STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES
BPU Docket No. EM05020106

OFFICE OF ADMINISTRATIVE LAW
OAL Docket No. PUC-1874-05

In The Matter of the Joint Petition of Public Service Electric and Gas Company and Exelon Corporation For Approval of a Change in Control of Public Service Electric and Gas Company and Related Authorizations

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Direct Testimony

on Behalf of the

New Jersey Division of the Ratepayer Advocate

Prepared by:
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November 14, 2005

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I. INTRODUCTION AND QUALIFICATIONS

Q. Mr. Biewald, please state your name, position and business address.

A. My name is Bruce E. Biewald. I am the President of Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. Mr. Fagan, please state your name, position and business address.

A. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. Mr. Schlissel, please state your name, position and business address.

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

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of the New Jersey Division of the Ratepayer Advocate ("Ratepayer Advocate").

Q. Please describe Synapse Energy Economics.

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

Q. Mr. Biewald, please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1981, where I studied energy use in buildings. I was employed for 15 years at the Tellus Institute, where I was Manager of the Electricity Program, responsible for studies on a broad range of electric system regulatory and policy studies. I have testified on energy issues in more than eighty regulatory proceedings in twenty-five states and two Canadian provinces and in state and Federal courts. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, and the National Association of Regulatory Utility Commissioners. My papers have been published in the Electricity Journal, Energy Journal, Energy Policy, Public Utilities Fortnightly and numerous conference proceedings, and I have made presentations on the economic and environmental dimensions of energy throughout the U.S. and internationally. I also have consulted for federal agencies, including the U.S. Department of Energy, the U.S. Department of Justice, the U.S. Environmental Protection Agency, the Federal Trade Commission and National Renewable Energy Laboratory. My resume is provided here as Exhibit BFS-1.

I have analyzed electricity market power issues in numerous markets throughout the Eastern, Central and Southern United States, including, but not limited to, PJM, New York, and New England. I have presented the results of these analyses as testimony on market power issues before the Connecticut Department of Public Utility Control, the New Jersey Board of Public Utilities, the Arkansas Public Service Commission, the West Virginia Public Service Commission, the Maryland Public Service Commission, the Mississippi Public Service Commission, the New York Public Service Commission, and the New Hampshire Public Utilities Commission. I also have submitted affidavits and testimony to the FERC in Dockets Nos. EC98-40-00, et al., EC97-46-000, OA97-237-000, and ER97-1079-000.

I have co-authored a number of studies on market power issues. These studies included The New England Experiment: An Evaluation of the Wholesale

Electricity Markets, June 2003; Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets, November 2001; Competition and Market Power in Northern Maine Electricity Market, November 1998; Analysis of Market Power in the APS and Duquesne Service Territories, February 1998; and, Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis, March 1997.

I have been invited to speak on market power issues by the National Association of Regulatory Utility Commissioners, the New England Conference of Public Utility Commissioners, the National Consumer Law Center, and the National Association of State Utility Consumer Advocates.

Q. Mr. Fagan, please summarize your educational background and recent work experience.

A. I am an energy economics analyst and mechanical engineer with 19 years of experience in the energy industry. My work has focused primarily on electric power industry issues, especially economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, and assessment and implementation of demand-side resource alternatives.

I have analyzed wholesale transmission system issues for numerous clients over the past nine years. This work has included: valuation of FTRs; examination of FTR and ARR auction and allocation mechanisms in New England, PJM, New York and the Midwest; study of alternative transmission rights models, including physical vs. financial paradigms; analysis of GE MAPS modeling results; review of LMP price data in PJM, NY, NE and the MISO ISO regions; and review and critique of transmission system embedded cost recovery issues including tariff design and the impacts of FERC's 888 open access transmission tariff.

I have testified before State regulatory commissions in Indiana, Illinois, Texas and Maine, and before provincial regulatory commissions in Ontario, Alberta and Nova Scotia on various retail and wholesale electricity market issues.

I hold an M.A. from Boston University in Energy and Environmental Studies and a B.S. from Clarkson University in Mechanical Engineering. Details of my experience are provided in Exhibit BFS-2.

Q. Mr. Schlissel, please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983, I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included the U.S. Department of Justice, the Staff of the Arizona Corporation Commission, the General Staff of the Arkansas Public Service Commission, cities and towns in Maine, Connecticut, and Illinois, and the Attorneys General of the States of New York and Rhode Island and the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Connecticut, Arizona, New Jersey, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

I have analyzed market power issues in PJM and New York State. I have presented the results of market power analyses in testimony before the New Jersey Board of Public Utilities.

A copy of my current resume is attached as Exhibit BFS-3.

Q. What is the purpose of your testimony?

A. Synapse was retained by the Ratepayer Advocate to examine market power and nuclear issues related to the proposed merger between Public Service Enterprise Group ("PSEG") and Exelon Corporation ("Exelon") (collectively "the Petitioners"). This testimony presents the results of our investigations and analyses of these issues.

Q. Please explain how you conducted your analyses.

A. We have reviewed the testimony and exhibits filed by the Petitioners at the FERC. We also have reviewed the comments, protests, reply protests, and requests for rehearing submitted by a number of parties including the New Jersey Board of Public Utilities ("BPU" or "the Board"). In addition, we have reviewed the FERC's July 1, 2005 Order approving the merger.

At the same time, we have reviewed the testimony and exhibits filed by the Petitioners at the BPU. We also have examined the responses that the Petitioners have provided to the more than one hundred and fifty data requests that the Ratepayer Advocate and other active parties have submitted to the Petitioners on market power and related issues. We also have participated in a telephone conference call with the Petitioners' market power witness, Mr. Rodney Frame, and members of his support staff.

In addition, we have performed some independent modeling of our own using Mr. Frame's HHI model and the Electric Market Optimization Model ("ELMO"). ELMO is a computer model developed to simulate the strategic pricing behavior of participants in wholesale electricity markets. ELMO can be used to assess the extent to which market power will be a problem in specific situations, and the extent to which various policies will be effective at mitigating the market power of dominant firms. ELMO was developed by Bruce Biewald and Dr. David White from Synapse. The ELMO model is described in more detail in Exhibit BFS-8 and Confidential Exhibit BFS-9.

II. SUMMARY OF FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your findings.

A. Our findings include the following:

1. The proposed merger would create a new company, Exelon Electric & Gas Corporation ("EEG"), that would own approximately 40,475 MW of capacity in Expanded PJM, pre-mitigation, and 34,000 MW of capacity if the Petitioners' mitigation plan is approved and carried out.

2. EEG would own more than 11,900 MW, or 29 percent, of the capacity in PJM East even if the Petitioners' mitigation plan is approved.

3. The Administrative Law Judge and the New Jersey BPU should not rely on the FERC's findings concerning the impact of the proposed merger on the ability of EEG to exercise market power.

   - The FERC applied a different standard than the BPU will apply in its evaluation of the proposed merger. The BPU will apply a positive benefits standard. The FERC does not apply this same standard. Indeed, the FERC's guidelines allow a proposed merger to increase the extent of concentration in the markets being examined, as long as the increases fall within prescribed limits.

   - The FERC does not address potential market power problems that could arise at the retail level as opposed to wholesale markets.

- The FERC relied solely on idealized concentration measures in approving the proposed merger.
- As the BPU convincingly argued in its filings at the FERC, the record before the FERC was inadequate to determine whether EEG will be able to exercise market power in the PJM energy and capacity markets and in the New Jersey BGS auction.
- The FERC's decision to approve the merger relies on its ability to address market power problems in future years.

4. The Petitioners have not presented in their testimony, exhibits or data responses in this proceeding any of the evidence that was lacking in the record at the FERC.

5. Evaluation of the effects of a merger requires modeling the hourly behavior of the market under a wide variety of external conditions and bidding behaviors. A realistic energy simulation model would provide better insight into potential market power concerns than idealized concentration measures. However, the Petitioners did not present such an analysis in their filings before the BPU or the FERC.

6. The modeling presented by Petitioner witness Frame does not accurately represent the pre-merger levels of concentration in the PJM East energy market.

7. Data published by the PJM Market Monitoring Unit indicate that the PJM East energy market is substantially more concentrated than the results of the modeling presented by Petitioner witness Frame.

8. The significant differences with historical PJM data on pre-merger market concentrations call into question the validity of all of Mr. Frame's modeling of the PJM system post-merger and post-mitigation market concentrations. Moreover, these differences lead Mr. Frame to understate

the amount of capacity that must be divested by EEG in order to satisfy the FERC Appendix A market screen criteria that Mr. Frame is attempting to satisfy.

9. The results of Petitioner witness Frame's market power modeling are rendered unrealistic by a number of serious flaws that cause him to understate the post-merger and post-mitigation levels of concentration in the PJM East energy market:

- Mr. Frame does not even attempt to address actual market power but instead relies on only a single idealized estimate of market concentration.
- The use of an inappropriate methodology for allocating the limited transmission import capability across PJM's Eastern Interface.
- The assumption that all of the capacity from the generating units being modeled will be available to serve load in his targeted geographic areas and ignores the fact that some capacity would already be committed to serving other load or be diverted to other areas for economic reasons.
- The failure to reflect transmission system outages or deratings.
- The unrealistic treatment of forced and planned generating unit outages.
- The inappropriate use of industry-average [REDACTED].
- The failure to reflect the expected improved output from the Salem and Hope Creek nuclear units that the Petitioners have cited as a benefit of the proposed merger.

- The failure to reflect future capacity uprates at Hope Creek and Salem.
- The failure to model purchases of capacity from other PJM participants.

10. Mr. Frame does not use an economic methodology to allocate the limited transmission capability across the PJM East interface. Such an economic allocation would assign limited transmission capability to the suppliers with the lowest delivered costs. Instead, Mr. Frame used a pro-rata allocation methodology. The use of the pro-rata methodology causes Mr. Frame to understate the amount of capacity that Exelon, PSEG and the combined company created by the merger, EEG, will be able to import into PJM East. It is reasonable to expect that the low-cost nuclear, hydro and, to a lesser extent, coal capacity that would be retained by the combined company will represent a large portion of the capacity imported into PJM East. For this reason, an economic allocation methodology will more realistically represent EEG's share of imports.

11. Our analysis of the PJM Annual Auction of Financial Transmission Rights for the 2005-2006 planning period shows that Exelon and PSEG currently use significantly more of the limited transmission capability into PJM East than is suggested by Mr. Frame's pro-rata methodology.

12. Mr. Frame's unrealistic representation of planned and forced generating unit outages in his modeling tends to overstate system reliability. He fails to consider situations that are "worse than average" at all. In fact, during "tight" conditions market power will tend to be much worse than it is during average conditions.

13. The results of Mr. Frame's modeling are distorted by his use of generic industry nuclear unit forced outage rates [REDACTED

REDACTED

] The inappropriate use of these generic, industry-average forced and scheduled outage rates for Exelon's nuclear units leads Mr. Frame to understate the amount of capacity that would be owned by Exelon pre-merger and by the combined company post-merger and post-mitigation. It also leads Mr. Frame to understate the combined company's post-merger and post-mitigation market shares.

14. Mr. Frame ignores the proposed power increase proposed for the Hope Creek nuclear unit in 2006. This leads him to further understate the amount of capacity that would be owned by the combined company if the merger is closed or by PSEG if there is no merger.

15. Mr. Frame fails to model the increased performance of the Salem and Hope Creek nuclear units that the Petitioners claim will result from the proposed merger.

16. We have recalculated Mr. Frame's modeling to reflect: (1) the proposed power uprate at Hope Creek in 2006, (2) the nuclear improvements in performance at both Salem and Hope Creek that the Petitioners claim will result from the merger, (3) the recent performance of Exelon's nuclear units, and (4) the use of an economic allocation of the transmission import capability across the PJM East interface.

17. Making just the above four realistic corrections, all three of Mr. Frame's Mitigation Scenarios would fail the FERC Appendix A Screening Analyses performed by Mr. Frame. In some hours, Mr. Frame's Mitigation Scenarios would fail the FERC Appendix A Screening by significant margins.

18. Mr. Frame's modeling does not reflect the potential for the combined company to make forward capacity purchases that would enhance its ability to exercise market power.

19. Mr. Frame's modeling does not accurately represent the pre-merger and post-mitigation levels of concentration in the PJM East capacity market because he unrealistically and unreasonably assigns none of the 7,300 MW of transmission import capability across the PJM East interface to Exelon, PSEG or the combined company that would be created by the proposed merger.

20. PJM recently filed at the FERC a proposal for new capacity markets, called the Reliability Pricing Model. The Reliability Pricing Model will involve a complicated series of four capacity auctions for each twelve month delivery year for each appropriate locational sub-areas within PJM. Eventually, there could be as many as 23 sub-areas within PJM, eleven of which would be within PJM East. New Jersey alone would have five of these sub-areas. It is possible that the FERC may require substantial revisions to the PJM proposal.

21. The Petitioners have not filed any analyses in this proceeding to show that EEG would not be able to exercise market power within the locational capacity markets that would be created under the Reliability Pricing Model.

22. EEG clearly would be the dominant firm within the Northern PSEG locational capacity sub-area of PJM East that would be created under the Reliability Pricing Model proposal.

23. The Petitioners have not provided a complete analysis of the potential impact of the proposed merger on the Northern New Jersey energy market.

24. The Petitioners' proposed mitigation plan is inadequate to prevent the combined company created by the merger from exercising market power.

- The plan does not identify the specific units to be divested.
- Under the Petitioners' proposed virtual divestiture of nuclear capacity, the merged company would still maintain control over operations of the "divested" capacity.
- Under the Petitioners' proposed virtual divestiture, the company created by the merger would have an incentive to exercise market power as that would indirectly increase the prices in the proposed yearly capacity auctions.
- As proposed by the Petitioners, the virtual divestiture is not symmetric because there would be no provision for increasing the amount of nuclear capacity to be divested if the combined company constructs or acquires additional nuclear capacity.

25. Although there are a large number of permutations of the parties that might be buyers of the capacity that would be divested by the combined company, Petitioner witness Frame has not examined a wide range of scenarios concerning the possible buyers.

26. In his mitigation scenarios, Petitioner witness Frame assumes that the virtually divested nuclear capacity is purchased either by buyers that do not currently own any generating capacity in PJM or by a large number of parties that currently do own capacity in PJM. He also assumes that the fossil capacity being divested is being purchased either by a single party that does not now own capacity in PJM or by three or more existing PJM participants. Given these assumptions, it is not surprising that his analyses show that post-mitigation concentration levels are not much different from pre-merger concentration levels.

27. In order to test the impact of the proposed merger in a wider range of possible mitigation scenarios, we have modeled the changes in concentration levels in PJM East in three realistic scenarios in which parties that are currently substantial participants in PJM purchase the capacity that would be divested by the combined company. In the three new mitigation scenarios that we have modeled, the changes from pre-merger to post-mitigation market concentrations fail the FERC Appendix A Screening Analysis in all ten hours studied under both Mr. Frame's assumptions and our more realistic inputs assumptions concerning future nuclear performance and the allocation of the limited transmission capability across the PJM East interface.

28. The Petitioners have not presented any analysis of the ability of the company created by the merger, EEG, to exercise market power in the New Jersey BGS auctions.

29. Our modeling shows that there already exists a significant potential for market power in PJM East because of PSEG's substantial market share. However, the proposed merger can be expected to make the situation worse, even with the Petitioners' proposed levels of virtual and actual divestiture. The amount by which the proposed merger will increase the ability of EEG to exercise market power will depend on the identities of the parties that actually purchase this divested capacity.

30. The merged company could earn additional revenues in the electric energy markets to the detriment of ratepayers if it were able to exercise market power in gas markets.

31. PJM only has a limited ability to ensure that market price outcomes are competitive and that participants are not exercising market power through strategic bidding or the withholding of otherwise available capacity. Therefore, the BPU cannot rely on PJM to effectively mitigate the exercise

of market power by the combined company that would be created by the merger.

32. The Petitioners have estimated that the merger would result in approximately $170 million of additional pre-tax earnings annually due to nuclear synergies and improved nuclear performance. Of the $170 million of additional nuclear-related earnings projected by the Petitioners as resulting from the proposed merger, approximately $100 million would be savings from nuclear cost reductions and roughly $70 million would be from nuclear production improvements. However, given current electricity forwards prices, the Petitioners may earn another $20-30 million more each year, based on anticipated nuclear production improvements in 2006 and 2007.

