10](#) and in Exhibit J-7. Pre-merger, Exelon's market share ranges from about 14
8 to 26 percent, and PSEG's from about 10 to 15 percent. The market is moderately
9 concentrated post-merger in all time periods, with HHI changes ranging from about 350
10 to 650 points.

11

Table 10: Economic Capacity, PJM Pre-2004

Period	Price	Pre-Merger						Post-Merger			
		Exelon		PSEG		Mkt Size	HHI	EEG			HHI Chg
		MW	Mkt Share	MW	Mkt Share			MW	Mkt Share	HHI	
S_SP1	\$250	10,508	13.6%	11,210	14.5%	77,273	896	21,718	28.1%	1,291	395
S_SP2	\$80	9,545	13.8%	9,288	13.4%	69,380	885	18,834	27.2%	1,254	369
S_P	\$55	7,976	14.6%	7,455	13.7%	54,517	971	15,431	28.3%	1,371	400
S_OP	\$25	6,416	25.9%	3,189	12.9%	24,749	1,217	9,605	38.8%	1,885	668
W_SP	\$80	9,899	14.1%	9,334	13.3%	70,238	883	19,233	27.4%	1,257	374
W_P	\$55	8,299	15.1%	7,273	13.2%	54,932	968	15,571	28.4%	1,368	400
W_OP	\$30	7,701	17.7%	4,946	11.4%	43,557	985	12,648	29.0%	1,386	401
SH_SP	\$65	7,866	15.6%	6,263	12.4%	50,501	951	14,129	28.0%	1,337	386
SH_P	\$45	6,936	17.2%	4,070	10.1%	40,251	1,004	11,006	27.3%	1,353	349
SH_OP	\$20	5,472	26.4%	2,440	11.8%	20,715	1,206	7,912	38.2%	1,828	622

12

1 **Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN**
2 **EXPANDED PJM?**

3 A. While Exelon’s market share in Expanded PJM is about the same as in PJM Pre-2004
4 (given the addition of its owned or controlled generation in the former ComEd control
5 area), PSEG’s market share is significantly smaller such that overall market shares and
6 HHI changes are significantly lower in Expanded PJM. The Competitive Analysis
7 Screen is failed in all time periods, as shown below in [Table 11](#) and in Exhibit J-
8 7. Pre-merger, Exelon’s market share ranges from about 15 to 22 percent, and PSEG’s
9 from about 5 to 8 percent. The market is moderately concentrated post-merger, with HHI
10 changes ranging from about 170 to about 250 points.

11 **Table 11: Economic Capacity, Expanded PJM**

Period	Price	Pre-Merger						Post-Merger			
		Exelon		PSEG		Mkt Size	HHI	EEG			
		MW	Mkt Share	MW	Mkt Share					MW	Mkt Share
S_SP1	\$250	24,354	14.9%	12,929	7.9%	163,707	774	37,283	22.8%	1,009	235
S_SP2	\$80	23,384	15.2%	11,006	7.1%	154,162	795	34,390	22.3%	1,011	216
S_P	\$55	18,813	15.3%	9,153	7.5%	122,719	902	27,966	22.8%	1,130	228
S_OP	\$25	16,950	22.3%	3,189	4.2%	76,038	1,447	20,139	26.5%	1,634	187
W_SP	\$80	24,013	15.4%	11,053	7.1%	156,250	804	35,067	22.4%	1,021	217
W_P	\$55	19,150	15.3%	8,973	7.2%	124,828	909	28,123	22.5%	1,130	221
W_OP	\$30	18,373	17.8%	4,946	4.8%	102,979	1,102	23,319	22.6%	1,274	172
SH_SP	\$65	19,460	16.4%	7,672	6.5%	118,586	850	27,133	22.9%	1,063	213
SH_P	\$45	15,842	16.5%	5,462	5.7%	95,869	932	21,304	22.2%	1,120	188
SH_OP	\$20	12,975	21.8%	2,440	4.1%	59,411	1,428	15,415	26.0%	1,608	180

13 **PJM Markets: Available Economic Capacity**

14 **Q. HAVE YOU ALSO ANALYZED THE EFFECTS OF THE MERGER ON**
15 **AVAILABLE ECONOMIC CAPACITY?**

16 A. Yes, although I note that developing a comprehensive Available Economic Capacity
17 analysis is quite difficult, given the status of retail access in PJM. Under conditions of
18 full retail access, the Available Economic Capacity analysis becomes identical to
19 Economic Capacity. However, despite full retail access in some portions of PJM (e.g.,
20 Pennsylvania, New Jersey and Illinois), both Exelon and PSEG have continuing load
21 obligations: PECO in the form of a requirement to provide POLR service to its

1 customers through 2010 and PSEG in the form of load commitments secured as a
2 participant in the New Jersey BGS auction. Thus, my analysis of Available Economic
3 Capacity takes into consideration Applicants' commitments to serve customer loads. As
4 described earlier, PECO's peak load commitments are forecast to be approximately 8,000
5 MW and PSEG's peak load commitments conservatively are assumed to conservatively
6 be 2,200 MW.⁷² ComEd also is assumed to have load consistent with its POLR
7 commitments totaling approximately 18,000 MW.

8 Utilities in New Jersey, Maryland, Pennsylvania and elsewhere in the mid-Atlantic
9 generally still have POLR responsibilities, but tend to serve load through PPAs or, as in
10 the case of New Jersey, through the BGS auction that effectively results in the sale of
11 load obligations to third-parties. Retail access also exists in other PJM states (*e.g.* Ohio)
12 and in states from which power is exported to PJM. The real analytic difficulty arises
13 because there are no publicly-available data identifying which generation is committed to
14 serving load. The BGS auction, for example, reflects that the winning bidders include
15 marketers, and it is impossible to determine from available data which generation they
16 may have procured to serve the load or for what period. A further complication is that
17 some of the retail load commitments that will be in effect in 2006 and beyond will be
18 determined in procurements that have not yet occurred. For these reasons, I have not
19 attempted to speculate on individual entities' load requirements.⁷³ Instead, I have looked
20 at bounding the results with two separate analyses. First, I take into account only
21 Applicants' load commitments (that is, ComEd's/PECO's and PSEG's commitments to
22 serve load directly or as the winner in the BGS auctions, respectively). I also take into
23 account the load obligations of AEP and Dominion, as both utilities continue to serve
24 most of their load or default service obligations from owned generation. In this scenario,
25 all other generation is assumed to be uncommitted. The second analysis, in addition to
26 taking into account Applicants' load commitments (as well as AEP's and Dominion's),
27 assumes that all other generation in the market was committed to the extent there existed

⁷² These peak load requirements are shaped to reflect the time period assumptions I described earlier.

⁷³ Elsewhere, the Commission has indicated its distaste for hypothetical assumptions about the extent of retail access in markets where such access has begun. *EME Homer City Generation, L.P.*, 86 FERC ¶ 61,016 (1999).

1 a load requirement somewhere in the market. For example, if the remaining generation in
2 the market is 50,000 MW and the remaining load is 40,000 MW, only 10,000 MW of
3 generation would count as Available Economic Capacity. Consistent with Appendix A
4 of the Merger Policy Statement, I assumed, in this example, that the 40,000 MW of
5 lowest variable cost generation was used to serve load, regardless of the actual party that
6 had load responsibility or owned generation. In this scenario, I have not matched specific
7 generation to specific load, but do measure remaining available market generation. This
8 analysis shows the minimum amount of non-applicant Available Economic Capacity,
9 since it assumes that all load is served from either owned generation or long-term
10 contracts. In fact, some load doubtless is served from short-term contracts or spot
11 purchases.

