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

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market.[1] During the first three months of 2013, the real-time net interchange of 1,640.5 GWh was greater than net interchange of 800.7 GWh in the first three months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market. During the first three months of 2013, the total day-ahead net interchange of -6,592.7 GWh was greater than net interchange of -3,224.6 GWh during the first three months of 2012.

  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 34,149 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 20,000 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2013, gross imports in the Day-Ahead Energy Market were 149.2 percent of gross import in the Real-Time Energy Market (408.9 percent during the first three months of 2012), gross exports in the Day-Ahead Energy Market were 243.3 percent of the gross exports in the Real-Time Energy Market (472.7 percent during the first three months of 2012). In the first three months of 2013, net interchange was -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market compared to -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market for the first three months of 2012.
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eleven of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eight of PJM's 18 interface pricing points eligible for day-ahead.[2]
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first three months of 2013, up-to congestion transactions had net exports at six of PJM's 18 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price

1 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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

differentials in only 42.6 percent of hours in the first three months of 2013.

- **PJM and New York ISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first three months of 2013.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow during the first three months of 2013 was -350 MW.[4] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 84.4 percent of the hours in the first three months of 2013.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[5] The average hourly flow during the first three months of 2013 was -188 MW.[6] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 77.6 percent of the hours in the first three months of 2013.
- **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 and NYISO. While the Hudson DC line will be a bidirectional line, power flows will only be from PJM to New York. The Hudson DC line is expected to be in service by the end of the second quarter of 2013.

3 In the first three months of 2013, there were 92 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $44.34 while the NYISO LMP at the Neptune Bus during non-zero flows was $88.60, a difference of $44.26.

4 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -366 MW.

5 In the first three months of 2013, there were 144 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.15 while the NYISO LMP at the Neptune Bus during non-zero flows was $154.78, a difference of $91.63.

6 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Linden VFT line was -202 MW.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power 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 the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. For the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh.[7] This difference is inadvertent interchange.
- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued eight TLRs in the first three months of 2013, compared to six TLRs issued in the first three months of 2012. The fact that PJM has issued only eight TLRs in the first three months of 2013, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO.
- **Up-To Congestion.** Following elimination of the requirement to procure transmission service for up-to congestion transactions in 2010, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012 (Figure 8-12).
- **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. On April 12, 2011, the PJM Market Implementation

7 The "Net Scheduled" values shown in Table 8-18 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 Table 8-1 through Table 8-6.

Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[8] These modifications are currently being evaluated by PJM.

- **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. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

Conclusion

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

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first three months of 2013, including evolving transaction patterns, economics and issues. 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. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

In the first three months of 2013, 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 57.4 percent of the hours for transactions between PJM and MISO and for 43.8 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to 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 relying 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.

On January 15, 2013, PJM and NYISO implemented the market to market provisions of the PJM/NYISO Joint Operating Agreement (JOA). Coordination between NYISO and PJM includes joint redispatch and coordinated operation of the Ramapo PARs located at the NYISO – PJM interface. The goal of this real-time coordination is a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints.[9]

Loop flows remain a significant concern for the efficiency of the PJM market. 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

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

9 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

attempts to game such markets. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[10] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

10 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Interchange Transaction Activity

Aggregate Imports and Exports

During the first three months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in all months (Figure 8-1).[11] During the first three months of 2013, the total real-time net interchange of 1,640.5 GWh was greater than the net interchange of 800.7 GWh during the first three months of 2012. During the first three months of 2013, the peak month for net importing interchange was February, 639.5 GWh; in 2012 it was March, 755.1 GWh. Gross monthly export volumes during the first three months of 2013 averaged 3,202.4 GWh compared to 3,396.8 GWh for the first three months of 2012, while gross monthly imports during the first three months of 2013 averaged 3,749.2 GWh compared to 3,663.7 GWh during the first three months of 2012.

During the first three months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 8-1). During the first three months of 2013, the total day-ahead net interchange of -6,592.7 GWh was greater than the net interchange of -3,224.6 GWh during the first three months of 2012. During the first three months of 2013, the peak month for net exporting interchange was January, -2,602.8 GWh; in 2012 it was January, -1,847.5 GWh. Gross monthly export volumes during the first three months of 2013 averaged 7,790.7 GWh compared to 16,056.3 GWh for the first three months of 2012, while gross monthly imports during the first three months of 2013 averaged 5,593.1 GWh compared to 14,981.4 GWh during the first three months of 2012.

The large decreases in import and export volumes in the Day-Ahead Energy Market were the result of the rule change in November, 2012, which permitted up-to congestion transactions to be submitted between two internal buses. Prior to the rule change, up-to congestion transactions were required to have the source at an interface (modeled as an import) or the sink at an interface (modeled as an export).

11 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Figure 8-1 shows the impact of net up-to congestion transactions on the overall net Day-Ahead Market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 8-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In the first three months of 2013, up-to congestion transactions accounted for 73.6 percent of all scheduled import MW transactions, 69.6 percent of all scheduled export MW transactions and 59.4 percent of the net interchange volume in the Day-Ahead Market. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 34,149 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 20,000 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012.

In the first three months of 2013, gross imports in the Day-Ahead Energy Market were 149.2 percent of gross imports in the Real-Time Energy Market (408.9 percent during the first three months of 2012), gross exports in the Day-Ahead Energy Market were 243.3 percent of gross exports in the Real-Time Energy Market (472.7 percent during the first three months of 2012). In the first three months of 2013, net interchange was -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market compared to -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market for the first three months of 2012.

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.[12] For the first three months of 2013, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: January through March, 2013

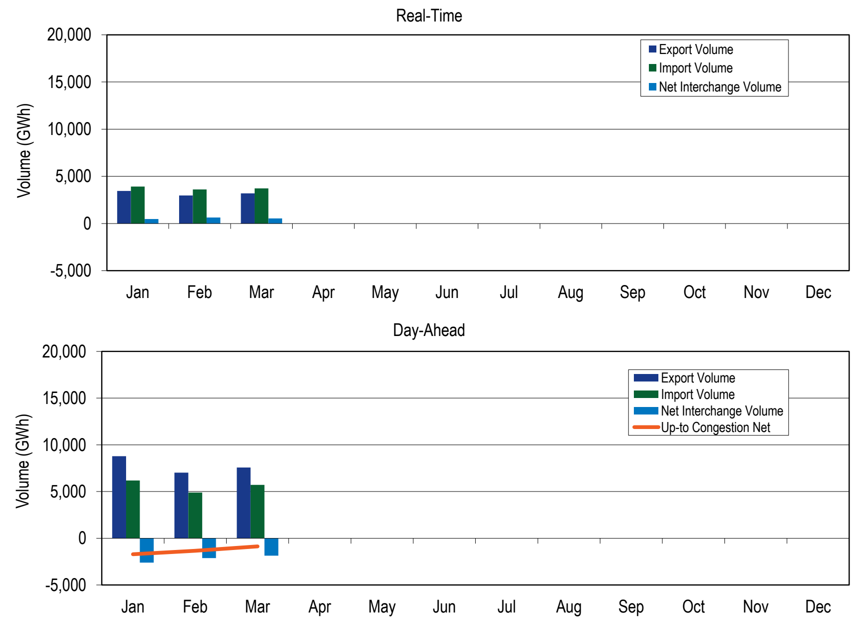


Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through March, 2013. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

12 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January through March, 2013

Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is 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 neighboring balancing authorities. See Table 8-16 for a list of active interfaces during the first three months of 2013. Figure 8-3 shows the approximate geographic location of the interfaces. In the first three months of 2013, PJM had 20 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all three are interfaces between PJM and the NYISO. Similarly, there are ten separate interfaces that make up the MISO Interface between the PJM and MISO balancing authorities. Table 8-1 through Table 8-3 show the Real-Time Market interchange totals at the individual NYISO interfaces, 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 the first three months of 2013 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 first three months of 2013, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 65.4 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 34.5 percent, PJM/MidAmerican Energy Company (MEC) with 17.8 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 12.5 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 54.6 percent of the total net PJM exports in the Real-Time Energy Market. Eight PJM interfaces had net scheduled imports, with three importing interfaces accounting for 62.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 28.2 percent, PJM/Tennessee Valley Authority (TVA) with 21.9 percent and PJM/Michigan Electric Coordinated System (MECS) with 12.7 percent of the net import volume.[13]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by 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.[14] OVEC itself does not serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

13 In the Real-Time Market, two PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/western portion of Carolina Power & Light Company (CPLW)).

14 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed May 6, 2013).

