SECTION 4 – 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 control areas.[1]

Overview

Interchange Transaction Activity

- Aggregate Imports and Exports in the Real-Time Market. During 2007, PJM was a net exporter of energy in the Real-Time Market. In the Real-Time Market, monthly net interchange averaged -1,189 GWh.[2] Gross monthly import volumes averaged 2,500 GWh while gross monthly exports averaged 3,689 GWh.

- Transactions in the Day-Ahead Energy Market. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. In 2007, gross imports in the Day-Ahead Energy Market were 85 percent of the Real-Time Market's gross imports (77 percent in 2006) while gross exports in the Day-Ahead Market were 103 percent of the Real-Time Market's gross exports (86 percent in 2006) and net interchange in the Day-Ahead Energy Market exceeded net interchange in the Real-Time Energy Market by 39 percent. In the Day-Ahead Market, monthly net interchange averaged -1,657 GWh. Gross monthly import volumes averaged 2,135 GWh while gross monthly exports averaged 3,792 GWh.

- Interface Imports and Exports in the Real-Time Market. In the Real-Time Market in 2007, there were net exports at 18 of PJM's 23 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 42 percent of the total net exports: PJM/Tennessee Valley Authority (TVA) with 19 percent, PJM/MidAmerican Energy Company (MEC) with 12 percent and PJM/Neptune (NEPT) with 11 percent of the net export volume. Five PJM interfaces had net imports, with two importing interfaces accounting for 95 percent of net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 74 percent and PJM/Duke Energy Corp. (DUK) with 21 percent.

- Interface Imports and Exports in the Day-Ahead Market. In the Day-Ahead Market, there were net exports at 16 of PJM's 23 interfaces. The top three net exporting interfaces accounted for 54 percent of the total net exports, PJM/Northern Indiana Public Service Company (PJM/NIPS) with 27 percent, PJM/western Alliant Energy Corporation (ALTW) with 16 percent and PJM/MEC with 11 percent. There were net imports in the Day-Ahead Market at six of PJM's 23 interfaces. The top three importing interfaces accounted for 98 percent of the total net imports, PJM/OVEC with 72 percent, PJM/New York Independent System Operator Interface (NYIS) and PJM/DUK each with 13 percent.

1 As part of this analysis of transactions, the Market Monitoring Unit (MMU) compared the market results in 2007 to those of 2006 and certain other prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on PJM's footprint and the definition of these phases, see *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

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

Interchange Transaction Topics

- PJM Interface Pricing with Organized Markets.

  - PJM and Midwest ISO Interface Pricing. During 2007, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

  - PJM and New York ISO Interface Pricing. During 2007, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

- PJM TLRs. The number of transmission loading relief procedures (TLRs) issued by PJM continued to decline, with 41 percent fewer during 2007 (80) than 2006 (136). The reduction in TLRs declared by PJM is consistent with the fact that market signals, rather than market interventions, are being used more frequently to manage constraints on interarea transactions. However, more needs to be done to assure that market signals rather than TLRs are used to manage constraints affecting interarea transactions. Access to the data required for understanding loop flow would be a positive first step toward economic management of regional constraints.

- Operating Agreements with Bordering Areas.

  - PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).[3] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. This agreement does not include provisions for market-based congestion management or other market-to-market activity. PJM and NYISO should develop market-based congestion management protocols as soon as practicable.

  - PJM and Midwest ISO Joint Operating Agreement. The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." continued, in 2007 as in 2006, in its second, and final, phase of implementation including market-to-market activity and coordinated, market-based congestion management within and between both markets.[4]

3 See "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed January 25, 2008) <http://www.pjm.com/documents/downloads/agreements/20071102-nyiso-pjm.pdf > (208 KB).

4 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (August 24, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,662 KB).

- PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.[5] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2007.

- PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.[6] On September 9, 2005, the United States Federal Energy Regulatory Commission (FERC) approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2007.

- PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.[7] On May 23, 2007, PJM and VACAR South (VACAR is a subregion within the NERC Southeastern Electric Reliability Council (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

• Interface Pricing Agreements with Individual Companies. PJM entered into locational interface pricing agreements with three companies in 2007 that extend the concept of the dynamic scheduling of individual units to entire control areas. These agreements were made available through the PJM website by PJM after a request by the MMU in October. Each of these agreements established a locational price for power sales between PJM and the individual company that applies under specified conditions and that differs from the generally applicable interface price. PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

• Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts. During 2007, PJM continued to operate under the terms of the operating protocol that had been developed in 2005.[8] All parties also continued to pursue work on the 19 items identified in the work plan to improve protocol performance. In August the FERC denied a rehearing of Con Edison's complaints regarding protocol performance and refunds.[9]

• Neptune Underwater Transmission Line to Long Island, New York. On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, including undersea and underground cable was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in 2007, with the exception of testing, power flows were only from PJM to New York. The average hourly flow for the period July through December was -599 MWh.

5 See "Joint Reliability Coordination (JRCA) among the Midwest ISO, PJM and TVA" (April 22, 2005) (Accessed February 4, 2008) <http://www.pjm.com/documents/downloads/agreements/20050422-jrca-final.pdf> (145 KB).

6 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed February 4, 2008) <http://www.pjm.com/documents/ferc/documents/2005/20050729-er05-___-000.pdf> (2.90 MB).

7 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed February 19, 2008) <http://www.pjm.com/documents/downloads/agreements/executed-pjm-vacar-rc-agreement.pdf > (532 KB).

8 111 FERC ¶ 61,228 (2005).

9 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 2007).

Interchange Transaction Issues

- Loop Flows. Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths that the energy takes. Although PJM's total scheduled and actual flows differed by less than 0.5 percent in 2007, greater differences existed at individual interfaces. Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

  – Loop Flows at the PJM/MECS and PJM/TVA Interfaces. As it had in 2006, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows, although these mismatches have declined since the consolidation of the former PJM southeast and southwest pricing points in October 2006. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

  – Loop Flows at PJM's Southern Interfaces. The improvements in the difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) observed at the end of 2006 continued during 2007. In order to reflect the actual flow of transactions associated with the southwest and southeast interface pricing points, on October 1, 2006, PJM began to price imports and exports differently based on their impacts on the PJM transmission system.

  – Data Required for Full Loop Flow Analysis. A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency, shed light on the interactions among market and non market areas and permit market-based congestion management across the Eastern Interconnection. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. A complete analysis of loop flow could advance the overall transparency of electricity transactions. The data to fully analyze loop flows affecting PJM are not currently available to PJM. PJM is presently working with the North American Electric Reliability Council (NERC) and North American Energy Standards Board (NAESB) to increase transparency of scheduled and actual transactions, generation and loads from other control areas. This effort should be given a high priority.

- Ramp Reservation Rule Change. In 2006 the MMU developed, PJM proposed and the membership agreed to, changes in the ramp reservation rules that imposed limits on the time that a ramp reservation could be held without an associated energy schedule. These rules showed positive results when they were implemented that were sustained through 2007. An additional rule to address artificial ramp creation was added in 2007. This rule sets out the procedure for PJM operators to follow if they observe a participant who has offsetting import and export ramp reservations, but is only scheduling on one of them while letting the other expire. This rule has not yet been incorporated in PJM's software although dispatchers may enforce the rule manually.

- Spot Import Service. A new interchange transaction issue emerged in 2007. Some participants obtain and hold large amounts of spot import service reservations without using the service. Prior to April 2007, PJM did not limit spot import service, preferring to let market prices ration the use of the service which is not physically limited. PJM interpreted its JOA with Midwest ISO to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates. The rule caused the availability of spot import service to be limited by ATC on the transmission path. Most of the spot import reservations were for monthly service and most monthly reservations were not used. Following implementation of the rule, participants have complained that they are not able to obtain this service. There are a number of possible options for addressing the issue including making reservations available only hourly or daily or requiring reservation holders to release reservations if they will not be used within a defined lead time.

- Up-to Congestion Transactions. Up-to congestion transactions are Day-Ahead Energy Market transactions for which participants can specify the maximum level of positive congestion cost that they are willing to pay, up to a cap of $25 per MWh. There is a mismatch between up-to congestion transactions in the Day-Ahead Energy Market and the Real-Time Energy Market. 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. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity.

Conclusion

Transactions between PJM and multiple control areas in the Eastern Interconnection are part of a single energy market. While some of these control areas 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 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 nontransparent.

The MMU analyzed the transactions between PJM and neighboring control areas for 2007 including evolving transaction patterns, economics and issues. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. PJM continued to be a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 42 percent of the total real-time net exports and two interfaces accounted for 95 percent of the real-time net import volume. Three interfaces accounted for 54 percent of the total day-ahead net exports and three interfaces accounted for 98 percent of the day-ahead net import volume.

As the data show, there is a substantial level of transactions between PJM and the contiguous control areas. The transactions with other market areas are largely driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. PJM and NYISO should implement market-to-market coordination modeled on the PJM and MISO JOA as soon as possible. The transactions with non market areas are driven by a mix of incentives including market fundamentals but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational price approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. The reverse can also occur. For interactions with both market and non market areas, the goal should be to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of control areas. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions and the number of required interventions in the market has declined, as measured, for example, by the reduction in TLRs declared by PJM in 2007. However, more needs to be done to assure that market signals rather than TLRs are used to manage constraints affecting interarea transactions. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols as soon as practicable. In addition, PJM should continue its efforts to gain access to the data required to understand loop flows in real time and to ensure that responsible parties pay the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other control areas as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners for specific units to permit transparent, market-based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous control areas to help ensure that transactions are free to respond to market signals and to reduce the ability to game or hoard ramp. PJM also entered into agreements with specific control areas for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external control areas. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. But this approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that continue not to be fully understood as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency, shed light on the interactions among market and non market areas and permit market-based congestion management across the Eastern Interconnection. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. PJM and Midwest ISO issued a joint loop flow report in 2007 that made three recommendations including the establishment of an energy schedule tag archive. The archive would capture and retain data for the entire Eastern Interconnection including tag impact, generation-to-load impact and market flow impact data for flowgates in the interchange distribution calculator (IDC). The archive would be a prime source of information needed to perform after-the-fact analyses and reviews. This effort should be given a high priority as the data needs have been well understood for some time.

PJM needs to continue to pay careful attention to all the mechanisms used to manage flows at the interfaces between PJM and surrounding areas. PJM manages its interface with external areas, in part, through limitations on the amount of change in net interchange within 15-minute intervals. The change in net interchange is referred to as ramp. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service. Up-to congestion service is a market option used to import power into PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM continues to be a net exporter of power. (See Figure 4-1, Figure 4-2 and Figure 4-3.)[10]

During 2007, PJM was a net exporter of energy in the Real-Time Market for each month except February. Total net interchange of -14,261 GWh was less than net interchange of -18,081 GWh in 2006. The peak month for net interchange was August in 2007, -3,483 GWh; it had been June in 2006, -2,738 GWh. Monthly gross exports averaged 3,689 GWh and monthly gross imports averaged 2,500 GWh, for an average monthly net interchange of -1,189 GWh. In the Day-Ahead Market, PJM was also a net exporter of energy. Total net interchange was -19,885 GWh. The peak month for net interchange was August, -3,472 GWh. Monthly gross exports averaged 3,792 GWh and monthly gross imports averaged 2,135 GWh, for an average monthly net interchange of -1,657 GWh.

While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. (See Figure 4-2.) Transactions in the Day-Ahead Market create financial obligations to deliver in the Real-Time Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets. In 2007, gross imports in

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

the Day-Ahead Energy Market were 85 percent of the Real-Time Market's gross imports (77 percent in 2006) while gross exports in the Day-Ahead Market were 103 percent of the Real-Time Market's gross exports (86 percent in 2006) and net interchange in the Day-Ahead Energy Market exceeded the net interchange in the Real-Time Energy Market by 39 percent.