33. It is possible that wholesale prices could be raised by more than one percent through the increased market power resulting from the proposed merger. This one percent increase in wholesale prices would amount to approximately $64 million per year in higher rates for New Jersey consumers.

34. Petitioners' claimed $12 million average annual savings from the proposed merger for the years 2006-2009 for New Jersey electric utility consumers could be wiped out if wholesale market prices were raised by approximately one-fifth of one percent as a result of the increased market power from the merger.

35. The BPU has the opportunity to consider all aspects of the proposed merger in the immediate proceeding. However, as filed by the Petitioners, the merger proposal allows many variables that are critically important to market power analysis to be settled after regulatory approvals have been issued and the merger is completed. If it approves the merger, the BPU may be forced to take a fragmented and narrow approach to mitigation. A

petition by the BPU to the FERC to review the situation and take necessary and appropriate action, such as determining whether appropriate generating units were divested or ordering divestment of different or additional generating facilities, would certainly be less effective than preventing the damages that could result from the exercise of merger-related market power in the first place.

Q. What is your overall conclusion?

A. Under the Petitioners' proposed mitigation plan, it is reasonable to expect that the combined company created by the proposed merger will be able to exercise market power in the relevant energy and capacity markets. For this reason, we recommend that the BPU reject the proposed merger.

Q. If the merger is approved, what actions should the BPU take to mitigate the potential exercise of market power by EEG in the Northern New Jersey and PJM East energy and capacity markets?

A. If it decides to approve the proposed merger, the BPU should require the following:

- There should be no virtual divestiture. All divestiture should involve the actual sale of ownership of capacity and energy.
- The amount of capacity that would have to be divested as part of the merger should be based on Synapse input assumptions and a strategic bidding analysis.
- The amount of capacity that would have to be divested also should be based on the actual units to be divested.
- The BPU should set limits on the parties that could purchase the divested capacity.
- The PJM Market Monitoring Unit's suggestions about expanding the application of bid capping and/or bidding at marginal cost should be adopted.

- The Petitioners should agree that after the merger is closed, the BPU would retain the same jurisdiction to address market power issues as it has before the merger.
- The BPU should conduct more detailed oversight of the BGS auction process in order to permit a meaningful investigation of whether any post-merger bidders, including EEG, exercise market power in the annual BGS auctions.

III. THE PROPOSED MERGER WILL CREATE A DOMINANT NEW COMPANY IN PJM AND PJM EAST

Q. Please describe the size of the combined company that would be created by the proposed merger.

A. The proposed merger between Exelon and PSEG is enormous in its scope and in its implications for the PJM markets generally and for customers in PJM East in particular. According to Petitioners' Exhibit RF-8, Exelon and PSEG currently own 26,437 MW and 14,037 MW, respectively, in Expanded PJM. These amounts of capacity represent 15.0 percent and 8.0 percent of the total capacity in Expanded PJM.[1] Post-merger, the combined capacity of the new company, EEG, would total approximately 40,475 MW.[2] As shown in Exhibit RF-8, this would give EEG approximately 23.0 percent of the total capacity in Expanded PJM, during the summer of 2006.[3]

As we will explain later in this testimony, the company created by the merger, EEG, would still maintain control over the nuclear capacity that would be virtually divested as part of the Petitioners' proposed mitigation. However, even if the Petitioners' divested 6,600 MW as they claim they will do as part of their revised mitigation plan, EEG would still own 34,000 MW, or approximately 19.2 percent, of the total capacity in Expanded PJM. Thus, even if EEG actually

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1 Direct Testimony of Rodney Frame, Exhibit RF-8 (Revised), page 2 of 2.
2 Ibid.

divested 6,600 MW of capacity, it would remain the largest capacity owner in Expanded PJM and, depending on the parties that purchased the divested capacity, could still be 50 percent larger than any other generation supplier in PJM Expanded.[4]

The capacity shares owned by Exelon and PSEG in PJM East are even higher. Prior to the merger, Exelon owns 18 percent and PSEG owns 25 percent of the capacity in PJM East, putting their combined capacity share at 43 percent.[5] Even if the Petitioners divest 5,500 MW in PJM East as they claim they will do as part of their revised mitigation, the EEG still would own 11,900 MW of capacity, or approximately 28.7 percent, of the capacity in PJM East, during the summer of 2006. Depending on which parties purchase the divested capacity, EEG could still be three times as large as the next largest competitor in PJM East.

IV. THE BPU SHOULD NOT RELY ON THE FERC'S MARKET POWER FINDINGS

Q. Does the FERC's approval of the merger on July 1, 2005 eliminate the need for the BPU to review market power issues?

A. No. The BPU is still required, pursuant to N.J.S.A. 48:2-51.1, to examine the impact of the proposed merger on competition, rates, service and employees.

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3 Ibid.
4 Ibid.
5 Direct Testimony of Rodney Frame, Exhibit RF-8 (Revised), page 1 of 2.

Q. Should the BPU nevertheless rely on the FERC's finding concerning the impact of the proposed merger on the ability of the combined company to exercise market power?

A. No. For the following reasons, the BPU should not rely on the FERC's finding that the merger, even with the mitigation proposed, will not harm competition in any relevant energy market.[6]

- The FERC applied a different standard than the BPU will apply in this proceeding.
- The FERC's decision to approve the merger relies on its ability to address market power problems after they occur. The BPU's ability to redress damages that will likely result from the proposed merger and that may not be recoverable at a later time is uncertain; hence, it cannot afford to adopt the FERC's reactive approach. The BPU should address all of the implications of the merger before such costs are incurred.
- The FERC does not address potential market power problems that could arise at retail.
- The FERC relied solely on Herfindahl-Hirschman Indices ("HHIs"), an approximate and contested measure of market concentration and market power (discussed in more detail below).
- The record before the FERC was inadequate to determine whether the combined company created by the merger would be able to exercise market power in the PJM energy and capacity markets and in the New Jersey BGS auction.

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[6] *FERC July 1, 2005 Order Authorizing Merger Under Section 203 of the Federal Power Act, Docket No. EC05-43-000*, ("*FERC Order Authorizing Merger*") at Paragraph 120. Several parties, including the Ratepayer Advocate, have filed motions for rehearing of the FERC's Order of July 1, 2005. These motions are pending at the FERC.

Q. Please describe the different standards being applied by the FERC and the BPU in evaluating the proposed Exelon-PSEG merger.

A. The BPU has stated that it will apply a positive benefits standard for reviewing the proposed merger.[7] Under that standard, the BPU must find that the proposed merger will provide a positive benefit for ratepayers. In addition, there must be a minimum of no adverse impact on the criteria used in the evaluation of the merger.[8]

The FERC, on the other hand, does not apply a positive benefits standard when evaluating whether a proposed merger is in the public interest. In fact, the FERC's merger guidelines specifically allow a proposed merger to increase the extent of concentration in the markets being examined, as long as those increases fall within prescribed limits. Consequently, the FERC is essentially concerned that proposed mitigation restores the concentration in the markets being examined to "near pre-merger levels" and has approved proposed mergers even if they make the relevant market(s) more concentrated.[9]

Q. If the proposed merger is consummated, would the FERC retain jurisdiction over the new merged company to address market power issues?

A. Yes. The FERC would continue to have the authority over EEG under Section 203(b) and 309 of the Federal Power Act to address market power issues. In fact, the FERC's July 1, 2005 Order approving the proposed merger noted that the FERC specifically retained jurisdiction over market power issues and specifically directed the Petitioners to submit a number of compliance filings to address certain issues raised in the Order:

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7 Transcript of BPU Session of June 22, 2005, at pages 8-9.
8 Ibid.
9 *FERC Order Authorizing Merger*, at Paragraph No. 132, on page 45, and Paragraph No. 139, on page 48.

- Petitioners must agree that, if the virtual divestiture does not in fact mitigate the problems identified, Petitioners will propose to the Commission mitigation that will mitigate the problems identified.[10]

- Moreover, Petitioners have committed to provide an Appendix A analysis of the merger's effect on competition, based on the actual acquirers of the actual divested assets, once they are known. We rely on that commitment in making our finding that the divestiture adequately mitigates any merger-related harm to competition in the relevant energy markets. If the analysis shows that the merger's harm to competition has not been sufficiently mitigated, we will require additional mitigation at that time, pursuant to our authority under FPA.[11]

- We reject arguments that we should address in this proceeding whether Petitioners will pass the Commission's market-based rates screen. Any issues regarding Petitioners' generation market dominance will be addressed in the pending proceeding on Exelon's triennial review filing, and in future similar proceedings.[12]

- Therefore, when the Commission approves a new capacity market for PJM, we will require Petitioners to submit a new analysis of the merger's effect on the PJM capacity market and, if the analysis shows that the merger-related harm to competition is not fully mitigated, propose a new mitigation plan for the Commission's approval within 30 days of such approvals.[13]

The FERC also would retain the jurisdiction under Section 205 of the Federal Power Act to authorize the new company to sell power at market based rates.

Q. What evidence did the Petitioners present at the FERC on market power issues?

A. The Petitioners presented two analyses at the FERC through the testimony of Dr. Hieronymus and Mr. Frame, which attempted to show that the proposed merger will meet the FERC's Appendix A guidelines in terms of post-merger concentration. They did so by examining pre-merger, post-merger and post-mitigation HHIs. The HHI is the sum of the squares of individual firms' market

[10] Ibid, at paragraph no. 134, at page 46.
[11] Ibid, at paragraph no. 142, at page 49 and paragraph no. 178, on page 61.
[12] Ibid, at paragraph no. 145, at page 50.
[13] Ibid, at paragraph no. 167, at page 57.

shares. The higher the index number, the greater the level of concentration and the more likely that market power will be a problem.

Q. What are the FERC Appendix A guidelines?

A. The FERC guidelines address three ranges of HHIs. If the post-merger HHI is below 1000, regardless of the change in HHI, the FERC will find that the merger is unlikely to have adverse competitive effects. If the post-merger HHI lies between 1000 and 1800 (considered a moderately concentrated market by the FERC's standards), the FERC will approve a proposed merger even if it increases HHIs by 100 points or less. Finally, if the post-merger HHI is greater than 1800 (considered a highly concentrated market), the FERC will approve a proposed merger even if it increases HHIs by 50 points or less.[14]

Q. What are the weaknesses in HHI analyses?

A. Although HHIs are a useful measure that can serve as a starting point in analyses of market power, they are only rough illustrations of relative market concentration. HHI calculations are based on a limited set of snapshots of the markets examined in terms of load, resources, and transmission capacities. It can reasonably be expected that there will be situations during a typical year when loads and transmission capacities differ from those studied and actual post-merger market shares will be higher than the HHI analysis predicted. Moreover, HHIs do not take into account the many complexities that can exist in the current electric energy and capacity markets. The most significant failure of HHI calculations is their inability to recognize strategic bidding or the withholding of otherwise available capacity in order to increase market clearing prices.

[14] FERC Order No. 592, Issued December 18, 1996, at page 61.

Q. Are there any factors specific to this proposed merger that make reliance upon HHIs as a measure of market concentration a particular concern?

A. Yes. In this case, because the post-merger market will be dominated by a single huge company, the focus on HHIs as a measure of market concentration in judging the merger is problematic. In our testimony, we do calculate and present HHI results in order to provide context for and rebuttal to Mr. Frame's analysis, and we also present some simulation modeling results of our own that illustrate the possible impact upon prices. However, in the case of this particular merger it must be noted that the commonly used concentration measure may be even more limited than usual, and perhaps quite misleading. Specifically, the HHI is defined as the sum of the squares of the market shares of individual companies in a market. Where there are several large companies they will all contribute significantly to the HHI calculated for the total market, and they will compete with each other. In this case, the post-merger market (e.g., in PJM East) will be characterized by one large firm (EEG) and many significantly smaller firms. In this sort of market it is possible that the single large firm could dominate the market, with the smaller firms unable to provide an adequate competitive threat to the dominant firm.

Consider the following concentration figures for capacity in PJM East from Mr. Frame's Exhibit RF-8 (revised). Mr. Frame shows pre-merger that Exelon and PSEG have 17.2 percent and 24.6 percent capacity market shares, respectively. In the next tier of firms are PEPCO, PPL and Reliant, at 7.5 percent, 6.4 percent, and 5.9 percent, respectively. Companies of this size are competitors with the two large firms, but they simply don't compare in size to either Exelon or PSEG, and certainly not with a post-merger EEG. Market dynamics can be quite complex and in general, lower levels of concentration as measured by the HHI are preferable. There is, however, a sense in which a market with a single mega-firm and second tier of smaller firms could be subject to problems not reflected in the HHI measure. For example, the large firm could have knowledge of market transactions and prices that is not available to the smaller competitors. There could be market leader and follower dynamics, in which the large firm is able to influence the market price to an extent that would not be possible in a market with two similarly sized large firms but an equivalent HHI.

Q. Did the FERC's approval of the proposed merger based on the Petitioners' HHI analyses conflict in any way with its prior statements concerning relying solely on HHI concentration ratios?

A. Yes. The FERC had previously noted that the HHI screening tool was "not infallible" and "in some cases may not detect certain market power problems."[15] The FERC also has stated that the HHI Guidelines are "just that, guidelines" and that "It is reasoned analysis, not blind faith in the [HHI concentration] thresholds, that must carry the day."[16]

These cautious statements contrast starkly with the FERC's complete reliance on HHI concentration figures in its review of the proposed Exelon-PSEG merger, its approval of HHI-determined mitigation, and its refusal to even hold hearings to examine in detail the validity of the Petitioners' HHI analyses.

Q. Has the BPU reached any conclusions regarding whether the record before the FERC was adequate for determining that the proposed merger was in the public interest?

A. Yes. The comments and testimony filed at the FERC by the BPU found that the evidence that had been presented by the Petitioners was inadequate for determining that the proposed merger was in the public interest. For example, the BPU's May 27, 2005 Comments to the FERC noted the following deficiencies in the record:

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15 *FERC Policy Statement Establishing the Factors the Commission will Consider in Evaluating Whether a Proposed Merger is Consistent with the Public Interest, December 18, 1996,* at page 25.

16 Ibid, at page 76.

- The Petitioners have proposed a variety of complicated and novel mitigation measures, the exact shape and results of which, as explained below and in the accompanying testimony, cannot be known on the current record.[17]
- Record evidence raises troubling concerns that the Petitioners may be able to exercise market power in the electric generating capacity market.[18]
- The Petitioners have provided very little analysis of their market power or the state of the market post-transaction in the electric generating installed capacity ("ICAP") market.[19]
- Record evidence raises troubling concerns that the Petitioners may be able to exercise market power in the electric energy market.[20]
- The BPU does not believe a determination can be made that the Transaction is in the public interest without much more data and investigation concerning the impacts the merger could have on the energy markets under each outcome permitted by the Petitioners' flexible proposal.[21]
- The BPU urges the Commission to set the issue of whether the Petitioners sliding scale divestiture can be made to effectively address market power. The existing record is simply not sufficient to take a leap of faith on virtual divestiture combined with substituted retirements.[22]
- The record is not adequate to determine that Petitioners would be unable to exercise vertical market power through the use of electric transmission or natural gas pipeline capacity.[23]
- The Petitioners fail to address the concerns of the BPU, among other intervenors, that the Petitioners will be able to use their possibly dominant position in upstream gas pipeline capacity and electric transmission ownership and control to raise barriers to entry, to raise rivals' costs or to cause other competitive harm.[24]

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17 *New Jersey Board of Public Utilities Comments in Support of Hearing and in Response to the Petitioners' Answer and Supplement to their Section 203 Application*, FERC Docket No. EC05-43-000, dated May 27, 2005, at page 2.
18 Ibid, at page 10.
19 Ibid, at page 10.
20 Ibid, at page 13.
21 Ibid, at pages 14 and 15.
22 Ibid, at page 18.
23 Ibid, at page 18.
24 Ibid, at page 18.

