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.

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 real-time interface pricing points from 17 to 16.[1]
- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. In 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 -813.5 GWh compared to -805.1 GWh for the calendar year 2010.[2] Gross monthly import volumes averaged 3,437.8 GWh compared to 3,495.6 GWh in 2010 while gross monthly exports averaged 4,251.3 GWh compared to 4,300.6 GWh for the calendar year 2010.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2011, PJM was a net importer of energy in the Day-Ahead Energy Market from January through June and December, and a net exporter of energy in the remaining months. In 2010, PJM was a net importer of energy in the Day-Ahead Energy Market in August, November and December, and a net exporter of energy in the remaining months. In the Day-Ahead Energy Market, monthly net interchange averaged 548.0 GWh compared to -539.2 GWh for the calendar year 2010. Gross monthly import volumes averaged 10,751.5 GWh compared to 7,341.6 GWh for the calendar year 2010 while gross monthly exports averaged 10,203.5 GWh compared to 7,880.8 GWh for the calendar year 2010.

  The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 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. In all months of 2011, the overall net PJM imports would have been net exports but for the net up-to congestion transaction imports. Figure 8-1 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange.
- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** In 2011, gross imports in the Day-Ahead Energy Market were 313 percent of gross imports in the Real-Time Energy Market (210 percent for the calendar year 2010). In 2011, gross exports in the Day-Ahead Energy Market were 240 percent of gross exports in the Real-Time Energy Market (183 percent for the calendar year 2010). In 2011, net interchange was 6,576.2 GWh in the Day-Ahead Energy Market and -9.761.8 GWh in the Real-Time Energy Market compared to -6,470.0 GWh in the Day-Ahead Energy Market and -9,661.0 GWh in the Real-Time Energy Market for the calendar year 2010.
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the calendar year 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 67.7 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 22.0 percent, PJM/MidAmerican Energy Company (MEC) with 19.5 percent, PJM/Neptune (NEPT) with 14.0 percent and PJM/Cinergy Corporation (CIN) with 12.2 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 39.4 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 74.0 percent of the total

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.

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.

net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 55.6 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18.4 percent.[3]

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the calendar year 2011, there were net exports at nine of PJM's 17 interface pricing points eligible for real-time transactions.[4] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 84.7 percent of the total net exports: PJM/MISO with 57.5 percent, PJM/NYIS with 16.6 percent and PJM/NEPTUNE (NEPT) with 10.6 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 29.8 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 78.7 percent of the total net imports: PJM/SouthIMP with 40.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 38.0 percent of the net import volume.[5]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the calendar year 2011, there were net exports at 13 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 60.5 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 25.7 percent, PJM/Neptune (NEPT) with 20.4 percent and PJM/Linden (LIND) with 14.4 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 32.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 95.5 percent of the total net imports: PJM/OVEC with 43.0 percent, PJM/Michigan Electric Coordinated System (MECS) with 31.2 percent and PJM/Eastern Alliant Energy Corporation (ALTE) with 21.3 percent.

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the calendar year 2011, there were net exports at eight of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 80.3 percent of the total net exports: PJM/SouthEXP with 39.7 percent, PJM/NEPTUNE (NEPT) with 26.7 percent, and PJM/Southeast with 13.9 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 13.9 percent of the total net PJM exports in the Real-Time Energy Market (PJM/NEPTUNE with 26.7 percent and PJM/LINDEN with 4.7 percent. The PJM/NYIS interface pricing point had net imports in the Day-Ahead Energy Market). Eleven PJM interface pricing points had net imports, with three importing interface pricing points accounting for 68.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.9 percent, PJM/SouthIMP with 17.8 percent and PJM/NYIS with 14.0 percent of the net import volume.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $32.32 while the MISO LMP at the border was $34.01, a difference of $1.69. The average hourly flow during the calendar year 2011 was -1,570 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 45 percent of hours in 2011.

- **PJM and New York ISO Interface Prices.** In 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

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

4 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

5 In the Real-Time Market, two PJM interface pricing points had a net interchange of zero (MICHFE and NCMPAEXP).

between PJM and the NYISO. In 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. In 2011, the PJM average hourly LMP at the PJM/NYISO border was $43.88 while the NYISO LMP at the border was $42.33, a difference of $1.55. The average hourly flow during the calendar year 2011 was -626 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 52 percent of the hours in 2011.

- **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. In 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Neptune Interface was $48.20 while the NYISO LMP at the Neptune Bus was $54.11, a difference of $5.91. The average hourly flow during the calendar year 2011 was -493 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 in 2011.
- **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.[6] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. In 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Linden Interface was $47.19 while the NYISO LMP at the Linden Bus was $48.70, a difference of $1.51. The average hourly flow during the calendar year 2011 was -122 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 61 percent of the hours in 2011.
- **Hudson DC Line.** The Hudson direct current (DC) line will be 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 will be 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 Hudson DC line is expected to be in service late in 2012.

Operating Agreements with Bordering Areas

- **PJM and MISO Joint Operating Agreement.**[7] The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during 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.

6 See PJM Interconnection, L.L.C, Docket No. ER11-3250-000 (March 31, 2011).

7 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx. (Accessed March 1, 2012)

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[8] 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 did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and NYISO began discussion of a market based congestion management protocol. On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that include a market to market process.[9]

- **PJM, MISO and TVA Joint Reliability Coordination Agreement.**[10] 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 parties meet on a yearly basis, and, in 2011, there were no developments. The agreement continued to be in effect in 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[11] 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. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). The parties meet on a yearly basis, and, in 2011, there were no developments. However, on May 25, 2011, PJM and Progress submitted a joint filing, requesting an additional six months to develop a mutually agreeable methodology to account for the compensation non-firm power flows have on each others transmission system.[12] The agreement remained in effect in 2011.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[13] 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. The parties meet on a yearly basis, and, in 2011, there were no developments. The agreement remained in effect in 2011.

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.** In 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[14] 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.

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)

8 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf>. (Accessed March 1, 2012)

9 See "Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (December 30,2011).

10 See "Congestion Management Process (CMP) Master," (May 1, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx>. (Accessed March 1, 2012)

11 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx>. (Accessed March 1, 2012)

12 PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc., Docket No. ER11-3637-000 (May 25, 2011)

13 See "Adjacent Reliability Coordinator Coordination Agreement," (May 23, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> . (Accessed March 1, 2012)

14 See 111 FERC ¶ 61,228 (2005).

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, through or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. In 2011, net scheduled interchange was -7,072 GWh and net actual interchange was -7,576 GWh, a difference of 504 GWh or 7.1 percent, an increase from 5.2 percent for the calendar year 2010. While actual interchange exceeded scheduled interchange in 2011, the opposite was true in 2010. This difference is system inadvertent. The total inadvertent over the two year period including 2010 and 2011 was 1.1 percent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** In 2011, PJM issued 62 TLRs of level 3a or higher. Of the 62 TLRs issued, 34 events were TLR level 3a, and the remaining 28 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 62 TLRs in 2011, compared to 110 during the calendar year 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 otherwise require the need for higher level TLRs.

- **Up-To Congestion.** Following the elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions significantly increased. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011, compared to an average of 4,269 bids per day, with an average cleared volume of 310,660 MWh per day, for the calendar year 2010.

  The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market. Up-to congestion transactions impact the day-ahead dispatch. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** Total uncollected congestion charges in 2011 were -$20,955, compared to $3.3 million for the calendar year 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. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case in for the net uncollected congestion charges in 2011. The fact that there was a total negative congestion collection in 2011, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

- **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.[15] These modifications are currently being evaluated by PJM. It is expected

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

that implementation of these changes will occur by the end of the second quarter 2012.

- **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 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.

  In 2011, PJM suggested including a utilization factor in the ATC calculation for all 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. 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. It is expected that implementation of these changes will occur by the end of the third quarter 2012.

- **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.

  Balancing operating reserve credits are paid to importing dispatchable transactions as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. In 2011, these balancing operating reserve credits were $1.3 million, a decrease from $23.0 million for the calendar year 2010. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and the absence of any such dispatchable transactions after April, 2011.

  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.[16] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in the first quarter of 2012.

- **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. This issue is currently being addressed at FERC and through the PJM stakeholder process.[17]

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

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

17 DC Energy, LLC and DC Energy Mid-Atlantic, LLC v. PJM Interconnection, L.L.C., Docket No. EL12-8-000 (October 28, 2011).

areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion hedging tools (FTRs and Auction 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 real-time interface pricing points from 17 to 16.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during 2011, including evolving transaction patterns, economics and issues. In 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 in 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 67.7 percent of the total real-time net exports and two interfaces accounted for 74.0 percent of the real-time net import volume. Three interfaces accounted for 60.5 percent of the total day-ahead net exports and three interfaces accounted for 95.5 percent of the day-ahead net import volume.

A large share of both import and export activity also occurred at a small number of interface pricing points. Three interface pricing ponts accounted for 84.7 percent of the total real-time net exports and two interfaces accounted for 78.7 percent of the real-time net import volume. Three interface pricing points accounted for 80.3 percent of the total day-ahead net exports and three interface pricing points accounted for 68.7 percent of the day-ahead net import volume.

In 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, 55 percent between PJM and MISO and 48 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.

Detailed Recommendations

- **The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent.**
  - The MMU recommends that the up-to congestion transaction product be eliminated. Alternatively, the MMU recommends that PJM require all import and export up-to congestion transactions pay day-ahead and balancing operating reserve charges. At the PJM Market Implementation Committee, held on February 17, 2012, the PJM stakeholders agreed to form a task force to address this recommendation.
  - The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding. The use of specific buses is equivalent to creating a scheduled transaction to a specific

point which will not be matched by the actual corresponding power flow.

- The MMU recommends that PJM perform a regular assessment of the mappings of external balancing authorities associated with the interface pricing points, and modifiy as necessary to reflect current system topology in order to ensure that transactions are priced based on the actual flows that they create on the transmission system.
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.
- The MMU recommends 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. 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.[18] These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
- The MMU recommends 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.[19] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in the first quarter of 2012.
- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions). 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.[20] These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
- The MMU recommends that the Enhanced Energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced.[21]
- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. 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.[22] 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.[23] As of December 31, 2011, the Commission had not made a final rulemaking decision on this proposal.
- The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing

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

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

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

21 See "PJM Manual 41: Managing Interchange," Revision 03 (November 24, 2008), External Transaction Minimum Duration Requirement.

22 See 135 FERC ¶ 61,052 (2011).

23 See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)

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. In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process.

— The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface 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 a single LMP market. PJM is engaged in preliminary discussions with both MISO and NYISO on interface pricing.

— The MMU recommends that the PJM and MISO JOA be modified to eliminate payments between RTOs when such payments would result from the failure of generating units to respond to appropriate pricing signals.

— The MMU recommends that the grandfathered Southeast and Southwest Interface pricing agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. These agreements expired on January 31, 2012 and have not been renewed. The MMU recommends that PJM not enter into any such special pricing agreements.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net importer of energy in the Real-Time Energy Market in January, and an exporter of energy in the remaining months of 2011 (Figure 8-1).[24,25]

The total 2011 real-time net interchange of -9,761.8 GWh was greater than net interchange of -9,661.0 GWh in 2010. The peak month in 2011 for net exporting interchange was September, -1,855.3 GWh; in 2010 it had been September, -1,778.1 GWh. Gross monthly import volumes averaged 3,437.8 GWh compared to 3,495.6 GWh in 2010, while gross monthly exports averaged 4,251.3 GWh compared to 4,300.6 GWh for the calendar year 2010.

In 2011, PJM was a net importer of energy in the Day-Ahead Energy Market from January through June and December, and a net exporter of energy in the remaining months (Figure 8-1). In 2010, PJM was a net importer of energy in the Day-Ahead Energy Market in August, November and December, and a net exporter of energy in the remaining months. In the Day-Ahead Energy Market, monthly net interchange averaged 548.0 GWh compared to -539.2 GWh for the calendar year 2010. Gross monthly import volumes averaged 10,751.5 GWh compared to 7,341.6 GWh for the calendar year 2010 while gross monthly exports averaged 10,203.5 GWh compared to 7,880.8 GWh for the calendar year 2010.

The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 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. In all months of 2011, the overall net PJM imports would have been net exports but for the net up-to congestion transaction imports. Figure 8-1 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 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011, compared to an average of 4,269 bids per day, with an average cleared volume of 310,660 MWh per day, for the calendar year 2010.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets.[26] In 2011, gross

24 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

25 The interchange values shown in Figure 8-1 and Figure 8-2, and Table 8-1 through Table 8-12 do not include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in these figures and tables does not match the "Net Scheduled" values shown in Table 8-16.

26 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges based on the differences between the transaction MW in the Day-Ahead and Real-Time Markets.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: Calendar year 2011

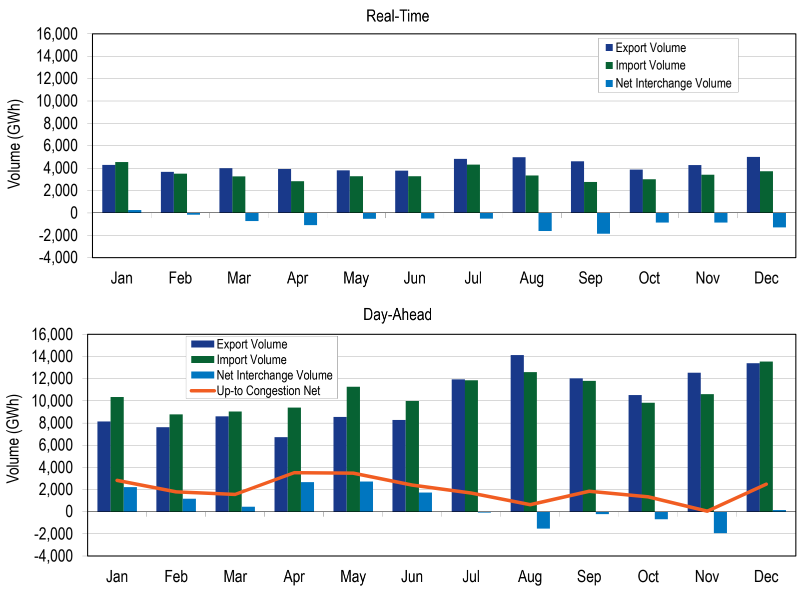
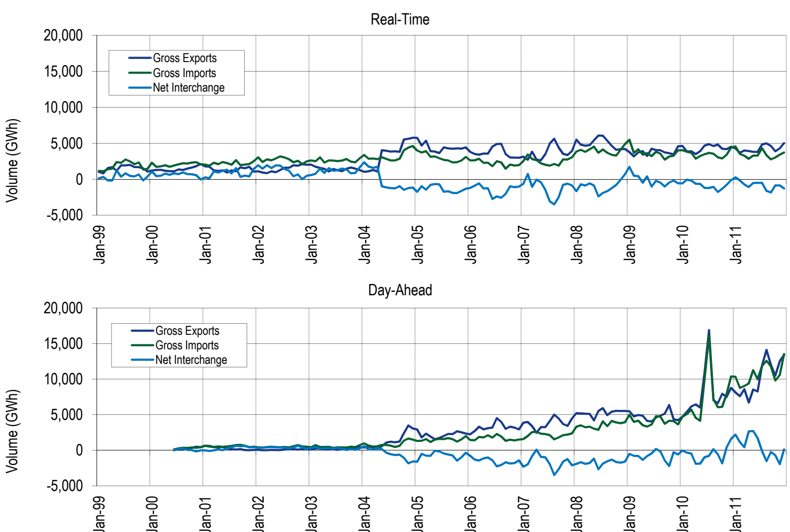


Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January 1999, through December, 2011



imports in the Day-Ahead Energy Market were 313 percent of the Real-Time Energy Market's gross imports (210 percent for the calendar year 2010), gross exports in the Day-Ahead Energy Market were 240 percent of the Real-Time Energy Market's gross exports (183 percent for the calendar year 2010). In 2011, net interchange was 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market compared to -6,470.0 GWh in the Day-Ahead Energy Market and -9,661.0 GWh in the Real-Time Energy Market for the calendar year 2010.

Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through 2011. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time. However, due to the increase in up-to congestion transactions in late 2010, PJM has been a net importer of energy in the Day-Ahead Market in eight months in 2011.

Real-Time Interface Imports and Exports

There are three steps required for market participants to enter external interchange transactions in PJM's Real-Time Energy Market. The steps are: acquisition of valid transmission via the Open Access Same Time Information System (OASIS); acquisition of available ramp via PJM's Enhanced Energy Scheduler system (EES); and the creation of a valid NERC Tag. In addition, the interchange request must pass the neighboring balancing authority checkout process in order for the request to be implemented. After a successful implementation of an external energy schedule, the energy will flow between balancing authorities. Such a transaction will continue to flow at its designated energy profile as long as the system can support it, it is deemed economic based on options set at the time of scheduling, or until the market participant chooses to curtail the transaction.

In the Real-Time Energy Market, scheduled imports and exports are determined by the market path (the transmission path a market participant selects from the original source to the final sink). These scheduled flows are measured at each of PJM's interfaces with

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(122.7)	(29.5)	(43.3)	(29.1)	(76.8)	(78.7)	(81.0)	(81.5)	(51.5)	(8.2)	(13.7)	(33.6)	(649.7)
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	0.0	0.0	2.4
DUK	(25.6)	218.8	(17.1)	12.8	34.7	(36.8)	33.9	(289.3)	(132.1)	(53.4)	(74.4)	57.7	(271.0)
EKPC	(61.4)	(10.1)	5.6	135.0	41.4	106.4	107.0	100.7	80.4	(70.6)	28.2	11.0	473.6
LGEE	392.9	385.8	314.6	200.0	241.7	322.1	303.1	246.6	327.7	416.9	368.5	361.6	3,881.4
MEC	(426.0)	(403.2)	(462.3)	(463.2)	(478.5)	(456.3)	(675.5)	(565.8)	(616.7)	(517.7)	(471.6)	(479.0)	(6,015.6)
MISO	(77.5)	(388.9)	(744.3)	(1,131.2)	(495.8)	(675.9)	(576.1)	(752.7)	(1,187.3)	(411.5)	(961.4)	(1,397.2)	(8,799.9)
ALTE	(116.1)	(128.3)	(76.0)	(4.5)	(7.6)	(105.7)	(210.6)	(193.5)	(378.8)	(467.0)	(722.0)	(1,015.2)	(3,425.3)
ALTW	(30.9)	(14.5)	(28.6)	(49.9)	(68.8)	(83.2)	(119.3)	(83.2)	(249.3)	(28.4)	(53.6)	(64.9)	(874.5)
AMIL	(2.9)	45.5	14.3	8.6	37.8	(17.5)	(34.8)	(101.8)	(120.2)	6.2	(10.5)	49.2	(126.2)
CIN	(85.6)	(314.7)	(454.6)	(713.8)	(242.7)	(423.9)	(338.1)	(113.3)	(376.2)	0.7	(298.9)	(410.5)	(3,771.6)
CWLP	0.0	0.0	0.0	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)	(250.9)	0.2	0.0	0.0	0.0	0.0	0.0	0.0	(554.2)
IPL	21.8	3.5	8.8	(3.4)	11.0	(12.8)	(60.6)	(111.3)	(30.9)	48.8	(12.1)	(18.0)	(155.2)
MECS	193.0	190.8	112.6	33.2	160.1	128.8	413.2	218.8	223.3	421.4	433.9	400.2	2,929.4
NIPS	(114.3)	(51.0)	(69.7)	(72.6)	(53.7)	(71.9)	(80.0)	(62.6)	(42.8)	(29.9)	(69.4)	(67.3)	(785.1)
WEC	(92.3)	(76.4)	(92.1)	(78.6)	(81.0)	(89.9)	(145.9)	(305.7)	(212.5)	(363.3)	(228.9)	(270.6)	(2,037.2)
NYISO	(1,349.2)	(1,268.3)	(1,021.4)	(855.2)	(721.4)	(665.7)	(929.2)	(1,336.3)	(1,141.1)	(1,030.7)	(858.9)	(964.1)	(12,141.5)
LIND	(156.0)	(145.3)	(115.1)	(128.9)	(90.5)	(77.8)	(25.1)	(90.8)	(121.9)	(40.9)	(29.3)	(39.7)	(1,061.4)
NEPT	(404.2)	(370.6)	(375.6)	(284.6)	(379.5)	(235.7)	(365.0)	(450.8)	(307.0)	(381.7)	(325.4)	(436.6)	(4,316.8)
NYIS	(789.1)	(752.3)	(530.7)	(441.6)	(251.4)	(352.2)	(539.0)	(794.8)	(712.2)	(608.1)	(504.2)	(487.7)	(6,763.4)
OVEC	1,242.2	1,110.7	1,065.8	1,018.9	1,030.7	1,014.6	1,040.8	1,011.9	828.9	666.5	759.6	903.9	11,694.6
TVA	681.6	222.8	170.3	20.0	(98.5)	(36.7)	264.2	41.8	36.4	151.9	360.8	249.3	2,063.8
Total	254.3	(162.0)	(732.1)	(1,092.1)	(522.5)	(504.7)	(512.8)	(1,624.6)	(1,855.3)	(856.9)	(862.8)	(1,290.3)	(9,761.8)

neighboring balancing authorities. (See Table 8-13 for a list of active interfaces in 2011. Figure 8-3 shows the approximate geographic location of the interfaces.) In 2011, PJM had 21 interfaces with neighboring balancing authorities.[27] The Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface. However, all three are interfaces between PJM and the NYISO. Table 8-1 through Table 8-3 show the Real-Time Market interchange totals at the individual interfaces with the NYISO, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Market is shown by interface for 2011 in Table 8-1, while gross imports and exports are shown in Table 8-2 and Table 8-3.

In the Real-Time Energy Market, for the calendar year 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 67.7 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 22.0 percent, PJM/MidAmerican Energy Company (MEC) with 19.5 percent, PJM/Neptune (NEPT) with 14.0 percent and PJM/Cinergy Corporation (CIN) with 12.2 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 39.4 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 74.0 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 55.6 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18.4 percent.[28]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of the shares of ownership belong to load serving entities, or their affiliates, within the PJM footprint. The agreement requires delivery of approximately 70 percent of the generation output into the PJM footprint.[29] OVEC itself does not serve load, and therefore does not generally import energy. The nature of the ownership of OVEC and the location of its affiliates within the PJM footprint account for the large percentage of PJM's net interchange volume.

27 The number of interfaces with PJM was reduced to 20 when FE was removed as an interface coincident with the integration of ATSI into the PJM footpring on June 1, 2011.

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

29 See "Ohio Valley Electric Corporation: Company Background." <http://www.ovec.com/OVECHistory.pdf>. (Accessed March 1, 2012).

Table 8-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	0.2	1.5	0.8	2.8	7.5	13.4	5.2	2.4	1.1	6.2	0.6	1.6	43.2
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	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	190.6	258.6	276.4	2,608.7
EKPC	31.7	46.5	41.0	143.3	85.5	112.3	116.7	110.3	85.9	36.2	32.3	21.6	863.2
LGEE	393.0	386.3	324.1	233.6	250.3	334.9	322.7	268.5	328.3	420.1	373.5	364.6	3,999.8
MEC	53.2	30.8	19.1	0.0	0.0	0.0	0.0	0.0	6.0	5.3	0.5	0.0	115.0
MISO	1,141.4	833.9	736.6	409.5	718.2	542.8	998.2	714.4	599.1	876.8	944.6	1,113.9	9,629.4
ALTE	0.0	0.0	0.0	0.0	0.0	0.2	1.6	0.0	0.0	0.0	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	0.0	0.0	0.0	1.5
AMIL	23.9	68.0	42.2	26.0	55.4	37.8	85.2	75.0	7.3	34.8	28.4	105.5	589.5
CIN	400.0	270.3	315.2	180.8	348.0	260.0	359.4	344.9	261.8	292.7	361.9	467.5	3,862.6
CWLP	0.0	0.0	0.0	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	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	71.5	70.7	94.0	539.5
MECS	250.9	270.3	241.4	141.4	224.3	176.7	460.7	256.8	289.3	477.8	479.6	442.7	3,711.8
NIPS	0.0	0.0	0.2	0.2	0.0	0.0	2.0	0.0	0.0	0.0	2.2	4.2	8.9
WEC	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.8	0.0	7.3
NYISO	681.0	534.7	646.6	686.3	911.1	975.9	1,144.4	961.2	731.3	652.8	637.5	713.9	9,276.6
LIND	0.0	0.0	0.0	0.0	0.0	14.3	51.7	27.9	10.6	19.1	17.6	24.4	165.6
NEPT	0.0	0.0	0.0	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	911.1	961.6	1,092.6	933.3	720.7	633.7	619.9	689.5	9,111.0
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	666.6	782.2	929.2	11,798.5
TVA	725.7	255.5	212.0	128.8	79.7	92.0	360.3	152.7	69.8	159.0	387.0	294.9	2,917.4
Total	4,540.1	3,509.7	3,257.7	2,831.4	3,280.8	3,272.7	4,310.7	3,344.9	2,759.5	3,013.6	3,416.9	3,716.0	41,254.1

Table 8-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	123.0	31.0	44.1	31.9	84.3	92.2	86.1	83.9	52.5	14.4	14.3	35.2	692.9
CPLW	0.0	0.0	0.0	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	244.1	333.0	218.7	2,879.6
EKPC	93.1	56.6	35.4	8.3	44.1	5.9	9.6	9.6	5.5	106.8	4.1	10.5	389.6
LGEE	0.1	0.4	9.5	33.6	8.6	12.8	19.6	21.9	0.6	3.2	5.0	3.0	118.4
MEC	479.2	434.1	481.3	463.2	478.5	456.3	675.5	565.8	622.7	523.0	472.1	479.0	6,130.6
MISO	1,218.8	1,222.8	1,480.9	1,540.7	1,214.1	1,218.8	1,574.2	1,467.1	1,786.4	1,288.3	1,906.1	2,511.1	18,429.2
ALTE	116.1	128.3	76.0	4.5	7.6	105.9	212.2	193.5	378.8	467.0	722.0	1,015.2	3,427.1
ALTW	30.9	14.5	28.6	49.9	68.8	84.1	119.3	83.8	249.3	28.4	53.6	64.9	876.0
AMIL	26.8	22.5	27.9	17.4	17.6	55.4	120.0	176.8	127.5	28.6	38.9	56.3	715.6
CIN	485.5	585.0	769.8	894.7	590.7	683.9	697.5	458.2	638.0	292.0	660.8	878.1	7,634.1
CWLP	0.0	0.0	0.0	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	0.0	0.0	0.0	1,460.8
IPL	3.6	1.3	6.5	8.9	8.3	79.7	149.9	148.4	70.5	22.7	82.8	112.0	694.7
MECS	57.9	79.5	128.8	108.2	64.2	47.8	47.4	38.1	66.0	56.4	45.7	42.5	782.4
NIPS	114.3	51.0	69.9	72.8	53.7	71.9	82.0	62.6	42.8	29.9	71.5	71.5	794.0
WEC	96.8	76.4	92.1	78.6	81.0	89.9	145.9	305.7	213.5	363.3	230.7	270.6	2,044.5
NYISO	2,030.2	1,803.0	1,667.9	1,541.5	1,632.5	1,641.6	2,073.6	2,297.5	1,872.5	1,683.5	1,496.3	1,678.0	21,418.1
LIND	156.0	145.3	115.1	128.9	90.5	92.1	76.8	118.7	132.5	59.9	46.9	64.1	1,226.9
NEPT	404.2	370.6	375.6	284.6	379.5	235.7	365.0	450.8	307.0	381.7	325.4	436.6	4,316.8
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	1,241.8	1,124.0	1,177.2	15,874.4
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	22.8	1.8	5.8	0.0	22.6	25.3	103.9
TVA	44.1	32.7	41.7	108.9	178.2	128.7	96.0	110.9	33.5	7.2	26.2	45.6	853.6
Total	4,285.8	3,671.8	3,989.8	3,923.5	3,803.3	3,777.4	4,823.4	4,969.6	4,614.9	3,870.5	4,279.7	5,006.3	51,015.9

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which imports or exports will flow.[30] An interface pricing point defines the price at which transactions are priced, and is based on the path of the physical transfer of energy. While a market participant designates a market path based from a generation control area (GCA) to load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the LGEE/PJM Interface based on the market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the LGEE/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with a GCA of LGEE, at the SouthIMP interface pricing point.

Interfaces differ from interface pricing points. Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[31] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. According to the PJM Interface Price Definition Methodology, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[32] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[33] Table 8-14 presents the interface pricing points used in 2011.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. Real-Time Energy Market transaction prices are determined based on transaction details as defined below:

- Real-Time Energy Market Imports: For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP). At the time the energy is scheduled, if the GCA on the NERC Tag shows that the physical flow would enter PJM at an interface other than the SouthIMP Interface pricing point, the source would then default to that new interface pricing point. The

30 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load.

