# 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 respond to price differentials. The external regions include both market and non-market balancing authorities.

## Overview

### Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2014, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in February and March.[1] During the first three months of 2014, the real-time net interchange of 240.8 GWh was lower than net interchange of 1,640.5 GWh in the first three months of 2013.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2014, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first three months of 2014, the total day-ahead net interchange of -4,982.0 GWh was lower than net interchange of -6,592.7 GWh during the first three months of 2013.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2014, gross imports in the Day-Ahead Energy Market were 112.9 percent of gross imports in the Real-Time Energy Market (149.2 percent during the first three months of 2013), gross exports in the Day-Ahead Energy Market were 152.8 percent of the gross exports in the Real-Time Energy Market (243.3 percent during the first three months of 2013).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2014, there were net scheduled exports at 11 of PJM's 18 interface pricing points eligible for real-time transactions.[2]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2014, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first three months of 2014, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.

## Interactions with Bordering Areas

### PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2014, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 48.9 percent of the hours in the first three months of 2014.

- **PJM and New York ISO Interface Prices.** In the first three months of 2014, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 57.8 percent of the hours in the first three months of 2014.

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between

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1   Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2   There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow in the first three months of 2014 was -518 MW.[4] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 71.4 percent of the hours in the first three month of 2014.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO Linden Bus.[5] The average hourly flow in the first three months of 2014 was -151 MW.[6] The flows were consistent with price differentials in 65.4 percent of the hours in the first three months of 2014.

- **Hudson DC Line.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO Hudson Bus.[7] The average hourly flow during the first three months of 2014 was -180 MW.[8] The flows were consistent with price differentials in 62.9 percent of the hours in the first three months of 2014.

## Interchange Transaction Issues

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

For the first three months of 2014, net scheduled interchange was -362 GWh and net actual interchange was -243 GWh, a difference of 119 GWh. For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued three TLRs of level 3a or higher during the first three months of 2014, compared to eight TLRs issued during the first three months of 2013.

- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 215,829 bids per day, with an average cleared volume of 1,486,359 MWh per day, in the first three months of 2014, compared to an average of 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013. (Figure 9-13).

## Recommendations

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.

- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction.

- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.

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3   In the first three months of 2014, there were 198 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 $102.11 while the NYISO LMP at the Neptune Bus during non-zero flows was $123.52, a difference of $21.41.

4   The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Neptune DC Tie line was -570 MW.

5   In the first three months of 2014, there were 128 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 $102.27 while the NYISO LMP at the Neptune Bus during non-zero flows was $109.82, a difference of $7.55.

6   The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Linden VFT line was -160 MW.

7   In the first three months of 2014, there were 841 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $131.57 while the NYISO LMP at the Hudson Bus during non-zero flows was $138.09, a difference of $6.52.

8   The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Hudson line was -295 MW.

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

## 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 offsets (FTRs and 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's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

## Interchange Transaction Activity

### Aggregate Imports and Exports

During the first three months of 2014, PJM was a monthly net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in February and March of 2014 (Figure 9-1).[9] For the first three months of 2014, the total real-time net interchange of 240.8 GWh was lower than the net interchange of 1,640.5 GWh during the first three months of 2013. In the first three months of 2014, the peak month for net importing interchange was January, 1,608.8 GWh; in the first three months of 2013 it was February, 639.5 GWh. Gross monthly export volumes during the first three months of 2014 averaged 4,392.7 GWh compared to 3,202.4 GWh for the first three months of 2013, while gross monthly imports in the first three months of 2014 averaged 4,472.9 GWh compared to 3,749.2 GWh for the first three months of 2013.

During the first three months of 2014, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). In the first three months of 2014, the total day-ahead net interchange of -4,982.0 GWh was lower than the net interchange of -6,592.7 GWh for the first three months of 2013. In the first three months of 2014, the peak month for net exporting interchange was March, -1,802.8 GWh; in the first three months of 2013 it was January, -2,602.8 GWh. Gross monthly export volumes in the first three months of 2014 averaged 6,711.8 GWh compared to 7,790.7 GWh for the first three months of 2013, while gross monthly imports in the first three months of 2014 averaged 5,051.1 GWh compared to 5,593.1 GWh for the first three months of 2013.

Figure 9-1 shows the impact of net import and export up-to congestion transactions on the overall net Day-Ahead Energy Market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 9-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

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9 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

In the first three months of 2014, gross imports in the Day-Ahead Energy Market were 112.9 percent of gross imports in the Real-Time Energy Market (149.2 percent for the first three months of 2013), gross exports in the Day-Ahead Energy Market were 152.8 percent of gross exports in the Real-Time Energy Market (243.3 percent for the first three months of 2013). In the first three months of 2014, net interchange was -4,982.0 GWh in the Day-Ahead Energy Market and 240.8 GWh in the Real-Time Energy Market compared to -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market for the first three months of 2013.

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 and price differences in the Day-Ahead and Real-Time Energy Markets.[10] In the first three months of 2014, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

**Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: January through March, 2014**
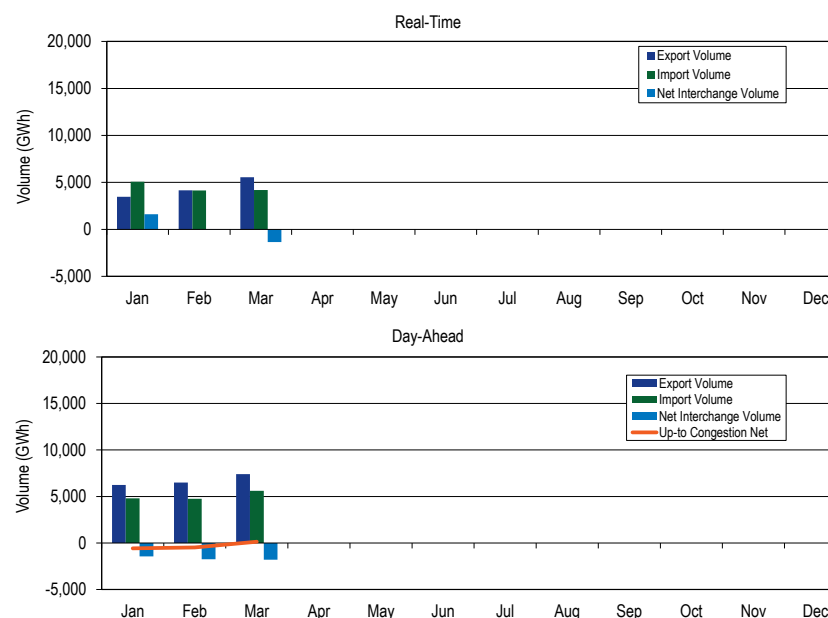


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through March, 2014. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows began to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Energy Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased.

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

While the gross import and export volumes in the Day-Ahead Energy Market have decreased, the net direction of power flows has remained predominantly in the export direction.

**Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through March, 2014**
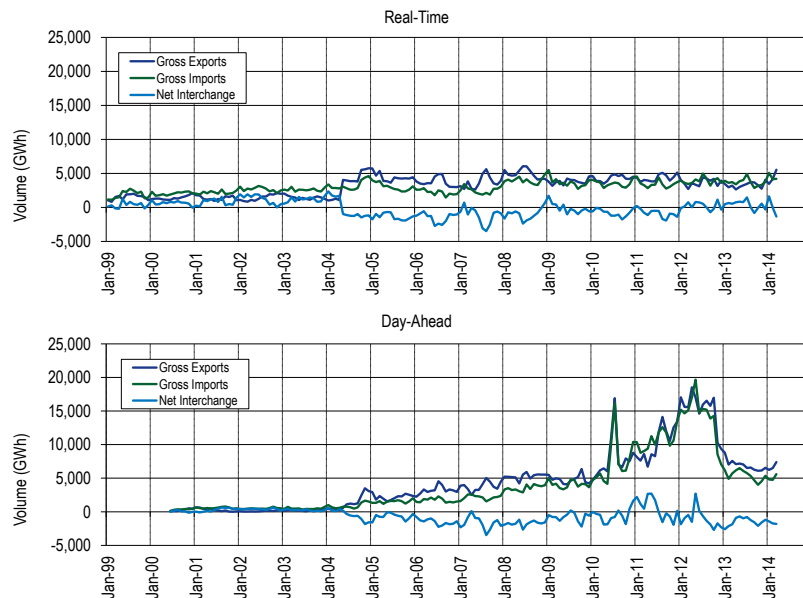


## Real-Time Interface Imports and Exports

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 9-16 for a list of active interfaces during the first three months of 2014. Figure 9-3 shows the approximate geographic location of the interfaces. In the first three months of 2014, PJM had 20 interfaces with neighboring balancing authorities. While the Linden (LIND)

Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are nine separate interfaces that make up the MISO Interface between the PJM and MISO. Table 9-1 through Table 9-3 show the Real-Time Energy 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 Energy Market is shown by interface for the first three months of 2014 in Table 9-1, while gross imports and exports are shown in Table 9-2 and Table 9-3.

In the Real-Time Energy Market, in the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 61.2 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 30.7 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 15.5 percent, and PJM/Neptune (NEPT) with 15.0 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 55.2 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net scheduled imports, with three importing interfaces accounting for 76.4 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 37.3 percent, PJM/Tennessee Valley Authority (TVA) with 17.9 percent and PJM/Ameren-Illinois (AMIL) with 21.2 percent of the net import volume.[11]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by load serving entities or their affiliates within the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 70 percent of the generation output into the PJM footprint.[12] OVEC itself does not serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

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11  In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).
12  See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed April 16, 2014).

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): January through March, 2014

|  |  | Jan | Feb | Mar | Total |
|---|---|---|---|---|---|
| CPLE |  | (33.5) | (11.2) | (12.8) | (57.5) |
| CPLW |  | 0.0 | 0.6 | 5.2 | 5.8 |
| DUK |  | 294.7 | 395.5 | 541.7 | 1,231.9 |
| LGEE |  | 262.4 | 230.3 | 159.5 | 652.2 |
| MEC |  | (421.8) | (387.0) | (239.8) | (1,048.6) |
| MISO |  | 1,193.0 | (460.9) | (1,620.2) | (888.1) |
|  | ALTE | (140.8) | (241.9) | (770.7) | (1,153.4) |
|  | ALTW | (49.5) | (85.5) | (98.5) | (233.5) |
|  | AMIL | 917.6 | 478.4 | 317.9 | 1,713.9 |
|  | CIN | 318.9 | (341.6) | (350.1) | (372.7) |
|  | CWLP | 0.0 | 0.0 | 0.0 | 0.0 |
|  | IPL | 87.3 | (65.3) | (2.3) | 19.6 |
|  | MECS | 158.2 | (25.4) | (564.6) | (431.9) |
|  | NIPS | 15.2 | (51.6) | (3.7) | (40.1) |
|  | WEC | (113.8) | (128.0) | (148.3) | (390.1) |
| NYISO |  | (1,091.2) | (1,328.3) | (1,701.2) | (4,120.8) |
|  | HUDS | (79.2) | (210.2) | (98.9) | (388.3) |
|  | LIND | (72.8) | (134.8) | (117.6) | (325.2) |
|  | NEPT | (303.6) | (424.0) | (390.7) | (1,118.2) |
|  | NYIS | (635.5) | (559.4) | (1,094.0) | (2,288.9) |
| OVEC |  | 1,055.5 | 990.6 | 972.3 | 3,018.4 |
| TVA |  | 349.8 | 552.2 | 545.5 | 1,447.4 |
| Total |  | 1,608.8 | (18.3) | (1,349.8) | 240.8 |

Table 9-2 Real-time scheduled gross import volume by interface (GWh): January through March, 2014

|  |  | Jan | Feb | Mar | Total |
|---|---|---|---|---|---|
| CPLE |  | 0.7 | 5.1 | 2.4 | 8.2 |
| CPLW |  | 0.0 | 0.6 | 5.2 | 5.8 |
| DUK |  | 355.0 | 427.5 | 563.5 | 1,346.0 |
| LGEE |  | 263.5 | 230.3 | 162.7 | 656.5 |
| MEC |  | 16.5 | 0.2 | 226.2 | 242.8 |
| MISO |  | 1,922.9 | 1,066.3 | 918.6 | 3,907.8 |
|  | ALTE | 55.0 | 9.3 | 0.3 | 64.7 |
|  | ALTW | 0.5 | 0.0 | 0.0 | 0.5 |
|  | AMIL | 967.4 | 627.9 | 486.4 | 2,081.7 |
|  | CIN | 517.5 | 160.6 | 176.7 | 854.7 |
|  | CWLP | 0.0 | 0.0 | 0.0 | 0.0 |
|  | IPL | 141.4 | 44.7 | 166.9 | 352.9 |
|  | MECS | 215.2 | 219.9 | 85.1 | 520.2 |
|  | NIPS | 25.9 | 3.9 | 0.9 | 30.6 |
|  | WEC | 0.0 | 0.0 | 2.4 | 2.4 |
| NYISO |  | 1,022.4 | 838.9 | 773.7 | 2,635.0 |
|  | HUDS | 0.0 | 0.0 | 0.0 | 0.0 |
|  | LIND | 23.2 | 5.2 | 5.8 | 34.3 |
|  | NEPT | 0.0 | 0.0 | 0.0 | 0.0 |
|  | NYIS | 999.1 | 833.6 | 767.9 | 2,600.7 |
| OVEC |  | 1,082.6 | 1,016.0 | 995.4 | 3,094.0 |
| TVA |  | 413.4 | 559.8 | 549.5 | 1,522.7 |
| Total |  | 5,076.9 | 4,144.7 | 4,197.2 | 13,418.8 |

**Table 9-3 Real-time scheduled gross export volume by interface (GWh): January through March, 2014**

|  |  | Jan | Feb | Mar | Total |
|---|---|---|---|---|---|
| CPLE |  | 34.2 | 16.3 | 15.2 | 65.7 |
| CPLW |  | 0.0 | 0.0 | 0.0 | 0.0 |
| DUK |  | 60.3 | 32.0 | 21.8 | 114.1 |
| LGEE |  | 1.1 | 0.0 | 3.2 | 4.2 |
| MEC |  | 438.3 | 387.1 | 466.0 | 1,291.4 |
| MISO |  | 729.9 | 1,527.2 | 2,538.8 | 4,795.9 |
|  | ALTE | 195.9 | 251.2 | 771.0 | 1,218.1 |
|  | ALTW | 50.1 | 85.5 | 98.5 | 234.1 |
|  | AMIL | 49.8 | 149.6 | 168.5 | 367.8 |
|  | CIN | 198.6 | 502.1 | 526.7 | 1,227.4 |
|  | CWLP | 0.0 | 0.0 | 0.0 | 0.0 |
|  | IPL | 54.1 | 110.0 | 169.2 | 333.3 |
|  | MECS | 57.1 | 245.3 | 649.7 | 952.1 |
|  | NIPS | 10.7 | 55.5 | 4.6 | 70.7 |
|  | WEC | 113.8 | 128.0 | 150.7 | 392.5 |
| NYISO |  | 2,113.6 | 2,167.2 | 2,475.0 | 6,755.7 |
|  | HUDS | 79.2 | 210.2 | 98.9 | 388.3 |
|  | LIND | 96.1 | 140.0 | 123.4 | 359.5 |
|  | NEPT | 303.6 | 424.0 | 390.7 | 1,118.2 |
|  | NYIS | 1,634.7 | 1,393.0 | 1,862.0 | 4,889.7 |
| OVEC |  | 27.1 | 25.5 | 23.0 | 75.6 |
| TVA |  | 63.6 | 7.6 | 4.0 | 75.2 |
| Total |  | 3,468.0 | 4,163.0 | 5,546.9 | 13,178.0 |

## 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.[13] 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.[14]

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.[15] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. According to the *PJM Interface Price Definition Methodology,* dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[16] 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 9-17 presents the interface pricing points used in the first three months of 2014.

