SECTION 4 - INTERCHANGE TRANSACTIONS

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non market balancing authorities.

Highlights

- On June 1, 2011 at 0100, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. As a result, the First Energy (FE) Interface and the MICHFE Interface Pricing Point were eliminated.

- Real-time net exports decreased to -7,113.9 GWh during the first nine months of 2011 from -7,411.9 GWh during the first nine months of 2010. Day-ahead net imports were 9,066.0 GWh compared to net exports of -6,657.8 GWh during the first nine months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period.

- The direction of power flows was not consistent with real-time energy market price differences in 56 percent of hours at the border between PJM and MISO and in 47 percent of hours at the border between PJM and NYISO during the first nine months of 2011.

- During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh or 8.3 percent, an increase from 4.8 percent during the first nine months of 2010 and 5.2 percent for the calendar year 2010. This difference is system inadvertent.

- PJM initiated 58 TLRs during the first nine months of 2011, a reduction from the 96 TLRs in the first nine months of 2010.

- The average daily volume of up-to congestion bids increased from 376 bids per day, for the period between March 1, 2009 through May 14, 2010, to 762 bids per day for the period between May 15, 2010 through September 16, 2010, to 1,987 bids per day for the period between September 17, 2010 through September 30, 2011. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids.

- Total uncollected congestion charges during the first nine months of 2011 were $11,942, compared to $2.9 million for the first nine months of 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present.

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were $1.3 million during the first nine months of 2011, an increase from $290,515 in the first nine months of 2010.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September,* the recommendations from the 2010 State of the Market Report for PJM remain MMU recommendations.

Overview

Interchange Transaction Activity

- **American Transmission System, Inc.** (ATSI) Integration. On June 1, 2011 at 0100, First Energy's American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. The integration also resulted in the elimination of the MICHFE Interface Pricing Point, reducing the total number of interface pricing points from 17 to 16.[1]

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2011, PJM was a net importer of energy

1 The tables and figures within this section continue to show that the FE Interace and the MICHFE Interface Pricing Points existed in June 2011, to account for the single hour in June where FE was still an external interface.

in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. During the first nine months of 2010, PJM was a net exporter of energy in the Real-Time Energy Market in all months. In the Real-Time Energy Market, monthly net interchange averaged -790.4 GWh compared to -823.5 GWh for the first nine months of 2010.[2] Gross monthly import volumes averaged 3,479.5 GWh compared to 3,475.1 GWh for the first nine months of 2010 while gross monthly exports averaged 4,269.9 GWh compared to 4,298.6 GWh for the first nine months of 2010.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market from January through June, and a net exporter of energy in the remaining months. During the first nine months of 2010, PJM was a net importer of energy in the Day-Ahead Energy Market only in August and a net exporter of energy in the remaining months. In the Day-Ahead Energy Market, monthly net interchange averaged 1,007.4 GWh compared to -739.7 GWh for the first nine months of 2010. Gross monthly import volumes averaged 10,561.2 GWh compared to 7,075.1 GWh for the first nine months of 2010 while gross monthly exports averaged 9,553.8 GWh compared to 7,814.8 GWh for the first nine months of 2010.

  The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. For the first six months of 2011, the overall net PJM imports would have been net exports but for the net up-to congestion transaction imports. Figure 4-2 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 1,462 bids per day, with an average cleared volume of 501,662 MWh per day, during the first nine months of 2011, compared to an average of 423 bids per day, with an average cleared volume of 297,071 MWh per day, during the first nine months of 2010.

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** During the first nine months of 2011, gross imports in the Day-Ahead Energy Market were 307 percent of gross imports in the Real-Time Energy Market (204 percent for the first nine months of 2010). During the first nine months of 2011, gross exports in the Day-Ahead Energy Market were 224 percent of gross exports in the Real-Time Energy Market (182 percent for the first nine months of 2010). During the first nine months of 2011, net interchange was 9,066.0 GWh in the Day-Ahead Energy Market and -7,113.9 GWh in the Real-Time Energy Market compared to -6,657.8 GWh in the Day-Ahead Energy Market and -7,411.9 GWh in the Real-Time Energy Market for the first nine months of 2010.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, during the first nine months of 2011, there were net exports at 14 of PJM's 21 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 71 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 23 percent, PJM/MidAmerican Energy Company (MEC) with 20 percent, PJM/Cinergy Corporation (CIN) with 14 percent and PJM/Neptune (NEPT) with 14 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 41 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interfaces had net imports, with two importing interfaces accounting for 78 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 60 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18 percent.[3]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, during the first nine months of 2011, there were net exports at 15 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 58 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 23 percent, PJM/Neptune (NEPT) with 19 percent and PJM/Linden (LIND) with 16 percent. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 27 percent of the total net PJM exports in the Day-Ahead Energy Market. Six PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 95 percent of the total net imports: PJM/OVEC with 39 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 31 percent and PJM/Michigan Electric Coordinated System (MECS) with 25 percent.

2 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

3 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent Transmission System Operator, Inc. (MISO) Interface Prices.** During the first nine months of 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $34.36 while the MISO LMP at the border was $35.71, a difference of $1.35. While the average hourly LMP difference at the PJM/MISO border was only $1.35, the average of the absolute values of the hourly differences was $12.54. The average hourly flow during the first nine months of 2011 was -1,628 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 44 percent of hours during the first nine months of 2011. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $16.39. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $9.73. During the first nine months of 2011, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from PJM to MISO, the average price difference was $15.49. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from MISO to PJM, the average price difference was $23.68. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from MISO to PJM, the average price difference was $23.47. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from PJM to MISO, the average price difference was $8.02.

- **PJM and New York ISO Interface Prices.** During the first nine months of 2011, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. During the first nine months of 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly LMP at the PJM/NYISO border was $46.75 while the NYISO LMP at the border was $45.03, a difference of $1.72. While the average hourly LMP difference at the PJM/NYISO border was only $1.72, the average of the absolute value of the hourly difference was $15.19. The average hourly flow during the first nine months of 2011 was -630 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 53 percent of the hours during the first nine months of 2011. During the first nine months of 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.68. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $16.68. During the first nine months of 2011, when the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from PJM to NYISO, the average price difference was $11.84. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from NYISO to PJM, the average price difference was $32.14. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM, the average price difference was $32.08. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from PJM to NYISO, the average price difference was $13.82.

- **Neptune Underwater Transmission Line to Long Island, New York.** The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. During the first nine months of 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly LMP at the Neptune Interface was $51.63 while the NYISO LMP at the Neptune Bus was $58.59, a difference of $6.96. While the average hourly LMP difference at the PJM/Neptune border was $6.96, the average of the absolute value of the hourly difference was $22.37. The average hourly flow during the first nine months of 2011 was -484

MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours during the first nine months of 2011. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average pirce difference was $22.15. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $21.75.

- **Linden Variable Frequency Transformer (VFT) Facility.** The Linden VFT facility is a merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM and NYISO. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provided that power flows would only be from PJM to New York. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16 of the PJM Open Access Transmission Tariff which requested the addition of Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.[4] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. During the first nine months of 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. During the first nine months of 2011, the PJM average hourly LMP at the Linden Interface was $51.13 while the NYISO LMP at the Linden Bus was $52.93, a difference of $1.80. While the average hourly LMP difference at the PJM/Linden border was $1.80, the average of the absolute value of the hourly difference was $18.71. The average hourly flow during the first nine months of 2011 was -146 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 62 percent of the hours during the first nine months of 2011. Following June 1, 2011, when bidirectional flows were permitted across the Linden VFT Facility, a total of 560 hours, out of the 2,927 hours in June, were imports into PJM. Of those 560 hours, 335 hours were economic (i.e. the NYISO/PJM Interface price was lower than the PJM/NYISO Interface price). When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM (335 hours), the average price difference was $32.65. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when power flows were from NYISO to PJM (225 hours), the average price difference was $28.42.

4 See Docket No. ER11-3250-000 (March 31, 2011).

- **Hudson DC Line.** The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection will be a submarine AC cable system. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). The current in-service date for this line is January 31, 2012.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[5] On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also formalized the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

  The PJM/NYISO JOA does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and NYISO began discussion of a market based congestion management protocol, which continued during the first nine months of 2011.

- **PJM and MISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first nine months of 2011. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately.

5 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed November 10, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).

- **PJM, MISO and TVA Joint Reliability Coordination Agreement.**[6] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of MISO and PJM and the service territory of TVA. The agreement continued to be in effect during the first nine months of 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[7] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect during the first nine months of 2011. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP).

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[8] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC SERC Reliability Corporation (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

Other Agreements/Protocols with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first nine months of 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[9] This protocol allows Con Edison to elect up to the flow specified in each of two contracts through the PJM Day-Ahead Energy Market. A 600 MW contract is for firm service and a 400 MW contract has a priority higher than non-firm service, but lower than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract.

6 See "Congestion Management Process (CMP) Master" (May 1, 2008) (November 10, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

7 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed November 10, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (642 KB).

8 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed November 10, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

9 See 111 FERC ¶ 61,228 (2005).

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces.

  Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also exist as a result of transactions within a market based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match pricing with physical flows and their impacts on the transmission system. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

  During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh or 8.3 percent, an increase from 4.8 percent during the first nine months of 2010 and 5.2 percent for the calendar year 2010. This difference is system inadvertent.

  Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

  A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and non market areas. A complete analysis of loop flow would improve the overall transparency of electicity transactions. To adequately investigate the causes of loop flows, complete data are required. The MMU has previously requested access to the data necessary to complete this analysis.[10] On April 21, 2011, FERC issued a Notice of Proposed Rulemaking addressing the issues associated with access to loop flow data by the Commission staff and market monitors.[11] On June 27, 2011, the North American market monitors provided comments to the Notice of Proposed Rulemaking, supporting the consideration to making the complete electronic tagging data used to schedule the transmission of electric power in wholesale markets available to entities involved in market monitoring functions.[12]

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2010, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-12,779 GWh during the first nine months of 2011 and -15,106 GWh for the calendar year 2010). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (3,030 GWh during the first nine months of 2011 and 4,015 GWh for the calendar year 2010). The net difference between scheduled flows and actual flows at the PJM/MECS Interface was exports while the net difference at the PJM/TVA Interface was imports.

- **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces was significant during the first nine months of 2011. PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) are in the west. The largest differences in the west were at the TVA Interface. The net scheduled power flow at the TVA Interface was 731 GWh and the actual flow was 3,761 GWh, a difference of 3,030 GWh. PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK are in the east. The largest differences in the east were at the CPLE Interface. The net scheduled power flow at the CPLE Interface was 18 GWh and the actual flow was 6,134 GWh, a difference of 6,116 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first nine months of 2011, PJM issued 58 TLRs of level 3a or higher. Of the 58 TLRs issued, 33 events were TLR level 3a, and the remaining 25 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. The fact that PJM issued only 58 TLRs during the first nine months of 2011, compared to 96 during the first nine months of 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would require the need for higher level TLRs.

- **Marginal Loss Surplus Allocation.** On May 15, 2010, in an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[13] PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus.

  As a result, on September 17, 2010, the marginal loss surplus allocation methodology was modified to mitigate the incentive to submit noneconomic transactions solely to receive a loss surplus allocation.