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	(30.6)	(38.3)	(48.4)	(117.3)
CPLW	0.0	0.0	0.0	0.0
DUK	175.2	122.7	148.1	446.0
EKPC	(149.7)	(139.9)	(152.7)	(442.3)
LGEE	281.5	272.0	302.2	855.7
MEC	(484.1)	(390.8)	(158.9)	(1,033.8)
MISO	283.1	518.3	572.6	1,374.1
ALTE	(306.7)	(176.9)	(239.3)	(723.0)
ALTW	(9.0)	(4.5)	(3.0)	(16.5)
AMIL	181.7	153.6	181.5	516.8
CIN	253.3	285.4	349.7	888.3
CWLP	0.0	0.0	0.0	0.0
IPL	(43.4)	48.1	63.8	68.5
MECS	322.3	298.9	322.5	943.6
NIPS	(22.9)	(12.5)	(22.0)	(57.4)
WEC	(92.1)	(73.8)	(80.5)	(246.4)
NYISO	(1,047.1)	(1,018.0)	(1,100.9)	(3,166.0)
LIND	(165.2)	(149.8)	(91.6)	(406.7)
NEPT	(270.9)	(245.9)	(239.2)	(756.0)
NYIS	(611.0)	(622.3)	(770.1)	(2,003.3)
OVEC	798.2	713.5	585.0	2,096.7
TVA	643.8	600.0	383.6	1,627.4
Total	470.4	639.5	530.6	1,640.5

Table 8-2 Real-time scheduled gross import volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	1.4	0.1	1.6	3.0
CPLW	0.0	0.0	0.0	0.0
DUK	225.0	190.6	157.0	572.7
EKPC	4.4	1.5	25.6	31.5
LGEE	299.0	272.4	302.2	873.6
MEC	0.2	48.2	320.6	369.1
MISO	1,026.7	971.1	1,110.5	3,108.2
ALTE	0.0	1.1	0.0	1.1
ALTW	0.0	0.0	0.0	0.0
AMIL	207.0	177.1	215.1	599.3
CIN	374.5	394.7	455.5	1,224.7
CWLP	0.0	0.0	0.0	0.0
IPL	95.9	76.5	101.6	274.0
MECS	349.1	321.6	338.3	1,009.0
NIPS	0.2	0.0	0.0	0.2
WEC	0.0	0.0	0.0	0.0
NYISO	871.0	782.0	820.7	2,473.8
LIND	0.6	10.4	7.5	18.5
NEPT	0.0	0.0	0.0	0.0
NYIS	870.5	771.6	813.2	2,455.3
OVEC	798.3	713.5	585.1	2,096.9
TVA	689.8	630.0	399.1	1,718.9
Total	3,915.7	3,609.5	3,722.4	11,247.6

Table 8-3 Real-time scheduled gross export volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	31.9	38.4	50.0	120.3
CPLW	0.0	0.0	0.0	0.0
DUK	49.8	67.9	8.9	126.6
EKPC	154.0	141.4	178.3	473.8
LGEE	17.5	0.4	0.0	17.9
MEC	484.4	439.0	479.6	1,403.0
MISO	743.5	452.8	537.9	1,734.1
ALTE	306.7	178.0	239.3	724.1
ALTW	9.0	4.5	3.0	16.5
AMIL	25.3	23.5	33.6	82.4
CIN	121.2	109.3	105.8	336.4
CWLP	0.0	0.0	0.0	0.0
IPL	139.3	28.4	37.8	205.5
MECS	26.8	22.7	15.8	65.3
NIPS	23.0	12.5	22.0	57.5
WEC	92.1	73.8	80.5	246.4
NYISO	1,918.1	1,800.1	1,921.6	5,639.8
LIND	165.8	160.3	99.1	425.2
NEPT	270.9	245.9	239.2	756.0
NYIS	1,481.5	1,393.9	1,583.3	4,458.7
OVEC	0.1	0.0	0.0	0.1
TVA	46.0	30.0	15.6	91.6
Total	3,445.3	2,970.0	3,191.9	9,607.1

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 scheduled imports or exports will flow.[15] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a 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 MISO/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the MISO/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. 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.[16]

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.[17] 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 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.[18] 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. Table 8-17 presents the interface pricing points used for the first three months of 2013.

15 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.

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

17 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed May 6, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

18 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 May 6, 2013)

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 by PJM only occasionally.

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. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

Real-Time Energy Market transaction prices are determined based on transaction details.[19]

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.[20]

In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[21] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 68.0 percent of the total net exports: PJM/MISO with 38.1 percent, and PJM/NYIS with 29.9 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 48.3 percent of the total net PJM exports in the Real-Time Energy Market. Five PJM interface pricing points had net imports, with two importing interface pricing points accounting for 75.3 percent of the total net imports: PJM/SouthIMP with 48.9 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 26.4 percent of the net import volume.[22]

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	592.6	395.0	556.4	1,543.9
LINDENVFT	(165.2)	(149.8)	(91.6)	(406.7)
MISO	(1,015.3)	(686.3)	(699.3)	(2,400.8)
NEPTUNE	(270.9)	(245.9)	(239.2)	(756.0)
NORTHWEST	(3.6)	(3.3)	(5.9)	(12.8)
NYIS	(603.2)	(572.1)	(706.3)	(1,881.7)
OVEC	798.2	713.5	585.0	2,096.7
SOUTHIMP	1,441.6	1,472.4	1,387.4	4,301.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	107.2	105.3	83.8	296.3
NCMPAIMP	68.6	31.3	19.5	119.5
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	3,885.5
SOUTHEXP	(303.9)	(283.9)	(255.9)	(843.7)
CPLEEXP	(31.3)	(33.4)	(47.6)	(112.3)
DUKEXP	(27.1)	(45.2)	(0.9)	(73.1)
NCMPAEXP	0.0	(0.1)	0.0	(0.1)
SOUTHWEST	(4.5)	(5.7)	(3.0)	(13.1)
SOUTHEXP	(241.0)	(199.6)	(204.5)	(645.1)
Total	470.4	639.5	530.6	1,640.5

19 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.
20 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.
21 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
22 In the Real-Time Market, one PJM interface pricing point had a net interchange of zero (PJM/CPLEIMP).

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	594.6	403.2	562.5	1,560.2
LINDENVFT	0.6	10.4	7.5	18.5
MISO	204.4	196.3	309.1	709.9
NEPTUNE	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0
NYIS	876.3	813.6	870.9	2,560.8
OVEC	798.3	713.5	585.1	2,096.9
SOUTHIMP	1,441.6	1,472.4	1,387.4	4,301.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	107.2	105.3	83.8	296.3
NCMPAIMP	68.6	31.3	19.5	119.5
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	3,885.5
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	3,915.7	3,609.5	3,722.4	11,247.6

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	2.0	8.2	6.1	16.3
LINDENVFT	165.8	160.3	99.1	425.2
MISO	1,219.7	882.6	1,008.4	3,110.7
NEPTUNE	270.9	245.9	239.2	756.0
NORTHWEST	3.6	3.3	5.9	12.8
NYIS	1,479.5	1,385.8	1,577.2	4,442.5
OVEC	0.1	0.0	0.0	0.1
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	303.9	283.9	255.9	843.7
CPLEEXP	31.3	33.4	47.6	112.3
DUKEXP	27.1	45.2	0.9	73.1
NCMPAEXP	0.0	0.1	0.0	0.1
SOUTHWEST	4.5	5.7	3.0	13.1
SOUTHEXP	241.0	199.6	204.5	645.1
Total	3,445.3	2,970.0	3,191.9	9,607.1

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. 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 could be supported in the Real-Time Energy Market.[23] 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 unless they are also submitted in the Real-Time Energy Market. 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.

23 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.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.[24]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. 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 bear any necessary relationship to 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 Day-Ahead Market. In the interface tables, 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 totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for the first three months of 2013 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eleven of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 81.9 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 37.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.5 percent, and PJM/NEPT with 15.9 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 54.1 percent of the total net PJM exports in the Day-Ahead Energy Market. The ten separate interfaces that connect PJM to MISO together represented 7.0 percent of the total net PJM exports in the Day-Ahead Energy Market. Seven PJM interfaces had net scheduled imports, with three importing interfaces accounting for 84.9 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 65.7 percent, PJM/DUK with 10.0 percent and PJM/Louisville Gas and Electric (LGEE) with 9.2 percent of the net import volume.[25]

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	(33.4)	(28.5)	(41.2)	(103.2)
CPLW	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	224.0
EKPC	(36.6)	(33.6)	(37.2)	(107.3)
LGEE	58.3	65.8	81.8	205.9
MEC	(483.0)	(435.7)	(477.7)	(1,396.3)
MISO	(242.1)	(52.6)	(48.7)	(343.5)
ALTE	(177.8)	(79.5)	(119.1)	(376.3)
ALTW	(7.6)	(2.5)	0.0	(10.1)
AMIL	8.7	5.2	26.3	40.2
CIN	7.9	45.9	37.1	90.9
CWLP	0.0	0.0	0.0	0.0
IPL	(0.9)	(5.9)	(1.6)	(8.4)
MECS	23.4	45.8	102.9	172.2
NIPS	(22.2)	(12.5)	(21.5)	(56.2)
WEC	(73.7)	(49.2)	(72.8)	(195.7)
NYISO	(833.6)	(874.4)	(944.3)	(2,652.3)
LIND	(15.3)	(14.3)	(2.6)	(32.2)
NEPT	(278.5)	(255.2)	(248.7)	(782.5)
NYIS	(539.7)	(604.9)	(693.0)	(1,837.6)
OVEC	561.5	494.4	408.0	1,463.9
TVA	32.7	3.6	(3.6)	32.7
Total without Up-To Congestion	(898.1)	(790.9)	(987.2)	(2,676.2)
Up-To Congestion	(1,704.8)	(1,336.7)	(875.0)	(3,916.5)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(6,592.7)