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13 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.

14 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.
15 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.
16 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>.

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.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[17]

In the Real-Time Energy Market, in the first three months of 2014, there were net scheduled exports at eleven of PJM's 18 interface pricing points eligible for real-time transactions.[18] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.1 percent of the total net exports: PJM/MISO with 57.6 percent, and PJM/NYIS with 20.4 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 39.5 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 84.4 percent of the total

net imports: PJM/SouthIMP with 53.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 30.7 percent of the net import volume.[19]

**Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2014**

| | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | (79.2) | (210.2) | (98.9) | (388.3) |
| IMO | 390.9 | 171.2 | 227.6 | 789.7 |
| LINDENVFT | (72.8) | (134.8) | (117.6) | (325.2) |
| MISO | (817.2) | (1,772.6) | (2,939.2) | (5,528.9) |
| NEPTUNE | (303.6) | (424.0) | (390.7) | (1,118.2) |
| NORTHWEST | (0.4) | (0.7) | (2.7) | (3.8) |
| NYIS | (548.6) | (414.6) | (997.0) | (1,960.2) |
| OVEC | 1,055.5 | 990.6 | 972.3 | 3,018.4 |
| SOUTHIMP | 2,145.9 | 1,840.7 | 2,040.8 | 6,027.3 |
| CPLEIMP | 0.4 | 0.0 | 0.1 | 0.4 |
| DUKIMP | 101.2 | 216.8 | 106.6 | 424.6 |
| NCMPAIMP | 96.3 | 113.1 | 113.1 | 322.6 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 1,948.0 | 1,510.7 | 1,820.9 | 5,279.6 |
| SOUTHEXP | (161.5) | (63.9) | (44.4) | (269.8) |
| CPLEEXP | (31.0) | (16.2) | (14.6) | (61.8) |
| DUKEXP | (32.3) | (22.3) | (14.9) | (69.5) |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | (2.7) | 0.0 | 0.0 | (2.7) |
| SOUTHWEST | (2.4) | (7.1) | 0.0 | (9.4) |
| SOUTHEXP | (93.2) | (18.4) | (14.9) | (126.4) |
| Total | 1,608.8 | (18.3) | (1,349.8) | 240.8 |

17 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.
18 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).
19 In the Real-Time Energy Market, one PJM interface pricing point had a net interchange of zero (NCMPAEXP).

**Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 |
| IMO | 447.2 | 222.9 | 260.3 | 930.4 |
| LINDENVFT | 23.2 | 5.2 | 5.8 | 34.3 |
| MISO | 341.1 | 123.6 | 57.0 | 521.7 |
| NEPTUNE | 0.0 | 0.0 | 0.0 | 0.0 |
| NORTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| NYIS | 1,036.9 | 935.0 | 834.9 | 2,806.9 |
| OVEC | 1,082.6 | 1,016.0 | 995.4 | 3,094.0 |
| SOUTHIMP | 2,145.9 | 1,841.9 | 2,043.8 | 6,031.5 |
| CPLEIMP | 0.4 | 0.0 | 0.1 | 0.4 |
| DUKIMP | 101.2 | 216.8 | 106.6 | 424.6 |
| NCMPAIMP | 96.3 | 113.1 | 113.1 | 322.6 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 1,948.0 | 1,511.9 | 1,824.0 | 5,283.9 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | 5,076.9 | 4,144.7 | 4,197.2 | 13,418.8 |

**Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | 79.2 | 210.2 | 98.9 | 388.3 |
| IMO | 56.3 | 51.7 | 32.6 | 140.6 |
| LINDENVFT | 96.1 | 140.0 | 123.4 | 359.5 |
| MISO | 1,158.3 | 1,896.2 | 2,996.2 | 6,050.7 |
| NEPTUNE | 303.6 | 424.0 | 390.7 | 1,118.2 |
| NORTHWEST | 0.4 | 0.7 | 2.7 | 3.8 |
| NYIS | 1,585.5 | 1,349.7 | 1,832.0 | 4,767.1 |
| OVEC | 27.1 | 25.5 | 23.0 | 75.6 |
| SOUTHIMP | 0.0 | 1.2 | 3.0 | 4.2 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 0.0 | 1.2 | 3.0 | 4.2 |
| SOUTHEXP | 161.5 | 63.9 | 44.4 | 269.8 |
| CPLEEXP | 31.0 | 16.2 | 14.6 | 61.8 |
| DUKEXP | 32.3 | 22.3 | 14.9 | 69.5 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 2.7 | 0.0 | 0.0 | 2.7 |
| SOUTHWEST | 2.4 | 7.1 | 0.0 | 9.4 |
| SOUTHEXP | 93.2 | 18.4 | 14.9 | 126.4 |
| Total | 3,468.0 | 4,163.0 | 5,546.9 | 13,178.0 |

## 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.[20] 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

20 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.

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.[21]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. In Table 9-7, Table 9-8 and Table 9-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow.

Table 9-7 through Table 9-9 show the day-ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Energy Market is shown by interface for the first three months of 2014 in Table 9-7, while gross imports and exports are shown in Table 9-8 and Table 9-9.

In the Day-Ahead Energy Market in the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 67.3 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 33.6 percent, PJM/MidAmerican Energy Company (MEC) with 17.5 percent, and PJM/NEPT with 16.1 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT,

PJM/HUDS and PJM/Linden (LIND)) together represented 54.1 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 24.4 percent of the total net PJM exports in the Day-Ahead Energy Market. Six PJM interfaces had net scheduled imports, with two importing interfaces accounting for 89.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 71.7 percent, and PJM/DUK with 18.0 percent of the net import volume.[22]

**Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through March, 2014**

| | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| CPLE | (30.1) | (15.5) | (13.9) | (59.5) |
| CPLW | 0.0 | 0.6 | 0.0 | 0.6 |
| DUK | 151.9 | 128.5 | 270.6 | 551.0 |
| LGEE | 0.0 | 0.0 | 0.0 | 0.0 |
| MEC | (433.6) | (375.5) | (438.5) | (1,247.6) |
| MISO | (137.8) | (528.3) | (1,069.7) | (1,735.8) |
| ALTE | (96.1) | (148.5) | (516.3) | (760.9) |
| ALTW | (7.3) | (18.8) | (13.8) | (39.9) |
| AMIL | 25.4 | 81.2 | 27.2 | 133.8 |
| CIN | (31.5) | (209.0) | (221.1) | (461.6) |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 0.0 | 0.0 | 87.1 | 87.1 |
| MECS | 75.0 | (113.1) | (360.3) | (398.4) |
| NIPS | 0.0 | (45.2) | 0.0 | (45.2) |
| WEC | (103.4) | (74.9) | (72.5) | (250.7) |
| NYISO | (1,140.8) | (1,230.9) | (1,482.8) | (3,854.5) |
| HUDS | (45.7) | (141.5) | (77.2) | (264.3) |
| LIND | (10.2) | (22.3) | (15.8) | (48.4) |
| NEPT | (280.3) | (437.6) | (430.2) | (1,148.1) |
| NYIS | (804.6) | (629.4) | (959.6) | (2,393.6) |
| OVEC | 727.2 | 728.3 | 733.3 | 2,188.8 |
| TVA | 8.8 | 29.3 | 55.2 | 93.3 |
| Total without Up-To Congestion | (854.4) | (1,263.4) | (1,945.9) | (4,063.7) |
| Up-To Congestion | (578.5) | (482.9) | 143.1 | (918.3) |
| Total | (1,433.0) | (1,746.3) | (1,802.8) | (4,982.0) |

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21 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

22 In the Day-Ahead Energy Market, two PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/ LG&E Energy Transmission Services (LGEE)).

**Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| CPLE | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLW | 0.0 | 0.6 | 0.0 | 0.6 |
| DUK | 157.5 | 128.5 | 270.6 | 556.6 |
| LGEE | 0.0 | 0.0 | 0.0 | 0.0 |
| MEC | 0.0 | 0.0 | 0.0 | 0.0 |
| MISO | 152.3 | 127.1 | 150.7 | 430.0 |
| ALTE | 1.1 | 0.0 | 0.0 | 1.1 |
| ALTW | 0.3 | 0.0 | 0.0 | 0.3 |
| AMIL | 25.4 | 88.7 | 45.4 | 159.5 |
| CIN | 26.1 | 0.0 | 0.0 | 26.1 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 0.0 | 0.0 | 87.1 | 87.1 |
| MECS | 99.4 | 38.4 | 15.9 | 153.7 |
| NIPS | 0.0 | 0.0 | 0.0 | 0.0 |
| WEC | 0.0 | 0.0 | 2.3 | 2.3 |
| NYISO | 679.5 | 611.9 | 610.9 | 1,902.3 |
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 |
| LIND | 3.6 | 2.6 | 3.5 | 9.6 |
| NEPT | 0.0 | 0.0 | 0.0 | 0.0 |
| NYIS | 675.9 | 609.4 | 607.4 | 1,892.6 |
| OVEC | 727.3 | 728.3 | 733.3 | 2,188.9 |
| TVA | 29.7 | 29.3 | 55.2 | 114.1 |
| Total without Up-To Congestion | 1,746.2 | 1,625.7 | 1,820.7 | 5,192.6 |
| Up-To Congestion | 3,054.9 | 3,127.2 | 3,778.6 | 9,960.7 |
| Total | 4,801.1 | 4,752.9 | 5,599.2 | 15,153.3 |

**Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| CPLE | 30.1 | 15.5 | 13.9 | 59.5 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.0 |
| DUK | 5.6 | 0.0 | 0.0 | 5.6 |
| LGEE | 0.0 | 0.0 | 0.0 | 0.0 |
| MEC | 433.6 | 375.5 | 438.5 | 1,247.6 |
| MISO | 290.1 | 655.3 | 1,220.4 | 2,165.9 |
| ALTE | 97.2 | 148.5 | 516.3 | 761.9 |
| ALTW | 7.6 | 18.8 | 13.8 | 40.2 |
| AMIL | 0.0 | 7.5 | 18.3 | 25.7 |
| CIN | 57.6 | 209.0 | 221.1 | 487.7 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 0.0 | 0.0 | 0.0 | 0.0 |
| MECS | 24.4 | 151.5 | 376.2 | 552.1 |
| NIPS | 0.0 | 45.2 | 0.0 | 45.2 |
| WEC | 103.4 | 74.9 | 74.8 | 253.0 |
| NYISO | 1,820.3 | 1,842.8 | 2,093.7 | 5,756.8 |
| HUDS | 45.7 | 141.5 | 77.2 | 264.3 |
| LIND | 13.8 | 24.9 | 19.3 | 58.0 |
| NEPT | 280.3 | 437.6 | 430.2 | 1,148.1 |
| NYIS | 1,480.5 | 1,238.8 | 1,567.0 | 4,286.2 |
| OVEC | 0.1 | 0.0 | 0.0 | 0.1 |
| TVA | 20.9 | 0.0 | 0.0 | 20.9 |
| Total without Up-To Congestion | 2,600.6 | 2,889.1 | 3,766.6 | 9,256.3 |
| Up-To Congestion | 3,633.4 | 3,610.2 | 3,635.5 | 10,879.0 |
| Total | 6,234.0 | 6,499.3 | 7,402.0 | 20,135.3 |

## Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the Day-Ahead Energy Market interchange totals at the individual interface pricing points. In the first three months of 2014, up-to congestion transactions accounted for 65.7 percent of all scheduled import MW transactions, 54.0 percent of all scheduled export MW transactions and 18.4 percent of the net interchange volume in the Day-Ahead Energy Market. Net interchange in the Day-Ahead Energy Market, including up-to congestion transactions, is shown by interface pricing point in the first three months of 2014 in Table 9-10. Up-to congestion transactions by interface pricing point in the first three months of 2014 are shown in Table

9-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Energy Market are shown in Table 9-12 and Table 9-14, while gross import up-to congestion transactions are show in Table 9-13 and gross export up-to congestion transactions are shown in Table 9-15.

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-Time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created at the NIPSCO Interface prior to the integration.

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. After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The Southeast pricing point also remains eligible to receive the real-time interface price only through the reserve sharing agreement with VACAR. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with

VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.

In the Day-Ahead Energy Market, in the first three months of 2014, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 61.9 percent of the total net exports: PJM/SouthEXP with 21.0 percent, PJM/NYIS with 21.0 percent and PJM/MISO with 19.9 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 33.8 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 76.3 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 35.1 percent, PJM/SouthIMP with 22.4 percent, and PJM/Southeast with 18.8 percent of the net import volume.[23]

In the Day-Ahead Energy Market, in the first three months of 2014, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 91.5 percent of the total net up-to congestion exports: PJM/SouthEXP with 41.8 percent, PJM/Southwest with 29.2 percent, and PJM/NIPSCO with 20.5 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 2.5 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/Linden with 1.8 percent and PJM/NEPTUNE with 0.7 percent). The PJM/NYIS, and PJM/HUDS interface pricing points had net imports in the Day-Ahead Energy Market. Seven PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 78.9 percent of the total net up-to congestion imports: PJM/Northwest with 34.8 percent,

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23 In the Day-Ahead Energy Market, one PJM interface pricing point had a net interchange of zero (PJM/DUKEXP).

