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.** PJM was a monthly net exporter of energy in the Real-Time Energy Market in January, August, September, October and December, and a net importer of energy in the remaining months of 2012.[1] The total 2012 real-time net interchange of 2,770.9 GWh (import) was greater than net interchange of -9,761.8 GWh (export) in 2011.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** PJM was a monthly net importer of energy in the Day-Ahead Energy Market in May and June, and a net exporter of energy in the remaining months of 2012. The total 2012 day-ahead net interchange of -12,548.4 GWh (export) was less than net interchange of 6,576.2 GWh (import) in 2011.

  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 24,808 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, for 2011.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2012, gross imports in the Day-Ahead Energy Market were 364 percent of the Real-Time Energy Market's gross imports (313 percent for 2011), gross exports in the Day-Ahead Energy Market were 416 percent of the Real-Time Energy Market's gross exports (240 percent for 2011). In 2012, net interchange was -12,548.4 GWh in the Day-Ahead Energy Market and 2,770.9 GWh in the Real-Time Energy Market compared to 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market for 2011.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, 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 69.6 percent of the total net exports: PJM/Eastern Alliant Energy Corporation (ALTE) with 26.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 21.8 percent, and PJM/MidAmerican Energy Company (MEC) with 21.3 percent of the net export volume.[2]

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[3] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.4 percent of the total net exports: PJM/MISO with 61.9 percent, and PJM/NYIS with 16.5 percent of the net export volume.

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, 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 77.8 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.0 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 percent of the net export volume.[4]

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions.[5] The top three net

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

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

4 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)).

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

exporting interface pricing points in the Day-Ahead Energy Market accounted for 71.3 percent of the total net exports: PJM/SouthEXP with 43.2 percent, PJM/Northwest with 16.6 percent and PJM/ PJM/ Ontario Independent Electricity System Operator (IMO) with 11.6 percent of the net export volume.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for 2012, up-to congestion transactions had net exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points for up-to congestion transactions accounted for 65.6 percent of the total net up-to congestion exports: PJM/SouthEXP with 49.1 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 16.5 percent of the net export up-to congestion volume.[6]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2012, the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average hourly flow. However, the direction of flows was consistent with price differentials in only 47 percent of hours in 2012.
- **PJM and New York ISO Interface Prices.** In 2012, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. However, the direction of flows was consistent with price differentials in only 52.8 percent of the hours in 2012.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2012, the PJM average hourly LMP at the Neptune Interface was $34.14 while the NYISO LMP at the Neptune Bus was $43.92, a difference of $9.78.[7] The average hourly flow during 2012 was -257 MW.[8] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64.5 percent of the hours in 2012.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2012, the average hourly difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average hourly flow. The average hourly flow during 2012 was -72 MW.[9] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 59.5 percent of the hours in 2012.
- **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.

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.

  In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh, compared to net scheduled interchange of -7,072 GWh and net actual interchange of -7,576 GWh, a difference of 504 GWh in 2011.[10] This difference is inadvertent interchange.

6 In the Day-Ahead Market, five PJM interface pricing points (PJM/CPLE, PJM/DUKIMP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

7 In 2012, there were 3,056 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 $32.96 while the NYISO LMP at the Neptune Bus during non-zero flows was $39.70, a difference of $6.74.

8 The average hourly flow during 2012, ignoring hours with no flow, on the Neptune DC Tie line was -393 MW.

9 The average hourly flow during 2012, ignoring hours with no flow, on the Linden VFT line was -89 MW.

10 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.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM called fewer TLRs in 2012 than in 2011. The fact that PJM has issued only 37 TLRs in 2012, compared to 62 in 2011, 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 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 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 29,665 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011 (Figure 8-10).
- **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 Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[11] 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. 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.

  PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.

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

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 2012, 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 2012, 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 53.3 percent of the hours for transactions between PJM and MISO and for 47.2 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.

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 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 to the expected actual power flows as possible 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 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. The average of the daily operating reserve rates paid by virtual transactions was $0.56 per MWh for the lowest five percent of all days 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.[12] 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.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net exporter of energy in the Real-Time Energy Market in January, August, September, October and December, and a net importer of energy in the remaining months of 2012 (Figure 8-1).[13] The total 2012 real-time net interchange of 2,770.9 GWh was greater than net interchange of -9,761.8 GWh in 2011. The peak month in 2012 for net exporting interchange was December, -337.2 GWh; in 2011 it was September, -1,855.3 GWh. The peak month in 2012 for net importing interchange was November, 1,152.7 GWh; in 2011 it was January, 254.3 GWh. Gross monthly export volumes averaged 3,671.3 GWh compared to 4,251.3 GWh in 2011, while gross monthly imports averaged 3,902.2 GWh compared to 3,437.8 GWh in 2011.

PJM was a monthly net importer of energy in the Day-Ahead Energy Market in May and June, and a net exporter of energy in the remaining months of 2012 (Figure 8-1). The total 2012 day-ahead net interchange of -12,548.4 GWh was less than net interchange of 6,576.2 GWh in 2011. The peak month in 2012 for net exporting interchange was October, -2,696.6 GWh; in 2011 it was November, -1,939.5 GWh. The peak month in 2012 for net importing interchange was May, 2,700.9 GWh; in 2011 it was May, 2,714.6 GWh. Gross monthly export volumes averaged 15,265.8 GWh compared to 10,203.5 GWh in 2011, while gross monthly imports averaged 14,220.1 GWh compared to 10,751.5 GWh in 2011.

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 24,808 bids per day, with an average cleared

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

13 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.

volume of 920,307 MWh per day, in 2012, compared to an average of 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, for 2011.

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.[14] In 2012, gross imports in the Day-Ahead Energy Market were 364 percent of the Real-Time Energy Market's gross imports (313 percent for 2011), gross exports in the Day-Ahead Energy Market were 416 percent of the Real-Time Energy Market's gross exports (240 percent for 2011). In 2012, net interchange was -12,548.4 GWh in the Day-Ahead Energy Market and 2,770.9 GWh in the Real-Time Energy Market compared to 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market for 2011.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: 2012

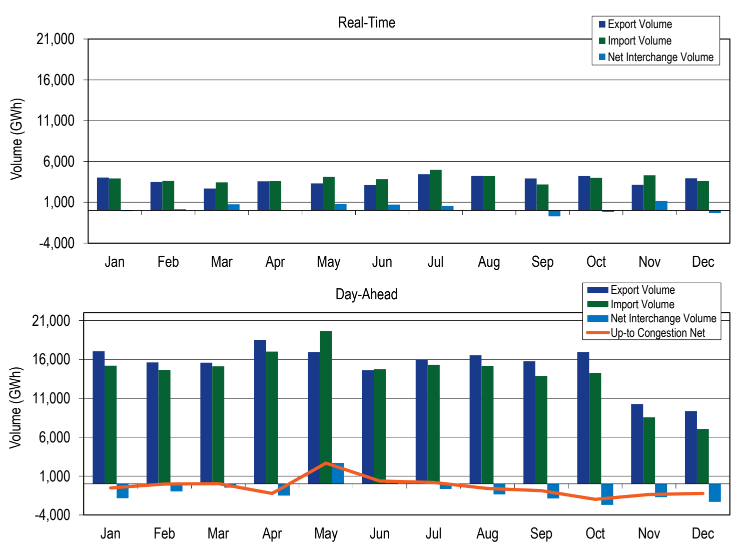


Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 2012

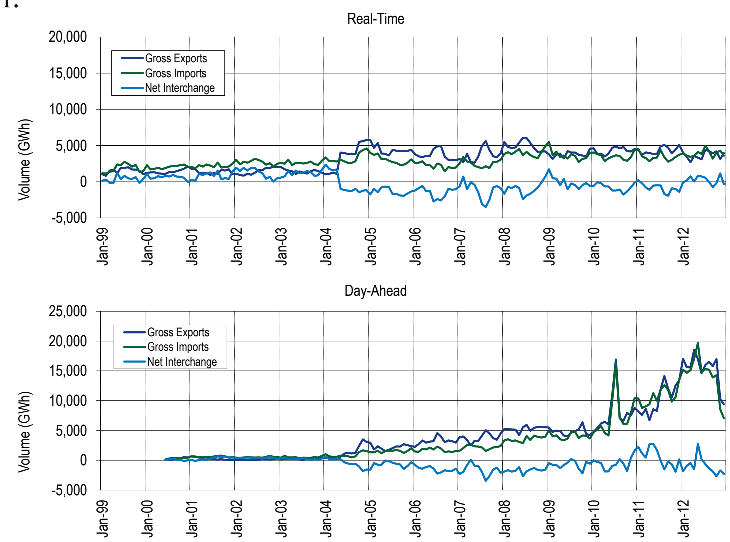


Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through 2012. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most 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.

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 in 2012. Figure 8-3 shows the approximate geographic location of the interfaces. In 2012, PJM had 20 interfaces with neighboring balancing authorities. While the Linden

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

(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 2012 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 2012, 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 69.6 percent of the total net exports: PJM/Eastern Alliant Energy Corporation (ALTE) with 26.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 21.8 percent, and PJM/MidAmerican Energy Company (MEC) with 21.3 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 33.2 percent of the total net PJM exports in the Real-Time Energy Market. The ten separate interfaces that connect PJM to MISO together represented 8.9 percent of the total net PJM exports in the Real-Time Energy Market. Nine PJM interfaces had net scheduled imports, with three importing interfaces accounting for 79.1 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 31.8 percent, PJM/Tennessee Valley Authority (TVA) with 27.1 percent and PJM/Michigan Electric Coordinated System (MECS) with 20.2 percent of the net import volume.[15]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of the shares of ownership belong to load serving entities, or their affiliates, within the PJM footprint. The agreement requires delivery of approximately 70 percent of the generation output into the PJM footprint.[16] OVEC itself does not serve load, and therefore does not generally import energy. The nature of the ownership of OVEC and the location of its affiliates within the PJM footprint account for the large percentage of PJM's net interchange import volume.

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

16 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed January 18, 2013).

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(52.5)	(29.2)	(27.8)	(34.3)	(15.3)	(22.7)	238.8	232.1	(30.4)	(32.4)	(36.6)	(45.8)	143.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
DUK	98.9	(85.3)	(13.0)	(73.2)	160.6	46.6	114.7	(9.7)	30.1	75.9	24.3	1.5	371.5
EKPC	(37.5)	(19.2)	(14.3)	(61.9)	(52.8)	(71.2)	(59.8)	(69.8)	(165.8)	(174.1)	(115.8)	(83.5)	(925.8)
LGEE	357.0	141.4	128.3	181.6	35.0	194.3	279.5	239.8	239.8	331.3	334.5	224.4	2,686.8
MEC	(468.8)	(446.6)	(430.5)	(400.2)	(482.9)	(467.3)	(485.4)	(475.5)	(475.9)	(490.6)	(463.1)	(303.2)	(5,389.9)
MISO	(368.7)	(141.8)	452.0	(380.6)	(366.3)	(154.8)	(1,028.6)	(214.7)	(236.7)	(575.2)	770.7	(15.3)	(2,259.9)
ALTE	(693.8)	(557.5)	(179.2)	(651.7)	(653.7)	(453.4)	(799.3)	(599.4)	(516.2)	(807.9)	(324.4)	(483.2)	(6,719.8)
ALTW	(49.7)	(22.7)	(4.9)	(12.9)	(32.6)	(12.1)	(9.5)	(42.6)	(16.4)	(31.8)	(15.0)	(32.0)	(282.2)
AMIL	17.7	39.9	106.3	(55.2)	(17.2)	(17.1)	146.1	151.3	133.3	146.2	248.2	249.6	1,148.9
CIN	377.7	179.8	300.2	241.2	13.5	87.1	(254.9)	161.4	41.5	(32.8)	233.9	162.2	1,510.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(172.2)	(76.5)	27.6	(123.5)	(162.6)	(72.9)	(224.2)	(98.3)	(202.1)	(193.4)	32.1	(72.4)	(1,338.5)
MECS	378.4	488.4	348.5	366.7	551.8	494.4	355.0	436.8	472.1	676.9	720.4	392.7	5,682.2
NIPS	(18.4)	(17.4)	14.3	10.4	19.3	(39.8)	(83.9)	(30.9)	76.8	(36.3)	(13.5)	(52.9)	(172.3)
WEC	(208.4)	(175.8)	(160.7)	(155.5)	(84.7)	(140.9)	(157.9)	(193.1)	(225.6)	(296.1)	(111.0)	(179.3)	(2,089.0)
NYISO	(1,127.3)	(750.9)	(508.4)	(317.8)	(110.2)	(396.7)	(577.6)	(1,168.5)	(869.2)	(523.8)	(825.8)	(1,228.7)	(8,404.8)
LIND	(63.9)	(6.3)	(64.5)	(60.6)	33.1	(39.4)	(62.6)	(119.1)	(77.0)	(8.5)	(8.2)	(159.3)	(636.3)
NEPT	(415.7)	(329.7)	(288.4)	(155.4)	(119.8)	0.0	(1.4)	(275.7)	(237.1)	(64.6)	(109.1)	(256.5)	(2,253.2)
NYIS	(647.8)	(414.9)	(155.5)	(101.8)	(23.5)	(357.3)	(513.5)	(773.8)	(555.1)	(450.7)	(708.4)	(812.9)	(5,515.3)
OVEC	712.5	693.4	588.3	627.1	835.9	714.4	834.9	745.2	526.7	814.1	1,007.9	825.6	8,925.8
TVA	783.0	787.2	580.6	485.4	794.0	883.5	1,229.6	703.0	254.9	377.9	456.6	287.7	7,623.4
Total	(103.4)	149.0	755.1	26.1	798.0	726.0	546.2	(18.2)	(726.5)	(196.8)	1,152.7	(337.2)	2,770.9