- **Up-To Congestion.** The May 15, 2010, modification to the marginal loss surplus allocation provided an allocation to up-to congestion transactions. In June and July of 2010, there was a significant increase in the total up-to congestion bids. This increase in activity was the result of the changes to the allocation methodology that provided an inappropriate incentive to submit noneconomic up-to congestion transactions solely to obtain a portion of the loss surplus.

  As part of the September 17, 2010 marginal loss surplus allocation modification, the up-to congestion product was modified to eliminate the requirement for up-to congestion transactions to obtain transmission service. In order to minimize the effects of eliminating the transmission requirement for up-to congestion transactions, PJM created a new product on the OASIS, called Up-to Congestion. Market participants are still required to access the PJM OASIS and obtain an up-to congestion

10 See the *2010 State of the Market Report for PJM*, Volume II, "Section 4, Interchange Transactions" at "Data Required for Full Loop Flow Analysis."
11 See 135 FERC ¶ 61,052 (April 21, 2011).
12 See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)
13 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

reservation. However, the product is not limited by ATC, nor is there a charge associated with the product. The sole purpose of this product is to allow market participants to specify specific sources and sinks for which up-to congestion transactions will be evaluated in the Day-Ahead Market.

Prior to the May 15, 2010, modification to the marginal loss surplus allocation, the average daily volume of up-to congestion was 376 bids per day (March 1, 2009 through May 14, 2010). The average daily volume of up-to congestion transactions increased to 762 bids per day for the period between the initial May 15, 2010, modification and the additional modification to the marginal loss surplus allocation methodology made on September 17, 2010. The average daily volume of up-to congestion bids further increased to 1,987 bids per day following the additional modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids, which was implemented as part of the September 17, 2010 marginal loss surplus allocation methodology changes (September 17, 2010, through September 30, 2011). (See Table 4-13.)

Effective May 16, 2011, for the May 17, 2011, Day-Ahead Market, PJM modified the available locations for up-to congestion transactions to eliminate the ability to submit up-to congestion bids at the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP Interface pricing points. These interface pricing points were eliminated to avoid wheeling up-to congestion transactions from being submitted at the same interface to arbitrage price differentials between the Day-Ahead and Real-Time Energy Markets created by existing JOA's (for example, using an import pricing point of CPLEIMP and an export pricing point of CPLEEXP or SOUTHEXP). The MMU agrees with the elimination of these interfaces for up-to congestion transactions, as wheeling transactions at the same interface are not permitted in the Real-Time Energy Market.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

  Total uncollected congestion charges during the first nine months of 2011 were $11,942, compared to $2.9 million for the first nine months of 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present.

  The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. PJM stakeholders approved the changes recommended by the MMU. These modifications are currently being evaluated by PJM to determine if tariff or operating agreement changes are necessary prior to implementation.

- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[14] These modifications are currently being evaluated by PJM to develop an implementation plan.

- **Spot Import.** In 2009, the MMU and PJM jointly addressed a concern regarding the underutilization of spot import service. Because spot import service is available at no cost, and is limited by available transfer capabilities (ATC), market participants were able to reserve all of the available service with no economic risk. The market participants could

14 See "Meeting Minutes" Minutes from PJM's MIC meeting (May 16, 2011) (Accessed on November 10, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> 121 KB).

then choose not to submit a transaction utilizing the service if they did not believe the transaction would be economic. By reserving the spot import service and not scheduling against it, they effectively withheld the service from other market participants who wished to utilize it.

To address the issue, PJM implemented new timing requirements that retracted spot import reservations if they were associated with a NERC Tag within 30 minutes of making the reservation. Although this resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service to flow energy. As a result, the MMU and PJM recommended that PJM revert to unlimited ATC for non-firm willing to pay congestion service. The PJM Stakeholders agreed with the recommendation, and requested that PJM determine what would be needed to implement the change.

PJM reported that further modifications to the various JOAs would be required to revert to unlimited ATC for non-firm willing to pay congestion service. To modify the JOA, both parties must be in agreement with any proposed changes. PJM reported that MISO and Progress Energy Carolinas, Inc., counterparties to two JOAs, expressed concerns about allowing for unlimited ATC, citing potential reliability concerns, and were unwilling to make the modifications.

As an alternative to creating an unlimited amount of ATC, PJM suggested including a utilization factor in the ATC calculation for non-firm service. This utilization factor is the ratio of utilized transmission on a particular path to the amount of that transmission reserved when determining how much transmission should be granted. For example, if a path has 1,000 MW of ATC available, and the utilization factor is sixty percent, rather than reducing the ATC to zero when a 1,000 MW reservation is made, there would still be 400 MW of ATC available to be requested. Including the utilization factor will allow PJM to adjust the amount of ATC available to permit a more efficient use of the transmission system. This proposed methodology was approved by PJM stakeholders during the third quarter of 2011, with a targeted implementation date in the fourth quarter of 2011.

- **Real-Time Dispatchable Transactions.** Real-Time Dispatchable Transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

  Dispatchable transactions were initially a valuable tool for market participants. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits. During the first nine months of 2011, $1.3 million in balancing operating reserve credits were paid due to the uneconomic loading of dispatchable transactions compared to $290,515 during first nine months of 2010.

  The MMU recommended that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.[15] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011.

- **Internal Bilateral Transactions.** In the third quarter of 2011, it was discovered that a number of companies had been utilizing internal bilateral transactions to inappropriately reduce, or eliminate, their exposure to balancing operating reserve (BOR) charges associated with their PJM Day-Ahead Market positions.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and Auction

15 See "Meeting Minutes" Minutes from PJM's MIC meeting (July 13, 2011) (Accessed on November 10, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> (121 KB).

Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are not transparent.

On June 1, 2011, at 0100, the American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. Additionally, following the ATSI integration, the MICHFE Interface Pricing Point was eliminated, reducing the total number of interface pricing points from 17 to 16.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first nine months of 2011, including evolving transaction patterns, economics and issues. During the first nine months of 2011, PJM was a net exporter of energy in the Real-Time Market and a net importer of energy in the Day-Ahead Market. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. A large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 71 percent of the total real-time net exports and two interfaces accounted for 78 percent of the real-time net import volume. Three interfaces accounted for 58 percent of the total day-ahead net exports and three interfaces accounted for 95 percent of the day-ahead net import volume.

During the first nine months of 2011, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for many hours, 56 percent between PJM and MISO and 47 percent between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through September 2011 (See 2010 SOM, Figure 4-1)

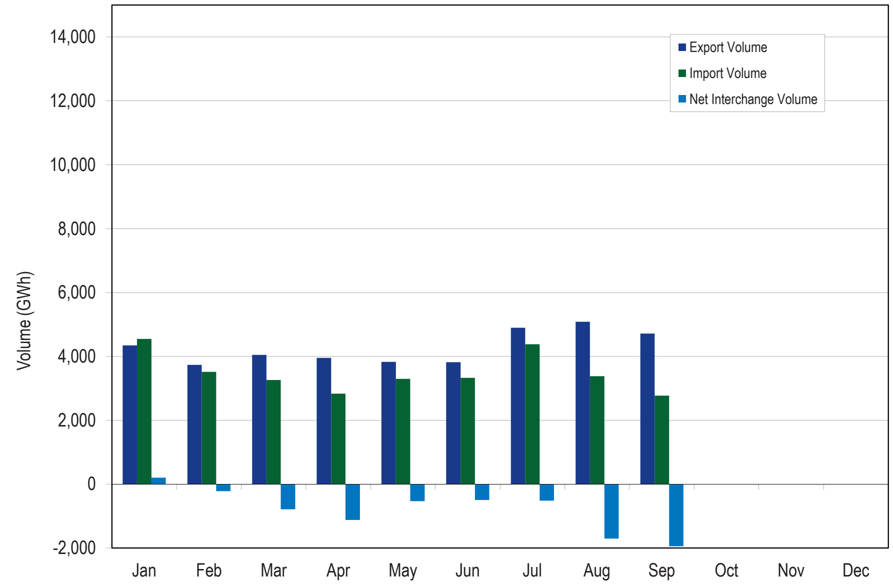


Figure 4-2 PJM day-ahead scheduled imports and exports: January through September 2011 (See 2010 SOM, Figure 4-2)

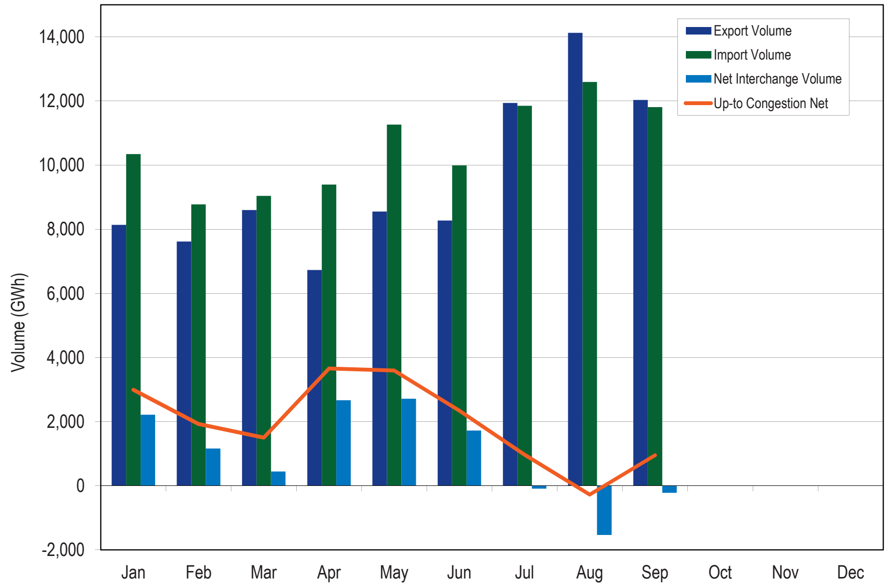


Figure 4-4 PJM day-ahead scheduled import and export transaction monthly volume history: June 2000 through September 2011 (New Figure)

