Interchange Transactions

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

Highlights

- Real-time net imports were 800.7 GWh for the first three months of 2012. For the first three months of 2011, there were net exports of -802.0 GWh in real-time. Day-ahead net exports were -3,224.6 GWh for the first three months of 2012. For the first three months of 2011, there were net imports of 3,813.0 GWh in day-ahead.
- The direction of power flows was not consistent with real-time energy market price differences in 58 percent of hours at the border between PJM and MISO and in 49 percent of hours at the border between PJM and NYISO during the first three months of 2012.
- During the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh (during the first three months of 2011, net scheduled interchange was -74 GWh and net actual interchange was -211 GWh, a difference of 137 GWh).
- PJM initiated 6 TLRs during the first three months of 2012, a reduction from the 13 TLRs initiated during the first three months of 2011.
- The average daily volume of up-to congestion bids increased from 20,753 bids per day, during the first three months of 2011, to 50,305 bids per day during the first three months of 2012. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids.
- Balancing operating reserve credits are paid to importing dispatchable transactions (also known as real-time with price) as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. During the first three months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.1 million for the first three months of 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted in three days during the first three months of 2012.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first three months of 2012, including evolving transaction patterns, economics and issues. In the first three months of 2012, PJM was a net importer of energy in the Real-Time Market and a net exporter of energy in the Day-Ahead Market.

In the first three months of 2012, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for many hours, 58 percent between PJM and MISO and 49 percent between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interchange Transaction Activity

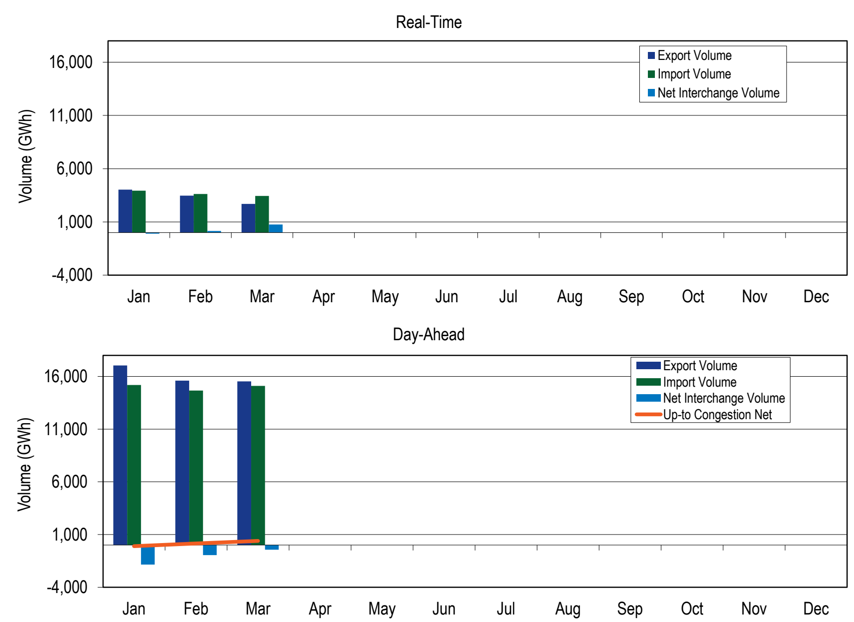
Aggregate Imports and Exports

During the first three months of 2012, PJM was a net exporter of energy in the Real-Time Energy Market in January, and a net importer of energy in February and March. During the first three months of 2011, 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. In the Real-Time Energy Market, monthly net interchange averaged 266.9 GWh for the first three months of 2012 compared to -213.3 GWh for the first three months of 2011.[1] Gross monthly import volumes during the first three months of 2012 averaged 3,663.7 GWh compared to 3,769.2 GWh for the first three months of 2011 while gross monthly exports averaged 3,396.8 GWh for the first three months of 2012 compared to 3,982.4 GWh for the first three months of 2011.

During the first three months of 2012, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first three months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in all months. In the Day-Ahead Energy Market, for the first three months of 2012, monthly net interchange averaged -1,074.9 GWh compared to 1,271.4 GWh for the first three months of 2011. Gross monthly import volumes averaged 14,981.4 GWh for the first three months of 2012 compared to 9,386.9 GWh for the first three months of 2011 while gross monthly exports averaged 16,056.3 GWh for the first three months of 2012 compared to 8,115.5 GWh for the first three months of 2011.

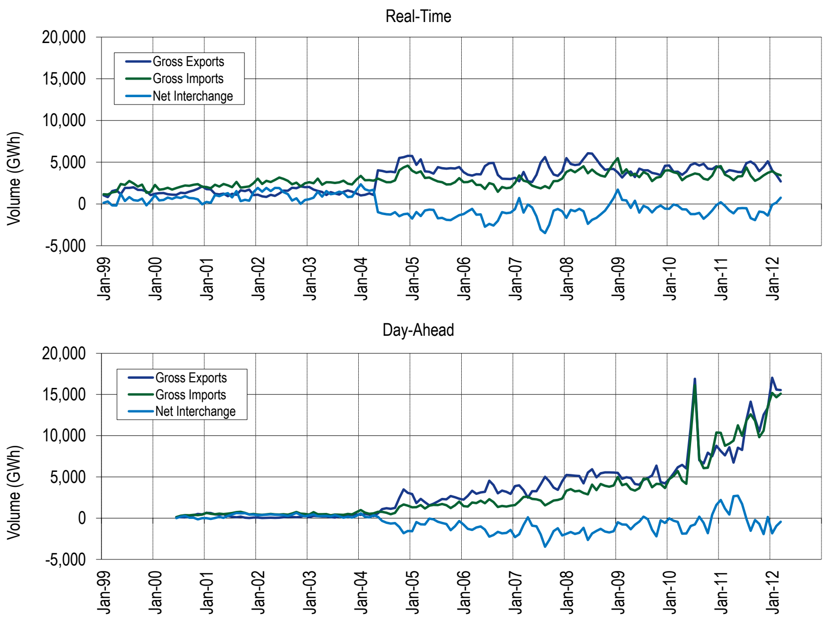
In the first three months of 2012, gross imports in the Day-Ahead Energy Market were 408.9 percent of gross imports in the Real-Time Energy Market (248.7 percent for the first three months of 2011). In the first three months of 2012, gross exports in the Day-Ahead Energy Market were 472.7 percent of gross exports in the Real-Time Energy Market (200.8 percent for the first three months of 2011). In the first three months of 2012, net interchange was -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market compared to 3,813.9 GWh in the Day-Ahead Energy Market and -802.0 GWh in the Real-Time Energy Market for the first three months of 2011.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: January through March, 2012 (See 2011 SOM, Figure 8-1)



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

Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January 1999, through March, 2012 (See 2011 SOM, Figure 8-2)



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path (the transmission path a market participant selects from the original source to the final sink). These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. (See Table 8-13 for a list of active interfaces in 2011. Figure 8-3 shows the approximate geographic location of the interfaces.) In the first quarter of 2012, PJM had 20 interfaces with neighboring balancing authorities.[2] The Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface. However, all three are interfaces between PJM and the NYISO. Table 8-1 through Table 8-3 show the Real-Time Market interchange totals at the individual interfaces with the NYISO, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Market is shown by interface for the first three months of 2012 in Table 8-1, while gross imports and exports are shown in Table 8-2 and Table 8-3.

In the Real-Time Energy Market, for the first three months of 2012, there were net exports at 11 of PJM's 20 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 81.0 percent of the total net exports: PJM/Eastern Alliant Energy Corporation with 23.0 percent, PJM/MidAmerican Energy Company (MEC) with 21.7 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 19.6 percent and PJM/Neptune (NEPT) with 16.6 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 38.4 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net imports, with two importing interfaces accounting for 59.1 percent of the total net imports: PJM/Tennessee Valley Authority (TVA) with 30.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 28.5 percent of the net import volume.[3]

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

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

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-1)

		Jan	Feb	Mar	Total
CPLE		(52.5)	(29.2)	(27.8)	(109.5)
CPLW		0.0	0.0	0.0	0.0
DUK		98.9	(85.3)	(13.0)	0.6
EKPC		(37.5)	(19.2)	(14.3)	(71.1)
LGEE		357.0	141.4	128.3	626.6
MEC		(468.8)	(446.6)	(430.5)	(1,345.9)
MISO		(368.7)	(141.8)	452.0	(58.5)
	ALTE	(693.8)	(557.5)	(179.2)	(1,430.5)
	ALTW	(49.7)	(22.7)	(4.9)	(77.3)
	AMIL	17.7	39.9	106.3	163.9
	CIN	377.7	179.8	300.2	857.7
	CWLP	0.0	0.0	0.0	0.0
	IPL	(172.2)	(76.5)	27.6	(221.1)
	MECS	378.4	488.4	348.5	1,215.3
	NIPS	(18.4)	(17.4)	14.3	(21.5)
	WEC	(208.4)	(175.8)	(160.7)	(545.0)
NYISO		(1,127.3)	(750.9)	(508.4)	(2,386.6)
	LIND	(63.9)	(6.3)	(64.5)	(134.7)
	NEPT	(415.7)	(329.7)	(288.4)	(1,033.7)
	NYIS	(647.8)	(414.9)	(155.5)	(1,218.2)
OVEC		712.5	693.4	588.3	1,994.1
TVA		783.0	787.2	580.6	2,150.8
Total		(103.4)	149.0	755.1	800.7

Table 8-2 Real-time scheduled gross import volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-2)