24 See the *2010 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.

25 In the Day-Ahead Market, two PJM interface had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	0.0	0.0	0.0	0.0
CPLW	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	224.0
EKPC	0.0	0.0	0.0	0.0
LGEE	58.3	65.8	81.8	205.9
MEC	0.0	0.0	0.0	0.0
MISO	75.2	115.2	196.6	387.0
ALTE	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0
AMIL	8.7	5.2	26.3	40.2
CIN	21.5	64.2	58.4	144.1
CWLP	0.0	0.0	0.0	0.0
IPL	5.6	0.0	0.0	5.6
MECS	39.3	45.8	111.9	197.1
NIPS	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0
NYISO	726.2	650.4	717.7	2,094.3
LIND	0.1	9.3	2.9	12.3
NEPT	0.0	0.0	0.0	0.0
NYIS	726.2	641.1	714.8	2,082.1
OVEC	561.5	494.4	408.0	1,463.9
TVA	41.7	13.6	3.6	58.9
Total without Up-To Congestion	1,540.9	1,409.5	1,483.5	4,434.0
Up-To Congestion	4,637.9	3,481.0	4,226.5	12,345.4
Total	6,178.8	4,890.5	5,710.0	16,779.3

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	33.4	28.5	41.2	103.2
CPLW	0.0	0.0	0.0	0.0
DUK	0.0	0.0	0.0	0.0
EKPC	36.6	33.6	37.2	107.3
LGEE	0.0	0.0	0.0	0.0
MEC	483.0	435.7	477.7	1,396.3
MISO	317.3	167.9	245.4	730.5
ALTE	177.8	79.5	119.1	376.3
ALTW	7.6	2.5	0.0	10.1
AMIL	0.0	0.0	0.0	0.0
CIN	13.7	18.3	21.3	53.3
CWLP	0.0	0.0	0.0	0.0
IPL	6.5	5.9	1.6	14.0
MECS	15.9	0.0	9.1	24.9
NIPS	22.2	12.5	21.5	56.2
WEC	73.7	49.2	72.8	195.7
NYISO	1,559.8	1,524.8	1,662.1	4,746.6
LIND	15.4	23.6	5.5	44.5
NEPT	278.5	255.2	248.7	782.5
NYIS	1,265.9	1,246.0	1,407.8	3,919.7
OVEC	0.0	0.0	0.0	0.0
TVA	9.0	10.0	7.2	26.2
Total without Up-To Congestion	2,439.0	2,200.5	2,470.7	7,110.2
Up-To Congestion	6,342.6	4,817.7	5,101.5	16,261.8
Total	8,781.6	7,018.2	7,572.2	23,372.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. In the first three months of 2013, up-to congestion transactions accounted for 73.6 percent of all scheduled import MW transactions, 69.6 percent of all scheduled export MW transactions and 59.4 percent of the net interchange volume in the Day-Ahead Market. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for the first three months of 2013 in Table 8-10. Up-to congestion transactions by interface pricing point for the first three months of 2013 are shown in Table 8-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Market are shown in Table 8-12 and Table 8-14, while gross import up-to congestion transactions are show in Table 8-13 and gross export up-to congestion transactions are shown in Table 8-15.

In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eight of PJM's 18 interface pricing points eligible for day-ahead.[26] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 59.3 percent of the total net exports: PJM/NIPSCO with 21.9 percent, PJM/Northwest[27] with 19.9 percent and PJM/SouthEXP with 17.4 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 25.8 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interface pricing points had net imports, with three importing interface pricing points accounting for 67.7 percent of the total net imports: PJM/Southeast with 24.0 percent, PJM/SouthIMP with 23.5 percent, and PJM/Ohio Valley Electric Corporation (OVEC) with 20.2 percent of the net import volume.[28]

In the Day-Ahead Market, for the first three months of 2013, up-to congestion transactions had net exports at six of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 77.3 percent of the total net up-to congestion exports: PJM/NIPSCO with 32.5 percent, PJM/SouthEXP with 24.1 percent and PJM/Southwest with 20.7 percent of the net export up-to congestion volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 4.5 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 4.5 percent). The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market. Six PJM interface pricing points had net up-to congestion imports, with two importing interface pricing points accounting for 71.1 percent of the total net up-to congestion imports: PJM/MISO with 40.8 percent and PJM/Southeast with 30.3 percent of the net import volume.[29]

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	27.4	235.1	206.5	468.9
LINDENVFT	102.2	14.5	(14.6)	102.1
MISO	192.7	130.5	453.0	776.3
NEPTUNE	(335.1)	(381.7)	(398.9)	(1,115.7)
NIPSCO	(927.2)	(757.5)	(743.5)	(2,428.2)
NORTHWEST	(744.5)	(810.7)	(646.6)	(2,201.8)
NYIS	(662.2)	(576.6)	(506.4)	(1,745.1)
OVEC	254.6	210.5	438.4	903.5
SOUTHIMP	1,255.6	902.5	877.1	3,035.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	22.5	22.0	9.0	53.5
NCMPAIMP	18.3	15.4	14.9	48.6
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	442.8	307.4	302.0	1,052.2
SOUTHEXP	(1,766.4)	(1,094.4)	(1,527.3)	(4,388.1)
CPLEEXP	(32.4)	(27.8)	(40.7)	(100.8)
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	(1.0)	(0.8)	(0.5)	(2.4)
SOUTHEAST	(49.3)	(28.8)	(26.5)	(104.6)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(2,247.7)
SOUTHEXP	(771.5)	(501.6)	(659.5)	(1,932.5)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(6,592.7)

26 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
27 The Northwest interface pricing point is assigned to external energy transactions that source or sink in balancing authorities located primarily in the Northwest United States and the contiguous region of Canada, and which are not balancing authorities within MISO. Many balancing authorities located in the Western Interconnection receive the Northwest interface pricing point because the DC Tie lines that connect the Eastern Interconnection with the Western Interconnection are located in the Northwest United States.
28 In the Day-Ahead Market, two PJM interface pricing points had a net interchange of zero (PJM/CPLEIMP and PJM/DUKEXP).
29 In the Day-Ahead Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 8-11 Up-to Congestion scheduled net interchange volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	(11.9)	189.4	94.5	272.0
LINDENVFT	117.5	28.8	(12.0)	134.3
MISO	500.7	288.8	660.8	1,450.2
NEPTUNE	(56.5)	(126.5)	(150.2)	(333.2)
NIPSCO	(927.2)	(757.5)	(743.5)	(2,428.2)
NORTHWEST	(261.6)	(375.0)	(168.9)	(805.4)
NYIS	(121.9)	25.3	185.7	89.2
OVEC	(306.9)	(281.8)	31.4	(557.2)
SOUTHIMP	1,050.5	694.0	668.9	2,413.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	278.5	136.1	117.7	532.3
SOUTHEXP	(1,687.4)	(1,022.2)	(1,441.8)	(4,151.4)
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	(49.3)	(28.8)	(26.5)	(104.6)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(2,247.7)
SOUTHEXP	(725.9)	(457.9)	(615.1)	(1,799.0)
Total Interfaces	(1,704.8)	(1,336.7)	(875.0)	(3,916.5)
INTERNAL	22,906.0	23,311.1	27,439.6	73,656.7
Total	21,201.2	21,974.3	26,564.6	69,740.2

Table 8-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	268.0	322.5	310.8	901.3
LINDENVFT	292.4	210.2	188.5	691.1
MISO	719.6	516.2	809.8	2,045.6
NEPTUNE	127.2	32.2	11.5	170.9
NIPSCO	35.0	17.1	15.0	67.2
NORTHWEST	287.9	214.8	229.9	732.5
NYIS	1,097.0	1,031.5	1,130.2	3,258.7
OVEC	2,096.0	1,643.5	2,137.2	5,876.7
SOUTHIMP	1,255.6	902.5	877.1	3,035.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	22.5	22.0	9.0	53.5
NCMPAIMP	18.3	15.4	14.9	48.6
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	442.8	307.4	302.0	1,052.2
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	6,178.8	4,890.5	5,710.0	16,779.3

Table 8-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	228.7	276.6	198.9	704.2
LINDENVFT	292.4	200.9	185.5	678.9
MISO	710.9	505.8	772.2	1,988.9
NEPTUNE	127.2	32.2	11.5	170.9
NIPSCO	35.0	17.1	15.0	67.2
NORTHWEST	287.9	214.8	229.9	732.5
NYIS	370.9	388.3	414.4	1,173.6
OVEC	1,534.5	1,151.2	1,730.2	4,416.0
SOUTHIMP	1,050.5	694.0	668.9	2,413.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	278.5	136.1	117.7	532.3
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	4,637.9	3,481.0	4,226.5	12,345.4

Table 8-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	240.6	87.4	104.4	432.3
LINDENVFT	190.2	195.7	203.1	589.0
MISO	526.9	385.6	356.8	1,269.3
NEPTUNE	462.2	413.9	410.4	1,286.6
NIPSCO	962.3	774.6	758.5	2,495.4
NORTHWEST	1,032.4	1,025.5	876.4	2,934.3
NYIS	1,759.2	1,608.1	1,636.5	5,003.8
OVEC	1,841.4	1,433.0	1,698.8	4,973.2
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	1,766.4	1,094.4	1,527.3	4,388.1
CPLEEXP	32.4	27.8	40.7	100.8
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	1.0	0.8	0.5	2.4
SOUTHEAST	49.3	28.8	26.5	104.6
SOUTHWEST	912.1	535.5	800.2	2,247.7
SOUTHEXP	771.5	501.6	659.5	1,932.5
Total	8,781.6	7,018.2	7,572.2	23,372.0