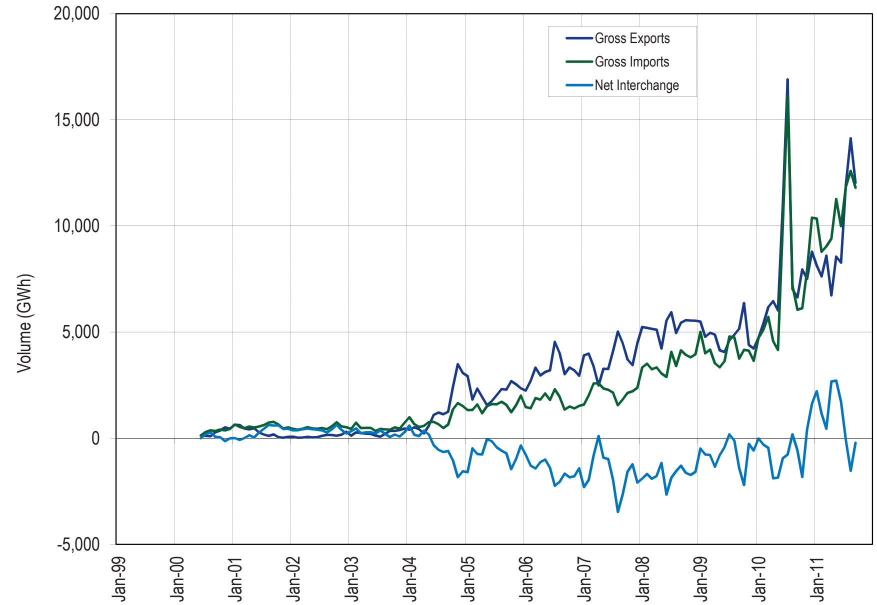
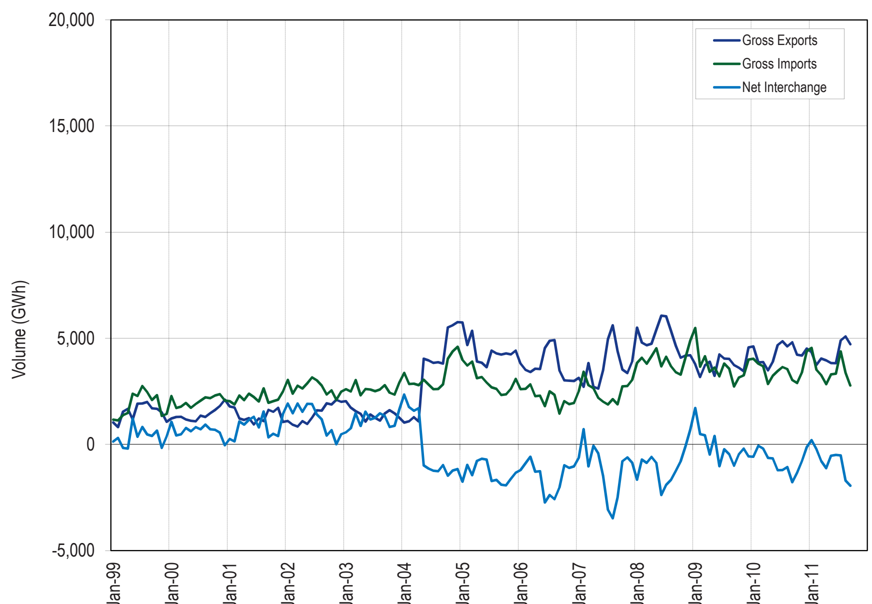


Figure 4-3 PJM real-time scheduled import and export transaction monthly volume history: 1999 through September 2011 (See 2010 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(162.6)	(76.3)	(85.5)	(48.3)	(77.6)	(59.1)	(75.1)	(150.1)	(129.5)	(864.1)
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	2.4
DUK	(25.6)	218.7	(17.1)	12.7	34.7	(36.8)	33.9	(289.3)	(132.2)	(201.0)
EKPC	(61.4)	(10.1)	5.6	135.0	41.4	106.4	107.1	100.7	80.4	505.1
LGEE	392.9	385.9	314.6	200.0	241.7	321.8	303.1	246.6	327.6	2,734.2
MEC	(426.0)	(403.3)	(462.2)	(463.2)	(478.5)	(456.3)	(675.5)	(565.8)	(616.7)	(4,547.5)
MISO	(77.3)	(389.0)	(744.4)	(1,131.2)	(495.8)	(675.9)	(576.0)	(752.7)	(1,187.4)	(6,029.7)
ALTE	(116.1)	(128.3)	(76.0)	(4.5)	(7.6)	(105.7)	(210.6)	(193.5)	(378.8)	(1,221.1)
ALTW	(30.9)	(14.5)	(28.6)	(49.9)	(68.8)	(83.2)	(119.3)	(83.2)	(249.3)	(727.7)
AMIL	(2.9)	45.5	14.3	8.6	37.9	(17.6)	(34.8)	(101.8)	(120.2)	(171.0)
CIN	(85.5)	(314.7)	(454.6)	(713.9)	(242.7)	(423.9)	(338.1)	(113.3)	(376.2)	(3,062.9)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	149.9	(43.9)	(159.1)	(250.2)	(251.0)	0.2	0.0	0.0	0.0	(554.1)
IPL	21.8	3.5	8.8	(3.3)	11.0	(12.8)	(60.6)	(111.3)	(30.9)	(173.8)
MECS	193.0	190.8	112.6	33.2	160.1	128.9	413.3	218.7	223.3	1,673.9
NIPS	(114.3)	(51.0)	(69.7)	(72.6)	(53.7)	(71.9)	(80.0)	(62.6)	(42.8)	(618.6)
WEC	(92.3)	(76.4)	(92.1)	(78.6)	(81.0)	(89.9)	(145.9)	(305.7)	(212.5)	(1,174.4)
NYISO	(1,361.0)	(1,279.3)	(1,032.0)	(864.2)	(731.7)	(673.6)	(939.5)	(1,348.3)	(1,150.1)	(9,379.7)
LIND	(159.1)	(148.1)	(117.7)	(131.7)	(93.0)	(80.4)	(27.6)	(93.4)	(124.6)	(975.6)
NEPT	(412.9)	(378.8)	(383.7)	(290.8)	(387.5)	(241.0)	(372.8)	(460.1)	(313.2)	(3,240.8)
NYIS	(789.0)	(752.4)	(530.6)	(441.7)	(251.2)	(352.2)	(539.1)	(794.8)	(712.3)	(5,163.3)
OVEC	1,242.2	1,110.7	1,065.8	1,019.0	1,030.7	1,014.6	1,040.8	1,011.9	828.9	9,364.6
TVA	681.6	222.8	170.3	19.9	(98.5)	(36.7)	264.3	41.8	36.3	1,301.8
Total	202.8	(219.9)	(784.9)	(1,120.3)	(533.6)	(493.2)	(516.9)	(1,705.2)	(1,942.7)	(7,113.9)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	6.4	7.4	4.6	6.6	23.4	67.7	74.7	37.6	13.0	241.4
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	2.4
DUK	271.7	309.8	186.2	208.2	197.7	184.4	299.8	121.8	103.3	1,882.9
EKPC	31.7	46.5	41.0	143.3	85.5	112.3	116.7	110.3	85.9	773.2
LGEE	393.0	386.3	324.1	233.6	250.3	334.6	322.7	268.5	328.2	2,841.3
MEC	53.2	30.8	19.1	0.0	0.0	0.0	0.0	0.0	6.0	109.1
MISO	1,141.5	833.9	736.6	409.5	718.2	542.8	998.2	714.4	599.0	6,694.1
ALTE	0.0	0.0	0.0	0.0	0.0	0.2	1.6	0.0	0.0	1.8
ALTW	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.6	0.0	1.5
AMIL	23.9	68.0	42.2	26.0	55.4	37.8	85.2	75.0	7.3	420.8
CIN	400.0	270.3	315.2	180.8	348.0	260.0	359.4	344.9	261.8	2,740.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	436.8	220.5	122.3	55.5	71.2	0.3	0.0	0.0	0.0	906.6
IPL	25.4	4.8	15.3	5.6	19.3	66.9	89.3	37.1	39.6	303.3
MECS	250.9	270.3	241.4	141.4	224.3	176.7	460.7	256.8	289.3	2,311.8
NIPS	0.0	0.0	0.2	0.2	0.0	0.0	2.0	0.0	0.0	2.4
WEC	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	5.5
NYISO	681.0	534.7	646.6	686.3	911.4	976.1	1,144.6	961.5	731.5	7,273.7
LIND	0.0	0.0	0.0	0.0	0.1	14.5	52.0	28.2	10.8	105.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	681.0	534.7	646.6	686.3	911.3	961.6	1,092.6	933.3	720.7	7,168.1
OVEC	1,242.2	1,110.7	1,091.3	1,019.0	1,030.7	1,014.6	1,063.6	1,013.7	834.7	9,420.5
TVA	725.7	255.5	212.0	128.8	79.7	92.0	360.3	152.7	69.8	2,076.5
Total	4,546.4	3,515.6	3,261.5	2,835.3	3,296.9	3,326.9	4,380.6	3,380.5	2,771.4	31,315.1

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	169.0	83.7	90.1	54.9	101.0	126.8	149.8	187.7	142.5	1,105.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	297.3	91.1	203.3	195.5	163.0	221.2	265.9	411.1	235.5	2,083.9
EKPC	93.1	56.6	35.4	8.3	44.1	5.9	9.6	9.6	5.5	268.1
LGEE	0.1	0.4	9.5	33.6	8.6	12.8	19.6	21.9	0.6	107.1
MEC	479.2	434.1	481.3	463.2	478.5	456.3	675.5	565.8	622.7	4,656.6
MISO	1,218.8	1,222.9	1,481.0	1,540.7	1,214.0	1,218.7	1,574.2	1,467.1	1,786.4	12,723.8
ALTE	116.1	128.3	76.0	4.5	7.6	105.9	212.2	193.5	378.8	1,222.9
ALTW	30.9	14.5	28.6	49.9	68.8	84.1	119.3	83.8	249.3	729.2
AMIL	26.8	22.5	27.9	17.4	17.5	55.4	120.0	176.8	127.5	591.8
CIN	485.5	585.0	769.8	894.7	590.7	683.9	697.5	458.2	638.0	5,803.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	286.9	264.4	281.4	305.7	322.2	0.1	0.0	0.0	0.0	1,460.7
IPL	3.6	1.3	6.5	8.9	8.3	79.7	149.9	148.4	70.5	477.1
MECS	57.9	79.5	128.8	108.2	64.2	47.8	47.4	38.1	66.0	637.9
NIPS	114.3	51.0	69.9	72.8	53.7	71.9	82.0	62.6	42.8	621.0
WEC	96.8	76.4	92.1	78.6	81.0	89.9	145.9	305.7	213.5	1,179.9
NYISO	2,042.0	1,814.0	1,678.6	1,550.5	1,643.1	1,649.7	2,084.1	2,309.8	1,881.6	16,653.4
LIND	159.1	148.1	117.7	131.7	93.1	94.9	79.6	121.6	135.4	1,081.2
NEPT	412.9	378.8	383.7	290.8	387.5	241.0	372.8	460.1	313.2	3,240.8
NYIS	1,470.0	1,287.1	1,177.2	1,128.0	1,162.5	1,313.8	1,631.7	1,728.1	1,433.0	12,331.4
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	22.8	1.8	5.8	55.9
TVA	44.1	32.7	41.7	108.9	178.2	128.7	96.0	110.9	33.5	774.7
Total	4,343.6	3,735.5	4,046.4	3,955.6	3,830.5	3,820.1	4,897.5	5,085.7	4,714.1	38,429.0