		Jan	Feb	Mar	Total
CPLE		0.3	0.0	0.4	0.7
CPLW		0.0	0.0	0.0	0.0
DUK		277.1	168.8	134.8	580.7
EKPC		41.0	31.5	26.7	99.2
LGEE		365.4	147.0	149.7	662.0
MEC		16.9	7.3	0.1	24.3
MISO		1,179.1	1,022.7	1,025.3	3,227.1
	ALTE	1.3	4.8	0.2	6.3
	ALTW	0.0	0.1	0.0	0.1
	AMIL	46.5	78.1	134.2	258.8
	CIN	526.9	330.4	340.5	1,197.8
	CWLP	0.0	0.0	0.0	0.0
	IPL	127.3	88.2	126.3	341.8
	MECS	408.3	520.4	390.7	1,319.4
	NIPS	59.4	0.7	32.5	92.6
	WEC	9.6	0.0	0.9	10.4
NYISO		506.4	678.3	887.4	2,072.1
	LIND	10.7	19.6	12.2	42.6
	NEPT	0.0	0.0	0.0	0.0
	NYIS	495.6	658.7	875.1	2,029.4
OVEC		738.2	716.7	611.5	2,066.5
TVA		802.8	845.0	610.7	2,258.6
Total		3,927.2	3,617.4	3,446.6	10,991.2

Table 8-3 Real-time scheduled gross export volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-3)

		Jan	Feb	Mar	Total
CPLE		52.8	29.2	28.2	110.3
CPLW		0.0	0.0	0.0	0.0
DUK		178.2	254.1	147.7	580.0
EKPC		78.5	50.7	41.1	170.3
LGEE		8.4	5.6	21.4	35.4
MEC		485.7	453.9	430.5	1,370.2
MISO		1,547.8	1,164.5	573.3	3,285.6
	ALTE	695.1	562.3	179.5	1,436.8
	ALTW	49.7	22.8	4.9	77.4
	AMIL	28.7	38.3	28.0	94.9
	CIN	149.2	150.6	40.3	340.0
	CWLP	0.0	0.0	0.0	0.0
	IPL	299.5	164.7	98.7	562.9
	MECS	29.9	32.0	42.2	104.1
	NIPS	77.8	18.1	18.2	114.1
	WEC	218.0	175.8	161.6	555.4
NYISO		1,633.7	1,429.2	1,395.7	4,458.7
	LIND	74.6	26.0	76.7	177.3
	NEPT	415.7	329.7	288.4	1,033.7
	NYIS	1,143.4	1,073.6	1,030.7	3,247.7
OVEC		25.7	23.3	23.3	72.3
TVA		19.8	57.8	30.2	107.8
Total		4,030.6	3,468.4	2,691.5	10,190.5

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which imports or exports will flow.[4] An interface pricing point defines the price at which transactions are priced, and is based on the path of the physical transfer of energy. While a market participant designates a market path based from a generation control area (GCA) to load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the LGEE/PJM Interface based on the market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the LGEE/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with a GCA of LGEE, at the SouthIMP interface pricing point.

Interfaces differ from interface pricing points. Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[5] 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.[6] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[7] Table 8-14 presents the interface pricing points used in the first three months of 2012.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified only occasionally.

4 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.

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

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

7 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.

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.

In the Real-Time Energy Market, for the first three months of 2012, there were net exports at nine of PJM's 17 interface pricing points eligible for real-time transactions.[8] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 85.6 percent of the total net exports: PJM/MISO with 57.1 percent, PJM/NYIS with 15.5 percent and PJM/NEPTUNE (NEPT) with 13.0 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 30.2 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 79.8 percent of the total net imports: PJM/SouthIMP with 57.0 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 22.8 percent of the net import volume.[9]

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-4)

	Jan	Feb	Mar	Total
IMO	479.8	485.2	431.3	1,396.2
LINDENVFT	(63.9)	(6.3)	(64.5)	(134.7)
MISO	(1,992.3)	(1,601.0)	(940.0)	(4,533.3)
NEPTUNE	(415.7)	(329.7)	(288.4)	(1,033.7)
NORTHWEST	(1.6)	(1.5)	(1.2)	(4.3)
NYIS	(648.1)	(415.3)	(166.8)	(1,230.2)
OVEC	712.5	693.4	588.3	1,994.1
SOUTHIMP	2,164.4	1,722.9	1,465.1	5,352.4
CPLEIMP	0.0	0.0	0.4	0.4
DUKIMP	106.7	88.6	56.7	252.0
NCMPAIMP	44.7	44.2	25.2	114.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	4,986.1
SOUTHEXP	(338.5)	(398.7)	(268.6)	(1,005.9)
CPLEEXP	(52.8)	(26.6)	(26.0)	(105.4)
DUKEXP	(172.0)	(233.9)	(141.2)	(547.1)
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHWEST	(1.6)	(1.3)	0.0	(2.8)
SOUTHEXP	(112.1)	(136.9)	(101.4)	(350.5)
Total	(103.4)	149.0	755.1	800.7

8 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
9 In the Real-Time Market, two PJM interface pricing points had a net interchange of zero (Southwest and NCMPAEXP).

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-5)

	Jan	Feb	Mar	Total
IMO	480.4	486.8	434.3	1,401.5
LINDENVFT	10.7	19.6	12.2	42.6
MISO	38.8	14.6	62.0	115.4
NEPTUNE	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0
NYIS	494.6	656.7	861.4	2,012.8
OVEC	738.2	716.7	611.5	2,066.5
SOUTHIMP	2,164.4	1,722.9	1,465.1	5,352.4
CPLEIMP	0.0	0.0	0.4	0.4
DUKIMP	106.7	88.6	56.7	252.0
NCMPAIMP	44.7	44.2	25.2	114.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	4,986.1
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
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	3,927.2	3,617.4	3,446.6	10,991.2

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-6)

	Jan	Feb	Mar	Total
IMO	0.7	1.6	3.1	5.4
LINDENVFT	74.6	26.0	76.7	177.3
MISO	2,031.1	1,615.6	1,002.0	4,648.7
NEPTUNE	415.7	329.7	288.4	1,033.7
NORTHWEST	1.6	1.5	1.2	4.3
NYIS	1,142.8	1,072.0	1,028.2	3,243.0
OVEC	25.7	23.3	23.3	72.3
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	338.5	398.7	268.6	1,005.9
CPLEEXP	52.8	26.6	26.0	105.4
DUKEXP	172.0	233.9	141.2	547.1
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHWEST	1.6	1.3	0.0	2.8
SOUTHEXP	112.1	136.9	101.4	350.5
Total	4,030.6	3,468.4	2,691.5	10,190.5

Day-Ahead Interface Imports and Exports

Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[10] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

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

10 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.

Because market participants choose the interface pricing point(s) they wish to have associated with their transaction in the Day-Ahead Energy Market, the scheduled interface is less meaningful than in the Real-Time Energy Market. In Table 8-7, Table 8-8 and Table 8-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not necessarily match that of the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction. In the interface tables below, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow. Table 8-7 through Table 8-9 show the Day-Ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for the first three months of 2012 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

In the Day-Ahead Energy Market, for the first three months of 2012, there were net exports at 13 of PJM's 20 interfaces. The top three net exporting interfaces accounted for 59.4 percent of the total net exports: PJM/Tennessee Valley Authority (TVA) with 26.4 percent, PJM/Easter Allient Energy Corporation (ALTE) with 17.6 percent and PJM/MidAmerican Energy Company (MEC) with 15.4 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 17.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Seven PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 89.4 percent of the total net imports: PJM/OVEC with 45.8 percent, PJM/Cinergy Corporation (CIN) with 31.6 percent and PJM/Wisconsin Energy Corporation (WEC) with 12.0 percent.

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-7)

	Jan	Feb	Mar	Total
CPLE	(9.6)	17.0	20.1	27.6
CPLW	(6.3)	(37.9)	(67.2)	(111.4)
DUK	38.8	18.0	31.4	88.1
EKPC	(39.0)	(36.5)	(39.7)	(115.2)
LGEE	(4.4)	(63.5)	(36.7)	(104.6)
MEC	(537.1)	(511.3)	(478.1)	(1,526.6)
MISO	(752.9)	407.1	151.5	(194.3)
ALTE	(921.0)	(594.9)	(228.0)	(1,743.9)
ALTW	(294.3)	(316.0)	(336.5)	(946.8)
AMIL	33.8	13.1	33.3	80.2
CIN	323.2	725.8	1,056.2	2,105.2
CWLP	(0.1)	0.0	0.0	(0.1)
IPL	(371.7)	(316.9)	(214.5)	(903.1)
MECS	217.0	568.0	(274.6)	510.5
NIPS	28.6	11.4	(137.9)	(97.9)
WEC	231.7	316.5	253.5	801.6
NYISO	(981.5)	(503.0)	(247.7)	(1,732.3)
LIND	(35.8)	(6.3)	(44.2)	(86.3)
NEPT	(425.2)	(355.9)	(314.5)	(1,095.5)
NYIS	(520.5)	(140.9)	111.0	(550.4)
OVEC	1,186.9	535.4	1,333.3	3,055.7
TVA	(742.4)	(770.7)	(1,098.6)	(2,611.7)
Total	(1,847.5)	(945.4)	(431.7)	(3,224.6)

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-8)