12 The HHIs in both of these analyses are somewhat suspect, and perhaps the proper focus is
13 on the Applicants' total amount of Available Economic Capacity, rather than the HHIs
14 and the HHI changes. However, this does not fully resolve the problem since one cannot
15 calculate HHI change without a proper measure of the size of the market and, hence,
16 Applicants' market share. For the Expanded PJM market, Applicants' mitigation
17 commitment exceeds Applicants' Available Economic Capacity, but in other markets and
18 time periods it does not. Of course, the proposed divestiture will substantially reduce
19 Applicants' shares of Available Economic Capacity.

20 In any event, Available Economic Capacity is a questionable metric for defining market
21 share in PJM. All capacity must be bid into the PJM market and selected to run before it
22 can generate. Hence, irrespective of retail load commitments, all of a supplier's
23 Economic Capacity is relevant to setting market prices. Thus, while I have presented an
24 Available Economic Capacity analysis as required by the Commission's regulations, I
25 have focused primarily on the Economic Capacity analysis in determining the effects of
26 the merger on competition and in assessing the efficacy of mitigation.

1 **Q. WHAT ARE THE RESULTS OF YOUR AVAILABLE ECONOMIC CAPACITY**
2 **ANALYSES?**

3 A. Exhibit J-8 presents a series of results for Available Economic Capacity. For PJM East,
4 as shown on page 1, Exelon's Available Economic Capacity ranges from about 800 MW
5 to about 2,400 MW, depending on the time period considered, and PSEG's ranges from
6 about 400 MW to about 8,300 MW. Assuming no other generation in PJM East is
7 committed to serving load, their combined shares of Available Economic Capacity range
8 from 12 to 32 percent. The market is unconcentrated or moderately concentrated and the
9 HHI changes are as high as about 400 points. However, after consideration of
10 Applicants' mitigation plan, Applicants' market share is reduced to no more than about
11 17 percent and, in all instances, the transaction is deconcentrating.

12 For PJM Pre-2004 (page 2 of Exhibit J-8), the level of Applicants' Available Economic
13 Capacity is higher than in PJM East, but assuming no other generation in PJM Pre-2004
14 is committed to serving load, their combined shares of Available Economic Capacity are
15 no more than 21 percent. The market is unconcentrated to moderately concentrated
16 before mitigation, and, once again, after consideration of Applicants' mitigation plan, the
17 transaction is deconcentrating and Applicants' market share is reduced to no more than
18 about 11 percent. Even with the highly conservative scenario in which the rest of PJM
19 Pre-2004 load is assumed to be served from long-term entitlements to capacity (page 3 of
20 Exhibit J-8), an assumption that is simply unrealistic, Applicant's mitigation plan results
21 in the market being deconcentrated relative to the pre-merger scenario.

22 Finally, for Expanded PJM, where I take into consideration the load commitments of
23 ComEd, Dominion and AEP, as well as PECO and PSE&G, as shown in page 4 of
24 Exhibit J-8, Applicants' combined shares of Available Economic Capacity are no more
25 than about 13 percent. The market is unconcentrated and the HHI changes pass the
26 screening thresholds, even before mitigation.

1 **Q. YOU STATED THAT YOU CONSIDERED WHETHER NORTHERN NEW**
2 **JERSEY, OR THE NORTHERN PSEG ZONE, WAS A RELEVANT MARKET.**
3 **PLEASE DESCRIBE YOUR ANALYSIS.**

4 A. As I noted earlier, the Northern PSEG zone is not a relevant geographic market for
5 purposes of the merger analysis because Exelon has no generation in that market. The
6 merger will have no incremental effect on the ability or the incentive of the Applicants to
7 influence prices in that market, other than the competitive effects of the merger on all of
8 PJM East, which are resolved in the Applicants' mitigation proposal.

9 First, consider the effects of the merger on northern New Jersey when there are no binding
10 constraints into that market. Under such circumstances, the geographic boundaries of this
11 market are no smaller than all of PJM East, and the proposed mitigation for PJM East
12 resolves any competitive effects.

13 Now consider the effects of the merger on northern New Jersey when constraints into that
14 market are binding. EEG will have no more generation in the market than did PSEG
15 before the merger. Thus, the incentive to raise prices in that market will be no greater after
16 the merger, and will be reduced to the extent Applicants, pursuant to their mitigation plan,
17 divest coal, mid-merit or peaking generation in northern New Jersey, because in either case
18 the Applicants will have the same amount of, or less, generation that benefits from higher
19 northern New Jersey prices.

20 The ability to raise prices in northern New Jersey also will not be increased after the
21 merger. The amount of the Applicants' generation in the market will be the same or less
22 after the merger, so there will be no additional ability to withhold generation from the
23 market. The only change caused by the merger will be the fact that EEG will have more
24 generation outside the market than PSEG had before the merger, but any generation that
25 EEG might withhold outside the constrained market will not affect prices inside the
26 constrained market. The only possible effect inside the northern New Jersey market of
27 withholding a former Exelon unit located outside the market is that the mix of imports into
28 northern New Jersey might change, but prices in the market will remain the same.

1 Hence, taking into consideration the mitigation plan in PJM East, the effect of withholding
2 generation in northern New Jersey is no different than it would be without the merger and
3 the effect of withholding Exelon (or former PSEG) generation elsewhere in PJM East also
4 is no different than pre-merger.

5 Notwithstanding the clear fact that the merger cannot have a unique effect on northern
6 New Jersey, a screen analysis limited to this area would show screen failures.⁷⁴ This is
7 merely a by-product of how other generation in PJM East is "squeezed down" by the
8 transmission limit into northern New Jersey. For the reasons discussed above, this does
9 not reflect a market power problem, and no additional mitigation should be required. If
10 the Commission determines, however, that additional mitigation is necessary, Applicants'
11 would agree to mitigate the northern New Jersey screen failures. The screen failures
12 would be eliminated by the divestiture of no more than 100 MW of coal-fired generation
13 and no more than 100 MW of mid-merit generation. This is a subset of the 5,500 MW of
14 overall mitigation. Applicants would agree to meet this requirement either by divesting
15 such generation in northern New Jersey as part of their overall divestiture commitment or
16 by delivering baseload energy into northern New Jersey (or selling it at Applicants' PJM
17 East buses plus a basis differential into northern New Jersey). As with other divestitures,
18 selling or delivering generation with a lower variable cost also mitigates the screen
19 failure.

20 **Other Relevant Markets**

21 **Q. ARE THERE OTHER MARKETS IN WHICH THERE IS AN OVERLAP IN**
22 **APPLICANTS' GENERATION?**

23 A. With two exceptions, Applicants either "do not currently operate in the same geographic
24 markets or...the extent of the business transactions is *de minimis*"⁷⁵ and, therefore, no

⁷⁴ This analysis is contained in my workpapers.

⁷⁵ Section 33(a)(2) of the Revised Filing Requirements. The Commission established an exemption from the requirement to file a horizontal Competitive Analysis Screen if the applicant:

1 further analysis is required. The following table was presented earlier in my testimony
2 and also is included in Exhibit J-3. The discussion below examines each of the markets
3 or regions in which Applicants own generation outside of PJM.⁷⁶

4 **Table 4: Applicants' Generation Outside of PJM**

NERC	RTO	Exelon (MW)	PSEG (MW)
NPCC	ISO-NE	630	967
NPCC	NYISO	-	761
WECC	CAISO	-	443
SPP	SPP	795	-
ERCOT	ERCOT	3,651	2,026
SERC		1,755	-
MAIN	MISO	713	-
Total, Non-PJM		6,714	4,197

Note: Exelon's total is adjusted to account for double-counting of a unit connected to both ERCOT and SERC.