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through September 2011 (See 2010 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(11.3)	89.8	126.7	234.5	159.9	(83.0)	(322.5)	(673.9)	(617.9)	(1,097.7)
CPLW	17.1	6.4	1.9	11.0	6.0	15.4	45.7	42.1	18.3	163.9
DUK	91.7	115.8	41.0	789.1	234.0	(240.7)	(617.8)	(495.5)	39.1	(43.3)
EKPC	(27.5)	(18.4)	27.8	6.8	(5.3)	0.9	(9.7)	(2.9)	(0.3)	(28.6)
LGEE	19.0	1.8	2.0	16.6	35.6	1.8	22.5	19.7	(2.1)	116.9
MEC	(458.7)	(421.4)	(463.2)	(455.2)	(472.2)	(437.3)	(542.0)	(493.2)	(512.4)	(4,255.6)
MISO	2,144.3	904.6	(182.2)	697.2	452.4	1,481.0	1,717.5	1,084.0	709.7	9,008.5
ALTE	1,996.5	908.2	99.1	833.9	1,037.3	1,333.0	911.8	730.0	583.1	8,432.9
ALTW	164.8	(49.7)	(48.1)	(40.1)	(7.3)	139.3	(0.4)	(42.6)	(205.5)	(89.6)
AMIL	34.6	70.2	67.5	31.0	33.6	(4.6)	74.1	(129.5)	(687.4)	(510.5)
CIN	(125.8)	(90.5)	(175.1)	(94.3)	(18.1)	(131.4)	(0.3)	100.0	178.4	(357.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	0.0	(1.7)
FE	(189.4)	(339.7)	(317.2)	(479.3)	(1,299.6)	(1.5)	0.0	0.0	0.0	(2,626.7)
IPL	(175.6)	(162.6)	(163.9)	(75.1)	(123.5)	(97.9)	(152.7)	(105.9)	(125.4)	(1,182.6)
MECS	742.4	580.2	567.2	591.2	992.5	336.2	932.0	816.5	1,150.4	6,708.6
NIPS	(280.6)	(111.0)	(130.3)	(65.9)	(108.8)	(90.8)	(50.9)	(1.7)	(6.8)	(846.8)
WEC	(22.6)	99.5	(81.4)	(4.2)	(53.7)	(1.3)	3.9	(281.1)	(177.1)	(518.0)
NYISO	(892.0)	(681.9)	(496.7)	(220.9)	611.3	(242.7)	(987.4)	(1,169.3)	(902.6)	(4,982.2)
LIND	(105.0)	(104.7)	(77.9)	(110.8)	(75.0)	(171.2)	(659.8)	(740.5)	(822.6)	(2,867.5)
NEPT	(427.9)	(379.7)	(385.0)	(298.1)	(405.2)	(250.0)	(396.6)	(508.6)	(339.6)	(3,390.7)
NYIS	(359.1)	(197.5)	(33.8)	188.0	1,091.5	178.5	69.0	79.8	259.6	1,276.0
OVEC	1,046.0	1,051.1	1,279.5	1,502.7	1,636.3	1,167.6	1,025.6	643.8	1,163.3	10,515.9
TVA	282.8	111.2	106.7	85.9	56.5	55.6	(422.1)	(489.8)	(118.6)	(331.8)
Total	2,211.4	1,159.0	443.5	2,667.7	2,714.5	1,718.6	(90.2)	(1,535.0)	(223.5)	9,066.0

Table 4-5 Day-ahead gross import volume by interface (GWh): January through September 2011 (See 2010 SOM, Figure 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	137.6	146.3	197.4	305.0	242.6	29.5	40.6	45.3	48.2	1,192.5
CPLW	19.5	6.5	8.1	13.9	24.6	27.2	64.9	69.3	47.9	281.9
DUK	150.8	155.5	88.5	935.0	269.0	50.9	99.2	50.2	55.3	1,854.4
EKPC	5.4	0.0	28.3	6.8	6.3	2.8	0.2	0.3	0.3	50.4
LGEE	21.6	2.1	13.5	17.1	40.8	41.6	71.0	21.6	14.1	243.4
MEC	21.7	19.8	20.1	8.2	15.9	67.5	102.8	107.1	106.2	469.3
MISO	7,393.7	5,782.6	5,316.8	4,391.0	5,686.9	5,791.8	7,048.6	7,143.8	6,968.3	55,523.5
ALTE	4,872.3	3,576.6	3,109.0	2,156.0	2,959.3	3,808.9	3,588.3	3,520.1	3,761.2	31,351.7
ALTW	375.6	52.1	29.0	19.3	74.1	284.8	183.7	129.2	51.9	1,199.7
AMIL	44.8	71.1	70.7	34.2	35.8	45.2	77.2	34.2	50.9	464.1
CIN	266.2	440.5	360.6	511.2	263.4	728.0	760.3	692.0	662.2	4,684.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	232.7	140.5	141.0	55.5	17.0	0.0	0.0	0.0	0.0	586.7
IPL	17.0	2.9	0.0	6.5	2.8	1.7	0.8	1.0	4.8	37.5
MECS	1,409.4	1,207.9	1,438.1	1,402.0	2,167.9	772.1	2,254.1	2,644.6	2,260.5	15,556.6
NIPS	32.0	48.2	27.0	33.9	11.6	29.2	33.2	35.2	26.0	276.3
WEC	143.7	242.8	141.4	172.4	155.0	121.9	151.0	87.5	150.8	1,366.5
NYISO	910.1	988.6	1,149.1	1,399.2	2,467.1	1,560.2	1,666.6	1,763.1	1,997.8	13,901.8
LIND	0.0	0.0	0.0	0.0	0.0	8.7	29.1	22.2	0.8	60.8
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	910.1	988.6	1,149.1	1,399.2	2,467.1	1,551.5	1,637.5	1,740.9	1,997.0	13,841.0
OVEC	1,272.8	1,355.2	1,898.8	1,976.7	2,223.0	1,886.6	2,006.4	2,750.1	2,146.5	17,516.1
TVA	412.1	318.7	318.9	341.8	286.8	529.3	748.6	639.7	421.3	4,017.2
Total	10,345.3	8,775.3	9,039.5	9,394.7	11,263.0	9,987.4	11,848.9	12,590.5	11,805.9	95,050.5

Table 4-6 Day-ahead gross export volume by interface (GWh): January through September 2011 (See 2010 SOM, Figure 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	148.9	56.5	70.7	70.5	82.7	112.5	363.1	719.2	666.1	2,290.2
CPLW	2.4	0.1	6.2	2.9	18.6	11.8	19.2	27.2	29.6	118.0
DUK	59.1	39.7	47.5	145.9	35.0	291.6	717.0	545.7	16.2	1,897.7
EKPC	32.9	18.4	0.5	0.0	11.6	1.9	9.9	3.2	0.6	79.0
LGEE	2.6	0.3	11.5	0.5	5.2	39.8	48.5	1.9	16.2	126.5
MEC	480.4	441.2	483.3	463.4	488.1	504.8	644.8	600.3	618.6	4,724.9
MISO	5,249.4	4,878.0	5,499.0	3,693.8	5,234.5	4,310.8	5,331.1	6,059.8	6,258.6	46,515.0
ALTE	2,875.8	2,668.4	3,009.9	1,322.1	1,922.0	2,475.9	2,676.5	2,790.1	3,178.1	22,918.8
ALTW	210.8	101.8	77.1	59.4	81.4	145.5	184.1	171.8	257.4	1,289.3
AMIL	10.2	0.9	3.2	3.2	2.2	49.8	3.1	163.7	738.3	974.6
CIN	392.0	531.0	535.7	605.5	281.5	859.4	760.6	592.0	483.8	5,041.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	1.7
FE	422.1	480.2	458.2	534.8	1,316.6	1.5	0.0	0.0	0.0	3,213.4
IPL	192.6	165.5	163.9	81.6	126.3	99.6	153.5	106.9	130.2	1,220.1
MECS	667.0	627.7	870.9	810.8	1,175.4	435.9	1,322.1	1,828.1	1,110.1	8,848.0
NIPS	312.6	159.2	157.3	99.8	120.4	120.0	84.1	36.9	32.8	1,123.1
WEC	166.3	143.3	222.8	176.6	208.7	123.2	147.1	368.6	327.9	1,884.5
NYISO	1,802.1	1,670.5	1,645.8	1,620.1	1,855.8	1,802.9	2,654.0	2,932.4	2,900.4	18,884.0
LIND	105.0	104.7	77.9	110.8	75.0	179.9	688.9	762.7	823.4	2,928.3
NEPT	427.9	379.7	385.0	298.1	405.2	250.0	396.6	508.6	339.6	3,390.7
NYIS	1,269.2	1,186.1	1,182.9	1,211.2	1,375.6	1,373.0	1,568.5	1,661.1	1,737.4	12,565.0
OVEC	226.8	304.1	619.3	474.0	586.7	719.0	980.8	2,106.3	983.2	7,000.2
TVA	129.3	207.5	212.2	255.9	230.3	473.7	1,170.7	1,129.5	539.9	4,349.0
Total	8,133.9	7,616.3	8,596.0	6,727.0	8,548.5	8,268.8	11,939.1	14,125.5	12,029.4	85,984.5

Interface Pricing

Table 4-7 Active interfaces: January through September 2011 (See 2010 SOM, Figure 4-7)

	PJM 2011 Interfaces (January through September)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active						
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 4-5 PJM's footprint and its external interfaces[16] (See 2010 SOM, Figure 4-4)

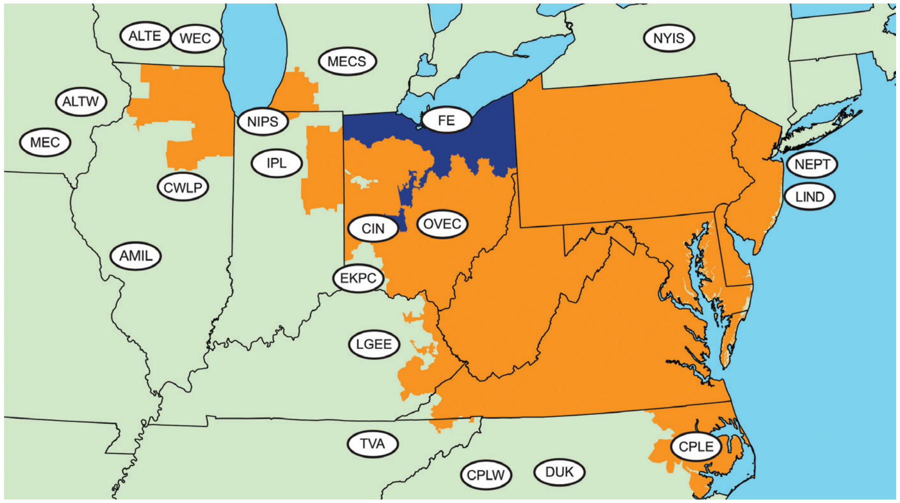


Table 4-8 Active pricing points: 2011 (See 2010 SOM, Table 4-8)

PJM 2011 Pricing Points (January through September)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MICHFE	Active	Active	Active	Active	Active	Active						
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

16 The area in blue on Figure 4 5 shows the region that was incorporated with PJM as part of the ATSI integration that occurred on June 1, 2011 at 0100. Additionally, at that same time, the PJM/First Energy Corp. (FE) Interface was eliminated..