	Jan	Feb	Mar	Total
CPLE	37.2	36.9	45.0	119.2
CPLW	22.0	27.4	34.6	84.0
DUK	54.7	51.8	47.7	154.2
EKPC	0.2	0.5	0.8	1.5
LGEE	56.0	4.4	11.7	72.0
MEC	189.3	126.6	202.6	518.6
MISO	9,151.4	9,200.8	8,689.6	27,041.7
ALTE	4,127.5	4,316.8	3,727.0	12,171.3
ALTW	21.1	46.7	66.3	134.1
AMIL	37.9	14.3	34.1	86.4
CIN	897.1	908.7	1,475.1	3,280.9
CWLP	0.0	0.0	0.0	0.0
IPL	19.3	17.9	15.7	52.9
MECS	3,191.6	2,857.0	2,455.8	8,504.3
NIPS	108.7	165.8	118.1	392.6
WEC	748.1	873.5	797.6	2,419.2
NYISO	1,245.5	1,440.8	1,684.0	4,370.3
LIND	1.8	5.2	5.6	12.6
NEPT	0.0	0.0	0.0	0.0
NYIS	1,243.7	1,435.6	1,678.4	4,357.7
OVEC	3,918.9	3,168.0	3,803.0	10,889.9
TVA	512.3	596.1	584.4	1,692.8
Total	15,187.4	14,653.3	15,103.4	44,944.1

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-9)

	Jan	Feb	Mar	Total
CPLE	46.8	19.9	24.9	91.6
CPLW	28.2	65.3	101.9	195.4
DUK	16.0	33.8	16.3	66.1
EKPC	39.2	37.1	40.4	116.7
LGEE	60.4	67.8	48.4	176.6
MEC	726.4	638.0	680.7	2,045.1
MISO	9,904.2	8,793.7	8,538.1	27,236.0
ALTE	5,048.5	4,911.7	3,955.0	13,915.2
ALTW	315.5	362.7	402.7	1,080.9
AMIL	4.1	1.3	0.8	6.2
CIN	573.9	182.9	418.9	1,175.7
CWLP	0.1	0.0	0.0	0.1
IPL	391.0	334.8	230.2	956.0
MECS	2,974.5	2,288.9	2,730.4	7,993.8
NIPS	80.1	154.4	255.9	490.5
WEC	516.4	557.1	544.1	1,617.6
NYISO	2,227.0	1,943.8	1,931.7	6,102.5
LIND	37.6	11.5	49.8	98.9
NEPT	425.2	355.9	314.5	1,095.5
NYIS	1,764.2	1,576.5	1,567.4	4,908.1
OVEC	2,731.9	2,632.6	2,469.7	7,834.2
TVA	1,254.7	1,366.8	1,682.9	4,304.5
Total	17,034.9	15,598.7	15,535.1	48,168.8

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-12 show the Day-Ahead Market interchange totals at the individual interface pricing points, including those pricing points that make up the southern region. Net interchange in the Day-Ahead Market is shown by interface pricing point for the first three months of 2012 in Table 8-10, while gross imports and exports are shown in Table 8-11 and Table 8-12.

In the Day-Ahead Energy Market, for the first three months of 2012, there were net exports at eleven of PJM's 20 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 67.4 percent of the total net exports: PJM/SouthEXP with 35.0 percent, PJM/Southwest with 18.5 percent and PJM/NEPTUNE (NEPT) with 13.9 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 14.0 percent of the total net PJM exports in the Real-Time Energy Market (PJM/NEPTUNE with 13.9 percent and PJM/LINDEN with 0.1 percent. The PJM/NYIS interface pricing point had net imports in the Day-Ahead Energy Market). Eight PJM interface pricing points had net imports, with two importing interface pricing points accounting for 50.8 percent of the total net imports: PJM/MISO with 25.6 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 25.2 percent of the net import volume.

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-10)

	Jan	Feb	Mar	Total
IMO	(1,019.1)	(410.0)	(868.4)	(2,297.5)
LINDENVFT	9.2	(51.2)	23.5	(18.5)
MISO	1,268.5	1,277.6	1,419.8	3,965.9
NEPTUNE	(891.7)	(837.7)	(870.3)	(2,599.7)
NIPSCO	(47.9)	(33.1)	(630.3)	(711.4)
NORTHWEST	(524.9)	(353.4)	(499.9)	(1,378.1)
NYIS	(35.0)	300.8	573.1	838.9
OVEC	1,236.4	779.2	1,898.6	3,914.3
SOUTHIMP	2,041.5	2,471.4	2,283.8	6,796.8
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	3.9	12.2	3.5	19.6
NCMPAIMP	0.2	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	1,923.0
SOUTHWEST	707.2	900.6	815.6	2,423.4
SOUTHIMP	777.6	801.7	851.2	2,430.6
SOUTHEXP	(3,884.4)	(4,089.1)	(3,761.8)	(11,735.3)
CPLEEXP	(46.7)	(19.8)	(24.9)	(91.4)
DUKEXP	(1.8)	(27.4)	(13.0)	(42.2)
NCMPAEXP	(0.1)	(0.1)	0.0	(0.2)
SOUTHEAST	(530.7)	(546.3)	(488.7)	(1,565.6)
SOUTHWEST	(1,146.0)	(1,425.1)	(912.1)	(3,483.2)
SOUTHEXP	(2,159.1)	(2,070.5)	(2,323.0)	(6,552.6)
Total	(1,847.5)	(945.4)	(431.7)	(3,224.6)

Table 8-11 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-11)

	Jan	Feb	Mar	Total
IMO	545.7	587.1	505.6	1,638.5
LINDENVFT	350.2	372.2	459.9	1,182.3
MISO	4,021.4	3,236.4	3,339.4	10,597.3
NEPTUNE	0.0	0.0	0.0	0.0
NIPSCO	456.4	514.0	364.9	1,335.3
NORTHWEST	769.8	664.5	502.0	1,936.3
NYIS	1,592.7	1,890.4	2,212.4	5,695.6
OVEC	5,409.6	4,917.3	5,435.3	15,762.1
SOUTHIMP	2,041.5	2,471.4	2,283.8	6,796.8
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	3.9	12.2	3.5	19.6
NCMPAIMP	0.2	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	1,923.0
SOUTHWEST	707.2	900.6	815.6	2,423.4
SOUTHIMP	777.6	801.7	851.2	2,430.6
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	15,187.4	14,653.3	15,103.4	44,944.1

Table 8-12 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-12)

	Jan	Feb	Mar	Total
IMO	1,564.8	997.1	1,374.0	3,935.9
LINDENVFT	341.0	423.5	436.3	1,200.8
MISO	2,753.0	1,958.8	1,919.6	6,631.4
NEPTUNE	891.7	837.7	870.3	2,599.7
NIPSCO	504.3	547.1	995.3	2,046.7
NORTHWEST	1,294.7	1,017.9	1,001.9	3,314.5
NYIS	1,627.7	1,589.6	1,639.4	4,856.7
OVEC	4,173.2	4,138.0	3,536.6	11,847.8
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	3,884.4	4,089.1	3,761.8	11,735.3
CPLEEXP	46.7	19.8	24.9	91.4
DUKEXP	1.8	27.4	13.0	42.2
NCMPAEXP	0.1	0.1	0.0	0.2
SOUTHEAST	530.7	546.3	488.7	1,565.6
SOUTHWEST	1,146.0	1,425.1	912.1	3,483.2
SOUTHEXP	2,159.1	2,070.5	2,323.0	6,552.6
Total	17,034.9	15,598.7	15,535.1	48,168.8

Table 8-13 Active interfaces: January through March, 2012 (See 2011 SOM, Table 8-13)

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

Figure 8-3 PJM's footprint and its external interfaces (See 2011 SOM, Figure 8-3)

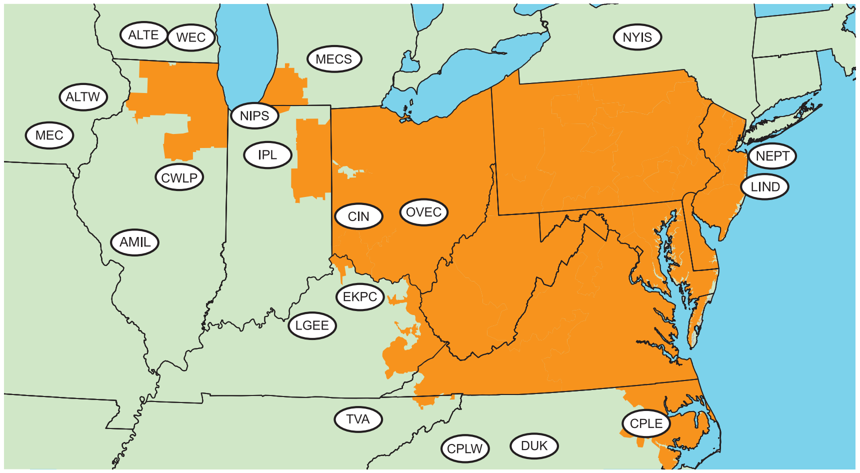


Table 8-14 Active pricing points: January through March, 2012 (See 2011 SOM, Table 8-14)