31 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 2012). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

32 See "PJM Interface Pricing Definition Methodology." (September 29, 2006) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> . (Accessed March 1, 2012)

33 See the *2007 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	675.9	414.1	468.0	243.5	429.8	335.0	500.6	364.0	230.5	352.1	436.4	413.9	4,863.8
LINDENVFT	(156.0)	(145.3)	(115.1)	(128.9)	(90.5)	(77.8)	(25.1)	(90.8)	(121.9)	(40.9)	(29.3)	(39.7)	(1,061.4)
MICHFE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	(1,491.8)	(1,449.0)	(1,825.9)	(1,916.3)	(1,575.4)	(1,611.9)	(2,154.5)	(1,934.1)	(2,334.5)	(1,740.6)	(2,324.6)	(2,952.2)	(23,310.8)
NEPTUNE	(404.2)	(370.6)	(375.6)	(284.6)	(379.5)	(235.7)	(365.0)	(450.8)	(307.0)	(381.7)	(325.4)	(436.6)	(4,316.8)
NORTHWEST	(5.3)	(6.9)	(8.6)	(7.5)	(1.1)	(1.4)	(2.6)	(0.7)	(19.0)	(4.5)	(5.1)	(3.4)	(66.2)
NYIS	(773.9)	(724.2)	(525.8)	(440.0)	(253.4)	(352.2)	(539.3)	(799.3)	(710.5)	(609.6)	(504.7)	(488.5)	(6,721.2)
OVEC	1,242.2	1,110.7	1,065.8	1,018.9	1,030.7	1,014.6	1,040.8	1,011.9	828.9	666.5	759.6	903.9	11,694.6
SOUTHIMP/EXP	1,167.4	1,009.2	585.1	422.8	316.9	424.7	1,032.5	275.1	578.1	901.7	1,130.3	1,312.2	9,156.0
CPLEEXP	(106.2)	(31.0)	(44.0)	(31.9)	(57.0)	(91.6)	(86.1)	(83.5)	(52.5)	(14.3)	(14.3)	(35.2)	(647.5)
CPLEIMP	0.2	0.9	0.3	1.7	5.0	8.2	3.6	1.2	1.1	6.2	0.6	1.4	30.4
DUKEXP	(189.8)	(60.0)	(153.2)	(133.8)	(151.7)	(132.5)	(245.9)	(348.5)	(181.7)	(218.9)	(315.3)	(208.2)	(2,339.5)
DUKIMP	87.0	146.9	70.1	93.8	89.6	89.2	151.5	82.3	61.6	65.5	71.6	66.8	1,076.1
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	68.6	100.4	46.7	67.0	24.9	18.3	12.3	5.1	21.2	68.2	76.6	82.2	591.6
SOUTHEXP	(245.8)	(119.6)	(128.7)	(203.1)	(257.7)	(209.9)	(144.6)	(191.8)	(78.8)	(134.8)	(53.3)	(69.4)	(1,837.6)
SOUTHIMP	1,574.7	989.0	821.0	650.8	683.5	785.6	1,358.3	852.7	833.5	1,145.0	1,368.5	1,476.9	12,539.5
SOUTHWEST	(21.4)	(17.4)	(27.1)	(21.8)	(19.8)	(42.6)	(16.8)	(42.4)	(26.2)	(15.2)	(4.1)	(2.3)	(257.0)
Total	254.3	(162.0)	(732.1)	(1,092.1)	(522.5)	(504.7)	(512.8)	(1,624.6)	(1,855.3)	(856.9)	(862.8)	(1,290.3)	(9,761.8)

sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- Real-Time Energy Market Exports: For a real-time export energy transaction, when a market participant selects the POR and POD on their OASIS reservation, the sink defaults to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface pricing point (i.e. SouthEXP). At the time the energy is scheduled, if the LCA on the NERC Tag shows that the physical flow would leave PJM at an interface other than the SouthEXP Interface pricing point, the sink would then default to that new interface pricing point. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.
- Real-Time Energy Market Wheels: For a real-time wheel through energy transaction, when a market participant selects the POR and POD on their OASIS reservation, both the source and sink default to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP), and the sink would initially default to NYIS's Interface pricing point (i.e. NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag shows that the physical flow would enter PJM at an interface other than the SouthIMP Interface pricing point, the source would then default to that new interface pricing point. Similarly, if the LCA on the NERC Tag shows that the physical flow would leave PJM at an interface other than the NYIS Interface pricing point, the sink would then default to that new interface pricing point.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[34] Table 8-4 through Table 8-6 show the Real-Time Market interchange totals at the individual interface pricing points, including those pricing points that make up the southern region. Net interchange in the Real-Time Market is shown by interface pricing point for 2011 in Table 8-4, while gross imports and exports are shown in Table 8-5 and Table 8-6.

In the Real-Time Energy Market, in 2011 there were net exports at nine of PJM's 17 interface pricing points

34 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for the grandfathered transactions, and suggests that no further such agreements be entered into.

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	695.7	442.3	472.9	246.6	429.8	336.6	503.4	365.4	233.1	352.5	436.5	413.9	4,928.7
LINDENVFT	0.0	0.0	0.0	0.0	0.0	14.3	51.7	27.9	10.6	19.1	17.6	24.4	165.6
MICHFE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	195.2	184.1	108.8	66.1	107.6	45.9	76.5	69.2	43.8	58.7	44.0	32.4	1,032.3
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.1	0.7	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4
NYIS	676.3	534.7	646.6	686.3	909.1	960.0	1,089.7	927.5	720.1	631.8	619.2	688.8	9,090.1
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	666.6	782.2	929.2	11,798.5
SOUTHIMP/EXP	1,730.6	1,237.2	938.1	813.4	803.1	901.3	1,525.7	941.3	917.3	1,284.8	1,517.3	1,627.3	14,237.5
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.2	0.9	0.3	1.7	5.0	8.2	3.6	1.2	1.1	6.2	0.6	1.4	30.4
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	87.0	146.9	70.1	93.8	89.6	89.2	151.5	82.3	61.6	65.5	71.6	66.8	1,076.1
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	68.6	100.4	46.7	67.0	24.9	18.3	12.3	5.1	21.2	68.2	76.6	82.2	591.6
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,574.7	989.0	821.0	650.8	683.5	785.6	1,358.3	852.7	833.5	1,145.0	1,368.5	1,476.9	12,539.5
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,540.1	3,509.7	3,257.7	2,831.4	3,280.8	3,272.7	4,310.7	3,344.9	2,759.5	3,013.6	3,416.9	3,716.0	41,254.1

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	19.8	28.1	4.9	3.1	0.0	1.6	2.8	1.3	2.6	0.5	0.1	0.0	64.8
LINDENVFT	156.0	145.3	115.1	128.9	90.5	92.1	76.8	118.7	132.5	59.9	46.9	64.1	1,226.9
MICHFE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	1,686.9	1,633.1	1,934.7	1,982.4	1,683.0	1,657.8	2,231.0	2,003.3	2,378.3	1,799.3	2,368.6	2,984.6	24,343.1
NEPTUNE	404.2	370.6	375.6	284.6	379.5	235.7	365.0	450.8	307.0	381.7	325.4	436.6	4,316.8
NORTHWEST	5.5	7.6	8.6	7.6	1.6	1.4	2.6	0.8	19.0	4.5	5.1	3.4	67.5
NYIS	1,450.2	1,258.9	1,172.3	1,126.3	1,162.5	1,312.2	1,629.0	1,726.8	1,430.5	1,241.4	1,123.9	1,177.2	15,811.3
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	22.8	1.8	5.8	0.0	22.6	25.3	103.9
SOUTHIMP/EXP	563.2	228.0	353.0	390.6	486.2	476.7	493.3	666.2	339.2	383.1	387.0	315.1	5,081.5
CPLEEXP	106.2	31.0	44.0	31.9	57.0	91.6	86.1	83.5	52.5	14.3	14.3	35.2	647.5
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	189.8	60.0	153.2	133.8	151.7	132.5	245.9	348.5	181.7	218.9	315.3	208.2	2,339.5
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	245.8	119.6	128.7	203.1	257.7	209.9	144.6	191.8	78.8	134.8	53.3	69.4	1,837.6
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	21.4	17.4	27.1	21.8	19.8	42.6	16.8	42.4	26.2	15.2	4.1	2.3	257.0
Total	4,285.8	3,671.8	3,989.8	3,923.5	3,803.3	3,777.4	4,823.4	4,969.6	4,614.9	3,870.5	4,279.7	5,006.3	51,015.9

eligible for real-time transactions.[35] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 84.7 percent of the total net exports: PJM/MISO with 57.5 percent, PJM/NYIS with 16.6 percent and PJM/NEPTUNE (NEPT) with 10.6 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 29.8 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 78.7 percent of the total net imports: PJM/SouthIMP with 40.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 38.0 percent of the net import volume.[36]

Day-Ahead Interface Imports and Exports

Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule

35 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

36 In the Real-Time Market, two PJM interface pricing points had a net interchange of zero (MICHFE and NCMPAEXP).

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(11.3)	89.8	126.8	234.4	159.9	(83.0)	(322.5)	(673.9)	(617.9)	(213.6)	13.6	6.3	(1,291.4)
CPLW	17.1	6.4	1.8	11.0	5.9	15.4	45.6	42.1	18.3	43.4	51.1	27.2	285.4
DUK	91.8	115.8	41.0	789.1	234.0	(240.7)	(617.8)	(495.5)	39.2	20.4	32.1	(25.5)	(16.2)
EKPC	(27.5)	(18.4)	27.8	6.8	(5.3)	1.0	(9.6)	(2.9)	(0.3)	(3.0)	(0.5)	(0.9)	(32.9)
LGEE	19.0	1.8	2.0	16.6	35.5	1.9	22.5	19.7	(2.1)	(2.0)	(21.7)	(12.3)	80.9
MEC	(458.7)	(421.3)	(463.2)	(455.3)	(472.2)	(437.3)	(542.1)	(493.2)	(512.4)	(525.7)	(512.6)	(502.3)	(5,796.3)
MISO	2,144.6	904.6	(182.2)	697.3	452.5	1,480.9	1,717.3	1,083.9	709.7	310.0	(199.3)	99.5	9,218.7
ALTE	1,996.5	908.2	99.1	833.9	1,037.2	1,333.0	911.8	729.9	583.2	(283.7)	(819.3)	(1,113.2)	6,216.7
ALTW	164.8	(49.7)	(48.1)	(40.1)	(7.3)	139.3	(0.4)	(42.6)	(205.5)	(74.1)	(198.4)	(183.1)	(545.2)
AMIL	34.6	70.2	67.5	31.0	33.6	(4.6)	74.1	(129.5)	(687.4)	(323.0)	41.1	32.0	(760.2)
CIN	(125.8)	(90.5)	(175.1)	(94.3)	(18.0)	(131.4)	(0.4)	100.0	178.4	217.7	114.7	315.4	290.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	(0.0)	(1.4)	(0.1)	0.0	(3.1)
FE	(189.2)	(339.8)	(317.2)	(479.3)	(1,299.6)	(1.5)	0.0	0.0	0.0	0.0	0.0	0.0	(2,626.5)
IPL	(175.6)	(162.6)	(163.9)	(75.1)	(123.5)	(97.9)	(152.7)	(106.0)	(125.5)	(161.9)	(194.6)	(183.9)	(1,723.1)
MECS	742.4	580.2	567.2	591.2	992.6	336.2	931.9	816.5	1,150.4	898.1	732.5	769.7	9,108.9
NIPS	(280.6)	(111.0)	(130.3)	(65.8)	(108.9)	(90.9)	(50.9)	(1.7)	(6.8)	12.5	10.0	(39.8)	(864.1)
WEC	(22.6)	99.6	(81.4)	(4.3)	(53.7)	(1.4)	3.8	(281.1)	(177.1)	25.6	114.7	502.3	124.6
NYISO	(892.0)	(681.9)	(496.7)	(220.9)	611.3	(242.7)	(987.4)	(1,169.2)	(902.6)	(769.2)	(673.8)	(919.7)	(7,344.8)
LIND	(105.0)	(104.7)	(77.9)	(110.8)	(75.0)	(171.2)	(659.8)	(740.4)	(822.6)	(279.9)	(54.5)	(48.9)	(3,250.9)
NEPT	(427.9)	(379.7)	(385.0)	(298.1)	(405.2)	(250.0)	(396.6)	(508.6)	(339.6)	(395.2)	(362.6)	(450.5)	(4,598.9)
NYIS	(359.1)	(197.5)	(33.8)	187.9	1,091.5	178.5	69.0	79.8	259.6	(94.0)	(256.6)	(420.3)	505.0
OVEC	1,046.0	1,051.1	1,279.5	1,502.8	1,636.3	1,167.6	1,025.6	643.8	1,163.3	564.8	(390.9)	1,859.2	12,549.0
TVA	282.8	111.2	106.7	85.8	56.5	55.6	(422.1)	(489.9)	(118.6)	(116.8)	(237.5)	(390.1)	(1,076.4)
Total	2,211.7	1,159.2	443.4	2,667.6	2,714.6	1,718.7	(90.4)	(1,535.1)	(223.5)	(691.7)	(1,939.5)	141.3	6,576.2

could be supported in the Real-Time Energy Market.[37] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.

A fixed Day-Ahead Energy Market transaction request means that the market participant agrees to be a price taker for the MW amount of the offer. There is no price associated with the request and the market participant agrees to take the day-ahead LMP at the associated import or export pricing point. If the market participant has met the required deadline and has acquired a valid willing-to-pay congestion OASIS reservation, a fixed day-ahead transaction request will be accepted in the Day-Ahead Energy Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay. If, in the Day-Ahead Energy Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

Dispatchable transactions in the Day-Ahead Energy Market are similar to those in the Real-Time Energy Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Energy Market represent a financial obligation. If the market

37 Effective September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in this report.

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	137.6	146.3	197.4	305.0	242.6	29.5	40.6	45.3	48.2	33.0	28.5	34.6	1,288.6
CPLW	19.5	6.5	8.1	13.9	24.6	27.2	64.9	69.3	47.9	71.8	87.9	48.2	489.8
DUK	150.8	155.5	88.5	935.0	269.0	50.9	99.2	50.2	55.3	44.9	46.4	48.5	1,994.2
EKPC	5.4	0.0	28.3	6.8	6.3	2.8	0.2	0.3	0.3	1.1	0.5	0.3	52.5
LGEE	21.6	2.1	13.5	17.1	40.8	41.6	71.0	21.6	14.1	15.9	2.7	12.0	274.0
MEC	21.7	19.8	20.1	8.2	15.9	67.5	102.8	107.1	106.2	74.7	60.8	131.9	736.7
MISO	7,394.0	5,782.6	5,316.8	4,391.0	5,686.9	5,791.8	7,048.5	7,143.7	6,968.3	5,502.7	6,247.2	7,793.2	75,066.8
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	2,596.8	2,470.0	2,916.7	39,335.2
ALTW	375.6	52.1	29.0	19.3	74.1	284.8	183.7	129.2	51.9	72.0	41.8	53.3	1,366.7
AMIL	44.8	71.1	70.7	34.2	35.8	45.2	77.2	34.2	50.9	23.1	43.7	32.3	563.3
CIN	266.2	440.5	360.6	511.2	263.4	728.0	760.3	692.0	662.2	583.9	926.4	970.3	7,165.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	232.9	140.5	141.0	55.5	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	586.8
IPL	17.0	2.9	0.0	6.5	2.8	1.7	0.8	1.0	4.8	0.0	1.5	1.5	40.4
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	1,890.5	2,214.2	2,785.6	22,446.9
NIPS	32.0	48.2	27.0	33.9	11.6	29.2	33.2	35.2	26.0	43.0	58.5	17.0	394.8
WEC	143.7	242.8	141.4	172.4	155.0	121.9	151.0	87.5	150.8	293.5	491.2	1,016.5	3,167.7
NYISO	910.1	988.6	1,149.1	1,399.2	2,467.1	1,560.2	1,666.6	1,763.1	1,997.7	1,520.7	1,305.1	1,266.5	17,994.0
LIND	0.0	0.0	0.0	0.0	0.0	8.7	29.1	22.2	0.8	1.6	2.7	3.2	68.3
NEPT	0.0	0.0	0.0	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	1,519.1	1,302.4	1,263.3	17,925.7
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	2,091.7	2,412.5	3,918.9	25,939.4
TVA	412.1	318.7	318.9	341.8	286.8	529.3	748.6	639.7	421.3	470.5	409.8	285.0	5,182.5
Total	10,345.6	8,775.5	9,039.6	9,394.6	11,263.0	9,987.4	11,848.8	12,590.5	11,805.9	9,827.0	10,601.5	13,539.2	129,018.5

participant does not meet the commitment in the Real-Time Energy Market, they are subject to the balancing market settlement.