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2007

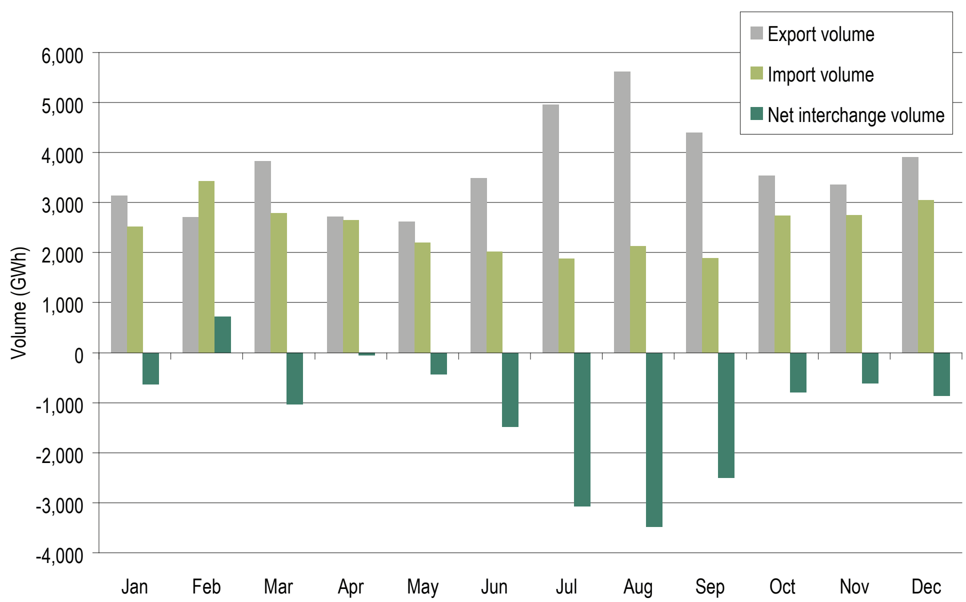


Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2007

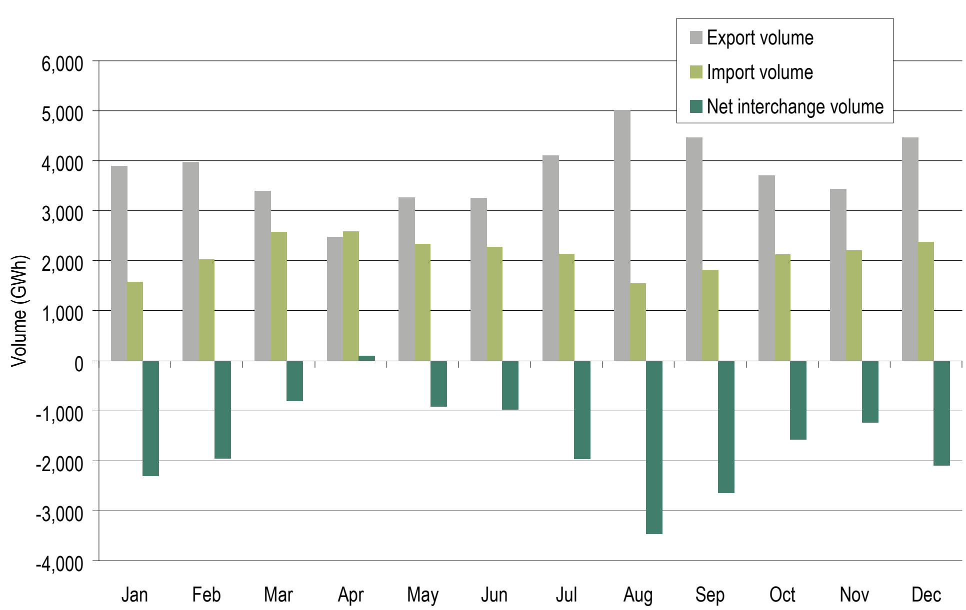
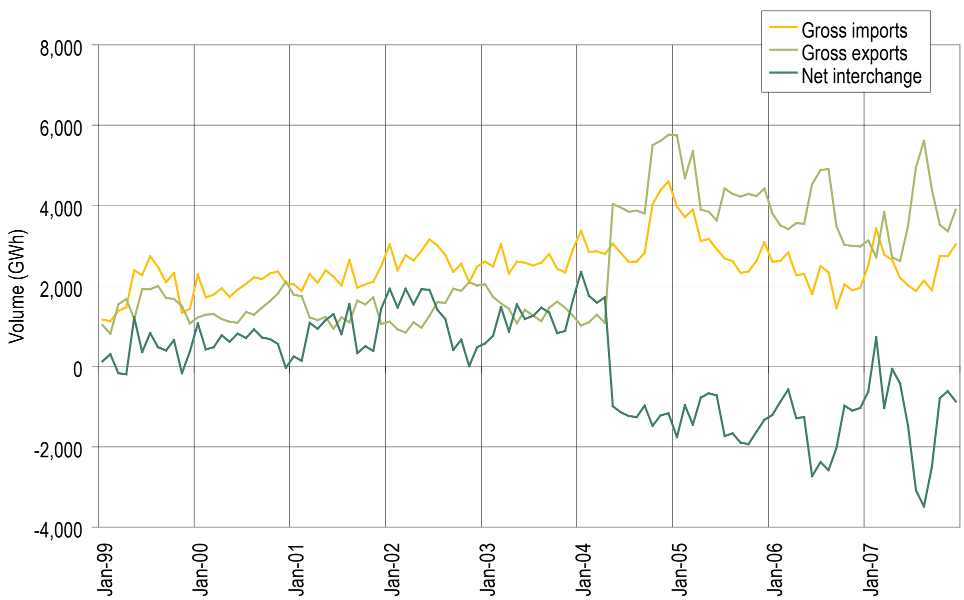


Figure 4-3 shows real-time import and export volume for PJM from 1999 through 2007. PJM became a consistent net exporter of energy in 2004 and has continued to be a net exporter since that time. During 2007, imports continued to be lower than exports, with the exception of February. Exports peaked in August while imports declined from February and net interchange had a record peak in August.

Figure 4-3 PJM scheduled import and export transaction volume history: Calendar years 1999 to 2007



Interface Imports and Exports

Total imports and exports are comprised of flows at each PJM interface.[11] Net interchange in the Real-Time Market is shown by interface for 2007 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3. Net interchange in the Day-Ahead Market is shown by interface for 2007 in Table 4-4 while gross imports and exports are shown in Table 4-5 and Table 4-6.

In 2007, there were net exports in the Real-Time Market at 18 of PJM's 23 interfaces. (See Table 4-8 for changes in defined interfaces during 2007.) The top three exporting interfaces accounted for 42 percent of the total net exports, PJM/TVA with 19 percent, PJM/MEC with 12 percent and PJM/NEPT with 11 percent of the net export volume. In 2007, there were net exports in the Day-Ahead Market at 16 of PJM's 23 interfaces. The top three exporting interfaces accounted for 54 percent of the total net exports, PJM/Northern Indiana Public Service Company (PJM/NIPS) with 27 percent, PJM/ALTW with 16 percent and PJM/MEC with 11 percent.

11 See "PJM Interface Price Definition Methodology" (September 14, 2007) (Accessed February 12, 2008) <http://www.pjm.com/committees/mic/downloads/20070925-item-06-definition-methodology.pdf> (97 KB).

There were net imports in the Real-Time Market at five of PJM's interfaces. Two net importing interfaces accounted for 95 percent of the net import volume, PJM/OVEC with 74 percent and PJM/DUK with 21 percent of the net import volume. There were net imports in the Day-Ahead Market at six of PJM's 23 interfaces. The top three net importing interfaces accounted for 98 percent of the total net imports, PJM/OVEC with 72 percent, PJM/NYIS and PJM/DUK each with 13 percent. The PJM/IP interface was in service only for the months of January and February. There was no Day-Ahead Market volume on that interface during those two months.

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(53.1)	(89.7)	(84.1)	(99.7)	(126.4)	(268.6)	(210.6)	(377.2)	(177.0)	(159.6)	(82.8)	(130.3)	(1,859.1)
ALTW	(91.2)	(83.6)	(92.6)	(88.3)	(183.1)	(194.3)	(276.7)	(284.0)	(253.0)	(104.7)	(95.6)	(98.1)	(1,845.2)
AMIL	0.0	0.0	(57.6)	(24.4)	2.0	52.9	6.0	(24.2)	51.6	101.6	82.2	77.9	268.0
AMRN	(112.2)	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(78.8)
CILC	1.0	(31.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(30.8)
CIN	(104.1)	(100.2)	(689.2)	(107.8)	18.9	(207.3)	(405.9)	(427.8)	(224.7)	(23.9)	109.5	75.3	(2,087.2)
CPLE	(100.4)	119.3	39.5	(115.6)	(2.0)	(104.1)	(204.8)	(214.7)	(194.0)	(77.9)	195.4	227.7	(431.6)
CPLW	(72.4)	(68.2)	(78.7)	(44.8)	0.0	(27.6)	(75.1)	(66.2)	(73.9)	(69.8)	(60.1)	(65.6)	(702.4)
CWLP	0.0	0.0	0.1	(1.1)	(0.1)	0.0	0.0	(123.9)	(29.8)	0.0	0.0	0.0	(154.8)
DUK	259.4	585.2	677.9	386.0	105.1	112.8	(49.2)	(393.7)	(121.7)	258.7	291.4	393.4	2,505.3
EKPC	(57.0)	(60.4)	(40.8)	(132.5)	(21.3)	(29.8)	(51.7)	(62.5)	(13.8)	(6.5)	(48.6)	(91.3)	(616.2)
FE	(97.5)	19.7	(73.4)	(162.4)	(180.6)	(48.5)	(88.0)	(8.8)	(6.9)	139.6	(155.5)	(102.6)	(764.9)
IP	3.6	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.7
IPL	0.0	(12.7)	0.0	0.0	0.0	(130.4)	(274.0)	(133.6)	(242.7)	(126.2)	(9.2)	(8.1)	(936.9)
LGEE	65.8	16.5	0.2	(11.5)	7.5	1.1	52.0	12.1	15.0	65.8	25.6	97.5	347.6
MEC	(453.9)	(372.3)	(340.3)	(88.9)	(228.5)	(291.3)	(473.6)	(237.2)	(14.4)	(117.1)	(199.4)	(416.3)	(3,233.2)
MECS	(83.0)	(52.6)	(288.6)	(139.8)	(122.1)	(94.3)	(147.2)	(247.7)	(199.3)	(60.0)	(58.9)	(54.4)	(1,547.9)
NEPT	0.0	0.0	0.0	0.0	(23.6)	(146.3)	(422.5)	(397.8)	(442.3)	(487.7)	(455.2)	(438.8)	(2,814.2)
NIPS	4.1	(1.8)	(14.0)	4.9	(23.0)	(74.4)	(93.5)	(132.5)	(68.4)	(62.2)	(45.8)	(78.9)	(585.5)
NYIS	(58.5)	452.9	(52.9)	531.8	75.5	(361.2)	(629.4)	(323.0)	(651.4)	(338.4)	(361.6)	(749.9)	(2,466.1)
OVEC	860.9	838.3	771.2	680.3	672.0	710.1	691.7	718.9	710.9	692.0	743.5	758.5	8,848.3
TVA	(412.6)	(356.3)	(551.9)	(567.5)	(362.6)	(324.1)	(352.7)	(659.8)	(444.4)	(318.6)	(420.6)	(171.0)	(4,942.1)
WEC	(126.5)	(126.9)	(164.5)	(80.7)	(36.3)	(55.7)	(73.4)	(99.3)	(125.6)	(98.1)	(66.1)	(90.4)	(1,143.5)
Total	(627.6)	715.9	(1,039.7)	(62.0)	(428.6)	(1,481.0)	(3,078.6)	(3,482.9)	(2,505.8)	(793.0)	(611.8)	(865.4)	(14,260.5)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	29.7	0.3	10.9	8.0	0.0	0.0	0.1	0.0	0.1	1.6	0.0	0.0	50.7
ALTW	0.3	0.0	0.2	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	1.0
AMIL	0.0	0.0	11.6	23.4	17.0	79.9	74.8	83.9	72.1	116.2	85.1	83.3	647.3
AMRN	66.6	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	166.2
CILC	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8
CIN	180.1	109.8	47.9	126.3	180.1	51.6	77.1	179.4	103.8	209.4	216.9	265.4	1,747.8
CPLE	149.1	327.3	234.2	47.7	109.2	74.1	65.1	87.3	62.2	127.7	359.6	418.9	2,062.4
CPLW	0.0	0.0	2.7	0.0	0.0	0.1	1.4	0.2	0.0	0.0	0.0	0.0	4.4
CWLP	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
DUK	328.6	659.8	753.7	471.0	224.8	267.0	240.9	107.4	158.4	377.5	401.9	486.4	4,477.4
EKPC	3.1	0.4	2.8	0.4	2.1	7.0	6.9	10.4	14.0	24.6	11.2	10.0	92.9
FE	93.2	214.2	143.7	45.9	40.9	187.6	124.1	215.8	177.6	347.9	52.0	104.4	1,747.3
IP	4.0	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7
IPL	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	9.0	9.1
LGEE	67.3	23.9	21.3	19.6	31.1	22.4	55.9	20.7	20.9	69.8	37.5	103.1	493.5
MEC	147.6	110.8	109.5	198.9	81.7	53.0	33.5	82.4	186.1	158.6	159.5	150.8	1,472.4
MECS	13.0	21.8	18.2	57.1	75.2	58.5	55.2	57.9	36.3	88.9	52.6	120.9	655.6
NEPT	0.0	0.0	0.0	0.0	0.9	6.5	0.0	0.1	0.1	0.0	0.1	0.0	7.7
NIPS	18.4	1.6	7.5	25.8	19.6	10.0	2.4	3.7	17.2	12.4	5.7	6.1	130.4
NYIS	508.9	891.1	557.6	896.3	652.8	430.8	361.6	489.0	273.9	436.8	550.1	395.2	6,444.1
OVEC	865.5	845.4	772.1	688.4	676.5	716.2	714.8	721.9	727.5	715.0	767.9	786.8	8,998.0
TVA	28.2	110.3	94.2	41.7	84.2	45.8	62.2	69.2	38.5	49.5	46.2	101.6	771.6
WEC	4.3	1.2	0.1	0.0	0.0	0.3	1.3	1.0	0.1	0.8	0.5	0.0	9.6
Total	2,509.3	3,426.6	2,788.3	2,650.6	2,196.2	2,011.3	1,877.3	2,130.3	1,888.8	2,736.7	2,746.8	3,041.9	30,004.1

Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	82.8	90.0	95.0	107.7	126.4	268.6	210.7	377.2	177.1	161.2	82.8	130.3	1,909.8
ALTW	91.5	83.6	92.8	88.3	183.2	194.7	276.7	284.0	253.0	104.7	95.6	98.1	1,846.2
AMIL	0.0	0.0	69.2	47.8	15.0	27.0	68.8	108.1	20.5	14.6	2.9	5.4	379.3
AMRN	178.8	66.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	245.0
CILC	0.4	33.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.6
CIN	284.2	210.0	737.1	234.1	161.2	258.9	483.0	607.2	328.5	233.3	107.4	190.1	3,835.0
CPLE	249.5	208.0	194.7	163.3	111.2	178.2	269.9	302.0	256.2	205.6	164.2	191.2	2,494.0
CPLW	72.4	68.2	81.4	44.8	0.0	27.7	76.5	66.4	73.9	69.8	60.1	65.6	706.8
CWLP	0.0	0.0	0.0	1.2	0.1	0.0	0.0	123.9	29.8	0.0	0.0	0.0	155.0
DUK	69.2	74.6	75.8	85.0	119.7	154.2	290.1	501.1	280.1	118.8	110.5	93.0	1,972.1
EKPC	60.1	60.8	43.6	132.9	23.4	36.8	58.6	72.9	27.8	31.1	59.8	101.3	709.1
FE	190.7	194.5	217.1	208.3	221.5	236.1	212.1	224.6	184.5	208.3	207.5	207.0	2,512.2
IP	0.4	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
IPL	0.0	12.7	0.0	0.0	0.0	130.5	274.0	133.6	242.7	126.2	9.2	17.1	946.0
LGEE	1.5	7.4	21.1	31.1	23.6	21.3	3.9	8.6	5.9	4.0	11.9	5.6	145.9
MEC	601.5	483.1	449.8	287.8	310.2	344.3	507.1	319.6	200.5	275.7	358.9	567.1	4,705.6
MECS	96.0	74.4	306.8	196.9	197.3	152.8	202.4	305.6	235.6	148.9	111.5	175.3	2,203.5
NEPT	0.0	0.0	0.0	0.0	24.5	152.8	422.5	397.9	442.4	487.7	455.3	438.8	2,821.9
NIPS	14.3	3.4	21.5	20.9	42.6	84.4	95.9	136.2	85.6	74.6	51.5	85.0	715.9
NYIS	567.4	438.2	610.5	364.5	577.3	792.0	991.0	812.0	925.3	775.2	911.7	1,145.1	8,910.2
OVEC	4.6	7.1	0.9	8.1	4.5	6.1	23.1	3.0	16.6	23.0	24.4	28.3	149.7
TVA	440.8	466.6	646.1	609.2	446.8	369.9	414.9	729.0	482.9	368.1	466.8	272.6	5,713.7
WEC	130.8	128.1	164.6	80.7	36.3	56.0	74.7	100.3	125.7	98.9	66.6	90.4	1,153.1
Total	3,136.9	2,710.7	3,828.0	2,712.6	2,624.8	3,492.3	4,955.9	5,613.2	4,394.6	3,529.7	3,358.6	3,907.3	44,264.6

Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(83.0)	(90.2)	(99.7)	(112.8)	(148.8)	(191.6)	(269.3)	(182.0)	(50.0)	(48.0)	(119.2)	(139.9)	(1,534.5)
ALTW	(203.8)	(261.2)	(99.9)	(161.0)	(500.5)	(488.3)	(539.6)	(620.9)	(553.0)	(446.8)	(528.2)	(821.8)	(5,225.0)
AMIL	0.0	0.0	(7.7)	(8.1)	(11.5)	18.1	4.6	(22.0)	54.0	66.9	55.7	42.0	192.0
AMRN	4.5	(3.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
CILC	0.0	(8.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.0)
CIN	(437.8)	(367.6)	(535.6)	(152.4)	(13.3)	32.4	(251.9)	(443.6)	(178.6)	(90.7)	56.4	(74.2)	(2,456.9)
CPLE	(287.6)	(16.8)	151.9	(110.1)	(47.4)	(89.3)	(142.3)	(147.3)	(113.5)	(76.1)	21.0	213.1	(644.4)
CPLW	(187.4)	(165.8)	(182.9)	(115.3)	2.4	(66.0)	(186.7)	(168.3)	(174.0)	(182.5)	(150.3)	(171.0)	(1,747.8)
CWLP	0.0	0.0	0.0	(1.2)	(0.1)	6.2	0.0	0.0	0.0	0.0	0.0	0.0	4.9
DUK	91.6	407.8	496.0	194.4	44.5	113.5	63.8	(258.2)	(63.0)	174.6	180.8	185.6	1,631.4
EKPC	(1.0)	(5.7)	(1.4)	(4.2)	(0.5)	2.4	12.1	1.3	0.0	3.7	0.0	(7.2)	(0.5)
FE	(156.0)	(257.5)	(190.5)	(168.2)	(76.0)	(36.0)	(75.0)	(146.4)	(153.6)	(188.8)	(160.1)	(137.3)	(1,745.4)
IP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(0.1)	(0.1)	0.0	0.0	(18.5)	(126.1)	(86.0)	(197.7)	(70.2)	(55.0)	(37.5)	(165.5)	(756.7)
LGEE	1.6	0.0	0.0	0.0	(31.4)	12.0	3.3	1.7	2.8	1.8	5.7	(8.1)	(10.6)
MEC	(443.4)	(382.5)	(354.7)	(198.8)	(248.1)	(289.2)	(345.7)	(295.4)	(146.9)	(197.8)	(260.6)	(355.8)	(3,518.9)
MECS	(257.5)	(213.2)	(201.1)	(70.4)	(169.2)	(68.2)	(33.4)	(246.8)	(175.9)	(144.9)	(15.2)	(61.0)	(1,656.8)
NEPT	0.0	0.0	0.0	0.0	(10.6)	(165.9)	(419.8)	(392.2)	(434.2)	(477.9)	(448.0)	(441.0)	(2,789.6)
NIPS	(606.7)	(525.3)	(512.1)	(146.7)	(716.8)	(901.1)	(743.1)	(867.6)	(1,018.2)	(769.3)	(733.0)	(1,086.0)	(8,625.9)
NYIS	(268.8)	(661.7)	185.3	725.7	500.2	338.1	286.4	214.8	(78.6)	197.5	113.2	120.9	1,673.0
OVEC	952.4	929.4	766.4	705.9	607.7	837.6	763.1	660.8	634.2	635.1	678.6	718.6	8,889.8
TVA	(99.0)	(105.3)	(87.9)	(183.1)	(25.3)	129.9	68.9	(273.0)	(45.2)	102.5	158.0	162.2	(197.3)
WEC	(325.9)	(233.6)	(142.7)	(92.8)	(58.5)	(47.1)	(75.8)	(89.4)	(88.0)	(84.0)	(49.2)	(71.2)	(1,358.2)
Total	(2,307.9)	(1,961.0)	(816.6)	100.9	(921.7)	(978.6)	(1,966.4)	(3,472.2)	(2,651.9)	(1,579.7)	(1,231.9)	(2,097.6)	(19,884.6)

Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	0.0	0.0	0.0	0.1	48.5	39.5	12.6	31.1	125.1	160.5	9.8	41.4	468.6
ALTW	0.0	0.0	0.0	0.0	17.2	23.7	2.0	6.5	54.1	54.1	27.0	27.3	211.9
AMIL	0.0	0.0	0.0	0.0	5.5	22.9	48.1	55.8	54.0	66.9	55.7	55.9	364.8
AMRN	8.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.2
CILC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	40.9	18.3	31.9	92.9	106.9	125.6	43.9	24.3	21.0	54.6	95.2	78.9	734.4
CPLE	78.1	132.9	272.7	87.0	89.0	27.6	0.0	2.3	1.2	18.2	118.6	310.1	1,137.7
CPLW	0.0	2.2	2.9	0.0	2.4	0.0	0.0	0.0	0.0	3.5	0.0	0.0	11.0
CWLP	0.0	0.0	0.0	0.0	0.0	6.2	0.0	0.0	0.0	0.0	0.0	0.0	6.2
DUK	95.9	421.2	496.4	205.3	79.3	143.0	125.5	59.3	102.9	204.4	236.1	216.1	2,385.4
EKPC	0.2	0.3	0.2	0.2	0.0	2.4	12.1	1.3	0.0	3.7	0.0	0.0	20.4
FE	50.8	72.2	137.5	117.3	221.8	81.8	64.8	8.9	39.6	19.9	6.1	19.9	840.6
IP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	32.8	13.1	21.4	4.4	2.1	3.3	4.5	5.1	86.7
LGEE	1.6	0.0	0.0	0.0	6.5	19.5	22.0	5.2	4.0	2.4	30.4	13.0	104.6
MEC	4.6	6.4	0.2	3.4	0.2	0.0	0.0	0.0	21.4	6.3	0.0	3.0	45.5
MECS	5.0	27.7	33.0	71.2	69.4	149.3	196.6	137.5	236.8	182.7	263.2	189.3	1,561.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	3.2	0.3	178.5	402.8	336.7	133.5	73.3	36.6	33.8	93.0	63.8	12.1	1,367.6
NYIS	334.4	304.5	547.9	855.2	666.0	500.8	589.0	411.2	309.8	361.5	337.8	414.6	5,632.7
OVEC	952.4	929.8	766.5	705.9	615.1	844.5	825.8	717.7	735.6	710.7	699.9	751.9	9,255.8
TVA	7.6	105.0	108.4	42.9	30.8	140.5	105.7	48.5	71.2	182.7	258.0	233.0	1,334.3
WEC	0.6	0.0	0.0	0.2	14.3	7.2	0.1	0.1	9.9	0.0	0.0	4.8	37.2
Total	1,583.5	2,020.8	2,576.1	2,584.4	2,342.4	2,281.1	2,142.9	1,550.7	1,822.5	2,128.4	2,206.1	2,376.4	25,615.3

Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	83.0	90.2	99.7	112.9	197.3	231.1	281.9	213.1	175.1	208.5	129.0	181.3	2,003.1
ALTW	203.8	261.2	99.9	161.0	517.7	512.0	541.6	627.4	607.1	500.9	555.2	849.1	5,436.9
AMIL	0.0	0.0	7.7	8.1	17.0	4.8	43.5	77.8	0.0	0.0	0.0	13.9	172.8
AMRN	3.7	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4
CILC	0.0	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0
CIN	478.7	385.9	567.5	245.3	120.2	93.2	295.8	467.9	199.6	145.3	38.8	153.1	3,191.3
CPLE	365.7	149.7	120.8	197.1	136.4	116.9	142.3	149.6	114.7	94.3	97.6	97.0	1,782.1
CPLW	187.4	168.0	185.8	115.3	0.0	66.0	186.7	168.3	174.0	186.0	150.3	171.0	1,758.8
CWLP	0.0	0.0	0.0	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
DUK	4.3	13.4	0.4	10.9	34.8	29.5	61.7	317.5	165.9	29.8	55.3	30.5	754.0
EKPC	1.2	6.0	1.6	4.4	0.5	0.0	0.0	0.0	0.0	0.0	0.0	7.2	20.9
FE	206.8	329.7	328.0	285.5	297.8	117.8	139.8	155.3	193.2	208.7	166.2	157.2	2,586.0
IP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.1	0.1	0.0	0.0	51.3	139.2	107.4	202.1	72.3	58.3	42.0	170.6	843.4
LGEE	0.0	0.0	0.0	0.0	37.9	7.5	18.7	3.5	1.2	0.6	24.7	21.1	115.2
MEC	448.0	388.9	354.9	202.2	248.3	289.2	345.7	295.4	168.3	204.1	260.6	358.8	3,564.4
MECS	262.5	240.9	234.1	141.6	238.6	217.5	230.0	384.3	412.7	327.6	278.4	250.3	3,218.5
NEPT	0.0	0.0	0.0	0.0	10.6	165.9	419.8	392.2	434.2	477.9	448.0	441.0	2,789.6
NIPS	609.9	525.6	690.6	549.5	1,053.5	1,034.6	816.4	904.2	1,052.0	862.3	796.8	1,098.1	9,993.5
NYIS	603.2	966.2	362.6	129.5	165.8	162.7	302.6	196.4	388.4	164.0	224.6	293.7	3,959.7
OVEC	0.0	0.4	0.1	0.0	7.4	6.9	62.7	56.9	101.4	75.6	21.3	33.3	366.0
TVA	106.6	210.3	196.3	226.0	56.1	10.6	36.8	321.5	116.4	80.2	100.0	70.8	1,531.6
WEC	326.5	233.6	142.7	93.0	72.8	54.3	75.9	89.5	97.9	84.0	49.2	76.0	1,395.4
Total	3,891.4	3,981.8	3,392.7	2,483.5	3,264.1	3,259.7	4,109.3	5,022.9	4,474.4	3,708.1	3,438.0	4,474.0	45,499.9