Table 8-2 Real-time scheduled gross import volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	0.3	0.0	0.4	1.6	2.1	2.7	274.0	256.4	0.0	0.9	0.0	2.4	540.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
DUK	277.1	168.8	134.8	187.5	288.2	142.0	268.7	167.6	120.5	149.4	198.6	115.7	2,218.9
EKPC	41.0	31.5	26.7	3.2	8.1	7.6	30.2	24.2	3.4	1.3	8.4	14.3	199.9
LGEE	365.4	147.0	149.7	186.2	94.6	204.4	282.2	244.2	243.3	331.4	335.2	252.0	2,835.6
MEC	16.9	7.3	0.1	0.2	0.2	0.0	0.0	0.3	1.3	0.0	7.0	181.0	214.2
MISO	1,179.1	1,022.7	1,025.3	1,229.0	1,147.9	929.4	991.6	1,112.4	1,187.9	1,420.6	1,534.9	1,132.0	13,912.7
ALTE	1.3	4.8	0.2	0.0	0.6	0.0	0.0	3.8	3.9	0.0	0.1	0.0	14.7
ALTW	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	1.5
AMIL	46.5	78.1	134.2	13.5	24.3	34.1	201.4	172.2	183.7	194.1	273.2	295.8	1,651.1
CIN	526.9	330.4	340.5	530.7	379.8	314.7	216.9	288.7	312.4	376.1	392.7	362.2	4,372.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	127.3	88.2	126.3	94.8	60.7	58.4	67.5	52.9	58.5	124.6	103.0	64.4	1,026.5
MECS	408.3	520.4	390.7	519.7	598.0	521.5	504.1	587.9	503.9	713.5	726.1	409.7	6,403.8
NIPS	59.4	0.7	32.5	70.2	84.0	0.7	1.6	6.3	125.5	12.1	38.3	0.0	431.3
WEC	9.6	0.0	0.9	0.0	0.6	0.0	0.0	0.7	0.0	0.2	0.1	0.0	11.9
NYISO	506.4	678.4	887.4	824.9	886.8	883.2	1,004.0	900.4	818.0	883.6	718.2	759.4	9,750.6
LIND	10.7	19.6	12.2	18.6	52.2	25.0	33.4	21.0	14.1	35.6	0.0	1.8	244.3
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	495.6	658.7	875.1	806.3	834.6	858.2	970.6	879.5	803.9	848.0	718.2	757.6	9,506.3
OVEC	738.2	716.7	611.5	647.2	856.0	731.7	853.5	763.8	544.3	832.3	1,029.0	847.4	9,171.8
TVA	802.8	845.0	610.7	510.0	835.2	927.7	1,272.0	742.8	273.1	386.6	471.8	303.7	7,981.3
Total	3,927.2	3,617.4	3,446.6	3,589.7	4,118.9	3,828.7	4,976.3	4,212.1	3,191.9	4,006.1	4,303.1	3,608.0	46,825.9

Table 8-3 Real-time scheduled gross export volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	52.8	29.2	28.2	35.9	17.4	25.5	35.2	24.3	30.5	33.3	36.6	48.1	397.0
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	178.2	254.1	147.7	260.6	127.6	95.4	154.0	177.3	90.5	73.5	174.3	114.2	1,847.4
EKPC	78.5	50.7	41.1	65.1	60.8	78.8	90.0	94.0	169.2	175.3	124.1	97.8	1,125.6
LGEE	8.4	5.6	21.4	4.6	59.6	10.1	2.7	4.4	3.5	0.2	0.8	27.6	148.9
MEC	485.7	453.9	430.5	400.4	483.0	467.3	485.4	475.8	477.2	490.6	470.1	484.2	5,604.1
MISO	1,547.8	1,164.5	573.3	1,609.6	1,514.2	1,084.1	2,020.2	1,327.2	1,424.6	1,995.8	764.2	1,147.3	16,172.7
ALTE	695.1	562.3	179.5	651.7	654.4	453.4	799.3	603.2	520.1	807.9	324.4	483.2	6,734.4
ALTW	49.7	22.8	4.9	12.9	32.6	12.1	9.5	42.6	16.4	31.8	16.4	32.0	283.7
AMIL	28.7	38.3	28.0	68.7	41.5	51.2	55.3	20.9	50.4	47.9	25.0	46.2	502.1
CIN	149.2	150.6	40.3	289.6	366.4	227.6	471.9	127.3	270.9	408.9	158.8	200.0	2,861.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	299.5	164.7	98.7	218.3	223.3	131.3	291.7	151.2	260.6	318.0	70.9	136.7	2,364.9
MECS	29.9	32.0	42.2	153.0	46.1	27.1	149.1	151.1	31.9	36.6	5.6	17.0	721.6
NIPS	77.8	18.1	18.2	59.8	64.7	40.5	85.5	37.2	48.7	48.4	51.9	52.9	603.6
WEC	218.0	175.8	161.6	155.5	85.3	140.9	157.9	193.7	225.6	296.3	111.1	179.3	2,100.9
NYISO	1,633.7	1,429.2	1,395.7	1,142.7	997.0	1,279.9	1,581.6	2,069.0	1,687.2	1,407.4	1,543.9	1,988.2	18,155.5
LIND	74.6	26.0	76.7	79.2	19.1	64.4	96.0	140.0	91.1	44.1	8.2	161.1	880.7
NEPT	415.7	329.7	288.4	155.4	119.8	0.0	1.4	275.7	237.1	64.6	109.1	256.5	2,253.2
NYIS	1,143.4	1,073.6	1,030.6	908.1	858.1	1,215.6	1,484.1	1,653.2	1,359.0	1,298.7	1,426.6	1,570.6	15,021.6
OVEC	25.7	23.3	23.3	20.1	20.1	17.3	18.6	18.6	17.7	18.2	21.2	21.8	246.0
TVA	19.8	57.8	30.2	24.6	41.2	44.1	42.4	39.8	18.2	8.7	15.2	15.9	357.9
Total	4,030.6	3,468.4	2,691.5	3,563.6	3,320.9	3,102.7	4,430.2	4,230.3	3,918.4	4,202.9	3,150.4	3,945.2	44,055.0

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.[17] 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.[18]

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.[19] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. According to the PJM Interface Price Definition Methodology, dynamic interface pricing calculations use actual system conditions to determine a

17 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.

18 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.

19 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed January 16, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

set of weighting factors for each external pricing point in an interface price definition.[20] 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 in 2012.

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 as defined below:

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

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special

20 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>. (January 16, 2013)

agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[21]

In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[22] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.4 percent of the total net exports: PJM/MISO with 61.9 percent, and PJM/NYIS with 16.5 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 25.5 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 77.6 percent of the total net imports: PJM/SouthIMP with 52.0 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 25.5 percent of the net import volume.

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	479.8	485.2	431.3	551.8	426.9	377.8	420.8	370.8	379.2	656.7	745.9	555.1	5,881.3
LINDENVFT	(63.9)	(6.3)	(64.5)	(60.6)	33.1	(39.4)	(62.6)	(119.1)	(77.0)	(8.5)	(8.2)	(159.3)	(636.3)
MISO	(1,992.3)	(1,601.0)	(940.0)	(1,985.0)	(1,934.8)	(1,496.7)	(2,196.9)	(1,565.4)	(1,671.9)	(2,254.3)	(934.9)	(1,356.1)	(19,929.4)
NEPTUNE	(415.7)	(329.7)	(288.4)	(155.4)	(119.8)	0.0	(1.4)	(275.7)	(237.1)	(64.6)	(109.1)	(256.5)	(2,253.2)
NORTHWEST	(1.6)	(1.5)	(1.2)	(3.5)	(21.2)	(0.3)	(55.0)	(25.2)	(1.5)	(2.3)	(2.4)	(1.5)	(117.1)
NYIS	(648.1)	(415.3)	(166.8)	(103.3)	(30.4)	(355.7)	(482.9)	(722.7)	(489.3)	(433.4)	(673.0)	(793.7)	(5,314.6)
OVEC	712.5	693.4	588.3	627.1	835.9	714.4	834.9	745.2	526.7	814.1	1,007.9	825.6	8,925.8
SOUTHIMP	2,164.4	1,722.9	1,465.1	1,550.6	1,920.1	1,783.4	2,432.6	1,919.0	1,163.6	1,387.3	1,478.5	1,155.6	20,143.1
CPLEIMP	0.0	0.0	0.4	1.0	1.4	2.4	273.5	256.4	0.0	0.2	0.0	0.0	535.1
DUKIMP	106.7	88.6	56.7	61.8	111.9	56.9	219.9	129.2	74.3	71.3	53.2	46.1	1,076.5
NCMPAIMP	44.7	44.2	25.2	21.8	72.6	41.5	25.6	24.8	15.8	12.0	9.9	10.3	348.4
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	1,465.9	1,734.2	1,682.5	1,913.7	1,508.6	1,073.5	1,303.9	1,415.4	1,099.2	18,183.0
SOUTHEXP	(338.5)	(398.7)	(268.6)	(395.7)	(311.9)	(257.4)	(343.3)	(345.2)	(319.2)	(291.8)	(351.9)	(306.4)	(3,928.6)
CPLEEXP	(52.8)	(26.6)	(26.0)	(31.3)	(16.9)	(24.3)	(30.9)	(24.0)	(29.0)	(33.0)	(23.8)	(48.1)	(366.7)
DUKEXP	(172.0)	(233.9)	(141.2)	(243.9)	(108.8)	(74.2)	(129.2)	(157.4)	(74.7)	(48.9)	(128.9)	(86.4)	(1,599.5)
NCMPAEXP	0.0	0.0	0.0	(2.6)	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)	(0.9)	(4.8)
SOUTHWEST	(1.6)	(1.3)	0.0	(4.2)	(5.0)	(3.5)	(10.9)	(5.1)	(7.4)	(0.6)	(0.3)	(2.4)	(42.0)
SOUTHEXP	(112.1)	(136.9)	(101.4)	(113.7)	(181.2)	(155.5)	(172.3)	(158.7)	(208.2)	(209.4)	(197.6)	(168.7)	(1,915.6)
Total	(103.4)	149.0	755.1	26.1	798.0	726.0	546.2	(18.2)	(726.5)	(196.8)	1,152.7	(337.2)	2,770.9

21 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.

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

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	480.4	486.8	434.3	554.0	433.1	385.6	443.5	389.1	400.8	658.6	747.8	558.8	5,972.9
LINDENVFT	10.7	19.6	12.2	18.6	52.2	25.0	33.4	21.0	14.1	35.6	0.0	1.8	244.3
MISO	38.8	14.6	62.0	15.3	31.4	47.6	225.4	205.4	210.7	227.8	295.6	271.2	1,645.8
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.2	0.0	0.0	0.4
NYIS	494.6	656.7	861.4	804.0	826.0	855.5	987.8	913.8	858.3	864.2	752.2	773.2	9,647.7
OVEC	738.2	716.7	611.5	647.2	856.0	731.7	853.5	763.8	544.3	832.3	1,029.0	847.4	9,171.8
SOUTHIMP	2,164.4	1,722.9	1,465.1	1,550.6	1,920.1	1,783.4	2,432.6	1,919.0	1,163.6	1,387.3	1,478.5	1,155.6	20,143.1
CPLEIMP	0.0	0.0	0.4	1.0	1.4	2.4	273.5	256.4	0.0	0.2	0.0	0.0	535.1
DUKIMP	106.7	88.6	56.7	61.8	111.9	56.9	219.9	129.2	74.3	71.3	53.2	46.1	1,076.5
NCMPAIMP	44.7	44.2	25.2	21.8	72.6	41.5	25.6	24.8	15.8	12.0	9.9	10.3	348.4
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	1,465.9	1,734.2	1,682.5	1,913.7	1,508.6	1,073.5	1,303.9	1,415.4	1,099.2	18,183.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,927.2	3,617.4	3,446.6	3,589.7	4,118.9	3,828.7	4,976.3	4,212.1	3,191.9	4,006.1	4,303.1	3,608.0	46,825.9

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	0.7	1.6	3.1	2.2	6.2	7.7	22.6	18.3	21.6	1.9	1.9	3.7	91.6
LINDENVFT	74.6	26.0	76.7	79.2	19.1	64.4	96.0	140.0	91.1	44.1	8.2	161.1	880.7
MISO	2,031.1	1,615.6	1,002.0	2,000.3	1,966.2	1,544.3	2,422.3	1,770.8	1,882.7	2,482.2	1,230.5	1,627.3	21,575.1
NEPTUNE	415.7	329.7	288.4	155.4	119.8	0.0	1.4	275.7	237.1	64.6	109.1	256.5	2,253.2
NORTHWEST	1.6	1.5	1.2	3.5	21.2	0.3	55.1	25.2	1.5	2.6	2.4	1.5	117.5
NYIS	1,142.8	1,072.0	1,028.2	907.3	856.4	1,211.2	1,470.7	1,636.5	1,347.6	1,297.6	1,425.2	1,566.9	14,962.3
OVEC	25.7	23.3	23.3	20.1	20.1	17.3	18.6	18.6	17.7	18.2	21.2	21.8	246.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	338.5	398.7	268.6	395.7	311.9	257.4	343.3	345.2	319.2	291.8	351.9	306.4	3,928.6
CPLEEXP	52.8	26.6	26.0	31.3	16.9	24.3	30.9	24.0	29.0	33.0	23.8	48.1	366.7
DUKEXP	172.0	233.9	141.2	243.9	108.8	74.2	129.2	157.4	74.7	48.9	128.9	86.4	1,599.5
NCMPAEXP	0.0	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.9	4.8
SOUTHWEST	1.6	1.3	0.0	4.2	5.0	3.5	10.9	5.1	7.4	0.6	0.3	2.4	42.0
SOUTHEXP	112.1	136.9	101.4	113.7	181.2	155.5	172.3	158.7	208.2	209.4	197.6	168.7	1,915.6
Total	4,030.6	3,468.4	2,691.5	3,563.6	3,320.9	3,102.7	4,430.2	4,230.3	3,918.4	4,202.9	3,150.4	3,945.2	44,055.0

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.