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

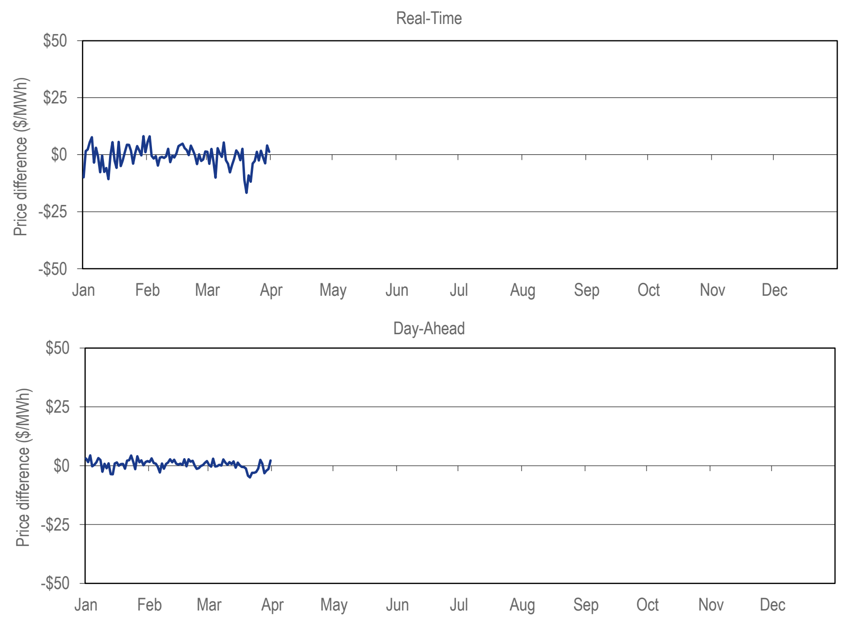
PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[11] 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.[12]

Real-Time and Day-Ahead Prices

In the first three months of 2012, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was inconsistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $25.27 while the MISO LMP at the border was $24.47, a difference of $0.80. The average hourly flow during the first three months of 2012 was -1,776 MW. (The negative sign means that the flow was an export from PJM to MISO, which is inconsistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 42 percent of hours during the first three months of 2012.

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through March, 2012 (See 2011 SOM, Figure 8-4)



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

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

Distribution of Economic and Uneconomic Hourly Flows

During the first three months of 2012, the direction of energy flow was consistent with PJM and MISO Interface Price differentials in 912 hours (42 percent of all hours), and were inconsistent with price differentials in 1,271 hours (58 percent). Table 15 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differentials of the PJM and MISO Interface Prices. Of the 1,271 hours where flows were uneconomic, 1,038 of those hours (81.7 percent) had a price difference greater than or equal to $1.00 and 330 of all uneconomic hours (26.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $142.58. Of the 912 hours where flows were economic, 729 of those hours (79.9 percent) had a price difference greater than or equal to $1.00 and 353 of all economic hours (38.7 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $113.33.

Table 8-15 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through March, 2012 (New Table)

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	1,271	100.0%	912	100.0%
$1.00	1,038	81.7%	729	79.9%
$5.00	330	26.0%	353	38.7%
$10.00	138	10.9%	189	20.7%
$15.00	84	6.6%	109	12.0%
$20.00	58	4.6%	92	10.1%
$25.00	45	3.5%	74	8.1%
$50.00	15	1.2%	19	2.1%
$75.00	3	0.2%	4	0.4%
$100.00	2	0.2%	1	0.1%
$200.00	0	0.0%	0	0.0%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

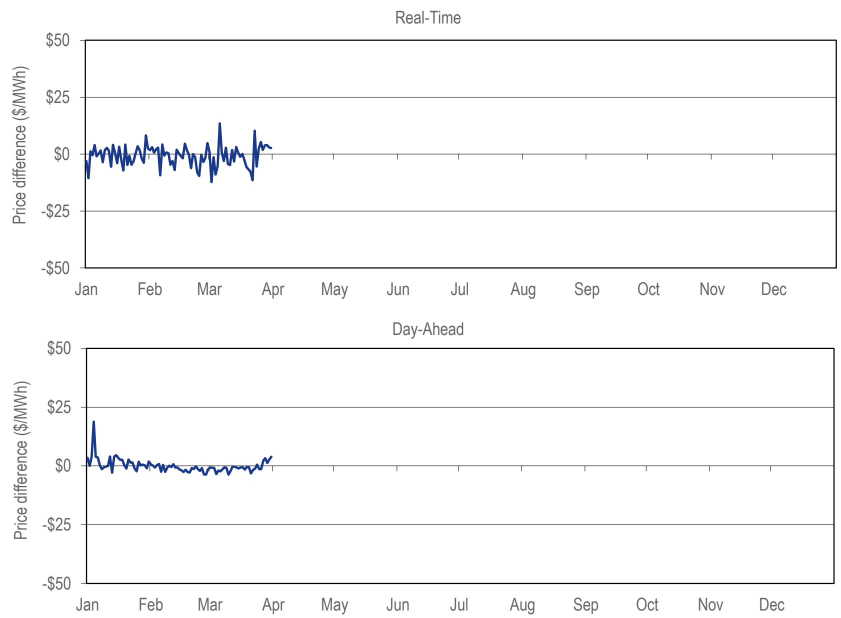
PJM and NYISO Interface Prices

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

Real-Time and Day-Ahead Prices

In the first three months of 2012, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first three months of 2012, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly LMP at the PJM/NYISO border was $30.53 while the NYISO LMP at the border was $29.74, a difference of $0.79. The average hourly flow during the first three months of 2012 was -563 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 51 percent of the hours during the first three months of 2012.

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March, 2012 (See 2011 SOM, Figure 8-5)



Distribution of Economic and Uneconomic Hourly Flows

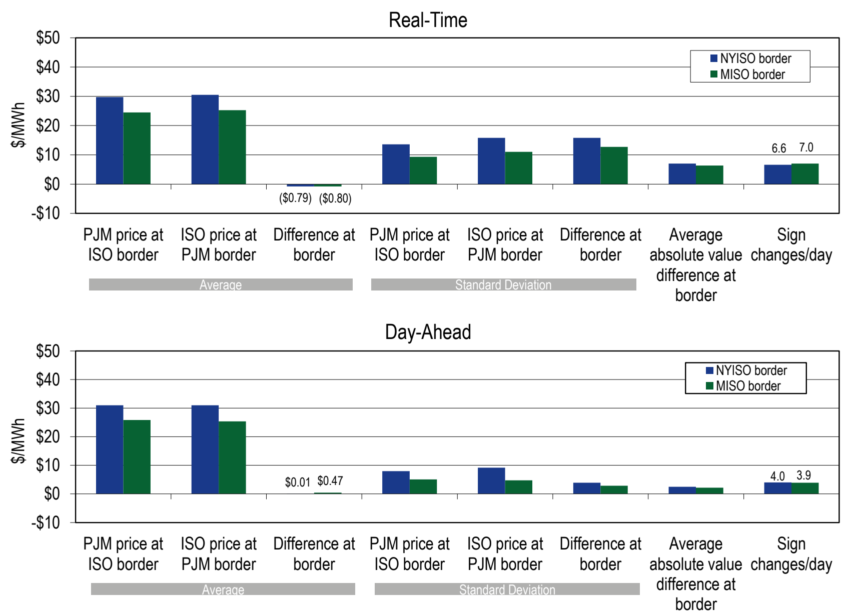
During the first three months of 2012, the direction of energy flow was consistent with PJM and NYIS Interface Price differentials in 1,103 hours (51 percent) of all hours, and were inconsistent with price diffeentials in 1,080 hours (49 percent). Table 8-16 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differentials of the PJM and NYISO Interface Prices. Of the 1,080 hours where flows were uneconomic, 920 of those hours (85.2 percent) had a price difference greater than or equal to $1.00 and 421 of all uneconomic hours (39.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $168.38. Of the 1,103 hours where flows were economic, 926 of those hours (84.0 percent) had a price difference greater than or equal to $1.00 and 349 of all economic hours (31.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $235.36.

Table 8-16 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through March, 2012 (New Table)

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	1,080	100.0%	1,103	100.0%
$1.00	920	85.2%	926	84.0%
$5.00	421	39.0%	349	31.6%
$10.00	202	18.7%	145	13.1%
$15.00	131	12.1%	79	7.2%
$20.00	83	7.7%	61	5.5%
$25.00	57	5.3%	43	3.9%
$50.00	25	2.3%	18	1.6%
$75.00	10	0.9%	8	0.7%
$100.00	4	0.4%	4	0.4%
$200.00	0	0.0%	2	0.2%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

Summary of Interface Prices between PJM and Organized Markets

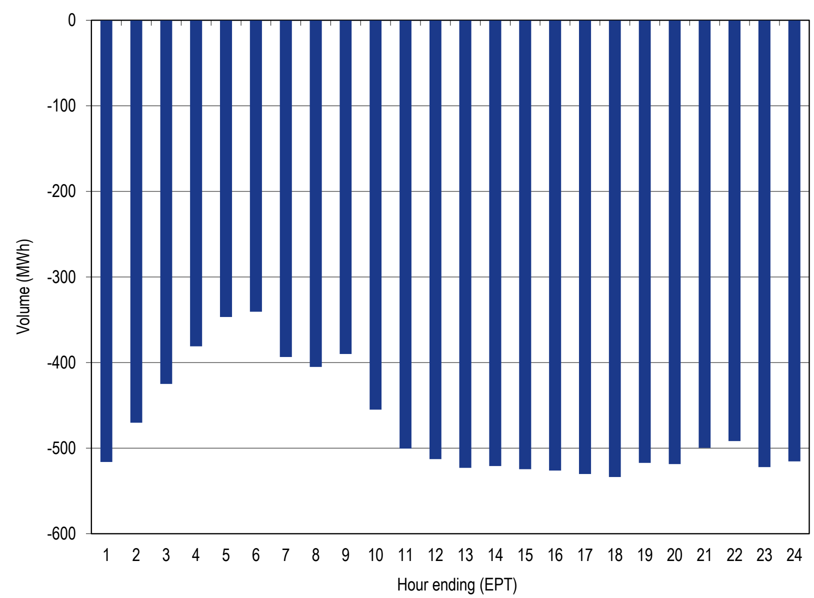
Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through March, 2012 (See 2011 SOM, Figure 8-6)



Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first three months of 2012, the average difference between the PJM/Neptune price and the NYISO/Neptune price was inconsistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly LMP at the Neptune Interface was $30.98 while the NYISO LMP at the Neptune Bus was $35.54, a difference of $4.56. The average hourly flow during the first three months of 2012 was -474 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 Neptune price.) However, the direction of flows was consistent with price differentials in only 57 percent of the hours during the first three months of 2012.