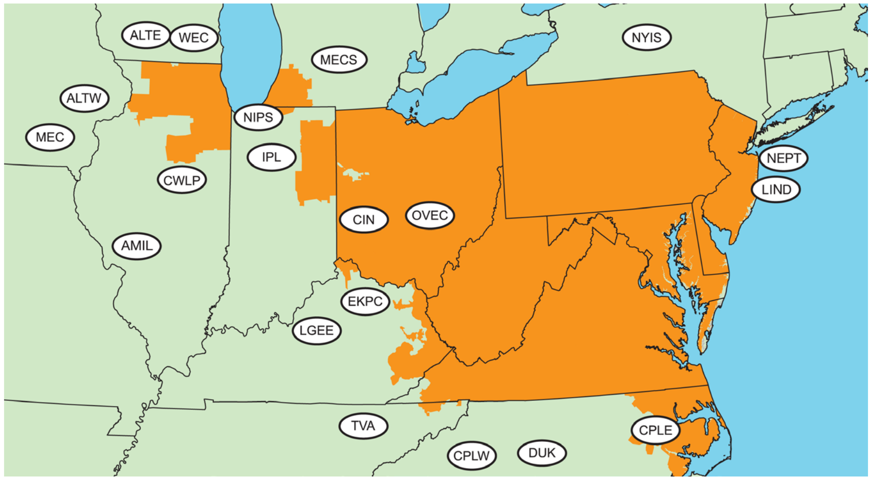
Table 8-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	240.6	87.3	104.4	432.2
LINDENVFT	174.8	172.1	197.6	544.5
MISO	210.2	217.0	111.4	538.7
NEPTUNE	183.7	158.7	161.7	504.1
NIPSCO	962.3	774.6	758.5	2,495.4
NORTHWEST	549.4	589.8	398.7	1,538.0
NYIS	492.8	362.9	228.7	1,084.4
OVEC	1,841.4	1,433.0	1,698.8	4,973.2
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	1,687.4	1,022.2	1,441.8	4,151.4
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	49.3	28.8	26.5	104.6
SOUTHWEST	912.1	535.5	800.2	2,247.7
SOUTHEXP	725.9	457.9	615.1	1,799.0
Total	6,342.6	4,817.7	5,101.5	16,261.8

Table 8-16 Active interfaces: January through March, 2013[30]

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
EKPC	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
OVEC	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

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



30 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of March 31, 2013, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

Table 8-17 Active pricing points: January through March, 2013

	Jan	Feb	Mar
CPLEEXP	Active	Active	Active
CPLEIMP	Active	Active	Active
DUKEXP	Active	Active	Active
DUKIMP	Active	Active	Active
LIND	Active	Active	Active
MISO	Active	Active	Active
NCMPAEXP	Active	Active	Active
NCMPAIMP	Active	Active	Active
NEPT	Active	Active	Active
NIPSCO	Active	Active	Active
Northwest	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
OVEC	Active	Active	Active
Southeast	Active	Active	Active
SOUTHEXP	Active	Active	Active
SOUTHIMP	Active	Active	Active
Southwest	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power 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 the difference between actual and scheduled power flows at 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 by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[31]

For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. For the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh.[32] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[33]

Table 8-18 Net scheduled and actual PJM flows by interface (GWh): January through March, 2013

	Actual	Net Scheduled	Difference (GWh)
CPLE	2,067	(159)	2,226
CPLW	(375)	-	(375)
DUK	229	446	(217)
EKPC	649	(368)	1,017
LGEE	365	856	(491)
MEC	(231)	(1,032)	801
MISO	(3,602)	1,303	(4,906)
ALTE	(1,589)	(723)	(866)
ALTW	(600)	(16)	(583)
AMIL	3,350	517	2,833
CIN	(1,557)	860	(2,417)
CWLP	(92)	0	(92)
IPL	(33)	26	(59)
MECS	(2,757)	944	(3,701)
NIPS	(1,727)	(57)	(1,669)
WEC	1,403	(246)	1,650
NYISO	(3,209)	(3,225)	15
LIND	(407)	(407)	0
NEPT	(756)	(756)	0
NYIS	(2,047)	(2,062)	15
OVEC	3,506	2,097	1,410
TVA	1,700	1,158	542
Total	1,098	1,076	22

Every external 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

31 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

32 The "Net Scheduled" values shown in Table 8-18 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 Table 8-1 through Table 8-6.

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

the specific interface price.[34] 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.

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. Scheduled transactions are assigned interface pricing points based on the generation balancing authority and load balancing authority. Scheduled power flows are assigned to interfaces based on the OASIS path that reflects the path of energy into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 8-19 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.

Because the SouthIMP and SouthEXP Interface Pricing Points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP Interface Pricing Point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points, provides some insight into how effective the interface pricing point mappings are. To accurately calculate the loop flows at the southern region, the net actual flows from the southern region (3,985 GWh of imports at the SouthIMP Interface Pricing Point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP Interface Pricing Points, or 2,946 GWh).

The IMO Interface Pricing Point with the IESO 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 mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 8-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through March, 2013

	Actual	Net Scheduled	Difference (GWh)
IMO	0	1,544	(1,544)
LINDENVFT	(407)	(407)	0
MISO	(2,953)	(2,397)	(556)
NEPTUNE	(756)	(756)	0
NORTHWEST	(231)	(11)	(220)
NYIS	(2,047)	(1,940)	(106)
OVEC	3,506	2,097	1,410
SOUTHIMP	3,985	3,790	196
CPLEIMP	0	0	0
DUKIMP	0	296	(296)
NCMPAIMP	0	119	(119)
SOUTHWEST	0	0	0
SOUTHIMP	3,985	3,374	612
SOUTHEXP	0	(844)	844
CPLEEXP	0	(112)	112
DUKEXP	0	(73)	73
NCMPAEXP	0	(0)	0
SOUTHWEST	0	(13)	13
SOUTHEXP	0	(645)	645
Total	1,098	1,076	22

34 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 8-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

Table 8-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through March, 2013

	Actual	Net Scheduled	Difference (GWh)
LINDENVFT	(407)	(407)	0
MISO	(2,953)	(837)	(2,116)
NEPTUNE	(756)	(756)	0
NORTHWEST	(231)	(11)	(220)
NYIS	(2,047)	(1,956)	(90)
OVEC	3,506	2,097	1,410
SOUTHIMP	3,985	3,790	196
CPLEIMP	0	0	0
DUKIMP	0	296	(296)
NCMPAIMP	0	119	(119)
SOUTHWEST	0	0	0
SOUTHIMP	3,985	3,374	612
SOUTHEXP	0	(844)	844
CPLEEXP	0	(112)	112
DUKEXP	0	(73)	73
NCMPAEXP	0	(0)	0
SOUTHWEST	0	(13)	13
SOUTHEXP	0	(645)	645
Total	1,098	1,076	22

PJM ensures that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC eTag. Assigning prices in this manner is an adequate method for ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this methodology does not address loop flow issues.

The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, PJM should, recognizing that transactions sourcing in SPP and sinking in PJM will create flows across the southern border, require that market participants submit the transaction to enter the PJM footprint across a neighboring balancing authority that is mapped to the SouthIMP Interface price. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

Table 8-21 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the Interface Pricing Points that were assigned to energy transactions that had market paths at each of PJM's interfaces. For example, Table 8-21 shows that for the first three months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area of the Ontario Independent Electricity System Operator (IMO), and thus actual flows were assigned the IMO Interface Pricing point (607 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM Energy Market at the MISO interface, and thus were assigned the MISO Interface Pricing point (261 GWh).

Table 8-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through March, 2013

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(1,589)	(723)	(866)	IPL		(33)	26	(59)
	MISO	(1,589)	(723)	(867)		IMO	0	232	(232)
	NORTHWEST	0	(1)	1		MISO	(33)	(244)	211
	SOUTHIMP	0	1	(1)		SOUTHIMP	0	39	(39)
ALTW		(600)	(16)	(583)	LGEE		365	856	(491)
	MISO	(600)	(16)	(583)		SOUTHEXP	0	(18)	18
AMIL		3,350	517	2,833		SOUTHIMP	365	874	(509)
	MISO	3,350	521	2,829	LIND		(407)	(407)	0
	SOUTHIMP	0	9	(9)		LINDENVFT	(407)	(407)	0
	SOUTHWEST	0	(13)	13	MEC		(231)	(1,032)	801
CIN		(1,557)	860	(2,417)		MISO	0	(1,379)	1,379
	IMO	0	607	(607)		NORTHWEST	(231)	2	(233)
	MISO	(1,557)	(261)	(1,296)		SOUTHIMP	0	345	(345)
	NORTHWEST	0	(11)	11	MECS		(2,757)	944	(3,701)
	NYIS	0	106	(106)		IMO	0	720	(720)
	SOUTHIMP	0	420	(420)		MISO	(2,757)	(65)	(2,692)
CPLE		2,067	(159)	2,226		SOUTHIMP	0	288	(288)
	CPLEEXP	0	(112)	112	NEPT		(756)	(756)	0
	SOUTHEXP	0	(8)	8		NEPTUNE	(756)	(756)	0
	SOUTHIMP	2,067	(39)	2,106	NIPS		(1,727)	(57)	(1,669)
CPLW		(375)	0	(375)		MISO	(1,727)	(58)	(1,669)
	SOUTHIMP	(375)	0	(375)	NYIS		(2,047)	(2,062)	15
CWLP		(92)	0	(92)		IMO	0	(16)	16
	MISO	(92)	0	(92)		NYIS	(2,047)	(2,046)	(1)
DUK		229	446	(217)	OVEC		3,506	2,097	1,410
	DUKEXP	0	(73)	73		OVEC	3,506	2,097	1,410
	DUKIMP	0	296	(296)	TVA		1,700	1,158	542
	NCMPAIMP	0	119	(119)		NORTHWEST	0	0	0
	SOUTHEXP	0	(53)	53		SOUTHEXP	0	(92)	92
	SOUTHIMP	229	157	72		SOUTHIMP	1,700	1,249	451
EKPC		649	(368)	1,017	WEC		1,403	(246)	1,650
	MISO	649	75	575		MISO	1,403	(246)	1,650
	SOUTHEXP	0	(474)	474	Total		1,098	1,076	22
	SOUTHIMP	0	31	(31)					

Table 8-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. This table shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 8-22 shows that for the first three months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified a generation control area for which it was assigned the IMO Interface Pricing Point, had market paths that entered the PJM Energy Market at the MECS Interface (720 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified a load control area for which it was assigned the IMO Interface Pricing Point, had market paths that exited the PJM Energy Market at the NYIS Interface (16 GWh).