PJM/Southeast with 25.5 percent, and PJM/Ontario Independent Electricity System Operator (IMO) with 18.6 percent of the net import volume.[24]

**Table 9-10 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2014**

| | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | (19.6) | (8.6) | 68.1 | 39.8 |
| IMO | 319.5 | 296.7 | 271.0 | 887.2 |
| LINDENVFT | (72.0) | (69.4) | (0.6) | (141.9) |
| MISO | (442.9) | (648.2) | (977.1) | (2,068.2) |
| NEPTUNE | (353.8) | (396.7) | (433.3) | (1,183.8) |
| NIPSCO | (763.3) | (19.3) | (274.5) | (1,057.1) |
| NORTHWEST | 24.1 | 134.8 | (36.0) | 123.0 |
| NYIS | (755.3) | (510.8) | (912.7) | (2,178.9) |
| OVEC | 1,225.6 | 54.0 | 599.1 | 1,878.6 |
| SOUTHIMP | 641.1 | 834.2 | 1,639.1 | 3,114.4 |
| CPLEIMP | 0.0 | 0.6 | 0.0 | 0.6 |
| DUKIMP | 29.3 | 64.1 | 17.8 | 111.2 |
| NCMPAIMP | 67.9 | 31.7 | 51.3 | 151.0 |
| SOUTHEAST | 216.3 | 238.1 | 718.8 | 1,173.2 |
| SOUTHWEST | 161.0 | 156.2 | 164.8 | 482.0 |
| SOUTHIMP | 166.5 | 343.6 | 686.3 | 1,196.4 |
| SOUTHEXP | (1,236.4) | (1,412.9) | (1,745.9) | (4,395.2) |
| CPLEEXP | (28.4) | (14.5) | (13.1) | (55.9) |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | (1.7) | (0.9) | (0.8) | (3.5) |
| SOUTHEAST | (59.9) | (83.4) | (26.0) | (169.2) |
| SOUTHWEST | (507.8) | (648.2) | (831.2) | (1,987.2) |
| SOUTHEXP | (638.6) | (665.8) | (874.8) | (2,179.3) |
| Total | (1,433.0) | (1,746.3) | (1,802.8) | (4,982.0) |

**Table 9-11 Up-to congestion scheduled net interchange volume by interface pricing point (GWh): January through March, 2014**

| | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | 26.1 | 123.2 | 145.2 | 294.6 |
| IMO | 218.6 | 259.9 | 255.7 | 734.1 |
| LINDENVFT | (61.7) | (47.1) | 15.3 | (93.5) |
| MISO | (195.6) | 5.7 | 243.1 | 53.2 |
| NEPTUNE | (73.5) | 41.0 | (3.1) | (35.7) |
| NIPSCO | (763.3) | (19.3) | (274.5) | (1,057.1) |
| NORTHWEST | 457.7 | 510.3 | 402.6 | 1,370.6 |
| NYIS | 49.3 | 128.0 | 42.5 | 219.8 |
| OVEC | 498.4 | (674.3) | (130.4) | (306.4) |
| SOUTHIMP | 445.3 | 587.1 | 1,178.8 | 2,211.3 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 216.3 | 238.1 | 718.8 | 1,173.2 |
| SOUTHWEST | 161.0 | 156.2 | 164.8 | 482.0 |
| SOUTHIMP | 68.0 | 192.9 | 295.2 | 556.1 |
| SOUTHEXP | (1,179.8) | (1,397.4) | (1,732.0) | (4,309.2) |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | (59.9) | (83.4) | (26.0) | (169.2) |
| SOUTHWEST | (507.8) | (648.2) | (831.2) | (1,987.2) |
| SOUTHEXP | (612.2) | (665.8) | (874.8) | (2,152.8) |
| Total Interfaces | (578.5) | (482.9) | 143.1 | (918.3) |
| INTERNAL | 35,413.4 | 36,715.9 | 41,839.2 | 113,968.6 |
| Total | 34,834.9 | 36,109.8 | 41,837.1 | 112,755.6 |

24 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

**Table 9-12 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | 187.4 | 317.0 | 257.6 | 761.9 |
| IMO | 358.4 | 375.9 | 340.3 | 1,074.7 |
| LINDENVFT | 84.4 | 70.4 | 100.5 | 255.3 |
| MISO | 334.1 | 318.3 | 445.6 | 1,097.9 |
| NEPTUNE | 38.4 | 133.4 | 156.1 | 327.9 |
| NIPSCO | 85.5 | 172.9 | 80.0 | 338.3 |
| NORTHWEST | 614.8 | 605.4 | 503.2 | 1,723.4 |
| NYIS | 810.5 | 787.0 | 726.5 | 2,323.9 |
| OVEC | 1,646.5 | 1,138.6 | 1,350.5 | 4,135.6 |
| SOUTHIMP | 641.1 | 834.2 | 1,639.1 | 3,114.4 |
| CPLEIMP | 0.0 | 0.6 | 0.0 | 0.6 |
| DUKIMP | 29.3 | 64.1 | 17.8 | 111.2 |
| NCMPAIMP | 67.9 | 31.7 | 51.3 | 151.0 |
| SOUTHEAST | 216.3 | 238.1 | 718.8 | 1,173.2 |
| SOUTHWEST | 161.0 | 156.2 | 164.8 | 482.0 |
| SOUTHIMP | 166.5 | 343.6 | 686.3 | 1,196.4 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | 4,801.1 | 4,752.9 | 5,599.2 | 15,153.3 |

**Table 9-13 Up-to congestion scheduled gross import volume by interface pricing point (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | 187.4 | 317.0 | 257.6 | 761.9 |
| IMO | 257.5 | 337.5 | 324.4 | 919.5 |
| LINDENVFT | 80.8 | 67.8 | 97.0 | 245.6 |
| MISO | 291.2 | 318.3 | 445.3 | 1,054.8 |
| NEPTUNE | 38.4 | 133.4 | 156.1 | 327.9 |
| NIPSCO | 85.5 | 172.9 | 80.0 | 338.3 |
| NORTHWEST | 614.8 | 605.4 | 503.2 | 1,723.4 |
| NYIS | 134.6 | 177.6 | 115.2 | 427.4 |
| OVEC | 919.3 | 410.3 | 621.0 | 1,950.6 |
| SOUTHIMP | 445.3 | 587.1 | 1,178.8 | 2,211.3 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 216.3 | 238.1 | 718.8 | 1,173.2 |
| SOUTHWEST | 161.0 | 156.2 | 164.8 | 482.0 |
| SOUTHIMP | 68.0 | 192.9 | 295.2 | 556.1 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | 3,054.9 | 3,127.2 | 3,778.6 | 9,960.7 |

**Table 9-14 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | 206.9 | 325.6 | 189.5 | 722.1 |
| IMO | 39.0 | 79.2 | 69.2 | 187.5 |
| LINDENVFT | 156.4 | 139.8 | 101.1 | 397.2 |
| MISO | 776.9 | 966.5 | 1,422.6 | 3,166.1 |
| NEPTUNE | 392.2 | 530.0 | 589.5 | 1,511.7 |
| NIPSCO | 848.8 | 192.2 | 354.4 | 1,395.4 |
| NORTHWEST | 590.7 | 470.6 | 539.1 | 1,600.4 |
| NYIS | 1,565.8 | 1,297.8 | 1,639.2 | 4,502.8 |
| OVEC | 421.0 | 1,084.6 | 751.4 | 2,257.0 |
| SOUTHIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 1,236.4 | 1,412.9 | 1,745.9 | 4,395.2 |
| CPLEEXP | 28.4 | 14.5 | 13.1 | 55.9 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 1.7 | 0.9 | 0.8 | 3.5 |
| SOUTHEAST | 59.9 | 83.4 | 26.0 | 169.2 |
| SOUTHWEST | 507.8 | 648.2 | 831.2 | 1,987.2 |
| SOUTHEXP | 638.6 | 665.8 | 874.8 | 2,179.3 |
| Total | 6,234.0 | 6,499.3 | 7,402.0 | 20,135.3 |

**Table 9-15 Up-to congestion scheduled gross export volume by interface pricing point (GWh): January through March, 2014**

|  | Jan | Feb | Mar | Total |
|---|---|---|---|---|
| HUDS | 161.2 | 193.7 | 112.4 | 467.4 |
| IMO | 39.0 | 77.6 | 68.7 | 185.3 |
| LINDENVFT | 142.6 | 114.9 | 81.7 | 339.2 |
| MISO | 486.8 | 312.6 | 202.2 | 1,001.6 |
| NEPTUNE | 111.9 | 92.4 | 159.3 | 363.6 |
| NIPSCO | 848.8 | 192.2 | 354.4 | 1,395.4 |
| NORTHWEST | 157.1 | 95.1 | 100.6 | 352.8 |
| NYIS | 85.3 | 49.6 | 72.8 | 207.6 |
| OVEC | 420.9 | 1,084.6 | 751.4 | 2,256.9 |
| SOUTHIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 1,179.8 | 1,397.4 | 1,732.0 | 4,309.2 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 59.9 | 83.4 | 26.0 | 169.2 |
| SOUTHWEST | 507.8 | 648.2 | 831.2 | 1,987.2 |
| SOUTHEXP | 612.2 | 665.8 | 874.8 | 2,152.8 |
| Total | 3,633.4 | 3,610.2 | 3,635.5 | 10,879.0 |

Table 9-16 Active interfaces: January through March, 2014[25]

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

Table 9-17 Active pricing points: January through March, 2014

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

Figure 9-3 PJM's footprint and its external interfaces



## 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.[26]

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

26 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission 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). In the first three months of 2014, there were net scheduled flows of 2,251 GWh through MISO that received an interface pricing point associated with the southern border. Conversely, in the first three months of 2014, there were no net scheduled flows across the southern border that received the MISO interface pricing point.

In the first three months of 2014, net scheduled interchange was -362 GWh and net actual interchange was -243 GWh, a difference of 119 GWh. In the first three months of 2013, net scheduled interchange was 1,076 GWh and net

actual interchange was 1,098 GWh, a difference of 22 GWh.[27] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[28]

## Table 9-18 Net scheduled and actual PJM flows by interface (GWh): January through March, 2014

|  | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| CPLE | 2,514 | (64) | 2,578 |
| CPLW | (326) | 6 | (332) |
| DUK | 347 | 1,232 | (885) |
| LGEE | 888 | 652 | 235 |
| MEC | (452) | (1,046) | 594 |
| MISO | (4,706) | (996) | (3,710) |
| ALTE | (1,848) | (1,153) | (695) |
| ALTW | (563) | (234) | (330) |
| AMIL | 3,111 | 1,714 | 1,397 |
| CIN | (1,685) | (429) | (1,256) |
| CWLP | (150) | 0 | (150) |
| IPL | 183 | (31) | 214 |
| MECS | (3,889) | (432) | (3,457) |
| NIPS | (917) | (40) | (877) |
| WEC | 1,052 | (390) | 1,442 |
| NYISO | (4,082) | (4,174) | 92 |
| HUDS | (388) | (388) | 0 |
| LIND | (325) | (325) | 0 |
| NEPT | (1,118) | (1,118) | 0 |
| NYIS | (2,250) | (2,342) | 92 |
| OVEC | 4,058 | 3,018 | 1,040 |
| TVA | 1,516 | 1,010 | 506 |
| Total | (243) | (362) | 119 |

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

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27 The "Net Scheduled" values shown in Table 9-18 include dynamic schedules. Dynamic schedules are commonly used for scheduling generation from one another balancing authority area to another. As defined by NERC, a dynamic schedule is a telemetered reading or value from such a generating unit that is updated in real time and used as a schedule in the AGC/ACE equation of the BA to which it is scheduled. The hourly integrated values of dynamic schedules are treated as a schedule for interchange accounting purposes. Table 9-1 through Table 9-6 represent block scheduled transactions, submitted through the Enhanced Energy Scheduling (EES) application and tagged through the NERC e-tag process only. As a result, the net interchange in Table 9-18 does not match the interchange values shown in Table 9-1 through Table 9-6.

28 See PJM. "M-12: Balancing Operations," Revision 30 (December 1, 2013).

the specific interface price.[29] 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 9-19 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points.

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

flows at the southern region, the net actual flows from the southern region (4,939 GWh of imports at the SouthIMP Interface Pricing Point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP Interface Pricing Points, or 5,313 GWh).

The IMO Interface Pricing Point with the IESO was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

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

Table 9-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through March, 2014

| | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| HUDSONTP | (388) | (388) | (0) |
| IMO | 0 | 790 | (790) |
| LINDENVFT | (325) | (325) | 0 |
| MISO | (4,706) | (5,636) | 930 |
| NEPTUNE | (1,118) | (1,118) | 0 |
| NORTHWEST | (452) | (2) | (450) |
| NYIS | (2,250) | (2,013) | (237) |
| OVEC | 4,058 | 3,018 | 1,040 |
| SOUTHIMP | 4,939 | 5,583 | (644) |
| CPLEIMP | 0 | 0 | (0) |
| DUKIMP | 0 | 425 | (425) |
| NCMPAIMP | 0 | 323 | (323) |
| SOUTHEAST | 0 | 0 | 0 |
| SOUTHWEST | 0 | 0 | 0 |
| SOUTHIMP | 4,939 | 4,835 | 104 |
| SOUTHEXP | 0 | (270) | 270 |
| CPLEEXP | 0 | (62) | 62 |
| DUKEXP | 0 | (69) | 69 |
| NCMPAEXP | 0 | 0 | 0 |
| SOUTHEAST | 0 | (3) | 3 |
| SOUTHWEST | 0 | (9) | 9 |
| SOUTHEXP | 0 | (126) | 126 |
| Total | (243) | (362) | 119 |

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through March, 2014

| | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| HUDSONTP | (388) | (388) | 0 |
| LINDENVFT | (325) | (325) | 0 |
| MISO | (4,706) | (4,724) | 18 |
| NEPTUNE | (1,118) | (1,118) | 0 |
| NORTHWEST | (452) | (2) | (450) |
| NYIS | (2,250) | (2,136) | (115) |
| OVEC | 4,058 | 3,018 | 1,040 |
| SOUTHIMP | 4,939 | 5,583 | (644) |
| CPLEIMP | 0 | 0 | 0 |
| DUKIMP | 0 | 425 | (425) |
| NCMPAIMP | 0 | 323 | (323) |
| SOUTHEAST | 0 | 0 | 0 |
| SOUTHWEST | 0 | 0 | 0 |
| SOUTHIMP | 4,939 | 4,835 | 104 |
| SOUTHEXP | 0 | (270) | 270 |
| CPLEEXP | 0 | (62) | 62 |
| DUKEXP | 0 | (69) | 69 |
| NCMPAEXP | 0 | 0 | 0 |
| SOUTHEAST | 0 | (3) | 3 |
| SOUTHWEST | 0 | (9) | 9 |
| SOUTHEXP | 0 | (126) | 126 |
| Total | (243) | (362) | 119 |

Table 9-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

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.

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 prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loops flows would be reduced.

The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.

Table 9-21 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 9-21 shows that in the first three months of 2014, 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 mapped to the SouthIMP interface, and thus actual flows were assigned the SouthIMP Interface Pricing point (312 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 (1,209 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through March, 2014

| Interface | Interface Pricing Point | Actual | Net Scheduled | Difference (GWh) | Interface | Interface Pricing Point | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| ALTE | | (1,848) | (1,153) | (695) | IPL | | 183 | (31) | 214 |
| | MISO | (1,848) | (1,165) | (683) | | IMO | 0 | 242 | (242) |
| | SOUTHIMP | 0 | 12 | (12) | | MISO | 183 | (362) | 545 |
| ALTW | | (563) | (234) | (330) | | SOUTHIMP | 0 | 89 | (89) |
| | MISO | (563) | (234) | (330) | LGEE | | 888 | 652 | 235 |
| AMIL | | 3,111 | 1,714 | 1,397 | | SOUTHEXP | 0 | (4) | 4 |
| | MISO | 3,111 | (26) | 3,137 | | SOUTHIMP | 888 | 656 | 231 |
| | SOUTHIMP | 0 | 1,750 | (1,750) | LIND | | (325) | (325) | 0 |
| | SOUTHWEST | 0 | (9) | 9 | | LINDENVFT | (325) | (325) | 0 |
| CIN | | (1,685) | (429) | (1,256) | MEC | | (452) | (1,046) | 594 |
| | IMO | 0 | 266 | (266) | | MISO | 0 | (1,275) | 1,275 |
| | MISO | (1,685) | (1,209) | (476) | | NORTHWEST | (452) | 2 | (454) |
| | NORTHWEST | 0 | (3) | 3 | | SOUTHIMP | 0 | 226 | (226) |
| | NYIS | 0 | 206 | (206) | MECS | | (3,889) | (432) | (3,457) |
| | SOUTHEXP | 0 | (1) | 1 | | IMO | 0 | 405 | (405) |
| | SOUTHIMP | 0 | 312 | (312) | | MISO | (3,889) | (933) | (2,955) |
| CPLE | | 2,514 | (64) | 2,578 | | NORTHWEST | 0 | (1) | 1 |
| | CPLEEXP | 0 | (62) | 62 | | SOUTHIMP | 0 | 98 | (98) |
| | DUKIMP | 0 | 7 | (7) | NEPT | | (1,118) | (1,118) | 0 |
| | SOUTHEXP | 0 | (1) | 1 | | NEPTUNE | (1,118) | (1,118) | 0 |
| | SOUTHIMP | 2,514 | (5) | 2,520 | NIPS | | (917) | (40) | (877) |
| | SOUTHEAST | 0 | (3) | 3 | | MISO | (917) | (40) | (877) |
| CPLW | | (326) | 6 | (332) | NYIS | | (2,250) | (2,342) | 92 |
| | SOUTHIMP | (326) | 6 | (332) | | IMO | 0 | (123) | 123 |
| CWLP | | (150) | 0 | (150) | | NYIS | (2,250) | (2,219) | (31) |
| | MISO | (150) | 0 | (150) | OVEC | | 4,058 | 3,018 | 1,040 |
| DUK | | 347 | 1,232 | (885) | | OVEC | 4,058 | 3,018 | 1,040 |
| | DUKEXP | 0 | (69) | 69 | TVA | | 1,516 | 1,010 | 506 |
| | DUKIMP | 0 | 418 | (418) | | SOUTHEXP | 0 | (75) | 75 |
| | NCMPAIMP | 0 | 323 | (323) | | SOUTHIMP | 1,516 | 1,085 | 431 |
| | SOUTHEXP | 0 | (45) | 45 | WEC | | 1,052 | (390) | 1,442 |
| | SOUTHIMP | 347 | 605 | (259) | | MISO | 1,052 | (392) | 1,444 |
| HUDS | | (388) | (388) | 0 | | SOUTHIMP | 0 | 2 | (2) |
| | HUDSONTP | (388) | (388) | 0 | Grand Total | | (243) | (362) | 119 |

Table 9-22 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 9-22 shows that in the first three months of 2014, 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 (405 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 (123 GWh).

**Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through March, 2014**

| Interface Pricing Point | Interface | Actual | Net Scheduled | Difference (GWh) | Interface Pricing Point | Interface | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| CPLEEXP | | 0 | (62) | 62 | NORTHWEST | | (452) | (2) | (450) |
| | CPLE | 0 | (62) | 62 | | CIN | 0 | (3) | 3 |
| CPLEIMP | | 0 | 0 | (0) | | MEC | (452) | 2 | (454) |
| | CPLE | 0 | 0 | (0) | | MECS | 0 | (1) | 1 |
| DUKEXP | | 0 | (69) | 69 | NYIS | | (2,250) | (2,013) | (237) |
| | DUK | 0 | (69) | 69 | | CIN | 0 | 206 | (206) |
| DUKIMP | | 0 | 425 | (425) | | NYIS | (2,250) | (2,219) | (31) |
| | CPLE | 0 | 7 | (7) | OVEC | | 4,058 | 3,018 | 1,040 |
| | DUK | 0 | 418 | (418) | | OVEC | 4,058 | 3,018 | 1,040 |
| HUDSONTP | | (388) | (388) | 0 | SOUTHEAST | | 0 | (3) | 3 |
| | HUDS | (388) | (388) | 0 | | CPLE | 0 | (3) | 3 |
| IMO | | 0 | 790 | (790) | SOUTHEXP | | 0 | (126) | 126 |
| | CIN | 0 | 266 | (266) | | CIN | 0 | (1) | 1 |
| | IPL | 0 | 242 | (242) | | CPLE | 0 | (1) | 1 |
| | MECS | 0 | 405 | (405) | | DUK | 0 | (45) | 45 |
| | NYIS | 0 | (123) | 123 | | LGEE | 0 | (4) | 4 |
| LINDENVFT | | (325) | (325) | 0 | | TVA | 0 | (75) | 75 |
| | LIND | (325) | (325) | 0 | | WEC | 0 | (0) | 0 |
| MISO | | (4,706) | (5,636) | 930 | SOUTHIMP | | 4,939 | 4,835 | 104 |
| | ALTE | (1,848) | (1,165) | (683) | | ALTE | 0 | 12 | (12) |
| | ALTW | (563) | (234) | (330) | | AMIL | 0 | 1,750 | (1,750) |
| | AMIL | 3,111 | (26) | 3,137 | | CIN | 0 | 312 | (312) |
| | CIN | (1,685) | (1,209) | (476) | | CPLE | 2,514 | (5) | 2,520 |
| | CWLP | (150) | 0 | (150) | | CPLW | (326) | 6 | (332) |
| | IPL | 183 | (362) | 545 | | DUK | 347 | 605 | (259) |
| | MEC | 0 | (1,275) | 1,275 | | IPL | 0 | 89 | (89) |
| | MECS | (3,889) | (933) | (2,955) | | LGEE | 888 | 656 | 231 |
| | NIPS | (917) | (40) | (877) | | MEC | 0 | 226 | (226) |
| | WEC | 1,052 | (392) | 1,444 | | MECS | 0 | 98 | (98) |
| NCMPAIMP | | 0 | 323 | (323) | | TVA | 1,516 | 1,085 | 431 |
| | DUK | 0 | 323 | (323) | | WEC | 0 | 2 | (2) |
| NEPTUNE | | (1,118) | (1,118) | 0 | SOUTHWEST | | 0 | (9) | 9 |
| | NEPT | (1,118) | (1,118) | 0 | | AMIL | 0 | (9) | 9 |
| | | | | | Grand Total | | (243) | (362) | 119 |

## 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 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.[30,31]

In 2013, questions were raised in the PJM/MISO Joint and Common Market (JCM) Initiative meetings whether the existing interface definitions utilized by PJM and MISO were accurately reflecting the value of congestion applied to interchange transactions when a M2M constraint is binding in either footprint.

When a M2M constraint binds, PJM's LMP calculations at the nine selected buses that make up PJM's MISO interface pricing point is determined based on the PJM model's distribution factors

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30 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed April 17, 2014). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.
31 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (Accessed April 17, 2014).

of those selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint.

PJM's MISO interface pricing point is a weighted aggregate price of the selected bus LMPs. Because PJM's MISO interface pricing point is calculated based on buses located within the MISO footprint (and in particular to the west of all M2M flowgates), PJM's calculated LMP at those buses may include a congestion component of the M2M flowgates located inside the MISO footprint.

MISO's calculated LMPs at those same buses also include the congestion component as determined based on the MISO model's distribution factors and the calculated MISO shadow price of the same binding M2M constraint. The MISO's PJM interface pricing point is a weighted aggregate price of the selected buses' LMPs. MISO's PJM interface pricing point includes all PJM generator buses located within the PJM footprint.

The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. By modifying interface price definitions in this manner, the congestion components of the bus LMPs that make up the interface prices in the individual RTOs would accurately reflect the value of congestion on M2M constraints to either RTO and therefore facilitate convergence through efficient price signals.

PJM is planning to modify the definition of the PJM/MISO interface.[32] The new interface definition will include ten equally weighted buses that are close to the PJM/MISO border. PJM's analysis of hourly flows on all of the ties between PJM and MISO showed that over 80 percent of the tie line flows were represented by the same ten ties composed of MISO and PJM monitored facilities. PJM selected generator buses electrically close to those ten tie lines. A PJM generator bus was selected for MISO monitored tie lines, and a MISO generator bus was selected for PJM monitored tie lines.

32 See "MISO Interface Definition Changes," PJM Presentation to the Markets Implementation Committee (February 5, 2014) <http://www.pjm.com/~/media/committees-groups/committees/mic/20140205/20140207-item-11a-miso-interface-definition.ashx> (February 5, 2014).

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

In the first three months of 2014, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first three months of 2014, the PJM average hourly locational marginal price (LMP) at the PJM/MISO border was $50.83 while the MISO LMP at the border was $51.20, a difference of $0.38. While the average hourly LMP difference at the PJM/MISO border was only $0.38, the average of the absolute values of the hourly differences was $25.58. The average hourly flow in the first three months of 2014 was -2,179 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.) The direction of flow was consistent with price differentials in only 48.9 percent of hours in the first three months of 2014. When the MISO/PJM interface price was greater than the PJM/MISO interface price, the average difference was $26.16. When the PJM/MISO interface price was greater than the MISO/PJM interface price, the average difference was $25.01. In the first three months of 2014, 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 $23.35. 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 $47.64. 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 $119.47. When the PJM/MISO interface price was greater than the MISO/PJM interface price, and when power flows were from PJM to MISO, the average price difference was $14.60.

In the first three months of 2014, the day-ahead PJM average hourly LMP at the PJM/MISO border was $56.83 while the MISO LMP at the border was $58.86, a difference of $2.03 per MWh.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-4). 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 9-6).

**Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through March, 2014**
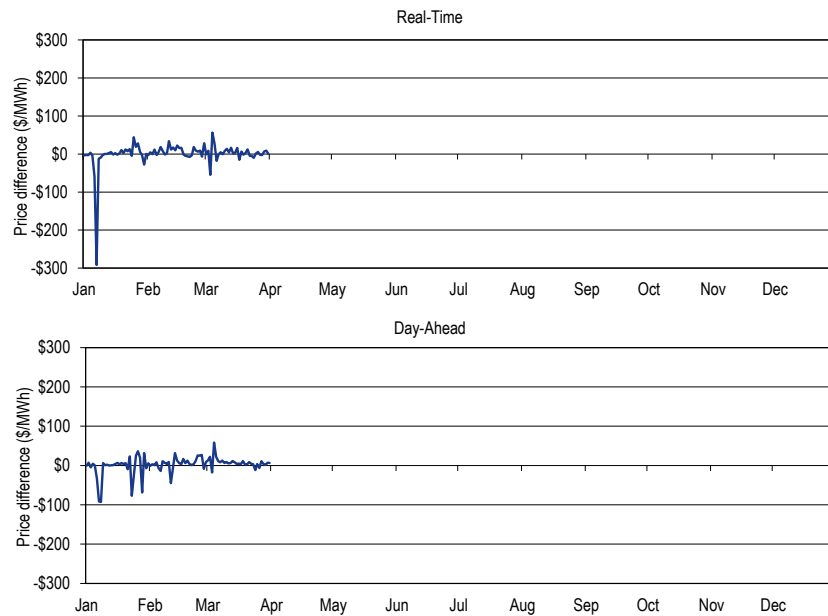


## Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

In the first three months of 2014, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,055 hours (48.9 percent of all hours), and was inconsistent with price differentials in 1,104 hours (51.1 percent of all hours). Table 9-23 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 1,104 hours where flows were uneconomic, 1,024 of those hours (92.8

percent) had a price difference greater than or equal to $1.00 and 643 of all uneconomic hours (58.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $592.36. Of the 1,055 hours where flows were economic, 978 of those hours (92.7 percent) had a price difference greater than or equal to $1.00 and 740 of all economic hours (70.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $1,576.11.

**Table 9-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through March, 2014**

| Price Difference Range (Greater Than or Equal To) | Uneconomic Hours | Percent of Total Hours | Economic Hours | Percent of Total Hours |
|---|---|---|---|---|
| $0.00 | 1,104 | 100.0% | 1,055 | 100.0% |
| $1.00 | 1,024 | 92.8% | 978 | 92.7% |
| $5.00 | 643 | 58.2% | 740 | 70.1% |
| $10.00 | 406 | 36.8% | 581 | 55.1% |
| $15.00 | 306 | 27.7% | 465 | 44.1% |
| $20.00 | 233 | 21.1% | 394 | 37.3% |
| $25.00 | 189 | 17.1% | 324 | 30.7% |
| $50.00 | 86 | 7.8% | 160 | 15.2% |
| $75.00 | 48 | 4.3% | 92 | 8.7% |
| $100.00 | 30 | 2.7% | 49 | 4.6% |
| $200.00 | 12 | 1.1% | 18 | 1.7% |
| $300.00 | 3 | 0.3% | 13 | 1.2% |
| $400.00 | 3 | 0.3% | 8 | 0.8% |
| $500.00 | 2 | 0.2% | 8 | 0.8% |
| $1,000.00 | 0 | 0.0% | 4 | 0.4% |
| $1,500.00 | 0 | 0.0% | 2 | 0.2% |
| $2,000.00 | 0 | 0.0% | 0 | 0.0% |

## PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions

exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[33]

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

In the first three months of 2014, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first three months of 2014, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first three months of 2014, the PJM average hourly LMP at the PJM/NYISO border was $100.51 while the NYISO LMP at the border was $97.37, a difference of $3.15. While the average hourly LMP difference at the PJM/NYISO border was only $3.15, the average of the absolute value of the hourly difference was $44.74. The average hourly flow in the first three months of 2014 was -1,042 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flow was consistent with price differentials in 57.8 percent of the hours in the first three months of 2014. In the first three months of 2014, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS interface price, the average difference was $37.70. When the PJM/NYIS interface price was greater than the NYIS/PJM proxy bus price, the average difference was $53.40. In the first three months of 2014, 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 $35.57. 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 $71.78. 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 $129.75. 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 $41.97.

In the first three months of 2014, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $110.55 while the NYIS LMP at the border was $106.28, a difference of $4.27.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-5). 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 9-6).

**Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY proxy – PJM/NYIS): January through March, 2014**



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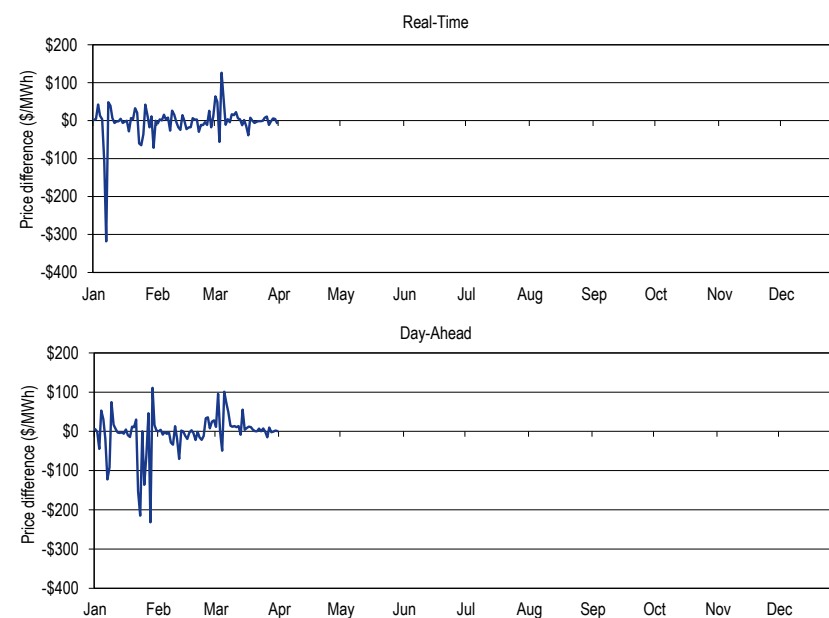
33 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

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

In the first three months of 2014, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,247 (57.8 percent of all hours), and was inconsistent with price differences in 912 hours (42.2 percent of all hours). Table 9-24 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 912 hours where flows were uneconomic, 872 of those hours (95.6 percent) had a price difference greater than or equal to $1.00 and 735 of all uneconomic hours (80.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $577.83. Of the 1,247 hours where flows were economic, 1,204 of those hours (96.6 percent) had a price difference greater than or equal to $1.00 and 1,005 of all economic hours (80.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $1,311.87.