- When the BPU, however, reviews those points in the Petitioners' market power mitigation proposal that may be exploited, the BPU is concerned that more evidence must be developed to determine whether the Petitioners' proposal satisfies the public interest standard. For instance, the Petitioners don't propose divestiture of specific units, but of several of many units; the Petitioners don't propose straight forward divestiture, but instead of sliding scale including real divestiture, "virtual divestiture," and retirements; in response to concerns over their dominant position in upstream gas pipeline capacity, the Petitioners answer that short-term, interruptible transportation service will be available. Perhaps one item requiring a leap of faith by itself would not raise the same degree of public interest concern. These less than plenary responses to legitimate market power concerns taken together with the Petitioners' dominant position in electric transmission within PJM raise numerous alarms and should be explored.[25]
- The record is inadequate to determine the sufficiency of the Petitioners' claim that the Transaction would produce competitive efficiencies that will benefit the public interest.[26]
- There are many permutations that the Petitioners' novel, shape-shifting proposal would permit. Based on the record before the Commission, these myriad permutations have not been adequately defined and need to be explored through discovery, testimony and cross-examination at hearings.[27]

Q. Have the Petitioners presented in their testimony, exhibits or data responses in this proceeding any of the evidence that the BPU has said was lacking in the record at the FERC?

A. No. In their testimony in this proceeding the Petitioners have ignored the BPU's desire to see such additional information. Instead, the Petitioners have merely filed an HHI analysis by Mr. Rodney Frame that is similar to the HHI screening analysis that they presented at the FERC. The Petitioners have not provided in their testimony or data responses any of the specific information identified by the BPU in its Comments on the merger Application before the FERC or any analyses showing that EEG will not be able to profitably exercise market power in the PJM

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[25] Ibid, at pages 19-20.
[26] Ibid, at page 20.

energy and/or capacity markets or the New Jersey BGS auctions through strategic bidding or physical withholding.

Q. What evidence does the Board need to determine if EEG will be able to profitably exercise market power in the PJM energy and/or capacity markets or in the New Jersey BGS auctions?

A. Horizontal market power in electricity can arise from horizontal concentration in generation. A key mechanism for exploiting horizontal market power is for a large firm to raise market prices by withholding capacity from the market, raising the market price and thereby increasing profits over competitive-market levels. The withholding can be "physical," such as declaring a unit to be out of service, or "economic," such as bidding some capacity at high prices that effectively remove it from the dispatch. Sophisticated strategies can be developed in which bidding generation into the market is done in order to maximize profits -- with bids differing by hour and tailored to create and exploit transmission constraints.

A proper analysis of the market power implications of the proposed Exelon-PSEG merger would require an energy simulation model to look at the hourly behavior of the market under a wide variety of external conditions and bidding behaviors. Such a more realistic model would provide better insight into potential market power concerns than just the idealized HHI calculations presented by Mr. Frame on behalf of the Petitioners.

Simulation models can be useful in directly analyzing market power, given the specific characteristics of a market such as the number of suppliers and their production facilities and cost structure. Such models help us to understand likely market behavior in particular cases, and to examine the ability of firms in the market to profitably raise prices. If a simulation model shows that it is not profitable for any individual firm to raise its prices significantly above its

[27] Ibid, at page 22.

marginal costs, that finding would offer some comfort that the market will be adequately competitive. If, on the other hand, simulations show that it is profitable for individual large firms to increase prices significantly above marginal costs, then there is cause for concern. In this case, models can be helpful for understanding the extent of the market power problem and exploring the effectiveness of various remedies.

Q. What specific analyses should be undertaken with such a simulation model?

A. The analyses that need to be performed prior to any approvals of this proposed merger include the following:

- Simulation with an hourly model that would represent generating unit outages probabilistically rather than as simple deratings of capacity.
- Analysis of a full range of input assumptions for system conditions such as generating unit and transmission line outages, loads, and markets prices.
- Consideration of possible strategies for the dominant firms to exercise market power by the physical and/or economic withholding of capacity of different types in different time periods.
- Analysis that includes the specific details of current (and possible future) market mitigation procedures and bid capping.
- Examination of a longer time frame than calendar year 2006 in order to reflect such changed circumstances as planned power plant additions and retirements, load growth, transmission system enhancements, and the addition of increased transmission links to New York State such as the proposed 600 MW HVDC Neptune Project from New Jersey to Long Island.
- Examination of divestiture scenarios in which the implications of divesting different sets of generating units are explored.
- Detailed analysis of specific constrained areas, including Northern New Jersey.
- Detailed analysis of the capacity markets recognizing that PJM has recently proposed a new capacity market structure. This analysis should include specific mitigation plans for addressing the market power of the merged companies in the proposed PJM capacity markets.

- A rigorous analysis of the effectiveness of the Petitioners' proposed "virtual divestiture" that would consider the distinctions between ownership and control, and the likely effects of power sales of different durations.

Q. Have you seen any instances in which the results of simulation modeling have been submitted to the FERC and a state regulatory commission in support of a proposed merger?

A. Yes. In support of their request for approval to merge, Allegheny Power System and Duquesne Light Company presented the results of their simulation modeling of bidding behavior to the FERC and the Pennsylvania Public Utilities Commission.[28] This modeling used the GE MAPS model to analyze cases in which generators offered their power at bid prices above marginal cost.

Q. Have you seen any instances in which Mr. Frame has used a simulation model to examine the potential for strategic bidding?

A. Yes. In testimony submitted to the Missouri Public Service Commission in February 1998 and the Mississippi Public Service Commission in August 1998, Mr. Frame used production cost analyses to conduct a behavioral analysis, which sought to assess whether a company acting unilaterally might be able to exercise market power in energy markets.[29]

Q. Would the BPU have the ability to redress the exercise of market power by EEG in the annual BGS auctions?

A. Not really. It is not reasonable to expect that the BPU will be able to identify the exercise of market power by EEG and act within the very limited time in which it has to review and approve the results of each year's BGS auction.

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[28] Testimony of Dr. Pifer in FERC Docket No. EC97-46-000, at pages 54 and 55.

[29] *Report of Ameren to the Public Service Commission of Missouri on Market Power Issues*, dated February 27, 1998, at pages 64-67, and , dated February 27, 1998, at pages 64-67, and *Report to the Mississippi Public Service Commission on Retail Market Power Issues*, dated August 1998, at page 65-69. Both of these documents were provided in PSEG's response to RAR-MKT-81(b).

V. DEFICIENCIES IN MR. FRAME'S ANALYSIS

Q: Do you have any concerns with the market concentration analysis submitted on behalf of the Petitioners?

A: Yes. Mr. Frame's modeling results misrepresent the current state of the PJM East energy market as well as the likely state of the market after the merger.

V.A. Mr. Frame's Modeling Understates the Level of Concentration in the PJM East Energy Market

Q. Does Mr. Frame's modeling in this proceeding accurately represent the pre-merger levels of concentration in the PJM East Energy Market?

A. No. Mr. Frame's modeling understates the pre-merger levels of concentration in the PJM East Energy market.

Table 1 below compares the pre-merger HHIs for the PJM East energy market developed for the year 2006 by Mr. Frame to the historical market concentration data published by the PJM Market Monitoring Unit for 2003 and 2004. ("PJM MMU").

Table 1: PJM East Energy Market – Mr. Frame's HHI Results vs. Historical PJM Data

	Frame-Projected HHI for the Year 2006[30]	PJM MMU Data for the Year 2003[31]	PJM MMU Data for the Year 2004[32]
High	1531	2500	1980
Low	989	1300	1156
Average		1935	1568

Thus, the PJM MMU data in Table 1 indicate a substantially more concentrated market than Mr. Frame's HHI results imply. In fact, the high ends of the PJM

[30] Direct Testimony of Rodney Frame, Exhibit RF-6 (Revised).
[31] PJM Market Monitoring Unit, *2003 State of the Market Report*, at page 42.

MMU data suggest that the PJM East energy market was very highly concentrated for some hours during the years 2003 and 2004.

As shown in Table 1, the *average* historical HHIs for the PJM East Energy market for 2003 were higher than the *high* ends of the pre-merger HHIs calculated by Mr. Frame. The average historical HHI for the PJM East Energy market for 2004 was approximately the same as the high end of Mr. Frame's calculated pre-merger HHIs.

Q. Do any scheduled increases in transmission system import capability into PJM East or planned new generation facilities explain or justify the differences between the actual PJM East 2003 and 2004 energy market HHIs and the substantially lower level of market concentration in PJM East suggested for 2006 by Mr. Frame's analyses?

A. No.

Q. Has the BPU expressed concern about the existing levels of concentration in the PJM markets?

A. Yes. In its comments to the FERC, the BPU noted that the data presented in the PJM 2004 State of the Market Report already raised red flags on market power issues before the merger.[33]

Q. What is the significance of the differences between Mr. Frame's pre-merger modeling results and actual historical PJM data?

A. The significant differences with historical PJM data on pre-merger market concentrations call into question the validity of all of Mr. Frame's modeling of the

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32 PJM Market Monitoring Unit, *2004 State of the Market Report*, at page 58.

33 *New Jersey Board of Public Utilities Comments in Support of Hearing and in Response to the Petitioners' Answer and Supplement to their Section 203 Application*, FERC Docket No. EC05-43-000, dated May 27, 2005, at page 13.

PJM system post-merger and post-mitigation market concentrations. Moreover, these differences lead Mr. Frame to understate the amount of capacity that must be divested by EEG in order to satisfy the HHI market screen criteria that Mr. Frame is attempting to satisfy.

V.B. Flaws and Weaknesses in Mr. Frame's HHI Modeling

Q. Has Synapse identified any specific flaws in the HHI modeling presented by Mr. Frame?

A. Yes. We have identified a number of serious flaws in Mr. Frame's modeling that render the results of his HHI analyses unrealistic and that cause him to understate the post-merger and post-mitigation levels of concentration in the PJM East energy market:

- Mr. Frame's analysis relies on an idealized estimate of market concentration using one measure, the HHI, which fails to recognize strategic bidding or the withholding of otherwise available capacity in order to increase market clearing prices (as noted in the previous section).
- The use of a proportional methodology for allocating the limited transmission import capability across PJM's Eastern Interconnection tends to understate EEG's share of capacity imports and its total market presence.
- Mr. Frame assumes that the capacity from all of the generating units being modeled will be available to serve load in his targeted geographic areas and would not already be committed to serving other load or because it is being diverted to other areas for economic reasons. Market concentration measures based on this assumption will not accurately reflect the amount of capacity that can actively compete in the market.
- Mr. Frame's failure to reflect transmission system outages or deratings misrepresents the amount of capacity that can reach markets or loads.
- The treatment of forced and planned outages as a reduction of capacity in all hours tends to minimize the effect of outages during peak hours.
- [REDACTED]

- The analysis fails to fully reflect the expected improved output from the Salem and Hope Creek nuclear units as a result of the proposed merger and hence understates market concentration.
- Likewise, the failure to reflect proposed nuclear unit capacity uprates[34] understates EEG's market share.
- EEG's purchases of capacity from other PJM participants should be reflected in the market concentration analysis, because under certain circumstances these purchases can enhance a firm's ability to exercise market power. Mr. Frame fails to model these purchases.

Each of these points will be addressed below.

V.B.1 Mr. Frame Uses a Methodology to Allocate Limited Transmission Import Capability that Leads Him to Understate the Concentration of the PJM East Energy Market

Q. Why should the BPU be concerned about the methodology used by Mr. Frame to allocate the limited transmission capability into PJM East?

A. The BPU should be concerned because the potential ability of EEG to exercise market power will depend not only on the generating resources that it would own within PJM East. It also would depend on how much of the limited transmission import capability into PJM East that the merged company will be able to use to effectively flow power from its low cost nuclear facilities located elsewhere in PJM. As we will show below, the pro-rata allocation methodology used by Mr. Frame in his analyses of the proposed merger understates the amount of power that the Petitioners can be expected to be able to import effectively into PJM East as compared to an economic allocation methodology in which the lowest cost power would be expected to gain preferential access to the limited transmission into PJM East.

[34] An uprate is an increase in a generating unit's Net Dependable Capacity.

Q. What methodology does Mr. Frame use in his energy market analyses to allocate the limited transmission import capability into PJM East?

A. He uses what he calls a "proportional" method to allocate limited transmission import capability. This means that he allocates to each supplier a share of the limited capability equal to the supplier's share of all generation deemed to be competing to use the path.[35]

Q. Does Mr. Frame use the same methodology to allocate other limited transmission import capability within PJM?

A. Yes.

Q. What other methodology could be used to allocate limited transmission import capability?

A. Mr. Frame identified the "economic" allocation method as an alternative that would assign limited transmission capability to the suppliers with the lowest delivered costs.[36]

Q. Does Mr. Frame acknowledge that it would be more realistic to use such an economic allocation methodology?

A. Yes. In his testimony he acknowledges that the economic methodology is "perhaps more realistic in terms of which suppliers ultimately will gain access to limited transmission capability."[37]

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35 Direct Testimony of Rodney Frame, at page 36, lines 4-9.
36 Ibid, at page 36, lines 11-13.
37 Ibid, at page 36, lines 13-15.

Q. In other proceedings, has Mr. Frame actually used an economic methodology to allocate limited transmission capability in other market power analyses?

A. Yes. Mr. Frame used an economic methodology to allocate transmission capability in at least three merger-related pieces of testimony that he filed in 1997.[38]

Q. What reasons did he provide in those cases for using an economic allocation of transmission capability?

A. Mr. Frame explained that "when qualifying supplies exceed the [transmission] interface limits, interface capability was assigned first to lower priced supplies on the assumption that those owning the lower cost supplies will be able to price their output in a fashion to win the sale over the limited tie capability."[39]

Q. What explanation has Mr. Frame given in this case for not using an economic allocation of the limited transmission into PJM East?

A. Mr. Frame claims that while an economic allocation is perhaps more realistic, it overlooks entirely all suppliers other than those that gain an allocation of the limited transmission capability even though those other suppliers also can deliver energy into the destination market at a price lower than 1.05 times the competitive price.[40] Therefore, according to Mr. Frame, the economic method ignores the competitive pressures from those suppliers.[41]

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[38] Prepared Supplemental Direct Testimony of Rodney Frame in FERC Docket No. EC97-5-000, at page 39; Additional Direct Testimony and Exhibits of Rodney W. Frame in FERC Dockets Nos. EC96-13-000, ER96-1236-000, and ER96-2560-000, at page 31; and Direct Testimony on Reopening of Rodney Frame, in Illinois Commerce Commission Docket No. 95-0551, at page 60.

[39] Additional Direct Testimony and Exhibits of Rodney W. Frame in FERC Dockets Nos. EC96-13-000, ER96-1236-000, and ER96-2560-000, at page 31; and Direct Testimony on Reopening of Rodney Frame, in Illinois Commerce Commission Docket No. 95-0551, at page 60.

[40] Direct Testimony of Rodney Frame, at page 36, lines 13-20.

[41] Direct Testimony of Rodney Frame at page 36 lines 13-20.

Q. Do you agree that applying the proportional method to allocate the limited transmission capability into the PJM East market is reasonable?

A. No. As explained below, we believe that the use of an economic allocation would be more realistic and reasonable.

Q. What capacity does Mr. Frame model as competing to serve load in PJM East?

A. Mr. Frame assumes that all of the capacity that meets his delivered price test would compete to serve load in PJM East. This includes capacity from throughout PJM Expanded and 7,500 MW of imports into PJM.

Q. Is it reasonable to assume that all of this capacity would be available to serve load in PJM East subject to the limited transmission import capability?

A. No. In the real world, much of the capacity that Mr. Frame assumes would be available to serve load in PJM East might not be available because of planned or forced outages or because it might already be committed to serving other load outside PJM East. It is highly unrealistic that all of the capacity in the remainder of PJM beyond the Eastern Interface would be competing to serve loads in PJM East instead of being used to serve loads in Baltimore, Pittsburgh, Columbus, Ohio, Washington, D.C., or Chicago, to name a few large urban centers in PJM.

Q. What impact does the assumption that all of this capacity is competing to serve load in PJM East have on the results of Mr. Frame's HHI analyses?

A. It unrealistically reduces the HHIs produced by Mr. Frame's model because it assumes that capacity will be provided by numerous other suppliers which, in the real world, might not be able to serve loads in PJM East because of other commitments.

Q. Does Mr. Frame make any adjustment to reflect the fact that any of this capacity would not be available because it would already be committed to serving other load outside PJM East or because it would be diverted to other areas for economic reasons?

A. No.

Q. How much of the 7,300 MW of import capability into the PJM East energy market is allocated to Exelon and PSEG in Mr. Frame's analyses?