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants.

- Day-Ahead Energy Market Imports: For day-ahead import energy transactions, the market participant chooses any import pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.
- Day-Ahead Energy Market Exports: For day-ahead export energy transactions, the market participant chooses any export pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.
- Day-Ahead Energy Market Wheels: For day-ahead wheel through energy transactions, the market participant chooses any import pricing point and export pricing point they wish to have associated with their transaction. These selections are made through the EES user interface.

Because market participants choose the interface pricing point(s) they wish to have associated with their transaction in the Day-Ahead Energy Market, the scheduled interface is less meaningful than in the Real-Time Energy Market. In Table 8-7, Table 8-8 and Table 8-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not necessarily match that of the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction. In the interface tables below, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow. Table 8-7 through Table 8-9 show the Day-Ahead interchange

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	148.9	56.5	70.7	70.5	82.7	112.5	363.1	719.2	666.1	246.5	14.9	28.4	2,579.9
CPLW	2.4	0.1	6.2	2.9	18.6	11.8	19.2	27.2	29.6	28.4	36.8	21.1	204.4
DUK	59.1	39.7	47.5	145.9	35.0	291.6	717.0	545.7	16.2	24.5	14.3	74.0	2,010.4
EKPC	32.9	18.4	0.5	0.0	11.6	1.9	9.9	3.2	0.6	4.1	1.1	1.2	85.4
LGEE	2.6	0.3	11.5	0.5	5.2	39.8	48.5	1.9	16.2	17.9	24.5	24.3	193.1
MEC	480.4	441.2	483.3	463.4	488.1	504.8	644.8	600.3	618.6	600.4	573.5	634.2	6,533.0
MISO	5,249.4	4,878.0	5,499.0	3,693.8	5,234.4	4,310.8	5,331.2	6,059.8	6,258.6	5,192.7	6,446.5	7,693.8	65,848.1
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	2,880.5	3,289.3	4,029.9	33,118.5
ALTW	210.8	101.8	77.1	59.4	81.4	145.5	184.1	171.8	257.4	146.0	240.3	236.4	1,911.9
AMIL	10.2	0.9	3.2	3.2	2.2	49.8	3.1	163.7	738.3	346.1	2.6	0.3	1,323.5
CIN	392.0	531.0	535.7	605.5	281.5	859.4	760.6	592.0	483.8	366.2	811.7	654.8	6,874.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	1.4	0.1	0.0	3.1
FE	422.1	480.2	458.2	534.8	1,316.6	1.5	0.0	0.0	0.0	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	161.9	196.0	185.5	1,763.6
MECS	667.0	627.7	870.9	810.8	1,175.4	435.9	1,322.1	1,828.1	1,110.1	992.4	1,481.7	2,015.9	13,338.0
NIPS	312.6	159.2	157.3	99.8	120.4	120.0	84.1	36.9	32.8	30.5	48.5	56.8	1,258.9
WEC	166.3	143.3	222.8	176.6	208.7	123.2	147.1	368.6	327.9	267.8	376.5	514.2	3,043.1
NYISO	1,802.1	1,670.5	1,645.8	1,620.1	1,855.7	1,802.9	2,654.0	2,932.4	2,900.3	2,289.9	1,978.9	2,186.2	25,338.7
LIND	105.0	104.7	77.9	110.8	75.0	179.9	688.9	762.7	823.4	281.5	57.3	52.1	3,319.1
NEPT	427.9	379.7	385.0	298.1	405.2	250.0	396.6	508.6	339.6	395.2	362.6	450.5	4,598.9
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	1,613.1	1,559.0	1,683.6	17,420.7
OVEC	226.8	304.1	619.3	474.0	586.7	719.0	980.8	2,106.3	983.2	1,527.0	2,803.4	2,059.7	13,390.4
TVA	129.3	207.5	212.2	255.9	230.3	473.7	1,170.7	1,129.5	539.9	587.3	647.3	675.1	6,258.9
Total	8,133.9	7,616.3	8,596.2	6,727.0	8,548.4	8,268.7	11,939.2	14,125.6	12,029.3	10,518.7	12,541.1	13,397.9	122,442.3

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	332.0	186.1	101.1	185.4	219.5	457.7	372.8	147.6	97.0	250.2	(83.7)	(256.2)	2,009.5
LINDENVFT	(142.5)	(153.1)	(129.7)	(163.6)	(162.2)	(130.5)	(111.7)	(94.9)	(105.1)	(101.6)	12.4	69.8	(1,212.6)
MICHFE	(63.5)	(343.7)	(215.0)	(149.8)	(144.6)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	(916.5)
MISO	(98.4)	(233.8)	(442.7)	(276.2)	202.2	174.1	176.9	(48.5)	(18.1)	282.3	218.5	586.3	522.5
NEPTUNE	(594.7)	(652.6)	(529.4)	(414.2)	(584.0)	(388.4)	(536.4)	(671.0)	(547.4)	(621.7)	(500.6)	(786.4)	(6,826.8)
NIPSCO	615.2	355.3	(30.6)	(355.3)	(90.3)	37.1	206.7	(59.2)	116.4	271.0	234.1	139.3	1,439.6
NORTHWEST	994.2	875.2	564.8	398.9	115.1	(94.3)	(118.1)	(152.2)	(89.6)	(623.5)	(699.1)	(616.5)	554.9
NYIS	137.2	281.9	263.9	404.8	839.2	580.8	638.4	525.1	563.6	231.2	53.2	(26.5)	4,492.7
OVEC	1,161.4	982.1	557.9	1,518.0	1,658.4	1,266.5	1,321.5	924.2	1,139.9	433.4	(711.3)	1,606.4	11,858.5
SOUTHIMP/EXP	(129.3)	(138.3)	303.3	1,519.5	661.4	(184.2)	(2,040.7)	(2,106.2)	(1,380.2)	(813.1)	(462.9)	(574.8)	(5,345.6)
CPLEEXP	(297.4)	(100.6)	(109.9)	(103.7)	(104.4)	(91.5)	(89.8)	(80.7)	(47.4)	(14.3)	(10.6)	(27.5)	(1,077.9)
CPLEIMP	304.8	269.2	274.7	351.5	935.0	1.9	0.4	1.2	0.0	0.0	0.0	0.0	2,138.7
DUKEXP	(57.9)	(40.1)	(50.8)	(209.0)	(330.5)	(8.4)	(4.5)	(10.4)	0.0	0.0	0.0	0.0	(711.5)
DUKIMP	98.4	107.1	37.9	1,211.0	315.4	4.5	45.9	1.0	8.7	1.2	1.9	5.2	1,838.3
NCMPAEXP	(154.6)	(341.4)	(61.4)	(78.3)	(452.6)	(0.5)	(0.4)	(0.4)	(0.4)	(0.2)	(0.4)	(0.9)	(1,091.5)
NCMPAIMP	38.0	26.8	44.9	111.6	73.1	0.0	0.0	0.0	2.4	0.0	0.0	0.0	296.9
SOUTHEAST	36.7	87.9	133.1	42.8	140.5	(344.8)	(1,179.7)	(1,075.2)	(1,077.0)	(464.2)	153.3	(4.8)	(3,551.2)
SOUTHEXP	(353.1)	(355.7)	(302.8)	(295.7)	(373.7)	(736.4)	(1,557.7)	(1,455.0)	(831.1)	(1,181.4)	(1,302.3)	(1,401.4)	(10,146.2)
SOUTHIMP	616.1	265.9	300.7	270.4	386.5	686.6	804.4	622.3	481.2	410.2	411.7	457.5	5,713.4
SOUTHWEST	(360.6)	(57.4)	36.9	219.0	71.9	304.3	(59.3)	(108.9)	83.4	435.7	283.4	397.0	1,245.5
Total	2,211.7	1,159.2	443.4	2,667.6	2,714.6	1,718.7	(90.4)	(1,535.1)	(223.5)	(691.7)	(1,939.5)	141.3	6,576.2

totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for 2011 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

There were net imports in the Day-Ahead Energy Market at seven of PJM's 21 interfaces. The top three net exporting interfaces accounted for 60.5 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 25.7 percent, PJM/Neptune (NEPT) with 20.4 percent and PJM/Linden (LIND) with 14.4 percent. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 32.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 95.5 percent of the total net imports: PJM/OVEC with 43.0 percent, PJM/Michigan

Table 8-11 Day-Ahead scheduled gross import volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	562.9	437.2	345.3	418.0	537.1	890.1	1,033.3	855.8	680.3	600.7	637.8	677.8	7,676.2
LINDENVFT	0.0	0.0	0.0	0.0	0.0	7.4	100.6	312.8	293.9	211.0	292.9	428.5	1,647.1
MICHFE	662.3	309.2	343.8	301.7	598.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,215.5
MISO	1,603.0	1,208.7	1,202.6	861.6	1,128.4	1,436.4	1,487.4	1,220.0	1,574.5	2,098.1	2,339.1	3,048.1	19,207.8
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPSCO	995.0	908.4	773.5	339.9	634.1	319.7	685.5	536.6	392.0	395.5	542.5	509.7	7,032.5
NORTHWEST	1,625.0	1,407.6	1,185.2	907.6	808.1	710.3	646.0	536.2	515.7	431.7	403.5	666.0	9,842.8
NYIS	1,430.9	1,386.0	1,475.4	1,676.5	2,273.3	2,107.1	2,377.5	2,272.0	2,230.8	1,622.1	1,454.7	1,605.5	21,911.6
OVEC	1,887.3	1,856.3	2,275.7	2,392.4	2,679.9	2,650.2	3,271.4	3,624.0	2,660.4	2,579.1	3,058.1	4,821.6	33,756.3
SOUTHIMP/EXP	1,579.3	1,262.0	1,438.2	2,497.0	2,603.7	1,866.1	2,247.0	3,233.1	3,458.5	1,888.8	1,873.0	1,782.0	25,728.8
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	304.8	269.2	274.7	351.5	935.0	1.9	0.4	1.2	0.0	0.0	0.0	0.0	2,138.7
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	98.4	107.1	37.9	1,211.0	315.4	4.5	45.9	1.0	8.7	1.2	1.9	5.2	1,838.3
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	38.0	26.8	44.9	111.6	73.1	0.0	0.0	0.0	2.4	0.0	0.0	0.0	296.9
SOUTHEAST	173.8	192.3	268.1	107.2	347.0	417.6	603.9	977.4	791.2	510.2	612.9	461.8	5,463.4
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.4
SOUTHIMP	616.1	265.9	300.7	270.4	386.5	686.6	804.4	622.3	481.2	410.2	411.7	457.5	5,713.4
SOUTHWEST	348.0	400.8	511.8	445.4	546.6	755.5	792.5	1,631.2	2,175.0	967.3	846.1	857.5	10,277.6
Total	10,345.6	8,775.5	9,039.6	9,394.6	11,263.0	9,987.4	11,848.8	12,590.5	11,805.9	9,827.0	10,601.5	13,539.2	129,018.5

Table 8-12 Day-Ahead scheduled gross export volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	230.9	251.2	244.1	232.5	317.6	432.4	660.4	708.2	583.3	350.5	721.5	934.0	5,666.7
LINDENVFT	142.5	153.1	129.7	163.6	162.2	137.9	212.3	407.7	399.0	312.6	280.5	358.8	2,859.7
MICHFE	725.7	652.9	558.8	451.4	743.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,132.0
MISO	1,701.4	1,442.5	1,645.4	1,137.8	926.2	1,262.4	1,310.5	1,268.5	1,592.5	1,815.8	2,120.5	2,461.7	18,685.2
NEPTUNE	594.7	652.6	529.4	414.2	584.0	388.4	536.4	671.0	547.4	621.7	500.6	786.4	6,826.8
NIPSCO	379.8	553.1	804.2	695.2	724.3	282.7	478.8	595.8	275.6	124.5	308.4	370.5	5,592.9
NORTHWEST	630.8	532.4	620.4	508.7	693.0	804.7	764.0	688.4	605.2	1,055.2	1,102.6	1,282.5	9,287.9
NYIS	1,293.7	1,104.1	1,211.5	1,271.7	1,434.1	1,526.3	1,739.0	1,746.9	1,667.2	1,390.9	1,401.5	1,632.0	17,419.0
OVEC	725.8	874.2	1,717.8	874.4	1,021.5	1,383.6	1,949.8	2,699.8	1,520.4	2,145.7	3,769.4	3,215.2	21,897.8
SOUTHIMP/EXP	1,708.6	1,400.3	1,134.9	977.5	1,942.3	2,050.3	4,287.8	5,339.3	4,838.7	2,701.9	2,336.0	2,356.8	31,074.4
CPLEEXP	297.4	100.6	109.9	103.7	104.4	91.5	89.8	80.7	47.4	14.3	10.6	27.5	1,077.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	57.9	40.1	50.8	209.0	330.5	8.4	4.5	10.4	0.0	0.0	0.0	0.0	711.5
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	154.6	341.4	61.4	78.3	452.6	0.5	0.4	0.4	0.4	0.2	0.4	0.9	1,091.5
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	137.1	104.4	135.0	64.3	206.5	762.5	1,783.6	2,052.6	1,868.2	974.4	459.6	466.6	9,014.6
SOUTHEXP	353.1	355.7	302.8	295.7	373.7	736.4	1,557.7	1,455.0	831.1	1,181.4	1,302.7	1,401.4	10,146.6
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	708.6	458.1	474.9	226.4	474.6	451.2	851.9	1,740.1	2,091.6	531.5	562.7	460.5	9,032.2
Total	8,133.9	7,616.3	8,596.2	6,727.0	8,548.4	8,268.7	11,939.2	14,125.6	12,029.3	10,518.7	12,541.1	13,397.9	122,442.3

Electric Coordinated System (MECS) with 31.2 percent and PJM/Eastern Alliant Energy Corporation (ALTE) with 21.3 percent.