### Table 9-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through March, 2014

| Price Difference Range (Greater Than or Equal To) | Uneconomic Hours | Percent of Total Hours | Economic Hours | Percent of Total Hours |
|---|---|---|---|---|
| $0.00 | 912 | 100.0% | 1,247 | 100.0% |
| $1.00 | 872 | 95.6% | 1,204 | 96.6% |
| $5.00 | 735 | 80.6% | 1,005 | 80.6% |
| $10.00 | 594 | 65.1% | 821 | 65.8% |
| $15.00 | 513 | 56.3% | 682 | 54.7% |
| $20.00 | 435 | 47.7% | 595 | 47.7% |
| $25.00 | 399 | 43.8% | 531 | 42.6% |
| $50.00 | 235 | 25.8% | 307 | 24.6% |
| $75.00 | 159 | 17.4% | 203 | 16.3% |
| $100.00 | 105 | 11.5% | 123 | 9.9% |
| $200.00 | 36 | 3.9% | 43 | 3.4% |
| $300.00 | 15 | 1.6% | 17 | 1.4% |
| $400.00 | 6 | 0.7% | 10 | 0.8% |
| $500.00 | 2 | 0.2% | 8 | 0.6% |
| $1,000.00 | 0 | 0.0% | 4 | 0.3% |
| $1,500.00 | 0 | 0.0% | 0 | 0.0% |
| $2,000.00 | 0 | 0.0% | 0 | 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 9-6, including average prices and measures of variability.

### Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through March, 2014
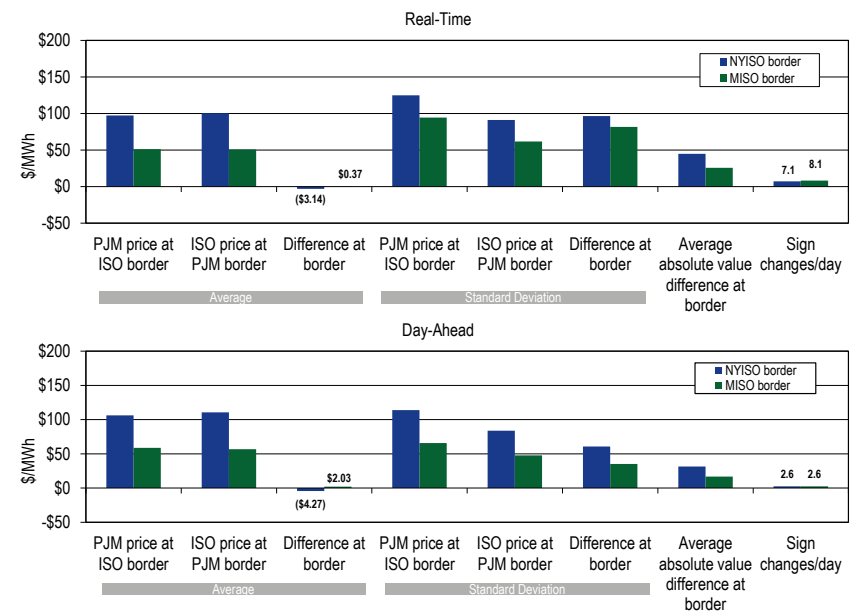


## Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will

only be from PJM to New York. In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first three months of 2014, the PJM average hourly LMP at the Neptune Interface was $104.25 while the NYISO LMP at the Neptune Bus was $128.10, a difference of $23.85.[34] While the average hourly LMP difference at the PJM/Neptune border was $23.85, the average of the absolute value of the hourly difference was $70.23. The average hourly flow during the first three months of 2014 was -518 MW.[35] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 71.4 percent of the hours in the first three months of 2014. When the NYISO/Neptune bus price was greater than the PJM/NEPT interface price, the average hourly price difference was $62.74. When the PJM/NEPT interface price was greater than the NYISO/Neptune bus interface price, the average price difference was $81.89.

Figure 9-7 Neptune hourly average flow: January through March, 2014
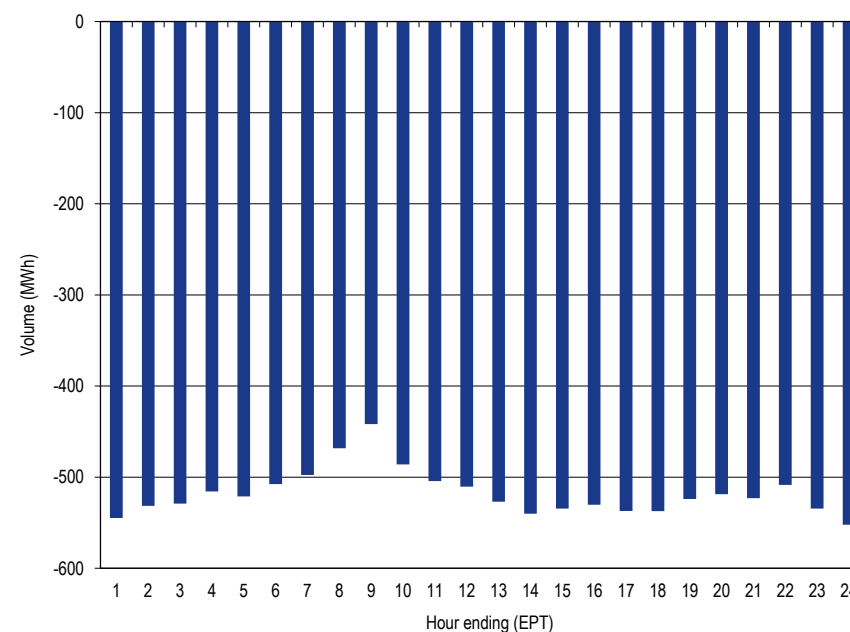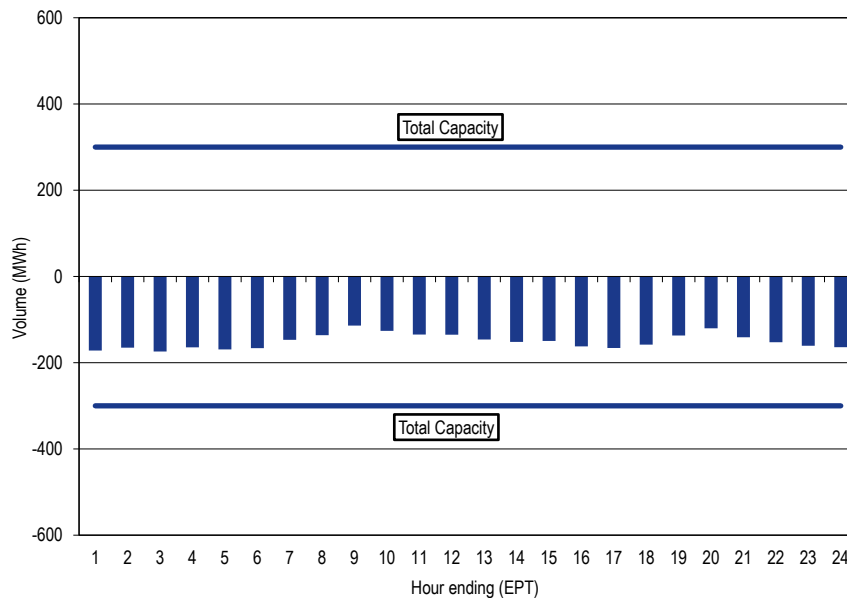


## Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first three months of 2014, the PJM average hourly LMP at the Linden Interface was $105.90 while the NYISO LMP at the Linden Bus was $110.97, a difference of $5.08.[36] While the average hourly LMP difference at the PJM/Linden border was $5.08, the average of the absolute value of the hourly difference was $58.36. The average

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34 In the first three months of 2014, there were 198 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 $102.11 while the NYISO LMP at the Neptune Bus during non-zero flows was $123.52, a difference of $21.41.

35 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Neptune DC Tie line was -570 MW.

36 In the first three months of 2014, there were 128 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 $102.27 while the NYISO LMP at the Neptune Bus during non-zero flows was $109.82, a difference of $7.55.

hourly flow in the first three months of 2014 was -151 MW.[37] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 65.4 percent of the hours in the first three months of 2014. When the NYISO/Linden bus price was greater than the PJM/LIND interface price, the average hourly price difference was $49.20. When the PJM/LIND interface price was greater than the NYISO/Linden bus price, the average price difference was $71.29.

**Figure 9-8 Linden hourly average flow: January through March, 2014[38]**



# Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC line is a bidirectional line, power flows are only 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). In the first three months of 2014, the average hourly flow (PJM to NYISO) was inconsistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus. The PJM average hourly LMP at the Hudson Interface was $124.61 while the NYISO LMP at the Hudson Bus was $123.22, a difference of $1.39.[39] While the average hourly LMP difference at the PJM/Hudson border was $1.39, the average of the absolute value of the hourly difference was $64.76. The average hourly flow during the first three months of 2014 was -180 MW.[40] (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) The flows were consistent with price differentials in 62.9 percent of the hours in the first three months of 2014. When the NYISO/Hudson bus price was greater than the PJM/HUDS interface price, the average hourly price difference was $62.04. When the PJM/HUDS interface price was greater than the NYISO/Hudson bus price, the average price difference was $87.58.

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37 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Linden VFT line was -160 MW.
38 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.

39 In the first three months of 2014, there were 841 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $131.57 while the NYISO LMP at the Hudson Bus during non-zero flows was $138.09, a difference of $6.52.
40 The average hourly flow during the first three months of 2014, ignoring hours with no flow, on the Hudson line was -295 MW.

**Figure 9-9 Hudson hourly average flow: January through March, 2014**
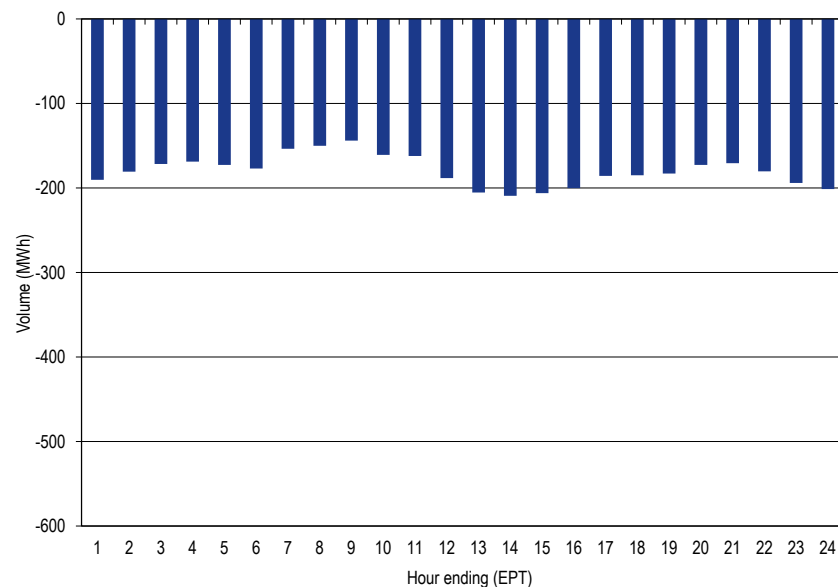


## Operating Agreements with Bordering Areas

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 an implemented operating agreement with MISO and the NYISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

### PJM and MISO Joint Operating Agreement[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.[43]

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

As of January 1, 2014, PJM had 159 flowgates eligible for M2M (Market to Market) coordination. Between January 1, 2014 and March 31, 2014, PJM added 12 and deleted 10 flowgates, leaving 161 flowgates eligible for M2M coordination as of March 31, 2014. As of January 1, 2014, MISO had 265 flowgates eligible for M2M coordination. Between January 1, 2014 and March 31, 2014, MISO added 33 and deleted 27 flowgates, leaving 271 flowgates eligible for M2M coordination as of March 31, 2014. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

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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 April 17, 2014).

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 the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first three months of 2014, 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 9-10 shows credits for coordinated congestion management between PJM and MISO.

**Figure 9-10 Credits for coordinated congestion management: January through March, 2014[44]**
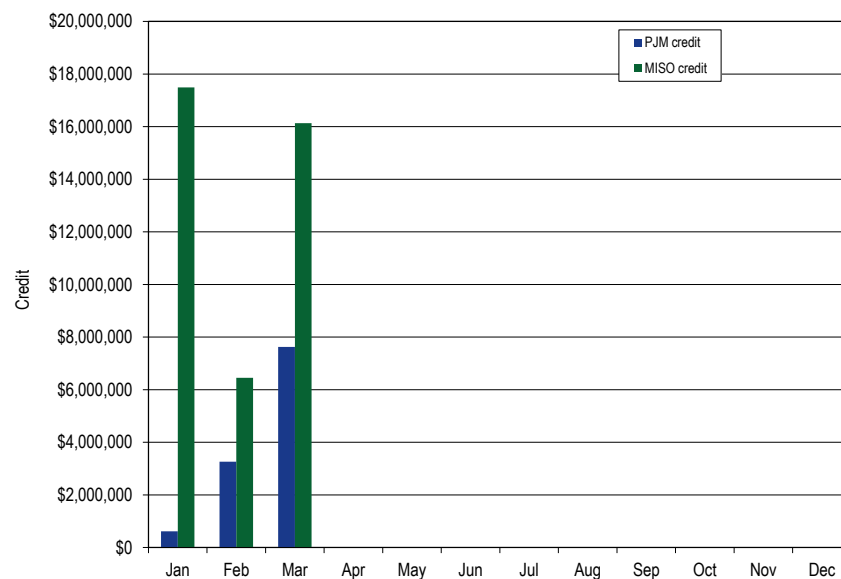


## PJM and New York Independent System Operator Joint Operating Agreement (JOA)[45]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/NYIS Interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

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

In the first three months of 2014, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The firm flow entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the

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

45 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (January 29, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2014).

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.

In the first three months of 2014, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

**Figure 9-11 Credits for coordinated congestion management (flowgates): January through March, 2014[46]**
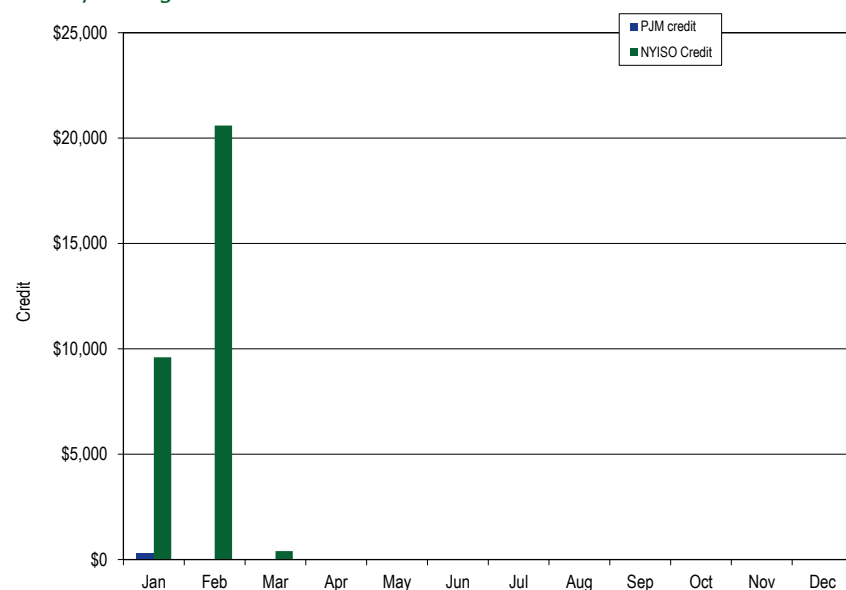


The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the PJM/NYIS border. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[47] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first three months of 2014, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

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

47 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (January 29, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2014).