A. In Mr. Frame's pre-merger modeling of the PJM East energy market, between [REDACTED] of the Eastern Interconnection transmission import capability is allocated to PSEG and Exelon-owned units.

Q. What would be the results if you applied an economic allocation methodology to Mr. Frame's data?

A. The results are shown in Table 2 below and in greater detail in Exhibit BFS-4.

Table 2: PSEG and Exelon Shares of Transmission Import Capability into PJM East - Mr. Frame's Pro-Rata Transmission Allocation versus an Economic Allocation[42]

Transmission Allocation (MW)		
	Pro-Rata	**Economic**
PSEG	**REDACTED**	
Exelon		**REDACTED**

Thus, significantly more of the imports into PJM East will be allocated to PSEG and Exelon using economic allocation methodology than the pro-rata methodology used by Mr. Frame.

[42] The confidential pro-rata transmission import figures in Table 2 are taken from Mr. Frame's workpapers. The confidential economic allocation transmission import figures are taken from our Exhibit BFS-4.

The same conclusion results from an examination of the data for individual hours studied by Mr. Frame. Exhibit BFS-4 shows, for example, that during Mr. Frame's Summer 3 period, a pro-rata allocation of transmission would [

REDACTED

] under an economic allocation.

Q. What generating capacity would EEG retain in the remainder of PJM Pre-2004 outside of PJM East if the proposed merger is consummated?

A. As shown in Exhibits RF-3 and RF-4, Exelon and PSEG together currently own more than 5,500 MW of low cost nuclear (3,010 MW), coal-fired (1,476 MW) and hydro (1,077 MW) capacity west of the PJM Eastern transmission interface. This capacity includes the nuclear units at Peach Bottom and Three Mile Island, the baseload coal-fired capacity at Conemaugh and Keystone, and hydro capacity at Muddy Run. EEG would retain approximately 4,400 MW of this capacity under the revised mitigation plan proposed by the Petitioners.

Q. Is it reasonable to expect that this capacity would be allocated across the interface if an economic methodology were used to allocate the limited transmission import capability into PJM East?

A. Yes. Mr. Frame has said that an economic method assigns limited transmission capability to the suppliers with the lowest delivered costs. That would certainly apply to the low-cost nuclear, hydro, and, to a lesser extent, coal capacity that would be retained by EEG.

Q. Have you seen any evidence that suggests how much of the limited transmission import capability into PJM East actually is being effectively used by Exelon and PSEG?

A. Yes. We have analyzed the results of the PJM Annual Auction of Financial Transmission Rights ("FTR") for the 2005-2006 planning period. This analysis is focused on FTRs bought or self-scheduled and sinking in the PJM East market area, i.e., the PJM sink nodes east of the PJM East transmission interface.

Q. What are the results of this analysis?

A. Allocating import capacity across the PJM East interface based on FTR ownership suggests that Exelon and PSEG currently use significantly more of the limited transmission import capability into PJM East than is suggested by Mr. Frame's pro-rata methodology. Using FTR ownership results in an allocation to EEG in the range of 32 to 42 percent. The results of this analysis provide direct evidence of the actual economic allocation of transmission rights. They confirm our conclusion that it is more appropriate to allocate the limited transmission import capability into PJM East using an economic allocation methodology instead of the pro-rata methodology used by Mr. Frame in his analyses.

Q. Please describe how you conducted this analysis.

A. The results of PJM's 2005-2006 Annual FTR Auction were analyzed to determine the makeup of auction winners who procured or self-scheduled FTRs across the PJM East interface. Auction winners or FTR self-schedulers hold transmission rights across the PJM East interface that entitle them to congestion payments from PJM, effectively hedging almost all of the costs of congestion associated with transferring energy across the interface.

Q. Please describe the way in which ownership of FTRs represents an alternative allocation method for transmission import capability into the PJM East market.

A. Market participants can no longer obtain physical transmission rights across the PJM East interface. FTRs are the form of transmission rights that now exist. FTRs allow for a market participant to almost fully hedge against all congestion costs associated with imports flowing across a constrained PJM East interface. While FTRs are not physical transmission rights, they do place a market participant "financially" into the PJM East market by allowing the holder to effectively obtain PJM East market prices for generation located outside of PJM East that is dispatched by PJM.

Q. Please describe what this analysis shows.

A. Exhibit BFS-5 presents our analysis of the allocation of FTRs across the PJM Eastern interface. The FTR allocation is composed of FTRs bought at auction, or self-scheduled by the holder of auction revenue rights. ("ARR") ARRs are a form of entitlement to the value of transmission interfaces.

Page 1 of Exhibit BFS-5 lists the forty-six (46) entities that bought or self-scheduled FTRs in the annual auction and now hold a hedge against congestion across the interface during the 2005-2006 planning period (June 1, 2005 through May 31, 2006). These entities paid a combined total of almost $300 million to obtain these transmission rights.

The exhibit also contains a listing of the "counterflow" FTRs bought at auction, i.e. those FTRs that source in the PJM East region and sink in the regions to the west of PJM East. The presence of counterflow FTRs allows the PJM RTO to essentially auction off more FTRs in the west-to-east direction than they otherwise would be able to. Thus, a total of 8,991.5 MW of FTRs were sold or self-scheduled at auction across the PJM East interface, which has a nominal capacity of 7,300 MW, based on the information used in Mr. Frame's testimony.

A total of 2,186.9 MW of "counterflow" FTRs were also sold. Thus, the "net" FTRs sold or self-scheduled across the interface was 6,804 MW, within the limit of the interface.

Q. How many FTRs across the PJM East interface are held by Exelon and PSEG?

A. Exelon holds 2,152 MW of FTRs, and PSEG holds 692 MW of FTRs, for a total of 2,844 MW of FTRs. This corresponds to somewhere between a 31.6 percent and a 41.8 percent share of the total import capacity when considered using FTR ownership. If the west-to-east FTRs across the interface are the only ones considered, then the merged company holds a 31.6 percent share. However, when the counterflow FTRs are also considered, the total share held by these companies increases to 41.8 percent. Using yet a third allocation method, the FTRs held by the merged companies can be compared to the total 7300 MW physical limitation of the PJM East interface. That computation results in a share of 39 percent.

Q. Why should counterflow FTRs be considered when computing the share of import capacity?

A. The only way in which the total of 8,991 MW of FTRs could be sold for an interface nominally rated at 7300 MW is if counterflow FTRs are also sold.

Q. Which FTRs across the PJM East Interface are held by Exelon?

A. As shown on page 2 of Exhibit BFS-5, Exelon holds 2,152 MW of FTRs sourced at nuclear, hydro and fossil generating plants in PJM – west of the PJM East interface - in which Exelon holds ownership or output rights. The FTRs sink in the PECO service territory, located in the PJM East market.

Q. Which FTRs across the PJM East Interface are held by PSEG?

A. As shown on page 3 of Exhibit BFS-5, PSEG holds 692 MW of FTRs sourced at nuclear, hydro and fossil generating plants in PJM in which PSEG holds ownership or output rights. The FTRs sink in the PJM East region, primarily in the PSEG, AECO, and JCPL zones. The FTRs also sink at a number of discreet nodes also located in the PJM East region.

Q. How did you determine if a FTR sinks in the "PJM East" region?

A. We examined the PJM LMP bus model and related information provided on the PJM website. From that information, we were able to map the source and sink node data from the FTR auction results and assign aggregate sinks and sources, allowing for a "PJM East" sink designation, and similar aggregations for source nodes and non-PJM East sink nodes.

Q. In conclusion, what is the significance of using an economic allocation methodology for import capacity instead of a pro-rata methodology?

A. Mr. Frame's use of a pro-rata allocation method tends to understate EEG's share of capacity imports, its total market presence in PJM East, and its ability to exercise market power. As our analysis of FTRs shows, the use of an economic allocation methodology will provide a more realistic assessment of how much capacity EEG can be expected to import across the PJM East Interface.

V.B.2. Mr. Frame Unrealistically Ignores Transmission Outages or Deratings

Q. Does Mr. Frame reflect any transmission outages or deratings in his HHI modeling?

A. No. Mr. Frame does not reflect any transmission system outages or deratings. He merely assumes that the calculated amounts of transmission import capability, subject to the determined simultaneous import limits, will be available during each of the hours that he examines.

Q. Is this a realistic assumption?

A. No. Transmission systems do have planned and unscheduled outages and deratings. These outages and deratings impact the ability of the electric system to import power and/or to deliver power from individual generating facilities. The occurrence of these outages and deratings will limit the amounts of capacity that can be imported into PJM East, Northern New Jersey or any other constrained areas and, thereby, affect the ability of EEG to exercise market power. For this reason, transmission outages and deratings need to be considered.

V.B.3 Mr. Frame Models Planned and Forced Generating Unit Outages in an Unrealistic Manner

Q. How does Mr. Frame treat planned and forced generating unit outages in his analyses?

A. Mr. Frame's modeling assumes that scheduled generating unit maintenance outages occur only during the non-peak (shoulder) seasons. Forced outages are assumed to occur uniformly throughout the year.

Q. Is this a reasonable way to represent planned and forced generating unit outages?

A. No. Mr. Frame's model represents an idealized and over-simplified world that doesn't accurately represent conditions and market behavior of participants in the system being modeled.

In the real world, planned outages sometimes occur, at least in part, during the summer and winter peak months. At the same time, forced outages do not occur in a smooth manner throughout the year. In other words, capacity availability on the actual PJM system is far more "lumpy" than Mr. Frame's model reflects. In the real world, generating units are often completely out of service for planned or forced outages – although in some circumstances units may be partially derated for maintenance. In Mr. Frame's modeling, all generating units are represented as running at lower than maximum capacity in all hours to reflect planned and forced outages, and are never assumed to be off line completely.

Q. Please give an example of the way in which Mr. Frame's modeling represents planned and forced outages.

A. Let's assume that there is a 1,000 MW (both summer and winter ratings) baseload nuclear unit that is offline for 36.5 days per year for scheduled refueling and maintenance and another 36.5 days for forced or unplanned outages. This plant then has a ten percent scheduled outage factor and a ten percent forced outage factor.

Instead of representing this baseload nuclear plant as being online for 80 percent of the year and offline for the remaining twenty percent, Mr. Frame unrealistically models the plant as being on line for the entire year but at a reduced capacity level. Because he assumes that forced outages occur smoothly throughout the year and planned outages occur only in the fall and spring off-peak seasons, he would model this hypothetical nuclear plant at 700 MW in the fall and spring and 900 MW in the summer and winter.

This is not the way that planned and forced outages affect the capacity and availability of generic units, particularly nuclear and coal-fired facilities.

Q. What is the effect of Mr. Frame's unrealistic modeling of planned and forced generating unit outages?

A. The overall effect of Mr. Frame's "smooth" and unrealistic representation of outages is that the model tends to overstate system reliability and not consider at all situations that are "worse than average." System operators would be ecstatic to have a system in which generating unit outages were so predictable and well-behaved. Unfortunately, the actual system does not operate like that. Generating units do fail and go off-line entirely; outages do sometimes bunch in terms of timing and location. This lumpiness has very important implications for market power and for analysis of market power.

In fact, market power tends to be asymmetrical. In other words, during “tight” conditions market power will tend to be much worse than it is during average conditions. Stated specifically for outage rates we might say that compared to average conditions, the degree of market power during those hours when there are fifty percent more generating unit outages than average will tend to be much worse than average. However, the degree of market power during those hours when there are fifty percent fewer outages than average will tend to be only slightly better than average. Of course, this also depends on the specific generating units that are out of service and which companies own them. By treating all of the outages as simple deratings in all hours, Mr. Frame entirely overlooks conditions in which the amount and distribution of outages will be worse than average, and so understates the overall degree to which market power will be a problem.

The discussion about the treatment of outages in Mr. Frame’s model and the model’s resulting tendency to understate market power applies to PJM conditions pre-merger and post-merger. It also has implications for the magnitude of the increase in market power caused by the merger. Because the ability to exercise market power is not symmetrical around the average conditions, a merger that worsens market conditions will tend to have proportionally greater effects during the “worse than average” conditions that are ignored in Mr. Frame’s HHI analyses.

V.B.4 The Nuclear Unit Scheduled and Forced Outage Factors Used by Mr. Frame Cause His Analyses to Understate the Amount of Capacity Owned by Exelon and PSEG in PJM East

Q. Does Mr. Frame use unit-specific or generic industry scheduled and forced outage factors in his modeling?

A. Mr. Frame uses generic industry outage rates from the North American Electric Reliability Council's Generating Availability Data System ("GADS") database. [REDACTED]

Q. Can you give some examples of how the generic industry outage rates used by Mr. Frame compare to [REDACTED] **for plants owned by Exelon and PSEG?**

A. As shown in Table 3 below, [

REDACTED

] The use of these [

REDACTED

] of baseload nuclear capacity from his HHI calculations.

Table 3: Actual Exelon Nuclear Unit Forced and Scheduled Outage Factors vs. Industry Average Figures Used by Mr. Frame

REDACTED

Q. [

REDACTED

]

A. Probably not. However, it is reasonable to expect that these units will achieve the approximately 2 percent forced outage factors achieved by Exelon's nuclear fleet during the past four years.

Q. What effect does Mr. Frame's use of the industry average forced and scheduled outage factors have on his modeling?

A. [

REDACTED

]

Table 4: Exelon Nuclear Unit Capacities for Mr. Frame's HHI Analysis – Impact of Using Actual Exelon Fleet Performance versus Industry Average Data

REDACTED

[

REDACTED

]

Q. Does Mr. Frame accurately model the capacity levels of all of the nuclear units owned by Exelon and PSEG?

A. No. Mr. Frame ignores an uprate planned to increase the power level of the Hope Creek nuclear unit by 15 percent, i.e., about 110-130 MW, in 2006.[43] This leads him to further understate the amount of capacity that would be owned by EEG if the merger is closed or by PSEG if there is no merger.

[43] "Hope Creek Tells NRC of plans to apply this spring for 15% uprate," *Nucleonics Week*, March 21, 2005, at page 11.

V.B.5 Mr. Frame Fails to Reflect the Improved Performance of Salem and Hope Creek Claimed as a Result of the Proposed Merger

Q. Does Mr. Frame model the increased performance of the Salem and Hope Creek nuclear units that the Petitioners claim will result from the proposed merger?

A. No. He uses the same generic industry performance data for the pre-merger, post-merger, and post-mitigation scenarios he examines. Consequently, he does not reflect the increased nuclear performance at Salem and Hope Creek that the Petitioners claim as a significant benefit from the proposed merger.

Q. Does Mr. Frame himself claim that the improved performance at Salem and Hope Creek resulting from the proposed merger would have benefits for customers in the market?

A. Yes. Mr. Frame claims in his Additional Testimony that:

> one of the expected benefits from the proposed merger will be an increase in the output from the more than 3,300 MW of nuclear generation now operated by PSEG. Increased output from low cost nuclear generators will lower the market-clearing prices during all seasons and time periods, benefiting all customers in the market, including BGS customers, in a fashion that is not picked up in the market concentration studies that I have provided.[44]

Similarly, Petitioner witness Christopher Crane at the FERC, began his testimony by explaining that his purpose "is to explain how we at Exelon expect the performance of the nuclear power plants operated by PSEG to improve significantly when fully assimilated into the Exelon [nuclear] Fleet through the proposed merger of Exelon and PSEG."[45]

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[44] Additional Testimony of Rodney Frame, at page 13, lines 15-20.
[45] Testimony of Christopher Crane in FERC Docket No. EC05-43-000, at page 3, lines 3-6.

Q. What improvements in forced and scheduled outage factors are predicted for Salem and Hope Creek from the merger?

A. Table 5 below compares the Petitioners' projections as to the most likely operating performance of Salem and Hope Creek based on the unit's historical performance with the performance that would be expected if the merger is closed. The scheduled and forced outage factors in this Table were developed from the Petitioners' projected annual capacity factors in outage and non-outage years.

Table 5: Petitioners' Expected Post-Merger Performance of Salem and Hope Creek versus Projected Performance Based on Recent History

REDACTED

Q. Have you re-calculated Mr. Frame's HHIs to reflect this improved performance of the Salem and Hope Creek nuclear units and the economic allocation of the transmission capability across the PJM East interface?