Interface Pricing Points

Interface pricing points differ from interfaces. 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. PJM establishes prices for transactions with external control areas by assigning interface pricing points to individual control areas. Interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically for areas that are both adjacent to, and not adjacent to, PJM. 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 control areas need to be priced at the PJM border. A set of external buses is used to create such interface prices.[12] The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and external sources of energy and, therefore, to create price signals that embody underlying economic fundamentals.[13]

12 See PJM. "LMP Aggregate Definitions" (December 12, 2007) (Accessed January 29, 2008) <http://www.pjm.com/markets/energy-market/downloads/20071211-aggregate-definitions.xls> (1,334 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

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

Table 4-7 presents the interface pricing points used during 2007. These pricing points include all those used at the end of 2006 plus the addition of the NEPT pricing point. The NEPT pricing point was added in July when the Neptune line went into commercial service.

Table 4-7 Active pricing points: Calendar year 2007

PJM 2007 Pricing Points				
MICHFE	MISO	NEPT	NIPSCO	Northwest
NYIS	Ontario IESO	OVEC	SOUTHEXP	SOUTHIMP

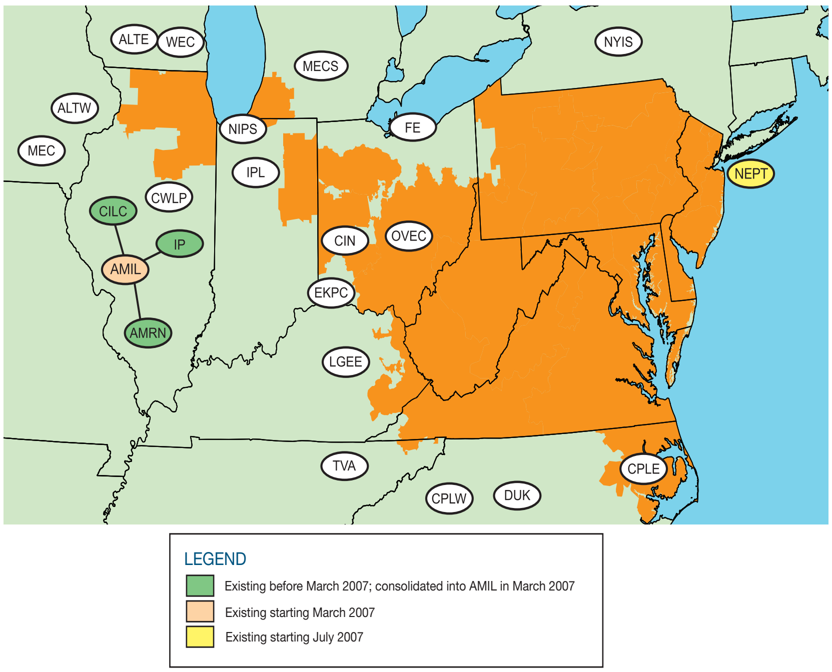
In March 2007, the Ameren (AMRN), Central Illinois Light Company (CILC) and Illinois Power Company (IP) control areas merged. As a result, PJM modified its interfaces. The PJM/AMRN, PJM/CILC and PJM/IP interfaces were retired and a new PJM/Ameren – Illinois (AMIL) Interface was created. In July 2007, the Neptune direct current (DC) transmission line was placed into commercial service. This addition created the new PJM/NEPT Interface. Table 4-8 presents the interfaces used during 2007.

Table 4-8 Active interfaces: Calendar year 2007

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

The approximate geographic location of these interfaces can be seen in Figure 4-4.

Figure 4-4 PJM's footprint and its external interfaces



Interchange Transaction Topics

There are six topics associated with interchange transactions that require more detailed discussion: interface pricing results with the Midwest ISO and NYISO; the frequency of TLRs; PJM's continued operations under agreements with bordering areas; new interface pricing agreements with individual companies; the Con Edison – PSE&G wheeling contract and the addition of the Neptune transmission line.

PJM Interface Prices with Organized Markets

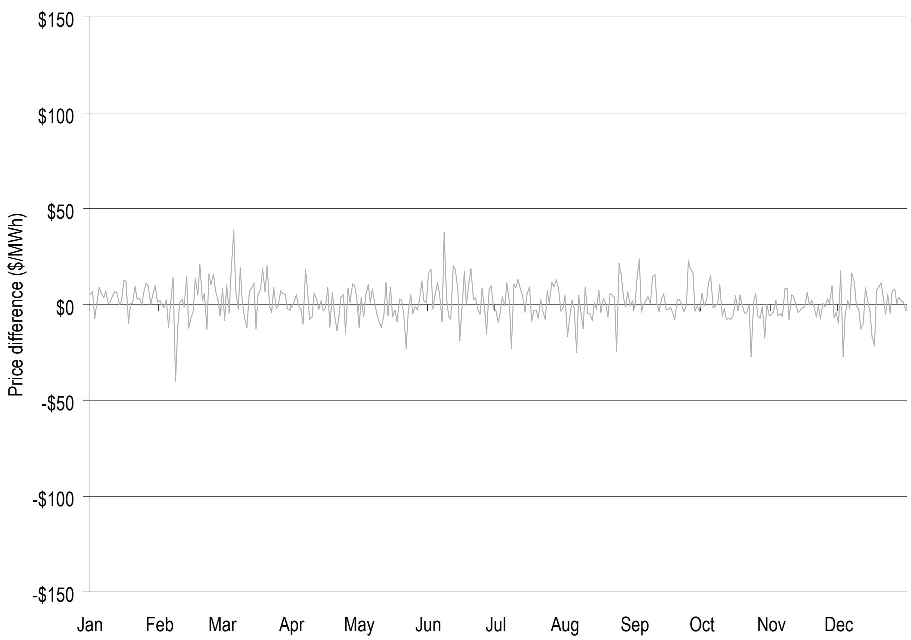
During 2007, prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces.

PJM and Midwest ISO Interface Prices

On April 1, 2005, with the introduction of price-based markets, the Midwest ISO created a new interface pricing point with PJM. Both the PJM/MISO and the MISO/PJM pricing points represent the value of power at the relevant border, as determined by each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from Midwest ISO would receive the PJM/MISO price upon entering PJM, while a transaction into Midwest ISO from PJM would receive the MISO/PJM price when entering Midwest ISO. PJM and Midwest ISO 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[14] within Midwest ISO to calculate the PJM/MISO Interface price while Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface price.[15]

The 2007 hourly average interface prices for PJM/MISO and MISO/PJM were $45.46 and $46.72, respectively. The simple average difference between the MISO/PJM Interface price and the PJM/MISO Interface price was $1.26 in 2007, 3 percent of the average PJM/MISO price. (See Figure 4-5.) The MISO/PJM Interface price was slightly higher on average than the PJM/MISO price in 2007.

Figure 4-5 Daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2007



The simple average interface price difference does not reflect the underlying hourly variability in prices. 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.

During 2007, the difference between the PJM/MISO Interface price and the MISO/PJM Interface price fluctuated between positive and negative about nine times per day. The standard deviation of the hourly price was $27.41 for the PJM/MISO price and $31.00 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $25.00. The average of the absolute value of the hourly price difference was $15.26. Absolute values reflect price differences regardless of whether they are positive or negative.

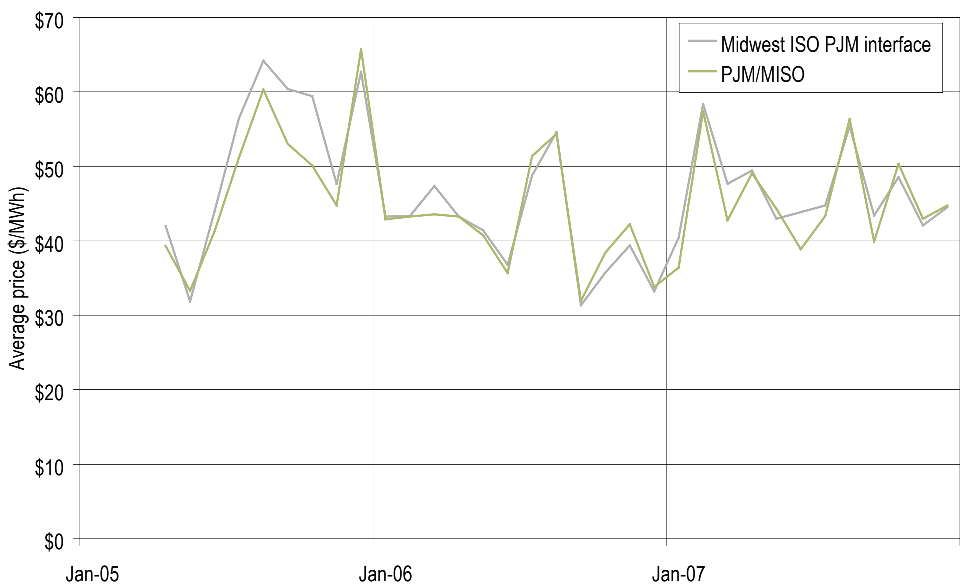
14 See PJM. "LMP Aggregate Definitions" (December 12, 2007) (Accessed January 29, 2008) <http://www.pjm.com/markets/energy-market/downloads/20071211-aggregate-definitions.xls> (1,334 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

15 Based on information obtained from the Midwest ISO Extranet (February 19, 2008) <http://extranet.midwestiso.org>.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative.

In addition, there is a significant correlation between monthly average hourly PJM and Midwest ISO interface prices during the 2007 period. Figure 4-6 shows this correlation between hourly PJM and Midwest ISO interface prices.

Figure 4-6 Monthly hourly average Midwest ISO PJM Interface price and the PJM/MISO price: April 2005 to 2007



The difference in PJM and MISO interface prices can also be measured by comparing the LMP for pairs of generating units that are located close together but on opposite sides of the border between PJM and the Midwest ISO and by comparing the LMP for jointly owned units that participate in both markets. The MMU compared two pairs of units and two jointly owned units. The LMP differences were compared over three time periods: calendar year 2006, January through May 2007 (i.e., the pre-marginal loss implementation period) and June through December 2007 (i.e., the post-marginal loss implementation period).

Table 4-9 shows that in 2006 all of the unit pairs and jointly owned units had LMP differences larger than the difference at the PJM/MISO Interface. After the implementation of marginal losses in PJM, the units all showed decreases in their LMP differences while also moving closer to the difference observed at the interface. While the sample is not adequate to permit general conclusions, the data from these units indicate that actual price differences at the border between PJM and the Midwest ISO have varied from the interface pricing differences.