**Figure 9-12 Credits for coordinated congestion management (Ramapo PARs): January through March, 2014[48]**
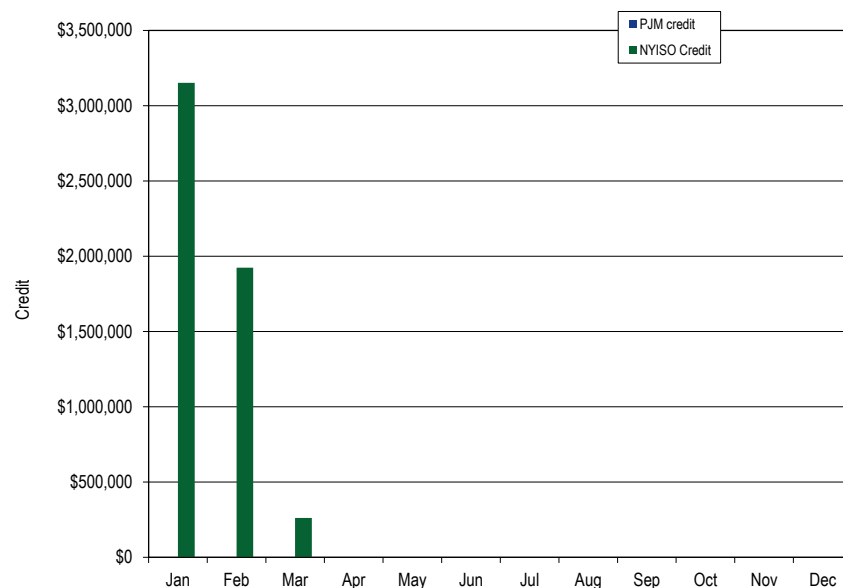


The PJM/NYISO JOA includes a provision that allows either party to suspend M2M operations when daily congestion charges exceed $500,000. On July 8, 2013, M2M congestion charges exceeded $500,000. These congestion charges were the result of its inability to meet the Ramapo PAR target values during thunderstorm alerts (TSA) called by the NYISO. During times when actual or anticipated severe weather conditions exist in the New York City area, the NYISO issues a TSA and operates in a more conservative manner, by reducing transmission transfer limits, which affects PJM's ability to meet the PAR targets. On July 12, 2013, PJM requested the suspension of M2M coordination for all TSA flowgates. PJM and NYISO are working together to develop additional operating and coordination procedures to ensure M2M processes continue to produce a just and reasonable result.

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

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a yearly basis. The agreement continued to be in effect in the first three months of 2014.

## PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[49] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[50] The existing JOA depended on the specific characteristics of PEC as a standalone company. The merged company has not engaged in discussions with PJM on this topic. The existing JOA does not apply to the merged company and should be terminated. The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.

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

49 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).
50 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).

## 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. It provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement continued to be in effect in the first three months of 2014.

## 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.

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[51] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

### Table 9-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2014

| | Import LMP | Export LMP | SOUTHIMP | SOUTHEXP | Difference IMP LMP – SOUTHIMP | Difference EXP LMP – SOUTHEXP |
|---|---|---|---|---|---|---|
| Duke | $72.63 | $75.86 | $67.15 | $67.15 | $5.48 | $8.71 |
| PEC | $74.36 | $80.82 | $67.15 | $67.15 | $7.20 | $13.66 |
| NCMPA | $74.38 | $74.95 | $67.15 | $67.15 | $7.23 | $7.80 |

### Table 9-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2014

| | Import LMP | Export LMP | SOUTHIMP | SOUTHEXP | Difference IMP LMP – SOUTHIMP | Difference EXP LMP – SOUTHEXP |
|---|---|---|---|---|---|---|
| Duke | $73.63 | $76.45 | $67.03 | $66.91 | $6.60 | $9.54 |
| PEC | $77.94 | $80.37 | $67.03 | $66.91 | $10.90 | $13.46 |
| NCMPA | $75.28 | $75.49 | $67.03 | $66.91 | $8.25 | $8.58 |

## Other Agreements with Bordering Areas

### Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey including lines controlled by PJM.[52] 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.[53]

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009, a settlement on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[54] By order issued September 16, 2010, the Commission approved this settlement,[55] which extends Con Edison's special protocol indefinitely. The Commission approved transmission service agreements provide for Con Edison to take firm point-to-point service going forward under the PJM OATT. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU, that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[56] The settlement defined Con Edison's cost

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

52 See "Section 4 – Energy Market Uplift" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.

53 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

54 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.

55 132 FERC ¶ 61,221 (2010).

56 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. Con Edison 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] Con Edison's rolled over service became effective on May 1, 2012. At that time, Con Edison became responsible for the entire 1,000 MW of transmission service and all associated charges and credits.

On December 11, 2013, the PJM Board approved changes to the Regional Transmission Expansion Plan (RTEP), which included approximately $1.5 billion in additional baseline transmission enhancements and expansions.[58] On January 10, 2014, in accordance with Schedule 12 of the PJM Tariff[59], PJM filed cost assignments for those upgrades. Using the hybrid cost allocation methodology approved by the Commission in Docket No. ER13-90-000 on March 22, 2013, PJM calculated Con Edison's cost responsibility assignment as approximately $629 million. On February 10, 2014, Con Edison filed a protest to the cost allocation proposal.[60] Con Edison asserted that the cost allocation proposal is not permitted under the service agreement for transmission service under the PJM Tariff and related settlement agreement, and that PJM's allocation of costs of the PSE&G upgrade to the Con Edison zone is unjust and unreasonable. On March 7, 2014, PJM submitted a motion for leave to answer and limited answer to the protest submitted by Con Edison.[61] PJM's response points out that the filed and approved RTEP cost allocation process was followed, and that Con Edison's cost assignment responsibilities were addressed by the Settlement agreement and Schedule 12 of the PJM Tariff.

# Interchange Transaction Issues

## PJM Transmission Loading Relief Procedures (TLRs)

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

PJM issued three TLRs of level 3a or higher in the first three months of 2014, compared to eight TLRs issued in the first three months of 2013. The number of different flowgates for which PJM declared TLRs decreased from five in the first three months of 2013 to three in the first three months of 2014. The total MWh of transaction curtailments decreased by 93.4 percent from 28,062 MWh in the first three months of 2013 to 1,852 MWh in the first three months of 2014.

MISO called fewer TLRs of level 3a or higher in the first three months of 2014 than in the first three months of 2013. MISO TLRs decreased from 107 in the first three months of 2013 to 60 in the first three months of 2014.

NYISO called fewer TLRs of level 3a or higher in the first three months of 2014 than in the first three months of 2013. NYISO TLRs decreased from two in the first three months of 2013 to one in the first three months of 2014.

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57 The terms of the settlement state that Con Edison 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.
58 See the *2013 State of the Market Report for PJM*, Volume II, Section 12, "Planning," for a more detailed discussion.
59 See PJM OATT, Schedule 12, Transmission Enhancement Charges, (February 1, 2013) pp 581-595.
60 See *Consolidated Edison Company of New York, Inc.* Docket No. ER14-972-000 (February 10, 2014).
61 See *PJM Interconnection L.L.C.* Docket No. ER14-972-000 (March 7, 2014).

### Table 9-27 PJM MISO, and NYISO TLR procedures: January, 2010 through March, 2014[62]

| Month | Number of TLRs Level 3 and Higher | | | Number of Unique Flowgates That Experienced TLRs | | | Curtailment Volume (MWh) | | |
|---|---|---|---|---|---|---|---|---|---|
| | PJM | MISO | NYISO | PJM | MISO | NYISO | PJM | MISO | NYISO |
| Jan-11 | 7 | 8 | 29 | 5 | 5 | 4 | 75,057 | 14,071 | 156,508 |
| Feb-11 | 6 | 7 | 10 | 5 | 4 | 2 | 6,428 | 23,796 | 27,649 |
| Mar-11 | 0 | 14 | 28 | 0 | 5 | 3 | 0 | 10,133 | 57,472 |
| Apr-11 | 3 | 23 | 12 | 3 | 9 | 3 | 8,129 | 44,855 | 15,761 |
| May-11 | 9 | 15 | 15 | 4 | 7 | 4 | 18,377 | 36,777 | 24,857 |
| Jun-11 | 15 | 14 | 24 | 7 | 6 | 9 | 17,865 | 19,437 | 31,868 |
| Jul-11 | 7 | 8 | 17 | 4 | 7 | 7 | 18,467 | 3,697 | 20,645 |
| Aug-11 | 4 | 6 | 4 | 4 | 4 | 2 | 3,624 | 11,323 | 12,579 |
| Sep-11 | 7 | 17 | 7 | 6 | 7 | 3 | 6,462 | 25,914 | 11,445 |
| Oct-11 | 4 | 16 | 5 | 2 | 6 | 1 | 16,812 | 27,392 | 3,665 |
| Nov-11 | 0 | 10 | 2 | 0 | 5 | 2 | 0 | 22,672 | 484 |
| Dec-11 | 0 | 5 | 8 | 0 | 3 | 2 | 0 | 8,659 | 26,523 |
| Jan-12 | 1 | 9 | 5 | 1 | 6 | 2 | 4,920 | 6,274 | 8,058 |
| Feb-12 | 4 | 6 | 16 | 2 | 6 | 2 | 0 | 5,177 | 35,451 |
| Mar-12 | 1 | 11 | 10 | 1 | 6 | 2 | 398 | 31,891 | 26,761 |
| Apr-12 | 0 | 14 | 11 | 0 | 7 | 1 | 0 | 8,408 | 29,911 |
| May-12 | 2 | 17 | 12 | 1 | 10 | 5 | 3,539 | 30,759 | 21,445 |
| Jun-12 | 0 | 24 | 0 | 0 | 7 | 0 | 0 | 31,502 | 0 |
| Jul-12 | 11 | 19 | 1 | 5 | 4 | 1 | 34,197 | 46,512 | 292 |
| Aug-12 | 8 | 13 | 0 | 1 | 6 | 0 | 61,151 | 13,403 | 0 |
| Sep-12 | 2 | 5 | 0 | 1 | 4 | 0 | 21,134 | 12,494 | 0 |
| Oct-12 | 3 | 9 | 0 | 2 | 6 | 0 | 0 | 12,317 | 0 |
| Nov-12 | 4 | 10 | 5 | 2 | 6 | 2 | 444 | 24,351 | 6,250 |
| Dec-12 | 1 | 22 | 0 | 1 | 12 | 0 | 0 | 17,761 | 0 |
| Jan-13 | 4 | 42 | 2 | 3 | 17 | 1 | 13,453 | 103,463 | 1,045 |
| Feb-13 | 4 | 26 | 0 | 3 | 10 | 0 | 14,609 | 66,086 | 0 |
| Mar-13 | 0 | 39 | 0 | 0 | 13 | 0 | 0 | 53,122 | 0 |
| Apr-13 | 1 | 45 | 0 | 1 | 20 | 0 | 84 | 64,938 | 0 |
| May-13 | 10 | 29 | 0 | 7 | 14 | 0 | 879 | 20,778 | 0 |
| Jun-13 | 4 | 25 | 1 | 1 | 11 | 1 | 5,036 | 76,240 | 4,102 |
| Jul-13 | 12 | 28 | 0 | 2 | 9 | 0 | 88,623 | 80,328 | 0 |
| Aug-13 | 4 | 19 | 0 | 4 | 8 | 0 | 3,469 | 38,608 | 0 |
| Sep-13 | 6 | 33 | 0 | 5 | 14 | 0 | 7,716 | 90,188 | 0 |
| Oct-13 | 2 | 42 | 0 | 1 | 20 | 0 | 534 | 72,121 | 0 |
| Nov-13 | 2 | 27 | 0 | 2 | 8 | 0 | 11,561 | 52,508 | 0 |
| Dec-13 | 0 | 16 | 0 | 0 | 5 | 0 | 0 | 20,257 | 0 |
| Jan-14 | 3 | 20 | 0 | 3 | 10 | 0 | 1,852 | 11,683 | 0 |
| Feb-14 | 0 | 29 | 1 | 0 | 10 | 1 | 0 | 33,189 | 991 |
| Mar-14 | 0 | 11 | 0 | 0 | 7 | 0 | 0 | 14,842 | 0 |

### Table 9-28 Number of TLRs by TLR level by reliability coordinator: January through March, 2014

| Year | Reliability Coordinator | 3a | 3b | 4 | 5a | 5b | 6 | Total |
|---|---|---|---|---|---|---|---|---|
| 2014 | ICTE | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | MISO | 35 | 18 | 0 | 4 | 2 | 0 | 59 |
| | NYIS | 1 | 0 | 0 | 0 | 0 | 0 | 1 |
| | ONT | 1 | 0 | 0 | 0 | 0 | 0 | 1 |
| | PJM | 2 | 1 | 0 | 0 | 0 | 0 | 3 |
| | SOCO | 3 | 0 | 0 | 0 | 0 | 0 | 3 |
| | SWPP | 65 | 26 | 0 | 22 | 13 | 0 | 126 |
| | TVA | 12 | 20 | 2 | 5 | 4 | 0 | 43 |
| | VACS | 6 | 14 | 2 | 2 | 0 | 0 | 24 |
| Total | | 125 | 79 | 4 | 33 | 19 | 0 | 260 |

## 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.[63]

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 Energy Market increased to 215,829 bids per day, with an average cleared volume of 1,486,359 MWh per day, in the first three months of 2014, compared to an average of 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013 (See Figure 9-13).

Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up-to congestion transactions do not pay operating reserves charges. Up-to congestion transactions also significantly affect FTR funding. The FTR forfeiture rule does not currently apply to UTCs.

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62 The curtailment volume for PJM TLRs was taken from the individual NERC TLR history reports as posted in the interchange distribution calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLRs was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx> (Accessed April 17, 2014).