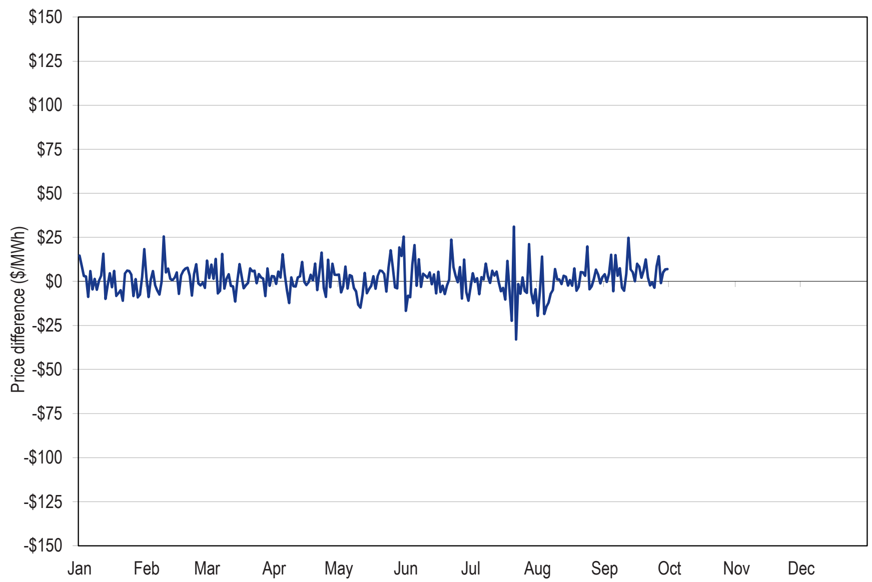
Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and MISO Interface Prices

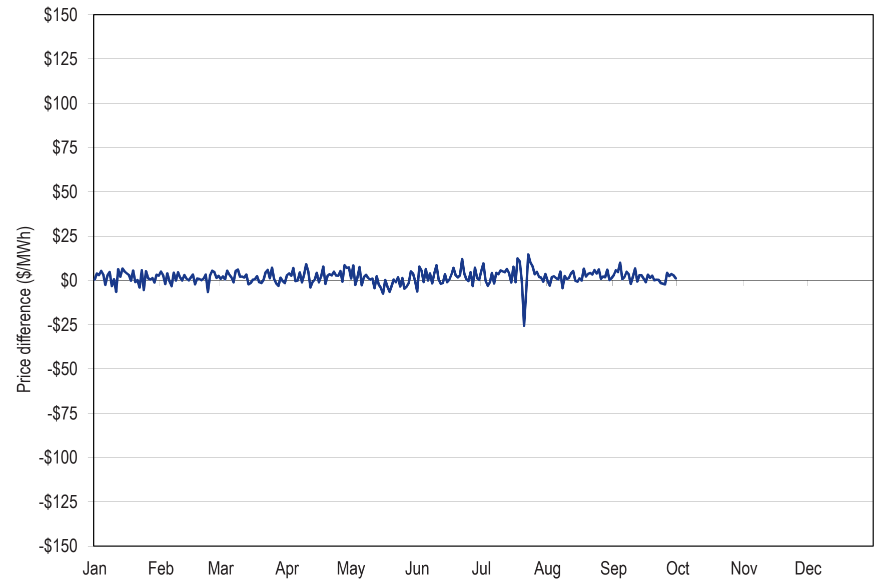
Real-Time Prices

Figure 4-6 Figure 4-6 Real-time daily hourly average price difference (MISO Interface minus PJM/MISO): January through September 2011 (See 2010 SOM, Figure 4-5)



Day-Ahead Prices

Figure 4-7 Day-ahead daily hourly average price difference (MISO interface minus PJM/MISO): January through September 2011 (See 2010 SOM, Figure 4-6)



PJM and NYISO Interface Prices

Real-Time Prices

Figure 4-8 Real-time daily hourly average price difference (NY proxy minus PJM/NYIS): January through September 2011 (See 2010 SOM, Figure 4-7)

Day-Ahead Prices

Figure 4-9 Day-ahead daily hourly average price difference (NY proxy minus PJM/NYIS): January through September 2011 (See 2010 SOM, Figure 4-8)

Summary of Interface Prices between PJM and Organized Markets

Figure 4-10 PJM, NYISO and MISO real-time border price averages: January through September 2011 (See 2010 SOM, Figure 4-9)

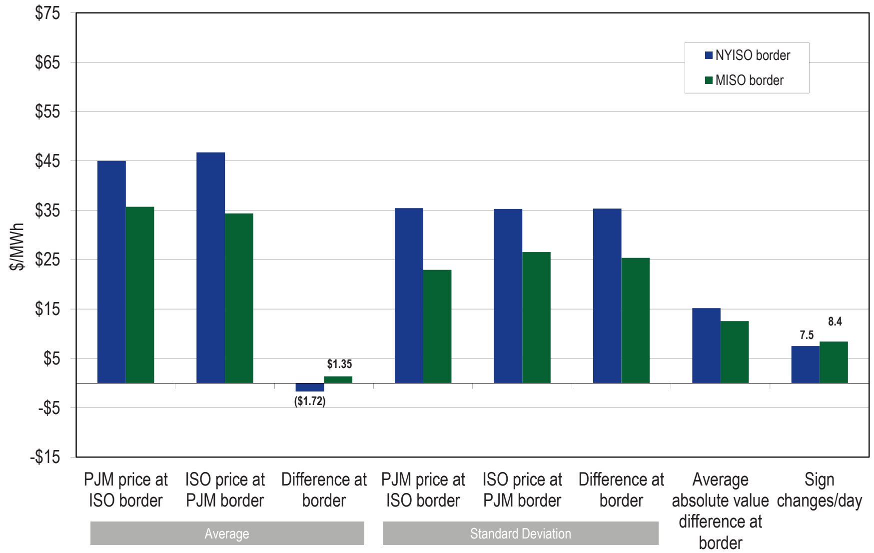
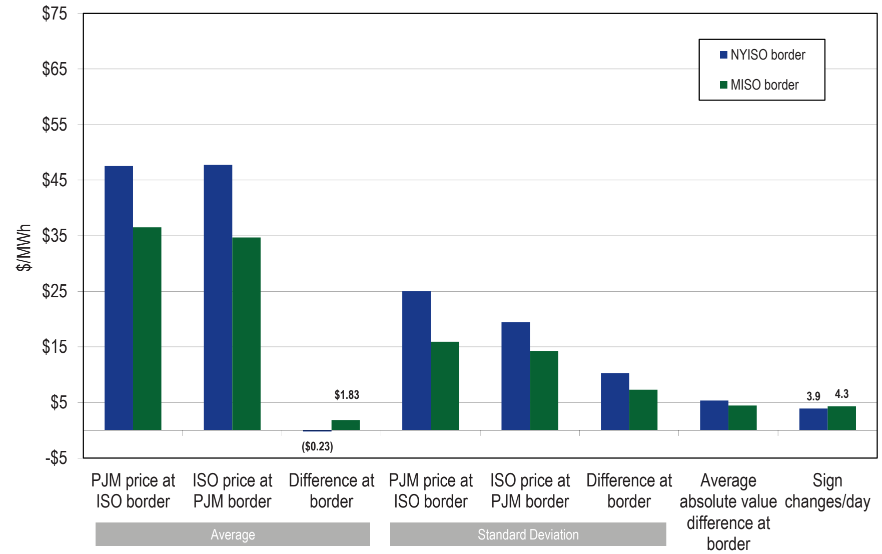
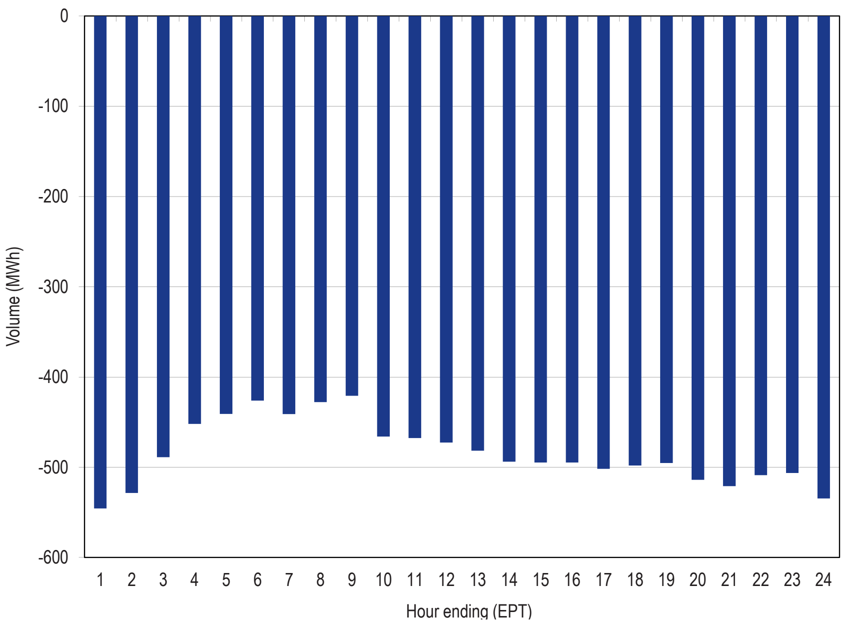


Figure 4-11 PJM, NYISO and MISO day-ahead border price averages: January through September 2011 (See 2010 SOM, Figure 4-10)



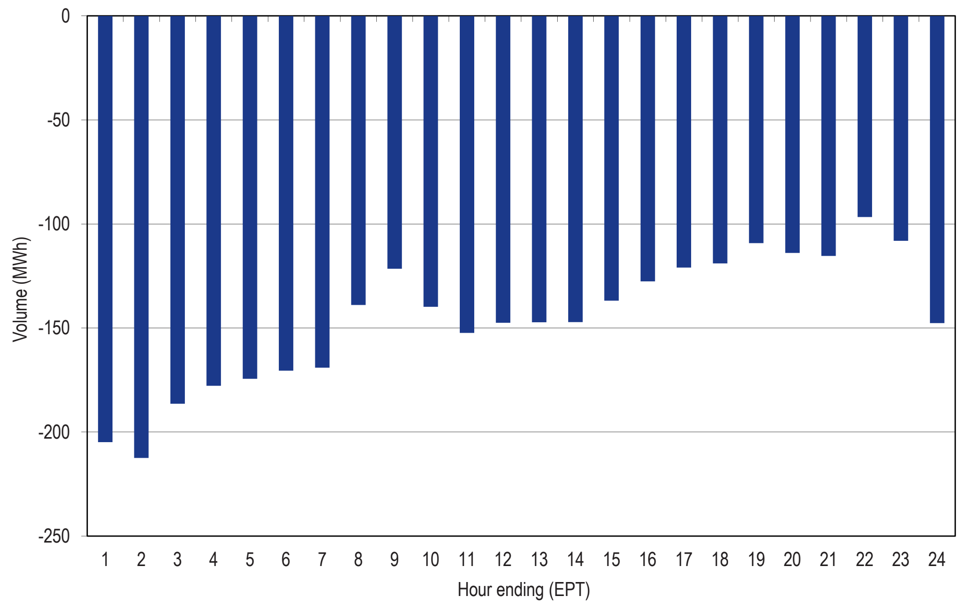
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-12 Neptune hourly average flow: January through September 2011 (See 2010 SOM, Figure 4-11)