Table 4-9 Average LMP difference (PJM minus Midwest ISO): January 1, 2006, through December 31, 2007

	2006	2007 (Pre-Marginal Losses)	2007 (Post-Marginal Losses)
Kincaid (PJM) & Coffeen (MISO)	$5.87	$4.31	$5.76
Beaver Valley (PJM) & Mansfield (MISO)	$2.28	($2.64)	$0.55
Miami Fort (PJM) & (MISO)	$1.95	($1.30)	($0.95)
Stuart (PJM) & (MISO)	$2.09	($0.81)	($0.64)
PJM/MISO Interface	($0.23)	($1.83)	($0.85)

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and NYISO, if identical rules governed external transactions in PJM and 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-ISO power flows, and those price differentials.[16]

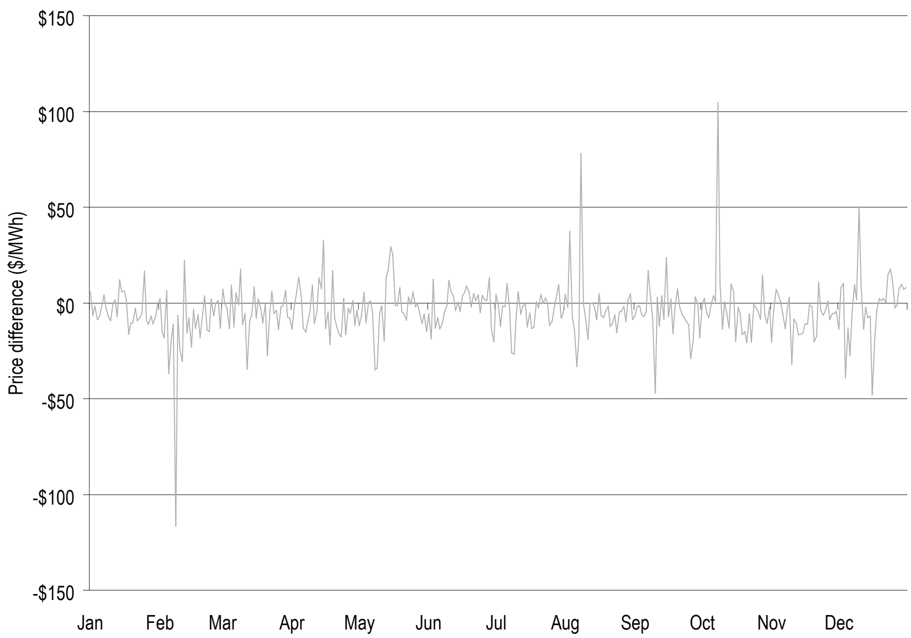
PJM's price for transactions with NYISO, termed the NYIS pricing point by PJM, represents the value of power at the PJM-NYISO border, as determined by the PJM market. PJM defines its NYIS pricing point using two buses.[17] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO-PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2007 hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $61.92 and $57.85, respectively. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price increased from -$2.47 per MWh in 2006 to -$4.07 per MWh in 2007, and the variability of the difference also increased. (See Figure 4-7.) PJM's net export volume to New York for 2007 was 76 percent lower than the six-year, 2001 to 2006, average. This is consistent with the fact that the difference between the PJM/NYIS price and the NYISO/PJM price increased.

16 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

17 See PJM. "LMP Aggregate Definitions" (December 12, 2007) (Accessed January 29, 2008) <http://www.pjm.com/markets/energy-market/downloads/20071211-aggregate-definitions.xls> (1,334 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

Figure 4-7 Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2007



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

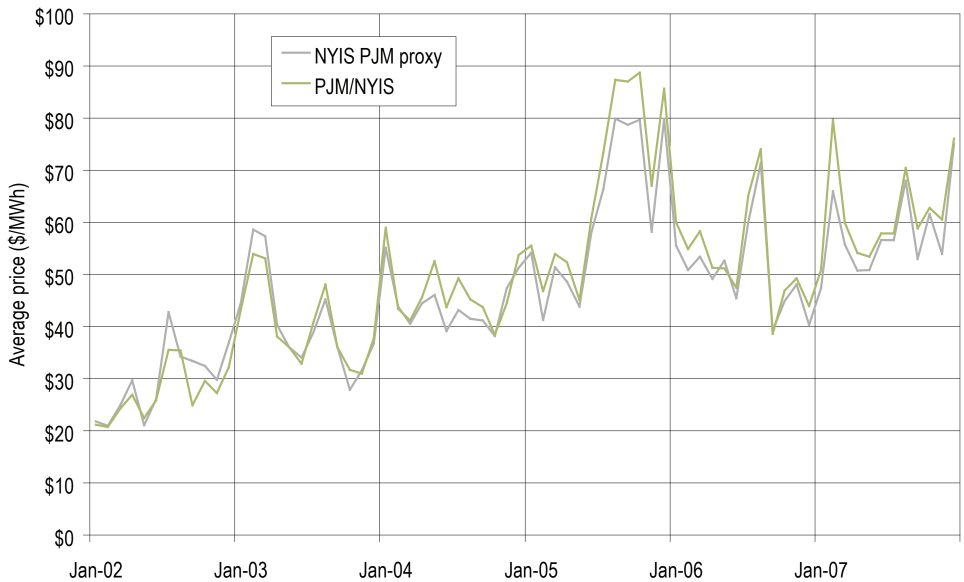
The difference between the PJM/NYIS Interface price and the NYISO/PJM price continued to fluctuate between positive and negative about eight times per day during 2007 as it has since 2003. The standard deviation of hourly price was $38.30 in 2007 for the PJM/NYIS price and $44.51 in 2007 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $43.60 in 2007. The average of the absolute value of the hourly price difference was $21.86 in 2007. Absolute values reflect price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface price differences is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.[18]

18 As previously noted, institutional difference between PJM and NYISO markets partially explains observed differences in border prices. For a description of those differences, see the *2005 State of the Market Report*, Appendix D, "Interchange Transactions" (March 8, 2006), pp. 195-198.

There has been a significant correlation between monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2007. Figure 4-8 shows this correlation between hourly PJM and NYISO interface prices.

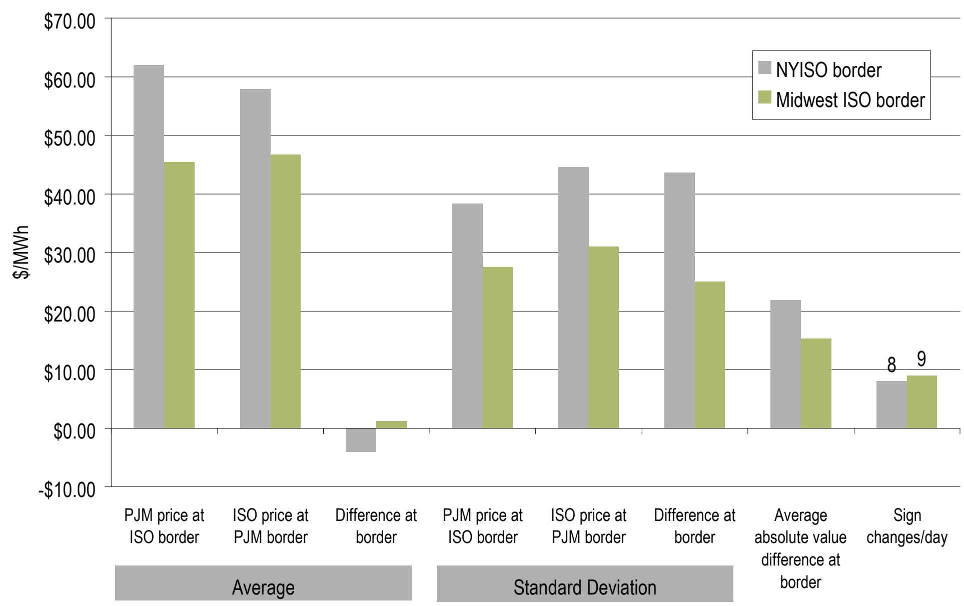
Figure 4-8 Monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2007



Summary of Interface Prices between PJM and Organized Markets

The key features of PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-9, including average prices and measures of variability.

Figure 4-9 PJM, NYISO and Midwest ISO border price averages: Calendar year 2007



PJM TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are generally called to control flows related to external control areas as redispatch within an LMP market can generally resolve overloads on internal transmission facilities. PJM called fewer TLRs in 2007 than in 2006. Total PJM TLRs declined by 41 percent, from 136 during 2006 to 80 in 2007. (See Figure 4-10.) In addition, the number of different flowgates for which PJM declared TLRs decreased from 41 different flowgates during 2006 to 38 different flowgates in 2007. (See Figure 4-11.) Of the 80 TLRs called by PJM in 2007, three facilities comprised 33 percent of the total. The three facilities were:

- Roseland – Cedar Grove F 230 kV Line for Loss of Roseland – Cedar Grove B 230 kV Line. These parallel path lines are located in northern New Jersey. Power transfers to New York and loop flows are the main reasons for TLRs on this line (nine TLRs in 2007; 29 TLRs in 2006);

- Kammer #200 765 to 500 kV Transformer for Loss of Belmont – Harrison 500 kV Line. This is a 765 to 500 kV transformer located near the border of Ohio and West Virginia. The Belmont – Harrison 500 kV line runs in northern West Virginia near the southwest corner of Pennsylvania. Economic dispatch of lower cost units in the west can cause high flows at Kammer. This constraint is not easily controllable with redispatch because of lack of generation with the necessary impact (nine TLRs in 2007; 16 TLRs in 2006); and

- **Person – Halifax 230 kV Line for Loss of Wake – Carson 500 kV Line.** These lines are located in southern Virginia and North Carolina. Power flows to/from PJM's southern neighbors, loop flows and heavy power flows in either the north-to-south or south-to-north direction at PJM's southeastern border are the main reasons for TLRs on this line (eight TLRs in 2007; no TLRs in 2006).

Midwest ISO called slightly more TLRs in 2007 than in 2006. Total Midwest ISO TLRs increased by less than 3 percent, from 796 during 2006 to 819 in 2007. (See Figure 4-10.)

Figure 4-10 PJM and Midwest ISO TLR procedures: Calendar years 2006 and 2007

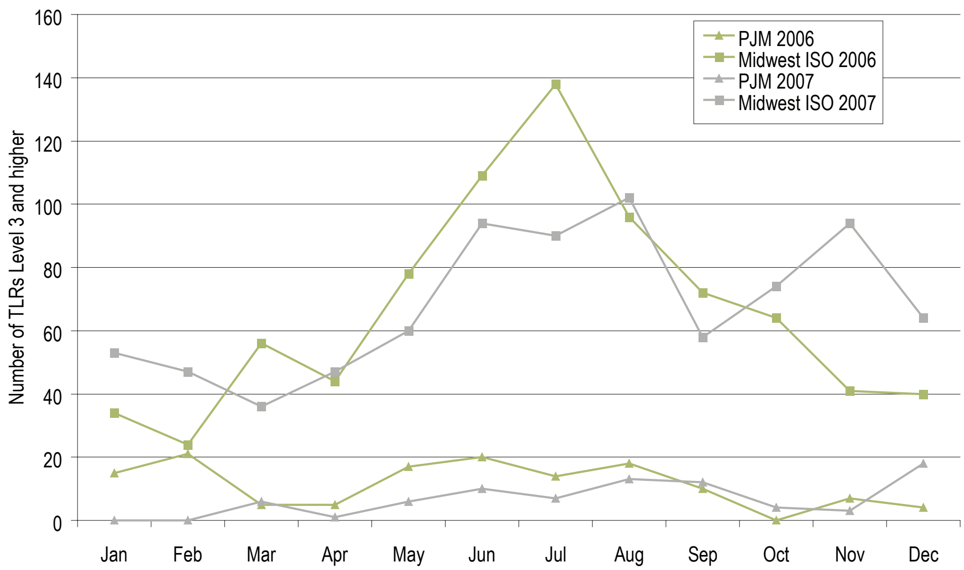


Figure 4-11 Number of different PJM flowgates that experienced TLRs: Calendar years 2006 to 2007

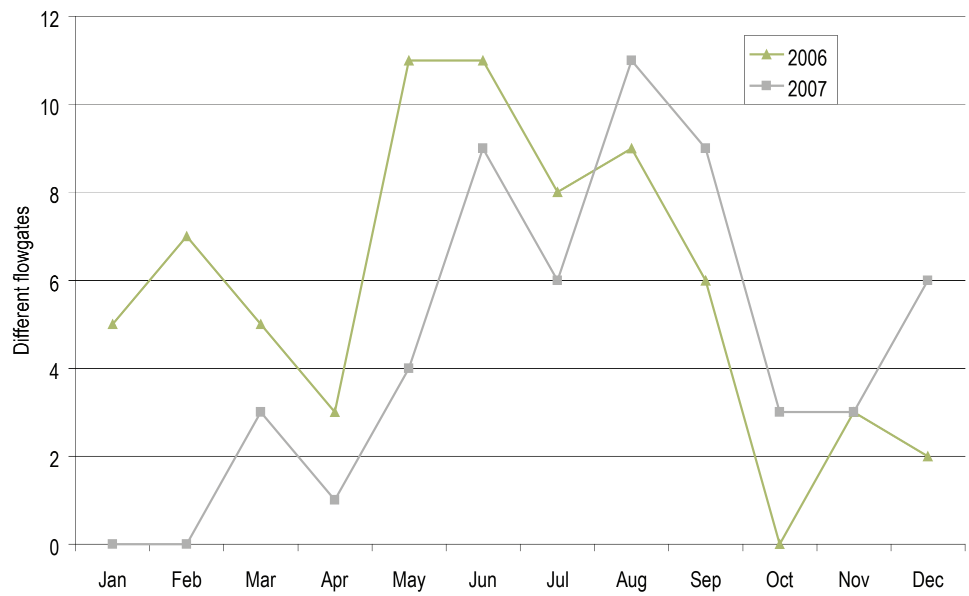
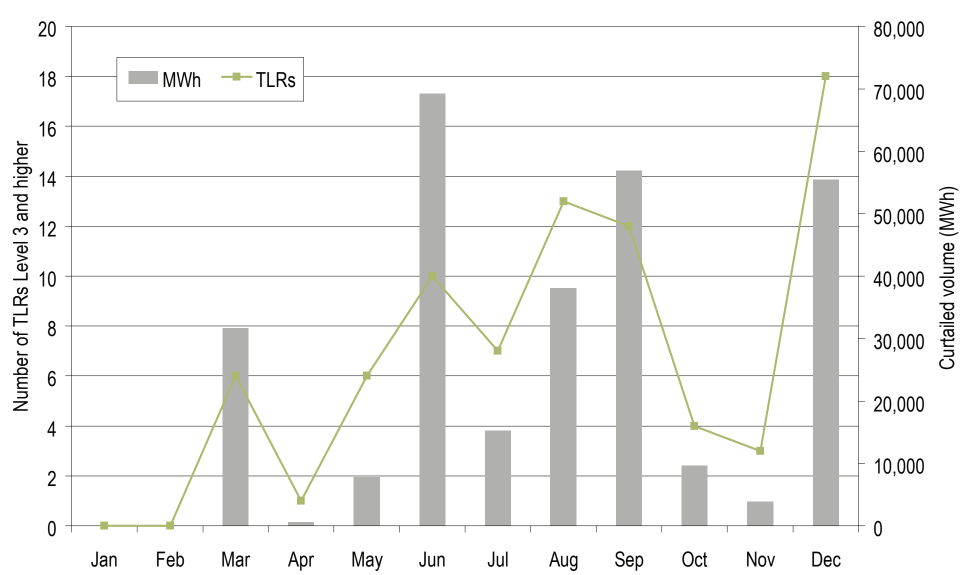