5 *ISO-NE*. Exelon's 630 MW of affiliated generation in ISO-NE includes New Boston and
6 West Medway located within the Northeastern Massachusetts ("NEMA") load pocket and
7 a few megawatts of generation located in Maine. PSEG's 967 MW of affiliated
8 generation in ISO-NE includes Bridgeport Harbor and New Haven Harbor located in
9 Southwest Connecticut and a few megawatts of generation located in New Hampshire.
10 Thus, the smallest relevant market in which both Applicants' generation would compete
11 is ISO-NE as a whole. Relative to ISO-NE's total generation (in excess of 30,000 MW),
12 Exelon's affiliated generation is only 2 percent and PSEG's affiliated generation is only 3
13 percent of ISO-NE capacity. New England is generally an unconcentrated market, and

-
- (i) Affirmatively demonstrates that the merging entities do not currently operate in the same geographic markets or that the extent of the business transactions in the same geographic market is *de minimis*; and
 - (ii) No intervenor has alleged that one of the merging entities is a perceived potential competitor in the same geographic market as the other.

⁷⁶ Although the discussion that follows presents market shares based on total capacity in the market (as opposed to Economic Capacity), market shares of Economic Capacity similarly would raise no competitive concerns in each of the relevant markets.

1 under any relevant condition studied in a Competitive Analysis Screen Applicants' shares
2 would not cause HHI screen failures. The competitive nature of the ISO-NE market is
3 exemplified by the fact that the Commission recently approved a transaction that
4 involved the purchase of approximately 2,800 MW of capacity in New England by a
5 generator that already owed about 2,000 MW of capacity in New England.⁷⁷ Since the
6 relevant transaction here involves combining 630 MW of generation owned by Exelon
7 with 957 MW of generation owned by PSEG, the results of a Competitive Screen
8 Analysis of the instant merger is by definition less than that of the transaction that the
9 Commission recently approved. No further analysis of the ISO-NE market is necessary.

10 *ERCOT.*⁷⁸ Exelon owns or controls via long-term contract 3,651 MW of generation in
11 ERCOT,⁷⁹ mostly located in the North zone of ERCOT, with a small amount located in
12 the Houston zone. PSEG owns 2,026 MW of affiliated generation in ERCOT, located in
13 either the South or West zones. Since Applicants' generation is located in different zones
14 within ERCOT, the only potentially relevant market is ERCOT as a whole. ERCOT's
15 total generation is in excess of 80,000 MW. Exelon's affiliated generation is less than 5
16 percent and PSEG's affiliated generation is only 2.5 percent of ERCOT capacity. These
17 shares are small and the combination of Applicants' shares presents no competitive
18 concerns in ERCOT. Specifically, the "2ab" change in HHI is only about 20 points in
19 peak periods and will be well under screen thresholds in other periods. A full
20 Competitive Screen Analysis is not necessary to conclude that the effect of the merger in
21 this market is not concerning.

22 *Other Markets.* In all other regions where Applicants own generation – WECC,
23 Southwest Power Pool ("SPP"), SERC, NYISO and the portion of Mid-America

⁷⁷ *USGen New England, Inc.*, 109 FERC ¶ 61,361 (2004). The Order describes applicant's (*i.e.*, Dominion's) analysis as follows: "For Economic Capacity, the post-acquisition New England market is unconcentrated (Herfindahl-Hirschman Index (HHI) < 1000)..."

⁷⁸ I have considered the effects of the merger on the ERCOT market despite the fact that it is not subject to the Commission's jurisdiction.

⁷⁹ This includes an 830 MW purchase (tolling agreement) from a plant that is capable of being dispatched into ERCOT or Entergy.

1 Interconnected Network, Inc. (“MAIN”) that is not part of PJM – only one of the merging
2 parties owns generation, so they “do not currently operate in the same geographic
3 markets.”

4 Capacity Markets in PJM

5 Q. PLEASE DESCRIBE PJM’S CURRENT MARKET FOR CAPACITY.

6 A. Beginning in June 2003, there was a single PJM capacity market that included the Mid-
7 Atlantic region and the then-styled PJM Western region (*i.e.*, Allegheny Energy), with
8 Daily and Monthly Unforced Capacity Credit markets. With the integration of ComEd, a
9 Monthly (and multi-monthly) NICA (Northern Illinois Control Area) Installed Capacity
10 Credit market was introduced. Effective January 1, 2005, there is a single capacity
11 market that includes all current PJM members. UCAP remains the measure of relevance
12 for the capacity market. Under UCAP, each unit’s capacity is adjusted to account for its
13 average forced outage rate.

14 Q. IS PJM CONSIDERING ALTERNATIVE MARKET STRUCTURES FOR THE 15 CAPACITY MARKET?

16 A. Yes, the capacity market is expected to be significantly restructured, as part of an
17 ongoing effort to improve system reliability and price signals. In addition to altering the
18 price mechanism (for example, basing capacity payments on a “demand curve” that
19 specifies the price of capacity given different levels of supply and ensuring prices that
20 support entry at the point when capacity is needed), PJM is considering the introduction
21 of a new series of auctions and a more formalized bilateral market for capacity. The
22 proposal is to eventually have four-year forward base auctions.⁸⁰ Incremental Auctions
23 would supplement Base Auctions three times during the four-year forward term. In
24 addition, local capacity requirements may be imposed to ensure local reliability in

⁸⁰ *PJM Reliability Pricing Model (RPM)*, DRAFT Business Rules, December 24, 2004.
<http://www.pjm.com/committees/working-groups/pjmramwg/downloads/reliability-pricing-model-business-rules.doc>

1 transmission constrained areas. “Locational Delivery Areas” are “geographic areas
2 within the PJM that have limited transmission capability to import capacity to satisfy the
3 Unforced Capacity Obligation of the load within that area.”⁸¹ Locational constraints may
4 be zonal-based (that is, for each EDC zone, such as PECO or PSEG), or may represent
5 sub-zones (such as PS North) or combinations of zones (such as Eastern PJM). The
6 zones to be created for the initial auction are under discussion, but it appears that
7 locational zones will not be applicable until the 2007/2008 planning year. The current
8 plan is that PJM East will become a zone in 2007-8 as will Southwestern MAAC
9 (PEPCO and BG&E). The balance of Pre-2004 PJM (*i.e.*, with PJM East and
10 Southwestern MAAC separated out) also will be a zone. Pending further analysis, each
11 of the major new PJM members’ former control areas (*e.g.* ComEd, AEP and DVP) will
12 be separate zones. The zonal structure of markets will be reanalyzed in the future and
13 appropriate changes made.

14 **Q. GIVEN PJM’S ONGOING STUDY OF ALTERNATIVE CAPACITY MARKET**
15 **MECHANISMS, HOW HAVE YOU ANALYZED PJM CAPACITY MARKETS?**

16 A. I have analyzed two definitions of ICAP markets: Expanded PJM and PJM East.
17 Expanded PJM is the currently relevant market. PJM East is one possible market
18 definition that may exist in the future; indeed it is a planned market for 2007-8. While
19 Southwestern MAAC would be a smaller market, it would not be a relevant market to this
20 merger because Applicants do not own generation in this market.