Table 8-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through March, 2013

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(112)	112	NORTHWEST		(231)	(11)	(220)
	CPLE	0	(112)	112		ALTE	0	(1)	1
DUKEXP		0	(73)	73		CIN	0	(11)	11
	DUK	0	(73)	73		MEC	(231)	2	(233)
DUKIMP		0	296	(296)	NYIS		(2,047)	(1,940)	(106)
	DUK	0	296	(296)		CIN	0	106	(106)
IMO		0	1,544	(1,544)		NYIS	(2,047)	(2,046)	(1)
	CIN	0	607	(607)	OVEC		3,506	2,097	1,410
	IPL	0	232	(232)		OVEC	3,506	2,097	1,410
	MECS	0	720	(720)	SOUTHEXP		0	(645)	645
	NYIS	0	(16)	16		CPLE	0	(8)	8
LINDENVFT		(407)	(407)	0		DUK	0	(53)	53
	LIND	(407)	(407)	0		EKPC	0	(474)	474
MISO		(2,953)	(2,397)	(556)		LGEE	0	(18)	18
	ALTE	(1,589)	(723)	(867)		TVA	0	(92)	92
	ALTW	(600)	(16)	(583)	SOUTHIMP		3,985	3,374	612
	AMIL	3,350	521	2,829		ALTE	0	1	(1)
	CIN	(1,557)	(261)	(1,296)		AMIL	0	9	(9)
	CWLP	(92)	0	(92)		CIN	0	420	(420)
	EKPC	649	75	575		CPLE	2,067	(39)	2,106
	IPL	(33)	(244)	211		CPLW	(375)	0	(375)
	MEC	0	(1,379)	1,379		DUK	229	157	72
	MECS	(2,757)	(65)	(2,692)		EKPC	0	31	(31)
	NIPS	(1,727)	(58)	(1,669)		IPL	0	39	(39)
	WEC	1,403	(246)	1,650		LGEE	365	874	(509)
NCMPAIMP		0	119	(119)		MEC	0	345	(345)
	DUK	0	119	(119)		MECS	0	288	(288)
NEPTUNE		(756)	(756)	0		TVA	1,700	1,249	451
	NEPT	(756)	(756)	0	SOUTHWEST		0	(13)	13
						AMIL	0	(13)	13
					Total		1,098	1,076	22

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange 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 these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

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 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 attempt to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[35] 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.[36]

Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first three months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first three months of 2013, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $29.73 while the MISO LMP at the border was $29.23, a difference of $0.50. While the average hourly LMP difference at the PJM/MISO border was only $0.50, the average of the absolute values of the hourly differences was $7.23. The average hourly flow during the first three months of 2013 was -1,667 MW. (The negative sign means that the flow was an export from PJM to MISO, which is inconsistent with the fact that the average MISO price was lower than the average PJM price.) The direction of flow was consistent with price differentials in only 42.6 percent of hours in the first three months of 2013. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $8.66. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $6.34. In the first three months of 2013, 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 $8.55. 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 $12.39. 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 $16.52. 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 $5.46.

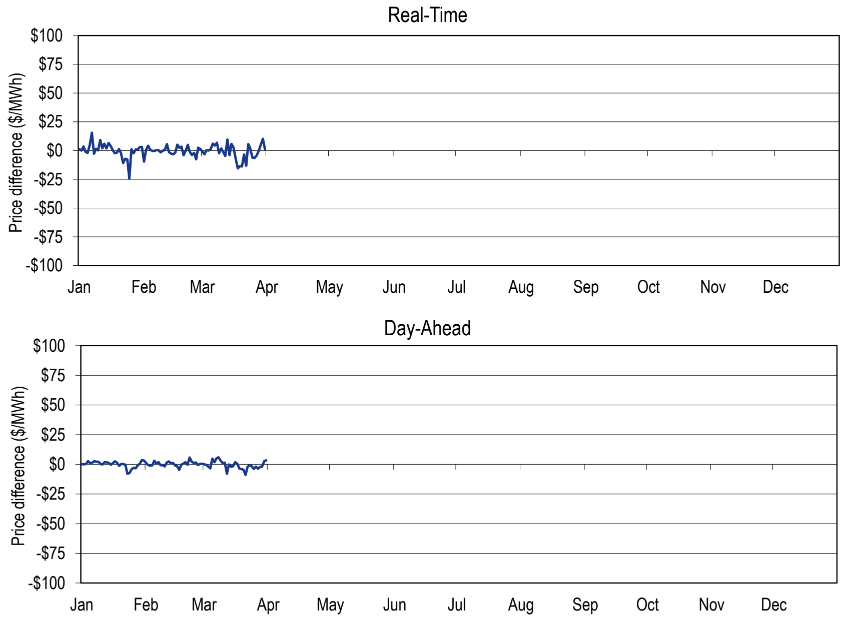
In the first three months of 2013, the day-ahead PJM average hourly LMP at the PJM/MISO border was $29.90 while the MISO LMP at the border was $29.72, a difference of $0.18.

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 (Figure 8-6).

35 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed May 6, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

36 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010). (Accessed January 16, 2013)

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through March, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

During the first three months of 2013, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 919 hours (42.6 percent of all hours), and was inconsistent with price differentials in 1,240 hours (57.4 percent of all hours). Table 8-23 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 919 hours where flows were uneconomic, 756 of those hours (82.3 percent) had a price difference greater than or equal to $1.00 and 427 of all uneconomic hours (46.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $272.26. Of the 1,240 hours where flows were economic, 1,060 of those hours (85.5 percent) had a price difference greater than or equal to $1.00 and 375 of all economic hours (30.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $313.55.

Table 8-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through March, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	1,240	100.0%	919	100.0%
$1.00	1,060	85.5%	756	82.3%
$5.00	375	30.2%	427	46.5%
$10.00	145	11.7%	236	25.7%
$15.00	78	6.3%	151	16.4%
$20.00	51	4.1%	95	10.3%
$25.00	31	2.5%	63	6.9%
$50.00	7	0.6%	22	2.4%
$75.00	4	0.3%	14	1.5%
$100.00	3	0.2%	9	1.0%
$200.00	1	0.1%	1	0.1%
$300.00	0	0.0%	1	0.1%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

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.[37]

37 See the 2012 *State of the Market Report fot PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

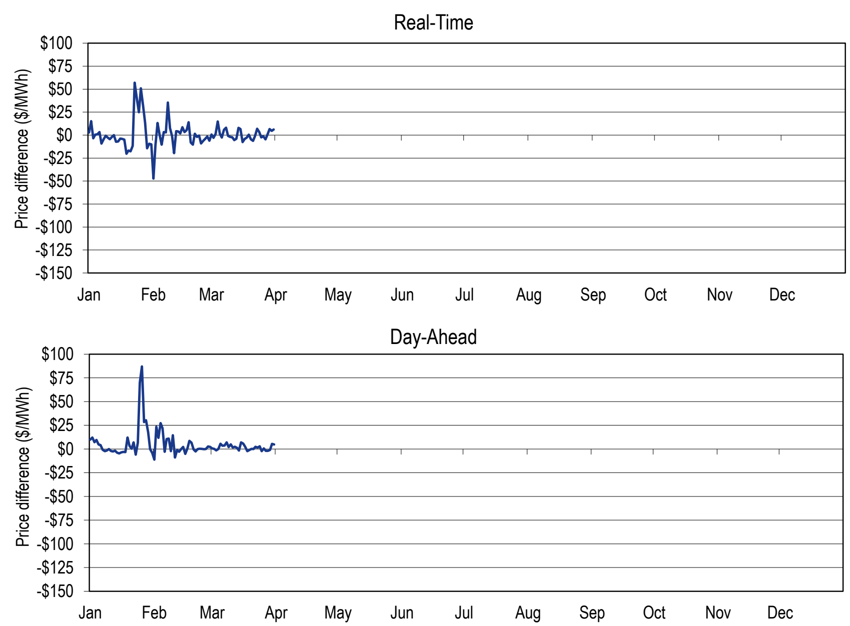
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first three months of 2013, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first three months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first three months of 2013, 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 the first three months of 2013, the PJM average hourly LMP at the PJM/NYISO border was $47.32 while the NYISO LMP at the border was $48.18, a difference of $0.87. While the average hourly LMP difference at the PJM/NYISO border was only $0.87, the average of the absolute value of the hourly difference was $18.08. The average hourly flow during the first three months of 2013 was -948 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.) The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first three months of 2013. In the first three months of 2013, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $17.00. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $19.46. In the first three months of 2013, 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 $16.86. 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 $30.56. 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 $31.84. 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 $19.15.

