Market Monitoring Unit

Exelon/PSEG Merger Sensitivity Analyses

PJM Market Monitoring Unit

March 1, 2006

Summary

In this report, the PJM Market Monitoring Unit ("MMU") presents the results of sensitivity analyses performed in response to specific requests submitted by the PPL Companies and the Staff of the New Jersey Board of Public Utilities in the matter of the proposed merger between PSEG and Exelon that is currently before the New Jersey Board of Public Utilities ("NJBPU").

The MMU analyzed the effects of the proposed divestiture scenarios on the structure of the aggregate PJM Energy Market, the local PJM Energy Market as defined by the PJM eastern interface constraint and the PJM Capacity Market. For each divestiture scenario, pre- and post-merger market structure was defined by the HHI and the merger impact was measured as the resultant difference in HHI. Pre-merger conditions were as defined in the Exelon/PSEG Merger Analysis Part Two as published by the PJM Market Monitoring Unit on October 14, 2005 unless specifically modified per a request.

The following table summarizes the requested 36 divestiture scenarios and the relevant markets for which impacts were evaluated that are in addition to the 184 divestiture scenarios already analyzed, a total of 220 scenarios.

	Divestiture	Studied Market		
Scenario Name	Options	Aggregate Energy	Local Energy	Capacity
Petitioner's Scenarios with Nuclear (2)	8			x
Petitioner's Scenarios with Nuclear (Multi)	8			x
Petitioner's Scenarios with Nuclear (4)	8	x		x
Petitioner's Scenarios with Buyer Substitutions	8		x	
Aggregate Energy with Revised Parameters - East Sub region	4	x		
Total	36			

Sensitivity Analysis Requests

A summary of the requests from the PPL Companies and the New Jersey Board of Public Utilities is provided below with tables showing the results of the MMU sensitivity analyses in each case and a summary of the results.

1. NJBPU Staff

The BPU staff requested a sensitivity analysis of the impact of certain previously analyzed Petitioners' scenarios on the capacity market with specified modifications to the assumed level of imports. The relevant scenarios are specified below.

By email dated January 25, 2006, the Petitioners requested additional analysis associated with their initial request dated December 28, 2005. The base analysis continues to be of two core fossil divestiture packages each containing coal, intermediate and peaking units. Core package one consisted of Eddystone, Cromby and Linden along with either the Edison and Croydon or the Edison and Essex plants. Core package two consisted of Mercer, Cromby and Linden with either the Burlington, Edison and Sewaren plants or Croydon, Essex and Sewaren. For each core package, the Petitioners set out four different ways the assets might be bundled to prospective purchasers, so that there are eight scenarios in all. The scenarios were identified by Petitioners as 1a through 1d for core package one and 2a through 2d for core package two. The MMU substituted the Bergen plant for the Linden plant in our analyses as the Linden plant was not in service for the periods included in our analyses and was therefore not included in our initial analyses. The Petitioners' additional request is to add

the divestiture of 2,446 MWH of 24 x 7 energy, equivalent to the divestiture of 2,600 MW of nuclear capacity with a 93 percent capacity.

The MMU responded to the Petitioners' request in the MMU's February 9, 2006 Report, Section 6 where it was noted that the MMU used a fixed percentage of six nuclear power plants owned by Exelon in the analysis. The average hourly MW divested in the analysis was 2,488 MW. This is the approach used consistently by the MMU in additional sensitivities related to this Petitioners' request.

The MMU also provided an analysis, in response to a NJBPU staff request, in the MMU's February 17, 2006 Report, Section 4 of the impact on the capacity market of these Petitioners' scenarios.

In particular, the Petitioners requested that the MMU use the following sets of buyer assumptions:

1. The additional nuclear divestiture goes equally to two parties without current market share;
2. The additional nuclear divestiture goes to the following sets of buyers in the proportions detailed below (the exact names and percentages were provided by Petitioners):

a.	BP Energy Company	8.70%
b.	Conectiv	2.90%
c.	Con Edison Development	1.45%
d.	Constellation Generation Gp	23.19%
e.	DTE	5.80%
f.	FPL Energy, Inc.	7.25%
g.	J. Aron and Co.	8.70%
h.	Morgan Stanley	7.25%
i.	NRG New Jersey	8.70%
j.	Reliant	13.04%
k.	Select Energy	13.04%