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-12 show the Day-Ahead Market interchange totals at the individual interface pricing points, including those pricing points that make up the southern region. Net interchange in the Day-Ahead Market is shown by interface pricing point for 2011 in Table 8-10, while gross imports and exports are shown in Table 8-11 and Table 8-12.

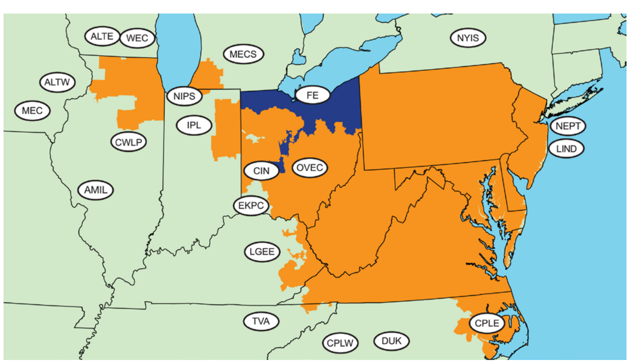
In the Day-Ahead Energy Market, in 2011 there were net exports at eight of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 80.3 percent of the total net exports: PJM/SouthEXP with 39.7 percent, PJM/

Table 8-13 Active interfaces: Calendar year 2011

	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

NEPTUNE (NEPT) with 26.7 percent, and PJM/Southeast with 13.9 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 13.9 percent of the total net PJM exports in the Real-Time Energy Market (PJM/NEPTUNE with 26.7 percent and PJM/LINDEN with 4.7 percent. The PJM/NYIS interface pricing point had net imports in the Day-Ahead Energy Market). Eleven PJM interface pricing points had net imports, with three importing interface pricing points accounting for 68.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.9 percent, PJM/SouthIMP with 17.8 percent and PJM/NYIS with 14.0 percent of the net import volume.

Figure 8-3 PJM's footprint and its external interfaces



Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations.

There are three types of economic curtailments: curtailments of dispatchable schedules, OASIS designation curtailments (willing to pay congestion or not willing to pay congestion), and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as "real-time with price") is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface where the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP at which they are willing to sell energy into PJM). An export dispatchable schedule specifies the maximum LMP at the interface where the market participant wishes to purchase energy from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or

Table 8-14 Active pricing points: 2011

	PJM 2011 Pricing Points											
	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

ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If the system operator does not feel that the transaction will be economic, they will elect to not load the transaction, or to curtail the dispatchable transaction at the top of the next hour if it has already been loaded. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. For importing dispatchable transactions, if the resulting hourly integrated prices are such that the transaction should not have been loaded, the transaction will be made whole through operating reserve credits.

Not willing to pay congestion transactions should be curtailed if there is realized congestion between the designated source and sink.

Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Interactions with Bordering Areas

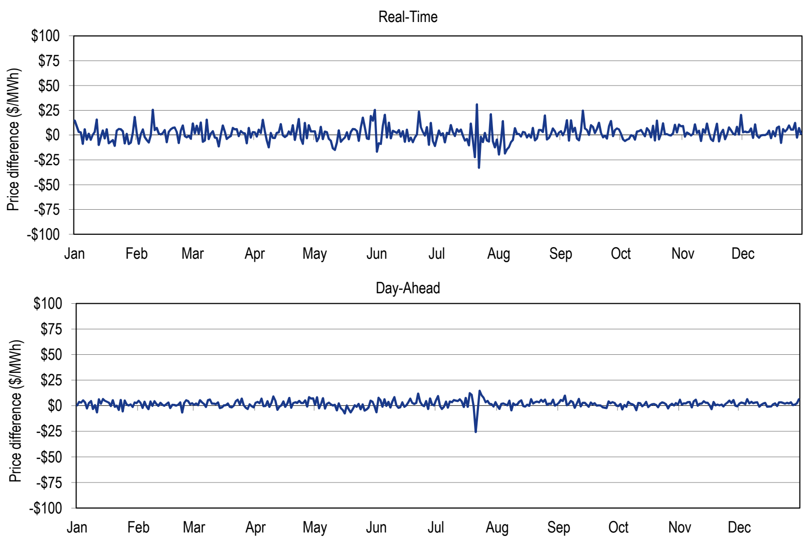
PJM Interface Pricing with Organized Markets

In 2011, the direction of power flows at the borders between PJM and MISO and between PJM and the NYISO was not consistent with real-time energy market price differences for a significant number of hours, 55 percent between PJM and MISO and 48 percent between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface 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. PJM is engaged in preliminary discussions with both MISO and NYISO on interface pricing.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): Calendar year 2011



entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[38] within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[39]

Real-Time Prices

In 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $32.32 while the MISO LMP at the border was $34.01, a difference of $1.69. While the average hourly LMP difference at the PJM/MISO border was only $1.69, the average of the absolute values of the hourly differences was $11.48. The average hourly flow during the calendar year 2011 was -1,570 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 45 percent of hours in 2011. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $15.02. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $8.74. In 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 $14.27. 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 $21.16. 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 $19.89. 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 $7.40. In 2011, for the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $62.8 million at the PJM/MISO Interface.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-4). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

In 2011, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about eight times per day. The standard deviation of the hourly price was $20.94 for the PJM/MISO Interface price and $24.33 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $23.40. The average of the absolute value of the hourly price difference was $11.53. Absolute values

38 See "LMP Aggregate Definitions" (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 2012). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

39 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010).

reflect price differences regardless of whether they are positive or negative.

The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, although with a lag that permits substantial price differences in both directions.

Day-Ahead Prices

The 2011 day-ahead hourly average interface prices for PJM/MISO and MISO/PJM were $33.00 and $34.80. The simple average difference between the day-ahead MISO/PJM Interface price and the PJM/MISO Interface was $1.80 in 2011. In the Day-Ahead Energy Market, gross exports to MISO were 65,848.1 GWh in 2011.

In 2011, the difference between the day-ahead PJM/MISO Interface price and the day-ahead MISO/PJM Interface price fluctuated between positive and negative about four times per day. The standard deviation of the hourly price was $14.52 for the PJM/MISO price and $13.10 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $6.74. The average of the absolute value of the hourly price difference was $4.26.

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the NYISO, all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The NYISO's Real-Time Commitment (RTC) tool evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected interchange for the next hour.

PJM's price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses.[40] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO/PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

Real-Time Prices

In 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

40 See "LMP Aggregate Definitions" (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 2012). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

the NYISO. In 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. In 2011, the PJM average hourly LMP at the PJM/NYISO border was $43.88 while the NYISO LMP at the border was $42.33, a difference of $1.55. While the average hourly LMP difference at the PJM/NYISO border was only $1.55, the average of the absolute value of the hourly difference was $13.31. The average hourly flow during the calendar year 2011 was -626 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 52 percent of the hours in 2011. In 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $12.01. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $14.56. In 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 $10.61. 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 $27.71. 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 $28.26. 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 $12.28. In 2011, for the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $37.7 million at the PJM/NYIS Interface.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the real-time PJM/NYIS Interface price and the real-time NYISO/PJM proxy bus price fluctuated between positive and negative about seven times per day in 2011. The standard deviation of hourly price was $31.77 in 2011 for the PJM/NYIS Interface price and $31.69 in 2011 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $31.53 in 2011. The average of the absolute value of the hourly price difference was $13.30 in 2011. Absolute values reflect price differences without regard to whether they are positive or negative.

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2011

Day-Ahead Prices

The 2011 day-ahead hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $44.87 and $44.57. The simple average difference between the day-ahead PJM/NYISO Interface price and the NYISO/PJM proxy bus price was $0.30 in 2011. In the Day-Ahead Energy Market, the gross exports to the NYISO were 17,420.7 GWh in 2011.

The difference between the day-ahead PJM/NYIS Interface price and the day-ahead NYISO/PJM proxy bus price fluctuated between positive and negative about four times per day in 2011. The

Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: Calendar year 2011

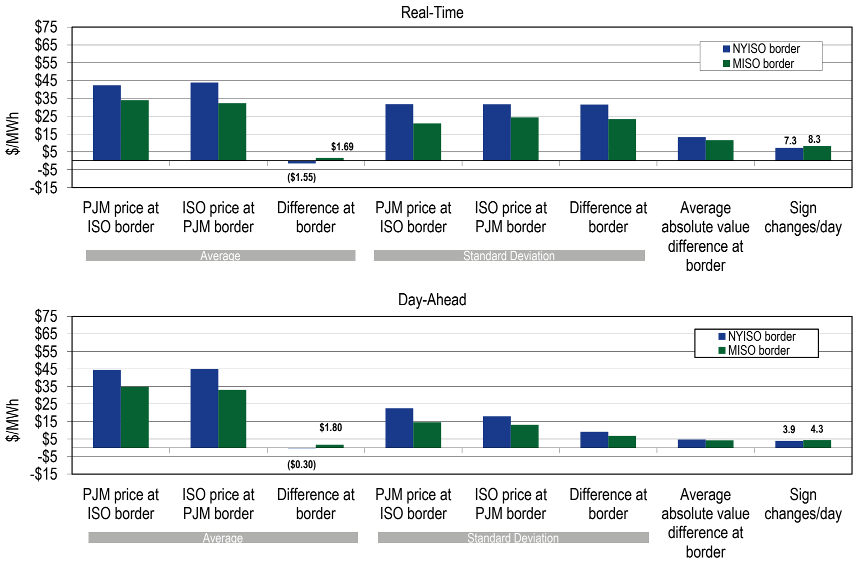
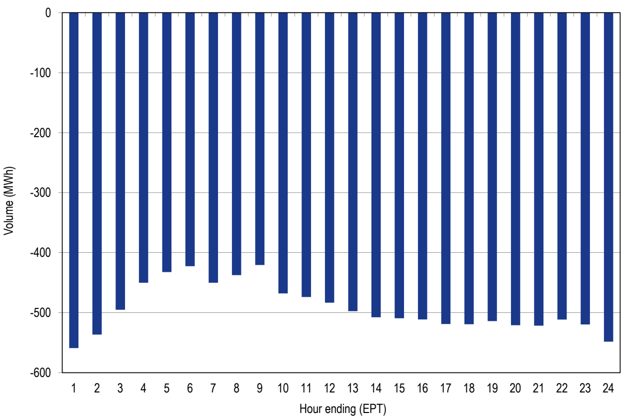


Figure 8-7 Neptune hourly average flow: Calendar year 2011



standard deviation of hourly price was $22.54 in 2011 for the PJM/NYIS Interface price and $17.96 in 2011 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $9.14 in 2011. The average of the absolute value of the hourly price difference was $4.75 in 2011. Absolute values reflect price differences without regard to whether they are positive or negative.

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Figure 8-6, including average prices and measures of variability.

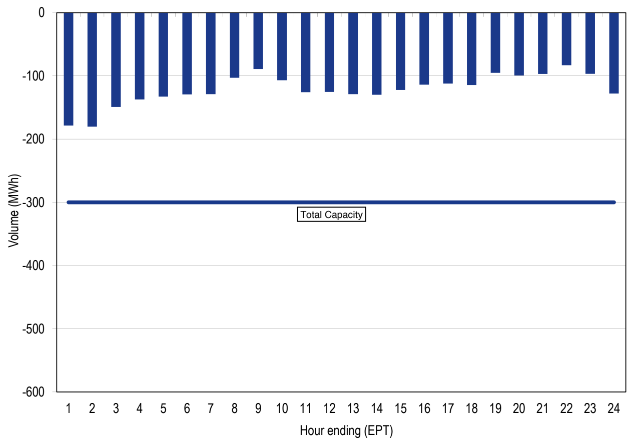
Neptune Underwater Transmission Line to Long Island, New York

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. In 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Neptune Interface was $48.20 while the NYISO LMP at the Neptune Bus was $54.11, a difference of $5.91. While the average hourly LMP difference at the PJM/Neptune border was $5.91, the average of the absolute value of the hourly difference was $20.38. The average hourly flow during the calendar year 2011 was -493 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 in 2011. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average pirce difference was $19.55. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $20.50. In 2011, for the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $32.8 million at the PJM/NEPT Interface.

Linden Variable Frequency Transformer (VFT) facility

On November 1, 2009, the Linden VFT facility was placed in service, providing an additional connection between PJM and the NYISO. The Linden VFT facility is

Figure 8-8 Linden hourly average flow: Calendar year 2011



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.[41] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. In 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Linden Interface was $47.19 while the NYISO LMP at the Linden Bus was $48.70, a difference of $1.51. While the average hourly LMP difference at the PJM/Linden border was $1.51, the average of the absolute value of the hourly difference was $16.24. The average hourly flow during the calendar year 2011 was -121 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 61 percent of the hours in 2011. Following June 1, 2011, when bidirectional flows were permitted across the Linden VFT Facility, a total of 1,064 hours, out of the 5,136 hours, were imports into PJM. Of those 1,064 hours, 580 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 (580 hours), the average price difference was $24.33. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when power flows were from NYISO to PJM (484 hours), the average price difference was $17.14. In 2011, for the hours where flows did not align with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $7.4 million at the PJM/LIND Interface.

Hudson Direct Current (DC) Merchant Transmission 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 Hudson DC line is expected to be in service in late 2012.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO, an implemented operating agreement with MISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

41 See PJM Interconnection, L.L.C,Docket No. ER11-3250-000 (March 31, 2011).

PJM and MISO Joint Operating Agreement

The market to market coordination between PJM and MISO continued in 2011. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.

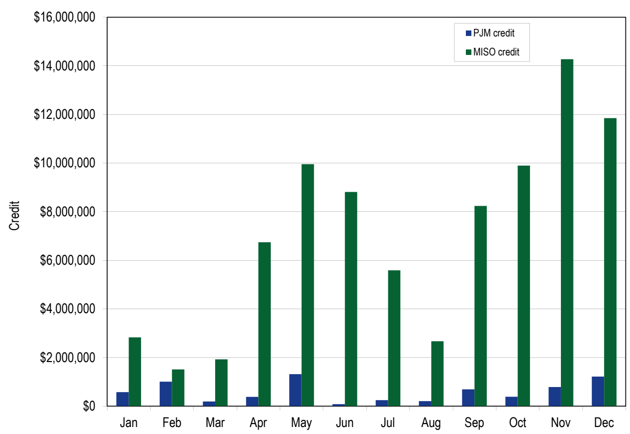
Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater then 5 percent impact based on transmission distribution factors and generation to load distribution factors). A Reciprocal Coordinated Flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCF's are subject to the market to market congestion management process.