21 Although the capacity credit markets are based on UCAP, lacking data on unit-specific
22 forced outages, I analyzed the market based on installed capacity. The use of installed
23 capacity should not materially impact the results of my analysis.⁸²

81 <http://www.pjm.com/committees/working-groups/pjmramwg/downloads/20041216-draft-tariff-revisions-rpm-att-y.pdf>

82 The use of ICAP is tantamount to assuming that the fleet of capacity owned by each market participant has the same forced outage rate. While not literally true, this will be nearly correct and any variation in forced outage rates could either increase or decrease market HHIs by small amounts.

1 **Q. IS THE MARKET DEFINITION FOR ICAP ESSENTIALLY IDENTICAL TO**
2 **THE MARKET DEFINITION FOR SUMMER SUPER-PEAK ENERGY?**

3 A. Essentially, yes. For an Eastern zonal market, other PJM capacity can qualify up to the
4 import limit. For all PJM markets, capacity can be imported provided *inter alia* that firm
5 transmission into PJM is demonstrated. Therefore, in my analysis of ICAP, I have used
6 the same 7,300 MW transmission limit for PJM East as I used for energy. For capacity
7 that can reach Pre-2004 PJM, and thus be available for proration into PJM East, I have
8 limited the imports to the 4,600 MW that were the maximum MW imported for ICAP
9 purposes in 2003. For Expanded PJM, I have used the same 7,500 MW import limit that
10 I used for the energy analysis. I assumed that imports were from external suppliers not
11 affiliated with Applicants and purchased by four market participants with non-material
12 shares of the market; unlike in the energy market analysis where imports would be
13 fragmented among many suppliers, the capacity market requires a unit-specific
14 commitment plus firm transmission and, hence, would tend to be significantly less
15 fragmented.⁸³

16 **Q. WHAT DOES YOUR ANALYSIS SHOW FOR PJM EAST?**

17 A. The capacity market for PJM East is highly concentrated, and the HHI change resulting
18 from the merger is about 900 points, assuming none of Applicants' capacity is
19 committed, as shown below in ~~Table 12~~ and in Exhibit J-9. This calculation
20 overstates the impact of the merger on capacity markets, given Exelon's 2006 load
21 commitments and PSEG's 2006 capacity commitments. Indeed, taking these
22 commitments into consideration, the impact on PJM East markets would be minimal.
23 Moreover, as shown below, the mitigation required to cure the screen failure
24 approximates the mitigation requirement for the PJM East Economic Capacity results, as
25 expected.

⁸³ In calculating the mitigation requirement to meet the thresholds of the Competitive Analysis Screen for capacity, I assumed divestiture to two parties with less than 5 percent capacity in either PJM East or Expanded PJM, consistent with my mitigation assumptions for energy as described earlier.

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Table 12: ICAP Results, PJM East

ICAP: PJM East			
	MW	Market Share	HHI
Exelon	7,180	18.0%	324
PSEG	10,134	25.4%	645
AEP	-	0.0%	-
Allegheny Energy	-	0.0%	-
Conectiv	4,800	12.0%	145
Constellation Energy	152	0.4%	0
DPL, Inc.	-	0.0%	-
Dominion	-	0.0%	-
Duke Energy	-	0.0%	-
Edison Mission Energy	-	0.0%	-
FirstEnergy	1,117	2.8%	8
Mirant	-	0.0%	-
NRG Energy	1,060	2.7%	7
PPL	2,071	5.2%	27
Reliant Energy	2,226	5.6%	31
Imports	7,300	18.3%	84
Others	3,862	9.7%	12
Total	39,902	100.0%	1,282
Post-Transaction HHI			2,196
HHI Change			914

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As shown in Exhibit J-9, divestiture of 5,300 MW will eliminate screen failures in the ICAP market. Applicants are committing to divest 2,900 MW of generation, which means the remaining ICAP to be divested is no more than 2,400 MW.

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Q. WHAT DOES YOUR ANALYSIS SHOW FOR EXPANDED PJM?

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A. The capacity market for Expanded PJM is unconcentrated pre-merger, and barely moderately concentrated post-merger with an HHI change of 245 points, assuming none of Applicants' capacity is committed, as shown below in [Table 13](#) and in Exhibit J-9. As with the PJM East capacity market analysis, this analysis overstates the impact of the merger on capacity markets, given Applicants' ICAP commitments. As shown below, the mitigation required to cure the screen failure is well less than the mitigation to which Applicants have committed.

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Table 13: ICAP Results, Expanded PJM

	ICAP: Expanded PJM		
	Market		
	MW	Share	HHI
Exelon	26,465	15.2%	230
PSEG	14,137	8.1%	66
AEP	23,980	13.7%	189
Allegheny Energy	9,724	5.6%	31
Conectiv	5,717	3.3%	11
Constellation Energy	7,279	4.2%	17
DPL, Inc.	4,799	2.7%	8
Dominion	21,700	12.4%	154
Duke Energy	2,736	1.6%	2
Edison Mission Energy	8,298	4.8%	23
FirstEnergy	3,732	2.1%	5
Mirant	6,051	3.5%	12
NRG Energy	2,834	1.6%	3
PPL	8,911	5.1%	26
Reliant Energy	6,805	3.9%	15
Imports	7,500	4.3%	5
Others	13,984	8.0%	4
Total	174,650	100.0%	799
Post-Transaction HHI			1,044
HHI Change			245

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3 **Ancillary Services**

4 **Q. WHAT ANCILLARY SERVICES ARE RELEVANT TO YOUR INQUIRY OF THE**
5 **EFFECT ON COMPETITION?**

6 A. Under the Merger Policy Statement, the Commission requires that Applicants consider
7 the impact of a transaction on markets for ancillary services, specifically spinning
8 reserves, non-spinning reserves and imbalance energy. PJM does not have an imbalance
9 energy market distinct from its spot energy markets since there is no requirement to
10 submit balanced schedules. Its spinning reserve market includes quick-start units,
11 essentially peaking units. There is no separate non-spin reserve market (other than
12 ICAP). PJM also operates a market-based regulation market. In reaching my
13 conclusions about the impact of the merger on ancillary services markets, I rely in part on
14 analyses conducted by PJM and its market monitor.

1 **Q. PLEASE DESCRIBE THE SPINNING RESERVE MARKET.**

2 A. There are two types of spinning reserve units: Tier 1 capacity, based on units already on
3 line that are capable of increasing output within 10 minutes, and Tier 2 capacity that is
4 synchronized to the grid and capable of providing spin, and turbines that are in
5 condensing mode and capable of “quick start”. At present, there are several spinning
6 reserve zones: Mid-Atlantic (75 percent of largest contingency as synchronized 10-
7 minute reserves plus 2 times the remaining 25 percent available as non-synchronized 10-
8 minute reserves); Western (1.5 percent of peak load forecast); Northern Illinois (50
9 percent of ComEd’s load ratio share of the largest system contingency); and Southern
10 (Dominion load ratio share of the largest system contingency within VACAR, minus the
11 available 15-minute quick start capability). Spinning reserves in the Mid-Atlantic zone
12 are market-based while the West zone is cost-based.

13 In 2003, concentration was high in the Tier 2 spinning reserve market in the Mid-Atlantic
14 region.^{84,85} For this reason, all bid prices for Tier 2 spin are offer-capped on a basis
15 related to costs.

16 In the PJM Mid-Atlantic in 2001 (no similar more recent data are available), there was a
17 maximum capability of 3,033 MW of spinning reserves relative to maximum requirements
18 of 2,271 MW.⁸⁶ Actual requirements ranged as high as 2,513 MW between 1999 and
19 2003. Lacking any other data, I have used these data in my analysis.