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

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

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay.[24] If, in the Day-Ahead Energy Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

Dispatchable transactions in the Day-Ahead Energy Market are similar to those in the Real-Time Energy Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Energy Market represent a financial obligation. If the market participant does not meet the commitment in the Real-Time Energy Market, they are subject to the balancing market settlement.

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

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

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.

24 Effective May 15, 2012, up-to congestion transactions were required to be submitted for the PJM Day-Ahead Market evaluation in the eMarket application, and are no longer accepted through the EES application.

participant chooses any import pricing point and export pricing point they wish to have associated with their transaction. These selections are made through the EES user interface.

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

On May 15, 2012, the submission of up-to congestion transactions was moved to the eMKT application. The submission of up-to congestion transactions in eMKT no longer requires market participants to acquire the up-to congestion OASIS reservation. This change eliminates all references to any specific interface previously identified by the OASIS reservation, and only identifies the relevant interface pricing points for the up-to congestion transaction as specified by the market participants at the time of submission. As a result, the up-to congestion transactions shown in the tables have been removed from the interface specific totals, and are now represented only as a single monthly total. 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 2012 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 2012, 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 77.8 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.0 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 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 43.2 percent of the total net PJM exports in the Day-Ahead Energy Market. The ten separate interfaces that connect PJM to MISO together represented 12.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net scheduled imports, with three importing interfaces accounting for 87.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 56.4 percent, PJM/Tennessee Valley Authority (TVA) with 13.6 percent and PJM/Michigan Electric Coordinated System (MECS) with 11.7 percent of the net import volume.[25]

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 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(46.8)	(19.9)	(24.9)	(29.6)	(15.3)	(23.9)	(8.8)	182.6	(27.6)	(33.0)	(23.3)	(43.9)	(114.3)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	39.0	18.6	19.8	11.3	40.4	35.5	29.5	96.6	35.2	39.4	26.5	35.7	427.5
EKPC	(35.6)	(34.8)	(37.2)	(36.0)	(37.2)	(36.0)	(37.2)	(36.6)	(36.0)	(37.2)	(36.1)	(37.2)	(437.0)
LGEE	52.9	0.0	(18.6)	4.6	12.3	39.2	50.8	18.1	48.4	59.0	102.3	72.5	441.5
MEC	(485.7)	(454.2)	(429.3)	(386.5)	(482.1)	(462.9)	(470.7)	(472.7)	(461.3)	(480.5)	(468.7)	(483.6)	(5,538.1)
MISO	(426.3)	(243.4)	114.8	(13.8)	(86.8)	(5.5)	(507.0)	(280.0)	(188.6)	(377.7)	(100.9)	(357.2)	(2,472.6)
ALTE	(474.1)	(476.4)	(145.4)	(410.0)	(243.1)	(170.6)	(438.6)	(356.9)	(204.6)	(318.0)	(132.9)	(261.1)	(3,631.7)
ALTW	(26.1)	(7.8)	(2.6)	(2.4)	(6.1)	(6.6)	(0.8)	(22.5)	(1.7)	(18.0)	(11.7)	(29.6)	(135.8)
AMIL	(3.1)	0.0	0.0	0.8	0.0	2.4	0.0	0.8	3.6	1.4	4.8	(1.0)	9.7
CIN	130.6	205.2	236.5	322.4	59.2	131.0	(90.5)	91.3	91.4	(2.6)	30.8	30.3	1,235.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(15.0)	(10.2)	(1.9)	(5.1)	(10.9)	(7.9)	(27.0)	(13.8)	(16.6)	(13.1)	(7.1)	(11.8)	(140.5)
MECS	81.3	148.4	112.3	183.2	177.4	115.5	128.7	133.8	58.2	82.9	128.8	34.0	1,384.5
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	(3.8)	(33.3)	(46.4)	(46.2)	(51.1)	(50.0)	(230.8)
WEC	(119.9)	(102.6)	(84.1)	(102.5)	(63.2)	(69.4)	(75.0)	(79.4)	(72.6)	(64.1)	(62.5)	(68.1)	(963.3)
NYISO	(1,175.9)	(928.5)	(661.4)	(399.5)	(302.6)	(458.5)	(679.2)	(966.4)	(821.6)	(613.4)	(690.2)	(856.7)	(8,553.8)
LIND	(10.2)	(2.2)	(7.2)	(0.7)	29.3	1.2	10.3	3.0	(2.4)	19.9	0.0	(3.3)	37.7
NEPT	(425.2)	(355.9)	(314.5)	(160.0)	(142.8)	0.0	(9.2)	(274.5)	(244.4)	(70.4)	(109.7)	(262.7)	(2,369.3)
NYIS	(740.4)	(570.4)	(339.7)	(238.8)	(189.2)	(459.8)	(680.3)	(694.9)	(574.8)	(562.9)	(580.5)	(590.7)	(6,222.2)
OVEC	545.7	521.4	440.8	472.6	625.9	552.9	640.1	548.9	379.4	610.5	726.9	584.8	6,649.8
TVA	204.7	195.9	92.8	95.4	275.9	136.6	156.9	147.4	64.6	116.5	104.7	5.6	1,597.0
Total without Up-To Congestion	(1,327.9)	(945.0)	(503.3)	(281.4)	30.5	(222.7)	(825.6)	(762.2)	(1,007.4)	(716.4)	(358.7)	(1,080.1)	(8,000.1)
Up-To Congestion	(519.6)	(17.7)	28.2	(1,223.6)	2,670.4	364.2	177.9	(586.8)	(872.8)	(1,980.3)	(1,354.7)	(1,233.5)	(4,548.3)
Total	(1,847.5)	(962.7)	(475.1)	(1,505.0)	2,700.9	141.5	(647.7)	(1,349.0)	(1,880.2)	(2,696.6)	(1,713.4)	(2,313.6)	(12,548.4)

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	0.0	0.0	0.0	0.0	0.0	0.0	27.6	204.2	0.0	0.0	0.0	0.0	231.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	40.8	47.9	32.8	18.9	41.2	35.5	35.4	116.5	35.2	39.4	28.4	35.7	507.8
EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LGEE	52.9	0.0	0.0	4.6	12.3	39.2	50.8	18.1	48.4	59.0	102.3	72.5	460.1
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.8
MISO	217.0	367.5	359.3	522.0	385.0	336.6	249.9	294.8	273.1	345.0	222.9	131.5	3,704.7
ALTE	0.0	0.0	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.0	1.5
AMIL	0.4	0.0	0.0	0.8	0.0	2.4	0.0	0.8	3.6	1.4	4.8	1.3	15.5
CIN	135.3	219.1	247.0	336.5	207.7	218.7	120.8	149.6	210.2	254.7	87.8	92.2	2,279.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
MECS	81.3	148.4	112.3	183.2	177.4	115.5	129.0	144.5	59.3	88.9	128.8	38.0	1,406.5
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	359.7	533.6	728.6	655.1	688.1	717.4	790.0	766.6	684.3	735.2	564.6	651.1	7,874.3
LIND	0.0	1.4	1.7	7.7	32.8	6.4	18.9	14.8	5.0	23.9	0.0	0.3	112.9
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	359.7	532.3	726.9	647.4	655.3	710.9	771.1	751.8	679.4	711.3	564.6	650.7	7,761.4
OVEC	571.3	544.6	464.0	491.4	645.9	552.9	640.1	567.3	397.1	610.5	726.9	584.8	6,797.0
TVA	217.7	223.7	100.5	105.5	307.3	149.1	165.0	150.1	64.8	117.1	111.2	8.0	1,720.0
Total without Up-To Congestion	1,459.4	1,717.4	1,685.2	1,797.4	2,079.8	1,830.6	1,958.9	2,117.7	1,503.9	1,906.3	1,756.4	1,483.5	21,296.4
Up-To Congestion	13,728.0	12,936.0	13,418.2	15,214.5	17,586.0	12,925.9	13,350.2	13,068.1	12,381.2	12,361.9	6,804.3	5,570.9	149,345.1
Total	15,187.4	14,653.3	15,103.4	17,011.9	19,665.8	14,756.4	15,309.1	15,185.8	13,885.1	14,268.1	8,560.7	7,054.4	170,641.5

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	46.8	19.9	24.9	29.6	15.3	23.9	36.4	21.5	27.6	33.0	23.3	43.9	346.1
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	1.8	29.3	13.0	7.6	0.8	0.0	5.9	20.0	0.0	0.0	1.9	0.0	80.3
EKPC	35.6	34.8	37.2	36.0	37.2	36.0	37.2	36.6	36.0	37.2	36.1	37.2	437.0
LGEE	0.0	0.0	18.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.6
MEC	485.7	454.2	429.3	386.5	482.1	462.9	470.7	472.7	462.1	480.5	468.7	483.6	5,538.9
MISO	643.3	611.0	244.5	535.8	471.8	342.1	757.0	574.9	461.7	722.8	323.8	488.7	6,177.3
ALTE	474.1	476.4	145.4	411.6	243.1	170.6	438.6	356.9	204.6	318.0	132.9	261.1	3,633.3
ALTW	26.1	7.8	2.6	2.4	6.1	6.6	0.8	22.5	1.7	18.0	13.2	29.6	137.3
AMIL	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	5.9
CIN	4.7	13.9	10.5	14.1	148.5	87.7	211.3	58.2	118.8	257.4	57.0	61.9	1,044.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	15.0	10.2	1.9	5.1	10.9	7.9	27.1	13.8	16.6	13.1	7.1	11.8	140.6
MECS	0.0	0.0	0.0	0.0	0.0	0.0	0.3	10.7	1.1	6.0	0.0	4.0	22.1
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	3.8	33.3	46.4	46.2	51.1	50.0	230.8
WEC	119.9	102.6	84.1	102.5	63.2	69.4	75.0	79.4	72.6	64.1	62.5	68.1	963.3
NYISO	1,535.5	1,462.1	1,390.0	1,054.5	990.7	1,175.9	1,469.2	1,733.0	1,505.9	1,348.7	1,254.9	1,507.8	16,428.1
LIND	10.2	3.6	8.9	8.4	3.4	5.2	8.6	11.9	7.4	4.0	0.0	3.6	75.2
NEPT	425.2	355.9	314.5	160.0	142.8	0.0	9.2	274.5	244.4	70.4	109.7	262.7	2,369.3
NYIS	1,100.1	1,102.7	1,066.6	886.2	844.5	1,170.7	1,451.4	1,446.7	1,254.1	1,274.2	1,145.1	1,241.4	13,983.6
OVEC	25.6	23.3	23.3	18.8	20.1	0.0	0.0	18.5	17.7	0.0	0.0	0.0	147.2
TVA	13.0	27.8	7.7	10.1	31.4	12.5	8.2	2.7	0.3	0.6	6.5	2.4	123.0
Total without Up-To Congestion	2,787.3	2,662.4	2,188.5	2,078.8	2,049.3	2,053.3	2,784.5	2,879.9	2,511.2	2,622.6	2,115.1	2,563.6	29,296.5
Up-To Congestion	14,247.6	12,953.7	13,390.0	16,438.1	14,915.6	12,561.6	13,172.3	13,654.9	13,254.1	14,342.2	8,159.0	6,804.4	153,893.4
Total	17,034.9	15,616.0	15,578.5	18,516.9	16,964.9	14,614.9	15,956.8	16,534.8	15,765.3	16,964.8	10,274.1	9,368.0	183,189.9

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. Up-to congestion transactions account for 87.5 percent of all scheduled import MW transactions and 84.0 percent of all scheduled export MW transactions in the Day-Ahead Market. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for 2012 in Table 8-10. Up-to congestion transactions by interface pricing point for 2012 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 2012, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions.[26] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 71.3 percent of the total net exports: PJM/SouthEXP with 43.2 percent, PJM/Northwest[27] with 16.6 percent and PJM/PJM/Ontario Independent Electricity System Operator (IMO) with 11.6 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 8.1 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interface pricing points had net imports, with three importing interface pricing points accounting for 78.0 percent of the total net imports: PJM/SouthIMP with 30.3 percent, PJM/Ohio Valley Electric Corporation (OVEC) with 24.5 percent, and PJM/MISO with 23.1 percent of the net import volume.