63 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

**Figure 9-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through March, 2014**
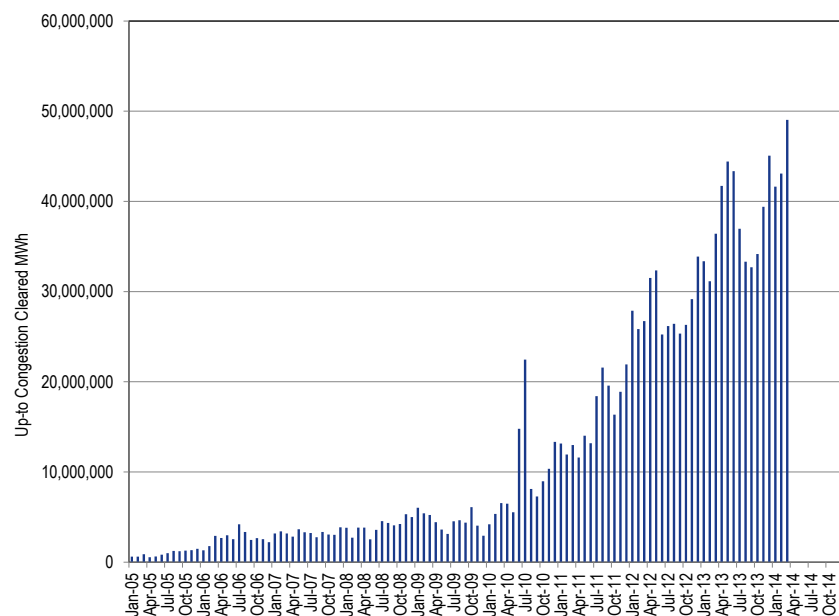
## Table 9-29 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2014

| Month | Bid MW | | | | | Bid Volume | | | | | Cleared MW | | | | | Cleared Volume | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Import | Export | Wheel | Internal | Total | Import | Export | Wheel | Internal | Total | Import | Export | Wheel | Internal | Total | Import | Export | Wheel | Internal | Total |
| Jan-09 | 4,218,910 | 5,787,961 | 319,122 | – | 10,325,993 | 90,277 | 74,826 | 6,042 | – | 171,145 | 2,591,211 | 3,242,491 | 202,854 | – | 6,036,556 | 56,132 | 45,303 | 4,210 | – | 105,645 |
| Feb-09 | 3,580,115 | 4,904,467 | 318,440 | – | 8,803,022 | 64,338 | 70,874 | 6,347 | – | 141,559 | 2,374,734 | 2,836,344 | 203,907 | – | 5,414,985 | 42,101 | 44,423 | 4,402 | – | 90,926 |
| Mar-09 | 3,649,978 | 5,164,186 | 258,701 | – | 9,072,865 | 64,714 | 72,495 | 5,531 | – | 142,740 | 2,285,412 | 2,762,459 | 178,507 | – | 5,226,378 | 42,408 | 42,007 | 4,299 | – | 88,714 |
| Apr-09 | 2,607,303 | 5,085,912 | 73,931 | – | 7,767,146 | 47,970 | 67,417 | 2,146 | – | 117,533 | 1,797,302 | 2,582,294 | 48,478 | – | 4,428,074 | 32,088 | 35,987 | 1,581 | – | 69,656 |
| May-09 | 2,196,341 | 4,063,887 | 106,860 | – | 6,367,088 | 40,217 | 54,745 | 1,304 | – | 96,266 | 1,496,396 | 2,040,737 | 77,553 | – | 3,614,686 | 26,274 | 29,720 | 952 | – | 56,946 |
| Jun-09 | 2,598,234 | 3,132,478 | 164,903 | – | 5,895,615 | 47,625 | 44,755 | 2,873 | – | 95,253 | 1,540,169 | 1,500,560 | 88,723 | – | 3,129,452 | 28,565 | 23,307 | 1,522 | – | 53,394 |
| Jul-09 | 3,984,680 | 3,776,957 | 296,910 | – | 8,058,547 | 67,039 | 56,770 | 5,183 | – | 128,992 | 2,465,891 | 1,902,807 | 163,129 | – | 4,531,826 | 41,924 | 31,176 | 2,846 | – | 75,946 |
| Aug-09 | 3,551,396 | 4,388,435 | 260,184 | – | 8,200,015 | 64,652 | 64,052 | 3,496 | – | 132,200 | 2,278,431 | 2,172,133 | 194,415 | – | 4,644,978 | 41,774 | 34,576 | 2,421 | – | 78,771 |
| Sep-09 | 2,948,353 | 4,179,427 | 156,270 | – | 7,284,050 | 51,006 | 64,103 | 2,405 | – | 117,514 | 1,774,589 | 2,479,898 | 128,344 | – | 4,382,831 | 31,962 | 40,698 | 1,944 | – | 74,604 |
| Oct-09 | 3,172,034 | 6,371,230 | 154,825 | – | 9,698,089 | 46,989 | 100,350 | 2,217 | – | 149,556 | 2,060,371 | 3,931,346 | 110,646 | – | 6,102,363 | 31,634 | 70,964 | 1,672 | – | 104,270 |
| Nov-09 | 3,447,356 | 3,851,334 | 103,325 | – | 7,402,015 | 53,067 | 61,906 | 1,236 | – | 116,209 | 2,065,813 | 1,932,595 | 51,929 | – | 4,050,337 | 33,769 | 32,916 | 653 | – | 67,338 |
| Dec-09 | 2,323,383 | 2,502,529 | 66,497 | – | 4,892,409 | 47,099 | 47,223 | 1,430 | – | 95,752 | 1,532,579 | 1,359,936 | 34,419 | – | 2,926,933 | 31,673 | 28,478 | 793 | – | 60,944 |
| Jan-10 | 3,794,946 | 3,097,524 | 212,010 | – | 7,104,480 | 81,604 | 55,921 | 3,371 | – | 140,896 | 2,250,689 | 1,789,018 | 161,977 | – | 4,201,684 | 49,064 | 33,640 | 2,318 | – | 85,022 |
| Feb-10 | 3,841,573 | 3,937,880 | 316,150 | – | 8,095,603 | 80,876 | 80,685 | 2,269 | – | 163,830 | 2,627,101 | 2,435,650 | 287,162 | – | 5,349,913 | 50,958 | 48,008 | 1,812 | – | 100,778 |
| Mar-10 | 4,877,732 | 4,454,865 | 277,180 | – | 9,609,777 | 97,149 | 74,568 | 2,239 | – | 173,956 | 3,209,064 | 3,071,712 | 263,516 | – | 6,544,292 | 60,277 | 48,596 | 2,064 | – | 110,937 |
| Apr-10 | 3,877,306 | 5,558,718 | 210,545 | – | 9,646,569 | 67,632 | 85,358 | 1,573 | – | 154,563 | 2,622,113 | 3,690,889 | 170,020 | – | 6,483,022 | 42,635 | 54,510 | 1,154 | – | 98,299 |
| May-10 | 3,800,870 | 5,062,272 | 149,589 | – | 9,012,731 | 74,996 | 78,426 | 1,620 | – | 155,042 | 2,366,149 | 3,049,405 | 112,700 | – | 5,528,253 | 47,505 | 48,996 | 1,112 | – | 97,613 |
| Jun-10 | 9,126,963 | 9,568,549 | 1,159,407 | – | 19,854,919 | 95,155 | 89,222 | 6,960 | – | 191,337 | 6,863,803 | 6,850,098 | 1,072,759 | – | 14,786,660 | 59,733 | 55,574 | 5,831 | – | 121,138 |
| Jul-10 | 12,818,141 | 11,526,089 | 5,420,410 | – | 29,764,640 | 124,929 | 106,145 | 18,948 | – | 250,022 | 8,971,914 | 8,237,557 | 5,241,264 | – | 22,450,734 | 73,232 | 60,822 | 16,526 | – | 150,580 |
| Aug-10 | 8,231,393 | 6,767,617 | 888,591 | – | 15,887,601 | 115,043 | 87,876 | 10,664 | – | 213,583 | 4,430,832 | 2,894,314 | 785,726 | – | 8,110,871 | 62,526 | 40,485 | 8,884 | – | 111,895 |
| Sep-10 | 7,768,878 | 7,561,624 | 349,147 | – | 15,679,649 | 184,697 | 161,929 | 4,653 | – | 351,279 | 3,915,814 | 3,110,580 | 256,039 | – | 7,282,433 | 63,405 | 45,264 | 3,393 | – | 112,062 |
| Oct-10 | 8,732,546 | 9,795,666 | 476,665 | – | 19,004,877 | 189,748 | 154,741 | 7,384 | – | 351,873 | 4,150,104 | 4,564,039 | 246,594 | – | 8,960,736 | 76,042 | 65,223 | 3,670 | – | 144,935 |
| Nov-10 | 11,636,949 | 9,272,885 | 537,369 | – | 21,447,203 | 253,594 | 170,470 | 9,366 | – | 433,430 | 5,765,905 | 4,312,645 | 275,111 | – | 10,353,661 | 112,250 | 71,378 | 4,045 | – | 187,673 |
| Dec-10 | 17,769,014 | 12,863,875 | 923,160 | – | 31,556,049 | 307,716 | 215,897 | 15,074 | – | 538,687 | 7,851,235 | 5,150,286 | 337,157 | – | 13,338,678 | 136,582 | 93,299 | 7,380 | – | 237,261 |
| Jan-11 | 20,275,932 | 11,807,379 | 921,120 | – | 33,004,431 | 351,193 | 210,703 | 17,632 | – | 579,528 | 7,917,986 | 4,925,310 | 315,936 | – | 13,159,232 | 151,753 | 91,557 | 8,417 | – | 251,727 |
| Feb-11 | 18,418,511 | 13,071,483 | 800,630 | – | 32,290,624 | 345,227 | 226,292 | 17,634 | – | 589,153 | 6,806,039 | 4,879,207 | 248,573 | – | 11,933,818 | 151,003 | 99,302 | 8,851 | – | 259,156 |
| Mar-11 | 17,330,353 | 12,919,960 | 749,276 | – | 30,999,589 | 408,628 | 274,709 | 15,714 | – | 699,051 | 7,104,642 | 5,603,583 | 275,682 | – | 12,983,906 | 178,620 | 124,990 | 7,760 | – | 311,370 |
| Apr-11 | 17,215,352 | 9,321,117 | 954,283 | – | 27,490,752 | 513,881 | 265,334 | 17,459 | – | 796,674 | 7,452,366 | 3,797,819 | 351,984 | – | 11,602,168 | 229,707 | 113,610 | 8,118 | – | 351,435 |
| May-11 | 21,058,071 | 11,204,038 | 2,937,898 | – | 35,200,007 | 562,819 | 304,589 | 24,834 | – | 892,242 | 8,294,422 | 4,701,077 | 1,031,519 | – | 14,027,018 | 261,355 | 143,956 | 11,116 | – | 416,427 |
| Jun-11 | 20,455,508 | 12,125,806 | 395,833 | – | 32,977,147 | 524,072 | 285,031 | 12,273 | – | 821,376 | 7,632,235 | 5,361,825 | 198,482 | – | 13,192,543 | 226,747 | 132,744 | 6,363 | – | 365,854 |
| Jul-11 | 24,273,892 | 16,837,875 | 409,863 | – | 41,521,630 | 603,519 | 338,810 | 13,781 | – | 956,110 | 9,585,027 | 8,617,284 | 205,599 | – | 18,407,910 | 283,287 | 186,866 | 7,008 | – | 477,161 |
| Aug-11 | 23,790,091 | 21,014,941 | 229,895 | – | 45,034,927 | 591,170 | 403,269 | 8,278 | – | 1,002,717 | 10,594,771 | 10,875,384 | 103,141 | – | 21,573,297 | 274,398 | 208,593 | 3,648 | – | 486,639 |
| Sep-11 | 21,740,208 | 18,135,378 | 232,626 | – | 40,108,212 | 526,945 | 377,158 | 7,886 | – | 911,989 | 10,219,806 | 9,270,121 | 82,200 | – | 19,572,127 | 270,088 | 185,585 | 3,444 | – | 459,117 |
| Oct-11 | 20,240,161 | 19,476,556 | 333,077 | – | 40,049,794 | 540,877 | 451,507 | 8,609 | – | 1,000,993 | 8,376,208 | 7,853,947 | 126,718 | – | 16,356,873 | 255,206 | 198,778 | 4,236 | – | 458,220 |
| Nov-11 | 27,007,141 | 28,994,789 | 507,788 | – | 56,509,718 | 594,397 | 603,029 | 13,379 | – | 1,210,805 | 9,064,570 | 9,692,312 | 131,670 | – | 18,888,552 | 254,851 | 256,270 | 5,686 | – | 516,807 |
| Dec-11 | 34,990,790 | 34,648,433 | 531,616 | – | 70,170,839 | 697,524 | 655,222 | 14,187 | – | 1,366,933 | 11,738,910 | 10,049,685 | 137,689 | – | 21,926,284 | 281,304 | 248,008 | 6,309 | – | 535,621 |
| Jan-12 | 38,906,228 | 36,928,145 | 620,448 | – | 76,454,821 | 745,424 | 689,174 | 16,053 | – | 1,450,651 | 13,610,725 | 14,120,791 | 145,773 | – | 27,877,288 | 289,524 | 304,072 | 5,078 | – | 598,674 |
| Feb-12 | 37,231,115 | 36,736,507 | 323,958 | – | 74,291,580 | 739,200 | 724,477 | 8,572 | – | 1,472,249 | 12,883,355 | 12,905,553 | 54,724 | – | 25,843,632 | 299,055 | 276,563 | 2,175 | – | 577,793 |
| Mar-12 | 38,824,528 | 39,163,001 | 297,895 | – | 78,285,424 | 802,983 | 842,857 | 8,971 | – | 1,654,811 | 13,328,968 | 13,306,689 | 89,262 | – | 26,724,918 | 320,210 | 320,252 | 3,031 | – | 643,493 |
| Apr-12 | 42,085,326 | 44,565,341 | 436,632 | – | 87,087,299 | 884,004 | 917,430 | 12,354 | – | 1,813,788 | 15,050,798 | 16,297,303 | 171,252 | – | 31,519,354 | 369,273 | 355,669 | 4,655 | – | 729,597 |
| May-12 | 44,436,245 | 43,888,405 | 489,938 | – | 88,814,588 | 994,735 | 885,319 | 10,294 | – | 1,890,348 | 17,416,386 | 14,733,838 | 189,667 | – | 32,339,891 | 434,919 | 343,872 | 4,114 | – | 782,905 |
| Jun-12 | 38,962,548 | 32,828,393 | 975,776 | – | 72,766,718 | 872,764 | 684,382 | 21,781 | – | 1,578,927 | 12,675,852 | 12,311,609 | 250,024 | – | 25,237,485 | 355,731 | 295,911 | 6,891 | – | 658,533 |
| Jul-12 | 45,565,682 | 41,589,191 | 855,676 | – | 88,010,549 | 1,077,721 | 911,300 | 27,173 | – | 2,016,194 | 13,001,225 | 12,823,361 | 348,946 | – | 26,173,532 | 399,135 | 321,062 | 9,958 | – | 730,155 |
| Aug-12 | 44,972,628 | 45,204,886 | 931,161 | – | 91,108,675 | 1,054,472 | 987,293 | 31,580 | – | 2,073,345 | 12,768,023 | 13,354,850 | 300,038 | | 26,422,911 | 377,146 | 343,717 | 12,738 | – | 733,601 |
| Sep-12 | 40,796,522 | 39,411,713 | 957,800 | – | 81,166,035 | 1,037,179 | 949,941 | 29,246 | – | 2,016,366 | 12,089,136 | 12,961,955 | 292,095 | – | 25,343,186 | 341,925 | 329,217 | 9,620 | – | 680,762 |
| Oct-12 | 35,567,607 | 42,489,970 | 1,415,992 | – | 79,473,570 | 908,200 | 1,048,029 | 46,802 | – | 2,003,031 | 11,969,576 | 13,949,871 | 392,286 | – | 26,311,733 | 345,788 | 376,513 | 14,089 | – | 736,390 |
| Nov-12 | 24,795,325 | 25,498,103 | 1,258,755 | 52,022,007 | 103,574,190 | 542,992 | 614,349 | 43,829 | 1,631,255 | 2,832,425 | 6,517,798 | 7,872,496 | 286,535 | 14,482,701 | 29,159,529 | 186,492 | 245,943 | 15,042 | 509,436 | 956,913 |
| Dec-12 | 22,597,985 | 22,560,837 | 1,727,510 | 84,548,868 | 131,435,199 | 489,208 | 515,873 | 55,376 | 2,767,292 | 3,827,749 | 5,116,607 | 6,350,080 | 454,289 | 21,958,089 | 33,879,065 | 180,592 | 224,830 | 24,459 | 820,991 | 1,250,872 |
| Jan-13 | 16,718,393 | 21,312,321 | 2,010,317 | 76,937,535 | 116,978,566 | 422,501 | 527,037 | 63,227 | 2,115,649 | 3,128,414 | 4,115,418 | 5,820,177 | 522,459 | 22,906,008 | 33,364,063 | 149,282 | 199,123 | 23,926 | 657,602 | 1,029,933 |
| Feb-13 | 12,567,004 | 15,509,978 | 1,477,275 | 67,258,116 | 96,812,373 | 352,963 | 400,563 | 43,133 | 1,798,434 | 2,595,093 | 3,019,380 | 4,356,113 | 461,615 | 23,311,066 | 31,148,173 | 110,397 | 158,085 | 15,892 | 669,364 | 953,738 |
| Mar-13 | 14,510,721 | 17,019,755 | 1,601,487 | 88,109,152 | 121,241,114 | 372,402 | 402,711 | 48,112 | 1,959,294 | 2,782,519 | 3,868,303 | 4,743,283 | 358,180 | 27,439,606 | 36,409,373 | 131,506 | 166,295 | 17,884 | 774,020 | 1,089,705 |
| Apr-13 | 14,538,907 | 17,419,505 | 1,337,680 | 105,927,107 | 139,223,200 | 358,245 | 364,008 | 47,048 | 2,275,846 | 3,045,147 | 4,413,047 | 4,834,302 | 315,867 | 32,152,243 | 41,715,459 | 145,860 | 157,031 | 16,315 | 892,562 | 1,211,768 |