20 **Q. WHAT IMPACT DOES THE MERGER HAVE ON THE SPIN MARKET?**

21 A. Based on the somewhat limited data available, it appears that Exelon’s spinning-capable
22 units represent 6 percent of the Mid-Atlantic regulation capability, and PSEG’s 39

⁸⁴ All units operating on the PJM system are considered Tier 1 resources, except for those explicitly assigned to Tier 2 spinning.

⁸⁵ *2003 State of the Market*, PJM Market Monitoring Unit, March 4, 2004, page 28. My understanding is that the Market Monitor limited the Tier 2 units considered to condensing turbines.

⁸⁶ *Report on Spinning Reserve Market*, Joseph E. Bowring - Manager PJM Market Monitoring Unit.

1 percent. From the standpoint of a Competitive Analysis Screen, the combination of the
 2 two companies results in an HHI change of about 500 points, as shown below in [Table](#)
 3 [14Table 14](#) and in Exhibit J-10. However, Applicants' divestiture of fossil generation
 4 will divest spinning capability as well. None of the nuclear units is capable of providing
 5 spin.

6 **Table 14: Spinning Reserves Market, Mid-Atlantic**

	<u>(MW)</u>	<u>Share</u>
Market Capability	3,033	
Exelon	196	6%
PSEG	1,191	39%
Other	1,646	54%
Market Concentration		Moderate
HHI Change		507
Implied Divestiture		147
HHI Change		99

7
 8 **Q. PLEASE DESCRIBE THE REGULATION MARKET.**

9 A. Regulation requirements apply to the Mid-Atlantic zone (1.1 percent of day-ahead peak
 10 load forecast for on-peak and valley load forecast for off-peak) and the Western zone (1
 11 percent of daily forecast peak). At present, regulation in the Mid-Atlantic zone is market-
 12 based while the West zone is cost-based. In other words, the Commission has found that
 13 the market for regulation in the Mid-Atlantic is competitive. In the context of this
 14 merger, the Mid-Atlantic zone is the relevant regulation market.

15 The PJM regulation market in 2003 was moderately concentrated, but available
 16 regulation supply relative to demand for the service was large. According to the Market
 17 Monitor, in the PJM Mid-Atlantic region in 2003 there were 113 units qualified to produce
 18 about 2,011 MW of regulation capability, but requirements ranged from approximately 750
 19 MW for the peak period to approximately 220 MW for the off-peak period.⁸⁷

⁸⁷ 2003 *State of the Market*, PJM Market Monitoring Unit, March 4, 2004, pages 27 and 136.

1 **Q. WHAT IMPACT DOES THE MERGER HAVE ON THE REGULATION**
2 **MARKET?**

3 A. As shown in ~~Table 15~~ Table 15 and Exhibit J-11, Applicants have about 500 MW of
4 regulation capability, about one-quarter of the capability identified by the Market
5 Monitor.⁸⁸ More than half of their regulation capability is pumped storage. The balance
6 is primarily baseload coal and mid-merit fossil.

7 The major component of regulation cost taken into account by PJM in scheduling
8 regulation is the opportunity cost of the unit. Thus, during overnight, low price period,
9 baseload coal units such as Keystone and Conemaugh are a source of regulation. Mid-
10 merit units generally cannot provide regulation in low load periods since they generally
11 are not on line.⁸⁹ Pumped storage units characteristically do not provide regulation
12 during such periods because they are filling reservoirs. Moreover, as a result of
13 efficiency losses of around 30 percent, they would be an uneconomic source of
14 regulation. During high priced periods, the opportunity costs of baseload units are too
15 high to be an economic source of regulation. Pumped storage units also generally are an
16 uneconomic source of regulation. Their limited capability is used for peak shaving;
17 hence their opportunity cost for providing regulation is high since it is based on their
18 value during the highest-priced hours of the day.

19 It would be possible in principle to analyze the effects of the merger on regulation by
20 time period. However, I have no data on unit- or owner-specific non-Applicant units so
21 the analysis cannot be performed. What I have been able to ascertain is that the
22 regulation requirement, which varies between about 200 and 700 MW, can be supplied at

⁸⁸ I do not know whether all of the regulation capability that I have identified as belonging to Applicants was included in the 2,011 MW cited by the market monitor. The market monitor's figure was based on MW offered as regulation. My understanding from Applicants is that a significant share of the regulation-capable capacity that I have attributed to Applicants is rarely if ever sold as regulation.

⁸⁹ While inflexible steam units could theoretically provide regulation in these periods, they cannot do so if they are at minimum load, as is typical.

1 least twice over by the capacity controlled by non-Applicants. Hence, Applicants are not
2 close to being pivotal in providing regulation.

3 **Table 15: Regulation Market, PJM Mid-Atlantic**

	<u>(MW)</u>	<u>Share</u>
Market Capability	2,011	
Exelon	267	13%
PSEG	241	12%
Other	1,504	75%

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5 It also should be noted that the separate analysis of ancillary services, including both spin
6 and regulation, is subject to the caveat that they cannot cleanly be analyzed separately
7 from energy and each other. PJM co-optimizes energy and ancillary services. A given
8 MW of capacity cannot be used to provide more than one service at any point in time.
9 Moreover, because the energy price is a major element in pricing both regulation and
10 spinning reserves, prices for the two products are intrinsically linked. Indeed, it is prices
11 in the energy market that primarily determine the cost of procuring regulation and Tier 1
12 spin.

13 **Mitigation**

14 **Q. HOW DID YOU DETERMINE THE MITIGATION REQUIRED TO CURE THE**
15 **COMPETITIVE ANALYSIS SCREEN FAILURES?**

16 A. The amount of mitigation required to eliminate screen failures in the Competitive
17 Analysis Screen is largely a mathematical exercise: determining the post-merger market
18 share for Applicants that yields HHI changes within the screen threshold, and then
19 translating the reduction in Applicants' market share into the required megawatts of
20 divestiture. This is done for each of the time periods/price levels analyzed. Since
21 Economic Capacity is an analysis of energy, the megawatts to be divested need to be
22 adjusted for assumed outages to determine the equivalent capacity to be divested. This
23 requires a determination of typical, or average, outages by season and by type of
24 generation within the relevant categories of coal, mid-merit and peaking capacity. Based
25 on this analysis, I determined the amount of divestiture required for each of the categories
26 of units to be divested. A specific divestiture outcome that solves screen failures in all

1 time periods will, in fact, reduce the HHI change to below target levels in other time
2 periods.⁹⁰ For example, a divestiture that eliminates a screen failure in the Summer SP2
3 period, with a price of \$80/MWh, will over-mitigate the Winter SP period, which also has
4 a price of \$80/MWh.

5 Thus, I undertook a two-step process to evaluate mitigation. First, I identified the
6 “mitigation-eligible” units, which are essentially Applicants’ generating units in PJM
7 East that pass the delivered price test for each of the tranches analyzed. Of course, any
8 unit eligible to mitigate screen failures at a lower price level is also eligible to mitigate
9 screen failures at higher price levels, but not vice versa. Exhibit J-12 summarizes the
10 mitigation-eligible units for each of the tranches for the Summer, Winter and Shoulder. I
11 also determined the relevant characteristics for each of the relevant categories of capacity
12 (nuclear baseload, and coal, mid-merit and peaking) in terms of outage factors by season
13 and approximate price by season, as shown in Exhibit J-13.

