# 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 balancing authorities.

## *Overview*

### Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During 2008, PJM was a net exporter of energy in the Real-Time Market for all months except December. In the Real-Time Market, monthly net interchange averaged -1,010 GWh.[1] Gross monthly import volumes averaged 3,962 GWh while gross monthly exports averaged 4,972 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2008, gross imports in the Day-Ahead Energy Market were 90 percent of the Real-Time Market's gross imports (85 percent in 2007) while gross exports in the Day-Ahead Market were 106 percent of the Real-Time Market's gross exports (103 percent in 2007) and net interchange in the Day-Ahead Energy Market exceeded net interchange in the Real-Time Energy Market by 58 percent. In the Day-Ahead Market, monthly net interchange averaged -1,732 GWh. Gross monthly import volumes averaged 3,552 GWh while gross monthly exports averaged 5,284 GWh.

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market in 2008, there were net exports at 16 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 53 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 24 percent, PJM/Neptune (NEPT) with 18 percent, and PJM/Tennessee Valley Authority (TVA) with 11 percent of the net export volume. Four PJM interfaces had net imports, with two importing interfaces accounting for 77 percent of net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 59 percent and PJM/Michigan Electric Coordinated System (MECS) with 18 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 16 of PJM's 20 interfaces. The top three net exporting interfaces accounted for 59 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 26 percent, PJM/Northern Indiana Public Service Company (PJM/NIPS) with 18 percent and PJM/NEPTUNE (NEPT) with 15 percent. There were net imports in the Day-Ahead Market at four of PJM's 20 interfaces. The top two importing interfaces accounted for 92 percent of the total net imports, PJM/OVEC with 75 percent and PJM/Ameren – Illinois (AMIL) with 17 percent.

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

## Interactions with Bordering Areas

- **PJM Interface Pricing with Organized Markets.**

  — **PJM and Midwest ISO Interface Pricing.** During 2008, 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 2008, 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 increased by 87.5 percent, from 80 in 2007 to 150 in 2008. The increase in TLRs declared by PJM can be attributed to transmission line outages caused by storms and tornados. These outages limited the ability to utilize market signals to manage constraints.

- **Operating Agreements with Bordering Areas.**

  — **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[2] 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. While the JOA does not include provisions for market-based congestion management or other market-to-market activity, at the request of PJM, PJM and the NYISO began discussion of a market-based congestion management protocol.

  — **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., executed on December 31, 2003, continued in 2008. The market-based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[3]

  — **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[4] 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 2008.

2 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

3 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (November 1, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

4 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[5] 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 2008.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[6] 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 confidential locational interface pricing agreements with Duke Energy Carolinas, Progress Energy Carolinas and North Carolina Municipal Power Agency (NCMPA) in 2007 that provided more advantageous pricing to these companies than the applicable interface pricing rules. Each of these agreements established a locational price for purchases and sales between PJM and the individual company that applies under specified conditions. There are a number of issues with these agreements including that they were not made public until specifically requested by the Market Monitoring Unit (MMU), that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate and notified the counterparties that PJM would terminate the agreements effective January 31, 2009.

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During 2008, PJM continued to operate under the terms of the operating protocol developed in 2005.[7] Significant progress was also made on the 19 items identified in the work plan to improve protocol performance in 2008.

- **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 2008 power flows were only from PJM to New York. The average hourly flow for 2008 was -572 MW.

5 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2.98 MB).

6 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

7 111 FERC ¶ 61,228 (2005).

## Interchange Transaction Issues

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with Midwest ISO (MISO) to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[8] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The new spot import rules have incented participant actions to evade the limits and to hoard spot import capability. The MMU recommends that PJM reconsider whether the new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable.

- **Up-To Congestion.** In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[9] 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. Increasing the offer cap, and allowing negative offers, could potentially increase the cleared volume of up-to congestion transactions, and aggravate the issue.

  On February 21, 2008, the MRC approved PJM's proposed resolution to the request for implementation on March 1, 2008.[10] The proposal allowed for an increased offer cap from $25 to ± $50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to address the mismatches between the Day-Ahead and Real-Time Markets.

  The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

8 See "WPC White Paper" (April 20, 2007) (Accessed December 29, 2008) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).
9 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed February 18, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).
10 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2009) <http://www.pjm.com/Media/committees-groups/committees/mrc/20080221-minutes.pdf > (61KB).

- **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 1.7 percent in 2008, greater differences existed at individual interfaces.[11] 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 2007, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-14,014 GWh in 2008 and -10,813 GWh in 2007), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,065 GWh in 2008 and 5,906 GWh in 2007), 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 improvement 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 in late 2006 and during 2007 was sustained in 2008 although the loop flows across the southern interfaces increased in 2008 from 2007. These improvements followed the changes from the Southeast and Southwest interface pricing points to the SOUTHIMP and SOUTHEXP interface pricing points that occurred on October 1, 2006.

11 The *2007 State of the Market Report* reported the difference between scheduled and actual flows as 0.5 percent. The calculation method incorrectly accounted for some dynamic schedules. The recalculated 2007 difference is 1.6 percent.

— **Loop Flows at PJM's Northern Interfaces.** In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows. In 2008, market participants scheduled transactions on a path from the NYISO to PJM through Ontario's Independent Electricity System Operator (IESO) and Midwest ISO systems, rather than reflecting the actual power flows which were primarily directly from NYISO to PJM. The participants faced a price incentive to engage in this behavior. When export transactions were scheduled from NYISO to Ontario, participants paid the lower export price at NYISO's Ontario interface rather than the higher export price at NYISO's PJM interface. The export price differences were more than enough to cover the cost of transmission through Ontario and MISO into PJM. When the export transactions were approved in the NYISO hourly market, the NYISO committed additional generation to support the transactions. The actual flow of energy that resulted was primarily directly from NYISO to PJM across the PJM/NYISO Interface. PJM's interface pricing calculations correctly reflected the actual power flows, but NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

— **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.

The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flows data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

## Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial 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 balancing authorities for 2008, 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 53 percent of the total real-time net exports and two interfaces accounted for 77 percent of the real-time net import volume. Three interfaces accounted for 59 percent of the total day-ahead net exports and two interfaces accounted for 92 percent of the day-ahead net import volume.