In the Day-Ahead Market, for 2012, up-to congestion transactions had net exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing

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.

points for up-to congestion transactions accounted for 65.6 percent of the total net up-to congestion exports: PJM/SouthEXP with 49.1 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 16.5 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 4.2 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 4.2 percent. The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market). Seven PJM interface pricing points had net up-to congestion imports, with two importing interface pricing points accounting for 60.0 percent of the total net up-to congestion imports: PJM/MISO with 36.1 percent and PJM/NYIS with 23.9 percent of the net import volume.[28]

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	(1,019.1)	(410.0)	(868.4)	(952.1)	(919.2)	(584.3)	(511.5)	(161.3)	(381.0)	(274.7)	54.4	(59.1)	(6,086.2)
LINDENVFT	9.2	(51.2)	23.5	74.6	97.9	77.2	113.1	29.3	12.3	(86.6)	5.7	(45.1)	259.9
MISO	1,268.5	1,277.6	1,419.8	1,454.3	1,351.1	782.5	384.0	81.6	527.4	389.1	180.5	158.6	9,275.0
NEPTUNE	(891.7)	(837.7)	(870.3)	(492.9)	(436.7)	(181.7)	(32.0)	(36.6)	(116.9)	(75.6)	40.5	(309.2)	(4,240.8)
NIPSCO	(47.9)	(33.1)	(630.3)	(902.3)	(479.9)	(435.1)	(238.4)	(374.2)	(495.0)	(372.9)	(558.8)	(762.2)	(5,330.2)
NORTHWEST	(524.9)	(370.7)	(543.2)	(751.2)	(644.5)	(750.1)	(776.1)	(880.8)	(770.4)	(1,126.1)	(835.2)	(750.9)	(8,724.0)
NYIS	(35.0)	300.8	573.1	528.3	1,717.1	882.6	231.6	40.2	78.7	(67.9)	(403.0)	(376.6)	3,469.8
OVEC	1,236.4	779.2	1,898.6	1,205.3	3,017.4	1,284.3	894.6	181.9	(271.9)	(564.3)	(74.0)	224.9	9,812.5
SOUTHIMP	2,041.5	2,471.4	2,283.8	2,888.6	3,375.8	2,915.1	3,635.1	3,249.3	2,718.9	3,106.1	1,661.2	1,194.4	31,541.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	27.3	204.2	0.0	0.0	0.0	0.0	231.4
DUKIMP	3.9	12.2	3.5	1.6	4.0	1.0	8.6	78.8	3.6	11.2	2.9	6.5	137.7
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,014.4	1,150.3	901.7	625.8	678.0	343.7	332.4	8,729.3
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	777.6	801.7	851.2	1,128.0	1,461.1	1,056.9	1,240.2	1,026.3	1,047.5	1,329.3	926.6	514.1	12,160.7
SOUTHEXP	(3,884.4)	(4,089.1)	(3,761.8)	(4,557.5)	(4,378.1)	(3,848.9)	(4,348.1)	(3,478.4)	(3,182.3)	(3,623.9)	(1,784.8)	(1,588.5)	(42,525.7)
CPLEEXP	(46.7)	(19.8)	(24.9)	(30.3)	(15.7)	(23.5)	(36.0)	(21.1)	(27.2)	(32.7)	(23.0)	(43.6)	(344.6)
DUKEXP	(1.8)	(27.4)	(13.0)	(7.6)	(0.8)	0.0	(5.9)	(20.0)	0.0	0.0	(1.9)	0.0	(78.3)
NCMPAEXP	(0.1)	(0.1)	0.0	(0.5)	(0.8)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(3.9)
SOUTHEAST	(530.7)	(546.3)	(488.7)	(588.0)	(566.5)	(334.4)	(287.6)	(166.4)	(124.7)	(252.2)	(47.8)	(66.5)	(3,999.8)
SOUTHWEST	(1,146.0)	(1,425.1)	(912.1)	(1,485.4)	(1,504.2)	(1,251.0)	(1,871.3)	(1,647.9)	(1,581.1)	(1,407.0)	(493.3)	(661.7)	(15,386.1)
SOUTHEXP	(2,159.1)	(2,070.5)	(2,323.0)	(2,445.7)	(2,290.0)	(2,239.7)	(2,146.9)	(1,622.6)	(1,448.9)	(1,931.7)	(1,218.5)	(816.3)	(22,713.0)
Total	(1,847.5)	(962.7)	(475.1)	(1,505.0)	2,700.9	141.5	(647.7)	(1,349.0)	(1,880.2)	(2,696.6)	(1,713.4)	(2,313.6)	(12,548.4)

28 In the Day-Ahead Market, five PJM interface pricing points (PJM/CPLE, PJM/DUKIMP, 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): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	(1,104.0)	(559.2)	(981.0)	(1,123.5)	(1,084.7)	(696.5)	(637.1)	(296.2)	(426.3)	(361.6)	(71.1)	(95.5)	(7,436.7)
LINDENVFT	19.4	(49.0)	30.8	75.3	68.6	76.0	102.7	24.8	14.8	(106.5)	5.7	(41.8)	220.8
MISO	1,777.3	1,735.2	1,436.5	1,856.8	1,658.4	1,122.6	1,138.6	653.8	982.7	1,106.0	494.8	648.3	14,610.9
NEPTUNE	(466.5)	(481.8)	(555.8)	(332.9)	(294.0)	(181.7)	(22.7)	237.9	127.4	(5.1)	150.3	(46.5)	(1,871.6)
NIPSCO	(47.9)	(33.1)	(630.3)	(902.3)	(479.9)	(435.1)	(238.4)	(374.2)	(495.0)	(372.9)	(558.8)	(762.2)	(5,330.2)
NORTHWEST	(39.2)	83.5	(113.9)	(364.6)	(162.4)	(287.6)	(305.4)	(408.1)	(310.8)	(645.6)	(366.5)	(267.3)	(3,188.0)
NYIS	710.1	872.0	911.2	767.0	1,905.9	1,342.3	911.9	736.5	653.5	495.0	177.4	211.7	9,694.6
OVEC	690.8	257.9	1,459.4	732.7	2,391.5	731.3	254.4	(367.0)	(651.3)	(1,174.7)	(800.9)	(359.9)	3,164.3
SOUTHIMP	1,727.7	2,134.2	2,131.7	2,542.2	2,960.4	2,469.4	3,234.4	2,603.1	2,350.8	2,638.3	1,331.5	984.6	27,108.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,013.7	1,150.3	901.7	625.6	674.4	343.7	332.4	8,724.7
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	467.7	476.7	702.6	783.3	1,049.8	612.9	875.4	663.1	683.1	876.3	599.9	310.8	8,101.5
SOUTHEXP	(3,787.2)	(3,977.3)	(3,660.3)	(4,474.2)	(4,293.4)	(3,776.5)	(4,260.5)	(3,397.6)	(3,118.4)	(3,553.1)	(1,717.1)	(1,504.9)	(41,520.7)
CPLEEXP	0.0	0.0	0.0	(1.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.2)
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(530.7)	(546.3)	(488.7)	(588.0)	(566.5)	(334.4)	(287.6)	(166.4)	(124.7)	(252.2)	(47.8)	(66.5)	(3,999.8)
SOUTHWEST	(1,146.0)	(1,425.1)	(912.1)	(1,485.4)	(1,504.2)	(1,251.0)	(1,871.3)	(1,647.9)	(1,581.1)	(1,407.0)	(493.3)	(661.7)	(15,386.1)
SOUTHEXP	(2,110.6)	(2,005.9)	(2,259.5)	(2,399.6)	(2,222.6)	(2,191.2)	(2,101.6)	(1,583.3)	(1,412.6)	(1,893.9)	(1,176.0)	(776.7)	(22,133.6)
Total Interfaces	(519.6)	(17.7)	28.2	(1,223.6)	2,670.4	364.2	177.9	(586.8)	(872.8)	(1,980.3)	(1,354.7)	(1,233.5)	(4,548.3)
INTERNAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14,482.7	21,958.1	36,440.8
Total	(519.6)	(17.7)	28.2	(1,223.6)	2,670.4	364.2	177.9	(586.8)	(872.8)	(1,980.3)	13,128.0	20,724.6	31,892.5

Table 8-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	545.7	587.1	505.6	549.9	792.8	623.9	610.5	804.1	524.1	572.5	405.3	329.2	6,850.7
LINDENVFT	350.2	372.2	459.9	514.9	577.6	520.9	627.9	508.6	477.9	519.1	17.6	159.5	5,106.4
MISO	4,021.4	3,236.4	3,339.4	3,847.6	3,669.5	2,551.1	2,146.4	1,882.8	2,373.8	2,212.7	992.5	819.9	31,093.6
NEPTUNE	0.0	0.0	0.0	0.0	13.4	86.9	250.9	436.3	418.9	172.6	184.2	156.0	1,719.2
NIPSCO	456.4	514.0	364.9	292.8	235.4	259.8	302.7	312.2	339.0	240.4	65.0	39.4	3,422.0
NORTHWEST	769.8	664.5	502.0	432.2	596.9	442.7	306.7	354.9	370.6	280.3	208.7	233.3	5,162.7
NYIS	1,592.7	1,890.4	2,212.4	1,963.8	3,173.2	2,504.8	2,037.3	2,025.9	1,973.7	2,052.3	1,271.8	1,464.8	24,163.2
OVEC	5,409.6	4,917.3	5,435.3	6,522.2	7,231.1	4,851.3	5,391.6	5,611.7	4,688.1	5,112.1	3,754.4	2,657.8	61,582.4
SOUTHIMP	2,041.5	2,471.4	2,283.8	2,888.6	3,375.8	2,915.1	3,635.1	3,249.3	2,718.9	3,106.1	1,661.2	1,194.4	31,541.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	27.3	204.2	0.0	0.0	0.0	0.0	231.4
DUKIMP	3.9	12.2	3.5	1.6	4.0	1.0	8.6	78.8	3.6	11.2	2.9	6.5	137.7
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,014.4	1,150.3	901.7	625.8	678.0	343.7	332.4	8,729.3
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	777.6	801.7	851.2	1,128.0	1,461.1	1,056.9	1,240.2	1,026.3	1,047.5	1,329.3	926.6	514.1	12,160.7
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	15,187.4	14,653.3	15,103.4	17,011.9	19,665.8	14,756.4	15,309.1	15,185.8	13,885.1	14,268.1	8,560.7	7,054.4	170,641.5

Table 8-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	460.9	437.9	393.0	378.5	627.2	511.7	484.9	669.2	478.7	485.5	279.7	292.8	5,500.2
LINDENVFT	350.2	370.9	458.2	507.2	544.9	514.5	609.0	493.8	473.0	495.1	17.6	159.1	4,993.5
MISO	3,891.7	3,083.1	3,111.6	3,714.3	3,504.7	2,548.7	2,144.0	1,880.1	2,364.8	2,206.9	982.9	818.6	30,251.3
NEPTUNE	0.0	0.0	0.0	0.0	13.4	86.9	250.9	436.3	418.9	172.6	184.2	156.0	1,719.2
NIPSCO	456.4	514.0	364.9	292.8	235.4	259.8	302.7	312.2	339.0	240.4	65.0	39.4	3,422.0
NORTHWEST	769.8	664.5	502.0	432.2	596.9	442.7	306.7	354.9	370.6	280.3	208.7	233.3	5,162.7
NYIS	1,233.0	1,358.8	1,484.0	1,316.4	2,517.9	1,793.8	1,266.2	1,274.1	1,294.3	1,341.1	707.2	814.1	16,400.9
OVEC	4,838.3	4,372.6	4,972.8	6,030.9	6,585.2	4,298.4	4,751.4	5,044.4	4,291.1	4,501.6	3,027.5	2,073.0	54,787.0
SOUTHIMP	1,727.7	2,134.2	2,131.7	2,542.2	2,960.4	2,469.4	3,234.4	2,603.1	2,350.8	2,638.3	1,331.5	984.6	27,108.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,013.7	1,150.3	901.7	625.6	674.4	343.7	332.4	8,724.7
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	1,087.6	387.9	341.4	10,281.9
SOUTHIMP	467.7	476.7	702.6	783.3	1,049.8	612.9	875.4	663.1	683.1	876.3	599.9	310.8	8,101.5
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	13,728.0	12,936.0	13,418.2	15,214.5	17,586.0	12,925.9	13,350.2	13,068.1	12,381.2	12,361.9	6,804.3	5,570.9	149,345.1