14 The second step was to determine the target divestiture amounts that eliminate the HHI
15 screen failures. These target amounts are also reflected in Exhibit J-13. As shown, I
16 identified two scenarios: the amount of generation in PJM East to be mitigated (Scenario
17 1), and the amount of additional generation either inside or outside of PJM East required
18 to mitigate any remaining screen failures in PJM Pre-2004 and Expanded PJM (Scenario
19 2). The particular set of units that cures the screen failures for the PJM East market falls
20 a bit short of eliminating all of the screen failures in the other relevant PJM markets,
21 merely because the mix of market supply in each of the time periods differs among the
22 relevant markets. My previously introduced [Table 1](#) reflects the results of these
23 two scenarios. Detailed results are provided below and in Exhibit J-14.

⁹⁰ In PJM East, where post-mitigation the market is moderately concentrated, I targeted a 99 point HHI change. (If the market had been highly concentrated, I would have mitigated to yield an HHI change of 49 points.) For PJM Pre-2004 and Expanded PJM, some time periods can be mitigated to a market HHI of 1,000 (unconcentrated) rather than to an HHI change of 99 points. Either represent passing the HHI screen.

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Table 1: Mitigation Commitments (MW)

Generation Type	PJM East	PJM Mid-Atlantic*	Total
Nuclear	2,400	200	2,600
Mid-Merit**	1,900	0	1,900
Peaking	1,000	0	1,000
Total	5,300	200	5,500

* The additional 200 MW of commitment can be delivered anywhere in PJM Mid-Atlantic, including PJM East.
** At least 550 MW of the mid-merit divestiture will include coal-fired capacity. . Also, within the mid-merit category, 1,200 MW must be economic at a \$55/MWh market price.

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Mitigation of 5,300 MW of equivalent capacity in PJM East eliminates all screen failures in PJM East. This includes 2,400 MW of nuclear baseload capacity. Since the virtual divestiture of nuclear capacity will be in the form of energy, rather than capacity, the equivalent of 2,400 MW of nuclear baseload capacity is approximately 2,250 MW of firm 24X7 energy. This is based on Exelon's three-year average capacity factor on its nuclear fleet. The additional 200 MW of nuclear baseload capacity can be delivered anywhere in PJM Mid-Atlantic, including PJM East. In total, an equivalent of 2,600 MW of nuclear baseload capacity, or 2,450 MW of energy will be subject to divestiture.

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With respect to the 1,900 of mid-merit capacity to be divested in PJM East, at least 550 MW will consist of coal-fired generation.

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Table 2 ~~Table 2~~ presented previously reflects the Economic Capacity results for PJM East following the divestiture of 5,300 MW in PJM East. This is also included in Exhibit J-14. As shown, the HHI changes are all below 100 points, and the market is moderately concentrated post-mitigation.

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Table 2: Economic Capacity, PJM East, Post-Mitigation

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer	
MW	Mkt Share	MW	Mkt Share	MW	Mkt Share			MW	Mkt Share								
S_SP1	\$250	6,961	18.3%	9,658	25.4%	38,040	1,298	16,620	43.7%	2,227	929	4,877	2,201	30.9%	1,329	31	5,300
S_SP2	\$80	6,032	18.4%	7,757	23.7%	32,786	1,218	13,788	42.1%	2,088	870	3,947	2,201	30.0%	1,273	55	4,300
S_P	\$55	5,122	21.3%	5,957	24.8%	24,011	1,327	11,079	46.1%	2,385	1,058	3,947	2,201	29.7%	1,236	(91)	4,300
S_OP	\$25	4,887	30.7%	2,631	16.5%	15,919	1,477	7,518	47.2%	2,492	1,015	2,201	2,201	33.4%	1,473	(4)	2,400
W_SP	\$80	6,417	19.3%	7,796	23.4%	33,333	1,228	14,213	42.6%	2,128	900	4,061	2,289	30.5%	1,291	63	4,300
W_P	\$55	5,451	22.5%	5,770	23.8%	24,281	1,323	11,221	46.2%	2,390	1,067	4,061	2,289	29.5%	1,222	(101)	4,300
W_OP	\$30	5,167	26.6%	3,594	18.5%	19,398	1,324	8,761	45.2%	2,311	987	2,833	2,289	30.6%	1,297	(27)	2,950
SH_SP	\$65	4,896	20.4%	5,095	21.3%	23,958	1,187	9,991	41.7%	2,057	870	3,233	1,800	28.2%	1,181	(6)	4,300
SH_P	\$45	4,675	26.0%	2,935	16.3%	17,988	1,257	7,610	42.3%	2,105	848	2,196	1,800	30.1%	1,287	30	2,950
2 SH_OP	\$20	4,338	30.3%	2,051	14.3%	14,305	1,406	6,389	44.7%	2,276	870	1,800	1,800	32.1%	1,389	(17)	2,400

3 [Table 16](#) below and Exhibit J-14 present the Economic Capacity results for PJM
4 Pre-2004 following the divestiture of 5,500 MW in total. As shown the HHI changes are
5 all at or below 100 points, and the market is unconcentrated to moderately concentrated
6 post-mitigation. I note that there is one time period when the HHI is 1,002 points, with
7 an HHI change of 106 points. Ultimately, the precise HHI change depends on which
8 specific plants are sold and who the specific buyers are. As a result, I would consider
9 these as passing the HHI screen.

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Table 16: Economic Capacity, PJM Pre-2004, Post-Mitigation

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer	
MW	Mkt Share	MW	Mkt Share	MW	Mkt Share			MW	Mkt Share								
S_SP1	\$250	10,508	13.6%	11,210	14.5%	77,273	896	21,718	28.1%	1,291	395	5,061	2,385	21.6%	1,002	106	5,500
S_SP2	\$80	9,545	13.8%	9,288	13.4%	69,380	885	18,834	27.2%	1,254	369	4,130	2,385	21.2%	995	110	4,500
S_P	\$55	7,976	14.6%	7,455	13.7%	54,517	971	15,431	28.3%	1,371	400	4,130	2,385	20.7%	1,043	72	4,500
S_OP	\$25	6,416	25.9%	3,189	12.9%	24,749	1,217	9,605	38.8%	1,885	668	2,385	2,385	29.2%	1,277	60	2,600
W_SP	\$80	9,899	14.1%	9,334	13.3%	70,238	883	19,233	27.4%	1,257	374	4,252	2,480	21.3%	993	110	4,500
W_P	\$55	8,299	15.1%	7,273	13.2%	54,932	968	15,571	28.4%	1,368	400	4,252	2,480	20.6%	1,034	66	4,500
W_OP	\$30	7,701	17.7%	4,946	11.4%	43,557	985	12,648	29.0%	1,386	401	3,024	2,480	22.1%	1,063	78	3,150
SH_SP	\$65	7,866	15.6%	6,263	12.4%	50,501	951	14,129	28.0%	1,337	386	3,383	1,950	21.3%	1,043	92	4,500
SH_P	\$45	6,936	17.2%	4,070	10.1%	40,251	1,004	11,006	27.3%	1,353	349	2,346	1,950	21.5%	1,090	86	3,150
11 SH_OP	\$20	5,472	26.4%	2,440	11.8%	20,715	1,206	7,912	38.2%	1,828	622	1,950	1,950	28.8%	1,242	36	2,600

12 Finally [Table 17](#) below and Exhibit J-14 present the Economic Capacity results
13 for Expanded PJM following the divestiture of 5,500 MW. This is also included in
14 Exhibit J-14. As shown, with one exception the HHI changes are all below 100 points or
15 the market is unconcentrated. The one exception is an HHI change of 102 points with an
16 HHI of 1,004. Again, while a technical violation of the screen, I view this as reflecting a
17 fully mitigated result.