Figure 8-7 Neptune hourly average flow: January through March, 2012 (See 2011 SOM, Figure 8-7)

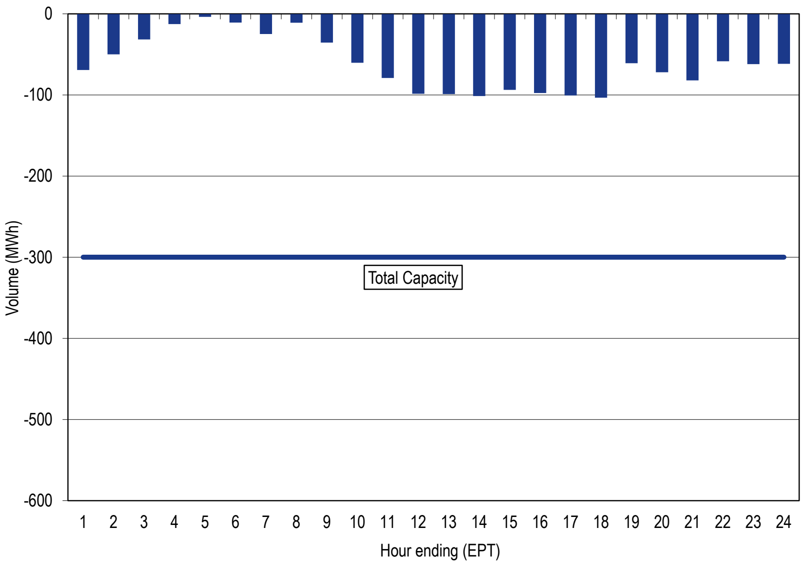


Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM and NYISO. In the first three months of 2012, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly

LMP at the Linden Interface was $31.04 while the NYISO LMP at the Linden Bus was $32.99, a difference of $1.95. The average hourly flow during the first three months of 2012 was -62 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 58 percent of the hours during the first three months of 2012.

Figure 8-8 Linden hourly average flow: January through March, 2012 (See 2011 SOM, Figure 8-8)



Operating Agreements with Bordering Areas

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

PJM and MISO Joint Operating Agreement[13]

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.

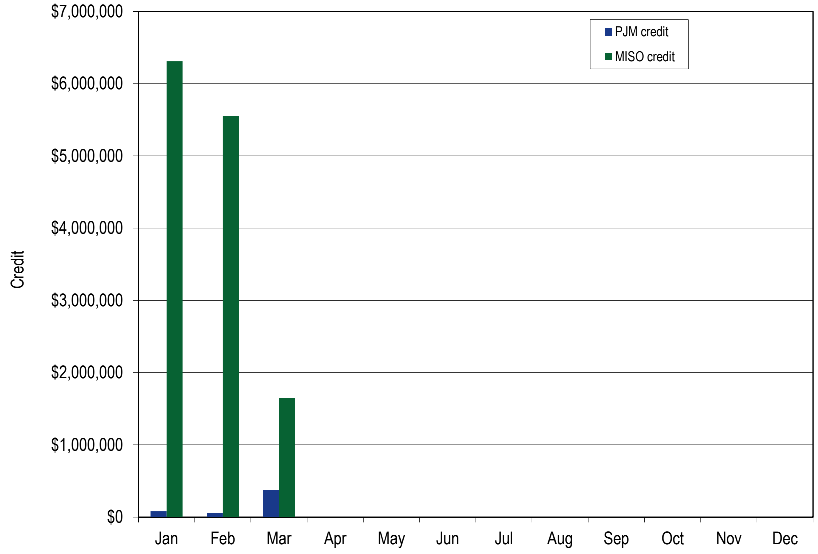
In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report, which was completed and distributed on January 20, 2012, showed that both PJM and MISO are conforming to the JOA.[14] The report also provided some potential areas of improvement including improved internal documentation, enhanced transparency, an increase of knowledge sharing and data exchange and an increase in attention to modeling differences.

In the first three months of 2012, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 8-9 shows credits for coordinated congestion management between PJM and MISO.

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

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

Figure 8-9 Credits for coordinated congestion management: January through March, 2012 (See 2011 SOM, Figure 8-9)



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[15]

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

The PJM/NYISO JOA did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol.[16] On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that included a draft market to market process.[17] On May 1, 2012, PJM and the NYISO filed a second revision to the JOA that included resolutions to several outstanding issues, present in the December 30, 2011 filing, which they requested additional time to resolve.[18] Some of the resolved issues were how to calculate firm flow entitlements (FFE), how to model external capacity resources in developing FFE's and how to include the Ontario/Michigan PAR operations in the market flow calculation.

Other Agreements/Protocols with Bordering Areas

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

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM.[19] 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.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[20] By order issued September 16, 2010, the Commission approved this settlement,[21] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and

15 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf>. (Accessed March 1, 2012)
16 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.
17 See "Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (December 30,2011).
18 See "Second Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (May 1, 2012).
19 See "Section 3 – Operating Reserve" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.
20 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.
21 132 FERC ¶ 61,221 (2010).

later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[22]

Table 8-17 Con Edison and PSE&G wheeling settlement data: January through March, 2012 (See 2011 SOM, Table 8-15)

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$285,069	($299)	$284,771	$543,866	$0	$543,866
Congestion Credit			$87,953			$458,087
Adjustments			$87			($2,911)
Net Charge			$196,731			$88,690

Interchange Transaction Issues

Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference.

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

Table 8-18 Net scheduled and actual PJM flows by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-16)

Interface	Actual	Net Scheduled	Difference (GWh)
CPLE	2,078	(232)	2,310
CPLW	(253)	-	(253)
DUK	40	1	39
EKPC	573	(19)	592
LGEE	420	627	(207)
MEC	(680)	(1,344)	663
MISO	(3,878)	(121)	(3,756)
ALTE	(1,827)	(1,431)	(397)
ALTW	(760)	(77)	(683)
AMIL	3,225	143	3,082
CIN	(1,749)	857	(2,606)
CWLP	(105)	-	(105)
IPL	(163)	(262)	99
MECS	(1,750)	1,215	(2,966)
NIPS	(1,996)	(22)	(1,975)
WEC	1,249	(545)	1,794
NYISO	(2,398)	(2,455)	57
LIND	(135)	(135)	-
NEPT	(1,034)	(1,034)	-
NYIS	(1,230)	(1,286)	57
OVEC	2,719	1,994	725
TVA	1,489	1,860	(371)
Total	110	310	(200)

Every balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface

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

price.[23] 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.

Table 8-19 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points. Following the consolidation of the Southeast and Southwest pricing points, a market participant requested grandfathered treatment to allow them to continue to receive the Southwest Interface Pricing Point. This pricing point is also a subset of the larger SouthIMP and SouthEXP Interface Pricing Points, and does not have physical ties that differ from the SouthIMP and SouthEXP Interafce Pricing Points.

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

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

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

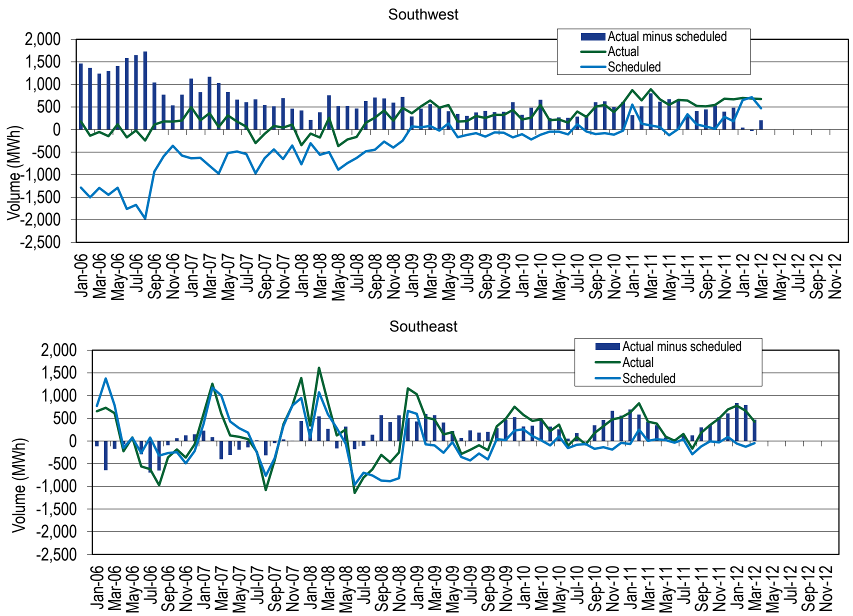
Table 8-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-17)

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
IMO	0	1,396	(1,396)
LINDENVFT	(135)	(135)	0
MISO	(3,304)	(4,544)	1,240
NEPTUNE	(1,034)	(1,034)	0
NORTHWEST	(680)	(2)	(678)
NYIS	(1,230)	(1,298)	69
OVEC	2,719	1,994	725
SOUTHIMP	3,773	4,939	(1,165)
CPLEIMP	0	0	(0)
DUKIMP	0	252	(252)
NCMPAIMP	0	114	(114)
SOUTHWEST	0	0	0
SOUTHIMP	3,773	4,572	(799)
SOUTHEXP	0	(1,006)	1,006
CPLEEXP	0	(105)	105
DUKEXP	0	(547)	547
NCMPAEXP	0	0	0
SOUTHWEST	0	(3)	3
SOUTHEXP	0	(350)	350
Total	110	310	(200)

Loop Flows at PJM's Southern Interfaces

Figure 8-10 illustrates the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP).