The BPU Staff requested a further sensitivity analysis of the impact of these Petitioners' scenarios on the capacity market. The BPU Staff requests that the analysis of the impact on the capacity market assume specific capacity market import criteria**:** For the analysis of the PJM East locational capacity market, perform discrete analyses under the following two import assumptions reflected in the NJBPU sensitivities contained in the MMU's February 9, 2006 Report: 1) assume imports into PJM East from existing entities consistent with the shares indicated in the FTR-based allocation contained in the direct testimony of Joseph P. Kalt (PP&L) at Exhibits JPK-4a and 4b; and 2) assume imports into PJM East from existing entities consistent with the NJ Ratepayer Advocate's "economic allocation" of imports specified in the direct testimony of Bruce Biewald, Robert Fagan and David Schlissel at Exhibit BFS-4, table denoted "Average Import Levels (MW)" at the "Synapse" column.

The results are presented in Table 1-1 and Table 1-2 below.

In summary, the proposed divestiture packages when the additional divestiture goes equally to two parties that are not current market participants and capacity market imports into PJM East are as specified above:

- Result in every case for the modified Petitioners' scenarios in an increase in HHI that is greater than that specified in the Guidelines for the capacity market.

In summary, the proposed divestiture packages when the additional divestiture goes to the specified multiple buyers and capacity market imports into PJM East are as specified above:

- Result in every case for the modified Petitioners' scenarios in an increase in HHI that is greater than that specified in the Guidelines for the capacity market.

Capacity Market

Table 1-1 Capacity Market HHIs – Nuclear Divestiture to 2 New Buyers

	PJM East On-Peak Multiple 7,778 MW Import	PJM East Off-Peak Multiple 6,803 MW Import	PJM East Synapse Multiple 7,300 MW Import
Pre-Merger HHI	1857	1958	1822
Scenario 1a (6,088 MW)			
HHI	1997	2110	1930
Difference from Pre-Merger HHI	140	152	108
Compliance	No	No	No
Scenario 1b (6,248 MW)			
HHI	1964	2075	1897
Difference from Pre-Merger HHI	107	117	75
Compliance	No	No	No
Scenario 1c (6,248 MW)			
HHI	1992	2103	1920
Difference from Pre-Merger HHI	135	145	98
Compliance	No	No	No
Scenario 1d (6,088 MW)			
HHI	2041	2155	1966
Difference from Pre-Merger HHI	184	197	144
Compliance	No	No	No
Scenario 2a (6,132 MW)			
HHI	1969	2080	1901
Difference from Pre-Merger HHI	112	122	79
Compliance	No	No	No
Scenario 2b (6,077 MW)			
HHI	1980	2092	1912
Difference from Pre-Merger HHI	123	134	90
Compliance	No	No	No
Scenario 2c (6,132 MW)			
HHI	2002	2114	1932
Difference from Pre-Merger HHI	145	156	110
Compliance	No	No	No
Scenario 2d (6,077 MW)			
HHI	2014	2127	1943
Difference from Pre-Merger HHI	157	169	121
Compliance	No	No	No

Table 1-2 Capacity Market HHIs – Nuclear Divestiture to Multiple Buyers

	PJM East On-Peak Multiple 7,778 MW Import	PJM East Off-Peak Multiple 6,803 MW Import	PJM East Synapse Multiple 7,300 MW Import
Pre-Merger HHI	1857	1958	1822
Scenario 1a (6,088 MW)			
HHI	2021	2132	1954
Difference from Pre-Merger HHI	164	174	132
Compliance	No	No	No
Scenario 1b (6,248 MW)			
HHI	1987	2096	1921
Difference from Pre-Merger HHI	130	138	99
Compliance	No	No	No
Scenario 1c (6,248 MW)			
HHI	2004	2112	1932
Difference from Pre-Merger HHI	147	154	110
Compliance	No	No	No
Scenario 1d (6,088 MW)			
HHI	2061	2173	1987
Difference from Pre-Merger HHI	204	215	165
Compliance	No	No	No
Scenario 2a (6,132 MW)			
HHI	1989	2099	1923
Difference from Pre-Merger HHI	132	141	101
Compliance	No	No	No
Scenario 2b (6,077 MW)			
HHI	2000	2111	1934
Difference from Pre-Merger HHI	143	153	112
Compliance	No	No	No
Scenario 2c (6,132 MW)			
HHI	2021	2132	1952
Difference from Pre-Merger HHI	164	174	130
Compliance	No	No	No
Scenario 2d (6,077 MW)			
HHI	2033	2144	1963
Difference from Pre-Merger HHI	176	186	141
Compliance	No	No	No

2. NJBPU Staff

The BPU staff also requested a sensitivity analysis of the impact of the same previously analyzed Petitioners' scenarios on the capacity market and the aggregate energy market with specified modifications to the assumed buyers and to the assumed level of imports. The relevant scenarios are specified below.