1

Table 17: Expanded PJM, Post Mitigation

Period	Price	Pre-Merger						Post-Merger				Mitigation and Post-Mitigation Results					
		Exelon		PSEG		Mkt Size	HHI	EEG		HHI Chg	Mitigation MW	Nuclear	Mkt Share	HHI	HHI Chg	MW Summer Equivalent	
MW	Share	MW	Share	MW	Share			MW	Share								
S_SP1	\$250	24,354	14.9%	12,929	7.9%	163,707	774	37,283	22.8%	1,009	235	5,061	2,385	19.7%	892	118	5,500
S_SP2	\$80	23,384	15.2%	11,006	7.1%	154,162	795	34,390	22.3%	1,011	216	4,130	2,385	19.6%	910	115	4,500
S_P	\$55	18,813	15.3%	9,153	7.5%	122,719	902	27,966	22.8%	1,130	228	4,130	2,385	19.4%	1,004	102	4,500
S_OP	\$25	16,950	22.3%	3,189	4.2%	76,038	1,447	20,139	26.5%	1,634	187	2,385	2,385	23.3%	1,483	36	2,600
W_SP	\$80	24,013	15.4%	11,053	7.1%	156,250	804	35,067	22.4%	1,021	217	4,252	2,480	19.7%	917	113	4,500
W_P	\$55	19,150	15.3%	8,973	7.2%	124,828	909	28,123	22.5%	1,130	221	4,252	2,480	19.1%	1,003	94	4,500
W_OP	\$30	18,373	17.8%	4,946	4.8%	102,979	1,102	23,319	22.6%	1,274	172	3,024	2,480	19.7%	1,158	56	3,150
SH_SP	\$65	19,460	16.4%	7,672	6.5%	118,586	850	27,133	22.9%	1,063	213	3,383	1,950	20.0%	951	101	4,500
SH_P	\$45	15,842	16.5%	5,462	5.7%	95,869	932	21,304	22.2%	1,120	188	2,346	1,950	19.8%	1,023	91	3,150
SH_OP	\$20	12,975	21.8%	2,440	4.1%	59,411	1,428	15,415	26.0%	1,608	180	1,950	1,950	22.7%	1,453	25	2,600

3 **Vertical Market Power**

4 **Q. ARE THERE ANY OTHER ISSUES THAT WOULD AFFECT COMPETITION IN**
5 **THE RELEVANT MARKETS?**

6 A. The other primary potential market power issue is vertical market power -- control over
7 electric transmission, generating sites or fuels supplies. There are no issues about electric
8 transmission market power since all of Applicants' transmission is controlled by PJM.

9 **Q. WHAT IS THE ISSUE CONCERNING AN APPLICANT'S CONTROL OVER**
10 **ESSENTIAL FUELS OR DELIVERY SYSTEMS?**

11 A. In the context of long-term capacity markets, the issue is whether the merging parties can
12 foreclose or impede the entry of competing generators. There also is a shorter-term issue
13 of whether the merger might increase the incentive or ability to raise rivals costs.

14 **Q. WHAT CONTROL DO APPLICANTS HAVE OVER FUELS OR FUEL**
15 **DELIVERY SYSTEMS?**

16 A. As described earlier, PECO's LDC operations serve a limited area in eastern
17 Pennsylvania. PECO offers transportation services to all of its customers, and a large
18 number of customers obtain their gas commodity from third-party suppliers. PECO's
19 LDC system is easily bypassed by large customers. While PECO Energy is permitted to
20 discount its transportation rate to meet competitive pressures, there are a number of
21 customers on PECO's system who have opted to bypass the utility completely and

1 connect directly to an interstate gas pipeline (e.g., Sun Oil and Tosco have done so).
2 Existing larger customers have used the threat of bypass to achieve reduced rates. As
3 noted earlier, PECO provides gas distribution service to only three unaffiliated electric
4 generators totaling less than 200 MW. These are either industrial facilities that consume
5 the bulk of their electricity on-site or facilities that use natural gas as a secondary fuel.
6 Other independent generators located in their service area take service directly from the
7 pipeline. Newly built facilities could readily avoid PECO's small service area or connect
8 directly to an interstate pipeline.

9 PSE&G's gas distribution system in New Jersey serves eight current or former QFs
10 under contract to the utility, as well as two merchant generators: the Tosco plant (172
11 MW) and the Williams Red Oak plant (765 MW). These generating facilities served by
12 PSE&G are under long-term contracts or discounted tariffs. PSE&G also provides
13 transportation service to affiliated generators in its service area.

14 With respect to both PECO and PSE&G, it is not necessary that new generation would
15 seek to be connected to an LDC as opposed to direct interconnection with a pipeline
16 system.

17 **Q. WHAT FIRM TRANSMISSION RIGHTS DO APPLICANTS HAVE ON**
18 **INTERSTATE GAS PIPELINES SERVING PJM?**

19 A. The three largest interstate pipelines serving Pennsylvania and New Jersey are Tennessee
20 Gas Pipeline, Texas Eastern Transmission and Transcontinental Gas Pipe Line. These
21 pipelines represent about 90 percent of capacity entering New Jersey and about 70
22 percent of capacity entering Pennsylvania. Columbia Gas Transmission and Dominion
23 Transmission are the other two significant pipelines serving Pennsylvania (12 percent and
24 10 percent of entering capacity, respectively).⁹¹ I examined Applicants' firm transmission
25 reservations on each of these pipelines (excluding those expiring prior to 2006 with no
26 rollover rights). Exelon's total firm transmission reservations total about 500 mmcf/day,

⁹¹ Only some of this capacity into New Jersey and Pennsylvania is relevant for PJM East.

1 and PSE&G's total about 1bcf/day (reflecting the fact that PSE&G is a much larger LDC
2 than PECO). ER&T also has firm transmission commitments for delivery into the market
3 area. PECO's firm transportation rights are fully committed to meet retail customer load.
4 The upstream market, no doubt, is not highly concentrated, as pipeline ownership
5 (measured by firm transportation rights) is diverse. Moreover, Applicants cannot
6 withhold these rights to reduce supply since failure to use rights simply increases the
7 amount of release capacity available to competitors.

8 The mere ownership of LDC operations does not give rise to a concern that Applicants
9 will use self-dealing or other means of using the gas LDC to favor affiliated activities.
10 Distribution tariffs are regulated by the respective state public utility commissions, which
11 impose open access distribution requirements. The ability to earn even the ceiling rates
12 in distribution tariffs frequently is constrained by bypass alternatives or the existence of
13 long-term (sometimes discounted) contracts. The ability of an LDC to impede entry is
14 very unlikely since new generation can be sited so as to connect directly to a transmission
15 pipeline system. Other vertical concerns are not present. Both Pennsylvania and New
16 Jersey have in place codes of conduct between gas and electric affiliates, and both
17 utilities are governed by FERC Order No. 2004. In any event, the amount of generation
18 served is so small that knowledge of customers' operations is of no commercial value to
19 electric generation. In short, none of the vertical concerns that the Commission focused
20 upon in prior vertical mergers exist in this merger and the transaction does not create or
21 enhance vertical market power.