Figure 8-10 Southwest and southeast actual and scheduled flows: January, 2006 through March, 2012 (See 2011 SOM, Figure 8-10)



PJM Transmission Loading Relief Procedures (TLRs)

In the first three months of 2012, PJM issued 6 TLRs of level 3a or higher, compared to 13 for the first three months of 2011. Of the 6 TLRs issued, 4 events were TLR level 3a, and the remaining 2 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces.

Table 8-20 PJM and MISO TLR procedures: January, 2010 through March, 2012[24] (See 2011 SOM, Table 8-19)

	Number of TLRs Level 3 and Higher		Number of Unique Flowgates That Experienced TLRs		Curtailment Volume (MWh)	
Month	PJM	MISO	PJM	MISO	PJM	MISO
Jan-10	6	23	3	5	18,393	13,387
Feb-10	1	9	1	7	1,249	13,095
Mar-10	6	18	3	10	2,376	27,412
Apr-10	15	40	7	11	26,992	29,832
May-10	11	20	4	12	22,193	54,702
Jun-10	19	19	6	8	64,479	183,228
Jul-10	15	25	8	8	44,210	169,667
Aug-10	12	22	9	7	32,604	189,756
Sep-10	11	15	7	7	82,066	32,782
Oct-10	4	26	3	12	2,305	29,574
Nov-10	1	25	1	10	59	66,113
Dec-10	9	7	6	5	18,509	5,972
Jan-11	7	8	5	5	75,057	14,071
Feb-11	6	7	5	4	6,428	23,796
Mar-11	0	14	0	5	0	10,133
Apr-11	3	23	3	9	8,129	44,855
May-11	9	15	4	7	18,377	36,777
Jun-11	15	14	7	6	17,865	19,437
Jul-11	7	8	4	7	18,467	3,697
Aug-11	4	6	4	4	3,624	11,323
Sep-11	7	17	6	7	6,462	25,914
Oct-11	4	16	2	6	16,812	27,392
Nov-11	0	10	0	5	0	22,672
Dec-11	0	5	0	3	0	8,659
Jan-12	1	9	1	6	4,920	6,274
Feb-12	4	6	2	6	0	5,177
Mar-12	1	11	1	6	398	31,891

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

Table 8-21 Number of TLRs by TLR level by reliability coordinator: January through March, 2012 (See 2011 SOM, Table 8-18)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2012	ICTE	6	2	2	8	10	0	28
	MISO	17	3	0	2	4	0	26
	NYIS	31	0	0	0	0	0	31
	ONT	15	1	0	0	0	0	16
	PJM	4	2	0	0	0	0	6
	SWPP	74	50	1	10	5	0	140
	TVA	20	18	7	0	0	0	45
	VACS	1	0	0	0	0	0	1
Total		168	76	10	20	19	0	293

Up-To Congestion

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

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

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

Following the elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions significantly increased. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012, compared to an average of 20,753 bids per day, with an average cleared volume of 423,077 MWh per day, for the the first three months of 2011.

Figure 8-11 Monthly up-to congestion cleared bids in MWh: January, 2006 through March, 2012 (See 2011 SOM, Figure 8-11)

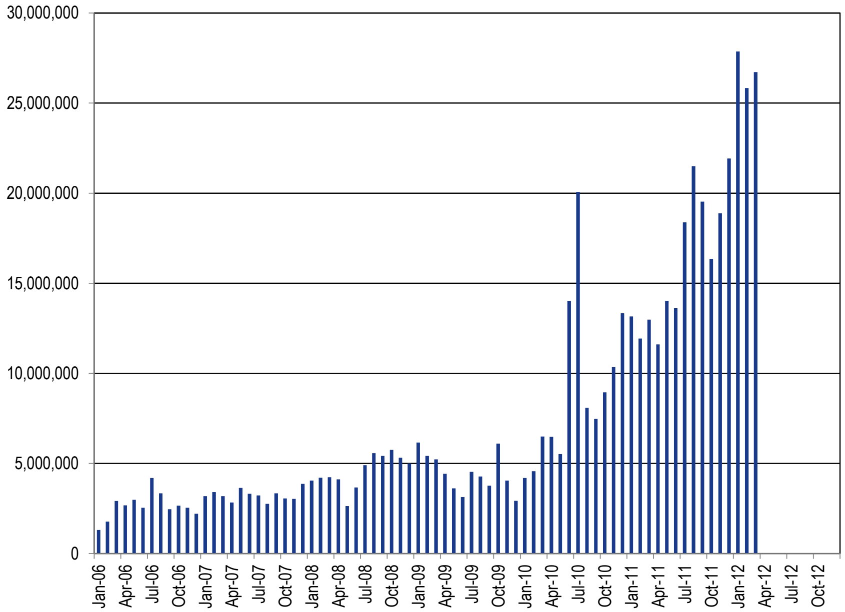


Figure 8-12 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction (physical) and without a matching Real-Time Energy Market transaction (financial): January through March, 2012 (See 2011 SOM, Figure 8-12)

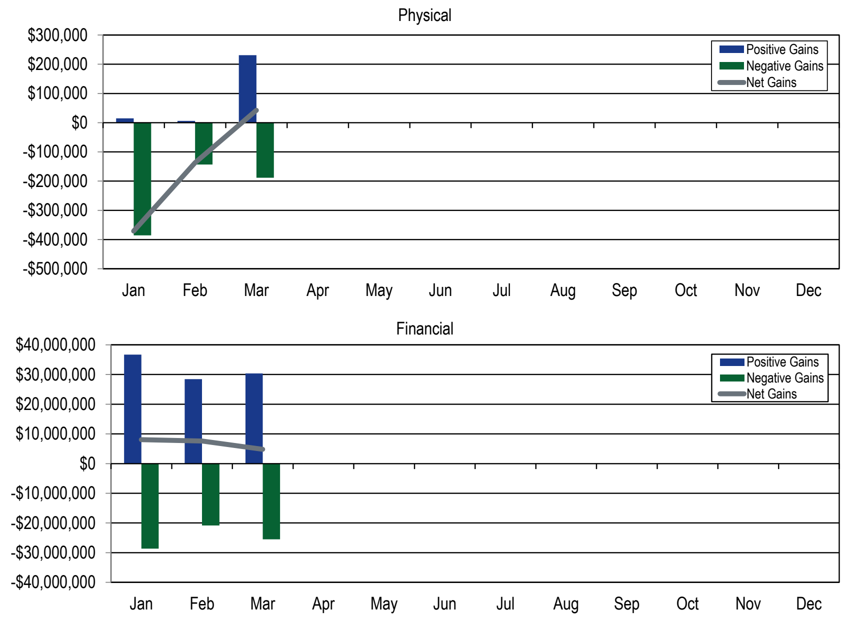


Table 8-22 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2012 (See 2011 SOM, Table 8-20)