By email dated January 25, 2006, the Petitioners requested additional analysis associated with their initial request dated December 28, 2005. The base analysis continues to be of two core fossil divestiture packages each containing coal, intermediate and peaking units. Core package one consisted of Eddystone, Cromby and Linden along with either the Edison and Croydon or the Edison and Essex plants. Core package two consisted of Mercer, Cromby and Linden with either the Burlington, Edison and Sewaren plants or Croydon, Essex and Sewaren. For each core package, the Petitioners set out four different ways the assets might be bundled to prospective purchasers, so that there are eight scenarios in all. The scenarios were identified by Petitioners as 1a through 1d for core package one and 2a through 2d for core package two. The MMU substituted the Bergen plant for the Linden plant in our analyses as the Linden plant was not in service for the periods included in our analyses and was therefore not included in our initial analyses. The Petitioners' additional request is to add the divestiture of 2,446 MWH of 24 x 7 energy, equivalent to the divestiture of 2,600 MW of nuclear capacity with a 93 percent capacity factor.

The MMU responded to the Petitioners' request in the MMU's February 9, 2006 Report, Section 6 where it was noted that the MMU used a fixed percentage of six nuclear power plants owned by Exelon in the analysis. The average hourly MW divested in the analysis was 2,488 MW. This is the approach used consistently by the MMU in additional sensitivities related to this Petitioners' request.

In particular, the BPU Staff requested that the MMU use the following sets of assumptions:

1. The nuclear divestiture identified in the Petitioners' request goes equally to the next four consecutive largest entities in PJM East after PSEG and Exelon.

2. The BPU Staff requested sensitivity analyses assuming the following capacity market import criteria**:** For the analysis of the PJM East locational capacity market, perform discrete analyses under the following two import assumptions reflected in the NJBPU sensitivities contained in the MMU's February 9, 2006 Report: 1) assume imports into PJM East from existing entities consistent with the shares indicated in the FTR-based allocation contained in the direct testimony of Joseph P. Kalt (PP&L) at Exhibits JPK-4a and 4b; and 2) assume imports into PJM East from existing entities consistent with the NJ Ratepayer Advocate's "economic allocation" of imports specified in the direct testimony of Bruce Biewald, Robert Fagan and David Schlissel at Exhibit BFS-4, table denoted "Average Import Levels (MW)" at the "Synapse" column.

The results are presented in Table 2-1 through Table 2-3 below.

In summary, the proposed divestiture packages when the additional divestiture goes equally to the next four consecutive largest entities in PJM East behind PSEG and Exelon:

- Result in scenarios 1a, 1b, 1c and 1d in an increase in HHI that is less than the increase specified in the Guidelines for the aggregate energy market when divestiture is to the next four largest market participants;

- Result in scenarios 2a, 2b, 2c and 2d in an increase in HHI that is greater than the increase specified in the Guidelines for the aggregate energy market when divestiture is to the next four largest market participants;
- Result in every case for the modified Petitioners' scenarios in an increase in HHI that is greater than that specified in the Guidelines for the capacity market when divestiture are to the next four largest market participants and capacity market imports into PJM East are as specified above.

Aggregate Hourly Energy Market

Table 2-1 Aggregate Energy Market – Pre-Merger HHIs

	Minimum	Average	Maximum	Number of Hours HHI > 1800	Number of Hours HHI > 2500
May 1 - July 31	856	1213	1565	0	0

Table 2-2 Aggregate Energy Market – Post-Merger HHIs – Nuclear Divestiture to the next four consecutive largest entities in PJM East after PSEG and Exelon