CFs and RCFs can be added at any time throughout the year. As of December 31, 2008, there were 247 CFs and 256 RCFs. As of December 31, 2011, there were 335 CFs and 418 RCFs.

In 2011, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

Figure 8-9 presents the monthly credits each organization received from redispatching for the other. A PJM credit is a payment by MISO to PJM and a MISO credit is a payment by PJM to MISO. The largest payments from PJM to MISO in 2011 were the result of redispatch by MISO to relieve congestion on the Oak Grove – Galesburg for the loss of Nelson – Electric Junction line. Total PJM payments to MISO in 2011 were approximately $84.3 million, a 52 percent increase from the 2010 level. The largest payments from MISO to PJM in 2011 were the result of redispatch by PJM to relieve congestion on the Nelson – Electric Junction for the loss of Cherry Valley – Silver Lake line. Total MISO payments to PJM were approximately $7.1 million, a 64 percent decrease from the 2010 level.

Figure 8-9 Credits for coordinated congestion management: Calendar year 2011



In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report is expected to be completed and distributed early in the first quarter of 2012.

Generation in one RTO may affect congestion in the other RTO. To ensure that the most economic mix of generation is being utilized to control constraints, it is important to ensure that generators within each RTO are following the dispatch signal. If a generator remains on when the economic signal suggests it should be reduced, or come offline, the output from that generator could contribute to congestion, and may create the need to enter into market to market activity. When this is the case, the generator that is operating uneconomically may create congestion credits to be paid from one RTO to the other. The MMU suggests that the RTOs evaluate whether this is occurring and the appropriate impact on the congestion payments under the JOA.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)

On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes 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 did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued in 2011.[42] On December 30, 2010, the Commission issued an Order on Rehearing and Compliance which directed the NYISO to make interface pricing revisions by the second quarter of 2011 required that congestion management/market-to-market coordination for the Commission-jurisdictional RTO/ISOs be completed concurrently by the second quarter of 2011.[43]

In 2008, loop flows were created when NYISO pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows.[44] PJM's interface pricing calculations correctly reflected the actual power flows, but the NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

On December 22, 2011, the NYISO filed a compliance notice to confirm a timely development of new interface pricing software.[45] The MMU responded to the NYISO's filing on January 12, 2012.[46] In its response, the MMU contended that the interface pricing methodology proposed by the NYISO does not comply with the FERC's December 30, 2010 Order.[47]

On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that include a market to market process.[48] The filing included provisions for the congestion management protocol between PJM and the NYISO. Some key aspects of the process, such as the determination of the Firm Flow Entitlements and the incorporation of existing agreements on PAR operations within the market to market construct are still under discussion, and are expected to be completed by the end of the second quarter of 2012.

PJM, MISO and TVA Joint Reliability Coordination Agreement (JRCA)

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a

42 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.

43 See 133 FERC ¶ 61,276 (2010).

44 See the *2008 State of the Market Report* for PJM, Volume II, "Interchange Transactions."

45 See "New York Independent System Operator, Inc.'s Compliance Notice." Docket No. ER08-1281-007 (December 22, 2011).

46 See "Protest of the Independent Market Monitor for PJM." Docket No. ER08-1281-005, -006, -007 and 010 (January 12, 2012).

47 The NYISO interface pricing methodology utilizes two scheduling modes. The "Conforming" scheduling mode assumes that scheduled and actual flows are aligned, and allows the NYISO to continue to price interchange based on scheduled rather than actual flows. The "Non-Conforming" mode assumes that scheduled and actual flows are not aligned, and the NYISO will price interchange schedules based on actual flows associated with a proxy bus The determination of scheduling modes is made quarterly. The MMU does not agree with this methodology, because it would permit pricing based on scheduled rather than actual flows and because it does not address interface pricing for GCAs which are not contiguous balancing authorities. The proposed solution would not address the Lake Erie loop flow issue.

48 See "Jointly Submitted Market-to Market Coordination Compliance Filing." Docket No. ER12-718-000 (December 30,2011).

yearly basis, and, in 2011, there were no developments. The agreement continued to be in effect in 2011.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

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. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[49] The MMU responded to the filing on February 23, 2010.[50] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors, and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[51] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[52] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[53] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[54] The MMU moved for a technical conference to explore these issues.[55] On January 20, 2011, the Commission conditionally accepted the compliance filing made by PJM and Carolina Power, stating that the proposed CMP was a just and reasonable solution to managing congestion between Regional Transmission Organizations (RTOs) and other systems. The acceptance of the JOA revisions is subject to the condition that PJM file a revised provision to its tariff that details how similarly situated parties can elect to use such a scheduled arrangement, including the after-the-fact transmission reservations provisions.[56] The agreement remained in effect in 2011. On May 25, 2011, PJM and Progress submitted a joint filing, requesting an additional six months to develop a mutually agreeable methodology to account for the compensation non-firm power flows have on each others transmission system.[57]

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The parties meet on a yearly basis, and, in 2011, there were no developments. The agreement remained in effect in 2011.

Other Agreements/Protocols with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using

49 See PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).

50 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010)

51 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.

52 See Docket No. ER10-713-000. Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas.

53 See "Compliance Filing," Docket No. ER10-713-002.

54 See "Comments and Motion for Technical Conference of the Independent Market Monitor for PJM," Docket No. ER10-713-002.

55 Id.

56 132 FERC ¶ 61,048 (2011).

57 Docket No. ER11-3637-000 (May 25, 2011)

Table 8-15 Con Edison and PSE&G wheeling settlement data: Calendar year 2011

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($2,173,141)	($2,471)	($2,175,611)	($12,580,355)	$0	($12,580,355)
Congestion Credit			$146,137			($12,803,800)
Adjustments			$15,611			$1,002,325
Net Charge			($2,337,360)			($778,879)

lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM.[58] This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[59] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[60] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[61] PJM continued to operate under the terms of the protocol through 2011.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City. Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less 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. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2011, PSE&G's revenues were more than its congestion charges by $778,879 after adjustments (revenues were less than its congestion charges by $1,028,909 in 2010.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2011, Con Edison's congestion credits were $2,319,278 more than its day-ahead congestion charges (Credits had been $3,066,001 less than charges in 2010 (Table 8-15)).

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion

58 See "Section 3 – Operating Reserve" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.
59 111 FERC ¶ 61,228 (2005).
60 "Protest of the Consolidated Edison Company of New York, Inc.", Protest, Docket No. EL02-23-000 (January 30, 2006).
61 120 FERC ¶ 61,161 (2007)

credits, which were -$2,715,707 in 2011. The parties should address this issue.

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 1.2 percent of the hours in 2011.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[62] By order issued September 16, 2010, the Commission approved this settlement,[63] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[64]

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 flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference.

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. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

If PJM net actual interface flows were close to net scheduled interface flows, on average for 2011, it would not necessarily mean that there was no loop flow. Loop flows are measured at individual interfaces.There can be no difference between scheduled and actual flows for PJM and still be significant differences between scheduled and actual flows for specific individual interfaces. From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

In 2011, for PJM as a whole, net scheduled and actual interchange differed by 7.1 percent, an increase from

62 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

63 132 FERC ¶ 61,221 (2010).

64 See, e.g., Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010). The MMU questioned whether allowing rollover is appropriate and raised concerns that continuing these agreements could interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. The MMU questioned whether a valid offsetting reliability consideration had been identified and explained. The MMU noted, "the settling parties fail to demonstrate any circumstances that may now exist warranting a non-conforming agreement under the current approach to seams management, nor do they attempt to explain how such circumstances would continue to exist under the reforms to be implemented through the Broader Regional Markets Initiative." Additionally, that MMU argued, "the settling parties have failed to show that continuation of the grandfathered transmission service agreements will neither interfere with the efficient calculation of LMPs in both PJM and the NYISO, and at their interface, nor harm the ability of parties to efficiently transact business."

5.2 percent for the calendar year 2010.[65] In 2011, net scheduled interchange was -7,072 GWh and net actual interchange was -7,576 GWh, a difference of 504 GWh. While actual interchange exceeded scheduled interchange in 2011, the opposite was true in 2010. This difference is system inadvertent. The total inadvertent over the two year period including 2010 and 2011 was 1.1 percent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[66]

Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 13,983 GWh exceeding scheduled imports of 2,929 GWh by 16,913 GWh or 577.4 percent, an average of 1,930 MW during each hour of the year. At the PJM/AMIL Interface, scheduled flows were imports of 10,215 GWh and actual flows were exports of 218 GWh, creating an imbalance of 10,433 GWh or 4,785.8 percent, an average of 1,191 MW during each hour of the year.

Every balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface price.[67] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

Defined in this way, Table 8-17 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points. Following the consolidation of the Southeast and Southwest pricing points, a market participant requested grandfathered treatment to allow them to continue to receive the Southwest Interface Pricing Point. This pricing point is also a subset of the larger SouthIMP and SouthEXP Interface Pricing Points, and does not have physical ties that differ from the SouthIMP and SouthEXP Interafce Pricing Points.

Table 8-16 Net scheduled and actual PJM flows by interface (GWh): Calendar year 2011

Interface	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	6,960	(1,188)	8,147	(686.0%)
CPLW	(1,842)	2	(1,845)	(77,181.6%)
DUK	(2,371)	(271)	(2,100)	775.2%
EKPC	2,820	516	2,304	446.3%
LGEE	1,283	3,881	(2,598)	(66.9%)
MEC	(2,278)	(6,008)	3,730	(62.1%)
MISO	(13,752)	(4,627)	(9,125)	197.2%
ALTE	(6,038)	(3,425)	(2,612)	76.3%
ALTW	(2,471)	(875)	(1,596)	182.5%
AMIL	10,215	(218)	10,433	(4,786.5%)
CIN	(518)	1,074	(1,592)	(148.3%)
CWLP	(295)	-	(295)	0.0%
FE	(3,464)	(1,005)	(2,459)	244.6%
IPL	1,394	(284)	1,678	(590.1%)
MECS	(13,983)	2,929	(16,913)	(577.4%)
NIPS	(4,049)	(785)	(3,264)	415.8%
WEC	5,459	(2,037)	7,496	(367.9%)
NYISO	(11,150)	(12,321)	1,171	(9.5%)
LIND	(1,061)	(1,061)	-	0.0%
NEPT	(4,317)	(4,317)	-	0.0%
NYIS	(5,772)	(6,943)	1,171	(16.9%)
OVEC	7,667	11,695	(4,028)	(34.4%)
TVA	5,088	1,248	3,841	307.9%
Total	(7,576)	(7,072)	(504)	7.1%

The table is somewhat difficult to interpret, but provides some insight into the accuracy of the interface pricing points if the limitations are recognized.

Because the SouthIMP and SouthEXP Interface Pricing Points are virtually the same point, if there are actual net exports from the PJM footprint to the southern region, by default, there will not be actual flows on the SouthIMP Interface Pricing Point. Conversely, if there are actual net imports into the PJM footprint from the southern region, there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points that make up the southern region, comparing the net scheduled and net actual flows from the aggregate pricing points provides some insight on how effective the interface pricing point mappings are.

65 The "Net Scheduled" values shown in Table 8-16 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Figure 8-1 and Figure 8-2 and Table 8-1 through Table 8-12.

66 See PJM. "M-12: Balancing Operations", Revision 23 (November 16, 2011).

67 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of GCA and LCA after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model" <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008)

Table 8-17 Net scheduled and actual PJM flows by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
IMO	0	4,864	(4,864)	(100.0%)
LINDENVFT	(1,061)	(1,061)	0	0.0%
MISO	(10,932)	(19,095)	8,164	(42.8%)
NEPTUNE	(4,317)	(4,317)	0	0.0%
NORTHWEST	(2,278)	(58)	(2,220)	3,798.2%
NYIS	(5,772)	(6,900)	1,129	(16.4%)
OVEC	7,667	11,695	(4,028)	(34.4%)
SOUTHIMP/EXP	9,117	7,802	1,315	16.9%
CPLEEXP	0	(648)	648	(100.0%)
CPLEIMP	0	30	(30)	(100.0%)
DUKEXP	0	(2,339)	2,339	(100.0%)
DUKIMP	0	1,076	(1,076)	(100.0%)
NCMPAEXP	0	0	0	0.0%
NCMPAIMP	0	592	(592)	(100.0%)
SOUTHEXP	0	(1,838)	1,838	(100.0%)
SOUTHIMP	9,117	11,185	(2,068)	(18.5%)
SOUTHWEST	0	(257)	257	(100.0%)
Total	(7,576)	(7,072)	(504)	7.1%

The IMO Interface Pricing Point was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so a one-to-one mapping could not be created. PJM created the IMO Interface Pricing Point that reflects the power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO Interface Pricing Point does not have physical ties with PJM. As a result, actual flows associated with the IMO Interface Pricing Point are zero. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Some variability can be expected between the scheduled and actual flows at interface pricing points. This is due to the fact that the topology of the transmission system is constantly changing with transmission and generation outages. Large deviations between scheduled and actual flows on an interface pricing point, with the exception of the IMO pricing point, may reflect the fact that some generating and load balancing authorities are mapped to an interface that does not correspond to the actual flows, and therefore, are priced incorrectly. The MMU recommends that PJM perform a regular assessment of the mappings associated with the interface pricing points and the weights applied to the components of the interfaces, and modify as necessary to reflect current system topology in order to ensure that transactions are priced based on the actual flows that they create on the transmission system.