	Bid MW				Bid Volume				Cleared MW				Cleared Volume			
Month	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total
Jan-09	4,218,910	5,787,961	319,122	10,325,993	90,277	74,826	6,042	171,145	2,591,211	3,242,491	202,854	6,036,556	56,132	45,303	4,210	105,645
Feb-09	3,580,115	4,904,467	318,440	8,803,022	64,338	70,874	6,347	141,559	2,374,734	2,836,344	203,907	5,414,985	42,101	44,423	4,402	90,926
Mar-09	3,649,978	5,164,186	258,701	9,072,865	64,714	72,495	5,531	142,740	2,285,412	2,762,459	178,507	5,226,378	42,408	42,007	4,299	88,714
Apr-09	2,607,303	5,085,912	73,931	7,767,146	47,970	67,417	2,146	117,533	1,797,302	2,582,294	48,478	4,428,074	32,088	35,987	1,581	69,656
May-09	2,196,341	4,063,887	106,860	6,367,088	40,217	54,745	1,304	96,266	1,496,396	2,040,737	77,553	3,614,686	26,274	29,720	952	56,946
Jun-09	2,598,234	3,132,478	164,903	5,895,615	47,625	44,755	2,873	95,253	1,540,169	1,500,560	88,723	3,129,452	28,565	23,307	1,522	53,394
Jul-09	3,984,680	3,776,957	296,910	8,058,547	67,039	56,770	5,183	128,992	2,465,891	1,902,807	163,129	4,531,826	41,924	31,176	2,846	75,946
Aug-09	3,551,396	4,388,435	260,184	8,200,015	64,652	64,052	3,496	132,200	2,278,431	2,172,133	194,415	4,644,978	41,774	34,576	2,421	78,771
Sep-09	2,948,353	4,179,427	156,270	7,284,050	51,006	64,103	2,405	117,514	1,774,589	2,479,898	128,344	4,382,831	31,962	40,698	1,944	74,604
Oct-09	3,172,034	6,371,230	154,825	9,698,089	46,989	100,350	2,217	149,556	2,060,371	3,931,346	110,646	6,102,363	31,634	70,964	1,672	104,270
Nov-09	3,447,356	3,851,334	103,325	7,402,015	53,067	61,906	1,236	116,209	2,065,813	1,932,595	51,929	4,050,337	33,769	32,916	653	67,338
Dec-09	2,323,383	2,502,529	66,497	4,892,409	47,099	47,223	1,430	95,752	1,532,579	1,359,936	34,419	2,926,933	31,673	28,478	793	60,944
Jan-10	3,794,946	3,097,524	212,010	7,104,480	81,604	55,921	3,371	140,896	2,250,689	1,789,018	161,977	4,201,684	49,064	33,640	2,318	85,022
Feb-10	3,841,573	3,937,880	316,150	8,095,603	80,876	80,685	2,269	163,830	2,627,101	2,435,650	287,162	5,349,913	50,958	48,008	1,812	100,778
Mar-10	4,877,732	4,454,865	277,180	9,609,777	97,149	74,568	2,239	173,956	3,209,064	3,071,712	263,516	6,544,292	60,277	48,596	2,064	110,937
Apr-10	3,877,306	5,558,718	210,545	9,646,569	67,632	85,358	1,573	154,563	2,622,113	3,690,889	170,020	6,483,022	42,635	54,510	1,154	98,299
May-10	3,800,870	5,062,272	149,589	9,012,731	74,996	78,426	1,620	155,042	2,366,149	3,049,405	112,700	5,528,253	47,505	48,996	1,112	97,613
Jun-10	9,126,963	9,568,549	1,159,407	19,854,919	95,155	89,222	6,960	191,337	6,863,803	6,850,098	1,072,759	14,786,660	59,733	55,574	5,831	121,138
Jul-10	12,818,141	11,526,089	5,420,410	29,764,640	124,929	106,145	18,948	250,022	8,971,914	8,237,557	5,241,264	22,450,734	73,232	60,822	16,526	150,580
Aug-10	8,231,393	6,767,617	888,591	15,887,601	115,043	87,876	10,664	213,583	4,430,832	2,894,314	785,726	8,110,871	62,526	40,485	8,884	111,895
Sep-10	7,768,878	7,561,624	349,147	15,679,649	184,697	161,929	4,653	351,279	3,915,814	3,110,580	256,039	7,282,433	63,405	45,264	3,393	112,062
Oct-10	8,732,546	9,795,666	476,665	19,004,877	189,748	154,741	7,384	351,873	4,150,104	4,564,039	246,594	8,960,736	76,042	65,223	3,670	144,935
Nov-10	11,636,949	9,272,885	537,369	21,447,203	253,594	170,470	9,366	433,430	5,765,905	4,312,645	275,111	10,353,661	112,250	71,378	4,045	187,673
Dec-10	17,769,014	12,863,875	923,160	31,556,049	307,716	215,897	15,074	538,687	7,851,235	5,150,286	337,157	13,338,678	136,582	93,299	7,380	237,261
Jan-11	20,275,932	11,807,379	921,120	33,004,431	351,193	210,703	17,632	579,528	7,917,986	4,925,310	315,936	13,159,232	151,753	91,557	8,417	251,727
Feb-11	18,418,511	13,071,483	800,630	32,290,624	345,227	226,292	17,634	589,153	6,806,039	4,879,207	248,573	11,933,818	151,003	99,302	8,851	259,156
Mar-11	17,330,353	12,919,960	749,276	30,999,589	408,628	274,709	15,714	699,051	7,104,642	5,603,583	275,682	12,983,906	178,620	124,990	7,760	311,370
Apr-11	17,215,352	9,321,117	954,283	27,490,752	513,881	265,334	17,459	796,674	7,452,366	3,797,819	351,984	11,602,168	229,707	113,610	8,118	351,435
May-11	21,058,071	11,204,038	2,937,898	35,200,007	562,819	304,589	24,834	892,242	8,294,422	4,701,077	1,031,519	14,027,018	261,355	143,956	11,116	416,427
Jun-11	20,455,508	12,125,806	395,833	32,977,147	524,072	285,031	12,273	821,376	7,632,235	5,361,825	198,482	13,192,543	226,747	132,744	6,363	365,854
Jul-11	24,273,892	16,837,875	409,863	41,521,630	603,519	338,810	13,781	956,110	9,585,027	8,617,284	205,599	18,407,910	283,287	186,866	7,008	477,161
Aug-11	23,790,091	21,014,941	229,895	45,034,927	591,170	403,269	8,278	1,002,717	10,594,771	10,875,384	103,141	21,573,297	274,398	208,593	3,648	486,639
Sep-11	21,740,208	18,135,378	232,626	40,108,212	526,945	377,158	7,886	911,989	10,219,806	9,270,121	82,200	19,572,127	270,088	185,585	3,444	459,117
Oct-11	20,240,161	19,476,556	333,077	40,049,794	540,877	451,507	8,609	1,000,993	8,376,208	7,853,947	126,718	16,356,873	255,206	198,778	4,236	458,220
Nov-11	27,007,141	28,994,789	507,788	56,509,718	594,397	603,029	13,379	1,210,805	9,064,570	9,692,312	131,670	18,888,552	254,851	256,270	5,686	516,807
Dec-11	34,990,790	34,648,433	531,616	70,170,839	697,524	655,222	14,187	1,366,933	11,738,910	10,049,685	137,689	21,926,284	281,304	248,008	6,309	535,621
Jan-12	38,944,873	37,006,724	503,224	76,454,821	746,076	691,873	12,702	1,450,651	13,629,676	14,149,243	98,370	27,877,288	289,814	305,070	3,790	598,674
Feb-12	37,241,552	36,801,215	248,813	74,291,580	739,421	726,346	6,482	1,472,249	12,889,962	12,907,675	45,995	25,843,632	299,159	276,636	1,998	577,793
Mar-12	38,834,123	39,165,771	285,530	78,285,424	803,126	843,024	8,661	1,654,811	13,334,937	13,306,764	83,218	26,724,918	320,301	320,267	2,925	643,493
TOTAL	516,370,951	465,207,832	23,241,663	1,004,820,445	10,907,007	8,797,650	323,842	20,028,499	223,929,177	203,891,027	14,129,702	441,949,905	5,002,106	4,017,582	175,153	9,194,841

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.[25] Table 8-23 shows the historical differences in Real-Time Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences, but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

Table 8-23 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through March, 2007 through 2012 (See 2011 SOM, Table 8-21)

Year	Southeast LMP	Southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$53.10	$44.81	$48.12	$46.15	$4.98	($3.31)	$6.95	($1.34)
2008	$60.33	$52.96	$55.85	$55.74	$4.48	($2.89)	$4.59	($2.78)
2009	$45.76	$38.72	$41.17	$41.17	$4.60	($2.44)	$4.60	($2.44)
2010	$44.57	$37.19	$40.33	$39.74	$4.25	($3.13)	$4.83	($2.55)
2011	$42.19	$36.24	$38.71	$38.71	$3.47	($2.47)	$3.47	($2.47)
2012	$29.80	$27.96	$28.81	$28.81	$0.99	($0.85)	$0.99	($0.85)

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[26] Progress Energy Carolinas, February 13, 2007;[27] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[28]

PJM recognized that the price signals in the agreements were inappropriate, and in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[29] [30] On January 20, 2011, the Commission issued an Order conditionally accepting the compliance filing submitted by PJM and PEC.[31]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology as defined in the PJM Tariff.[32]

The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

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

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

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

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

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

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

31 134 FERC ¶ 61,048 (2011).

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

Table 8-24 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2012 (See 2011 SOM, Table 8-22)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$29.30	$29.38	$28.81	$28.81	$0.49	$0.57
PEC	$29.68	$29.90	$28.81	$28.81	$0.87	$1.09
NCMPA	$29.40	$29.38	$28.81	$28.81	$0.59	$0.57

Figure 8-13 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March, 2012 (See 2011 SOM, Figure 8-13)

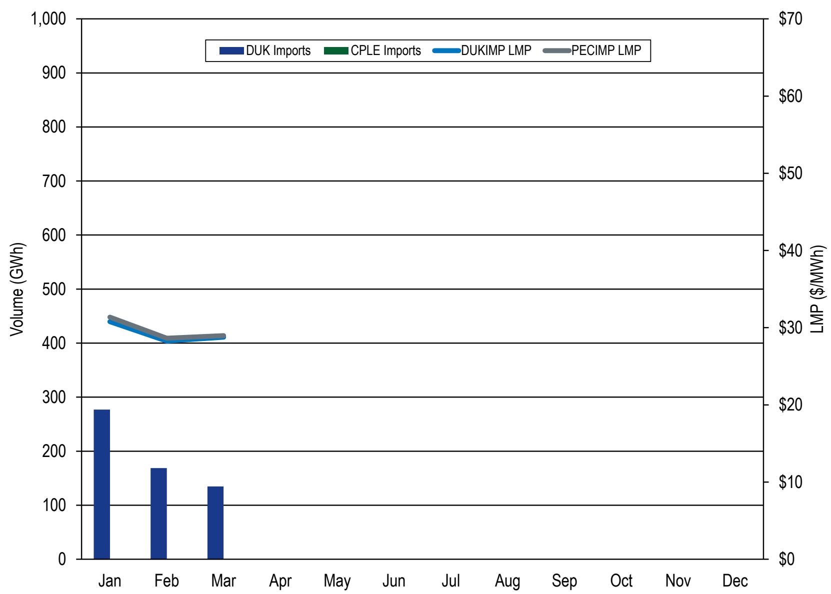


Figure 8-14 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March, 2012 (See 2011 SOM, Figure 8-14)