**Table 9-29 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2014** *(continued)*

| Month | Bid MW | | | | | Bid Volume | | | | | Cleared MW | | | | | Cleared Volume | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Import | Export | Wheel | Internal | Total | Import | Export | Wheel | Internal | Total | Import | Export | Wheel | Internal | Total | Import | Export | Wheel | Internal | Total |
| May-13 | 16,565,868 | 17,640,682 | 1,640,097 | 115,572,648 | 151,419,296 | 431,892 | 389,254 | 54,873 | 2,660,793 | 3,536,812 | 4,556,277 | 4,747,887 | 333,677 | 34,778,962 | 44,416,803 | 144,444 | 144,482 | 16,317 | 944,116 | 1,249,359 |
| Jun-13 | 16,698,203 | 18,904,971 | 1,337,373 | 128,595,957 | 165,536,504 | 452,145 | 433,010 | 48,007 | 3,384,811 | 4,317,973 | 3,823,166 | 4,280,538 | 312,158 | 34,935,141 | 43,351,002 | 143,223 | 151,603 | 17,518 | 1,116,318 | 1,428,662 |
| Jul-13 | 15,436,914 | 16,428,662 | 1,473,144 | 116,673,912 | 150,012,631 | 430,120 | 387,969 | 49,712 | 3,075,624 | 3,943,425 | 3,250,706 | 3,502,990 | 320,374 | 29,883,430 | 36,957,500 | 131,535 | 127,032 | 17,948 | 957,260 | 1,233,775 |
| Aug-13 | 12,332,984 | 14,354,140 | 1,370,624 | 89,306,595 | 117,364,344 | 328,835 | 326,637 | 40,325 | 2,223,269 | 2,919,066 | 2,862,764 | 3,232,565 | 309,069 | 26,900,995 | 33,305,393 | 111,715 | 122,061 | 16,299 | 848,490 | 1,098,565 |
| Sep-13 | 10,767,257 | 11,322,974 | 729,332 | 75,686,010 | 98,505,573 | 264,095 | 262,486 | 21,968 | 1,976,741 | 2,525,290 | 2,962,619 | 3,467,611 | 221,329 | 26,044,742 | 32,696,300 | 102,984 | 107,604 | 10,233 | 792,766 | 1,013,587 |
| Oct-13 | 9,081,257 | 11,106,943 | 853,397 | 86,857,535 | 107,899,131 | 280,821 | 338,374 | 31,031 | 2,524,127 | 3,174,353 | 2,201,219 | 3,532,253 | 186,113 | 28,243,584 | 34,163,168 | 108,189 | 145,667 | 11,551 | 1,002,832 | 1,268,239 |
| Nov-13 | 9,219,216 | 15,052,563 | 1,307,989 | 98,027,480 | 123,607,248 | 267,704 | 394,031 | 39,095 | 3,167,638 | 3,868,468 | 2,640,001 | 3,986,788 | 332,814 | 32,437,908 | 39,397,511 | 112,850 | 154,379 | 13,958 | 1,238,589 | 1,519,776 |
| Dec-13 | 9,934,234 | 16,089,101 | 1,696,981 | 118,916,149 | 146,636,465 | 286,295 | 404,788 | 42,367 | 3,691,770 | 4,425,220 | 3,189,261 | 3,234,196 | 503,666 | 38,150,077 | 45,077,200 | 119,954 | 122,683 | 14,318 | 1,382,736 | 1,639,691 |
| Jan-14 | 10,359,891 | 16,047,391 | 2,326,490 | 119,848,848 | 148,582,620 | 350,248 | 469,176 | 47,801 | 4,382,482 | 5,249,707 | 2,594,374 | 3,172,914 | 460,495 | 35,413,440 | 41,641,223 | 116,316 | 143,021 | 15,323 | 1,537,418 | 1,812,078 |
| Feb-14 | 11,351,094 | 14,846,332 | 1,854,617 | 126,008,272 | 154,060,316 | 382,148 | 480,055 | 47,526 | 5,151,647 | 6,061,376 | 2,764,565 | 3,247,481 | 362,670 | 36,715,916 | 43,090,631 | 132,870 | 147,766 | 14,045 | 1,897,337 | 2,192,018 |
| Mar-14 | 14,669,735 | 17,135,117 | 1,949,978 | 147,142,336 | 180,897,166 | 515,877 | 516,871 | 54,575 | 7,026,221 | 8,113,544 | 3,442,624 | 3,293,865 | 341,620 | 41,962,312 | 49,040,421 | 165,663 | 148,671 | 15,214 | 2,290,716 | 2,620,264 |
| TOTAL | 1,050,843,817 | 1,043,289,049 | 55,462,419 | 1,697,438,527 | 3,847,033,812 | 24,263,557 | 22,403,801 | 1,286,828 | 51,812,893 | 99,767,079 | 380,206,775 | 373,968,703 | 22,219,114 | 507,716,220 | 1,284,110,812 | 9,919,410 | 9,048,733 | 515,031 | 18,332,553 | 37,815,727 |

In the first three months of 2014, the cleared MW volume of up-to congestion transactions was comprised of 6.6 percent imports, 7.3 percent exports, 0.9 percent wheeling transactions and 85.3 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions.

## Sham Scheduling

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

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

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.

## Elimination of Ontario Interface Pricing Point

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. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy.

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.[64] 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. Transactions between PJM and external balancing authorities need to be priced at the PJM border.

The IMO Interface Pricing Point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO Interface Pricing Points. 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.

The IMO Interface Pricing Point is defined as the LMP at the Bruce bus, which is located in IESO. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The non-contiguous nature of the Ontario Interface Pricing Point creates over payments or additional credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. Of the 1,035 GWh of the net scheduled transactions between PJM and IESO, 912 GWh wheeled through MISO in the first three months of 2014 (see Table 9-22).

The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.[65]

## PJM and NYISO Coordinated Interchange Transaction Proposal

The coordinated transaction scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price from the ITSCED results with the NYISO. The NYISO compares the PJM/NYISO Interface Price with its RTC calculated NYISO/PJM Interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

On December 13, 2013, PJM submitted proposed revisions to the PJM Operating Agreement, and parallel provisions of the PJM Tariff, to implement CTS.[66] This filing requested that the Commission issue an order accepting the proposed revisions by no later than February 13, 2014 to allow for adequate time to develop the infrastructure necessary to implement CTS in November, 2014. The Commission issued an order conditionally accepting the tariff revisions on February 20, 2014, for implementation on the later of November, 2014, or the date that CTS becomes operational, subject to the submission of an informational filing informing the Commission of the acceptance of ITSCED forecasting accuracy standards, and an additional revised tariff no later than fourteen days prior to the official implementation date of CTS.[67]

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for 2013. Table 9-30 shows that over all forecast ranges ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 31.8 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.59. In 4.2 percent of all intervals, the

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64 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed April 17, 2014). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

65 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

66 See PJM Interconnection, L.L.C., OA Schedule 1 and Attachment K Revisions, Docket No. ER14-623-000. (December 13, 2013).

67 146 FERC ¶ 61,096 (2014).

average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20, with an average price difference of $56.39, and in 6.5 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was greater than -$20, with an average price difference of $45.23.

**Table 9–30 ITSCED/real-time LMP – PJM/NYIS interface price comparison (all intervals): 2013**

| Range | Percent of All Intervals | Average Price Difference |
|---|---|---|
| > $20 | 4.2% | $56.39 |
| $10 to $20 | 3.6% | $14.27 |
| $5 to $10 | 4.9% | $7.06 |
| $0 to $5 | 31.8% | $1.59 |
| -$5 to $0 | 38.1% | $1.67 |
| -$10 to -$5 | 6.6% | $7.07 |
| -$20 to -$10 | 4.3% | $14.26 |
| < -$20 | 6.5% | $45.23 |

**Table 9–31 ITSCED/real-time LMP – PJM/NYIS interface price comparison (by interval): 2013**

| | ~ 135 Minutes Prior to Real-Time | | ~ 90 Minutes Prior to Real-Time | | ~ 45 Minutes Prior to Real-Time | | ~ 30 Minutes Prior to Real-Time | |
|---|---|---|---|---|---|---|---|---|
| Range | Percent of Intervals | Average Price Difference | Percent of Intervals | Average Price Difference | Percent of Intervals | Average Price Difference | Percent of Intervals | Average Price Difference |
| > $20 | 5.8% | $59.57 | 4.1% | $51.80 | 2.4% | $47.60 | 3.3% | $62.21 |
| $10 to $20 | 4.5% | $14.46 | 3.7% | $14.18 | 2.6% | $14.50 | 2.9% | $14.07 |
| $5 to $10 | 6.1% | $7.20 | 4.9% | $7.11 | 4.4% | $6.99 | 3.7% | $6.92 |
| $0 to $5 | 31.3% | $1.70 | 34.6% | $1.64 | 34.0% | $1.53 | 30.7% | $1.43 |
| -$5 to $0 | 34.1% | $1.78 | 35.5% | $1.67 | 40.2% | $1.56 | 43.5% | $1.58 |
| -$10 to -$5 | 6.8% | $7.14 | 6.3% | $7.07 | 6.5% | $7.02 | 6.8% | $7.07 |
| -$20 to -$10 | 4.3% | $14.38 | 4.5% | $14.31 | 4.1% | $14.07 | 4.1% | $14.03 |
| < -$20 | 7.0% | $40.95 | 6.4% | $49.12 | 5.8% | $46.64 | 5.0% | $50.05 |

The ITSCED application runs approximately every 5 minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. As the ITSCED utilizes closer to real-time data in its cases, the expectation would be that the accuracy of the forecasted interface prices would improve. Table 9-31 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

Table 9-31 shows that while there is some improvement as the forecast gets closer to real time, a substantial range of forecast errors remain even in the thirty-minute ahead forecast. In the final ITSCED results prior to real time, in 74.2 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5 of the actual PJM/NYIS interface real-time LMP, compared to 65.4 percent in the 135 minute ahead ITSCED results.

While in only 8.3 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20 in the thirty-minute ahead cases, the average price differences were $62.21 when the price difference was greater than $20, and $50.05 when the price difference was greater than -$20.

The NYISO will utilize PJM's ITSCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO will approve CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the ITSCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences in forecasted LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to implement the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to

improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.

It does not appear that ITSCED can accurately predict real-time PJM/NYIS interface prices. But as long as the risk associated with CTS transactions remains entirely with market participants, it is the participants who should be concerned about the accuracy of the forecasts and the participants who take the risks associated with the accuracy of the forecasts.

## 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.

The MMU recommended that PJM modify the not willing to pay congestion product to 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. The elimination of internal sources and sinks on transmission reservations mostly addresses these concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM (Table 9-32 shows that there have been no uncollected congestion charges since the inception of the business rule change on April 12, 2013.) There is still potential exposure to uncollected congestion charges

in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be necessary in the future to address this exposure.

**Table 9-32 Monthly uncollected congestion charges: January, 2010 through March, 2014**

| Month | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Jan | $148,764 | $3,102 | $0 | $5 | $0 |
| Feb | $542,575 | $1,567 | ($15) | $249 | $0 |
| Mar | $287,417 | $0 | $0 | $0 | $0 |
| Apr | $31,255 | $4,767 | ($68) | ($3,114) | |
| May | $41,025 | $0 | ($27) | $0 | |
| Jun | $169,197 | $1,354 | $78 | $0 | |
| Jul | $827,617 | $1,115 | $0 | $0 | |
| Aug | $731,539 | $37 | $0 | $0 | |
| Sep | $119,162 | $0 | $0 | $0 | |
| Oct | $257,448 | ($31,443) | ($6,870) | $0 | |
| Nov | $30,843 | ($795) | ($4,678) | $0 | |
| Dec | $127,176 | ($659) | ($209) | $0 | |
| Total | $3,314,018 | ($20,955) | ($11,789) | ($2,860) | $0 |

## Spot Imports

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[68] 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

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[68] 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 April 17, 2014).

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

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding.

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

**Figure 9–14 Spot import service utilization: January, 2009 through March, 2014**
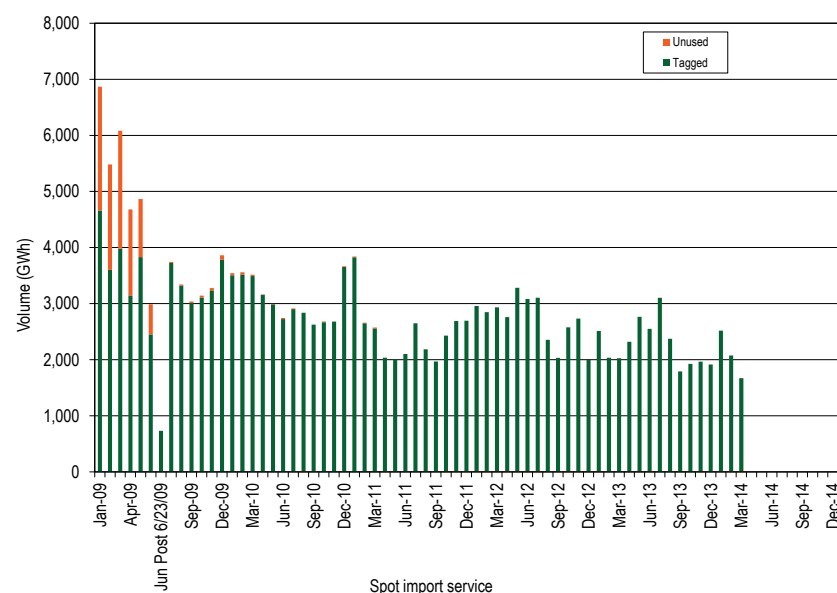


## Real–Time Dispatchable Transactions

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

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted in the first three months of 2014.