Linden Variable Frequency Transformer (VFT) facility

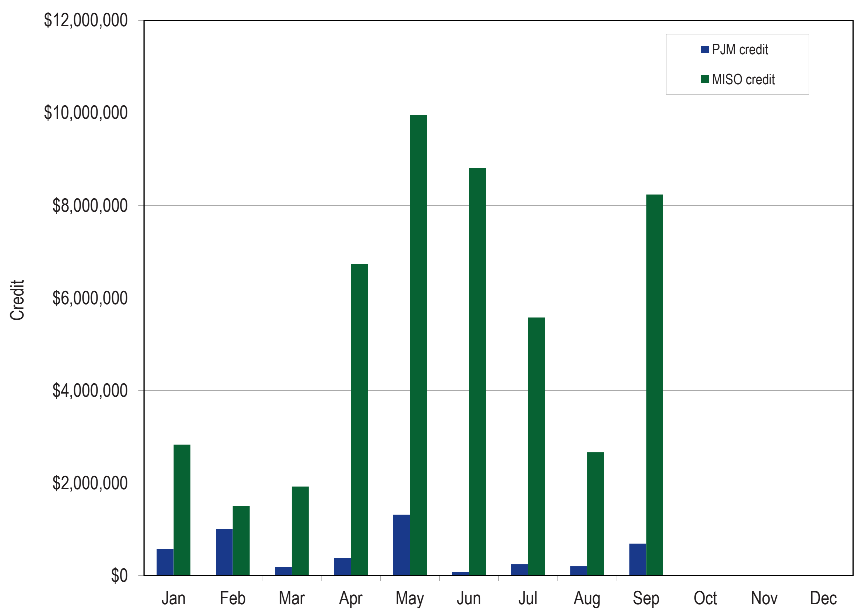
Figure 4-13 Linden hourly average flow: January through September 2011 (See 2010 SOM, Figure 4-12)



Operating Agreements with Bordering Areas

PJM and MISO Joint Operating Agreement

Figure 4-14 Credits for coordinated congestion management: January through September 2011 (See 2010 SOM, Figure 4-13)



Other Agreements/Protocols with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

Table 4-9 Con Edison and PSE&G wheeling settlement data: January through September 2011 (See 2010 SOM, Table 4-9)

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($2,115,263)	($962)	($2,116,225)	($12,053,779)	$0	($12,053,779)
Congestion Credit			$142,667			($12,246,931)
Adjustments			$15,459			$1,004,637
Net Charge			($2,274,350)			($811,484)

Interchange Transaction Issues

Loop Flows

Table 4-10 Net scheduled and actual PJM interface flows (GWh): January through September 2011 (See 2010 SOM, Table 4-10)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	6,134	18	6,116	33,978%
CPLW	(1,456)	2	(1,458)	(72,900%)
DUK	(2,147)	(201)	(1,946)	968%
EKPC	2,208	505	1,703	337%
LGEE	984	2,734	(1,750)	(64%)
MEC	(1,678)	(4,542)	2,864	(63%)
MISO	(10,667)	(3,381)	(7,286)	215%
ALTE	(4,345)	(1,221)	(3,124)	256%
ALTW	(1,680)	(728)	(952)	131%
AMIL	7,571	(239)	7,810	(3,268%)
CIN	187	197	(10)	(5%)
CWLP	(219)	-	(219)	0%
FE	(3,464)	(1,005)	(2,459)	245%
IPL	1,174	(266)	1,440	(541%)
MECS	(11,105)	1,674	(12,779)	(763%)
NIPS	(3,107)	(619)	(2,488)	402%
WEC	4,321	(1,174)	5,495	(468%)
NYISO	(8,312)	(9,407)	1,095	(12%)
LIND	(1,011)	(951)	(60)	6%
NEPT	(3,173)	(3,173)	-	0%
NYIS	(4,128)	(5,283)	1,155	(22%)
OVEC	6,649	9,365	(2,716)	(29%)
TVA	3,761	731	3,030	415%
Total	(4,524)	(4,176)	(348)	8.3%

Loop Flows at PJM's Southern Interfaces

Figure 4-15 Southwest actual and scheduled flows: January 2006 through September 2011 (See 2010 SOM, Figure 4-14)

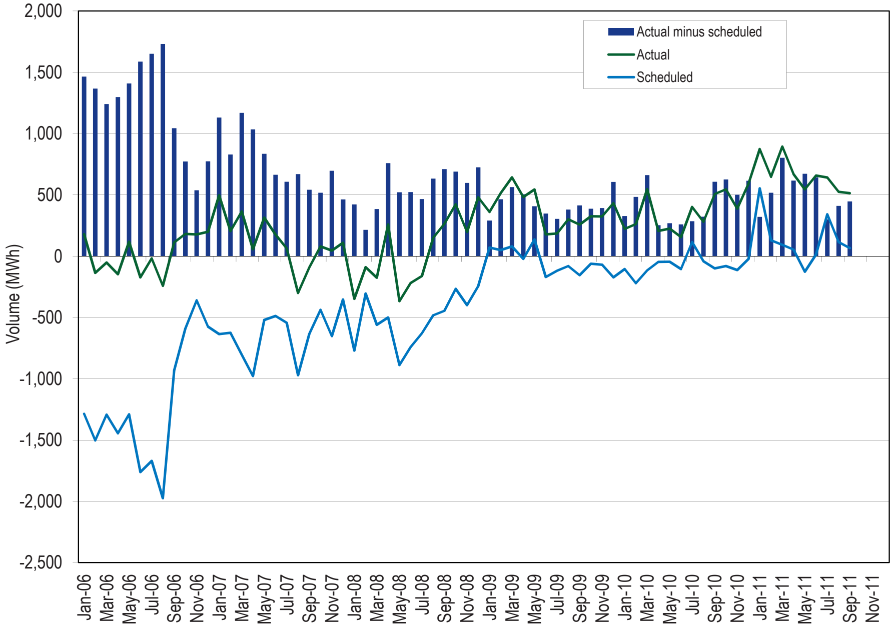
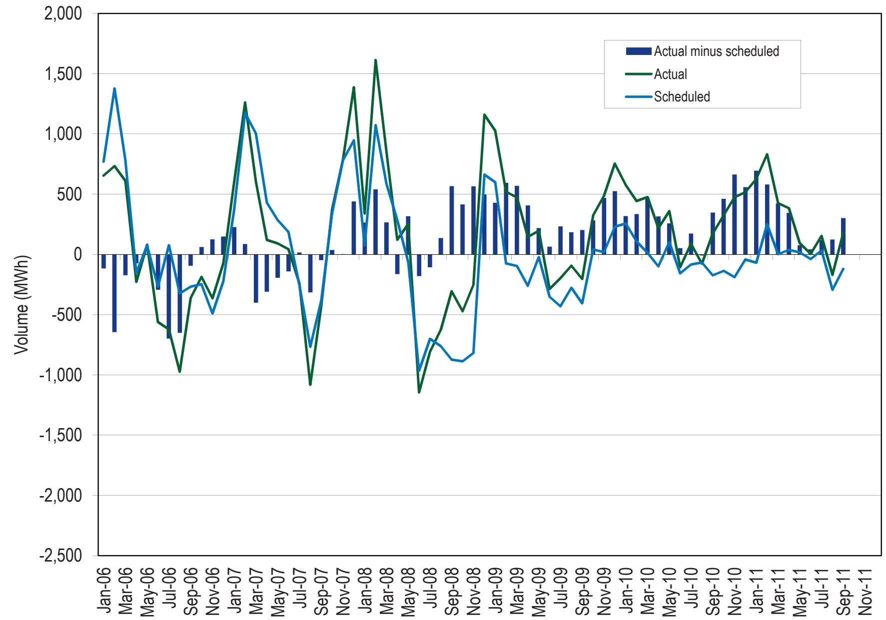


Figure 4-16 Southeast actual and scheduled flows: January 2006 through September 2011 (See 2010 SOM, Figure 4-15)



TLR Procedures

Table 4-11 Table 4-11 PJM and MISO TLR procedures: Calendar year 2010 and January through September 2011[17] (See 2010 SOM, Figure 4-16, Figure 4-17 and Figure 4-18)

	Number of TLRs Level 3 and Higher		Number of Unique Flowgates That Experienced TLRs		Curtailment Volume (MWh)	
Month	PJM	MISO	PJM	MISO	PJM	MISO
Jan-10	6	23	3	5	18,393	13,387
Feb-10	1	9	1	7	1,249	13,095
Mar-10	6	18	3	10	2,376	27,412
Apr-10	15	40	7	11	26,992	29,832
May-10	11	20	4	12	22,193	54,702
Jun-10	19	19	6	8	64,479	183,228
Jul-10	15	25	8	8	44,210	169,667
Aug-10	12	22	9	7	32,604	189,756
Sep-10	11	15	7	7	82,066	32,782
Oct-10	4	26	3	12	2,305	29,574
Nov-10	1	25	1	10	59	66,113
Dec-10	9	7	6	5	18,509	5,972
Jan-11	7	8	5	5	75,057	14,071
Feb-11	6	7	5	4	6,428	23,796
Mar-11	0	14	0	5	0	10,133
Apr-11	3	23	3	9	8,129	44,855
May-11	9	15	4	7	18,377	36,777
Jun-11	15	14	7	6	17,865	19,437
Jul-11	7	8	4	7	18,467	3,697
Aug-11	4	6	4	4	3,624	11,323
Sep-11	7	17	6	7	6,462	25,914

17 The curtailment volume for PJM TLR's was taken from the individual NERC TLR history reports as posted in the Interchange Distribution Calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLR's was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx>.

Table 4-12 Number of TLRs by TLR level by reliability coordinator: January through September 2011 (See 2010 SOM, Table 4-11)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	20	11	120	39	34	0	224
	MISO	66	27	1	7	9	0	110
	NYIS	146	0	0	0	0	0	146
	ONT	79	0	0	0	0	0	79
	PJM	33	25	0	0	0	0	58
	SWPP	210	239	1	18	17	0	485
	TVA	55	71	3	1	15	0	145
	VACS	9	3	0	0	0	0	12
Total		618	376	125	65	75	0	1,259

Up-To Congestion

Figure 4-17 Monthly up-to congestion cleared bids in MWh: January 2006 through September 2011 (See 2010 SOM, Figure 4-19)