	Scenario	Minimum	Average	Maximum	Number of Hours HHI > 1800	Number of Hours HHI > 2500
May 1 - July 31	1A	957	1306	1708	0	0
May 1 - July 31	1B	945	1305	1708	0	0
May 1 - July 31	1C	941	1301	1706	0	0
May 1 - July 31	1D	957	1305	1707	0	0
May 1 - July 31	2A	953	1314	1720	0	0
May 1 - July 31	2B	960	1313	1720	0	0
May 1 - July 31	2C	955	1314	1720	0	0
May 1 - July 31	2D	962	1313	1720	0	0

Table 2-3 Aggregate Energy Market HHI Differences – Nuclear Divestiture to the next four consecutive largest entities in PJM East after PSEG and Exelon

	Scenario	Minimum	Average	Maximum	Number of Hours HHI > 1800	Number of Hours HHI > 2500	Compliant
May 1 - July 31	1A	101	93	143	0	0	Yes
May 1 - July 31	1B	89	92	143	0	0	Yes
May 1 - July 31	1C	85	88	141	0	0	Yes
May 1 - July 31	1D	101	92	142	0	0	Yes
May 1 - July 31	2A	97	101	155	0	0	No
May 1 - July 31	2B	104	100	155	0	0	No
May 1 - July 31	2C	99	101	155	0	0	No
May 1 - July 31	2D	106	100	155	0	0	No

Capacity Market

Table 2-4 Capacity Market HHIs – Nuclear Divestiture to the next four consecutive largest entities in PJM East after PSEG and Exelon

	PJM East On-Peak Multiple 7,778 MW Import	PJM East Off-Peak Multiple 6,803 MW Import	PJM East Synapse Multiple 7,300 MW Import
Pre-Merger HHI	1857	1958	1822
Scenario 1a (6,088 MW)			
HHI	2075	2192	2006
Difference from Pre-Merger HHI	218	234	184
Compliance	No	No	No
Scenario 1b (6,248 MW)			
HHI	2041	2156	1973
Difference from Pre-Merger HHI	184	198	151
Compliance	No	No	No
Scenario 1c (6,248 MW)			
HHI	2058	2172	1984
Difference from Pre-Merger HHI	201	214	162
Compliance	No	No	No
Scenario 1d (6,088 MW)			
HHI	2119	2236	2042
Difference from Pre-Merger HHI	262	278	220
Compliance	No	No	No
Scenario 2a (6,132 MW)			
HHI	2041	2156	1972
Difference from Pre-Merger HHI	184	198	150
Compliance	No	No	No
Scenario 2b (6,077 MW)			
HHI	2052	2168	1983
Difference from Pre-Merger HHI	195	210	161
Compliance	No	No	No
Scenario 2c (6,132 MW)			
HHI	2079	2195	2007
Difference from Pre-Merger HHI	222	237	185
Compliance	No	No	No
Scenario 2d (6,077 MW)			
HHI	2090	2207	2018
Difference from Pre-Merger HHI	233	249	196
Compliance	No	No	No

3. PPL Companies

The PPL Companies requested a sensitivity analysis of the impact of certain previously analyzed Petitioners' scenarios on the local energy market as defined by the Eastern Interface. The MMU agreed to do specific analyses set forth in a letter from PJM's General Counsel F. John Hagele to Susan Vercheak, dated February 24, 2006. The PPL Companies requested that the MMU use the following buyer assumptions in place of the Petitioners' buyer assumptions:

Scenario	Buyer 1	Buyer 2	Buyer 3	Buyer 4
1a	Pepco	Reliant		
1b	Pepco	Reliant		
1c	NRG	Pepco	Dominion	Reliant
1d	NRG	Pepco	Dominion	Reliant
2a	Pepco	Reliant		
2b	Pepco	Reliant		
2c	NRG	Pepco	Reliant	Dominion
2d	NRG	Pepco	Dominion	Reliant

By letter dated December 28, 2005, the Petitioners requested analysis of two core fossil divestiture packages each containing coal, intermediate and peaking units. Core package one consisted of Eddystone, Cromby and Linden along with either the Edison and Croydon or the Edison and Essex plants. Core package two consisted of Mercer, Cromby and Linden with either the Burlington, Edison and Sewaren plants or Croydon, Essex and Sewaren. For each core package, the Petitioners set out four different ways the assets might be bundled to prospective purchasers, so that there are eight scenarios in all. The scenarios were identified by Petitioners as 1a through 1d for core package one and 2a through 2d for core package two.