As the data show, there is a substantial level of transactions between PJM and the contiguous balancing authorities. 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. 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 balancing authorities. 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. However, more needs to be done to assure that market signals 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 their appropriate share of the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities 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 balancing authorities 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 balancing authorities 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 balancing authorities. 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. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

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 to or export power from 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 continued to be a net exporter of power in 2008. (See Figure 4-1, Figure 4-2 and Figure 4-3).[12] During 2008, PJM was a net exporter of energy in the Real-Time Market for all months except December. Total net interchange of -12,124 GWh was less than net interchange of -14,274 GWh

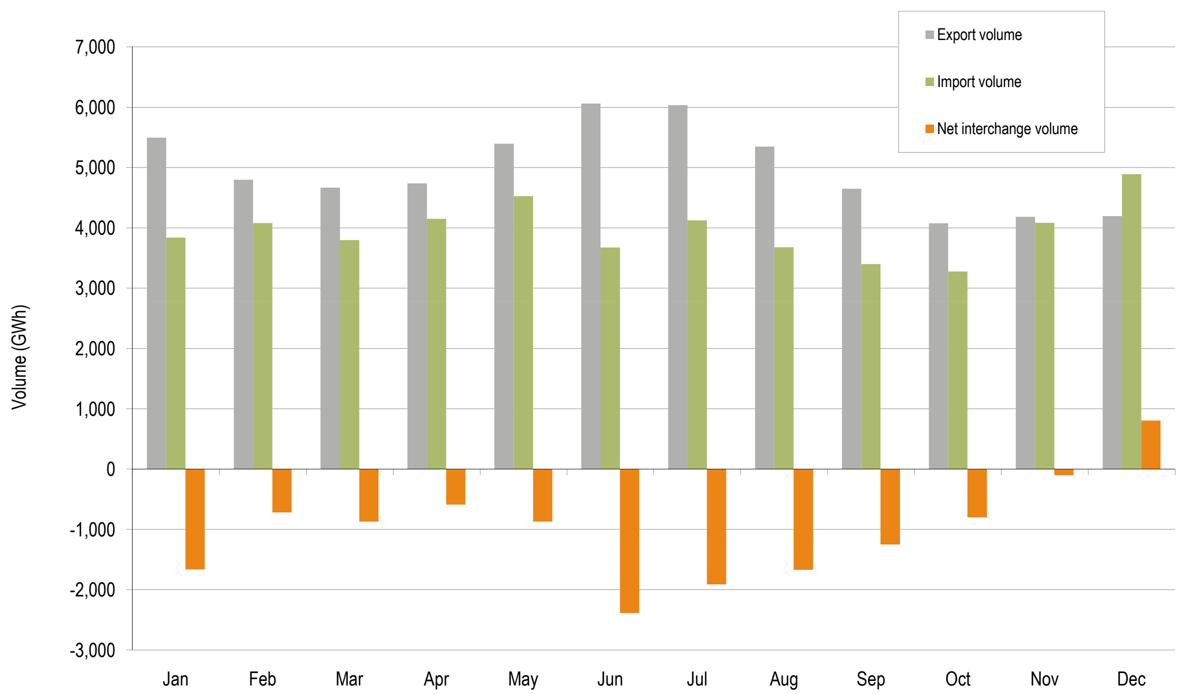
12 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

in 2007.[13] The peak month for net interchange was June in 2008, -2,388 GWh; it had been August in 2007, -3,470 GWh. Monthly gross exports averaged 4,972 GWh and monthly gross imports averaged 3,962 GWh, for an average monthly net interchange of -1,010 GWh.

In the Day-Ahead Market, PJM continued to be a net exporter of energy as well. Total net interchange was -20,783 GWh. The peak month for net interchange was June, -2,657 GWh. Monthly gross exports averaged 5,284 GWh and monthly gross imports averaged 3,552 GWh, for an average monthly net interchange of -1,732 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 2008, gross imports in the Day-Ahead Energy Market were 90 percent of the Real-Time Market's gross imports (85 percent in 2007) while gross exports in the Day-Ahead Market were 106 percent of the Real-Time Market's gross exports (103 percent in 2007) and net interchange in the Day-Ahead Energy Market exceeded the net interchange in the Real-Time Energy Market by 58 percent.

***Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2008***




13 Note: The totals referenced for 2007 do not match those stated in the *2007 State of the Market Report*. The *2007 State of the Market* Report did not include wheeling transactions. Additionally, the totals presented in the *2007 State of the Market Report* for the AMIL interface were not properly accounted for after the merger of the CILC, IP and AMRN control areas.

*Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2008*

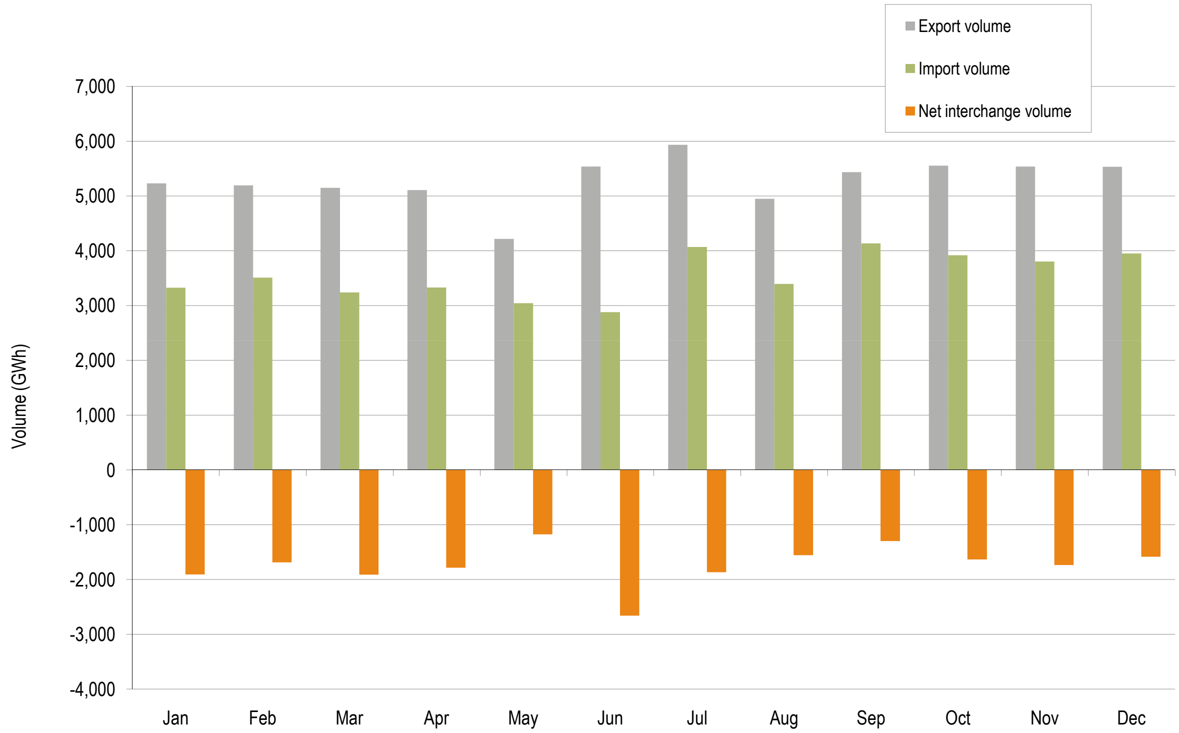
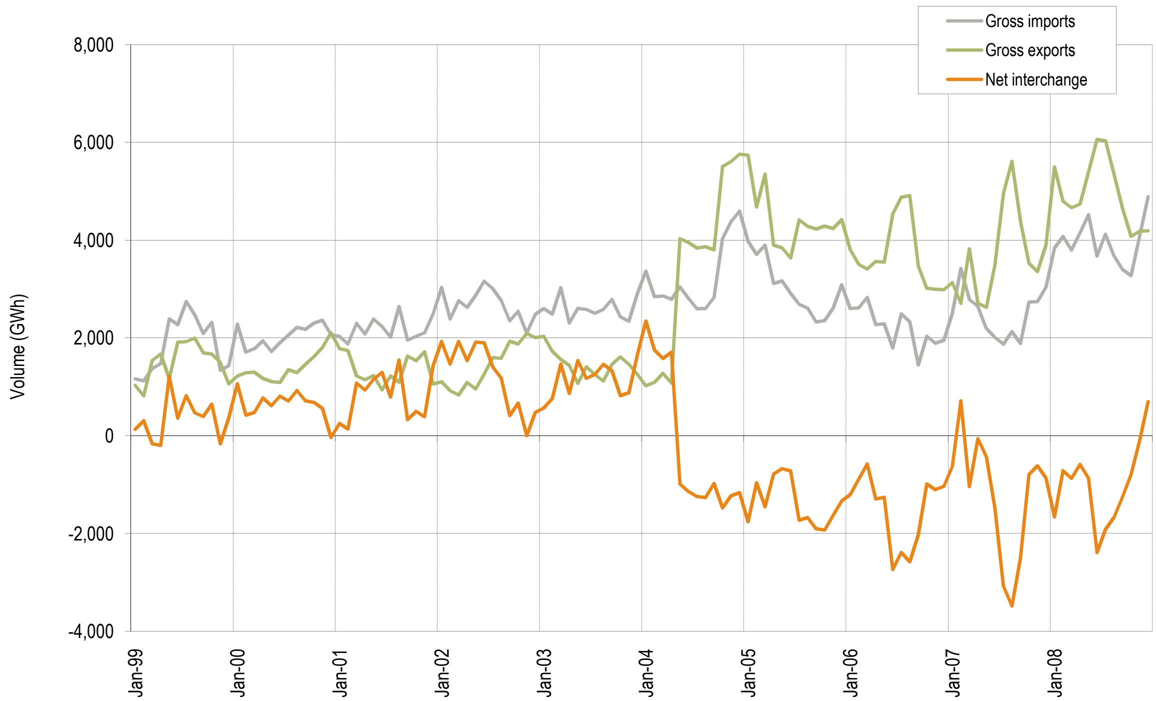



Figure 4-3 shows real-time import and export volume for PJM from 1999 through 2008. PJM became a consistent net exporter of energy in 2004, coincident with the expansion of the PJM footprint, and has continued to be a net exporter since that time. During 2008, imports continued to be lower than exports, with the exception of December. Exports peaked in June, while imports peaked in December.

*Figure 4-3 PJM scheduled import and export transaction volume history: Calendar years 1999 to 2008*




## Interface Imports and Exports

Total imports and exports are comprised of flows at each PJM interface. Net interchange in the Real-Time Market is shown by interface for 2008 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3 respectively. Net interchange in the Day-Ahead Market is shown by interface for 2008 in Table 4-4 while gross imports and exports are shown in Table 4-5 and Table 4-6 respectively.

In March of 2007, Ameren (AMRN), Central Illinois Light Company (CILC) and Illinois Power Company (IP) merged to form Ameren-Illinois. 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. The *2007 State of the Market Report* included the partial years' totals in the summaries, accounting for 23 total interfaces (20 interfaces at the end of 2007, and the three retired, partial year, interfaces (AMRN, CILC and IP). For 2008, there were no changes to interfaces with PJM.[14]

In 2008, there were net exports in the Real-Time Market at 16 of PJM's 20 interfaces. (See Table 4-7 for active interfaces during 2008.) The top three exporting interfaces accounted for 53 percent of PJM's total net exports, PJM/NYIS with 24 percent, PJM/NEPT with 18 percent and PJM/TVA with 11 percent of the net export volume.

14 See the *2007 State of the Market Report* (March 11, 2008), p. 200, for the active interfaces for calendar year 2007.

In 2008, there were net exports in the Day-Ahead Market at 16 of PJM's 20 interfaces. The top three exporting interfaces accounted for 59 percent of PJM's total net exports, PJM/ALTW with 26 percent, PJM/NIPS with 18 percent and PJM/NEPT with 15 percent.

There were net imports in the Real-Time Market at four of PJM's interfaces. Two net importing interfaces accounted for 77 percent of PJM's net import volume, PJM/OVEC with 59 percent and PJM/MECS with 18 percent of the net import volume.

There were net imports in the Day-Ahead Market at four of PJM's 20 interfaces. The top two net importing interfaces accounted for 92 percent of PJM's total net imports, PJM/OVEC with 75 percent and PJM/AMIL with 17 percent.

*Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2008*

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALTE | (178.8) | (144.9) | (131.7) | (136.0) | (99.2) | (161.6) | (151.7) | (127.2) | (123.8) | (123.1) | (76.7) | (31.7) | (1,486.4) |
| ALTW | (120.2) | (160.5) | (130.3) | (106.9) | (95.0) | (131.7) | (101.6) | (102.6) | (105.3) | (119.0) | (60.4) | (105.3) | (1,338.8) |
| AMIL | (28.0) | 12.8 | (6.3) | 8.3 | (8.6) | (77.0) | (93.6) | (48.8) | 26.7 | 17.5 | 7.2 | 35.6 | (154.2) |
| CIN | 181.1 | 67.7 | 201.0 | 469.9 | 562.2 | 336.3 | (11.3) | 132.7 | 97.3 | 44.2 | 90.6 | (75.9) | 2,095.8 |
| CPLE | (55.2) | 151.8 | 32.6 | 59.2 | (119.3) | (213.4) | (313.7) | (471.6) | (390.2) | (427.7) | (446.7) | 107.6 | (2,086.6) |
| CPLW | (74.4) | (69.6) | (33.8) | (57.9) | (69.0) | (60.9) | (73.8) | (74.0) | (71.7) | (76.0) | (73.7) | (74.6) | (809.3) |
| CWLP | (0.4) | 0.0 | (4.8) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (7.8) | 0.0 | 0.0 | 0.0 | (13.1) |
| DUK | 83.2 | 574.2 | 345.2 | 115.8 | 75.8 | (527.8) | (230.3) | (126.0) | (273.5) | (241.0) | (166.5) | 362.5 | (8.2) |
| EKPC | (140.8) | (78.1) | (208.8) | (122.4) | (146.5) | (132.8) | (131.0) | (90.5) | (63.9) | (100.3) | (107.2) | (124.9) | (1,447.2) |
| FE | (27.9) | 17.8 | (85.7) | 41.9 | 29.5 | (287.6) | (276.6) | (257.0) | (184.2) | (219.4) | (236.3) | (228.9) | (1,714.3) |
| IPL | (160.7) | (147.6) | (119.6) | (72.4) | 9.2 | (309.0) | (268.9) | (81.6) | (1.3) | 30.5 | 238.9 | 94.1 | (788.4) |
| LGEE | 78.6 | (1.7) | 16.4 | 33.5 | 103.5 | 101.6 | 172.8 | 130.2 | 210.8 | 264.7 | 314.4 | 255.2 | 1,679.9 |
| MEC | (257.6) | (270.4) | (280.1) | (387.3) | (347.1) | (275.1) | (342.4) | (291.4) | 136.8 | 191.3 | 189.4 | 184.5 | (1,749.4) |
| MECS | (89.7) | (12.8) | (55.8) | 249.6 | 657.7 | 536.7 | 554.6 | 191.8 | 172.6 | 227.8 | 225.3 | 354.6 | 3,012.3 |
| NEPT | (431.0) | (408.7) | (346.7) | (389.6) | (452.5) | (471.7) | (468.2) | (497.4) | (476.0) | (270.9) | (469.4) | (451.3) | (5,133.4) |
| NIPS | (62.2) | (103.7) | (85.6) | (37.0) | 5.1 | (87.1) | (85.4) | (83.9) | (27.3) | (60.2) | (50.1) | (56.4) | (733.8) |
| NYIS | (699.2) | (526.1) | (398.2) | (669.6) | (1,094.7) | (860.9) | (478.1) | (346.0) | (626.6) | (609.2) | (217.1) | (412.0) | (6,937.7) |
| OVEC | 856.5 | 632.5 | 728.1 | 727.0 | 687.5 | 768.1 | 794.6 | 814.2 | 763.2 | 829.7 | 973.1 | 976.8 | 9,551.4 |
| TVA | (431.9) | (133.4) | (207.5) | (237.6) | (514.2) | (401.0) | (336.8) | (268.8) | (256.8) | (97.5) | (180.8) | (57.1) | (3,123.2) |
| WEC | (101.7) | (116.1) | (98.8) | (74.6) | (55.7) | (133.4) | (69.7) | (70.6) | (47.4) | (60.7) | (53.1) | (57.6) | (939.4) |
| Total | (1,660.3) | (716.9) | (870.2) | (586.1) | (871.4) | (2,388.2) | (1,911.0) | (1,668.3) | (1,248.4) | (799.3) | (99.0) | 695.2 | (12,124.0) |

*Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2008*

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALTE | 0.1 | 0.0 | 0.0 | 0.0 | 1.1 | 0.0 | 0.0 | 0.0 | 10.2 | 0.6 | 0.6 | 54.6 | 67.2 |
| ALTW | 3.5 | 2.8 | 0.5 | 0.0 | 0.1 | 0.8 | 0.0 | 0.2 | 0.2 | 2.0 | 0.4 | 9.5 | 20.0 |
| AMIL | 86.6 | 96.8 | 104.7 | 155.0 | 129.5 | 42.0 | 31.4 | 47.2 | 61.8 | 41.4 | 28.1 | 67.7 | 892.2 |
| CIN | 590.3 | 400.9 | 609.6 | 731.4 | 791.4 | 637.0 | 356.3 | 479.6 | 315.2 | 277.4 | 303.3 | 257.7 | 5,750.1 |
| CPLE | 207.1 | 328.1 | 167.3 | 255.9 | 104.1 | 40.9 | 22.6 | 8.3 | 8.4 | 9.8 | 7.8 | 332.5 | 1,492.8 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUK | 358.1 | 679.3 | 523.4 | 385.8 | 347.6 | 74.4 | 209.8 | 188.9 | 151.5 | 118.3 | 201.9 | 533.5 | 3,772.5 |
| EKPC | 12.4 | 24.4 | 3.6 | 2.9 | 0.0 | 6.6 | 0.8 | 0.0 | 1.1 | 0.2 | 1.3 | 0.5 | 53.8 |
| FE | 153.5 | 200.1 | 98.9 | 260.5 | 294.3 | 32.6 | 31.6 | 40.8 | 46.3 | 42.2 | 22.4 | 31.6 | 1,254.8 |
| IPL | 0.9 | 79.0 | 4.9 | 20.7 | 45.4 | 24.0 | 4.0 | 23.8 | 80.5 | 70.1 | 258.8 | 164.4 | 776.5 |
| LGEE | 98.6 | 49.1 | 64.9 | 70.5 | 126.2 | 146.4 | 172.8 | 149.8 | 211.3 | 268.6 | 314.4 | 261.4 | 1,934.0 |
| MEC | 190.9 | 247.4 | 58.3 | 29.6 | 32.6 | 56.5 | 127.5 | 80.2 | 394.0 | 341.6 | 364.8 | 506.6 | 2,430.0 |
| MECS | 108.1 | 235.2 | 217.6 | 395.3 | 756.7 | 685.0 | 718.2 | 327.0 | 280.9 | 348.1 | 338.3 | 464.2 | 4,874.6 |
| 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 | 29.3 | 5.0 | 2.9 | 8.2 | 56.7 | 0.2 | 18.0 | 8.9 | 15.1 | 14.9 | 3.2 | 1.2 | 163.6 |
| NYIS | 1,026.5 | 991.6 | 1,131.3 | 1,039.6 | 1,091.2 | 1,085.4 | 1,530.0 | 1,429.8 | 969.5 | 852.4 | 1,204.7 | 1,145.8 | 13,497.8 |
| OVEC | 887.3 | 661.8 | 758.3 | 753.6 | 711.7 | 791.2 | 819.2 | 814.2 | 764.0 | 829.7 | 973.1 | 976.8 | 9,740.9 |
| TVA | 85.5 | 75.5 | 51.0 | 36.4 | 30.6 | 53.0 | 84.1 | 76.5 | 90.7 | 62.9 | 62.3 | 81.1 | 789.6 |
| WEC | 0.9 | 3.7 | 1.2 | 8.7 | 7.3 | 0.2 | 0.0 | 6.2 | 0.0 | 0.0 | 0.1 | 2.5 | 30.8 |
| Total | 3,839.6 | 4,080.7 | 3,798.4 | 4,154.1 | 4,526.5 | 3,676.3 | 4,126.3 | 3,681.4 | 3,400.7 | 3,280.2 | 4,085.5 | 4,891.6 | 47,541.3 |

*Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2008*

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALTE | 178.9 | 144.9 | 131.7 | 136.0 | 100.3 | 161.6 | 151.7 | 127.2 | 134.0 | 123.7 | 77.3 | 86.3 | 1,553.6 |
| ALTW | 123.7 | 163.3 | 130.8 | 106.9 | 95.1 | 132.5 | 101.6 | 102.8 | 105.5 | 121.0 | 60.8 | 114.8 | 1,358.8 |
| AMIL | 114.6 | 84.0 | 111.0 | 146.7 | 138.1 | 119.0 | 125.0 | 96.0 | 35.1 | 23.9 | 20.9 | 32.1 | 1,046.4 |
| CIN | 409.2 | 333.2 | 408.6 | 261.5 | 229.2 | 300.7 | 367.6 | 346.9 | 217.9 | 233.2 | 212.7 | 333.6 | 3,654.3 |
| CPLE | 262.3 | 176.3 | 134.7 | 196.7 | 223.4 | 254.3 | 336.3 | 479.9 | 398.6 | 437.5 | 454.5 | 224.9 | 3,579.4 |
| CPLW | 74.4 | 69.6 | 33.8 | 57.9 | 69.0 | 61.0 | 73.8 | 74.0 | 71.7 | 76.0 | 73.7 | 74.6 | 809.4 |
| CWLP | 0.4 | 0.0 | 4.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.8 | 0.0 | 0.0 | 0.0 | 13.1 |
| DUK | 274.9 | 105.1 | 178.2 | 270.0 | 271.8 | 602.2 | 440.1 | 314.9 | 425.0 | 359.3 | 368.4 | 171.0 | 3,780.7 |
| EKPC | 153.2 | 102.5 | 212.4 | 125.3 | 146.5 | 139.4 | 131.8 | 90.5 | 65.0 | 100.5 | 108.5 | 125.4 | 1,501.0 |
| FE | 181.4 | 182.3 | 184.6 | 218.6 | 264.8 | 320.2 | 308.2 | 297.8 | 230.5 | 261.6 | 258.7 | 260.5 | 2,969.1 |
| IPL | 161.6 | 226.6 | 124.5 | 93.1 | 36.2 | 333.0 | 272.9 | 105.4 | 81.8 | 39.6 | 19.9 | 70.3 | 1,564.9 |
| LGEE | 20.0 | 50.8 | 48.5 | 37.0 | 22.7 | 44.8 | 0.0 | 19.6 | 0.5 | 3.9 | 0.0 | 6.2 | 254.1 |
| MEC | 448.5 | 517.8 | 338.4 | 416.9 | 379.7 | 331.6 | 469.9 | 371.6 | 257.2 | 150.3 | 175.4 | 322.1 | 4,179.4 |
| MECS | 197.8 | 248.0 | 273.4 | 145.7 | 99.0 | 148.3 | 163.6 | 135.2 | 108.3 | 120.3 | 113.0 | 109.6 | 1,862.3 |
| NEPT | 431.0 | 408.7 | 346.7 | 389.6 | 452.5 | 471.7 | 468.2 | 497.4 | 476.0 | 270.9 | 469.4 | 451.3 | 5,133.4 |
| NIPS | 91.5 | 108.7 | 88.5 | 45.2 | 51.6 | 87.3 | 103.4 | 92.8 | 42.4 | 75.1 | 53.3 | 57.6 | 897.4 |
| NYIS | 1,725.7 | 1,517.7 | 1,529.5 | 1,709.2 | 2,185.9 | 1,946.3 | 2,008.1 | 1,775.8 | 1,596.1 | 1,461.6 | 1,421.8 | 1,557.8 | 20,435.5 |
| OVEC | 30.8 | 29.3 | 30.2 | 26.6 | 24.2 | 23.1 | 24.6 | 0.0 | 0.8 | 0.0 | 0.0 | 0.0 | 189.5 |
| TVA | 517.4 | 208.9 | 258.5 | 274.0 | 544.8 | 454.0 | 420.9 | 345.3 | 347.5 | 160.4 | 243.1 | 138.2 | 3,912.8 |
| WEC | 102.6 | 119.8 | 100.0 | 83.3 | 63.0 | 133.6 | 69.7 | 76.8 | 47.4 | 60.7 | 53.2 | 60.1 | 970.2 |
| Total | 5,499.9 | 4,797.6 | 4,668.6 | 4,740.2 | 5,397.9 | 6,064.5 | 6,037.3 | 5,349.7 | 4,649.1 | 4,079.5 | 4,184.5 | 4,196.4 | 59,665.3 |

*Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2008*

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALTE | (197.1) | (121.4) | (148.9) | (117.6) | (15.8) | 203.2 | 409.9 | 293.3 | 229.9 | (41.4) | (496.1) | (506.4) | (508.4) |
| ALTW | (918.9) | (944.3) | (1,045.9) | (843.5) | (475.8) | (818.5) | (548.0) | (456.0) | (403.3) | (699.5) | (765.2) | (766.1) | (8,685.0) |
| AMIL | 221.6 | 273.1 | 454.3 | 449.9 | 173.7 | 116.0 | 68.1 | 33.3 | (4.7) | 191.0 | 170.3 | 115.0 | 2,261.6 |
| CIN | (148.8) | (172.1) | (238.4) | (197.8) | (44.2) | (180.7) | (223.6) | 76.5 | (195.4) | (264.3) | (171.4) | (240.9) | (2,001.2) |
| CPLE | (70.1) | 24.0 | (63.5) | (55.1) | (13.6) | (106.7) | (99.3) | (84.2) | (97.1) | (52.6) | (36.9) | 61.2 | (594.0) |
| CPLW | (186.0) | (174.0) | (88.3) | (150.0) | (180.3) | (154.7) | (186.0) | (186.1) | (180.0) | (186.0) | (183.5) | (183.6) | (2,038.3) |
| CWLP | (6.8) | (0.4) | (4.8) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.1) | (0.2) | (0.0) | 0.0 | (12.3) |
| DUK | 130.9 | 277.0 | 109.4 | 20.6 | 62.1 | (194.8) | (90.5) | (17.3) | (8.7) | (86.9) | (69.0) | 106.6 | 239.3 |
| EKPC | (27.6) | (38.5) | (37.2) | (36.0) | (37.2) | (36.0) | (38.4) | (37.3) | (36.0) | (37.2) | (36.0) | (76.0) | (473.3) |
| FE | (119.6) | (114.7) | (153.7) | (98.8) | (156.3) | (226.8) | (216.7) | (205.9) | (155.0) | (139.0) | (124.9) | (155.7) | (1,867.0) |
| IPL | (49.7) | (77.0) | (129.0) | (170.3) | (44.7) | (104.1) | (115.3) | (86.7) | (58.4) | (212.0) | 34.5 | (58.9) | (1,071.7) |
| LGEE | (44.6) | (33.2) | (14.0) | (10.3) | 1.6 | (27.8) | (13.6) | (0.6) | 0.0 | (0.9) | 6.6 | 2.0 | (134.8) |
| MEC | (154.6) | (126.2) | (120.6) | (255.6) | (233.5) | (282.6) | (283.5) | (278.6) | (154.4) | (132.1) | (144.9) | (91.4) | (2,258.1) |
| MECS | (91.0) | (262.2) | (405.4) | (334.4) | 167.2 | (164.7) | 55.1 | 97.4 | 197.4 | 99.2 | (112.6) | (110.1) | (864.1) |
| NEPT | (426.2) | (400.3) | (344.0) | (381.5) | (442.1) | (478.0) | (474.7) | (498.1) | (483.7) | (300.6) | (470.0) | (469.8) | (5,169.0) |
| NIPS | (728.3) | (762.9) | (545.3) | (394.8) | (344.6) | (595.3) | (609.0) | (602.4) | (528.8) | (515.5) | (325.3) | (207.0) | (6,159.4) |
| NYIS | (31.1) | (129.9) | (74.8) | (134.1) | (236.6) | (162.2) | (205.7) | (329.2) | (52.4) | (15.0) | 69.6 | (29.6) | (1,331.0) |
| OVEC | 1,052.7 | 893.6 | 957.6 | 894.7 | 786.0 | 712.0 | 787.4 | 788.7 | 717.2 | 773.7 | 694.0 | 696.9 | 9,754.6 |
| TVA | (35.5) | 240.7 | 53.4 | 57.4 | (75.2) | (81.3) | (5.2) | (2.5) | (47.0) | 42.3 | 278.7 | 387.5 | 813.2 |
| WEC | (77.1) | (35.5) | (72.0) | (24.3) | (62.9) | (73.8) | (75.9) | (58.8) | (38.5) | (56.8) | (50.9) | (57.6) | (684.3) |
| Total | (1,907.8) | (1,684.3) | (1,911.0) | (1,781.8) | (1,172.3) | (2,656.9) | (1,864.9) | (1,554.5) | (1,299.0) | (1,633.8) | (1,733.3) | (1,583.9) | (20,783.4) |

Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2008

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALTE | 68.6 | 26.9 | 51.4 | 147.3 | 194.4 | 544.5 | 1,104.2 | 1,282.8 | 1,073.2 | 635.5 | 290.3 | 318.1 | 5,737.3 |
| ALTW | 171.2 | 246.0 | 314.8 | 353.2 | 233.5 | 83.8 | 201.1 | 82.2 | 109.2 | 182.8 | 46.5 | 25.1 | 2,049.5 |
| AMIL | 238.0 | 286.8 | 463.7 | 460.2 | 181.1 | 120.7 | 72.6 | 33.4 | 2.9 | 195.9 | 180.0 | 118.7 | 2,354.0 |
| CIN | 37.5 | 25.3 | 22.1 | 7.0 | 65.8 | 57.3 | 59.9 | 138.0 | 51.3 | 41.3 | 50.4 | 89.3 | 645.3 |
| CPLE | 49.9 | 115.2 | 32.0 | 60.3 | 86.4 | 21.6 | 25.5 | 44.4 | 30.4 | 61.5 | 79.3 | 167.5 | 773.9 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.2 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUK | 184.4 | 302.7 | 133.5 | 136.1 | 118.9 | 6.9 | 77.0 | 63.3 | 67.0 | 26.0 | 79.5 | 178.1 | 1,373.4 |
| EKPC | 0.0 | 1.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| FE | 28.8 | 16.1 | 6.3 | 43.7 | 28.3 | 9.3 | 20.9 | 24.3 | 8.6 | 45.7 | 43.1 | 14.9 | 289.9 |
| IPL | 14.0 | 127.8 | 64.8 | 61.3 | 54.6 | 91.3 | 87.4 | 76.5 | 232.1 | 170.9 | 291.9 | 184.1 | 1,456.7 |
| LGEE | 13.6 | 31.2 | 12.7 | 19.2 | 1.6 | 1.3 | 0.4 | 1.1 | 0.0 | 0.0 | 6.6 | 2.0 | 89.7 |
| MEC | 46.6 | 73.8 | 0.0 | 0.0 | 3.4 | 0.0 | 48.5 | 0.0 | 67.8 | 0.0 | 3.7 | 159.0 | 402.7 |
| MECS | 256.3 | 164.4 | 154.6 | 187.0 | 311.4 | 273.9 | 454.4 | 536.0 | 561.0 | 567.1 | 386.4 | 349.7 | 4,202.2 |
| 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 | 92.1 | 29.7 | 14.3 | 11.7 | 39.6 | 37.3 | 6.7 | 71.1 | 171.3 | 227.6 | 308.3 | 344.8 | 1,354.6 |
| NYIS | 883.3 | 762.9 | 823.4 | 804.8 | 805.5 | 877.9 | 1,017.1 | 157.7 | 1,012.9 | 888.1 | 956.4 | 879.1 | 9,869.1 |
| OVEC | 1,062.9 | 932.8 | 998.9 | 903.2 | 790.1 | 742.0 | 854.8 | 852.6 | 744.6 | 790.4 | 703.6 | 707.3 | 10,083.2 |
| TVA | 149.4 | 290.5 | 128.7 | 95.7 | 127.1 | 9.7 | 37.2 | 26.1 | 4.5 | 84.9 | 377.4 | 413.6 | 1,744.8 |
| WEC | 30.0 | 80.8 | 19.7 | 39.3 | 6.1 | 4.8 | 2.5 | 7.2 | 1.3 | 4.7 | 4.4 | 0.0 | 200.7 |
| Total | 3,326.7 | 3,513.9 | 3,240.9 | 3,330.1 | 3,047.7 | 2,882.3 | 4,070.2 | 3,396.7 | 4,138.1 | 3,922.5 | 3,807.8 | 3,951.5 | 42,628.5 |

*Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2008*

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALTE | 265.7 | 148.3 | 200.4 | 265.0 | 210.3 | 341.3 | 694.3 | 989.5 | 843.2 | 676.9 | 786.4 | 824.5 | 6,245.7 |
| ALTW | 1,090.2 | 1,190.3 | 1,360.7 | 1,196.7 | 709.3 | 902.3 | 749.1 | 538.2 | 512.5 | 882.3 | 811.8 | 791.2 | 10,734.5 |
| AMIL | 16.3 | 13.7 | 9.3 | 10.4 | 7.5 | 4.7 | 4.5 | 0.1 | 7.6 | 4.9 | 9.7 | 3.7 | 92.4 |
| CIN | 186.3 | 197.4 | 260.5 | 204.8 | 110.0 | 238.0 | 283.5 | 61.5 | 246.7 | 305.7 | 221.9 | 330.2 | 2,646.5 |
| CPLE | 120.1 | 91.2 | 95.5 | 115.4 | 100.0 | 128.3 | 124.8 | 128.6 | 127.5 | 114.1 | 116.2 | 106.3 | 1,368.0 |
| CPLW | 186.0 | 174.0 | 88.3 | 150.0 | 180.3 | 154.7 | 186.0 | 186.1 | 180.0 | 186.0 | 183.5 | 183.8 | 2,038.5 |
| CWLP | 6.8 | 0.4 | 4.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.0 | 0.0 | 12.3 |
| DUK | 53.5 | 25.7 | 24.1 | 115.5 | 56.8 | 201.7 | 167.5 | 80.6 | 75.7 | 112.9 | 148.5 | 71.5 | 1,134.1 |
| EKPC | 27.6 | 39.6 | 37.2 | 36.0 | 37.2 | 36.0 | 38.4 | 37.3 | 36.0 | 37.2 | 36.0 | 76.0 | 474.4 |
| FE | 148.4 | 130.8 | 160.0 | 142.5 | 184.5 | 236.1 | 237.6 | 230.2 | 163.6 | 184.7 | 168.0 | 170.6 | 2,156.9 |
| IPL | 63.7 | 204.8 | 193.8 | 231.6 | 99.3 | 195.4 | 202.7 | 163.2 | 290.5 | 382.9 | 257.4 | 243.0 | 2,528.4 |
| LGEE | 58.2 | 64.4 | 26.7 | 29.5 | 0.0 | 29.1 | 14.0 | 1.7 | 0.0 | 0.9 | 0.0 | 0.0 | 224.5 |
| MEC | 201.2 | 200.0 | 120.6 | 255.6 | 236.9 | 282.6 | 332.0 | 278.6 | 222.2 | 132.1 | 148.6 | 250.4 | 2,660.8 |
| MECS | 347.2 | 426.6 | 560.0 | 521.4 | 144.2 | 438.6 | 399.3 | 438.6 | 363.6 | 467.9 | 499.0 | 459.8 | 5,066.4 |
| NEPT | 426.2 | 400.3 | 344.0 | 381.5 | 442.1 | 478.0 | 474.7 | 498.1 | 483.7 | 300.6 | 470.0 | 469.8 | 5,169.0 |
| NIPS | 820.4 | 792.6 | 559.6 | 406.5 | 384.2 | 632.6 | 615.7 | 673.5 | 700.1 | 743.1 | 633.7 | 551.8 | 7,514.0 |
| NYIS | 914.4 | 892.8 | 898.2 | 938.9 | 1,042.2 | 1,040.1 | 1,222.8 | 486.9 | 1,065.3 | 903.1 | 886.8 | 908.7 | 11,200.1 |
| OVEC | 10.3 | 39.2 | 41.3 | 8.5 | 4.0 | 30.0 | 67.4 | 63.9 | 27.4 | 16.7 | 9.6 | 10.4 | 328.6 |
| TVA | 184.9 | 49.8 | 75.3 | 38.3 | 202.3 | 91.0 | 42.4 | 28.6 | 51.5 | 42.6 | 98.7 | 26.1 | 931.6 |
| WEC | 107.2 | 116.3 | 91.7 | 63.6 | 69.0 | 78.6 | 78.4 | 66.0 | 39.8 | 61.5 | 55.3 | 57.6 | 885.0 |
| Total | 5,234.5 | 5,198.2 | 5,151.9 | 5,111.9 | 4,220.0 | 5,539.2 | 5,935.1 | 4,951.2 | 5,437.1 | 5,556.2 | 5,541.1 | 5,535.4 | 63,411.8 |

## Interface Pricing

Interface pricing points differ from interfaces. (See Table 4-7 for a list of active interfaces in 2008. Figure 4-4 shows the approximate geographic location of the 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.[15] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area (GCA) and Load Control Area (LCA) as specified on the NERC Tag. 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 balancing authorities need to be priced at the PJM border. A set of external buses is used to create such interface prices. The challenge is to create an interface price, composed

15 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 13, 2009) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1MB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

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.[16] Table 4-8 presents the interface pricing points used during 2008.

*Table 4-7 Active interfaces: Calendar year 2008*

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

16 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.