22 **Q. DID YOU CONDUCT ANY FURTHER ANALYSIS TO DEMONSTRATE THAT**
23 **VERTICAL CONCERNS ARE NOT PRESENT?**

24 A. I completed the downstream portion of the required analysis under Section 33.4 of the
25 Commission's regulations. That framework requires that the structure of downstream
26 markets be analyzed using the same delivered price test methodology as in the horizontal
27 market power analysis, but with gas-fired generation deemed to be controlled by (*i.e.*, is
28 assigned to) its gas supplier rather than its owner. I attributed gas-fired generation to the
29 upstream suppliers, *i.e.*, the pipeline that serves it. For power plants directly connected to

1 a single pipeline, the entire capacity of the plant is attributed to the pipeline. If the
 2 pipeline is jointly owned, the capacity is divided among the pipeline owners. For power
 3 plants directly connected to multiple pipelines, the plant’s capacity is divided into equal
 4 shares and attributed to the pipelines that are connected. If a pipeline connection cannot
 5 be determined, or the plant is served by an LDC (other than Applicants’ LDC) that is fed
 6 by multiple pipelines, the capacity is assigned to the actual owner of the unit. For plants
 7 served by PECO or PSE&G, as well as for gas-fired plants owned by Applicants, I
 8 assigned the capacity to Applicants. These are detailed in [Table 18](#) below.

Table 18: Unaffiliated Gas-Fired Generation Served by Applicants

LDC	Owner	Location	Unit Name	Capacity (MW)
PSE&G	Newmarket Power	PJM - East	Bayonne	165
PSE&G	Newmarket Power	PJM - East	Camden	149
PSE&G	Sunoco	PJM - East	Eagle Point	195
PSE&G	Trenton District Energy Co.	PJM - East	TDEC	12
PSE&G	Calpine/FirstEnergy	PJM - East	Parlin	125
PSE&G	Newmarket Power	PJM - East	Newark Bay	123
PSE&G	FPL/Tractabel	PJM - East	Sayreville	290
PSE&G	AEP	PJM - East	Red Oak	765
PSE&G	Goldman Sachs	PJM - East	Tosco	172
PSE&G	Calpine	PJM - East	Newark Boxboard	52
PECO	Merck	PJM - East	Merck	65
PECO	Kimberly Clark	PJM - East	Kimberly Clark	50
PECO	American Refuel	PJM - East	American Refuel	83

11 I analyzed the downstream market for PJM East, PJM Pre-2004 and Expanded PJM.
 12 After taking into account Applicants’ mitigation commitments, neither the PJM Pre-2004
 13 nor the Expanded PJM markets are highly concentrated post-merger, as shown in Exhibit
 14 J-15. However, the PJM East market remains highly concentrated post-mitigation. In
 15 performing this analysis, I only counted the divestiture of nuclear or coal units; if some of
 16 the divested units are oil-fired, they too would represent a reduction in Applicants’
 17 market share and would likely reduce concentration below 1800. Nevertheless, since the
 18 PJM East downstream market is highly concentrated, consistent with the Commission’s
 19 regulations, I conducted an analysis of the PJM East upstream market. The analysis of
 20 the upstream market requires that the structure of control of transportation capacity be
 21 examined. For this purpose, I allocated control of gas transportation pipelines to holders

1 of firm capacity rights, with any unsubscribed capacity allocated to the pipeline owner.
2 Details of this approach are provided below and in Exhibit No. J-4.

3 As shown in Exhibit J-17, I found that the PJM East upstream market is not highly
4 concentrated and thus the competitive conditions in the market are not conducive to a
5 vertical foreclosure strategy.

6 The weight of the evidence indicates that the likelihood of a successful strategy of
7 vertical foreclosure or raising rivals' cost is simply not present. Downstream markets in
8 PJM Pre-2004 and Expanded PJM are not highly concentrated, and even in PJM East the
9 downstream market is mostly just above the threshold levels for a concentrated market.
10 Moreover, the ability of an LDC such as PECO or PSE&G to successfully implement a
11 foreclosure strategy is unlikely. This is further evidenced by the result that the upstream
12 market in PJM East is not highly concentrated.

13 **Q. ARE THERE ANY OTHER VERTICAL ISSUES OF CONCERN IN THIS**
14 **MERGER?**

15 A. No. This merger should raise no other vertical market power concerns. The Commission
16 also has considered competition in transmission services and has examined whether the
17 combination of ownership of transmission facilities creates the opportunity or incentive
18 for the merging parties to restrict access to transmission. Here, all of Applicants'
19 transmission assets are under the control of PJM.

20 **Q. DO APPLICANTS EXERCISE CONTROL OVER THE AVAILABLE**
21 **GENERATION SITES?**

22 A. No. I was unable to identify any special barriers to entry in this regard. The service areas
23 of these Applicants are relatively small, and the relevant geographic markets in PJM
24 encompass a large region and includes many possible generating sites. Entrants who
25 could compete in areas potentially affected by this merger would not need to locate new
26 facilities in Applicants' service areas or connect to Applicants' transmission systems. In

1 any event, PJM, not Applicants, controls the interconnection process for new generation.
2 Thus Applicants' RTO membership should moot any concerns in this regard.

3 **Q. EARLIER, YOU STATED THAT THE COMMISSION HAS FOUND LONG-**
4 **TERM MARKETS TO BE PRESUMPTIVELY COMPETITIVE. PLEASE**
5 **ELABORATE.**

6 A. In Order No. 888, the Commission in referring to a decision in *Entergy Services,*
7 *Inc.*, noted that "after examining generation dominance in many different cases over the
8 years, we have yet to find an instance of generation dominance in long-run bulk power
9 markets."⁹² In the Merger NOPR, the Commission stated that "[a]s restructuring in the
10 wholesale and retail electricity markets progresses, short-term markets appear to be
11 growing in importance. The role of long-term capacity markets appears to be
12 diminishing."⁹³ While the Commission has indicated its intent to review the presumption
13 that long-term markets are competitive, there is no evidence to overcome that
14 presumption. Certainly, the entry of new generation into PJM and its ownership by
15 numerous independent entities shows that entry is not constrained.

16 **Q. IS THERE ANY EVIDENCE THAT THERE WILL BE ENTRY INTO PJM**
17 **WITHIN THE NEXT FEW YEARS?**

18 A. Yes. Although PJM has been capacity-long in the past few years, its reserve margin is
19 expected to decline relatively quickly given planned retirements and load growth. PJM
20 forecasts retirements of approximately 3,000 MW and additions of approximately 5,000
21 MW by 2006/2007. Moreover, as part of the Reliability Pricing Model being considered
22 by PJM, the introduction of a demand curve-based capacity payment is intended to
23 encourage necessary generation investment when needed.

⁹² Order No. 888 at 31,649 n.86 (citation omitted).

⁹³ Merger NOPR, *op. cit.*, at 20.

1

VI. CONCLUSION

2 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.**

3 A. I recommend that the Commission determine that this merger will not have an adverse
4 effect on competition in markets subject to its jurisdiction.

5 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

6 A. Yes.

EXHIBITS

Exhibit J-1	Testimony
Exhibit J-2	Resume of William H. Hieronymus
Exhibit J-3	Applicants' Generation
Exhibit J-4	Data and Methodology
Exhibit J-5	Description of CASm Model
Exhibit J-6	Schematic of Relevant PJM Markets
Exhibit J-7	Economic Capacity
Exhibit J-8	Available Economic Capacity
Exhibit J-9	ICAP
Exhibit J-10	Spinning Reserves
Exhibit J-11	Regulation
Exhibit J-12	Mitigation-Eligible Units
Exhibit J-13	Mitigation Scenarios
Exhibit J-14	Economic Capacity, Post-Mitigation Results
Exhibit J-15	Downstream Economic Capacity
Exhibit J-16	Upstream Market, PJM East

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