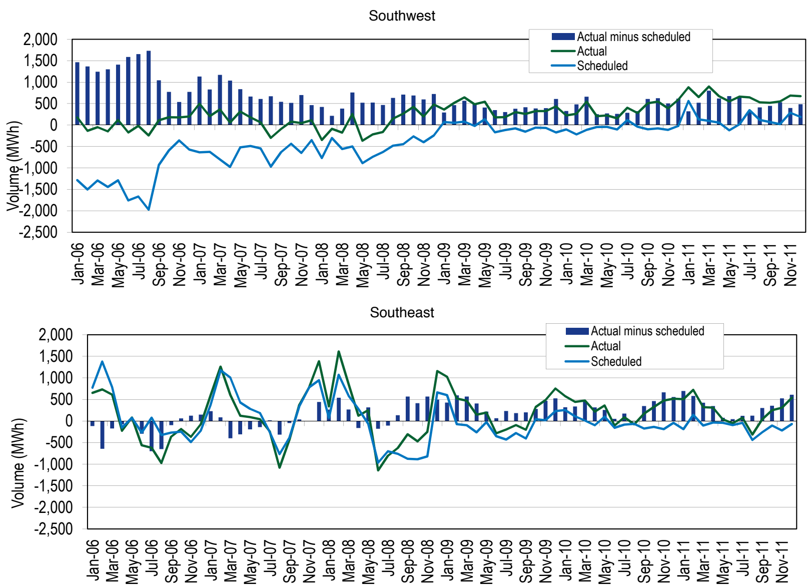
Loop Flows at the PJM/MECS and PJM/TVA Interfaces

As it had in 2010, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-16,913 GWh in 2011 and -15,106 GWh in 2010), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (3,840 GWh in 2011 and 4,015 GWh in 2010). The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

Loop Flows at PJM's Southern Interfaces

Figure 8-10 illustrates the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, a market participant requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the real-time LMP at the Southeast pricing points and the SouthEXP pricing point was $2.14 in 2011 and the average difference between the real-time LMP at the Southwest pricing points and the SouthEXP pricing point was -$1.94 in 2011. In other words, it was more expensive to buy from PJM for export to the south under the old pricing for Southeast pricing point and less expensive to buy from PJM for export to the south under the old pricing for the Southwest pricing point.) The MMU recommended that these grandfathered agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing.

Figure 8-10 Southwest and southeast actual and scheduled flows: January 2006 through December 2011



transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both MISO's border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities. These agreements expired on January 31, 2012 and have not been renewed. The MMU recommends that PJM not enter into any such special pricing agreements.

Despite some improvements, significant loop flows persist. While the SouthIMP and SouthEXP pricing points have replaced the Southeast and Southwest pricing points Figure 8-10 is included for comparison.

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 prices with physical flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Actual power flows are the metered flows at an interface for a defined period. Scheduled power flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for a balancing authority (net actual interchange) and the total scheduled flows for the balancing authority (net scheduled interchange) for a defined period. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference. As an illustration, although PJM's total scheduled and actual flows differed by only 7.1 percent in 2011, much greater differences existed at individual interfaces.

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 can arise from transactions scheduled into, out of or around a balancing authority 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 result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

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 electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (non market areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. NERC Tag data, dynamic schedule and pseudo-tie data and actual tie line data are required in order to analyze the differences between actual and scheduled transactions. The ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions. All data should be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.[68]

The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. The MMU has been attempting to obtain access to this data for several years without success. Attempts to obtain the data from NERC or tagging vendors have led to denials or to the option of very expensive subscriptions that would still require obtaining approval from every entity registered in the NERC Transmission System Information Network (TSIN) due to data confidentiality agreements, including Transmission Providers and Market Participants.

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.[69] 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.[70] As of December 31, 2011, the Commission had not made a final rulemaking decision on this proposal.

TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM called fewer TLRs in 2011 than in 2010. The fact that PJM has issued only 62 TLRs in 2011, compared to 110 in 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM TLRs decreased by 44 percent, from 110 during 2010 to 62 in 2011 (Table 8-19). In addition, the number of different flowgates for

68 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for a more complete description of the data needed.

69 See 135 FERC ¶ 61,052 (2011).

70 See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)

which PJM declared TLRs decreased from 28 in 2010 to 18 in 2011. The total MWh of transaction curtailments decreased by 46 percent, from 315,435 MWh in 2010 to 171,221 MWh in 2011. Of the 62 TLRs called by PJM in 2011, two facilities comprised 43 percent of the total. The two facilities were:

- **2419 Danville – E Danville 138 kV line for the loss of Jacksons Ferry – Antioch 500 kV line.** This line is located in southern Virginia. In 2011, TLRs on this flowgate were used to control constraints created by forced outages of nearby facilities due to storm damage (18 TLRs in 2011; 22 TLRs in 2010);

Table 8-18 Number of TLRs by TLR level by reliability coordinator: Calendar Year 2011

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	23	12	123	54	48	0	260
	MISO	92	30	1	9	9	0	141
	NYIS	161	0	0	0	0	0	161
	ONT	88	0	0	0	0	0	88
	PJM	34	28	0	0	0	0	62
	SWPP	292	298	1	25	22	0	638
	TVA	75	99	9	2	15	0	200
	VACS	9	3	0	0	0	0	12
Total		774	470	134	90	94	0	1,562

Table 8-19 PJM and MISO TLR procedures: Calendar years 2010 and 2011[71]

	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	4	4	4	3,624	11,323
Sep-11	7	17	6	7	6,462	25,914
Oct-11	4	16	2	6	16,812	27,392
Nov-11	0	10	0	5	0	22,672
Dec-11	0	5	0	3	0	8,659

- **310 Person – Halifax 230 kV for the loss of Wake – Carson 500 kV.** This line is also located in southern Virginia. In 2011, TLRs were used on this flowgate to control constraints created by changes in load and generation patterns due to extreme weather (9 TLRs in 2011; 12 TLRs in 2010).

MISO called significantly fewer TLRs in 2011 than in 2010. MISO TLRs decreased by 43 percent, from 249 in 2010 to 141 in 2011 (Table 8-19).

Table 8-18 shows the number of TLRs by TLR level for each reliability coordinator in the Eastern Interconnection. The TLR levels are defined in Appendix E "Interchange Transactions" of this document. In 2011, PJM issued 62 transmission loading relief procedures (TLRs). Of the 62 TLRs issued, the highest levels reached were TLR 3a in 34 instances and TLR 3b in the remaining 28 events (2010 totals were 65 TLR 3a, 45 TLR 3b, 0 TLR 4 and 0 TLR 5b).

Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.

An up-to congestion transaction is analogous to a matched set of incremental offers (INC) and decrement bids (DEC) that are evaluated together and approved or denied as a single transaction, subject to a limit on the cleared price difference. For import up-to congestion transactions, the import pricing point specified looks like a DEC bid and the sink specified on the OASIS reservation looks like an INC offer. For export transactions, the specified source on the OASIS reservation looks like a DEC bid, and the export pricing point looks

71 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>.

like an INC offer. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like a DEC bid, and the export pricing point specified looks like an INC offer. In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. Conversely, an up-to congestion export transaction is submitted and modeled as a withdrawal at the interface, and an injection at a specific PJM node. Wheel through up-to congestion transactions are modeled as an injection at the importing interface and a withdrawal at the exporting interface.

While an up-to congestion bid is analogous to a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Energy Market if the maximum congestion bid criteria is met, is not subject to day-ahead or balancing operating reserve charges and does not have clear rules governing credit requirements. Additionally, effective September 17, 2010, up-to congestion transactions are no longer required to pay for transmission, which, prior to that time, was the only cost of submitting an up-to congestion transaction not incurred by a matched pair of INC offers and DEC bids.

Prior to the May 15, 2010, modification to the marginal loss surplus allocation, the average daily volume of up-to congestion transactions was 4,269 bids per day (March 1, 2009 through May 14, 2010).[72] The average daily volume of up-to congestion transactions increased to 6,881 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 26,303 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 December 31, 2011). (See Figure 8-11and Table 8-20.)

The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market. Up-to congestion transactions impact the day-ahead dispatch. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions.

The MMU recommends that the up-to congestion transaction product be eliminated. This product could work as a derivative product traded outside PJM markets and without any of these impact on the actual operation of PJM markets. Alternatively, the MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges and to make appropriate provisions for credit. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

The MMU also recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding for all import and export transactions in the Day-Ahead Energy Market. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

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

72 In prior state of the market reports for PJM, the number of bids reported represented unique up-to congestion bids. The new totals represent the total hours of up-to congestion bids per day. For example, if a unique up-to congestion transaction spanned all 24 hours of the day, it would have counted as one bid in previous reports, and now is counted as 24 bids.

wheeling transactions at the same interface are not permitted in the Real-Time Energy Market.

The up-to congestion transactions in 2011 were comprised of 54.1 percent imports, 44.2 percent exports and 1.7 percent wheeling transactions. Only 0.2 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions. Of the up-to congestion transactions with matching Real-Time Energy Market transactions, 0.5 percent were imports, 93.7 percent were exports and 5.9 percent were wheel through transactions.

When the up-to congestion product was used as intended, with matching Real-Time Energy Market transactions, 19.8 percent of such cleared transaction MW were profitable in 2011. The net loss on all these transactions was approximately $4.0 million. When up-to congestion transactions did not have a matching Real-Time Energy Market transaction, 48.0 percent of such cleared transaction MW were profitable. The net profit on all these transactions was approximately $110.3 million.

Figure 8-12 shows the monthly positive, negative and net gains for matching and non-matching up-to congestion transactions. Figure 8-12 shows the physical transactions on a different scale than the financial transactions. There is such a small number of physical transactions that the results would not be visible on the scale of the financial chart.

Figure 8-11 Monthly up-to congestion cleared bids in MWh: January 2006 through December 2011

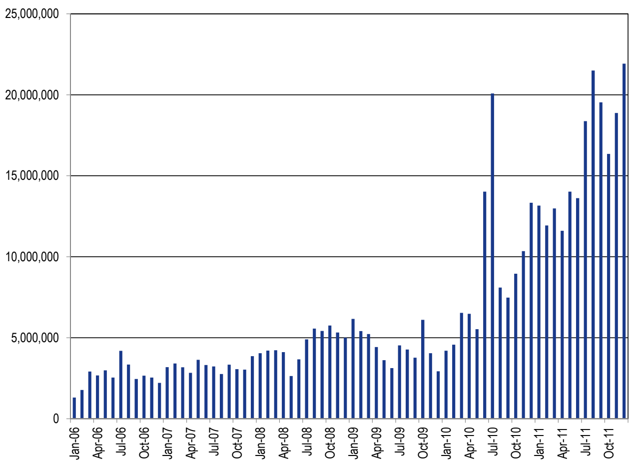
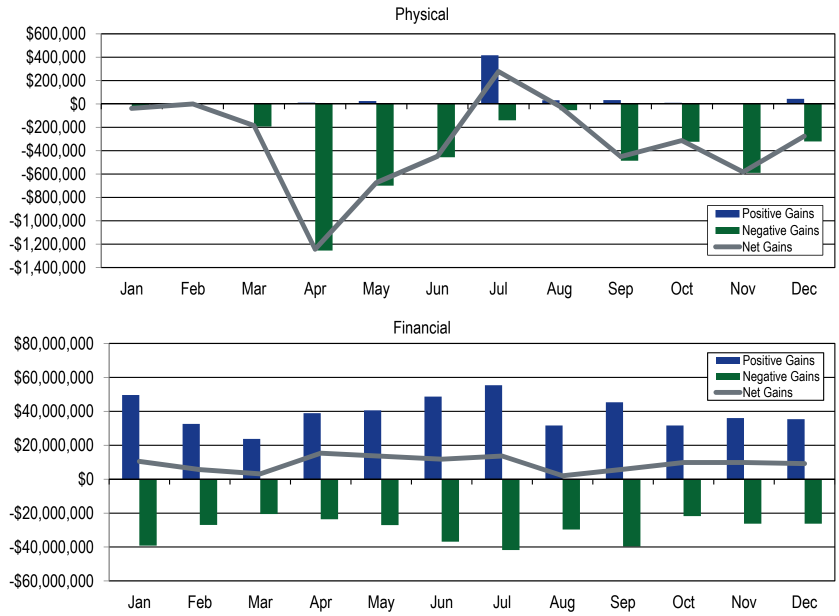


Table 8-20 Monthly volume of cleared and submitted up-to congestion bids: Calendar years 2009 through 2011

	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
Oct-11	20,240,161	19,476,556	333,077	40,049,794	540,877	451,507	8,609	1,000,993	8,376,208	7,853,947	126,718	16,356,873	255,206	198,778	4,236	458,220
Nov-11	27,007,141	28,994,789	507,788	56,509,718	594,397	603,029	13,379	1,210,805	9,064,570	9,692,312	131,670	18,888,552	254,851	256,270	5,686	516,807
Dec-11	34,990,790	34,648,433	531,616	70,170,839	697,524	655,222	14,187	1,366,933	11,738,910	10,049,685	137,689	21,926,284	281,304	248,008	6,309	535,621
TOTAL	401,350,403	352,234,122	22,204,096	775,788,621	8,618,384	6,536,407	295,997	15,450,788	184,074,602	163,527,346	13,902,119	361,504,067	4,092,832	3,115,609	166,440	7,374,881

Figure 8-12 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction (physical) and without a matching Real-Time Energy Market transaction (financial): Calendar year 2011



Of all the market participants that utilize up-to congestion transactions, the top five participants accounted for 55.9 percent of all cleared transactions and the top ten participants accounted for 72.1 percent of all cleared transactions. The top five participants that experienced losses accounted for 50.2 percent of all the losses, and the top ten participants that experienced losses accounted for 68.5 percent of all the losses on those bids.

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the southeast and southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[73] Table 8-21 shows the historical differences in Real-Time Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences, but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[74] Progress Energy Carolinas, February 13, 2007;[75] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[76]

There were a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate, and in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

73 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx>.

74 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx>. (Accessed March 1, 2012)

75 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx> (Accessed March 1, 2012).

76 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx>. (Accessed March 1, 2012)

Table 8-21 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: Calendar years 2007 through 2011

Year	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.00)
2008	$62.97	$51.42	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.02)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)
2010	$43.46	$36.27	$39.29	$39.14	$4.17	($3.02)	$4.32	($2.87)
2011	$40.77	$36.69	$38.63	$38.63	$2.14	($1.94)	$2.14	($1.94)

Table 8-22 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2011

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$39.05	$40.01	$38.63	$38.63	$0.42	$1.38
PEC	$39.73	$41.43	$38.63	$38.63	$1.10	$2.80
NCMPA	$39.59	$39.73	$38.63	$38.63	$0.96	$1.10

On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[77,78] On January 20, 2011, the Commission issued an Order conditionally accepting the compliance filing submitted by PJM and PEC.[79] The parties meet on a yearly basis, and, in 2011, there were no developments. On May 25, 2011, PJM and Progress submitted a joint filing, requesting an additional six months to develop a mutually agreeable methodology to account for the compensation non-firm power flows have on each others transmission system.[80] The agreement remained in effect in 2011.