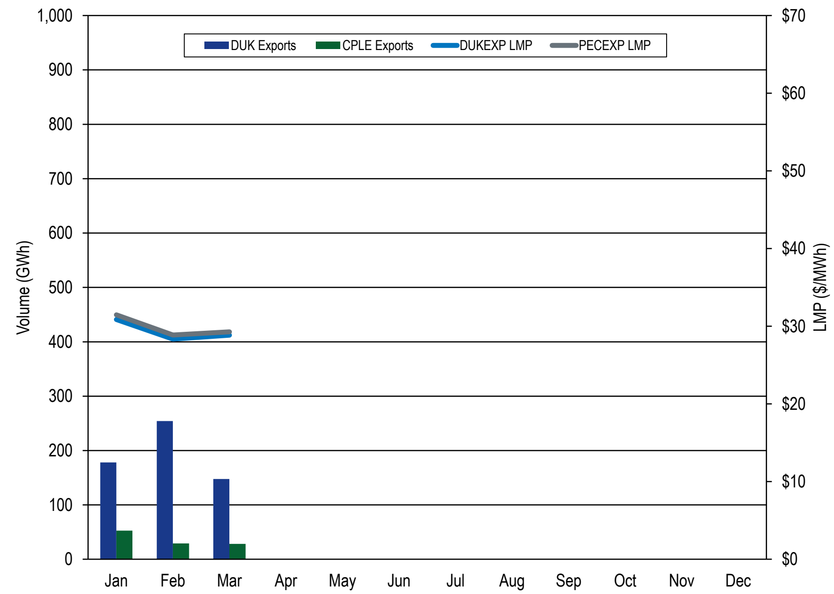


Table 8-25 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through March, 2007 through 2012 (See 2011 SOM, Table 8-23)

Year	Southeast LMP	Southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$51.80	$44.25	$48.23	$45.55	$3.57	($3.97)	$6.25	($1.30)
2008	$61.71	$53.52	$56.45	$56.45	$5.26	($2.93)	$5.26	($2.93)
2009	$46.49	$38.58	$41.37	$41.37	$5.12	($2.78)	$5.12	($2.78)
2010	$47.69	$38.43	$41.63	$41.63	$6.07	($3.20)	$6.07	($3.20)
2011	$43.68	$36.97	$39.26	$39.26	$4.42	($2.30)	$4.42	($2.30)
2012	$30.31	$28.33	$29.11	$29.12	$1.20	($0.78)	$1.20	($0.79)

Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2012 (See 2011 SOM, Table 8-24)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$29.25	$30.08	$29.11	$29.11	$0.14	$0.96
PEC	$30.02	$30.42	$29.11	$29.11	$0.90	$1.31
NCMPA	$29.67	$29.72	$29.11	$29.11	$0.56	$0.60

Figure 8-15 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March, 2012 (See 2011 SOM, Figure 8-15)

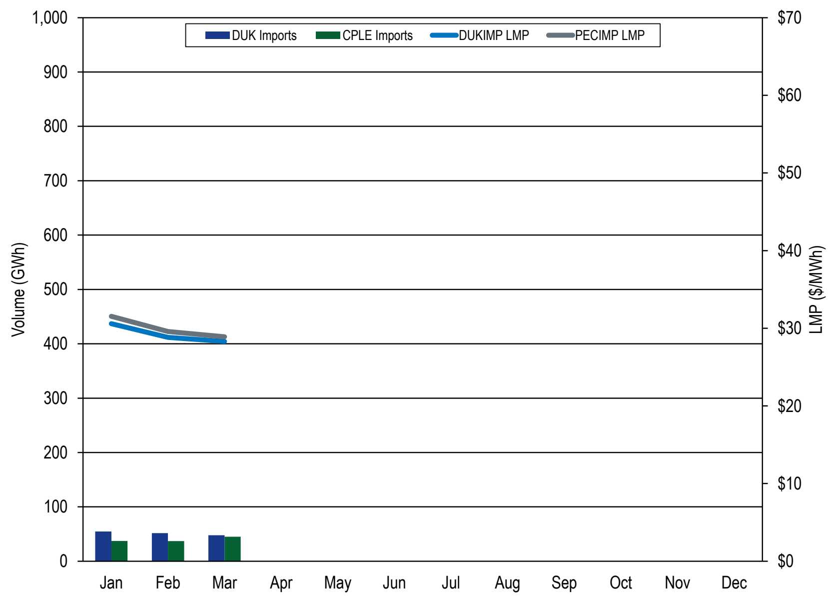
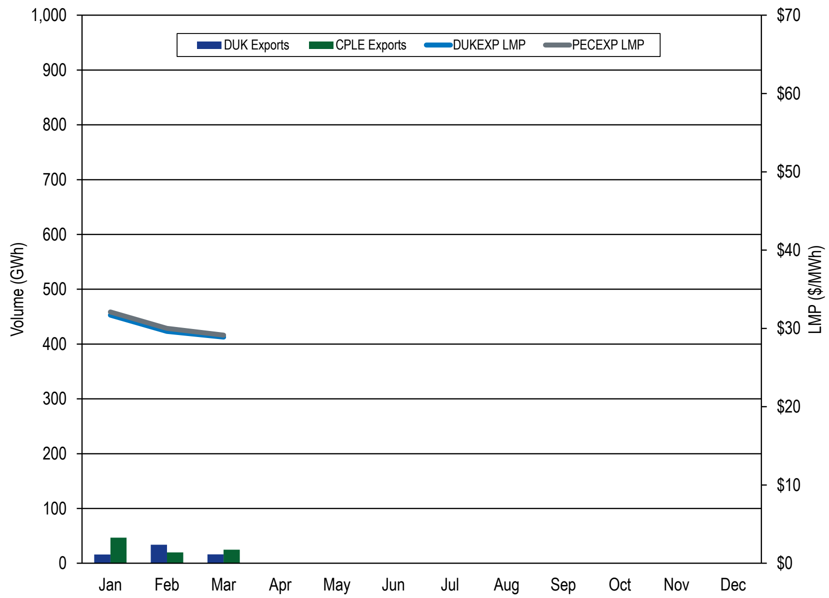


Figure 8-16 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March, 2012 (See 2011 SOM, Figure 8-16



Willing to Pay Congestion and Not Willing to Pay Congestion

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

Total uncollected congestion charges in the first three months of 2012 were -$15.00, compared to $4,669 for the the first three months of 2011. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case in for the net uncollected congestion charges in the first three months of 2012.

Table 8-27 Monthly uncollected congestion charges: Calendar years 2010 and 2011 and January through March, 2012 (See 2011 SOM, Table 8-25)

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

Spot Import

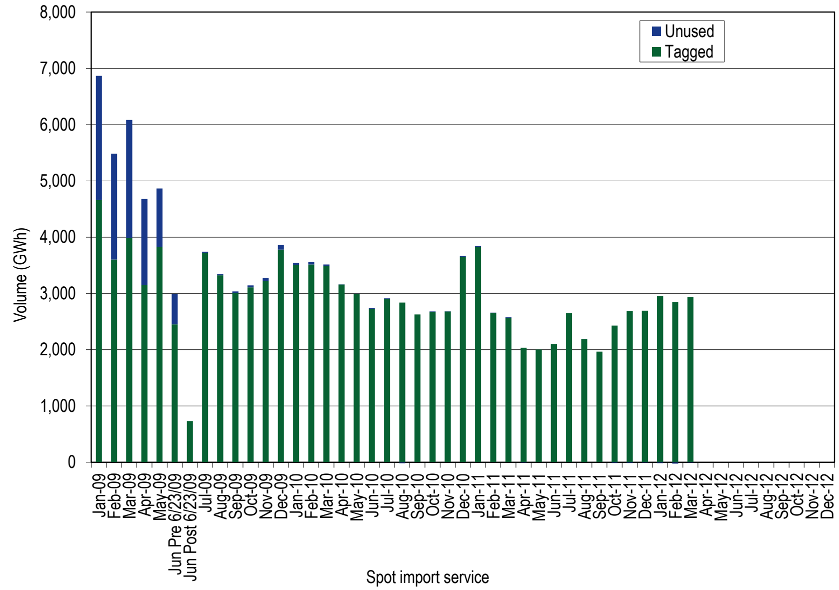
Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing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

However, PJM interpreted its JOA with MISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[33] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result, requests for service sometimes exceeded the amount of service available to customers. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

After a series of rule changes intended to address the hoarding of spot in service, and as an alternative to creating an unlimited amount of ATC, PJM suggested including a utilization factor in the ATC calculation for non-firm service. This utilization factor is the ratio of utilized transmission on a particular path to the amount of that transmission reserved when determining how much transmission should be granted. For example, if a path has 1,000 MW of ATC available, and the utilization factor is sixty percent, rather than reducing the ATC to zero when a 1,000 MW reservation is made, there would still be 400 MW of ATC available to be requested. Including the utilization factor will allow PJM to adjust the amount of ATC available to permit a more efficient use of the transmission system. This proposed methodology was approved by PJM stakeholders during the third quarter of 2011. It is expected that implementation of these changes will occur by the end of the third quarter 2012.

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

Figure 8-17 Spot import service utilization: January, 2009 through March, 2012 (See 2011 SOM, Figure 8-17)



Real-Time Dispatchable Transactions

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

Dispatchable transactions were initially a valuable tool for market participants. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits.

Balancing operating reserve credits are paid to importing dispatchable transactions as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. During the first three months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.1 million for the first three months of 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted in three days during the first three months of 2012.