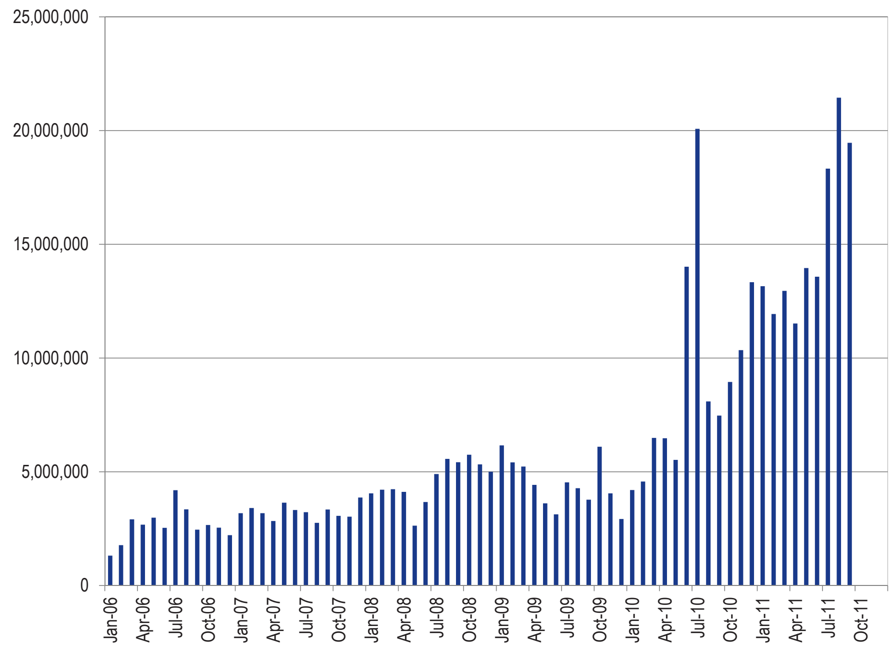


Table 4-13 Monthly volume of cleared and submitted up-to congestion bids: January, 2009, through September, 2011. (See 2010 SOM, Table 4-12)

	Bid MW				Bid Volume				Cleared MW				Cleared Volume			
Month	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total
Jan-09	4,218,910	5,787,961	319,122	10,325,993	90,277	74,826	6,042	171,145	2,591,211	3,242,491	202,854	6,036,556	56,132	45,303	4,210	105,645
Feb-09	3,580,115	4,904,467	318,440	8,803,022	64,338	70,874	6,347	141,559	2,374,734	2,836,344	203,907	5,414,985	42,101	44,423	4,402	90,926
Mar-09	3,649,978	5,164,186	258,701	9,072,865	64,714	72,495	5,531	142,740	2,285,412	2,762,459	178,507	5,226,378	42,408	42,007	4,299	88,714
Apr-09	2,607,303	5,085,912	73,931	7,767,146	47,970	67,417	2,146	117,533	1,797,302	2,582,294	48,478	4,428,074	32,088	35,987	1,581	69,656
May-09	2,196,341	4,063,887	106,860	6,367,088	40,217	54,745	1,304	96,266	1,496,396	2,040,737	77,553	3,614,686	26,274	29,720	952	56,946
Jun-09	2,598,234	3,132,478	164,903	5,895,615	47,625	44,755	2,873	95,253	1,540,169	1,500,560	88,723	3,129,452	28,565	23,307	1,522	53,394
Jul-09	3,984,680	3,776,957	296,910	8,058,547	67,039	56,770	5,183	128,992	2,465,891	1,902,807	163,129	4,531,826	41,924	31,176	2,846	75,946
Aug-09	3,551,396	4,388,435	260,184	8,200,015	64,652	64,052	3,496	132,200	2,278,431	2,172,133	194,415	4,644,978	41,774	34,576	2,421	78,771
Sep-09	2,948,353	4,179,427	156,270	7,284,050	51,006	64,103	2,405	117,514	1,774,589	2,479,898	128,344	4,382,831	31,962	40,698	1,944	74,604
Oct-09	3,172,034	6,371,230	154,825	9,698,089	46,989	100,350	2,217	149,556	2,060,371	3,931,346	110,646	6,102,363	31,634	70,964	1,672	104,270
Nov-09	3,447,356	3,851,334	103,325	7,402,015	53,067	61,906	1,236	116,209	2,065,813	1,932,595	51,929	4,050,337	33,769	32,916	653	67,338
Dec-09	2,323,383	2,502,529	66,497	4,892,409	47,099	47,223	1,430	95,752	1,532,579	1,359,936	34,419	2,926,933	31,673	28,478	793	60,944
Jan-10	3,794,946	3,097,524	212,010	7,104,480	81,604	55,921	3,371	140,896	2,250,689	1,789,018	161,977	4,201,684	49,064	33,640	2,318	85,022
Feb-10	3,841,573	3,937,880	316,150	8,095,603	80,876	80,685	2,269	163,830	2,627,101	2,435,650	287,162	5,349,913	50,958	48,008	1,812	100,778
Mar-10	4,877,732	4,454,865	277,180	9,609,777	97,149	74,568	2,239	173,956	3,209,064	3,071,712	263,516	6,544,292	60,277	48,596	2,064	110,937
Apr-10	3,877,306	5,558,718	210,545	9,646,569	67,632	85,358	1,573	154,563	2,622,113	3,690,889	170,020	6,483,022	42,635	54,510	1,154	98,299
May-10	3,800,870	5,062,272	149,589	9,012,731	74,996	78,426	1,620	155,042	2,366,149	3,049,405	112,700	5,528,253	47,505	48,996	1,112	97,613
Jun-10	9,126,963	9,568,549	1,159,407	19,854,919	95,155	89,222	6,960	191,337	6,863,803	6,850,098	1,072,759	14,786,660	59,733	55,574	5,831	121,138
Jul-10	12,818,141	11,526,089	5,420,410	29,764,640	124,929	106,145	18,948	250,022	8,971,914	8,237,557	5,241,264	22,450,734	73,232	60,822	16,526	150,580
Aug-10	8,231,393	6,767,617	888,591	15,887,601	115,043	87,876	10,664	213,583	4,430,832	2,894,314	785,726	8,110,871	62,526	40,485	8,884	111,895
Sep-10	7,768,878	7,561,624	349,147	15,679,649	184,697	161,929	4,653	351,279	3,915,814	3,110,580	256,039	7,282,433	63,405	45,264	3,393	112,062
Oct-10	8,732,546	9,795,666	476,665	19,004,877	189,748	154,741	7,384	351,873	4,150,104	4,564,039	246,594	8,960,736	76,042	65,223	3,670	144,935
Nov-10	11,636,949	9,272,885	537,369	21,447,203	253,594	170,470	9,366	433,430	5,765,905	4,312,645	275,111	10,353,661	112,250	71,378	4,045	187,673
Dec-10	17,769,014	12,863,875	923,160	31,556,049	307,716	215,897	15,074	538,687	7,851,235	5,150,286	337,157	13,338,678	136,582	93,299	7,380	237,261
Jan-11	20,275,932	11,807,379	921,120	33,004,431	351,193	210,703	17,632	579,528	7,917,986	4,925,310	315,936	13,159,232	151,753	91,557	8,417	251,727
Feb-11	18,418,511	13,071,483	800,630	32,290,624	345,227	226,292	17,634	589,153	6,806,039	4,879,207	248,573	11,933,818	151,003	99,302	8,851	259,156
Mar-11	17,330,353	12,919,960	749,276	30,999,589	408,628	274,709	15,714	699,051	7,104,642	5,603,583	275,682	12,983,906	178,620	124,990	7,760	311,370
Apr-11	17,215,352	9,321,117	954,283	27,490,752	513,881	265,334	17,459	796,674	7,452,366	3,797,819	351,984	11,602,168	229,707	113,610	8,118	351,435
May-11	21,058,071	11,204,038	2,937,898	35,200,007	562,819	304,589	24,834	892,242	8,294,422	4,701,077	1,031,519	14,027,018	261,355	143,956	11,116	416,427
Jun-11	20,455,508	12,125,806	395,833	32,977,147	524,072	285,031	12,273	821,376	7,632,235	5,361,825	198,482	13,192,543	226,747	132,744	6,363	365,854
Jul-11	24,273,892	16,837,875	409,863	41,521,630	603,519	338,810	13,781	956,110	9,585,027	8,617,284	205,599	18,407,910	283,287	186,866	7,008	477,161
Aug-11	23,790,091	21,014,941	229,895	45,034,927	591,170	403,269	8,278	1,002,717	10,594,771	10,875,384	103,141	21,573,297	274,398	208,593	3,648	486,639
Sep-11	21,740,208	18,135,378	232,626	40,108,212	526,945	377,158	7,886	911,989	10,219,806	9,270,121	82,200	19,572,127	270,088	185,585	3,444	459,117
Total	319,112,311	269,114,344	20,831,615	609,058,270	6,785,586	4,826,649	259,822	11,872,057	154,894,915	135,931,402	13,506,042	304,332,358	3,301,471	2,412,553	150,209	5,864,233

Figure 4-18 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: January through September 2011 (See 2010 SOM, Figure 4-20)

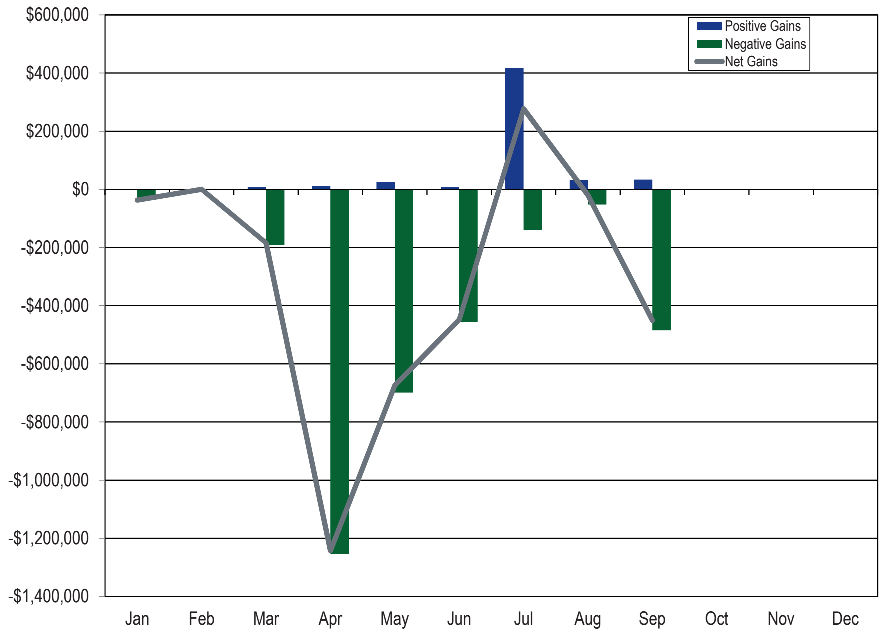
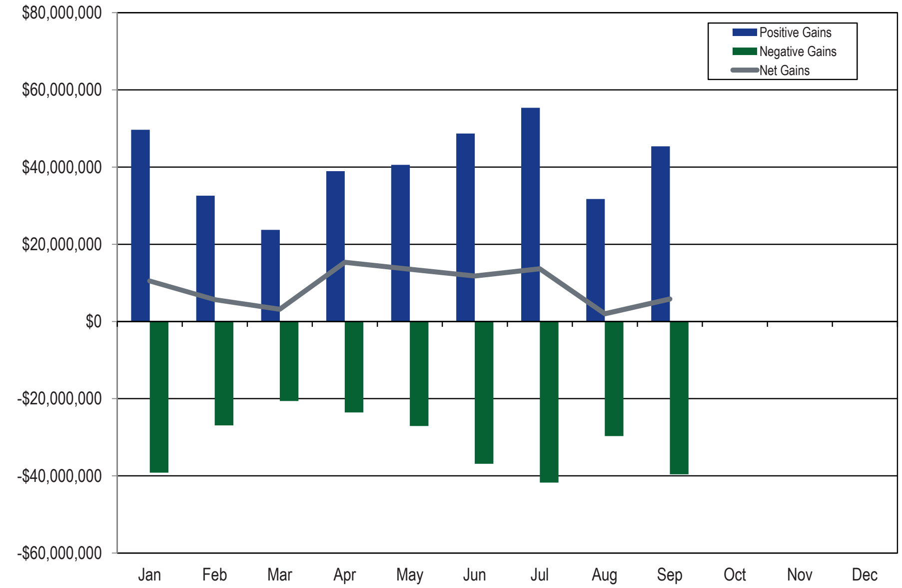