Table 8-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	1,564.8	997.1	1,374.0	1,502.0	1,711.9	1,208.3	1,122.0	965.4	905.1	847.2	350.8	388.3	12,936.9
LINDENVFT	341.0	423.5	436.3	440.3	479.7	443.7	514.9	479.3	465.6	605.7	11.9	204.5	4,846.4
MISO	2,753.0	1,958.8	1,919.6	2,393.3	2,318.5	1,768.5	1,762.3	1,801.2	1,846.4	1,823.6	812.0	661.4	21,818.6
NEPTUNE	891.7	837.7	870.3	492.9	450.2	268.6	282.9	472.9	535.8	248.1	143.7	465.3	5,960.1
NIPSCO	504.3	547.1	995.3	1,195.1	715.3	694.8	541.1	686.4	834.1	613.3	623.8	801.6	8,752.2
NORTHWEST	1,294.7	1,035.1	1,045.3	1,183.3	1,241.3	1,192.8	1,082.9	1,235.7	1,141.1	1,406.4	1,043.9	984.2	13,886.7
NYIS	1,627.7	1,589.6	1,639.4	1,435.5	1,456.1	1,622.2	1,805.7	1,985.7	1,895.0	2,120.2	1,674.9	1,841.3	20,693.3
OVEC	4,173.2	4,138.0	3,536.6	5,317.0	4,213.8	3,567.0	4,497.0	5,429.8	4,960.0	5,676.4	3,828.4	2,432.8	51,769.9
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	3,884.4	4,089.1	3,761.8	4,557.5	4,378.1	3,848.9	4,348.1	3,478.4	3,182.3	3,623.9	1,784.8	1,588.5	42,525.7
CPLEEXP	46.7	19.8	24.9	30.3	15.7	23.5	36.0	21.1	27.2	32.7	23.0	43.6	344.6
DUKEXP	1.8	27.4	13.0	7.6	0.8	0.0	5.9	20.0	0.0	0.0	1.9	0.0	78.3
NCMPAEXP	0.1	0.1	0.0	0.5	0.8	0.4	0.4	0.4	0.4	0.3	0.3	0.3	3.9
SOUTHEAST	530.7	546.3	488.7	588.0	566.5	334.4	287.6	166.4	124.7	252.2	47.8	66.5	3,999.8
SOUTHWEST	1,146.0	1,425.1	912.1	1,485.4	1,504.2	1,251.0	1,871.3	1,647.9	1,581.1	1,407.0	493.3	661.7	15,386.1
SOUTHEXP	2,159.1	2,070.5	2,323.0	2,445.7	2,290.0	2,239.7	2,146.9	1,622.6	1,448.9	1,931.7	1,218.5	816.3	22,713.0
Total	17,034.9	15,616.0	15,578.5	18,516.9	16,964.9	14,614.9	15,956.8	16,534.8	15,765.3	16,964.8	10,274.1	9,368.0	183,189.9

Table 8-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	1,564.8	997.1	1,374.0	1,502.0	1,711.9	1,208.3	1,122.0	965.4	905.1	847.2	350.8	388.3	12,936.9
LINDENVFT	330.8	419.9	427.4	431.9	476.3	438.5	506.3	469.0	458.2	601.7	11.9	200.9	4,772.7
MISO	2,114.4	1,347.8	1,675.1	1,857.6	1,846.3	1,426.0	1,005.4	1,226.3	1,382.2	1,100.9	488.1	170.2	15,640.4
NEPTUNE	466.5	481.8	555.8	332.9	307.4	268.6	273.6	198.4	291.5	177.7	33.9	202.6	3,590.8
NIPSCO	504.3	547.1	995.3	1,195.1	715.3	694.8	541.1	686.4	834.1	613.3	623.8	801.6	8,752.2
NORTHWEST	809.1	581.0	615.9	796.8	759.3	730.3	612.2	763.0	681.5	925.9	575.2	500.6	8,350.7
NYIS	522.9	486.9	572.8	549.4	612.0	451.5	354.3	537.6	640.8	846.0	529.8	602.3	6,706.2
OVEC	4,147.5	4,114.8	3,513.3	5,298.2	4,193.7	3,567.0	4,497.0	5,411.4	4,942.4	5,676.4	3,828.4	2,432.8	51,622.8
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	3,787.2	3,977.3	3,660.3	4,474.2	4,293.4	3,776.5	4,260.5	3,397.6	3,118.4	3,553.1	1,717.1	1,504.9	41,520.7
CPLEEXP	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	530.7	546.3	488.7	588.0	566.5	334.4	287.6	166.4	124.7	252.2	47.8	66.5	3,999.8
SOUTHWEST	1,146.0	1,425.1	912.1	1,485.4	1,504.2	1,251.0	1,871.3	1,647.9	1,581.1	1,407.0	493.3	661.7	15,386.1
SOUTHEXP	2,110.6	2,005.9	2,259.5	2,399.6	2,222.6	2,191.2	2,101.6	1,583.3	1,412.6	1,893.9	1,176.0	776.7	22,133.6
Total	14,247.6	12,953.7	13,390.0	16,438.1	14,915.6	12,561.6	13,172.3	13,654.9	13,254.1	14,342.2	8,159.0	6,804.4	153,893.4

Table 8-16 Active interfaces: 2012[29]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

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

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

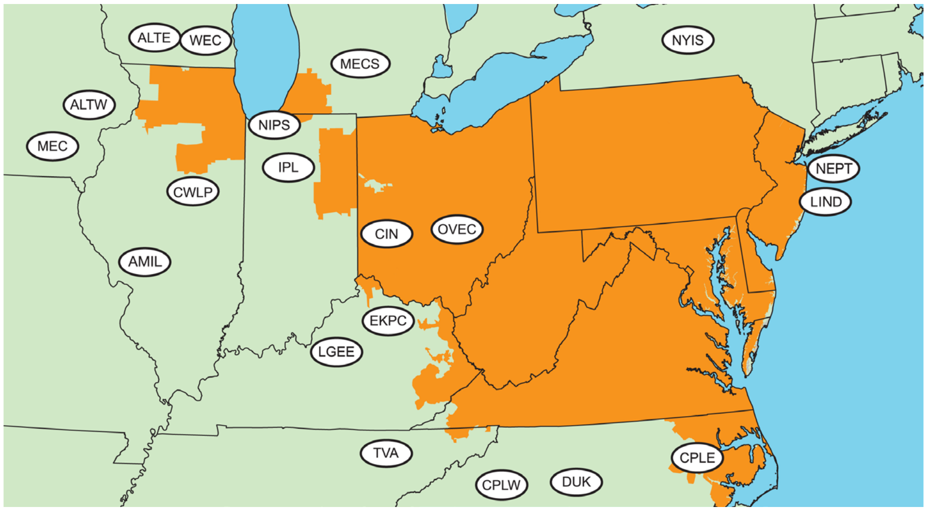


Table 8-17 Active pricing points: 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	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.

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

Loop flows 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 attempts to game such markets. Loop flows also have poorly understood impacts on non-market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both MISO's border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

If PJM net actual interface flows were close to net scheduled interface flows, on average for 2012, it would not necessarily mean that there was no loop flow. Loop flows are measured at individual interfaces. There can be no difference between scheduled and actual flows for PJM and still be significant differences between scheduled and actual flows for specific individual interfaces. From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh, compared to net scheduled interchange of -7,072 GWh and net actual interchange of -7,576 GWh, a difference of 504 GWh in 2011.[30] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[31]

Table 8-18 Net scheduled and actual PJM flows by interface (GWh): 2012

	Actual	Net Scheduled	Difference (GWh)
CPLE	7,954	(350)	8,304
CPLW	(1,500)	0	(1,500)
DUK	(717)	371	(1,089)
EKPC	2,455	(625)	3,080
LGEE	1,370	2,687	(1,316)
MEC	(2,627)	(5,382)	2,756
MISO	(15,262)	(2,663)	(12,599)
ALTE	(5,869)	(6,720)	850
ALTW	(2,497)	(282)	(2,214)
AMIL	11,190	1,078	10,112
CIN	(6,112)	1,308	(7,420)
CWLP	(537)	0	(537)
IPL	669	(1,467)	2,136
MECS	(10,337)	5,682	(16,019)
NIPS	(6,375)	(172)	(6,203)
WEC	4,607	(2,089)	6,696
NYISO	(8,664)	(8,574)	(90)
LIND	(636)	(636)	0
NEPT	(2,253)	(2,253)	0
NYIS	(5,774)	(5,685)	(90)
OVEC	11,578	8,926	2,652
TVA	6,084	6,508	(424)
Total	672	898	(226)

30 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.

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

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 the specific interface price.[32] 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, as opposed to the individual pricing points, provides some insight on 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 (13,191 GWh of imports at the SouthIMP Interface Pricing Point) would best be 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 14,604 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 did 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): 2012

	Actual	Net Scheduled	Difference (GWh)
IMO	0	5,881	(5,881)
LINDENVFT	(636)	(636)	0
MISO	(12,806)	(20,031)	7,225
NEPTUNE	(2,253)	(2,253)	0
NORTHWEST	(2,627)	(110)	(2,517)
NYIS	(5,774)	(5,484)	(290)
OVEC	11,578	8,926	2,652
SOUTHIMP	13,191	18,533	(5,343)
CPLEIMP	0	535	(535)
DUKIMP	0	1,077	(1,077)
NCMPAIMP	0	348	(348)
SOUTHWEST	0	0	0
SOUTHIMP	13,191	16,573	(3,383)
SOUTHEXP	0	(3,929)	3,929
CPLEEXP	0	(367)	367
DUKEXP	0	(1,599)	1,599
NCMPAEXP	0	(5)	5
SOUTHWEST	0	(42)	42
SOUTHEXP	0	(1,916)	1,916
Total	672	898	(226)

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

32 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) (Accessed January 16, 2013)

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): 2012

	Actual	Net Scheduled	Difference (GWh)
LINDENVFT	(636)	(636)	0
MISO	(12,806)	(14,129)	1,323
NEPTUNE	(2,253)	(2,253)	0
NORTHWEST	(2,627)	(110)	(2,517)
NYIS	(5,774)	(5,505)	(270)
OVEC	11,578	8,926	2,652
SOUTHIMP	13,191	18,533	(5,343)
CPLEIMP	0	535	(535)
DUKIMP	0	1,077	(1,077)
NCMPAIMP	0	348	(348)
SOUTHWEST	0	0	0
SOUTHIMP	13,191	16,573	(3,383)
SOUTHEXP	0	(3,929)	3,929
CPLEEXP	0	(367)	367
DUKEXP	0	(1,599)	1,599
NCMPAEXP	0	(5)	5
SOUTHWEST	0	(42)	42
SOUTHEXP	0	(1,916)	1,916
Total	672	898	(226)

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 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 for which the actual flows would enter the PJM Energy Market at the southern region, and thus were assigned the SouthIMP Interface Pricing point (3,237 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 (2,907 GWh).

Table 8-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): 2012

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(5,869)	(6,720)	850	IPL		669	(1,467)	2,136
	MISO	(5,869)	(6,718)	848		IMO	0	897	(897)
	NORTHWEST	0	(7)	7		MISO	669	(2,353)	3,022
	SOUTHEXP	0	(0)	0		NORTHWEST	0	(72)	72
	SOUTHIMP	0	5	(5)		SOUTHEXP	0	(6)	6
ALTW		(2,497)	(282)	(2,214)		SOUTHIMP	0	66	(66)
	MISO	(2,497)	(259)	(2,238)	LGEE		1,370	2,687	(1,316)
	NORTHWEST	0	(23)	23		SOUTHEXP	0	(149)	149
AMIL		11,190	1,078	10,112		SOUTHIMP	1,370	2,836	(1,465)
	IMO	0	(0)	0	LIND		(636)	(636)	0
	MISO	11,190	890	10,300		LINDENVFT	(636)	(636)	0
	NORTHWEST	0	(0)	0	MEC		(2,627)	(5,382)	2,756
	SOUTHEXP	0	(0)	0		IMO	0	0	(0)
	SOUTHIMP	0	230	(230)		MISO	0	(5,600)	5,600
	SOUTHWEST	0	(41)	41		NORTHWEST	(2,627)	4	(2,630)
CIN		(6,112)	1,308	(7,420)		SOUTHIMP	0	214	(214)
	IMO	0	811	(811)	MECS		(10,337)	5,682	(16,019)
	MISO	(6,112)	(2,907)	(3,205)		IMO	0	4,192	(4,192)
	NORTHWEST	0	(10)	10		MISO	(10,337)	(712)	(9,625)
	NYIS	0	180	(180)		NORTHWEST	0	(0)	0
	SOUTHEXP	0	(4)	4		NYIS	0	0	(0)
	SOUTHIMP	0	3,237	(3,237)		SOUTHIMP	0	2,202	(2,202)
CPLE		7,954	(350)	8,304	NEPT		(2,253)	(2,253)	0
	CPLEEXP	0	(367)	367		NEPTUNE	(2,253)	(2,253)	0
	CPLEIMP	0	535	(535)	NIPS		(6,375)	(172)	(6,203)
	DUKIMP	0	0	(0)		IMO	0	1	(1)
	SOUTHEXP	0	(30)	30		MISO	(6,375)	(575)	(5,800)
	SOUTHIMP	7,954	(489)	8,443		NORTHWEST	0	(0)	0
CPLW		(1,500)	0	(1,500)		SOUTHIMP	0	402	(402)
	SOUTHIMP	(1,500)	0	(1,500)	NYIS		(5,774)	(5,685)	(90)
CWLP		(537)	0	(537)		IMO	0	(21)	21
	MISO	(537)	0	(537)		NYIS	(5,774)	(5,664)	(110)
DUK		(717)	371	(1,089)	OVEC		11,578	8,926	2,652
	DUKEXP	0	(1,599)	1,599		OVEC	11,578	8,926	2,652
	DUKIMP	0	1,073	(1,073)	TVA		6,084	6,508	(424)
	NCMPAEXP	0	(5)	5		DUKIMP	0	4	(4)
	NCMPAIMP	0	348	(348)		SOUTHEXP	0	(358)	358
	SOUTHEXP	0	(243)	243		SOUTHIMP	6,084	6,862	(778)
	SOUTHIMP	(717)	798	(1,515)		SOUTHWEST	0	(0)	0
	SOUTHWEST	0	(0)	0	WEC		4,607	(2,089)	6,696
EKPC		2,455	(625)	3,080		MISO	4,607	(2,099)	6,705
	MISO	2,455	301	2,154		NORTHWEST	0	(1)	1
	SOUTHEXP	0	(1,126)	1,126		SOUTHEXP	0	(0)	0
	SOUTHIMP	0	200	(200)		SOUTHIMP	0	11	(11)
					Total		672	898	(226)

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 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 (4,192 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 (21 GWh).