A. Yes. As discussed in more detail in Section IX of this testimony and presented in Exhibit BFS-6, we have recalculated Mr. Frame's HHIs for his Mitigation Scenarios 1 through 3 to reflect (1) the proposed [ ] MW power uprate at Hope Creek in 2006, (2) the claimed improvements in operating performance at both Salem and Hope Creek, (3) the use of the recent performance of Exelon's nuclear units, and (4) the use of an economic allocation of the transmission import capability across the PJM East interface.

Q. What are the results of recalculating the pre-merger to post-divestiture HHI changes in Mr. Frame's Mitigation Scenarios 1 through 3 to reflect these corrections?

A. As shown on page 2 of Exhibit BFS-6, as a result of just these realistic changes, the merger would fail the FERC Appendix A Screening Analysis due to HHI changes greater than 100 in six of the ten hours studied in Mitigation Scenario 1; in all ten of the hours studied in Mr. Frame's Mitigation Scenario 2; and in seven of the ten hours studied in Mr. Frame's Mitigation Scenario 3. Indeed, in some of the hours studied in these Scenarios, the pre-merger to post-mitigation HHI changes would be significantly higher than 100.

V.B.6. Mr. Frame Does Not Reflect Capacity Purchases from Other PJM Participants

Q. Did Mr. Frame reflect any forward capacity purchases by EEG from other PJM participants in his analyses?

A. No.

Q. Is it important to consider such forward capacity purchases when evaluating the ability of the merged company to exercise market power and the incentive to do so?

A. Yes. Depending on the magnitude of the purchases, the additional capacity could noticeably increase the merged company's market shares and HHIs. Also, the merged company's ability to exercise market power might be enhanced by such purchases, depending on the location, fuel and operating costs of the capacity being acquired.

Q. Have you seen any evidence that Exelon or PSEG has engaged in such forward capacity purchases in recent years?

A. [REDACTED

REDACTED]

Q. Have Exelon or PSEG made such forward capacity purchases for 2006?

A. [REDACTED]

Q. Have you seen any recent evidence that suggests that Exelon may be intending to make such a forward capacity purchase for 2006?

A. Yes. A slide used in a presentation given in early August 2005 to an investor conference by the President of Exelon's Power Team noted that for 2006 Exelon is "acquiring load-following capability from bilateral market to better match assets with the load obligation."[48] The same slide indicated that Exelon is developing strategies for 2007 and beyond "for potential mitigation scenarios associated with merger."

VI. PJM CAPACITY MARKETS

Q. Have you reviewed Mr. Frame's analysis of the PJM East Capacity Market?

A. Yes. Mr. Frame's Exhibit RF-8 (Revised) is his analysis of the Capacity Market concentration in PJM East for the summer of 2006. He lists capacity by owner, including the 7,300 MW of imports over the transmission into PJM East, and then based upon those capacity figures, he calculates market shares and HHI. Mr. Frame's conclusion from this analysis is a "mitigation requirement" of 4,659 MW of capacity.

[46] Provided in Response to RAR-MKT-25, at pages 29 and 38 of the December 12, 2004 Presentation.

[47] Ibid.

Q. Does Mr. Frame's analysis accurately represent the pre-merger levels of concentration in the PJM capacity market?

A. No. As we have explained earlier in this testimony, we have identified a number of ways in which Mr. Frame's modeling assumptions are unrealistic. One factor that certainly leads him to seriously understate the pre-merger and post-mitigation levels of concentration in the PJM capacity markets is the totally unrealistic assumption in preparing Exhibit RF-8 (Revised) that the 7,300 MW of transmission import capability into PJM East is evenly assigned to four suppliers that do not currently own generating facilities in PJM East. This assumption means that Mr. Frame assigns none of the 7,300 MW of import capability to Exelon, PSEG or EEG. This leads Mr. Frame to understate the level of concentration in this capacity market and causes him to severely understate the amount of capacity that must be divested to mitigate the levels of market concentration that would result from the proposed merger.

Q. Did you have any other observations concerning Mr. Frame's Exhibit RF-8 (Revised), page 1 of 2?

A. Yes. We have several important observations concerning the analysis of the PJM capacity market presented in Exhibit RF-8 (Revised).

First, Exhibit RF-8 (Revised) misrepresents the effect of the Petitioners' proposed mitigation plan. In that Exhibit, Mr. Frame notes that he has allocated none of the 7,300 MW of import capability into PJM East to either Exelon or PSEG. However, instead of reflecting just the 3,100 MW of the actual capacity divestiture proposed for PJM East, Mr. Frame uses all 4,000 MW of the proposed actual capacity divestiture proposed for the entire PJM Expanded. This is misleading and understates the amount of additional actual divestiture, above and

[48] Exhibit BFS-7, at page 9 of 14.

beyond that proposed by the Petitioners, that would be necessary to bring the HHI to within the screening limits permitted by the FERC.

Second, even if you accept the figures presented in Exhibit RF-8 (Revised), which as we have noted are misleading, an additional 659 MW of actual capacity mitigation is required beyond that proposed by the Petitioners. However, as we have noted above, Mr. Frame's analysis more correctly suggests that at least 1,559 MW of additional mitigation would be required. This 1,559 MW figure represents the difference between the 4,659 MW Mitigation Requirement shown on Exhibit RF-8 (Revised) and the 3,100 MW that the Petitioners actually are proposing to divest in PJM East.

Third, even if you accept the analysis in Exhibit RF-8 (Revised), the new company created by the merger, EEG, would be by far the most dominant participant in PJM East, with 13,430 total MWs (after divesting 4,000 MW) and a 32.3 percent share of the market. EEG would be more than four times larger than the next largest companies in the market. EEG's dominance in the anticipated PJM capacity markets would be even more shocking if Exhibit RF-8 (Revised) appropriately reflected the allocation of some of the 7,300 MW of transmission import capability to Exelon and PSEG.

Q. Is Mr. Frame's assumption in Exhibit RF-8 (Revised) that none of the transmission import capability into PJM East should be assigned to PSEG, Exelon or EEG consistent with the results of his own modeling of the PJM East energy market?

A. No. As we have noted previously, in Mr. Frame's pre-merger modeling of the PJM East energy market, which uses a proportional allocation methodology, between [REDACTED]of the 7,300 MW Eastern Interconnection transmission import capability is allocated to PSEG and Exelon-owned units. Thus, Mr. Frame's assumption in his analysis of the PJM East capacity market that none of the transmission import capability should be allocated to Exelon, PSEG or EEG contradicts his own assumption regarding the allocation of transmission capability into the PJM East energy market.

Q. What would EEG's post-merger market shares be if the import capacity shown in Exhibit RF-8 were allocated to EEG using Mr. Frame's pro-rata allocation methodology or an economic allocation methodology?

A. Using the data from Exhibit RF-8 (Revised) and assuming that 3,100 MW of capacity in PJM East is divested, EEG's capacity market share would be 34.4 percent if none of the 7,300 MW of imports is allocated to the company. EEG's market share would increase to [ ] percent if [ ] MW were allocated to the company to reflect a pro-rata allocation of the 7,300 MW of imports. EEG's capacity market share would increase further to [ ] percent if approximately [ ] MW of imports were allocated to the company to reflect an economic allocation of the PJM East interface transmission capability.

Q. Have the Petitioners filed any proposed long-term mitigation for potential market power in capacity markets?

A. No. The Petitioners have proposed to make a filing at the FERC to mitigate whatever Appendix A screen violations are suggested by any new capacity obligation paradigm adopted by PJM.[49] They also have proposed some interim mitigation until new PJM capacity markets are approved by the FERC.[50]

Q. Has the FERC accepted this proposal?

A. Yes. In its July 1, 2005 Order approving the proposed merger, the FERC stated that when it approves a new capacity market for PJM, it would require the Petitioners to submit a new analysis of the merger's effect on the PJM capacity market and, if the analysis shows that the merger-related harm to competition is

[49] Direct Testimony of Rodney Frame, at page 19, lines 13-18.
[50] Direct Testimony of Rodney Frame, at page 20, line 15, to page 21, line 2.

not fully mitigated, propose a new mitigation plan for approval within 30 days of the FERC's approval of the new PJM capacity market.[51]

Q. In fact, has PJM recently filed a new proposal at the FERC that would drastically change the capacity market construct?

A. Yes. On August 31, 2005 PJM filed a proposal at the FERC to adopt a Reliability Pricing Model ("RPM") to address what it considers to be serious inadequacies in the existing capacity rules.

Q. What does PJM consider to be the serious inadequacies in the current capacity markets?

A. PJM has said that the current capacity construct has the following serious shortcomings:

- it does not look far enough into the future to secure capacity in time to meet reliability needs;
- it lacks an important locational element;
- it is not providing sufficient financial incentives for supply additions; and
- without revision, it will not ensure the future reliability of the region.[52]

Q. Please describe the main features of this proposed Reliability Pricing Model.

A. According to PJM's filing to the FERC, the RPM's primary features would include:

- valuing capacity resources by location;
- use of a downward-sloping variable resource requirement curve;
- four-year-forward commitment of capacity resources;
- recognizing the added value of capacity resources that preserve operational aspects of reliability; and

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[51] FERC Order Authorizing Merger, at Paragraph 167, at page 57.

[52] PJM August 31, 2005 submission in FERC Dockets Nos. EL05-148-000 and ER05-1410-000, at page 5.

- allowing planned generation, planned and existing demand resources, and planned transmission upgrades to compete on an equal basis with existing generation resources to meet capacity requirements.[53]

The RPM also will have explicit market mitigation rules to address market-structure concerns of capacity markets.[54]

The RPM will include a complicated series of four capacity auctions for each twelve month delivery year for each appropriate sub-region within PJM. The first of these auctions will be held four years before the start of each delivery year. There also will be three later incremental auctions, at 23 months, 13 months, and 4 months before the start of each delivery year.[55] These auctions would be conducted to match the region's need for capacity with offers to sell capacity, to determine the clearing prices to be paid to capacity resource sellers, and to determine the reliability charges to be paid by load serving entities.[56]

Q. What areas within PJM would be considered for separate locational auctions and prices?

A. The capacity areas to be used in RPM would be called Locational Deliverability Areas ("LDAs").[57] The LDAs would be those areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations.[58]

According to PJM, there would be two LDAs for the first year under RPM, i.e., June 1, 2006 through May 31, 2007. Another two LDAs would be added in the second year, 2007-2008. In the third (2008-2009) and fourth (2009-2010) years,

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53 PJM August 31, 2005 submission in FERC Dockets Nos. EL05-148-000 and ER05-1410-000, at page 3.
54 Ibid.
55 PJM August 31, 2005 submission in FERC Dockets Nos. EL05-148-000 and ER05-1410-000, at page 52.
56 Ibid.
57 PJM FERC Electric Tariff, Sixth Revised Volume No. 1, at Original Sheet No. 552, included in the PJM August 31, 2005 submission in FERC Dockets Nos. EL05-148-000 and ER05-1410-000.

PJM would implement a full complement of LDAs, based on the areas analyzed in the [Regional Transmission Expansion Planning] process.[59] For these two years (2008-2009 and 2009-2010) there would be 23 LDAs.[60]

PJM would determine and post the LDAs applicable to subsequent years (beyond 2009-2010) at least four months before the start of the first RPM auction for each such year. However, changes are not currently expected from the above list.[61]

Q. How many separate LDAs would there be in PJM East?

A. PJM proposes to include ten LDAs within PJM East. These would be the MAAC region; Eastern MAAC region; PSEG; PSEG northern region; JCPL; PECO; AE; DPL; Southern Delmarva; and RECO.[62] New Jersey alone would have five distinct LDAs: PSEG, PSEG northern region; JCPL; AE and RECO.

There would be a complicated set of four capacity auctions in the RPM proposal for each of these LDAs for every twelve month delivery year.

Q. When does PJM want to implement the new RPM?

A. PJM wants to implement the new RPM beginning on June 1, 2006.[63] In order to do so, PJM says that it needs an Order by the FERC no later than January 31, 2006.[64]

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58 PJM August 31, 2005 submission in FERC Dockets Nos. EL05-148-000 and ER05-1410-000, at page 57.

59 Ibid.

60 These include: MAAC region; ComEd, AEP, Dominion, Dayton, and Duquesne; Virginia Power; eastern MAAC region; southwestern MAAC region; the western MAAC region consisting of the Pennsylvania Electric Company zone; RECO; ComEd; AEP; Dayton; Duquesne; APS; AE; BGE; Delmarva; PECO; PEPCO; PSEG; JCPL; Metropolitan Edison Company; PPL; PSEG northern region; Delmarva southern region. Source: PJM August 31, 2005 RPM submission to the FERC, at page 58.

61 Ibid.

62 Ibid, at page 58.

63 PJM August 31, 2005 submission to the FERC in Dockets Nos. EL05-148-000 and ER05-1410-000, at page 2.

64 Ibid.

Comments were due on the PJM RPM filing October 19, 2005, and many parties did file comments asking that the FERC have a fully contested proceeding. To the best of our knowledge the FERC has not set a schedule for its RPM process.

Q. Is it possible that the FERC will require substantial revisions to PJM's proposed RPM?

A. Yes. The new capacity market designs, features, and rules will be uncertain, at least until the FERC issues an Order, and, perhaps, for a significantly longer period.

In its filing, PJM suggests that after the FERC issues an initial Order approving the key features of the RPM proposal, a FERC-sponsored technical conference may be appropriate to determine the specific parameters of the demand curve that will be used to clear the capacity auctions.[65] Moreover, PJM notes that its RPM proposal did not receive a majority vote from PJM's stakeholders, which suggests that the FERC review process may be a contested and lengthy proceeding.[66]

Q. Have the Petitioners filed any analyses to show that EEG would not be able to exercise market power within the new locational markets that would be created under the RPM?

A. No. We have seen no evidence or analyses from the Petitioners that EEG would not be able to exercise market power within the complicated locational markets that would be created under the RPM.

Q. Is it reasonable to expect that EEG would be the dominant firm in the Northern PSEG LDA?

A. [REDACTED

[65] Ibid, at pages 2 and 13.
[66] Ibid, at page 50.

REDACTED

]

Q. Should the BPU approve the proposed merger before evaluating the ability of EEG to exercise market power in whatever new capacity market structure ultimately is approved by the FERC?

A. No. The BPU should not approve the proposed merger until it has had a reasonable opportunity to review concrete proposals from the Petitioners identifying the amounts and locations of capacity that would have to be divested in order to mitigate market power concerns under the proposed RPM or whatever new or revised market construct is ordered by the FERC. In addition, the BPU should review the market power mitigation rules that PJM has proposed for its RPM approach and determine that they will address any concerns regarding the Exelon-PSEG merger that have been identified in this proceeding,

VII. THE NORTHERN NEW JERSEY MARKETS

Q. Is northern New Jersey a highly concentrated market?

A. Yes. According to the PJM MMU, the PSEG North[67] market was congested for 1,059 hours in 2003 and 456 hours in 2004. The average, minimum and maximum HHIs for the PSEG North area for 2003 and 2004 are shown in Table 6 below.[68]

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67 Mr. Frame uses the term "Northern New Jersey" in his testimony (e.g., page 26 of his Exhibit JP-6 in this case) while the PJM Market Report uses the term "PSEG North." We believe that these are synonymous.

68 PJM MMU *2004 State of the Market Report*, at page 57 and PJM MMU *2003 State of the Market Report*, at page 42.

Table 6: PJM Measured PSEG North HHIs in 2003 and 2004

	2003	2004
Average HHI	6500	5500
Maximum HHI	8900	7300
Minimum HHI	4300	3800

The FERC Merger Guidelines consider markets with HHIs about 1800 to be highly concentrated. By this standard, northern New Jersey is an extremely highly concentrated market with HHIs in excess of 3800. This is essentially due to the dominance of PSEG's capacity in the area.

Q. Do the Petitioners present an analysis of the impact of the proposed merger on northern New Jersey?

A. In his Direct Testimony, Petitioner witness Frame acknowledges that northern New Jersey is a load pocket but asserts that the merger will have no impact on competition because Exelon does not own generation there and because capacity owned by Exelon outside northern New Jersey cannot affect the market whether or not transmission is constrained.[69]

Nevertheless, Mr. Frame did conduct a delivered price test for the northern New Jersey market and found that the merger would result in some measured change in market concentration.[70] Unfortunately, Mr. Frame did not discuss the results of his delivered price test in his testimony. Nor did he include the results in any of his exhibits.