The MMU responded to the Petitioners' request in the MMU's February 9, 2006 Report, Section 1 where it was noted that the MMU substituted the Bergen plant for the Linden plant in our analyses as the Linden plant was not in service for the periods included in our analyses and was therefore not included in our initial analyses. This is the approach used consistently by the MMU in all sensitivities related to this Petitioners' request.

The PPL Companies requested a sensitivity analysis, of these identified Petitioners' scenarios with new buyer assumptions, of the impact to the local energy market as defined by the Eastern Interface.

The results are presented in Table 3-1 below.

In summary, the proposed sensitivity analysis:

- Result in every case for the modified Petitioners' scenarios in an increase in HHI that is greater than that specified in the Guidelines for the market defined as requested.

Local Energy Market defined by Eastern Interface

Table 3-1 East Interface Constraint HHIs

	HHI			
Scenario	Pre-Merger	Post-Divestiture	Difference	Compliant
1a	2641	3017	376	No
1b	2641	2993	352	No
1c	2641	2718	77	No
1d	2641	2747	106	No
2a	2641	2916	275	No
2b	2641	2913	272	No
2c	2641	2800	159	No
2d	2641	2793	152	No

4. PPL Companies

The PPL Companies requested an analysis of the energy market defined by the eastern interface to include all units operating when the eastern interface was constrained. The MMU agreed to do specific analyses set forth in a letter from PJM's General Counsel F. John Hagele to Susan Vercheak, dated February 24, 2006. The relevant scenarios are specified below.

By email dated January 25, 2006, the Petitioners requested additional analysis associated with their initial request dated December 28, 2005. The base analysis continues to be of two core fossil divestiture packages each containing coal, intermediate and peaking units. Core package one consisted of Eddystone, Cromby and Linden along with either the Edison and Croydon or the Edison and Essex plants. Core package two consisted of Mercer, Cromby and Linden with either the Burlington, Edison and Sewaren plants or Croydon, Essex and Sewaren. For each core package, the Petitioners set out four different ways the assets might be bundled to prospective purchasers, so that there are eight scenarios in all. The scenarios were identified by Petitioners as 1a through 1d for core package one and 2a through 2d for core package two. The MMU substituted the Bergen plant for the Linden plant in our analyses as the Linden plant was not in service for the periods included in our analyses and was therefore not included in our initial analyses. The Petitioners' additional request is to add the divestiture of 2,446 MWH of 24 x 7 energy, equivalent to the divestiture of 2,600 MW of nuclear capacity with a 93 percent capacity

In particular, the Petitioners requested that the MMU use the following sets of buyer assumptions:

- The additional nuclear divestiture goes to the following sets of buyers in the proportions detailed below (the exact names and percentages were provided by Petitioners):

a.	BP Energy Company	8.70%
b.	Conectiv	2.90%
c.	Con Edison Development	1.45%
d.	Constellation Generation Gp	23.19%
e.	DTE	5.80%
f.	FPL Energy, Inc.	7.25%
g.	J. Aron and Co.	8.70%
h.	Morgan Stanley	7.25%
i.	NRG New Jersey	8.70%
j.	Reliant	13.04%
k.	Select Energy	13.04%

The PPL Companies requested sensitivity analyses consistent with the following:

1. Include all hours in which the PJM Eastern Interface was constrained during the study period.
2. Include only the Petitioner's scenarios 1c, 1d, 2c, and 2d.
3. Include only the nuclear divestiture multiple buyer analysis using the specific buyer details set forth at page 27, buyer assumptions number 2, of the February 9 Revised Report.
4. Include only the Petitioners' nuclear generating units located east of the PJM Eastern Interface in the divestiture analysis.
5. For each scenario modeled assume that imports across the PJM Eastern Interface are allocated for purposes of calculating HHI concentration statistics using the FTR-based allocation contained in the direct testimony of Dr. Joseph P. Kalt at Exhibits JPK-4a and 4b, referred to by the MMU on p. 10 of the February 9 Revised Report. Apply the peak shares (JPK-4a) to peak periods and the off-peak shares (JPK-4b) to off-peak periods.
6. Aggregate the hourly results separately for PJM peak and off-peak periods, presenting each in the same manner as the Aggregate Energy Market presentation in Tables 6-4, 6-5, and 6-6 of the February 9 Revised Report.
7. Identify each constrained hour analyzed.

The results are presented in Table 4-1 through Table 4-3 below.