In the first three months of 2013, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $45.55 while the NYIS LMP at the border was $50.28, a difference of $4.73.

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 (Figure 8-6).

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

During the first three months of 2013, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,213 (56.2 percent of all hours), and was inconsistent with price differences in 946 hours (43.8 percent of all hours). Table 8-24 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 946 hours where flows were uneconomic, 870 of those hours (92.0 percent) had a price difference greater than or equal to $1.00 and 610 of all uneconomic hours (64.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $231.63. Of the 1,213 hours where flows were economic, 1,134 of those hours (93.5 percent) had a price difference greater than or equal to $1.00 and 780 of all economic hours (64.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $634.79.

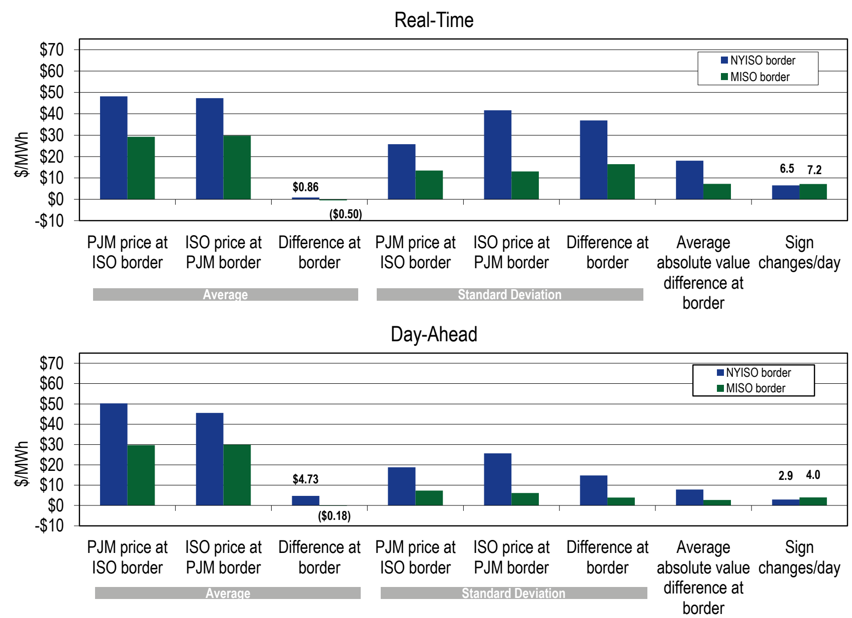
Table 8-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through March, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	946	100.0%	1,213	100.0%
$1.00	870	92.0%	1,134	93.5%
$5.00	610	64.5%	780	64.3%
$10.00	399	42.2%	468	38.6%
$15.00	308	32.6%	315	26.0%
$20.00	245	25.9%	243	20.0%
$25.00	205	21.7%	188	15.5%
$50.00	105	11.1%	92	7.6%
$75.00	54	5.7%	54	4.5%
$100.00	28	3.0%	42	3.5%
$200.00	2	0.2%	4	0.3%
$300.00	0	0.0%	2	0.2%
$400.00	0	0.0%	1	0.1%
$500.00	0	0.0%	1	0.1%

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.

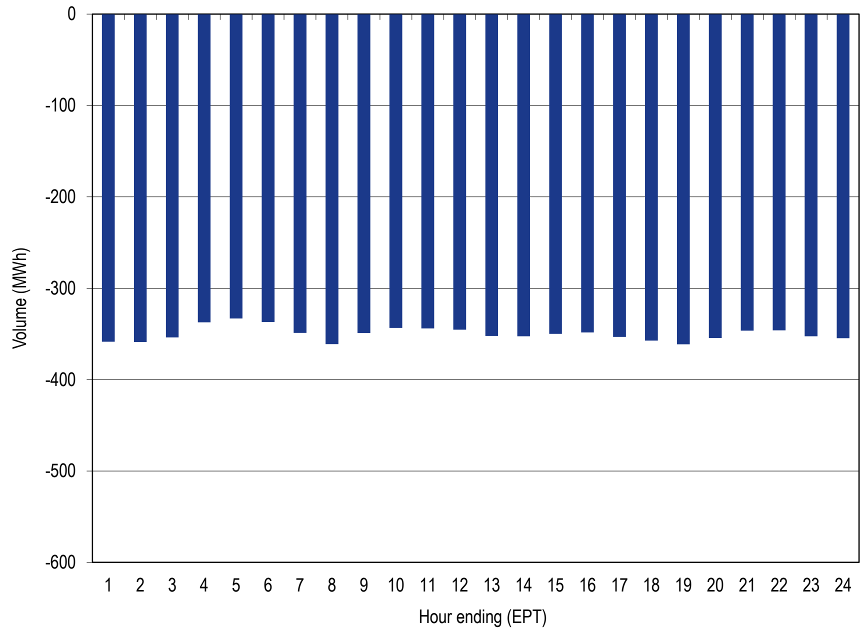
Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through March, 2013



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). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first three months of 2013, the PJM average hourly LMP at the Neptune Interface was $41.69 while the NYISO LMP at the Neptune Bus was $85.94, a difference of $44.25.[38] While the average hourly LMP difference at the PJM/Neptune border was $44.25, the average of the absolute value of the hourly difference was $54.16. The average hourly flow during the first three months of 2013 was -350 MW.[39] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 84.4 percent of the hours in the first three months of 2013. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $58.12. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $32.43.

Figure 8-7 Neptune hourly average flow: January through March, 2013



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 (Linden, New Jersey) and NYISO (Staten Island, New York). In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first three months of 2013, the PJM average hourly LMP at the Linden Interface was $43.44 while the NYISO LMP at the Linden Bus was $64.00, a difference of $20.56.[40] While the average hourly LMP difference at the PJM/Linden border was $20.56, the average of the absolute value of the hourly difference was $30.13. The average hourly flow during the first three

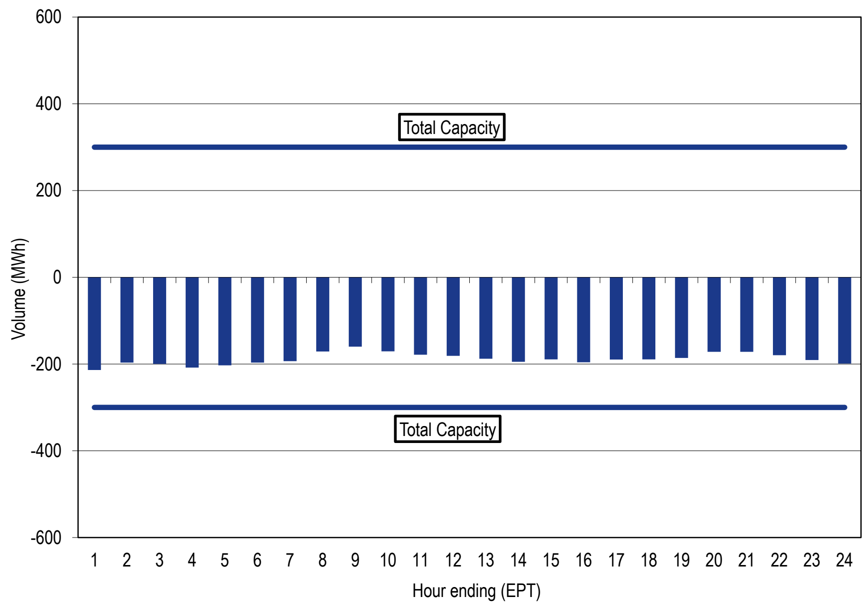
38 In the first three months of 2013, there were 92 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $44.34 while the NYISO LMP at the Neptune Bus during non-zero flows was $88.60, a difference of $44.26.

39 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -366 MW.

40 In the first three months of 2013, there were 144 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.15 while the NYISO LMP at the Neptune Bus during non-zero flows was $154.78, a difference of $91.63.

months of 2013 was -188 MW.[41] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 77.6 percent of the hours in the first three months of 2013. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $32.51. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $21.71.

Figure 8-8 Linden hourly average flow: January through March, 2013[42]



Hudson Direct Current (DC) Merchant Transmission 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 by the end of the second quarter of 2013.

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.

PJM and MISO Joint Operating Agreement[43]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. 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. In 2012, MISO and

41 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Linden VFT line was -202 MW.
42 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.