Q. Did Mr. Frame include the results of his delivered price test for northern New Jersey in his workpapers?

A. [REDACTED]

[69] Direct Testimony of Rodney Frame, at page 26, line 14, to page 27, line 14.
[70] Direct Testimony of Rodney Frame, at page 27, lines 14-21.

Q. Does Mr. Frame find that the northern New Jersey market is highly concentrated both before the merger and after the Petitioners' proposed mitigation?

A. [

REDACTED

]

Q. Does Mr. Frame's analysis suggest the need for additional divestiture of capacity in northern New Jersey in order to bring the changes in HHIs below the 50 point increase permitted by the FERC's merger guidelines?

[

REDACTED

]

A. No. Mr. Frame's testimony was silent on this point.

Q. Was the testimony filed by the Petitioners at the FERC also silent on the need for some divestiture of capacity in northern New Jersey?

A. No. The testimony filed by the Petitioners at the FERC noted a screen analysis of the northern New Jersey market would show screen failures. Although the Petitioners claimed that this did not reflect a market power problem, they offered to mitigate the northern New Jersey screen failures by the divestiture of 100 MW of coal-fired generation and 100 MW of mid-merit generation.[71] Mr. Frame's BPU testimony does not offer similar divestiture if the BPU is concerned about the impact of the merger on the northern New Jersey market.

Q. Did the FERC accept the Petitioners' commitment to divest 100 MW of generation within northern New Jersey?

A. Yes. The FERC relied on statements by the Petitioners to find that there was a commitment by the Petitioners to divest 100 MW of generation located within Northern PSEG.[72]

Q. Does Mr. Frame's analysis show that the proposed merger would have a positive benefit in terms of reducing the market concentration in northern New Jersey?

A. [

REDACTED

]

If the BPU is concerned about concentration in the northern New Jersey market, as we believe it should be, then it should work with PJM to identify potential actions to actually reduce the levels of concentration, not approve a merger that will increase the level of concentration. Such actions could include the development of demand response programs, the siting of distributed generation facilities, or transmission system enhancements.

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71 Testimony of William Hieronymus, FERC Docket No. EC05-43-000, Exhibit J-1, at page 54, lines 5-13.

72 *FERC Order Authorizing Merger*, dated July 1, 2005, Paragraph No. 122, at page 41.

73 Mr. Frame's confidential workpapers.

74 Mr. Frame's confidential workpapers.

Q. Does Mr. Frame's analysis of the northern New Jersey market suffer from the same problems as you have found in his analyses of the PJM East market?

A. Yes. Mr. Frame's analysis of the northern New Jersey area suffers from the same weaknesses as we discussed earlier regarding his analyses of the PJM East energy market. Specifically, Mr. Frame's analysis of Northern New Jersey is unrealistic and oversimplified, and the mitigation is not defined. In addition, Mr. Frame's analysis of Northern New Jersey does not even include the level of detail that his other destination market analyses (e.g., the analysis of PJM East) do.

Q. Consequently, is it reasonable to expect that additional capacity might have to be divested in northern New Jersey to bring the HHIs changes from the proposed merger to within the 50 points permitted by the FERC Merger Guidelines?

A. Yes. Because of the flaws that we have identified in his assumptions and analytic methodology, we are concerned that the 100 MW of capacity that the FERC has ordered the Petitioners to divest in northern New Jersey is inadequate even to satisfy the FERC Merger Guidelines.

VIII. THE PETITIONERS' PROPOSED MITIGATION PLAN IS INADEQUATE TO PREVENT EEG FROM EXERCISING MARKET POWER

Q. Please describe the Petitioners' proposed mitigation plan.

A. The Petitioners have proposed a mitigation plan to offset the FERC Appendix A competitive screen failures identified by Mr. Frame.

The revised mitigation plan proposed by the Petitioners includes the actual divestiture of 3,100 MW of non-nuclear capacity in PJM East and another 900

MW in the remainder of PJM-Pre 2004 outside of PJM East.[75] This capacity would consist of coal-fired, mid-merit and peaking facilities.

The plan also would include the untested concept of the virtual divestiture of 2,600 MW of nuclear capacity, 2,400 MW of which would be in PJM East.[76] According to the Petitioners, the virtual divestiture of this nuclear baseload capacity would be accomplished through a combination of annual auctions of rolling three-year firm contracts and long-term energy sales contracts or swaps with the buyers.[77]

In the Petitioners' proposed virtual divestiture plan, EEG would retain the capacity associated with the virtually divested units while selling only the energy.[78] Notably, the Petitioners have not proposed a mitigation plan to address the ability that EEG would have to exercise market power through strategic bidding or through the physical withholding of capacity.

Q. Would the Petitioners be selling energy from any specific nuclear units as part of the virtual divestiture?

A. No. The virtual divestiture by auction would not be provided by any specific nuclear units owned by the Petitioners.[79] Only in one of the 15 year options would the sale be based on the historical performance of a specific unit from which energy is being sold.

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75 Supplemental Testimony of Rodney Frame, Table 1, at page 6.
76 Ibid.
77 Testimony of Rodney Frame, at page 17, lines 16-21.
78 Testimony of Rodney Frame, at page 17, line 18, to page 18, line 10.
79 Ibid.

Q. Is the Petitioners' revised mitigation plan adequate to offset the market power problems that would be created by the merger?

A. No. The Petitioners' revised mitigation plan has a number of critical weaknesses that render it inadequate for offsetting the market power problems that would be created by the merger.

- The plan does not identify the specific units to be divested.
- Under the proposed virtual divestiture EEG still would maintain control over operations of the "divested" nuclear capacity.
- Under the proposed virtual divestiture EEG would have an incentive to exercise market power as that would indirectly increase the prices in the yearly nuclear capacity auctions.
- As proposed, the virtual divestiture is not symmetric because there would be no provision for increasing the amount of nuclear capacity to be divested if EEG constructs or acquires additional nuclear capacity.

Q. Please explain why it is essential that the proposed mitigation plan identify the specific units to be divested?

A. The location, fuel type, marginal operating costs, operating characteristics, age, and economic viability of the divested units will have a significant impact on the ability of the merged company to exercise market power in both the short-term and the long-term.

Q. Is it also essential to know the specific parties who will be purchasing each divested asset?

A. Yes. The post-mitigation market concentration indices will be very different if the purchasers of the divested capacity are new participants in the market or already own substantial generating assets. Therefore, it is essential to know the specific purchasers and the capacity that they are acquiring.

Q. Has the PJM Market Monitoring Unit similarly concluded that it is not possible to determine whether the Petitioners' proposed mitigation plan is adequate without knowing which specific units will be divested and what parties will purchase the divested capacity?

A. Yes. The PJM Market Monitoring Unit issued a report on the proposed merger titled "Exelon/PSEG Merger Analysis," dated May 24, 2005. The key conclusions in this Merger Analysis included the following:

- The proposed merger would significantly increase concentration in the Energy, Capacity and Regulation markets and therefore raises concern about potential adverse competitive effects, absent mitigation.[80]
- Whether the Guidelines are met by the proposed mitigation depends on the specific units to be divested, the specific purchasers of the divested capacity and the nature of the divestiture.[81]
- For the Locational Energy Markets (i.e., PJM East, Western Interface and Central Interface), it is not possible to determine whether divestiture will in fact mitigate the issues without knowing the exact units and their distribution factor impacts on the identified constraints.[82]
- It is not possible to make a meaningful assessment of the effectiveness of the proposed divestiture in remedying structural market problems in the Locational PJM Energy Markets resulting from the proposed merger in the absence of the actual identification of specific units. A supplemental analysis must be performed once a definitive declaration of divested assets has been developed.[83]

In Part Two of its Exelon/PSEG Merger Analysis, dated October 14, 2005, the PJM Market Monitoring Unit reaffirmed its earlier conclusions regarding the importance of identifying the specific units to be divested and the nature of the companies purchasing the divested capacity. For example, the Market Monitoring Unit noted the following concerning the need to consider the companies purchasing the divested capacity:

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80 May 24, 2005 PJM Market Monitoring Unit "*Merger Analysis*," at pages 14, 35, and 47.
81 Ibid, at pages 4.
82 Ibid, at pages 19, 21, and 25.
83 Ibid, at pages 19, 21, 25 and 26.

> In fact, the conclusions about the required level of divestiture in the Energy Market depend on the nature of the companies purchasing the divested assets. The initial analysis assumes that the purchasing company has no capacity ownership in the relevant market. If the divested assets are sold to a company with a market share of from 16 percent to 35 percent, the proposed divestiture results in HHI levels that exceed the levels reached when the divested assets are sold to a company with a market share closer to five percent. In some cases the results after divestiture are worse than the results without divestiture. Conclusions about the required level of divestiture in the Locational energy markets also depend on the nature of the companies purchasing the divested assets.[84]

The PJM Market Monitoring Report reaches similar conclusions with regard to the capacity and regulation markets.[85]

Q. What did the PJM Market Monitoring Unit's Part Two Merger Analysis conclude regarding the need to consider the specific units to be divested when assessing the effectiveness of the Petitioners' proposed mitigation plan?

A. The Part Two Merger Analysis noted that the Market Monitoring Unit had evaluated the Petitioners' mitigation proposal:

> The analysis performed by the [Market Monitoring Unit] was designed to determine whether a return to pre-merger HHI levels was achievable given the candidate facilities and total volume of CT capacity to be divested… For the Eastern Interface, there was sufficient CT capacity available within the list of candidate facilities to return the post-merger HHI to pre-merger levels when such units are divested to a company with no generation assets in the market. There are two critical caveats to this conclusion: effective mitigation is, and can only be, based on specific units; and that the effectiveness of mitigation depends heavily on the nature of the purchasing companies…. It is not possible to make a meaningful assessment of the effectiveness of a proposed divestiture in remedying structural market problems resulting from the proposed merger in the absence of the actual identification of

[84] October 14, 2005, PJM Market Monitoring Unit "*Exelon/PSEG Merger Analysis Part Two*," at page 3.

[85] Ibid, at page 4.

specific units. A supplemental analysis must be performed once a definitive declaration of divested assets has been developed.[86]

Q. Have the Petitioners acknowledged that the location of a generating plant and its fuel type may be properly viewed as important factors in assessing the plant's potential contribution to the mitigation of their market power?

A. Yes. The Petitioners acknowledged this in their response to Data Request NJEUC/RESA-PSEG-52.

Q. Has the FERC accepted the Petitioners' proposed mitigation plan even though it does not identify the specific units to be divested or the buyers of the divested capacity?

A. Yes. The FERC notes that specific units to be divested have not been identified but states that it will be able to address this issue in the subsequent compliance filing.[87]

Q. Is this consistent with the FERC's own merger guidelines?

A. No. In its Order approving the proposed merger, the FERC essentially acknowledges that its own merger guidelines require the specific units to be divested.[88] However, the FERC believed that through a subsequent compliance filing it could ensure that the appropriate units are being divested.

Q. Would the buyer of the nuclear capacity that is being "virtually divested" have any control over plant operations?

A. No. In fact, the Petitioners do not propose to sell the energy from any specific nuclear asset(s) through the proposed auction of rolling three-year firm contracts or one of the alternative products available under the long-term contract option. Instead, the capacity will be available at an aggregate of the Petitioners' PJM East

[86] Ibid, at page 20.
[87] *FERC Order Authorizing Merger*, Paragraphs 141 and 142 at pages 48 and 49.
[88] Ibid, at Paragraph 141, on pages 48-49.

nuclear generation buses. Only in the second alternative product available under the long-term contract option does it appear that the Petitioners would be guaranteeing delivery of firm energy based on the performance of a designated PJM East nuclear facility.[89]

Consequently, in none of the virtual divestiture alternatives, that is, virtual divestiture through the auction of rolling three-year firm contracts or through long-term energy sales contracts or swaps, would operational control over any of EEG's nuclear units be transferred to any buyer. Instead, in all instances, EEG would retain all operational control over the scheduling of the output of the nuclear units and the scheduling of plant outages. EEG would retain control and decision-making authority over all aspects of plant operations, such as decisions to require a plant to run or shut-down, to declare an unscheduled outage, or to establish output levels when operating.

The buyer of the firm energy that the Petitioners propose to sell as part of their virtual divestiture would not have any control over the operations of EEG's nuclear units.

Q. Have the Petitioners acknowledged that the virtual divestiture of the nuclear units would not transfer operational control of the plant?

A. Yes. The Petitioners have agreed that the virtually divested capacity would not carry with it the right to:

a. determine when the generating plant is operated;

b. set the price at which the plant is bid into PJM;

c. determine when, and for how long, the plant will shut down for maintenance;

d. determine whether, and to what extent, capital improvements are to be made to the plant;

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[89] Direct Testimony of Rodney Frame, at page 18, lines 2-7.

e. decide whether and when to retire the unit.[90]

Q. Has the FERC approved the virtual divestiture plan proposed by the Petitioners?

A. Yes. the FERC found that the virtual divestiture would effectively transfer control of the output of the nuclear capacity from the merged firm to the purchasers.[91] The FERC further found that the merged firm could not withhold the energy from the market and that the buyer of the energy would determine where and to whom the energy is ultimately sold.[92]

Q. Is this consistent with FERC precedent?

A. No. It is a well established FERC precedent that the capacity associated with firm energy sales must be attributed to the party that has the authority to decide when generating resources are available for operation[93] and that an applicant may only add or subtract long-term firm purchases or sales, respectively, that assign operational control of such capacity to the buyer:

> In short, if an Applicant has control over certain capacity such that the Petitioner can affect the ability of that capacity to reach the relevant market, then that capacity should be attributed to the Petitioner when performing the screens.[94]

Q. Is there any actual experience with the concept of virtual divestiture of a power plant?

A. No. The concept of virtual divestiture is novel and untested.

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90 Response to Data Request NJEUC/RESA-PSEG-63.
91 *FERC Order Authorizing Merger*, Paragraph 134, at page 46.
92 Ibid.
93 FERC Revised Filing Requirements, Section 33.3(c)(4)(i)(A).
94 110 FERC 61,097, at page 29.

Q. Have you examined what Mr. Frame's HHI pre-merger to post-mitigation changes would be if the virtually divested capacity was considered to be within the operational control of EEG?

A. Yes. We have examined the pre-merger to post-mitigation HHI changes in Mr. Frame's Mitigation Scenario 1 if only the actual divestment was considered. The results are presented in Table 7 below. As this Table shows, the PJM East market would be substantially more concentrated if the virtually divested nuclear capacity were not allocated to other participants.

Table 7: Pre-Merger to Post-Mitigation HHI Changes, Frame Mitigation Scenario 1, with and without nuclear virtual divestments

		Summer				Winter			Shoulder		
		1	2	3	4	1	2	3	1	2	3
HHI Change: Post-Mitigation Scenario 1											
	With nuclear virtual divestment	-23	-1	1	-78	-33	40	-28	2	-33	-12
	Without nuclear virtual divestment	332	394	547	910	344	757	822	387	562	784
	Difference	355	395	546	989	377	717	850	385	595	796

Q. Is the Petitioners' proposed virtual divestiture plan symmetric in terms of increasing and decreasing the amounts of capacity that would be divested as circumstances change?

A. No. The Petitioners have proposed that the amount of capacity that would be virtually divested would decrease in response to (i) the sale of a nuclear generating unit to a non-affiliated entity; (ii) the retirement or permanent derating of a nuclear generating unit; and (iii) the construction of facilities that provide additional transfer capacity into PJM East, excluding any increase in transfer capability that might result from the construction included in the PJM Regional Transmission Expansion Plan that is effective June 2005.[95] However, the amount of nuclear capacity to be virtually divested would not be increased even if the Petitioners acquired or built more capacity or increased the capacity of an existing generating facility.

Q. Is there any provision of the Petitioners proposed mitigation plan that would prevent EEG from purchasing or building new capacity in PJM East or Northern New Jersey?

A. No.

Q. Will the Petitioners agree to a moratorium on generating facility development as a condition precedent to the approval of the proposed merger?

A. No.[96]

Q. Have you seen any evidence that the Petitioners are planning to increase the capacity of any of their nuclear units in PJM East?