In summary, the proposed divestiture packages when the additional divestiture goes to the specified multiple buyers:

- Result in every case in an increase in HHI that is less than the increase specified in the Guidelines for the aggregate energy market.

Sub Region Energy Market defined by Eastern Interface

Table 4-1 Aggregate Energy Market – Pre-Merger HHIs

	Scenario	Minimum	Average	Maximum	Number of Hours HHI > 1800	Number of Hours HHI > 2500
June 17, 2005 (HE 10 - 11)	ONPEAK	1942	2009	2076	2	2

Table 4-2 Aggregate Energy Market – Post-Merger HHIs – Nuclear Divestiture to Multiple Buyers

		Scenario	Minimum	Average	Maximum	Number of Hours HHI > 1800	Number of Hours HHI > 2500
June 17, 2005 (HE 10 - 11)	ONPEAK	1C	1919	1972	2024	2	2
June 17, 2005 (HE 10 - 11)	ONPEAK	1D	1935	1987	2039	2	2
June 17, 2005 (HE 10 - 11)	ONPEAK	2C	1875	1932	1989	2	2
June 17, 2005 (HE 10 - 11)	ONPEAK	2D	1947	2009	2070	2	2

Table 4-3 Aggregate Energy Market HHI Differences – Nuclear Divestiture to Multiple Buyers

			Minimum	Average	Maximum	Number of Hours HHI > 1800	Number of Hours HHI > 2500	Compliant
June 17, 2005 (HE 10 - 11)	ONPEAK	1C	-23	-37	-52	0	0	Yes
June 17, 2005 (HE 10 - 11)	ONPEAK	1D	-7	-22	-37	0	0	Yes
June 17, 2005 (HE 10 - 11)	ONPEAK	2C	-67	-77	-87	0	0	Yes
June 17, 2005 (HE 10 - 11)	ONPEAK	2D	5	0	-6	0	0	Yes

5. PPL Companies' Analysis

The PPL Companies requested that the MMU review a specific PPL analysis of the energy market defined by the eastern interface to include all units operating when the eastern interface was constrained. The MMU agreed to respond to two specific questions as set forth in the attachment to a letter from PJM's General Counsel F. John Hagele to Susan Vercheak, dated February 24, 2006.

As set forth in that February 24 letter: PPL proposes to analyze the impact of the merger on the energy market defined by the PJM Eastern Interface in the same manner as the Aggregate Energy Market analysis described at p. 27 of the February 9 Revised Report and presented in Table 6-4, 6-5, and 6-6, but including only generating units located east of the PJM Eastern Interface. PPL will use the aggregate energy market database provided in the February 17 report workpapers and the units identified in the file labeled "East Units.xls." This analysis would be conducted making the following changes to the MMU's Aggregate Energy Market analysis:

- PPL will analyze each hour that the PJM Eastern Interface is constrained in the day-ahead market.
- PPL would analyze PPL divestiture scenarios 1b, 2b, and 3b and Petitioners' scenarios analyzed, only 1c, 1d, 2c, and 2d. Petitioners' scenarios would be analyzed both with and without the proposed virtual divestiture.
- PPL would assume that, where applicable, the virtual divestiture would be sold to multiple buyers using the virtual divestiture shares allocated to buyers in accordance with the shares set forth at the paragraph numbered, "2" on page 27 of the February 9 Revised Report.
- The nuclear capacity allocated in the virtual divestiture will be modeled from only the Petitioners' nuclear generating units located east of the PJM Eastern Interface.
- For each scenario analyzed, PPL would assume that imports across the PJM Eastern Interface are allocated for purposes of calculating HHI concentration statistics using the FTR-based allocation contained in the direct testimony of Dr. Joseph P. Kalt at Exhibits JPK-4a and 4b, referred to by the MMU on p. 10 of the February 9 Revised Report. Apply the peak shares (JPK-4a) to peak periods and the

offpeak shares (JPK-4b) to off-peak periods. PPL will assume 7300 MW of import capacity in both on-peak and off-peak periods.

- PPL will aggregate the hourly results separately for peak and off-peak periods, presenting each in the same manner as the Aggregate Energy Market presentation in Tables 6-4, 6-5, and 6-6 of the February 9 Revised Report.