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology as defined in the PJM Tariff.[81] Under the marginal cost proxy pricing methodology, the price for imports of energy to PJM from the external balancing authority area is the LMP, calculated by PJM, of the lowest priced generator bus in the external balancing authority area that has an output greater than zero and is less than its marginal cost. If no generator, with an output greater than zero, has an LMP less than its marginal cost, the import price is calculated as the average of the bus LMPs for the set of generators that PJM determines to be moving to support the import transaction. Conversely, the price for exports of energy from PJM to the external balancing authority area is the LMP, calculated by PJM, of the highest priced generator bus in the external balancing authority area that has an output greater than zero and is greater than its marginal cost (excluding nuclear and hydro units). If no generator, with an output greater than zero, has an LMP greater than its marginal cost, the export price is calculated as the average of the bus LMPs for the set of generators that PJM determines to be moving to support the export transaction. The LMPs under this methodology are calculated every five minutes and aggregated on an hourly basis in the Real-Time Energy Market, and are calculated for each hour in the Day-Ahead Energy Market. These pricing points are only eligible during hours where the entity importing energy into PJM can confirm that the source of the energy is in the neighboring balancing authority, or where the entity exporting energy out of PJM can confirm that the sink of the energy is in the neighboring balancing authority.

The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff. Under the high-low pricing methodology, the price for imports of energy to PJM from the external balancing authority area is the LMP, calculated by PJM, at the lowest priced generator bus in the external balancing authority area that has an output greater than zero. Conversely, the price for exports of energy from PJM to the external balancing authority area is the LMP, calculated by PJM, at the highest priced generator bus in the external balancing authority area that has an output greater than zero. The LMPs under this methodology are calculated every five minutes and

77 See PJM Interconnection, L.L.C., and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).

78 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.

79 134 FERC ¶ 61,048 (2011).

80 PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc., Docket No. ER11-3637-000 (May 25, 2011)

81 See PJM Interconnection, L.L.C, Docket No. ER10-2710-000 (September 17, 2010).

Figure 8-13 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2011

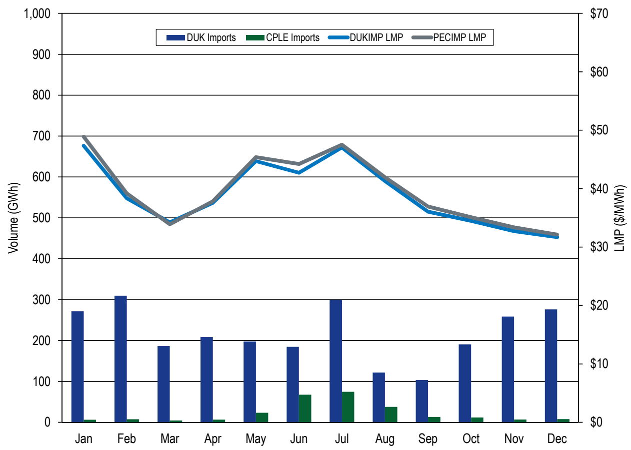
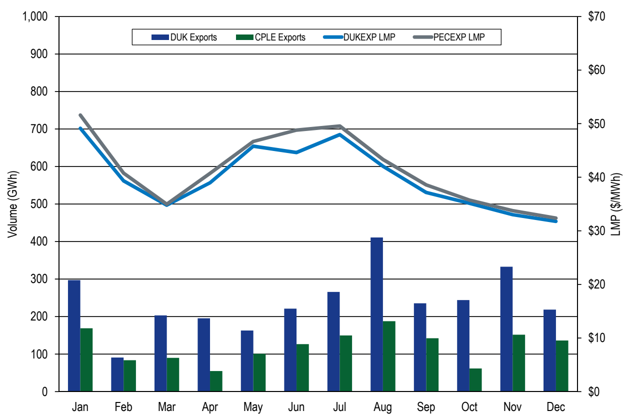


Figure 8-14 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2011



aggregated on an hourly basis in the Real-Time Energy Market, and are calculated for each hour in the Day-Ahead Energy Market. These pricing points are only eligible during hours where the entity importing energy into PJM can confirm that the source of the energy is in the neighboring balancing authority, or where the entity exporting energy out of PJM can confirm that the sink of the energy is in the neighboring balancing authority.

Table 8-22 shows the real-time LMP calculated per the revised PJM/PEC JOA and the high/low pricing methodology used by Duke and NCMPA for the calendar year 2011. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.42 with Duke to $1.10 with PEC.[82] This means that under the specific interface pricing agreements, Duke receives, on average, $0.42 more for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $1.10 with NCMPA to $2.80 with PEC. This means that under the specific interface pricing agreements, Duke pays, on average, $1.38 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point.

Table 8-23 shows the historical differences in Day-Ahead Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation.

Table 8-24 shows the day-ahead LMP calculated per the revised PJM/PEC JOA and the high/low pricing methodology used by Duke and NCMPA for the calendar year 2011. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.81 with Duke to $1.73 with PEC.[83] This means that under the specific interface pricing agreements, Duke receives, on average, $0.81 more for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $1.85 with NCMPA to $3.79 with PEC. This means that under the specific interface pricing agreements, Duke pays, on average, $1.85 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point.

82 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

83 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

Table 8-23 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: Calendar years 2007 through 2011

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$53.50	$45.01	$48.45	$47.76	$5.06	($3.44)	$5.75	($2.75)
2008	$63.44	$52.27	$56.26	$56.26	$7.17	($3.99)	$7.17	($3.99)
2009	$36.42	$32.05	$33.59	$33.59	$2.83	($1.54)	$2.83	($1.54)
2010	$44.42	$36.76	$39.40	$39.40	$5.03	($2.63)	$5.03	($2.63)
2011	$41.27	$37.34	$38.69	$38.69	$2.58	($1.35)	$2.57	($1.36)

Table 8-24 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2011

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$39.50	$41.14	$38.69	$38.69	$0.81	$2.45
PEC	$40.42	$42.48	$38.69	$38.69	$1.73	$3.79
NCMPA	$39.90	$40.54	$38.69	$38.69	$1.21	$1.85

Figure 8-15 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2011

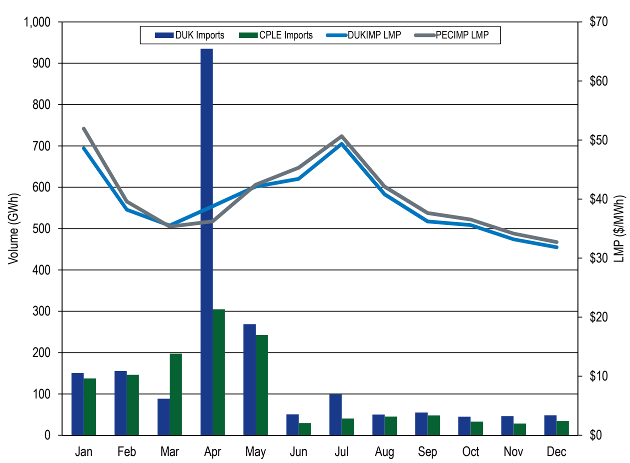
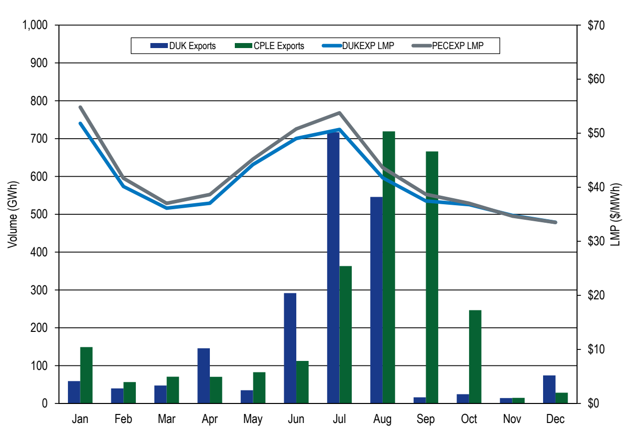


Figure 8-16 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2011



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 calendar year 2011 were -$20,955, compared to $3.3 million in 2010 (Table 8-25). If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction. Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case in for the net uncollected congestion charges in 2011. In other words, when market participants utilize the not willing to pay congestion product, it also means that they are not willing to receive congestion credits when the LMP at the source is greater than the LMP at the sink. The fact that there was a total negative congestion collection in 2011, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

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. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed 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.

Table 8-25 Monthly uncollected congestion charges: Calendar years 2010 and 2011

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	($31,443)
Nov	$30,843	($795)
Dec	$127,176	($659)
Total	$3,314,018	($20,955)

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.[84] These modifications are currently being evaluated by PJM to develop an implementation plan.

Until the internal source and sink designations are eliminated from the external energy transactions in the Day-Ahead Energy Market, the MMU continues to recommend that PJM require that all import and export up-to congestion transactions pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserve charges.

Spot Import

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM interpreted its JOA with MISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[85] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result, requests for service sometimes exceeded the amount of service available to customers. Spot import service (a

84 See "Meeting Minutes" Minutes from PJM's MIC meeting (May 16, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>. (Accessed on March 1, 2012)

85 See "Modifications to the Practices of Non-Firm and Spot market Import Service" (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>. (Accessed March 1, 2012)

network service) is provided at no charge to the market participant offering into the PJM spot market.

In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[86] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

The new spot import rules provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and two hours when queued the day prior. On June 23, 2009 PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage (defined as scheduling) has been over 99 percent, compared to 70 percent prior to the modification (Figure 8-17).

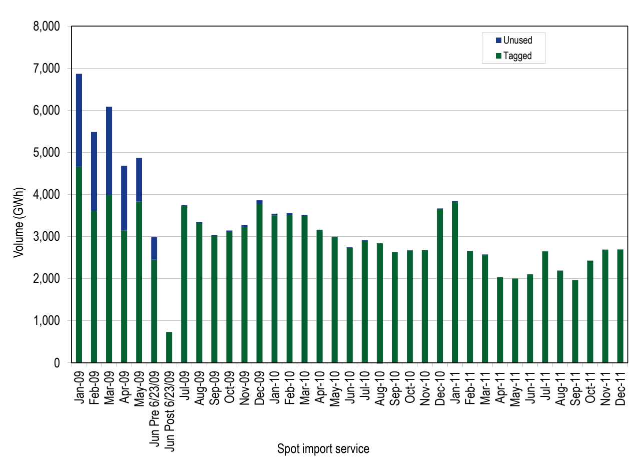
Although the rule change resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service. In 2010, market participants were still unable to acquire spot import service on the NYIS-PJM path when it was not being used to flow energy. The MMU found that the bidding process in the NYISO resulted in market participants reserving and scheduling but not using transmission to flow energy.

At the December 7, 2010, meeting of the Market Implementation Committee (MIC), PJM and the MMU made a joint recommendation to return to unlimited ATC for non-firm willing to pay congestion service on all paths for all non-firm willing to pay congestion transmission service. The PJM Stakeholders agreed with recommendation.

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. It is expected that implementation of these changes will occur by the end of the third quarter 2012.

Figure 8-17 Spot import service utilization: Calendar years 2010 and 2011



86 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) <http://www.pjm.com/markets-and-operations/etools/~/media/etools/oasis/regional-practices-redline-doc.ashx>. (Accessed March 1, 2012)

Real-Time Dispatchable Transactions

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. For example, an import dispatchable transaction would specify the minimum price the market participant wishes to receive when selling into the PJM market. If the interface pricing point for the transaction is expected to be greater than the price specified by the market participant, the transaction would be loaded for the next hour. For an export dispatchable transaction, the market participant specifies the maximum price they are willing to buy from at the interface pricing point. PJM dispatchers evaluate dispatchable transactions 30 minutes prior to the hour. If they believe the LMP at the interface pricing point will be economic they will load the transaction for the next hour. Once loaded, the transaction will flow for the entire hour. Import dispatchable transactions receive the hourly integrated import pricing point LMP for the hours when energy flows. If the hourly integrated import pricing point LMP is less than the price specified, the market participant is made whole through balancing operating reserve credits. Exporting dispatchable transactions are not made whole, as Schedule 6 of the PJM Open Access Transmission Tariff does not include export transactions in the calculation for balancing operating reserve credits.

Dispatchable transactions were initially a valuable tool for market participants. Currently, real-time LMPs are readily available to market participants, and the timing requirement for submitting transactions has been reduced to 20 minutes notification. The value that dispatchable transactions once provided market participants no longer exists 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. In 2011, $1.3 million in balancing operating reserve credits were paid due to the uneconomic loading of dispatchable transactions compared to $23.0 million for the calendar year 2010.

Balancing operating reserve credits are paid to importing dispatchable transactions as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. In 2011, these balancing operating reserve credits were $1.3 million, a decrease from $23.0 million for the calendar year 2010. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and the absence of any such dispatchable transactions after April, 2011.

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 PJM dispatch tool, the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. Including dispatchable transactions in the ITSCED application allows them to be evaluated and included in the economic dispatch along with generator bids, and removes the guesswork for the PJM dispatch on whether the transaction is likely to be economic in the next hour. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.[87] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in 2012.

Internal Bilateral Transactions

In the third quarter of 2011, it was discovered that a number of companies had used internal bilateral transactions to improperly reduce, or eliminate, their exposure to balancing operating reserve (BOR) charges associated with virtual positions taken in the PJM Day-Ahead Market.[88] Use of IBTs in this manner was improper because these transactions, designed to offset virtual positions, do not "contemplate the physical transfer of energy," as the market rules require.[89]

At the PJM Markets Implementation Committee, held on November 1, 2011, PJM submitted the following issue charge:

87 See "Meeting Minutes" Minutes from PJM's MIC meeting (July 13, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> (Accessed on March 1, 2012).

88 See Comments of the Independent Market Monitor for PJM in Docket No. EL12-8-000 (December 2, 2011); see also Complaint of DC Energy and DC Energy Mid-Atlantic, LLC in Docket No. EL12-8-000, Attachment A (October 20,2011 PJM Notification) (October 28, 2011).

89 PJM Operating Agreement Schedule 1 § 1.7.10.

> Under the current rules for Balancing Operating Reserve (BOR) deviation calculations, deviations are netted by transaction type (INC, DEC, import, export, internal bilateral purchase or sale) at the location where there transaction occurred (ie Hub, Zone, Interface, Aggregate, bus). This rule was retained on a locational basis when the package of BOR changes was implemented in December of 2008 in order to recognize that deviations at differing locations on the system can impact BOR costs. PJM has identified and documented activity by market participants whereby Internal Bilateral Transactions (IBTs) may have been submitted in order to inappropriately avoid BOR charges. PJM believes the potential for using IBTs in this manner extends beyond the behavior that PJM has already identified. PJM therefore recommends that stakeholders revisit the netting rule and explore potential improvements to eliminate the potential for inappropriate use of IBTs.[90]

The PJM stakeholders unanimously approved the issue charge to evaluate the BOR netting rules. This issue is currently being addressed at FERC and through the PJM stakeholder process.[91]

90 See "Investigation of Balancing Operating Reserve Netting Rules" from PJM's MIC meeting (November 1, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20111101/20111101-item-03a-investigation-of-bor-netting-rules-presentation.ashx> (Accessed on March 1, 2012).

91 DC Energy, LLC and DC Energy Mid-Atlantic, LLC v. PJM Interconnection, L.L.C., Docket No. EL12-8-000 (October 28, 2011).