A. Yes. PSEG already has announced that it will seek approval from the Nuclear Regulatory Commission to increase the power level of the Hope Creek nuclear plant by approximately 15 percent beginning in 2006.[97] At the same time, [

REDACTED

]

Q. How much nuclear capacity would the Petitioners retain under their proposed virtual divestiture plan?

A. If the merger is approved and closed, the combined company will own and have operational control over more than 6,200 MW of baseload nuclear capacity in PJM East.

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95 Direct Testimony of Rodney Frame, at page 19, lines 5-11.

96 Response to Data Request NJLEUC/RESA-PSEG-41.

97 "Hope Creek Tells NRC of plans to apply this spring for 15% uprate," *Nucleonics Week*, March 21, 2005, at page 11.

Table 8: EEG Nuclear Capacity in PJM East

Nuclear Unit	Summer Capacity (MW)[98]
Oyster Creek	619
Limerick	2,268
Salem	2,300
Hope Creek	1,049

EEG also will own and have operational control over another 3,010 MW of baseload nuclear capacity at the Peach Bottom and Three Mile Island nuclear units located next to PJM East, and 10,439 MW of baseload nuclear capacity in the remainder of PJM Expanded.[99] These figures do not include the power uprates at Hope Creek and [REDACTED] that we mentioned previously.

Q. If the virtual divestiture of nuclear capacity through periodic auctions were approved, would EEG nevertheless continue to have a significant incentive to exercise market power?

A. Yes. EEG would continue to own and benefit from the energy generated at more than 3,800 MW of nuclear capacity in PJM East, another 2,800 MW of nuclear capacity located just west of the Eastern Interface, as well as substantial baseload fossil capacity. Therefore, even if it divested the energy output from 2,600 MW of nuclear capacity, EEG would still profit greatly from the higher prices in the PJM energy markets that would result from the exercise of market power.

At the same time, the higher energy prices in the PJM markets that would result from the exercise of market power by EEG also would boost the prices that the Company can be expected to receive in the yearly nuclear auctions that would be conducted as part of the virtual divestiture plan proposed by the Petitioners. After all, it is reasonable to expect that the higher the prices in the PJM energy markets at which potential bidders believe that they would be able to sell the energy that

98 Source data from the Direct Testimony of Rodney Frame, Exhibits RF-3 and RF-4.
99 Exhibit RF-4.

they are buying from EEG, the higher the prices those potential bidders would be willing to pay to EEG in the virtual auction.

Q. Is it the Petitioners' position that the BPU would have an oversight role or authority concerning the nuclear auctions conducted as part of the virtual divestiture?

A. No. The Petitioners have said that the BPU would have no active role with respect to the auctions.[100]

IX. SYNAPSE HHI ANALYSES

Q. Does Mr. Frame examine a wide range of scenarios concerning the possible buyers of the capacity that would be actually or virtually divested by EEG?

A. No. There are a large number of permutations of the parties that might be buyers of the capacity that would be divested by EEG and the amounts of capacity each such potential buyer might purchase. However, Mr. Frame examined only one base case divestiture mitigation scenario in his Direct Testimony. He also examined another three alternative mitigation scenarios in his Supplemental Testimony:

Mitigation Scenario 1 – The virtual divestiture of nuclear capacity is to two parties that do not currently own any generating capacity in PJM and the fossil divestiture is split among Edison Mission Energy (50 percent), Mirant (25 percent) and Constellation (25 percent).

Mitigation Scenario 2 – The virtual divestiture of nuclear capacity is made on a pro-rata basis to the winning suppliers in the recent New Jersey BGS auctions, but excluding PSEG from that allocation, and the fossil divestiture was made equally to FirstEnergy, PHI, PPL and Reliant.

Mitigation Scenario 3 – The virtual divestiture of nuclear capacity is made on the same basis as under Alternative 2 and all of the fossil divestiture is made to a single party that does not now own any generation capacity in PJM.[101]

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[100] Response to NJLEUC/RESA-PSEG-88.

The base case divestiture scenario in Mr. Frame's Direct Testimony reflected the specific restrictions and limitations on potential purchasers that the Petitioners originally proposed. These restrictions and limitations were eliminated by the Petitioners and, consequently, they were not reflected in the three alternative Mitigation Scenarios examined by Mr. Frame in his Supplemental Testimony.

Consequently, in each of the Mitigation Scenarios he examines, Mr. Frame assumes that the virtually divested nuclear capacity is purchased either by buyers that do not currently own any generating capacity in PJM or by a large number of parties that currently do own capacity in PJM. He also assumes that the fossil capacity being divested is being purchased either by a single party that does not now own capacity in PJM or by three or more existing PJM participants. Given these assumptions, it is not surprising that his analyses show that post-mitigation HHIs are not much different from pre-merger concentration levels.

Q. Has Mr. Frame modeled the full range of possible buyers of the capacity that EEG would have to divest and the amounts of capacity that each buyer might purchase?

A. No. Mr. Frame only examines a very limited range of mitigation scenarios. In order to test the impact of the proposed merger in a wider range of possible mitigation scenarios, we have modeled the HHI changes in the PJM East energy market in the following three realistic scenarios:

Mitigation Scenario 4 -- all of the divested capacity is purchased by PPL.

Mitigation Scenario 5 -- the divested nuclear capacity is purchased equally by PPL and PEPCO and the divested fossil capacity is purchased by PPL.

Mitigation Scenario 6 – the virtually divested nuclear capacity is purchased by PPL and the divested fossil capacity is purchased by PEPCO and Reliant.

PPL, PEPCO and Reliant are the next largest owners of capacity in PJM East, after PSEG and Exelon.

[101] Supplemental Testimony of Rodney Frame, at page 8.

Q. Please summarize the Mitigation Scenarios that you have analyzed and what input and mitigation assumptions were used in each of these cases.

A. As noted above, we have evaluated six Mitigation Scenarios. As shown in Table 9 below, three of the Mitigation Scenarios (Nos. 1-3) were developed by Mr. Frame. The other three Mitigation Scenarios were developed by Synapse.

Table 9: Mitigation Scenarios evaluated by Synapse

	Mitigation Scenario 1	Mitigation Scenario 2	Mitigation Scenario 3	Mitigation Scenario 4	Mitigation Scenario 5	Mitigation Scenario 6
Who developed this mitigation case?	Mr. Frame	Mr. Frame	Mr. Frame	Synapse	Synapse	Synapse
Parties who purchase the nuclear virtual divestiture (2600 MW)	Two new entrants	Pro-rata to BGS auction winners (excluding PSE&G)	Pro-rata to BGS auction winners (excluding PSE&G)	PPL	PPL (50%) and PEPCO (50%)	PPL
Parties who purchase the actual fossil divestiture (4000 MW)	EME (50%), Mirant (25%) and Constellation (25%)	FE (25%), PHI (25%), PPL (25%), and Reliant (25%)	One new entrant	PPL	PPL	PEPCO (50%) and Reliant (50%)

Q. What input assumptions did you use to evaluate these Mitigation Scenarios?

A. We have used two sets of input assumptions to evaluate these Mitigation Scenarios: Set one included all of the input assumptions used by Mr. Frame in the HHI analyses that he has discussed in his Direct and Supplemental Testimony in this proceeding. Set two included most of Mr. Frame's input assumptions but with the nuclear and transmission assumptions corrected as we have discussed earlier in this testimony.

This means that we have examined a total of twelve cases, involving six Mitigation Scenarios under each of the two sets of input assumptions.

Q. Please summarize the corrections that you have made to Mr. Frame's input assumptions.

A. As we have explained in Sections V.B.1, V.B.4 and V.B.5 above, we have corrected Mr. Frame's input assumptions to reflect (1) the proposed [ ] MW power uprate at Hope Creek in 2006, (2) Petitioners' claimed improvements in operating performance at both Salem and Hope Creek, (3) the use of the recent performance of Exelon's nuclear units, and (4) the use of an economic allocation of the transmission import capability across the PJM East interface.

Q. Does this mean that you are satisfied that the remainder of Mr. Frame's input assumptions are reasonable and produce realistic results?

A. Not at all. As we have discussed in Section V of this testimony, we believe that, overall, Mr. Frame's assumptions and modeling methodology bias his analyses and cause him to understate the potential impact of the proposed merger on the levels of concentration in the PJM energy market. However, it was not possible for us to modify Mr. Frame's assumptions to make them more realistic and still be able to use his database to run revised HHI analyses. For this reason, we have accepted most of Mr. Frame's input assumptions with confidence that their use causes us to understate the post-divestiture levels of concentration in the PJM East energy market and the ability of EEG to exercise market power.

Q. Have you rerun Mr. Frame's HHI model using all of his input assumptions?

A. Yes. As shown on Exhibit BFS-6, when we reran Mr. Frame's model, we obtained the same results as Mr. Frame has presented in his Exhibit RF-9 (Revised).

Q. What are the results of rerunning Mr. Frame's Mitigation Scenarios 1 through 3 to reflect your corrected nuclear and transmission import assumptions?

A. These results are presented in Table 10 below and in Exhibit BFS-6.

Table 10: Pre-Merger to Post-Mitigation HHI Changes in Mr. Frame's Mitigation Scenarios 1-3, with Frame and Synapse Input Assumptions

	Summer				Winter			Shoulder		
	1	2	3	4	1	2	3	1	2	3
HHI Change: Mitigation Scenario 1										
Frame input assumptions	-23	-1	1	-78	-33	40	-28	2	-33	-12
Synapse input assumptions	75	106	151	139	63	246	209	75	75	137
HHI Change: Mitigation Scenario 2										
Frame input assumptions	60	63	36	-88	34	68	-21	58	4	-4
Synapse input assumptions	167	179	198	160	138	287	240	141	126	160
HHI Change: Mitigation Scenario 3										
Frame input assumptions	5	13	5	-110	-18	39	-44	11	-33	-26
Synapse input assumptions	110	128	166	139	86	262	218	92	86	138

As a result of making just our four corrections to Mr. Frame's input assumptions, the merger would fail the FERC Appendix A Screening Analysis due to HHI changes greater than 100 in six of the ten hours studied in Mitigation Scenario 1; in all ten of the hours studied in Mr. Frame's Mitigation Scenario 2; and in seven of the ten hours studied in Mr. Frame's Mitigation Scenario 3. Indeed, in some of the hours studied in these Scenarios, the pre-merger to post-mitigation HHI changes would be significantly higher than 100.

Q. What are the results of your modeling of your three additional Mitigation Scenarios (Nos. 4-6) using all of Mr. Frame's modeling assumptions?

A. As shown in Table 11 below, in Mitigation Scenarios 4, 5 and 6, the HHI changes from pre-merger to post-mitigation are significantly above 100 in all ten hours examined using Mr. Frame's input assumptions.[102] Consequently, even if we use all of Mr. Frame's input assumptions, the proposed merger fails the Appendix A

Screening Analysis in all ten hours studied if it is assumed the divested capacity is purchased by parties which are already substantial participants in PJM, as is modeled in Mitigation Scenarios 4, 5 and 6.

Table 11: Pre-Merger to Post-Mitigation HHI Changes in Synapse Mitigation Scenarios 4, 5 and 6, with Frame and Synapse Input Assumptions

	Summer				Winter			Shoulder		
	1	2	3	4	1	2	3	1	2	3
HHI Change: Mitigation Scenario 4										
Frame input assumptions	339	367	323	348	362	340	358	351	294	359
Synapse input assumptions	506	544	557	683	523	621	692	540	577	686
HHI Change: Mitigation Scenario 5										
Frame input assumptions	274	289	222	130	274	255	188	270	204	194
Synapse input assumptions	422	441	420	416	410	502	479	414	413	440
HHI Change: Mitigation Scenario 6										
Frame input assumptions	200	224	207	192	205	273	235	221	185	242
Synapse input assumptions	318	363	412	541	329	554	579	363	412	571

Q. Finally, what are the results of your modeling of your three additional Mitigation Scenarios (Nos. 4-6) when you use your corrected nuclear and transmission input assumptions?

A. As shown in Table 11 above, the use of our four corrections to Mr. Frame's inputs assumptions for future nuclear unit performance and the allocation of the limited transmission capability across the PJM East interface results in the proposed merger failing the FERC Appendix A Screening Analysis by very substantial margins in all of the hours examined.

[102] These results are presented in greater detail in Exhibit BFS-6.

Q. Are there any restrictions on the potential buyers of either the fossil capacity being actually divested or the nuclear capacity being virtually divested that would prevent the third, fourth and fifth largest existing participants in PJM from buying all the divested capacity as you have assumed in Mitigation Scenarios 4, 5 and 6?

A. No.

X. THE BGS AUCTION

Q. Have the Petitioners presented any analysis of the ability of EEG to exercise market power in the BGS auctions?

A. No. The Petitioners have not presented any analysis beyond several pages of narrative discussion in the Additional Testimony of Mr. Frame.[103]

Q. Have the Petitioners conducted a market power study of the BGS auctions?

A. No.[104]

Q. Should the BPU be concerned about the potential for EEG to exercise market power in the BGS auctions?

A. Yes. PSEG has supplied substantial amounts of power through the BGS auctions, both as a successful bidder and as a supplier to other successful bidders. For example, see the Direct Testimony of Petitioner witness Mr. Frank Cassidy in JP-9, at pages 18 through 26.

Q. Has Exelon supplied a significant amount of BGS power?

A. No.

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103 See the Additional Direct Testimony of Mr. Frame in JP-6 Additional.
104 Response to NJLEUC/RESA-PSEG-125.

Q. Is there any reason to expect that this might change in the near future?

A. Yes. Exelon has been committed to using its nuclear capacity in Illinois to serving loads in its Chicago service area. This commitment will no longer exist after the end of 2006. At that time, Exelon will be free to bid some or all of its 10,000 MW+ of nuclear capacity into the BGS auctions.

Q. Wouldn't BGS customers be expected to benefit from the availability of this additional low-cost nuclear energy?

A. Yes, unless EEG is able to exercise market power to boost BGS prices due to the availability of this additional nuclear energy, its dominance in the PJM East market, and/or its position as a supplier of natural gas to competitor power plants.

Q. What action would the BPU need to take to provide an adequate check that no BGS bidder has exercised market power?

A. In order to permit a meaningful investigation of whether any post-merger bidder(s) will exercise market power in the annual BGS auctions, the BPU needs to conduct more detailed oversight of the BGS auction process.

XI THE ABILITY OF EEG TO EXERCISE MARKET POWER THROUGH STRATEGIC BIDDING

Q. Please explain why it is important for the BPU to be concerned that EEG, the new company created by the proposed merger, would be able to exercise market power even if the merger satisfied the FERC merger guidelines.

A. At the same time that the merger would result in a huge new company, the merger-related savings claimed by Petitioners are extremely minor. For example, in the testimony of Petitioner witness William D. Arndt, the Petitioners have noted that the electric merger-related savings in New Jersey would average only $12 million per year during the first four years after the merger is completed, the period emphasized by the Petitioners in their merger studies.[105] These claimed savings could easily be lost if EEG were able to raise market prices only slightly through the exercise of the market power that comes from its dominant size.

Given the size of the proposed merged company, the potential impact of the merged company and energy and capacity market prices in PJM East and the extremely minor merger-related savings claimed by the Petitioners, it is critical for the BPU to look beyond the results of Mr. Frame's idealized HHI analyses. In particular, the BPU must examine whether or not it will be profitable for the merged company to exercise market power through strategic bidding or by physically withholding capacity from the market. This is crucial because the merger will create a situation in PJM East with a single dominant firm, even if the Petitioners actually carry out the revised mitigation that they propose. In this situation, it is important to determine whether EEG, which will be the dominant firm and "market leader" in PJM East, will be able to profitably exercise market power through strategic bidding because merely looking at the usual market concentration indices for the total market (the "HHI") does not address this adequately.

Q. Have the Petitioners presented a strategic bidding analysis in this proceeding?

A. No. Neither the Petitioners nor Mr. Frame have performed any strategic bidding analyses.

Q. Have you prepared an analysis to evaluate whether EEG would be able to benefit from strategic bidding?

A. Yes. We used the ELMO model to evaluate whether EEG would be able to exercise market power by strategic bidding.[106]

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[105] Exhibit JP-5, at page 54.