PPL will provide this analysis to the PJM MMU on Monday, February 27. PPL will ask the MMU to state:

- o That other than the specified changes to the analysis, it was conducted in accordance with the methodology used by the MMU in its Aggregate Energy Market Analysis presented at Tables 6-4, 6-5, and 6-6 of the February 9 Revised Report; and
- o That the units shown as running in the Aggregate Energy Market work papers provided with the February 17 Report would closely correlate to the unit bids accepted in the day-ahead market for the same hour and, if possible, how they would differ.

The February 24th letter stated: In response to the second question, the MMU will attempt to analyze selected hours in both the day ahead and real time markets and will express such opinion thereon as it is able.

In response to the PPL Companies requests, the MMU concludes:

1. The PPL analysis of the data provided by the MMU calculates the hourly HHIs, for the hours that the MMU identified as constrained in the real time market, in a mathematically correct fashion, consistent with the way in which the MMU calculated HHIs presented in the February 9, 2006 Revised Report at Tables 6-4, 6-5 and 6-6.

2. There is no reason to believe either that there is a close correlation between the units accepted in the day-ahead and real-time markets or that there is a close correlation between the operation of the day ahead and real time energy markets for a specific hour. As an example, dispatch in the day-ahead market is influenced by virtual bidding, which does not exist in the real-time market. The difference in the number of constrained hours on the Eastern Interface between the Day Ahead and Real Time Energy markets during the study period is also an illustration of the differences between the markets. The demand being satisfied in the day-ahead market generally differs from that in real-time. During the real-time hours analyzed by the MMU, the PJM RTO load was 84,585 MW and 87,226 MW respectively. This compares to day-ahead loads in the corresponding hours of 96,508 MW and 99,034 MW respectively.[1]

3. The MMU analyzed selected hours in both the day-ahead and real-time markets. The MMU analyzed the structure of the aggregate energy market as defined by the eastern interface constraint for June 13, 2005 at hour ending 1500 and for June 17, 2005 at hour ending 1100.[2] During hour ending 1500 on June 13, 2005, the Eastern Interface was

[1] It should be noted that the day-ahead demand levels posted by PJM do not equal total day-ahead load that must be met in the day-ahead market by offers from units plus increment offers. Day-ahead demand bid data is posted to the PJM website and is comprised of the sum of fixed and price sensitive demand and decrement bids minus increment offers. Day-ahead demand calculated in this manner for the corresponding hours is 80,168 MW and 82,516 MW respectively. http://www.pjm.com/markets/energy-market/hourly-demand-bid-data.html

[2] Market structure analysis for these days considered generation only and did not include virtual bids, imports or transactions.

constrained in the day-ahead market but not in the real-time market. The pre-merger HHI in the day-ahead market for June 13, 2005 at hour ending 1500 was 1961. The analysis of market structure in the day-ahead market considers generating units only and does not include increment offers. The pre-merger HHI in the real-time market for June 13, 2005 at hour ending 1500 was 1551. The post-merger HHI in the day-ahead market for June 13, 2005 at hour ending 1500 was 3423. The post-merger HHI in the real-time market for June 13, 2005 at hour ending 1500 was 2668. During hour ending 1100 on June 17, 2005, the Eastern Interface was constrained in both the day-ahead market and in the real-time market. The pre-merger HHI in the day-ahead market for June 17, 2005 at hour ending 1100 was 3233. The pre-merger HHI in the real-time market for June 17, 2005 at hour ending 1100 was 2661. The post-merger HHI in the day-ahead market for June 17, 2005 at hour ending 1100 was 6020. The post-merger HHI in the real-time market for June 17, 2005 at hour ending 1100 was 3454. The HHI data is summarized in Table 5-1 through Table 5-3 below.

Sub Region Energy Market defined by Eastern Interface

Table 5-1 Aggregate Energy Market – Pre-Merger HHIs

	Day-ahead	Real-time	Difference
June 13, 2005 (HE 15)	1961	1551	410
June 17, 2005 (HE 11)	3233	2661	572

Table 5-2 Aggregate Energy Market – Post-Merger HHIs

	Day-ahead	Real-time	Difference
June 13, 2005 (HE 15)	3423	2668	755
June 17, 2005 (HE 11)	6020	3454	2566

Table 5-3 Aggregate Energy Market HHI Differences

	Day-ahead	Real-time
June 13, 2005 (HE 15)	1462	1117
June 17, 2005 (HE 11)	2787	793