Figure 4-12 Number of PJM TLRs and curtailed volume: Calendar year 2007



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 new reliability agreement with NYISO, an implemented operating agreement with Midwest ISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc. that is not yet fully implemented and a reliability coordination agreement with VACAR South.

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

On May 22, 2007, the JOA between PJM and NYISO became effective. This agreement was developed to improve reliability and includes obligations concerning: maintaining interconnected operations, voltage control and reactive power; coordinating scheduled outages and transmission planning; and providing emergency assistance. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. This agreement references and confirms earlier PJM/NYISO agreements, protocols and procedures. These remain in effect. This agreement does not include provisions for market-based congestion management or other market-to-market activity. PJM and NYISO should develop market-based congestion management protocols as soon as practicable.

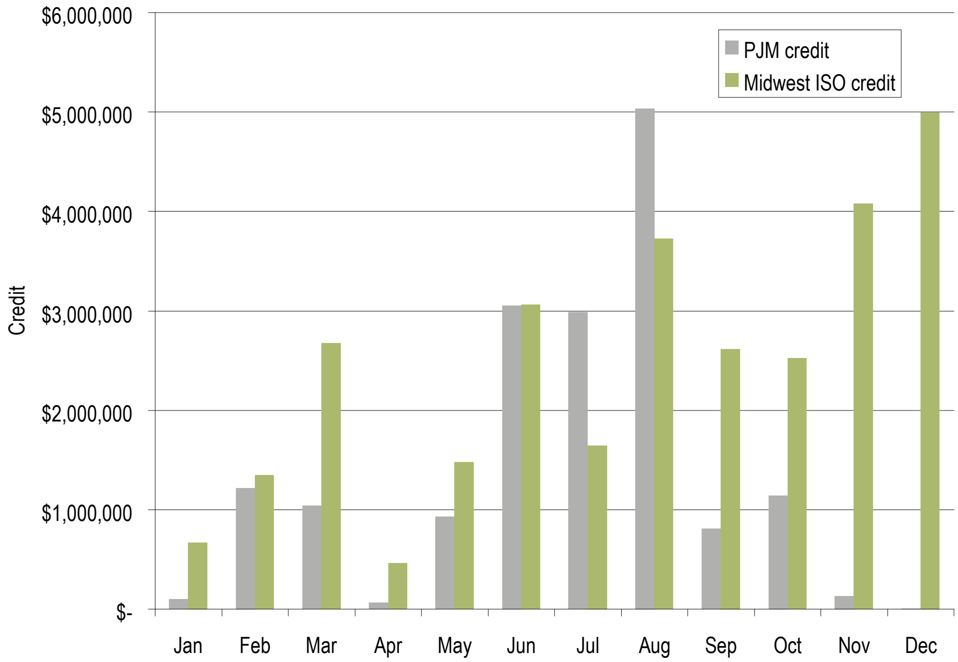
PJM and Midwest ISO Joint Operating Agreement (JOA)

On April 1, 2005, the Midwest ISO market became operational. That triggered the second, market-to-market phase, of the JOA. This second phase remained in effect through 2007.

Under the market-to-market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculates locational marginal price (LMP) for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM pricing point.

In 2007, the market-to-market operations resulted both in Midwest ISO and PJM redispatching units to control congestion in the other's area and in the exchange of payments for this redispatch. Figure 4-13 presents the monthly credits each organization received from redispatching for the other. The largest payments from PJM to Midwest ISO during the year were the result of redispatch by Midwest ISO to relieve congestion on the Eau Clair — Arpin 345 kV line. Total PJM payments to Midwest ISO were $26.1 million, a 74 percent increase from the 2006 level. The largest payments from Midwest ISO to PJM during the year were the result of redispatch by PJM to relieve congestion on the Darwin — Eugene 345 kV line for loss of the Jefferson — Rockport 765 kV line. Total Midwest ISO payments to PJM were $13.4 million, a 24.3 percent decrease from the 2006 level.

Figure 4-13 Credits for coordinated congestion management: Calendar year 2007



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement

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 the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2007. 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.

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. The agreement remained in effect through 2007. Since Progress Energy Carolinas is not a market system, the coordination between PEC and PJM is similar to that between the Midwest ISO and PJM during the first phase of their JOA. The details that had been expected to be completed during the first half of 2006 remained under development during 2007. A phased approach is being discussed.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems.

Interface Pricing Agreements with Individual Companies

PJM entered into locational interface pricing agreements with three companies in 2007 that extend the concept of the dynamic scheduling of individual units to entire control areas. These agreements were posted by PJM on October 10, 2007, after a request by the MMU. Each of these agreements established a locational price for power sales between PJM and the individual company that applies under specified conditions and that differs from the generally applicable interface price. The purpose was to make sales and purchases at a price reflective of power flows between PJM and each control area individually. The agreements set out the protocols necessary to assure that the power flows sink (or source) only from each company's control area. The protocols include rules that govern when the identified LMP is available. When the company desires to sell into PJM, the rules require the company not to have simultaneous imports from other areas. Similarly, when a company wants to purchase from PJM, it cannot be simultaneously exporting to other areas. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[19] Progress Energy Carolinas, February 13, 2007;[20] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[21]

A potential issue with these agreements is the inability of other participants to receive comparable prices for comparable power flows. For example, if a participant is purchasing from one of the companies and then selling that power to PJM, that participant would receive the SOUTHIMP LMP while, at the same time, the company may be receiving its specific LMP if it is following the protocol. If the protocol was being followed, the source of power in both cases would be the same units.

PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

For the periods of time that each agreement was in effect, Table 4-10 shows the LMP calculated per the agreement and, for comparison, the SOUTHIMP and SOUTHEXP LMPs. The difference between the LMP under the agreements and PJM's SOUTHIMP LMP ranged from $2.32 with Duke to $5.12 with PEC while the difference between the LMP under the agreements and PJM's SOUTHEXP LMP ranged from $2.80 with NCMPA to $5.52 with PEC.

19 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/duke-pricing-agreement.pdf> (171 KB).

20 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/pec-pricing-agreement.pdf> (210 KB).

21 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/electricities-pricing-agreement.pdf> (279 KB).

Table 4-10 Average hourly LMP comparison for Duke, PEC and NCMPA: For the time period in 2007 when the applicable agreement was in effect

	LMP	SOUTHIMP	SOUTHEXP	LMP - SOUTHIMP	LMP - SOUTHEXP
Duke	$51.63	$49.31	$48.70	$2.32	$2.93
PEC	$55.03	$49.91	$49.51	$5.12	$5.52
NCMPA	$51.77	$49.14	$48.97	$2.63	$2.80

Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and NYISO.[22] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[23]

PJM continued to operate under the terms of the protocol during 2007 while continuing to pursue work on the 19 items identified in the work plan to improve protocol performance. In August the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[24]

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

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2007, PSE&G's FTR revenues were equal to its congestion charges. (Revenues were $0.4 million less than charges in 2006.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2007, Con Edison's congestion credits equaled its day-ahead congestion charges. However, Con Edison had substantial negative day-ahead congestion charges with the result that Con Edison's total credits exceeded its congestion charges by approximately $1.7 million. (Credits had been $0.7 million less than charges in 2006.) (See Table 4-11.)

22 111 FERC ¶ 61,228 (2005).

23 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).

24 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 2007).

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were about $1.7 million in 2007. The parties should address this issue.

Table 4-11 Con Edison and PSE&G wheeling settlement data: Calendar year 2007

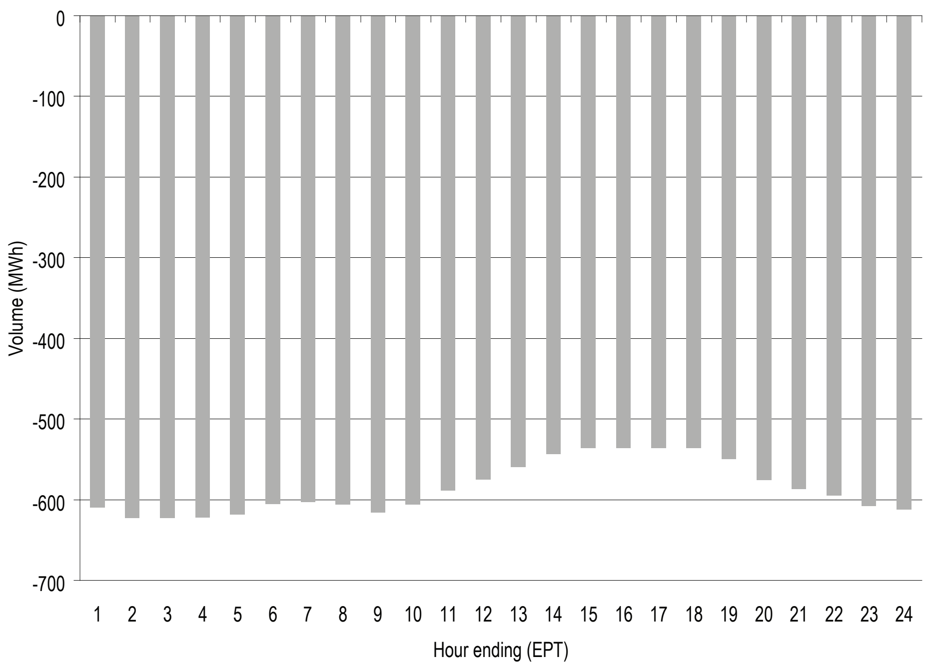
		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total	Congestion charge	$1,245,646.52	($463,565.37)	$782,081.15	$2,040,446.98	$0.00	$2,040,446.98
	Congestion credit			$2,320,742.14			$2,040,446.98
	Adj.			$119,684.99			($479.36)
	Net charge			($1,658,345.98)			$479.36

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 13 percent of the hours in 2007.

Neptune Underwater Transmission Line to Long Island, New York

On July 1, 2007, a 65-mile, DC transmission line from Sayreville, New Jersey, to Nassau County on Long Island via undersea and underground cable was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in 2007, with the exception of testing, power flows were only from PJM to New York. Power is exported directly from New Jersey to Long Island. For 2007, the total real-time scheduled net exports on the Neptune line were 2,814 GWh while the day-ahead scheduled net exports were 2,790 GWh. (See Table 4-1 through Table 4-6.) Figure 4-14 shows the hourly average flow, by hour of the day, on the Neptune line for the period July through December 2007. The average hourly flow for the period July through December was -599 MWh. For the time period July through December, the average hourly PJM/NEPT Interface price was $76.29 per MWh, while in NYISO the Long Island zone's average price was $80.64 per MWh.

Figure 4-14 Neptune hourly average flow: July to December 2007



Interchange Transaction Issues

Four issues are associated with interchange transactions that require more detailed discussion: loop flows, ramp reservation rules, spot import service rules and up-to congestion transactions.

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

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

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

The fact that total PJM net actual interface flows were very close to net scheduled interface flows on average for 2007 as a whole is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-12.) 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 control areas.