Figure 4-19 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: January through September 2011 (See 2010 SOM, Figure 4-21)



Interface Pricing Agreements with Individual Balancing Authorities

Table 4-14 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through September 2007 through 2011 (See 2010 SOM, Table 4-13)

Jan - Sep	Southeast LMP	Southwest LMP	SOUTHIIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$54.99	$45.44	$49.32	$48.56	$5.67	($3.88)	$6.44	($3.11)
2008	$67.99	$54.53	$59.19	$59.15	$8.81	($4.65)	$8.84	($4.62)
2009	$36.41	$32.05	$33.58	$33.58	$2.83	($1.54)	$2.83	($1.54)
2010	$44.30	$37.18	$40.18	$39.99	$4.12	($3.01)	$4.31	($2.81)
2011	$43.12	$38.26	$40.41	$40.41	$2.71	($2.15)	$2.71	($2.15)

Table 4-15 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2011 (See 2010 SOM, Table 4-14)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.10	$42.26	$40.41	$40.41	$0.69	$1.86
PEC	$41.81	$43.95	$40.41	$40.41	$1.41	$3.54
NCMPA	$41.73	$41.92	$40.41	$40.41	$1.33	$1.52

Figure 4-20 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2011 (See 2010 SOM, Figure 4-22)

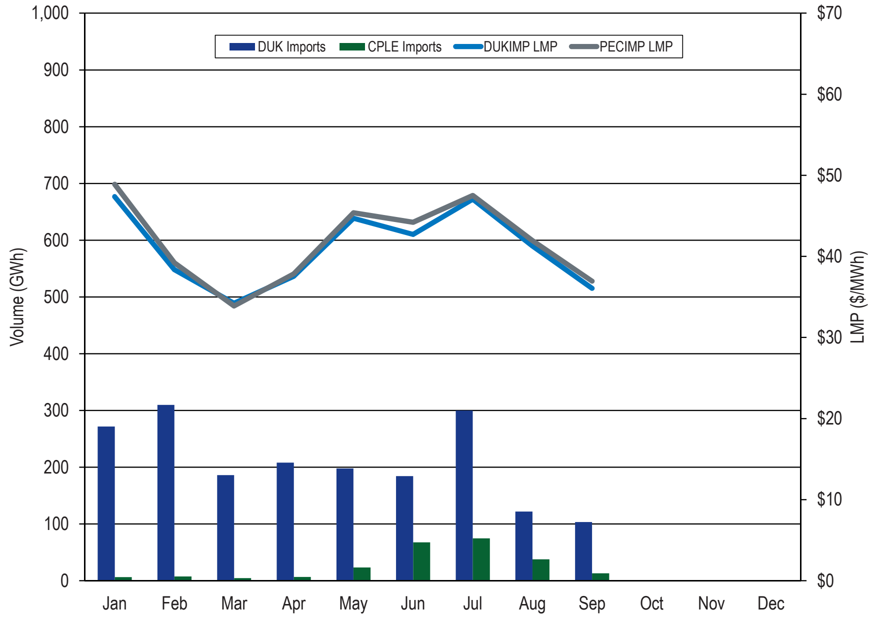


Figure 4-21 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2011 (See 2010 SOM, Figure 4-23)

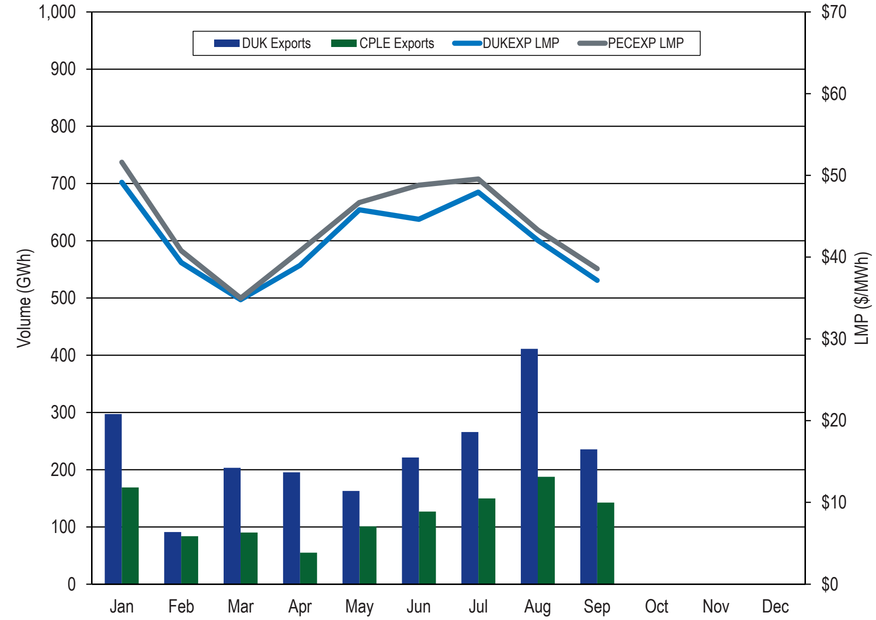


Table 4-16 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through September 2007 through 2011 (See 2010 SOM, Table 4-15)

Jan - Sep	Southeast LMP	Southwest LMP	SOUTHIIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$53.50	$45.05	$48.60	$47.68	$4.90	($3.55)	$5.82	($2.63)
2008	$68.22	$55.57	$60.09	$60.09	$8.12	($4.53)	$8.12	($4.53)
2009	$36.78	$32.20	$33.83	$33.83	$2.95	($1.63)	$2.95	($1.63)
2010	$45.33	$37.57	$40.24	$40.24	$5.09	($2.66)	$5.09	($2.66)
2011	$43.45	$38.69	$40.30	$40.30	$3.15	($1.61)	$3.15	($1.61)

Table 4-17 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2011 (See 2010 SOM, Table 4-16)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.51	$43.20	$40.30	$40.30	$1.20	$2.90
PEC	$42.42	$44.99	$40.30	$40.30	$2.12	$4.68
NCMPA	$41.97	$42.59	$40.30	$40.30	$1.67	$2.28

Figure 4-22 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2011 (See 2010 SOM, Figure 4-24)

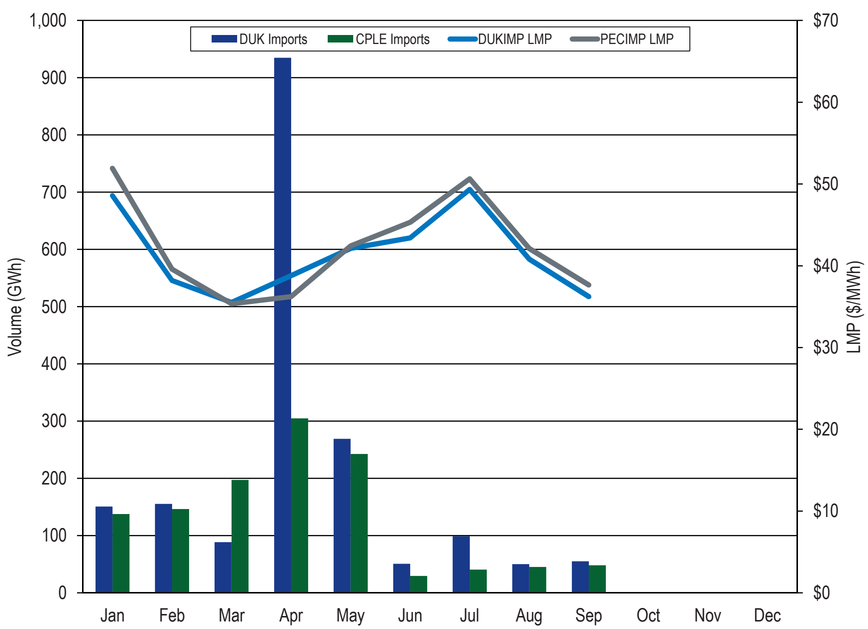
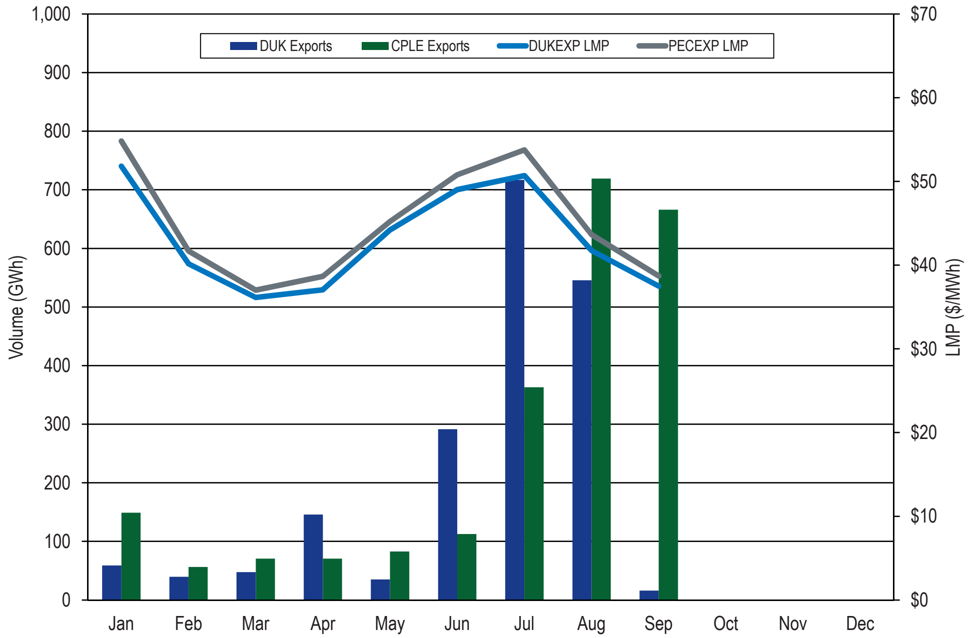


Figure 4-23 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2011 (See 2010 SOM, Figure 4-25)



Willing to Pay Congestion and Not Willing to Pay Congestion

Table 4-18 Monthly uncollected congestion charges: Calendar year 2010 and January through September 2011 (See 2010 SOM, Figure 4-26)

Month	2010	2011
Jan	$148,764	$3,102
Feb	$542,575	$1,567
Mar	$287,417	$0
Apr	$31,255	$4,767
May	$41,025	$0
Jun	$169,197	$1,354
Jul	$827,617	$1,115
Aug	$731,539	$37
Sep	$119,162	$0
Oct	$257,448	
Nov	$30,843	
Dec	$127,176	
Total	$3,314,018	$11,942

Spot Import

Figure 4-24 Spot import service utilization: January 2009 through September 2011 (See 2010 SOM, Figure 4-27)