Table 8-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): 2012

Interface pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(367)	367
	CPLE	0	(367)	367
CPLEIMP		0	535	(535)
	CPLE	0	535	(535)
DUKEXP		0	(1,599)	1,599
	DUK	0	(1,599)	1,599
DUKIMP		0	1,077	(1,077)
	CPLE	0	0	(0)
	DUK	0	1,073	(1,073)
	TVA	0	4	(4)
IMO		0	5,881	(5,881)
	AMIL	0	(0)	0
	CIN	0	811	(811)
	IPL	0	897	(897)
	MEC	0	0	(0)
	MECS	0	4,192	(4,192)
	NIPS	0	1	(1)
	NYIS	0	(21)	21
LINDENVFT		(636)	(636)	0
	LIND	(636)	(636)	0
MISO		(12,806)	(20,031)	7,225
	ALTE	(5,869)	(6,718)	848
	ALTW	(2,497)	(259)	(2,238)
	AMIL	11,190	890	10,300
	CIN	(6,112)	(2,907)	(3,205)
	CWLP	(537)	0	(537)
	EKPC	2,455	301	2,154
	IPL	669	(2,353)	3,022
	MEC	0	(5,600)	5,600
	MECS	(10,337)	(712)	(9,625)
	NIPS	(6,375)	(575)	(5,800)
	WEC	4,607	(2,099)	6,705
NCMPAEXP		0	(5)	5
	DUK	0	(5)	5
NCMPAIMP		0	348	(348)
	DUK	0	348	(348)
NEPTUNE		(2,253)	(2,253)	0
	NEPT	(2,253)	(2,253)	0
NORTHWEST		(2,627)	(110)	(2,517)
	ALTE	0	(7)	7
	ALTW	0	(23)	23
	AMIL	0	(0)	0
	CIN	0	(10)	10
	IPL	0	(72)	72
	MEC	(2,627)	4	(2,630)
	MECS	0	(0)	0
	NIPS	0	(0)	0
	WEC	0	(1)	1
NYIS		(5,774)	(5,484)	(290)
	CIN	0	180	(180)
	MECS	0	0	(0)
	NYIS	(5,774)	(5,664)	(110)
OVEC		11,578	8,926	2,652
	OVEC	11,578	8,926	2,652
SOUTHEXP		0	(1,916)	1,916
	ALTE	0	(0)	0
	AMIL	0	(0)	0
	CIN	0	(4)	4
	CPLE	0	(30)	30
	DUK	0	(243)	243
	EKPC	0	(1,126)	1,126
	IPL	0	(6)	6
	LGEE	0	(149)	149
	TVA	0	(358)	358
	WEC	0	(0)	0
SOUTHIMP		13,191	16,573	(3,383)
	ALTE	0	5	(5)
	AMIL	0	230	(230)
	CIN	0	3,237	(3,237)
	CPLE	7,954	(489)	8,443
	CPLW	(1,500)	0	(1,500)
	DUK	(717)	798	(1,515)
	EKPC	0	200	(200)
	IPL	0	66	(66)
	LGEE	1,370	2,836	(1,465)
	MEC	0	214	(214)
	MECS	0	2,202	(2,202)
	NIPS	0	402	(402)
	TVA	6,084	6,862	(778)
	WEC	0	11	(11)
SOUTHWEST		0	(42)	42
	AMIL	0	(41)	41
	DUK	0	(0)	0
	TVA	0	(0)	0
Total		672	898	(226)

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[33] 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.[34]

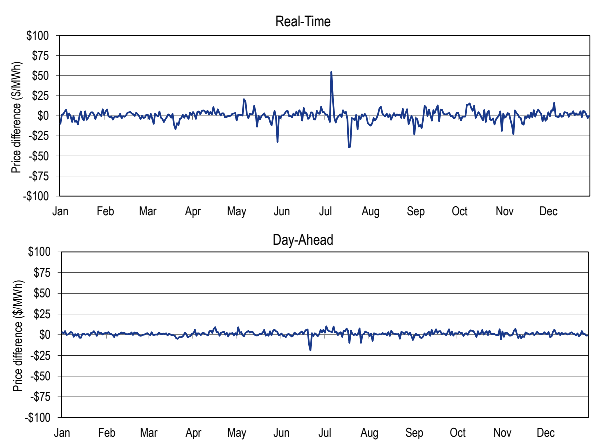
Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2012, the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average hourly flow. In 2012, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $26.95 while the MISO LMP at the border was $27.15, a difference of $0.20. While the average hourly LMP difference at the PJM/MISO border was only $0.20, the average of the absolute values of the hourly differences was $8.93. The average hourly flow during 2012 was -1,737 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 47 percent of hours in 2012. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $10.36. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $7.83. In 2012, 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 $9.80. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from MISO to PJM, the average price difference was $21.11. 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 $17.32. 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 $6.92.

In 2012, the day-ahead PJM average hourly LMP at the PJM/MISO border was $26.62 while the MISO LMP at the border was $27.72, a difference of $1.10.

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).

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): 2012



33 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed January 16, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

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

Distribution of Economic and Uneconomic Hourly Flows

During 2012, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 4,104 hours (46.7 percent of all hours), and was inconsistent with price differentials in 4,680 hours (53.3 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 4,680 hours where flows were uneconomic, 3,981 of those hours (85.1 percent) had a price difference greater than or equal to $1.00 and 1,656 of all uneconomic hours (35.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $949.61. Of the 4,104 hours where flows were economic, 3,499 of those hours (85.3 percent) had a price difference greater than or equal to $1.00 and 1,989 of all economic hours (48.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $440.39.

Table 8-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: 2012

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	4,680	100.0%	4,104	100.0%
$1.00	3,981	85.1%	3,499	85.3%
$5.00	1,656	35.4%	1,989	48.5%
$10.00	714	15.3%	1,118	27.2%
$15.00	424	9.1%	696	17.0%
$20.00	308	6.6%	495	12.1%
$25.00	226	4.8%	383	9.3%
$50.00	89	1.9%	140	3.4%
$75.00	39	0.8%	72	1.8%
$100.00	26	0.6%	44	1.1%
$200.00	7	0.1%	6	0.1%
$300.00	2	0.0%	3	0.1%
$400.00	2	0.0%	2	0.0%
$500.00	1	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.

The NYISO Locational Based Marginal Pricing (LBMP) calculation methodology differs from the PJM LMP calculation methodology. PJM uses real-time operating conditions and real-time energy flows to calculate LMPs. The NYISO software calculates LBMP using expected flows derived from Real-Time Commitment (RTC) software based on the assumption that phase angle regulators (PARs) can be set such that the average actual flows match the expected interchange on PAR controlled lines. The NYISO also calculates the flows across their free-flowing A/C tie lines using current network configurations for the purposes of calculating line loadings and the resulting congestion costs. 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 Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines. This Keystone proxy bus is an aggregate pricing point, representing the price of energy between PJM and the NYISO, with a 40 percent weighting on the Branchburg to Ramapo line and a 60 percent weighting on the remaining free flowing ties. PJM calculates the NYISO Interface Price using an 80 percent weighting on the Roseton 345 KV bus, and a 20 percent weighting on the Dunkirk 115 KV bus.

Effective June 27, 2012, the NYISO implemented 15-minute scheduling of external energy transactions between the NYISO and PJM.[35] However, the timing requirements for market participants to submit external energy transactions did not change as a result of the new process. All transactions must continue to be submitted to the NYISO 75 minutes prior to the operating hour, and the NYISO's RTC application commits (or decommits) external energy transactions for each 15-minute interval of the operating hour. While this modification provides a better economic mix of generation and interchange transactions during the operating hour, it does not allow market participants to react to real-time pricing, as all transactions must be submitted in advance of real-time price signals.

35 See *New York Independent System Operator, Inc.* Docket No. ER11-2547-001 (June 6, 2012).

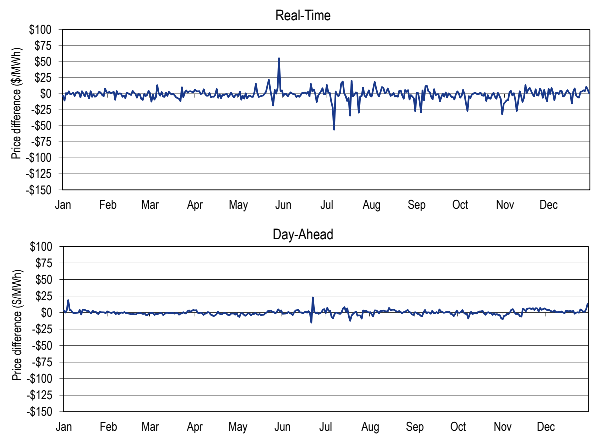
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 2012, 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 2012, 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 2012, the PJM average hourly LMP at the PJM/NYISO border was $34.09 while the NYISO LMP at the border was $33.15, a difference of $0.94. While the average hourly LMP difference at the PJM/NYISO border was only $0.94, the average of the absolute value of the hourly difference was $9.69. The average hourly flow during 2012 was -657 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 52.8 percent of the hours in 2012. In 2012, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $9.11. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $10.25. In 2012, 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 $8.49. 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 $14.80. 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 $11.61. 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 $9.94.

In 2012, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $33.68 while the NYIS LMP at the border was $33.79, a difference of $0.11.

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): 2012



Distribution of Economic and Uneconomic Hourly Flows

During 2012, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,641 (52.8 percent of all hours), and was inconsistent with price differences in 4,143 hours (47.2 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 4,143 hours where flows were uneconomic, 3,591 of those hours (86.7 percent) had a price difference greater than or equal to $1.00 and 1,952 of all uneconomic hours (47.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $389.38. Of the 4,641 hours where flows were economic, 4,085 of those hours (88.0 percent) had a price difference greater than or equal to $1.00 and 2,027 of all economic hours (43.7 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $597.32.

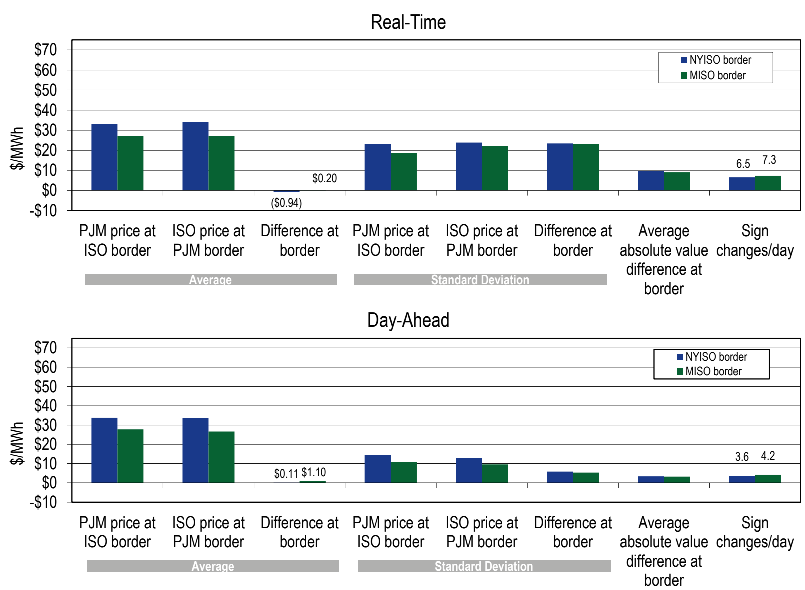
Table 8-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: 2012

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	4,143	100.0%	4,641	100.0%
$1.00	3,591	86.7%	4,085	88.0%
$5.00	1,952	47.1%	2,027	43.7%
$10.00	1,028	24.8%	943	20.3%
$15.00	690	16.7%	548	11.8%
$20.00	479	11.6%	376	8.1%
$25.00	355	8.6%	285	6.1%
$50.00	162	3.9%	115	2.5%
$75.00	89	2.1%	62	1.3%
$100.00	42	1.0%	41	0.9%
$200.00	4	0.1%	13	0.3%
$300.00	1	0.0%	4	0.1%
$400.00	0	0.0%	2	0.0%
$500.00	0	0.0%	1	0.0%

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: 2012



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 2012, the average hourly difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average hourly flow. In 2012, the PJM average hourly LMP at the Neptune Interface was $34.14 while the NYISO LMP at the Neptune Bus was $43.92, a difference of $9.78.[36] While the average hourly LMP difference at the PJM/Neptune border was $9.78, the average of the absolute value of the hourly difference was $17.07. The average hourly flow during 2012 was -257 MW.[37] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64.5 percent of the hours in 2012. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $20.31. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $10.79.