During 2007, for PJM as a whole, net scheduled and actual interchange differed by less than 0.5 percent.[25] (See Table 4-12.) Actual system exports were 14,766 GWh, 63 GWh less than the scheduled total exports of 14,829 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 12,414 GWh exceeding scheduled exports of 1,610 GWh by 10,804 GWh or 671 percent, for an average of 1,233 MW during each hour of the year. At the PJM/TVA Interface, net actual flow was in the import direction at 924 GWh while scheduled flow was in the export direction at 4,938 GWh. The net difference was 5,862 GWh or -119 percent. At the PJM/CPLE Interface, net actual imports exceeded scheduled imports by 6,557 GWh or 858 percent. At the PJM/DUK Interface, net scheduled imports exceeded actual exports by 5,828 GWh or -203 percent. At the PJM/NYIS Interface, net actual exports exceeded scheduled exports by 5,279 GWh or 239 percent.

25 Net scheduled volumes include dynamic schedules. These are scheduled flows from generating units that are physically located in one control area but deliver power to another control area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. Since the dynamic schedules are included in the actual flows, they must be included in the scheduled flows in order to accurately compare actual to scheduled flows. Dynamic flows are included in the "Net Scheduled" column of Table 4-12. As a result, the total "Net Scheduled" in Table 4-12 does not match the total net interchange in Table 4-1. The difference of 569 GWh is the net dynamic schedule.

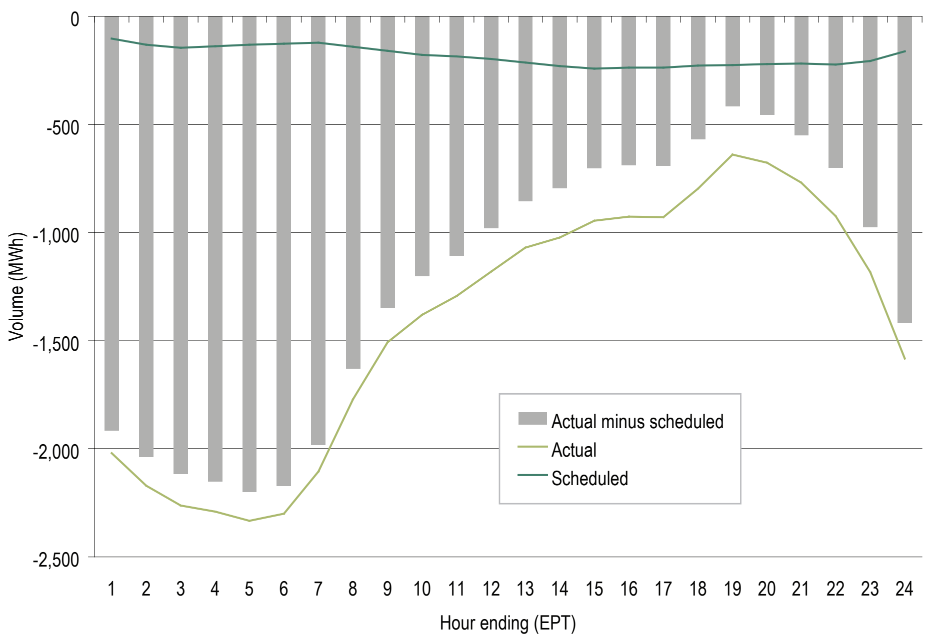
Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2007

	Actual	Net Scheduled	Difference (GWh)	Difference (Percent of Net Scheduled)
ALTE	(6,827)	(1,856)	(4,971)	268%
ALTW	(3,015)	(1,843)	(1,172)	64%
AMIL	4,791	(511)	5,302	(1038%)
AMRN	26	(134)	160	(119%)
CILC	181	(31)	212	(684%)
CIN	431	(2,607)	3,038	(117%)
CPLE	7,321	764	6,557	858%
CPLW	(1,881)	(704)	(1,177)	167%
CWLP	(617)	(155)	(462)	298%
DUK	(2,961)	2,867	(5,828)	(203%)
EKPC	183	(625)	808	(129%)
FE	2,356	(1,786)	4,142	(232%)
IP	616	11	605	5500%
IPL	3,803	(937)	4,740	(506%)
LGEE	1,087	344	743	216%
MEC	(4,726)	(3,228)	(1,498)	46%
MECS	(12,414)	(1,610)	(10,804)	671%
NEPT	(2,739)	(2,740)	1	(0%)
NIPS	(2,609)	(584)	(2,025)	347%
NYIS	(7,486)	(2,207)	(5,279)	239%
OVEC	9,212	8,823	389	4%
TVA	924	(4,938)	5,862	(119%)
WEC	(422)	(1,142)	720	(63%)
Total	(14,766)	(14,829)	63	(0.4%)

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

As in 2006, the PJM/MECS Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight hours (hour ending 2400 through hour ending 0700). (See Figure 4-15.) Generally, the PJM/MECS Interface is an exporting interface meaning that power flows from PJM to MECS. The actual exports exceeded the scheduled exports at that interface by an average of 2,000 MW per hour for those overnight hours. The daytime hours (hour ending 0800 through hour ending 2300) difference between actual and scheduled exports averaged 855 MW.

Figure 4-15 PJM/MECS Interface average actual minus scheduled volume: Calendar year 2007



While the PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows, the magnitude of the mismatches declined after consolidation. The PJM/MECS differences and the PJM/TVA differences were in opposite directions. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports. (See Figure 4-16 and Figure 4-17.) The consolidation of the former southeast and southwest pricing points in October 2006 has had an ongoing impact at the PJM/TVA Interface.[26] Figure 4-16 shows the average hourly actual, scheduled flows and the difference between them for the preconsolidation time period January 1, 2006, through September 30, 2006. Actual exports were less than scheduled exports by 1,328 MWh every hour, on average during nine-month preconsolidation period. During calendar year 2007, this difference decreased by 50 percent to 670 MW (on average) each hour. (See Figure 4-17.)

26 For a more detailed discussion of this issue, see the *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Loop Flows at PJM's Southern Interfaces."

Figure 4-16 PJM/TVA average flows: January 1, to September 30, 2006, preconsolidation

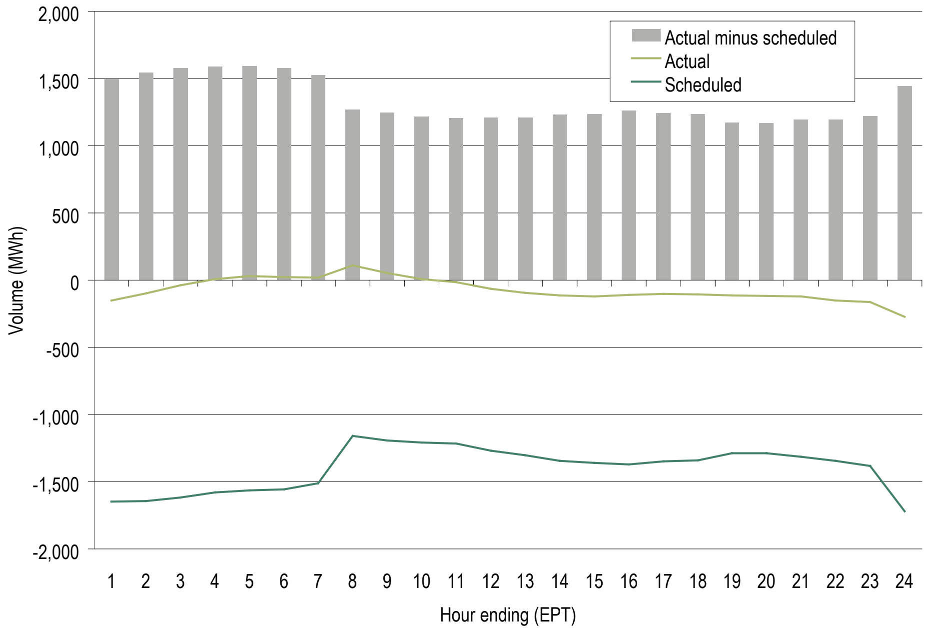
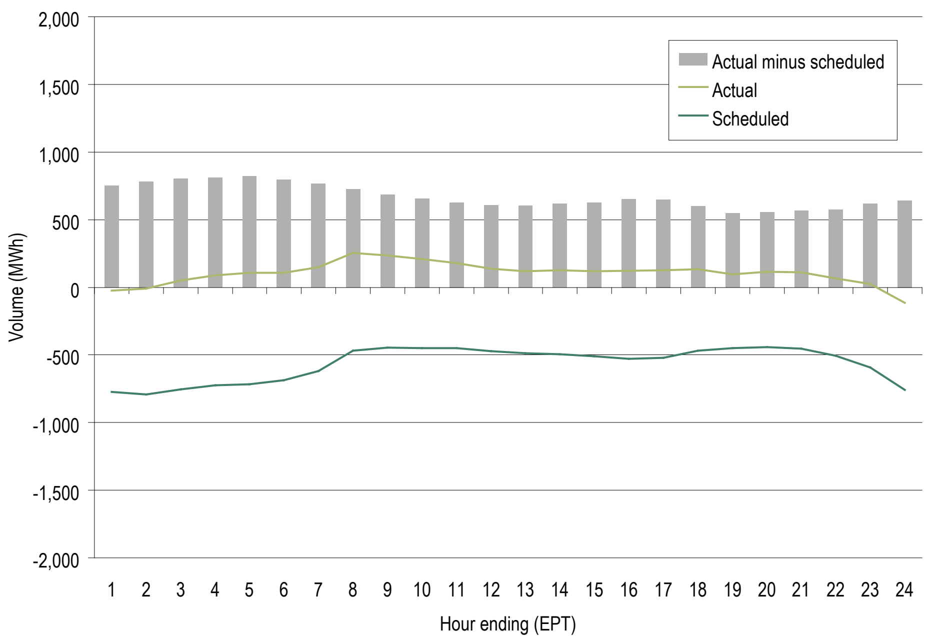


Figure 4-17 PJM/TVA average flows: Calendar year 2007



Loop Flows at PJM's Southern Interfaces

Figure 4-18 and Figure 4-19 illustrate 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. One reason for this improvement was the consolidation of the former southeast and southwest pricing points into the SOUTHEXP and SOUTHIMP pricing points. In order to reflect the actual flow of transactions associated with the southeast and southwest interface pricing points, on October 1, 2006, PJM began to price all transactions that source in PJM and sink in one of the relevant, defined control areas, at the SOUTHEXP interface pricing point. Similarly, PJM began to price all transactions that sink in PJM and source in one of the defined control areas, at the SOUTHIMP interface pricing point. This practice enabled PJM to price imports and exports differently based on their impacts on the PJM transmission system.

Figure 4-18 Southwest actual and scheduled flows: Calendar years 2006 to 2007

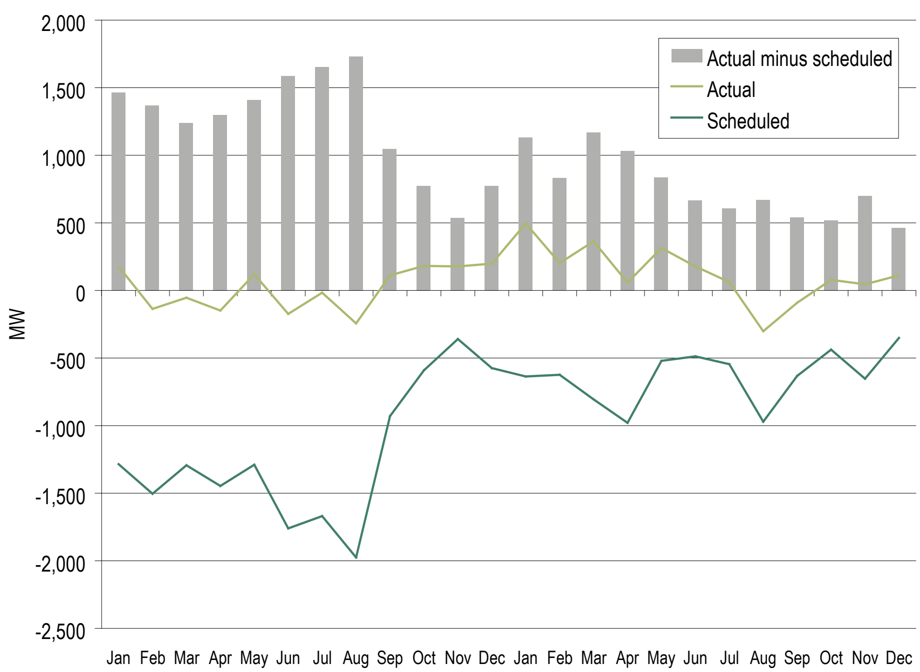
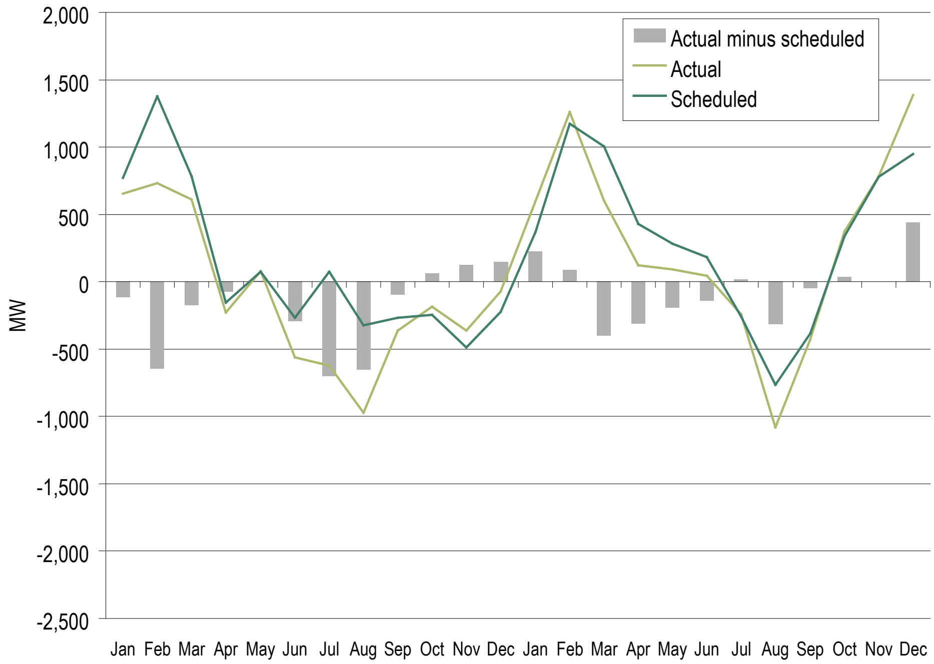