43 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 May 6, 2013)

PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[44]

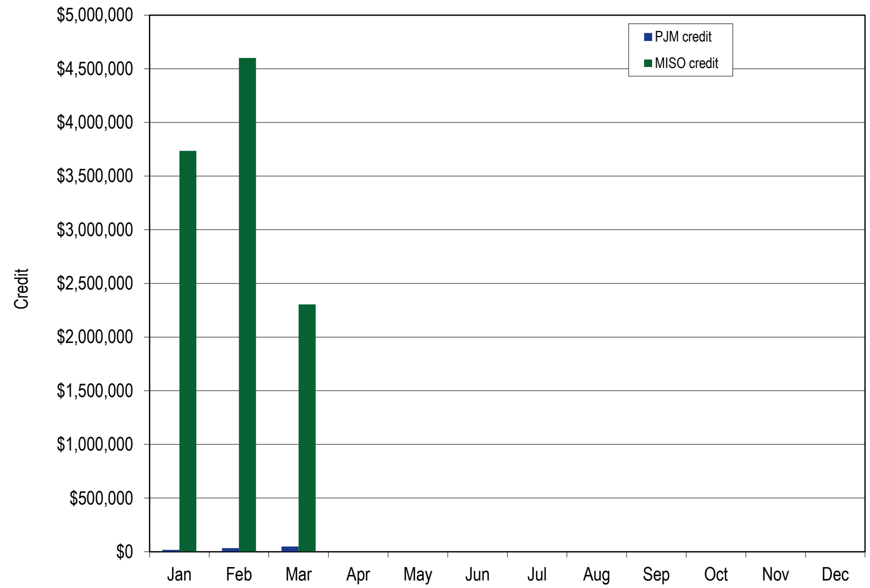
Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.[45]

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 than 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 RCFs are subject to the market to market congestion management process.

In the first three months of 2013, MISO added 38 RCFs, compared to 7 RCFs added in the first three months of 2012 (35 RCFs were added by MISO in 2012). In the first three months of 2013, PJM added 10 RCFs, compared to 4 RCF's added in the first three months of 2012 (12 RCF's were added by PJM in 2012).

During the first three months of 2013, 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. Figure 8-9 shows credits for coordinated congestion management between PJM and MISO.

Figure 8-9 Credits for coordinated congestion management: January through March, 2013[46]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[47]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/MISO Interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the

44 See www.pjm.com "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.
45 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

46 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
47 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

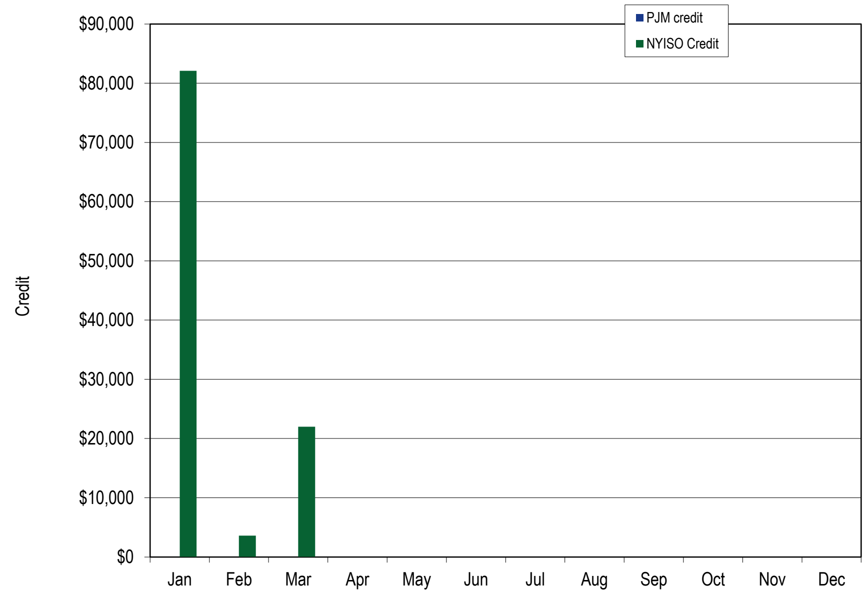
Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, in which only one has a significant impact (defined as a greater than 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.

In the first three months of 2013, the market to market operations resulted in NYISO 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.

During the first three months of 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 8-10 shows credits for coordinated congestion management between PJM and NYISO.

Figure 8-10 Credits for coordinated congestion management (flowgates): January through March, 2013[48]



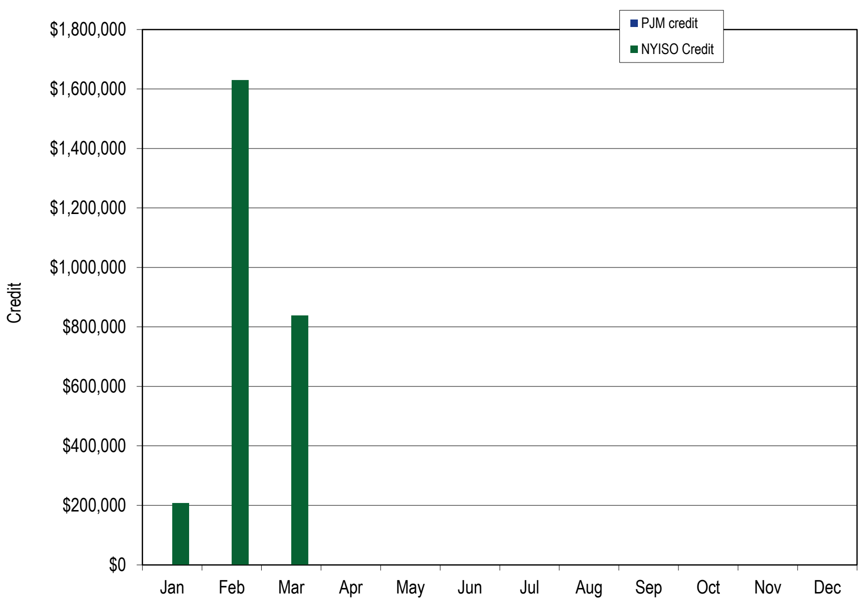
The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the NYISO – PJM interface. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[49] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow

48 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

49 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first three months of 2013, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 8-11 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

Figure 8-11 Credits for coordinated congestion management (PARs): January through March, 2013[50]



50 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

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 yearly basis, and, in the first three months of 2013, there were no developments. The agreement continued to be in effect in the first three months of 2013.

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.[51] On January 20, 2011, the Commission conditionally accepted the compliance filing.

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

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

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 the first three months of 2013, there were no developments. The agreement remained in effect in the first three months of 2013.

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.[52]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[53] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[54] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. However, the MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

Table 8-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$33.12	$34.06	$32.96	$32.96	$0.16	$1.11
PEC	$34.55	$35.35	$32.96	$32.96	$1.59	$2.39
NCMPA	$33.57	$33.73	$32.96	$32.96	$0.61	$0.78

Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$34.46	$35.27	$33.08	$33.08	$1.39	$2.19
PEC	$35.46	$36.32	$33.08	$33.08	$2.38	$3.25
NCMPA	$34.88	$34.95	$33.08	$33.08	$1.80	$1.87

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

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 including lines controlled by PJM.[55] 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.[56]

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[57] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special

52 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>. (Accessed May 6, 2013)
53 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).
54 See Docket Nos. ER12-1338-000 and ER12-1343-000.

55 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.
56 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
57 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.

protocol indefinitely.[58] The settlement defined ConEd's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. ConEd is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[59] ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement data as shown in Table 8-27 below reflecting those charges effective May 1, 2012.

Table 8-27 Con Edison and PSE&G wheeling agreement data: January through March, 2013

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$2,152,420	$32,582	$2,185,002	$0	$0	$0
Congestion Credit			$941,714			$0
Adjustments and Transmission Charges			($9,534,255)			$0
Net Charge			$10,777,544			$0

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (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 issued eight TLRs in the first three months of 2013, compared to six TLRs issued in the first three months of 2012. The fact that PJM has issued only eight TLRs in the first three months of 2013, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM TLRs increased by 33 percent, from six during the first three months of 2012 to eight during the first three months of 2013 (Table 8-28). In addition, the number of different flowgates for which PJM declared TLRs increased from four in the first three months of 2012 to six in the first three months of 2013. The total MWh of transaction curtailments increased by 528 percent, from 5,318 MWh in the first three months of 2012 to 28,062 MWh in the first three months of 2013.

MISO called more TLRs in the first three months of 2013 than in the first three months of 2012. MISO TLRs increased by 412 percent, from 26 in the first three months of 2012 to 107 in the first three months of 2013.

58 132 FERC ¶ 61,221 (2010).