36 In 2012, there were 3,056 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 $32.96 while the NYISO LMP at the Neptune Bus during non-zero flows was $39.70, a difference of $6.74.

37 The average hourly flow during 2012, ignoring hours with no flow, on the Neptune DC Tie line was -393 MW.

Figure 8-7 Neptune hourly average flow: 2012

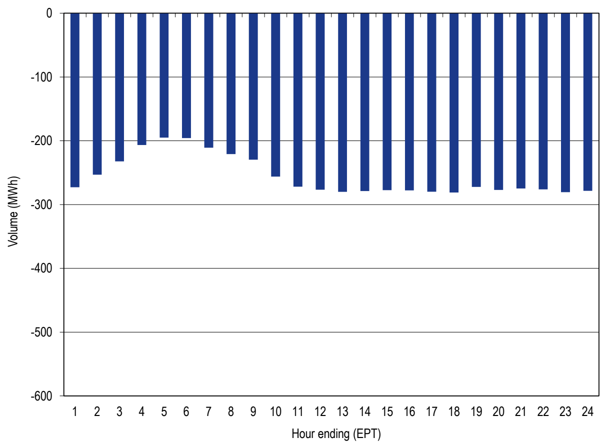
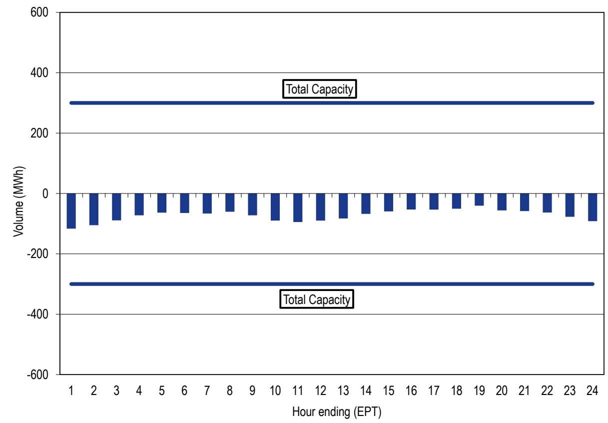


Figure 8-8 Linden hourly average flow: 2012[40]



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 2012, the average hourly difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average hourly flow. In 2012, the PJM average hourly LMP at the Linden Interface was $34.70 while the NYISO LMP at the Linden Bus was $37.63, a difference of $2.93.[38] While the average hourly LMP difference at the PJM/Linden border was $2.93, the average of the absolute value of the hourly difference was $12.49. The average hourly flow during 2012 was -72 MW.[39] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 59.5 percent of the hours in 2012. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $12.88. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $11.92.

38 In 2012, there were 1,630 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 $34.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $36.61, a difference of $2.38.

39 The average hourly flow during 2012, ignoring hours with no flow, on the Linden VFT line was -89 MW.

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.

40 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.

PJM and MISO Joint Operating Agreement[41]

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 PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[42]

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

Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater 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 2012, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

During 2012, 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.

In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report, which was completed and distributed on January 20, 2012, showed that both PJM and MISO are conforming to the JOA.[43] The report also provided some potential areas of improvement including improved internal documentation, enhanced transparency, and an increase of knowledge sharing, data exchange and attention to modeling differences.

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

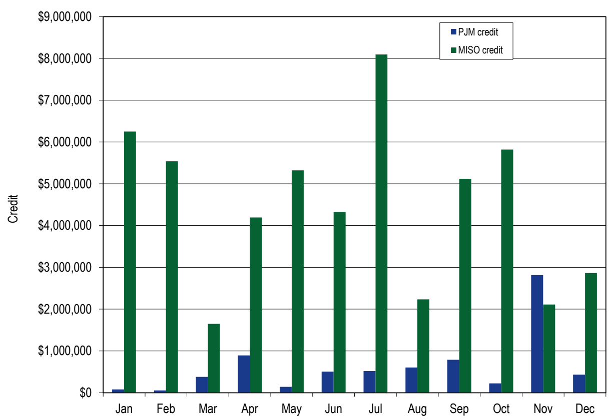
41 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>. (Accessed October 16, 2012)

42 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>.

43 See "Utilicast Final Report - JOA Baseline Review," (January 20, 2012) <http://www.pjm.com/documents/~/media/documents/reports/20120120-utilcast-final-report-joa-baseline-review.ashx> (Accessed January 16, 2013)

to the other. The MMU suggests that the RTOs evaluate whether this is occurring and the appropriate impact on the congestion payments under the JOA.

Figure 8-9 Credits for coordinated congestion management: 2012



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[44]

On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It formalized the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

The PJM/NYISO JOA did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol.[45] On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that included a draft market to market process.[46] On May 1, 2012, PJM and the NYISO filed a second revision to the JOA that included resolutions to several outstanding issues, present in the December 30, 2011 filing, which they requested additional time to resolve.[47]

Some of the resolved issues were how to calculate firm flow entitlements (FFE), how to model external capacity resources in developing FFEs and how to include the Ontario/Michigan PAR operations in the market flow calculation. On September 20, 2012, FERC issued an Order On Compliance Filing, accepting the implementation date of a market to market coordination process to be effective no later than January 15, 2013.[48] The September 20, 2012, Order requires modifications to the JOA to provide for incremental impacts of the Ontario/Michigan PARs when any of the PARs are in service.

In 2012, the MMU protested the Interface Pricing methodology proposed by the NYISO.[49] The MMU filed comments that the method implemented by NYISO failed to address the issues identified by the Commission in its prior orders and leaves in place the potential incentives to inefficient scheduling and gaming that the changes were intended to address. The MMU suggested that if NYISO were to extend their eTag path validation approach, NYISO could ensure that all external energy transactions are scheduled on a market path on which the energy will actually flow and for which the NYISO calculates a price. This approach would substitute a rule that identifies scheduled paths to reject, for the approach that tries to identify, in advance, every possible circuitous path. This method would be entirely consistent with the current NYISO approach, and could provide for accurate transaction pricing and eliminate the pricing incentive for market participants to schedule along inefficient paths of the type which contribute to Lake Erie loop flows.

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

44 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (June 30, 2010) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed January 16, 2013)

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

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

47 See "Second Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (May 1, 2012).

48 140 FERC ¶ 61,205 (2012).

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

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 2012, there were no developments. The agreement continued to be in effect in 2012.

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.[50] 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 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 2012, there were no developments. The agreement remained in effect in 2012.

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.[51]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[52] 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.[53] 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: 2012

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.11	$31.30	$30.97	$30.97	$0.14	$0.33
PEC	$31.50	$31.53	$30.97	$30.97	$0.53	$0.56
NCMPA	$31.25	$31.25	$30.97	$30.97	$0.28	$0.28

Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: 2012

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.99	$31.59	$30.66	$30.66	$0.33	$0.93
PEC	$31.46	$31.81	$30.66	$30.66	$0.80	$1.16
NCMPA	$31.26	$31.33	$30.66	$30.66	$0.60	$0.67

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

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

51 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 January 16, 2013)

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

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

York and wheeled through New York and New Jersey including lines controlled by PJM.[54] 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.

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

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2012, PSE&G's revenues were more than its congestion charges by $80,727 after adjustments (revenues were more than its congestion charges by $778,879 in 2011.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2012, Con Edison's congestion credits were $3,627.462 less than its day-ahead congestion charges (credits had been $2,319,278 more than charges in 2011).

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$42,203 in 2012. The parties should address this issue.

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[55] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[56] 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.[57] 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.

54 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.

55 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.

56 132 FERC ¶ 61,221 (2010).

57 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 8-27 Con Edison and PSE&G wheeling agreement data: 2012

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$5,722,599	$104,705	$5,827,303	$865,217	$0	$865,217
Congestion Credit			$2,095,137			$953,303
Adjustments and Transmission Charges			($23,149,300)			($7,358)
Net Charge			$26,881,466			($80,727)

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 called fewer TLRs in 2012 than in 2011. The fact that PJM has issued only 37 TLRs in 2012, compared to 62 in 2011, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM TLRs decreased by 60 percent, from 62 during 2011 to 37 in 2012 (Table 8-28). In addition, the number of different flowgates for which PJM declared TLRs decreased from 18 in 2011 to 13 in 2012. The total MWh of transaction curtailments decreased by 46 percent, from 171,221 MWh in 2011 to 125,783 MWh in 2012.

MISO called more TLRs in 2012 than in 2011. MISO TLRs increased by 11 percent, from 143 in 2011 to 159 in 2012.

Table 8-28 PJM and MISO TLR procedures: January, 2010 through December, 2012[58]

	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

58 The curtailment volume for PJM TLR's was taken from the individual NERC TLR history reports as posted in the Interchange Distribution Calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLR's was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx>. (Accessed January 16, 2013)

Table 8-29 Number of TLRs by TLR level by reliability coordinator: 2012

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2012	ICTE	25	7	11	63	40	0	146
	MISO	75	26	0	16	42	0	159
	NYIS	60	0	0	0	0	0	60
	ONT	47	1	0	0	0	0	48
	PJM	18	19	0	0	0	0	37
	SOCO	0	1	0	0	0	0	1
	SWPP	248	165	5	78	33	0	529
	TVA	55	32	9	7	5	0	108
	VACS	6	4	0	0	0	0	10
Total		534	255	25	164	120	0	1,098

Up-To Congestion

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

An up-to congestion transaction is analogous to a matched set of incremental offers (INC) and decrement bids (DEC) that are evaluated together and approved or denied as a single transaction, subject to a limit on the cleared price difference. For import up-to congestion transactions, the import pricing point specified looks like an INC offer and the sink looks like a DEC bid. For export transactions, the specified source looks like an INC offer, and the export pricing point looks like a DEC bid. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like an INC offer, and the export pricing point specified looks like a DEC bid. In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. Conversely, an up-to congestion export transaction is submitted and modeled as a withdrawal at the interface, and an injection at a specific PJM node. Wheel through up-to congestion transactions are modeled as an injection at the importing interface and a withdrawal at the exporting interface.

While an up-to congestion bid is analogous to a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Energy Market if the maximum congestion bid criteria is met, is not subject to day-ahead or balancing operating reserve charges and does not have clear rules governing credit requirements. Effective September 17, 2010, up-to congestion transactions were no longer required to pay for transmission.[59]

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 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 29,665 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011 (See Figure 8-10).

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 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.

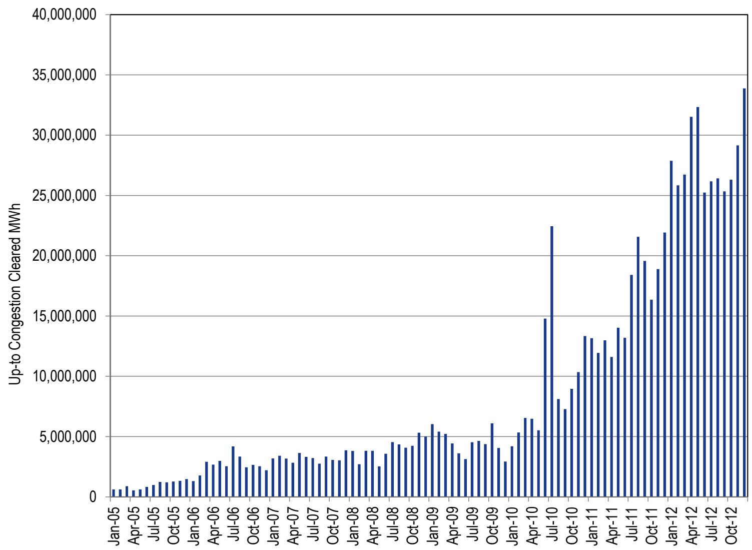
The MMU recommended that the up-to congestion transaction product be eliminated. This product could work as a derivative product traded outside PJM markets and without any of these impacts on the actual operation of PJM markets. Alternatively, the MMU recommended that PJM require all import and export 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. To address this concern, in 2012, PJM formed the "Transactions Task Force," with the goal of determining whether or not up-

59 In addition to the cost of transmission, transactions utilizing transmission also incur additional ancillary service charges such as black start and reactive services.

to congestion transaction should be subject to balancing operating reserve charges. After several meetings, the task force was shut down due to fact that the PJM did not believe that it was possible to perform adequate study on the effects of up-to congestion transactions on balancing operating reserves without necessitating a broader scope. While the MMU does not believe that to be the case, the stakeholders agreed with PJM, and the group was dissolved.