Figure 4-19 Southeast actual and scheduled flows: Calendar years 2006 to 2007



Data Required for Full Loop Flow Analysis

A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets and there are areas with less transparent markets, but these areas together comprise a market and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

PJM and Midwest ISO issued a joint loop flow report in 2007 that made three recommendations including the establishment of an energy schedule tag archive.[27] The archive would capture and retain data for the entire Eastern Interconnection including tag impact, generation-to-load impact and market flow impact data for flowgates in the IDC. The archive would be a prime source of information needed to perform after-the-fact analyses and reviews. This effort should be given a high priority.

27 See "Investigation of Loop Flows Across Combined Midwest ISO AND PJM Footprint" (May 25, 2007) (Accessed February 15, 2008) <http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf> (2,597 KB).

PJM and Midwest ISO also submitted a memorandum to a NAESB committee reiterating and elaborating the recommendation regarding data retention and suggesting a process for determining the allocation of responsibility for congestion relief.[28] The NAESB committee included in their annual plan a commitment to work with NERC on the congestion management issue.[29]

Ramp Reservation Issues

PJM limits the amount of change in net interchange within 15-minute intervals in order to ensure compliance with NERC performance standards. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. The change in net interchange is referred to as ramp. Any market participant wishing to initiate (or to change) a transaction must obtain a ramp reservation. PJM issues reservations, on a first-come, first-served basis, up to the ramp limit.

While ramp limits may be modified by PJM depending on system conditions, the limit is generally ± 1,000 MW within a 15-minute interval. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15-minute period would not exceed 1,000 MW in either direction.

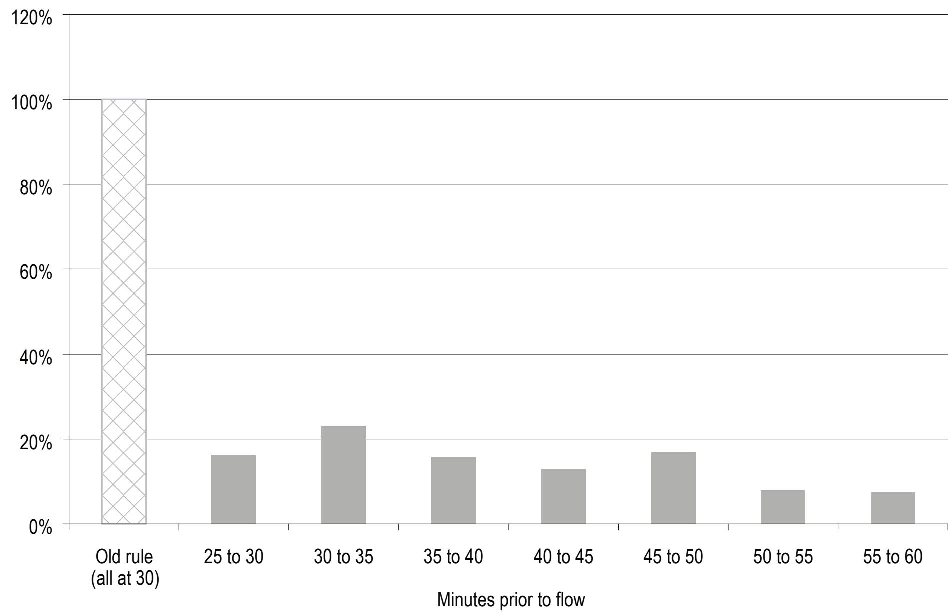
Figure 4-20 shows the ongoing results of the ramp rule change that became effective on August 7, 2006.[30] Under the new rule, unused ramp reservations expire at the conclusion of a defined time interval that starts when a reservation is approved. The goal was to prevent large swings in ramp at 30 minutes prior to flow and to spread automatic ramp reservation expirations over a longer period to permit other participants to use them. The actual distribution pattern of expirations since the rule change is compared to when reservations would have expired under the old rule in Figure 4-20. Under the old rule, all unused reservations had expired at the same time, 30 minutes prior to flow or just 10 minutes prior to the deadline for scheduling a transaction (20 minutes prior to flow).

28 See "Annual Plan Item: Determine Future Path for TLR in Concert with NERC" (October 24, 2007) (Accessed January 29, 2008) <http://www.naesb.org/pdf3/weq_aplan102907w1.pdf> (26 KB).

29 See "North American Energy Standards Board, 2008 WEQ Annual Plan Adopted by the Board of Directors on December 13, 2007" (December 13, 2007) (Accessed January 29, 2008) <http://www.naesb.org/pdf3/weq_2008_annual_plan.doc> (281 KB).

30 The MMU developed, PJM proposed, and the membership agreed, to changes in the ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. (See the *2006 State of the Market Report*.)

Figure 4-20 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)): October 2006 to December 2007



While the rule change has had a positive effect, the MMU continues to monitor the reservation and use of ramp. In the *2006 State of the Market Report,* the MMU indicated that the artificial creation of ramp room was another issue that needed to be addressed. For example, a market participant who wishes to initiate an import transaction when there is no available import ramp, requests a ramp reservation in the exporting direction. When accepted, this reservation creates apparent import ramp which permits the participant to obtain an import reservation. Ultimately, the import transaction would flow and the export reservation would not be used to export energy, expiring after its time limit. In 2007, PJM modified its business rules to permit PJM to cut such a participant's transaction(s) prior to using the normal, last-in-first-out method of ordering cuts, if PJM determines that a participant has scheduled an offsetting reservation that is unused.[31] Although the rule has been added, the mechanism for automatically performing this task has not yet been developed. System operators may apply this rule manually.

During 2007 a ramp-related issue emerged associated with transactions into and out of New York. Large swings in PJM's New York ramp availability have been regularly observed at the New York interface. The NYISO rules for its hourly market require transaction bids to be placed at least 75 minutes prior to flow. For each potential import or export transaction that is bid into the NYISO market, a PJM ramp reservation is required. During the time between the bid submission to NYISO and the time the NYISO market results are posted, all ramp reservations associated with all the bids are in PJM's system, often leaving no ramp available, awaiting the outcome of the NYISO market clearing. When the NYISO market results are posted, the ramp reservations for any unsuccessful bids are returned to the PJM system. This results in the large

31 PJM. "Manual 41: Managing Interchange," Revision 01 (September 5, 2007), p. 9.

swing in ramp observed at about 20 minutes after the hour. The difference between transaction rules in NYISO and PJM create incentives to obtain ramp that will not be needed. There is also the potential for gaming in that out-of-market bids and offers for import or export transactions to the NYISO could be used to limit ramp availability to competitors. Both areas should be addressed.

Spot Import Service

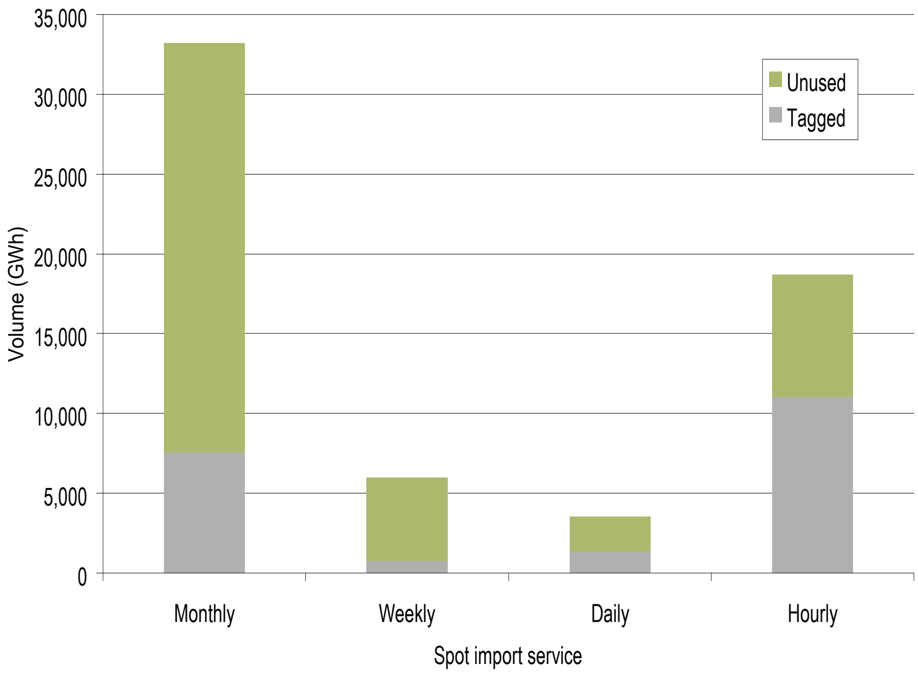
A new interchange transaction issue emerged in 2007. Some participants obtain and hold large amounts of spot import service reservations without using the service. Prior to April 2007, PJM did not limit spot import service, preferring to let market prices ration the use of the service which is not physically limited. PJM interpreted its JOA with the Midwest ISO to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates.[32] The rule caused the availability of spot import service to be limited by ATC on the transmission path.

The four spot import reservation types are: monthly, weekly, daily and hourly. Figure 4-21 shows the utilization of the four spot import service products for May through December 2007, the period when PJM's new rule regarding the reservation of spot import service was in place. Most of the spot import reservations were for monthly service and most monthly reservations were not used. Only 23 percent of the reserved volume was used on NERC tags. The hourly service was the most utilized with 59 percent of the reserved volume used on NERC tags.

Following implementation of the rule, participants have complained that they are not able to obtain this service. There are a number of options for addressing the issue including making reservations available only hourly or daily or requiring reservation holders to release reservations if they will not be used within a defined lead time.

32 See "Modifications to the Practices for Non-Firm and Spot Market Import Service" (April 20, 2007) (Accessed February 7, 2008) <http://www.pjm.com/etools/oasis/downloads/wpc-white-paper.pdf > (97 KB).

Figure 4-21 Spot import service utilization: May through December 2007



Up-to Congestion Transactions

Up-to congestion transactions are Day-Ahead Market transactions for which a participant can specify the maximum level of positive congestion cost that they are willing to pay, up to a cap of $25 per MWh.[33]

There is a mismatch between up-to congestion transactions in the Day-Ahead Energy Market and the Real-Time Energy Market.[34] 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. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity.[35]

33 See "External Interchange Transaction Issue" (June 27, 2007), pp. 10-11 (Accessed February 20, 2008) <http://www.pjm.com/committees/mic/downloads/20070627-item-05-transaction-issue.pdf> (298 KB).

34 See "Up-to Congestion Transactions: Proposed Interim Changes Pending Development of a Spread Product" (December 13, 2007) (Accessed February 13, 2008) <http://www.pjm.com/committees/mic/downloads/20080130-item-03b-up-to-congestion-transactions.pdf> (34 KB).

35 See "Proposed Elimination of Up To Source Sinks" (December 13, 2007) (Accessed February 13, 2008) <http://www.pjm.com/committees/mic/downloads/20080130-item-03b-proposed-elimination-of-up-to-source-sinks.xls> (111 KB).