59 The terms of the settlement state that ConEd shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

Table 8-28 PJM and MISO TLR procedures: January, 2010 through March, 2013[60]

	Number of TLRs Level 3 and Higher		Number of Unique Flowgates that Experienced TLRs		Curtailment Volume (MWh)	
Month	PJM	MISO	PJM	MISO	PJM	MISO
Jan-10	6	23	3	5	18,393	13,387
Feb-10	1	9	1	7	1,249	13,095
Mar-10	6	18	3	10	2,376	27,412
Apr-10	15	40	7	11	26,992	29,832
May-10	11	20	4	12	22,193	54,702
Jun-10	19	19	6	8	64,479	183,228
Jul-10	15	25	8	8	44,210	169,667
Aug-10	12	22	9	7	32,604	189,756
Sep-10	11	15	7	7	82,066	32,782
Oct-10	4	26	3	12	2,305	29,574
Nov-10	1	25	1	10	59	66,113
Dec-10	9	7	6	5	18,509	5,972
Jan-11	7	8	5	5	75,057	14,071
Feb-11	6	7	5	4	6,428	23,796
Mar-11	0	14	0	5	0	10,133
Apr-11	3	23	3	9	8,129	44,855
May-11	9	15	4	7	18,377	36,777
Jun-11	15	14	7	6	17,865	19,437
Jul-11	7	8	4	7	18,467	3,697
Aug-11	4	6	4	4	3,624	11,323
Sep-11	7	17	6	7	6,462	25,914
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
Jan-12	1	9	1	6	4,920	6,274
Feb-12	4	6	2	6	0	5,177
Mar-12	1	11	1	6	398	31,891
Apr-12	0	14	0	7	0	8,408
May-12	2	17	1	10	3,539	30,759
Jun-12	0	24	0	7	0	31,502
Jul-12	11	19	5	4	34,197	46,512
Aug-12	8	13	1	6	61,151	13,403
Sep-12	2	5	1	4	21,134	12,494
Oct-12	3	9	2	6	0	12,317
Nov-12	4	10	2	6	444	24,351
Dec-12	1	22	1	12	0	17,761
Jan-13	4	42	3	17	13,453	103,463
Feb-13	4	26	3	10	14,609	66,086
Mar-13	0	39	0	13	0	53,122

60 The curtailment volume for PJM TLRs 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 TLRs 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>. (Accessed January 16, 2013)

Table 8-29 Number of TLRs by TLR level by reliability coordinator: January through March, 2013

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2013	ICTE	0	0	0	0	0	0	0
	MISO	27	9	1	44	26	0	107
	NYIS	2	0	0	0	0	0	2
	ONT	0	0	0	0	0	0	0
	PJM	3	4	0	1	0	0	8
	SOCO	0	0	0	0	0	0	0
	SWPP	54	31	0	13	6	0	104
	TVA	9	10	0	0	2	0	21
	VACS	0	0	0	0	0	0	0
Total		95	54	1	58	34	0	242

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.[61]

Following elimination of the requirement to procure transmission for up-to congestion transactions, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012 (See Figure 8-12).

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 and unit commitment. 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. Additionally, the MMU is concerned about

61 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

the potential for market participants to utilize up-to congestion transactions to affect their other market positions, and the potential impacts that up-to congestion transactions may have on meeting FTR target allocations.

The MMU recommended 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 impacts on the actual operation of PJM markets. Alternatively, the MMU recommended 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.

While the MMU previously recommended the elimination of all internal PJM buses for use in up-to congestion bidding, on November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

Figure 8-12 Monthly up-to congestion cleared bids in MWh: January, 2006 through March, 2013

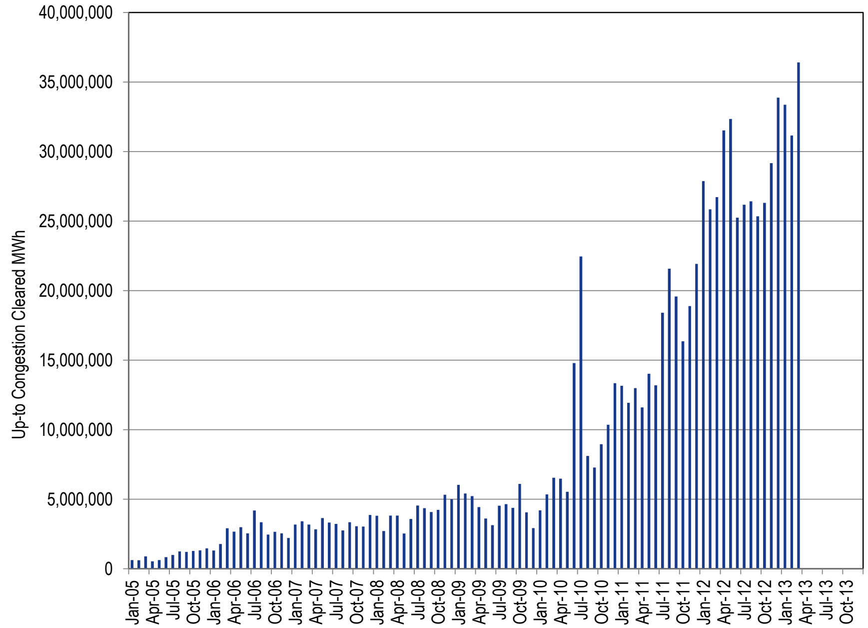


Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2013

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	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
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	24,795,325	25,498,103	1,258,755	52,022,007	103,574,190	542,992	614,349	43,829	1,631,255	2,832,425	6,517,798	7,872,496	286,535	14,482,701	29,159,529	186,492	245,943	15,042	509,436	956,913
Dec-12	22,597,985	22,560,837	1,727,510	84,548,868	131,435,199	489,208	515,873	55,376	2,767,292	3,827,749	5,116,607	6,350,080	454,289	21,958,089	33,879,065	180,592	224,830	24,459	820,991	1,250,872
Jan-13	16,718,393	21,312,321	2,010,317	76,937,535	116,978,566	422,501	527,037	63,227	2,115,649	3,128,414	4,115,418	5,820,177	522,459	22,906,008	33,364,063	149,282	199,123	23,926	657,602	1,029,933
Feb-13	12,567,004	15,509,978	1,477,275	67,258,116	96,812,373	352,963	400,563	43,133	1,798,434	2,595,093	3,019,380	4,356,113	461,615	23,311,066	31,148,173	110,397	158,085	15,892	669,364	953,738
Mar-13	14,510,721	17,019,755	1,601,487	88,109,152	121,241,114	372,402	402,711	48,112	1,959,294	2,782,519	3,868,303	4,743,283	358,180	27,439,606	36,409,373	131,506	166,295	17,884	774,020	1,089,705
Total	899,888,259	856,940,667	37,584,717	368,875,677	2,163,289,320	19,915,132	17,637,142	762,500	10,271,924	48,586,698	341,506,153	329,435,313	18,219,264	110,097,470	799,258,199	8,383,807	7,376,733	335,992	3,431,413	19,527,945

In the first three months of 2013, the cleared MW volume of up-to congestion transactions was comprised of 10.9 percent imports, 14.8 percent exports, 1.3 percent wheeling transactions and 73.0 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load. This can create loop flows and inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM Energy Market, at the PJM/NYIS Interface regardless of the submitted market path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT market path, and a second segment on the ONT-MISO-PJM market path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source is Ontario (the ONT Interface price).

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

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. These modifications are currently being evaluated by PJM.

Willing to Pay Congestion and Not Willing to Pay Congestion

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

Total uncollected congestion charges during the first three months of 2013 were $254, compared to -$15 in the first three months of 2012 (Table 8-31). 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 for the net uncollected congestion charges in the first three months of 2012. 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 the first three months of 2012, 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 planned for implementation in the second quarter of 2013.

Table 8-31 Monthly uncollected congestion charges: January, 2010 through March, 2013

Month	2010	2011	2012	2013
Jan	$148,764	$3,102	$0	$5
Feb	$542,575	$1,567	($15)	$249
Mar	$287,417	$0	$0	$0
Apr	$31,255	$4,767	($68)	
May	$41,025	$0	($27)	
Jun	$169,197	$1,354	$78	
Jul	$827,617	$1,115	$0	
Aug	$731,539	$37	$0	
Sep	$119,162	$0	$0	
Oct	$257,448	($31,443)	($6,870)	
Nov	$30,843	($795)	($4,678)	
Dec	$127,176	($659)	($209)	
Total	$3,314,018	($20,955)	($11,789)	$254

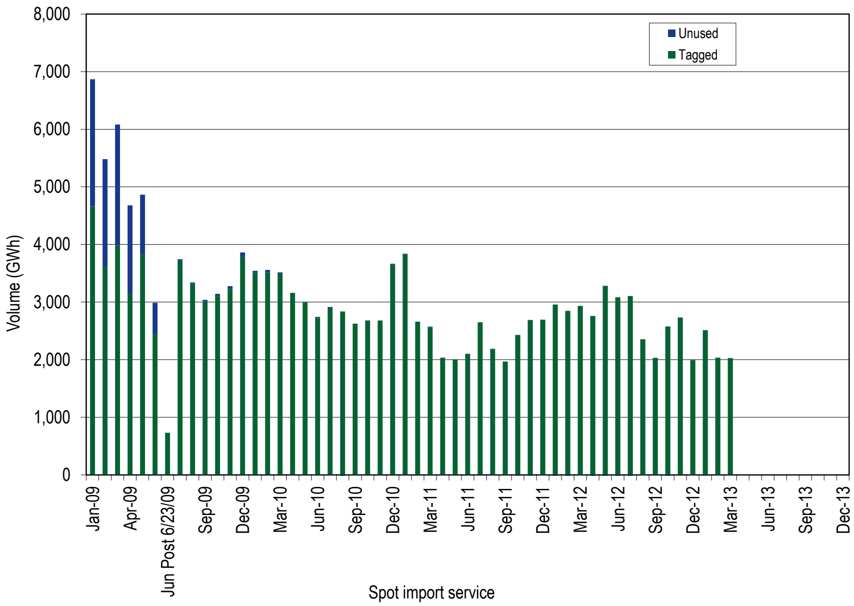
Spot Imports

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. Under this approach, market participants could 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. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[62] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding. The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

62 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>.

Figure 8-13 Spot import service utilization: January, 2009 through March, 2013



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 a valuable tool for market participants when implemented. 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, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted during the first three months of 2013.