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.

Figure 8-10 Monthly up-to congestion cleared bids in MWh: January, 2006 through December, 2012



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. While a rate equal to the average of the lowest ten percent of daily operating reserve rates paid by other virtuals would be reasonable, the MMU recommends a rate equal to the average of the lowest 3.3 percent of daily operating reserve rates paid by other virtuals. The average of the daily operating reserve rates paid by virtual transactions was \$0.72 per MWh for the lowest ten percent of all days in 2012. The average of the daily operating reserve rates paid by virtual transactions was \$0.56 per MWh for the lowest five percent of all days in 2012. The average of the daily operating reserve rates paid by virtual transactions was \$0.50 per MWh for the lowest 3.3 percent of all days in 2012.

Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through December, 2012

	Bid MW					Bid Volume				
Month	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
Feb-09	3,580,115	4,904,467	318,440	-	8,803,022	64,338	70,874	6,347	-	141,559
Mar-09	3,649,978	5,164,186	258,701	-	9,072,865	64,714	72,495	5,531	-	142,740
Apr-09	2,607,303	5,085,912	73,931	-	7,767,146	47,970	67,417	2,146	-	117,533
May-09	2,196,341	4,063,887	106,860	-	6,367,088	40,217	54,745	1,304	-	96,266
Jun-09	2,598,234	3,132,478	164,903	-	5,895,615	47,625	44,755	2,873	-	95,253
Jul-09	3,984,680	3,776,957	296,910	-	8,058,547	67,039	56,770	5,183	-	128,992
Aug-09	3,551,396	4,388,435	260,184	-	8,200,015	64,652	64,052	3,496	-	132,200
Sep-09	2,948,353	4,179,427	156,270	-	7,284,050	51,006	64,103	2,405	-	117,514
Oct-09	3,172,034	6,371,230	154,825	-	9,698,089	46,989	100,350	2,217	-	149,556
Nov-09	3,447,356	3,851,334	103,325	-	7,402,015	53,067	61,906	1,236	-	116,209
Dec-09	2,323,383	2,502,529	66,497	-	4,892,409	47,099	47,223	1,430	-	95,752
Jan-10	3,794,946	3,097,524	212,010	-	7,104,480	81,604	55,921	3,371	-	140,896
Feb-10	3,841,573	3,937,880	316,150	-	8,095,603	80,876	80,685	2,269	-	163,830
Mar-10	4,877,732	4,454,865	277,180	-	9,609,777	97,149	74,568	2,239	-	173,956
Apr-10	3,877,306	5,558,718	210,545	-	9,646,569	67,632	85,358	1,573	-	154,563
May-10	3,800,870	5,062,272	149,589	-	9,012,731	74,996	78,426	1,620	-	155,042
Jun-10	9,126,963	9,568,549	1,159,407	-	19,854,919	95,155	89,222	6,960	-	191,337
Jul-10	12,818,141	11,526,089	5,420,410	-	29,764,640	124,929	106,145	18,948	-	250,022
Aug-10	8,231,393	6,767,617	888,591	-	15,887,601	115,043	87,876	10,664	-	213,583
Sep-10	7,768,878	7,561,624	349,147	-	15,679,649	184,697	161,929	4,653	-	351,279
Oct-10	8,732,546	9,795,666	476,665	-	19,004,877	189,748	154,741	7,384	-	351,873
Nov-10	11,636,949	9,272,885	537,369	-	21,447,203	253,594	170,470	9,366	-	433,430
Dec-10	17,769,014	12,863,875	923,160	-	31,556,049	307,716	215,897	15,074	-	538,687
Jan-11	20,275,932	11,807,379	921,120	-	33,004,431	351,193	210,703	17,632	-	579,528
Feb-11	18,418,511	13,071,483	800,630	-	32,290,624	345,227	226,292	17,634	-	589,153
Mar-11	17,330,353	12,919,960	749,276	-	30,999,589	408,628	274,709	15,714	-	699,051
Apr-11	17,215,352	9,321,117	954,283	-	27,490,752	513,881	265,334	17,459	-	796,674
May-11	21,058,071	11,204,038	2,937,898	-	35,200,007	562,819	304,589	24,834	-	892,242
Jun-11	20,455,508	12,125,806	395,833	-	32,977,147	524,072	285,031	12,273	-	821,376
Jul-11	24,273,892	16,837,875	409,863	-	41,521,630	603,519	338,810	13,781	-	956,110
Aug-11	23,790,091	21,014,941	229,895	-	45,034,927	591,170	403,269	8,278	-	1,002,717
Sep-11	21,740,208	18,135,378	232,626	-	40,108,212	526,945	377,158	7,886	-	911,989
Oct-11	20,240,161	19,476,556	333,077	-	40,049,794	540,877	451,507	8,609	-	1,000,993
Nov-11	27,007,141	28,994,789	507,788	-	56,509,718	594,397	603,029	13,379	-	1,210,805
Dec-11	34,990,790	34,648,433	531,616	-	70,170,839	697,524	655,222	14,187	-	1,366,933
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031
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
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
TOTAL	856,092,141	803,098,614	32,495,637	136,570,875	1,828,257,267	18,767,266	16,306,831	608,028	4,398,547	40,080,672

Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through December, 2012 *(continued)*

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	2,591,211	3,242,491	202,854	-	6,036,556	56,132	45,303	4,210	-	105,645
Feb-09	2,374,734	2,836,344	203,907	-	5,414,985	42,101	44,423	4,402	-	90,926
Mar-09	2,285,412	2,762,459	178,507	-	5,226,378	42,408	42,007	4,299	-	88,714
Apr-09	1,797,302	2,582,294	48,478	-	4,428,074	32,088	35,987	1,581	-	69,656
May-09	1,496,396	2,040,737	77,553	-	3,614,686	26,274	29,720	952	-	56,946
Jun-09	1,540,169	1,500,560	88,723	-	3,129,452	28,565	23,307	1,522	-	53,394
Jul-09	2,465,891	1,902,807	163,129	-	4,531,826	41,924	31,176	2,846	-	75,946
Aug-09	2,278,431	2,172,133	194,415	-	4,644,978	41,774	34,576	2,421	-	78,771
Sep-09	1,774,589	2,479,898	128,344	-	4,382,831	31,962	40,698	1,944	-	74,604
Oct-09	2,060,371	3,931,346	110,646	-	6,102,363	31,634	70,964	1,672	-	104,270
Nov-09	2,065,813	1,932,595	51,929	-	4,050,337	33,769	32,916	653	-	67,338
Dec-09	1,532,579	1,359,936	34,419	-	2,926,933	31,673	28,478	793	-	60,944
Jan-10	2,250,689	1,789,018	161,977	-	4,201,684	49,064	33,640	2,318	-	85,022
Feb-10	2,627,101	2,435,650	287,162	-	5,349,913	50,958	48,008	1,812	-	100,778
Mar-10	3,209,064	3,071,712	263,516	-	6,544,292	60,277	48,596	2,064	-	110,937
Apr-10	2,622,113	3,690,889	170,020	-	6,483,022	42,635	54,510	1,154	-	98,299
May-10	2,366,149	3,049,405	112,700	-	5,528,253	47,505	48,996	1,112	-	97,613
Jun-10	6,863,803	6,850,098	1,072,759	-	14,786,660	59,733	55,574	5,831	-	121,138
Jul-10	8,971,914	8,237,557	5,241,264	-	22,450,734	73,232	60,822	16,526	-	150,580
Aug-10	4,430,832	2,894,314	785,726	-	8,110,871	62,526	40,485	8,884	-	111,895
Sep-10	3,915,814	3,110,580	256,039	-	7,282,433	63,405	45,264	3,393	-	112,062
Oct-10	4,150,104	4,564,039	246,594	-	8,960,736	76,042	65,223	3,670	-	144,935
Nov-10	5,765,905	4,312,645	275,111	-	10,353,661	112,250	71,378	4,045	-	187,673
Dec-10	7,851,235	5,150,286	337,157	-	13,338,678	136,582	93,299	7,380	-	237,261
Jan-11	7,917,986	4,925,310	315,936	-	13,159,232	151,753	91,557	8,417	-	251,727
Feb-11	6,806,039	4,879,207	248,573	-	11,933,818	151,003	99,302	8,851	-	259,156
Mar-11	7,104,642	5,603,583	275,682	-	12,983,906	178,620	124,990	7,760	-	311,370
Apr-11	7,452,366	3,797,819	351,984	-	11,602,168	229,707	113,610	8,118	-	351,435
May-11	8,294,422	4,701,077	1,031,519	-	14,027,018	261,355	143,956	11,116	-	416,427
Jun-11	7,632,235	5,361,825	198,482	-	13,192,543	226,747	132,744	6,363	-	365,854
Jul-11	9,585,027	8,617,284	205,599	-	18,407,910	283,287	186,866	7,008	-	477,161
Aug-11	10,594,771	10,875,384	103,141	-	21,573,297	274,398	208,593	3,648	-	486,639
Sep-11	10,219,806	9,270,121	82,200	-	19,572,127	270,088	185,585	3,444	-	459,117
Oct-11	8,376,208	7,853,947	126,718	-	16,356,873	255,206	198,778	4,236	-	458,220
Nov-11	9,064,570	9,692,312	131,670	-	18,888,552	254,851	256,270	5,686	-	516,807
Dec-11	11,738,910	10,049,685	137,689	-	21,926,284	281,304	248,008	6,309	-	535,621
Jan-12	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	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	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
TOTAL	330,503,051	314,515,740	16,877,010	36,440,790	698,336,591	7,992,622	6,853,230	278,290	1,330,427	16,454,569

In 2012, the cleared MW volume of up-to congestion transactions were comprised of 43.5 percent imports, 44.8 percent exports, 0.9 percent wheeling transactions and 10.8 percent internal transactions. Only 0.2 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 locational marginal prices at interfaces accurately reflect the price of energy at the interfaces based on the modeled impacts of actual flows when energy is transferred between markets. 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 2012 were -$11,789, compared to -$20,955 in 2011 (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 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 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 on March 1, 2013.

Table 8-31 Monthly uncollected congestion charges: 2010 through 2012

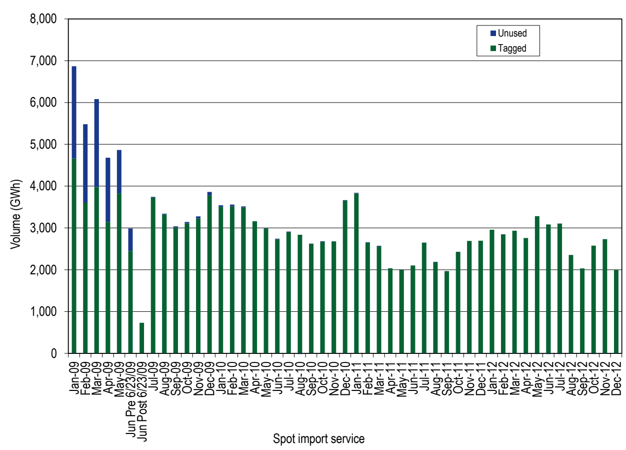
Month	2010	2011	2012
Jan	$148,764	$3,102	$0
Feb	$542,575	$1,567	($15)
Mar	$287,417	$0	$0
Apr	$31,255	$4,767	($68)
May	$41,025	$0	($27)
Jun	$169,197	$1,354	$78
Jul	$827,617	$1,115	$0
Aug	$731,539	$37	$0
Sep	$119,162	$0	$0
Oct	$257,448	($31,443)	($6,870)
Nov	$30,843	($795)	($4,678)
Dec	$127,176	($659)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

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. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports.[60] 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. After a series of rule changes intended to address the hoarding of spot in service that resulted from this change, and after several conversations with MISO regarding the limitation of spot market imports, PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.

Figure 8-11 Spot import service utilization: January, 2009 through December, 2012



Real-Time Dispatchable Transactions

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

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency

60 See "Modifications to the Practices of Non-Firm and Spot Market Import Service," (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>. (Accessed January 16, 2013)

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. During 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.3 million for 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted for three days during 2012.

NYISO Interface Pricing Error

On October 8, 2012, in compliance with the PJM Tariff and Operating Agreement, PJM provided notification to market participants after an error was identified in the calculation of the NYIS Interface LMP calculation that occurred starting on October 1, 2012.[61] The error was related to the congestion components of the underlying buses that make up the NYIS Interface price definition. The PJM Tariff only permits modifications to posted Real-Time Energy Market prices in cases where market participants are notified within two business days of the operating day. Therefore, corrections to the prices for the period spanning October 1, 2012, through October 3, 2012 could not be made. PJM determined that there were only minor differences in the calculated prices for October 4, 2012, and PJM did not repost prices for that day.

The error was corrected on October 6, 2012. On October 8, 2012, through the LMP verification process, PJM corrected the previously posted prices for the period from October 5, 2012, through the time the issue was resolved on October 6, 2012.

61 OATT Attachment K (Office of the Interconnection Responsibilities) § 1.10.8 (e)