ELMO is a screening model developed by Synapse to evaluate the market power potential in the electricity energy market. The model is based on the supply curve concept and the potential revenue gain that participants could earn by bidding resources above their costs. The basic mechanism is that the owners of units on or below the margin can increase the market price by bidding up or withholding capacity. Then all the resources that still remain in the market receive a higher price. For any given participant one can think of low-cost baseload resources as the motive and intermediate cost marginal resources as the means to exercise market power in this way. Any company that has both may be able to independently increase their net revenues – although all generators benefit when any one boosts the market price.

ELMO is not a detailed market simulation, so its results are indicative but not definitive. Some of the characteristics of ELMO are:

- A single resource curve representing complete units.
- Outages represented by derated capacity rather than probabilistically.
- A single market with no internal transmission constraints.
- No operational limits related to unit commitment or ramping.
- No operational restrictions related to grid stability requirements.
- No fixed contracts or obligations.
- Independent pricing behavior, i.e., no implicit or explicit collusion.

Thus, in a number of ways ELMO does not represent all the complications and restrictions of the actual market that both provide and limit opportunities for the exercise of market power.

Q. What analyses did you do with ELMO?

A. In performing this market power evaluation, we have examined the same six Mitigation Scenarios that we examined in our HHI analyses discussed in Section

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[106] See Exhibit BFS-8.

IX of this testimony. As with the HHI analyses, we examined each Mitigation Scenario using two sets of input assumptions. Our first set of analyses used all of Mr. Frame's input assumptions. Our second set of analyses used most of Mr. Frame's input assumptions except that we made corrections to reflect improved nuclear power plant performance capacity and economic allocation of the transmission into PJM East.

In both sets of analyses we used the resources as identified by Mr. Frame in his various pre and post merger cases and look at the market power potential. For the basic resource curve we used Mr. Frame's "Summer1" period data which gave the most total resources.

Q. What were the results of your analyses?

A. The results of our strategic bidding analyses are presented in Exhibit BFS-9. These analyses with the Synapse ELMO model revealed substantial market power potential in the existing PJM East energy market in which PSEG has a resource share of roughly 25 percent. However, the potential for the exercise of market power increases as a result of the merger even after mitigation. This increase in the potential for the exercise is represented by percentage increases in market clearing prices in the pre-merger and post-mitigation situations. For example, a 15.8 percent result in a post-mitigation situation represents a greater potential for the exercise of market power than does a 13.5 percent result in the corresponding pre-merger situation.

All of the scenarios that we examined showed increases in the average energy market clearing price as a result of the exercise of market power. In the first set of analyses, which used all of Mr. Frame's input assumptions, our projections of pre-merger to post-mitigation increases range from two tenths of one percent increase (for Mr. Frame's Mitigation Scenarios 1 and 3) to slightly more than one percent increase (for Synapse Mitigation Scenarios 4,5 and 6).[107] The net revenue changes (difference between market price and production costs) for the participants range from 12 percent to 16 percent depending on the Mitigation Scenario.

The results of our second set of analyses, which used corrected nuclear performance and transmission import assumptions, also showed potential increases in the potential for the exercise of market power from the pre-merger to the post-mitigation scenarios. For example, Synapse Mitigation Scenarios 4 and 5 showed potential market power revenue impacts 2.3 percent greater than the pre-merger situation. The market power revenue impact under Synapse Mitigation Scenario 6 was 1.3 percent.[108]

Q. What is your overall conclusion from the ELMO modeling?

A. Our ELMO modeling shows that there already is a significant potential for market power in PJM East because of PSEG's substantial market share. However, the proposed merger can be expected to make the situation worse, even with the Petitioners' proposed levels of virtual and actual divestiture. The amount by which the proposed merger will increase the ability of EEG to exercise market power will depend on the identities of the parties that actually purchase this divested capacity.

Q. Have you seen any other studies that have concluded that market concentration is associated with higher prices in electricity markets?

A. Yes. In addition to theoretical models, the economics literature contains a wealth of empirical analyses dealing with market concentration and market power in electricity markets, both before and after the energy crisis in California. In its

[107] Confidential Exhibit BFS-9, Table 5, at page 4.
[108] Confidential Exhibit BFS-9, Table 6, at page 5.

report on market power in restructured electricity markets, the U.S. Department of Energy finds that:

> There is strong evidence that market power has been exercised in the electricity context. In both the United Kingdom (U.K.) and California, where data from competitive electricity generation markets are now available, researchers have found that wholesale power prices have been as much as 75 percent above competitive levels at times. Other studies examining electricity markets in Australia, New Jersey, and Colorado identify potential market power issues in those areas as well.[109]

Just to name a few other studies, Bushnell (2003) argues that "more advanced methods, such as models of oligopoly competition, can potentially provide a much better understanding of the competitive outlook for a market" than the tests historically used by regulators as screens for the potential abuse of market power by suppliers. Under an alternative plan for the divestiture of California's thermal generation units, Bushnell finds that "a more substantial, but still plausible, reduction in supplier concentration would have saved consumers nearly $2 billion during the summer of 2000."[110]

Likewise, Borenstein et al. (1999) examine the degree of competition in the California wholesale electricity market during June-November 1998 by comparing the market prices with estimates of the prices that would have resulted if all firms were price takers (i.e., if no firm had market power). They find significant departures from competitive pricing, raising the cost of power purchases by about 22 percent above the competitive level. Borenstein et al. find

[109] U.S. Department of Energy Office of Economic, Electricity and Natural Gas Analysis, Office of Policy. "Horizontal Market Power in Restructured Electricity Markets." March 2000. Washington, D.C. DOE/PO-0060.

[110] Bushnell, Jim. 2003. "Looking for Trouble: Competition Policy in the U.S. Electricity Industry" *Center For the Study of Energy Markets* (CSEM) Working Paper Series. Paper CSEMWP-109. http://repositories.cdlib.org/uce i/csem/CSEMWP-109

that these departures are most pronounced during the highest demand periods but that the observed prices cannot be attributed to competitive peak-load pricing.[111]

Q. Have economists studied the effect of concentration on market price in other industries?

A. Yes. We will discuss several examples. Lopez et al. (2002) seek to separate oligopoly-power and cost-efficiency effects of changes in industrial concentration and assesses their impact on output prices in 32 food-processing industries. Their empirical results indicate that although concentration induces cost efficiency in one-third of the industries, oligopoly-power effects either dominate cost efficiency or reinforce inefficiency, resulting in higher output prices in most industries.[112]

Gasoline markets have been the focus of several studies of market concentration and price effects. GAO finds that increases in HHI as a result of mergers in the 1990s were associated with an increase in the price of gasoline averaging about 1 cent to 2 cents per gallon.[113]

The banking industry has also been scrutinized for price effects associated with market concentration. Supporting earlier studies,[114] Rhoades (1992) found that

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[111] Borenstein, Severin, James Bushnell, and Frank Wolak. "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market." 2000. Working Paper No. PWP-064. Berkeley, Calif.: University of California Energy Institute.

[112] Lopez, Rigoberto A., Azzeddine M. Azzam, and Carmen Liron-Espana. Mar 2002. "Market Power and/or Efficiency: A Structural Approach." *Review of Industrial Organization.* Vol. 20, No. 2. pp 115-126.

[113] U.S. General Accounting Office. 2004. "Effects of Mergers and Market Concentration in the U.S. Petroleum Industry." GAO-04-96.

[114] Berger, Alan N. and Timothy H. Hannan, 1989. "Deposit Interest Rates and Local Market Concentration." In Concentration and Price. The MIT Press: Cambridge MA. ed. Leonard W. Weiss.

mortgage interest rates tended to be higher in cities where concentration was relatively high, based on data on loan rates from 20 cities in 1987 and 1988.[115]

In an extensive review of existing empirical studies, Leonard Weiss found that higher levels of concentration do indeed tend to correlate with higher prices throughout most of the markets considered.[116] Weiss's summary of 121 data sets of concentration and price covering a wide range of industries (including airlines, supermarkets, cement, and many others) shows a convincing majority of studies in which concentration appears to result in higher market price:

Significant positive effects	76
Non-significant positive effects	30
Non-significant negative effects	11
Significant negative effects	4
TOTAL	121

In the table above, a "significant positive effect" refers to a statistically significant result in which higher concentration correlates with higher prices. For roughly two-thirds of data sets, a 10 percentage point rise in the combined market share of the three largest firms was associated with an increase in price of more than 1 percent.[117] Another 20 percent are correlated with a price increase of zero to 1 percent.[118]

Q. Are studies of other industries relevant to electricity markets?

A. Electricity differs from other commodities in significant ways. Competition from substitute products can mitigate the effects of concentrated markets for other commodities (i.e., if the price of one product increases, consumers may be willing

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115 Rhoades, Stephen A. 1992. "Evidence on the Size of Banking Markets from Mortgage Loan Rates in Twenty Cities." *Federal Reserve Bulletin* 78 pp. 117-118.
116 *Concentration and Price*, Weiss, editor, the MIT Press, 1989.
117 *Competition and Price*, Weiss, Editor, MIT Press, 1989, at page 19.
118 We group these datasets by the lower value when a range of associated price increases is presented.

to purchase another). Electricity does not have obvious or readily available substitutes for many purposes. Moreover, demand for electricity does not easily respond to changes in price. Where other sources of energy can be substituted for electricity (e.g., furnaces burning natural gas or oil are an alternative to electric heat), shifting to other commodities is quite limited.

Generally, other commodities face competition from other countries or regions. To some extent, the effects of concentration in electricity markets can be moderated by importing power, but these imports are limited by the transmission system.

In general, these differences will intensify the effects of market concentration on price in electricity markets relative to many other industries.

XII. THE IMPACT OF MARKET POWER ON NEW JERSEY ELECTRIC PRICES

Q. Have you quantified what the exercise of market power identified in these analyses could cost New Jersey electricity ratepayers?

A. Yes. Based upon the information discussed above, we conclude that the wholesale market price increases of more than 1 percent resulting from the merger are possible. For New Jersey, where annual electricity sales are about 80 thousand GWh per year and wholesales prices for 2006 are anticipated to be in the neighborhood of $80/MWh (load weighted price for PJM East based upon current forward market prices for PJM West, scaled up based upon the past actual ratio of PJM West to PJM East prices), the total wholesale cost is about $6.4 billion per year. A one percent increase in the wholesale market price would amount to $64 million per year. Over ten years, not accounting for market changes, escalation, or discounting, the total impact on NJ customers would amount to $640 million. This calculation is shown in Exhibit BFS-10. There are credible scenarios in which the impact would be significantly greater.

Q. What increase in wholesale market prices would wipe out the merger related savings claimed by the Petitioners for New Jersey ratepayers?

A. The $12 million average annual electric merger-related savings claimed for the years 2006-2009 by the Petitioners for New Jersey ratepayers would be wiped out by just a 0.20 percent increase in wholesale prices from the exercise of market power.

XIII. THE IMPLICATIONS OF GAS MARKET POWER

Q. Have you evaluated whether the merged company could exercise market power in gas markets?

A. No. Ratepayer Advocate witness Mr. Richard Lelash has examined that issue.

Q. Have seen any evidence that suggests that the merged company's ability to exercise market power in gas markets also would enable it to earn additional revenues in electric energy markets?

A. Yes. The following evidence suggests that the new company created by the merger could earn additional revenues in electric markets and disadvantage electric competitors through the exercise of market power in gas markets.

For example, an August 2005 Presentation to investors by the President of Exelon's Power Team noted that in Exelon's market in the East (PJM) "natural gas prices drive power prices and that "power prices are tracking closely to increasing fuel costs."[119] Because the merged company will have such substantial amounts of nuclear capacity, it will be able to profit from higher power prices due to increasing natural gas prices. Natural gas tends to set the marginal cost of power. Nuclear power generation cost will be substantially less.

[119] Exhibit BFS-7, at page 8 of 14.

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Q. Have you seen any evidence that the merged company would be able to disadvantage electric competitors through the exercise of market power in gas markets?

A. Yes. PSEG has indicated that during 2004 it delivered natural gas to power eleven merchant plants.[121]

XIV. THE BPU CANNOT RELY ON PJM TO EFFECTIVELY MITIGATE THE EXERCISE OF MARKET POWER BY EEG

Q. Can the BPU rely on PJM to effectively mitigate the exercise of market power by EEG?

A. No. Primarily, PJM is limited to offer-capping suppliers at 110 percent of marginal costs, even if such an offer cap results in a greater return to the supplier than would be expected in a fully competitive market. The ten percent adder is somewhat arbitrary and it has not been definitively shown that a lower level would not result in outcomes more closely approximate fully competitive markets.

Moreover, energy offers are not capped at 110 percent of marginal cost if the only binding constraint is the PJM East interface itself.

[120] Confidential Response to RAR-MKT-87 (CONF).
[121] Response to RAR-MKT-11.

Q. What is the impact of the limited market power mitigation tools available to the PJM?

A. The result is a reduced ability to ensure that market price outcomes are competitive and that participants are not exercising market power through strategic bidding or the withholding of otherwise available capacity.

Q. Given the current tools available to PJM, could the BPU rely on PJM to effectively monitor and mitigate the exercise of market power by EEG if the merger were approved and closed?

A. No.

XV. NUCLEAR-RELATED EARNINGS

Q. Have the Petitioners provided any estimate of their projected nuclear-related earnings/savings from the proposed merger?

A. Yes. The Petitioners have estimated that the merger would result in approximately $170 million of additional pre-tax earnings each year. Approximately $70 million of these additional earnings would be from nuclear production improvements. Approximately $100 million would be savings from nuclear cost reductions.[122]

Q. What are the nuclear production improvements that the Petitioners expect to achieve from the proposed merger?

A. The testimony filed at the FERC by Christopher Crane, the President and Chief Nuclear Officer of Exelon Nuclear, emphasizes the significantly improved performance that the Petitioners expect at the Salem and Hope Creek nuclear

[122] *Financial Overview*, presentation by John F. Young, Exelon Vice President, Finance and Markets, at the Exelon Investor Conference, held in New York City on August 5, 2005, at the 10th unnumbered page. Exhibit BFS-11, at page 13 of 15.

plants as a result of the proposed merger.[123] For example, Mr. Crane notes the following in his testimony:

> I see no reason why, over time following the merger, Salem and Hope Creek cannot be improved to the same level of performance of the plants in the Exelon Fleet. What that means, among other things, is that there is no reason why these plants cannot consistently produce more electricity than they do today. As I have testified, capacity factors at Salem and Hope Creek in 2004 were 74.9% (Salem 1), 89.8% (Salem 2), and 65.6% (Hope Creek), as compared to Exelon's Fleet 2004 average capacity factor of 93.5%. If we bring each of the three PSEG reactors up to the Exelon Fleet average in terms of capacity factor, then in effect, we will be able to produce approximately 4.8 million MWh of additional electricity annually from these plants.[124]

Q. Would the approximately $170 million in additional annual nuclear-related pre-tax earnings that the Petitioners expect from the merger be on the regulated or the unregulated side of their business?

A. These additional nuclear-related pre-tax earnings would be on the unregulated side of the merged company.

Q. Is it reasonable to expect that the additional nuclear-related pre-tax earnings resulting from the merger could exceed even the $170 million per year estimated by the Petitioners?

A. Yes. Given the significant increases in natural gas futures and forward electricity prices for the years 2006 and 2007, it is reasonable to expect that, for near term years, at least, the additional annual pre-tax earnings from nuclear production improvements at Salem and Hope Creek could exceed the approximate $70 million annual figure that the Petitioners currently project by $30 million in 2006 and $20 million in 2007.

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123 Prepared Direct Testimony of Christopher M. Crane in FERC Docket No. EC05-43-000, at page 2.

124 Ibid, at page 20.

Q. Is it also reasonable to expect that EEG also will earn other profits from the sale of its nuclear capacity and energy?

A. Yes. EEG will be able to earn significant profits from the sale of its nuclear capacity and energy in a number of different auctions and markets. For example, EEG will be able to sell capacity in the proposed PJM RPM markets. It also will be able to bid in the New Jersey BGS auction. In addition, if the merger is approved as proposed, there will be periodic auctions of the energy from the virtually divested nuclear plants. Finally, EEG will be able to participate in the spot PJM energy markets.

Q. Will any of these profits be on the regulated side of EEG?

A. No. All of the profits from these capacity and energy sales will be on the unregulated side of EEG.

Q. Does this complete your testimony?

A. Yes.