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

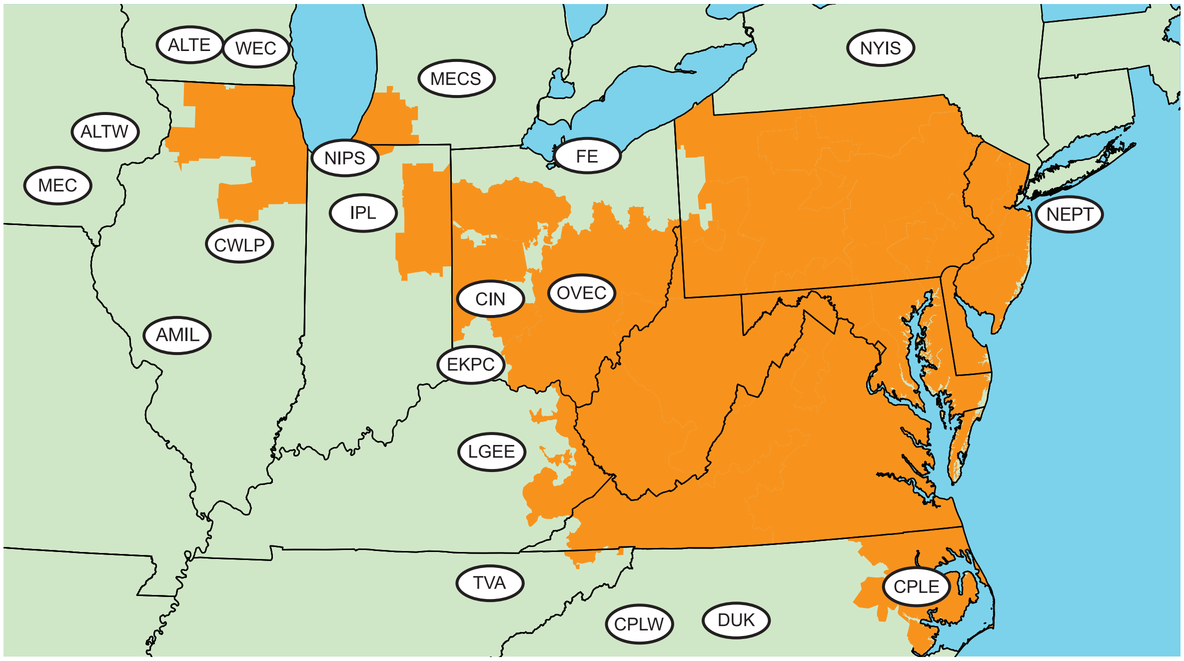



*Table 4-8 Active pricing points: Calendar year 2008*

| PJM 2008 Pricing Points | | | | |
|---|---|---|---|---|
| MICHFE | MISO | NEPT | NIPSCO | Northwest |
| NYIS | Ontario IESO | OVEC | SOUTHEXP | SOUTHIMP |

## Interactions with Bordering Areas

### PJM Interface Prices with Organized Markets

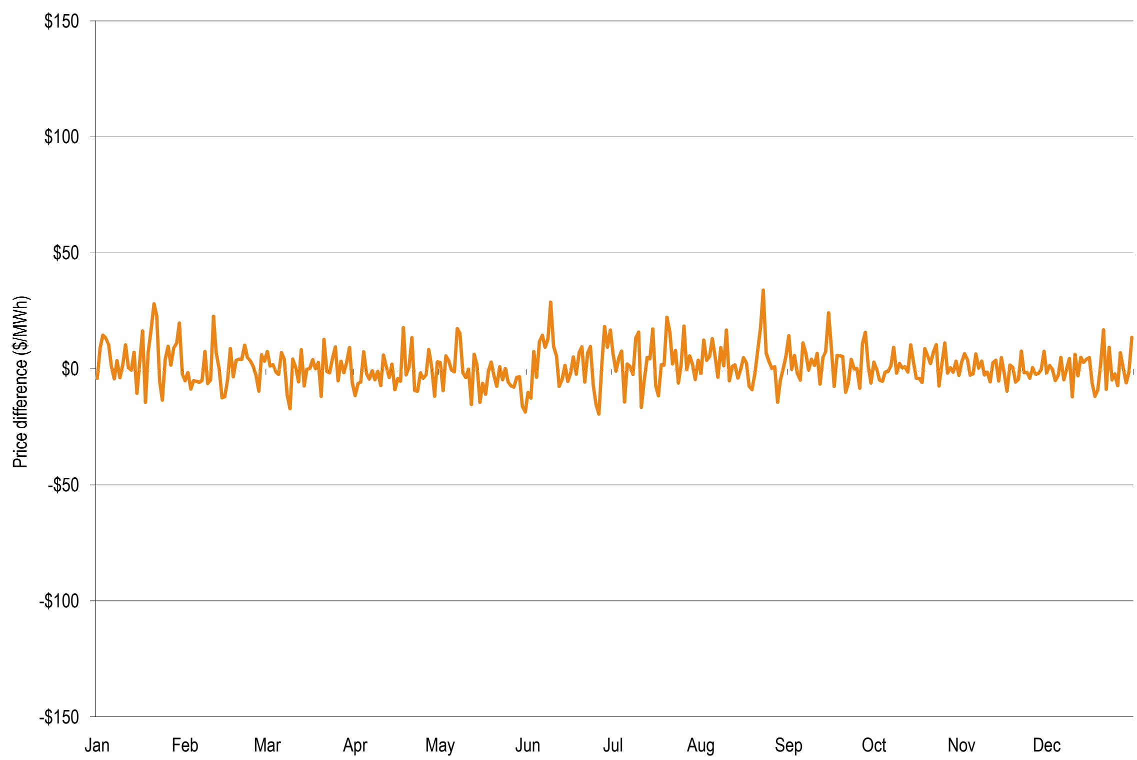
During 2008, Real-Time Market prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces.

#### 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[17] 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.[18]

The 2008 real-time hourly average interface prices for PJM/MISO and MISO/PJM were $49.80 and $50.97, respectively. The simple average difference between the real-time MISO/PJM interface price and the PJM/MISO Interface price was $1.17 in 2008, 2 percent of the average PJM/MISO price. (See Figure 4-5.) The real-time MISO/PJM interface price was slightly higher on average than the PJM/MISO price in 2008.

***Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2008***




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 2008, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about ten times per day. The standard deviation of the hourly price was $31.61 for the PJM/MISO price and $35.09 for the MISO/

17 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 13, 2009) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1MB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

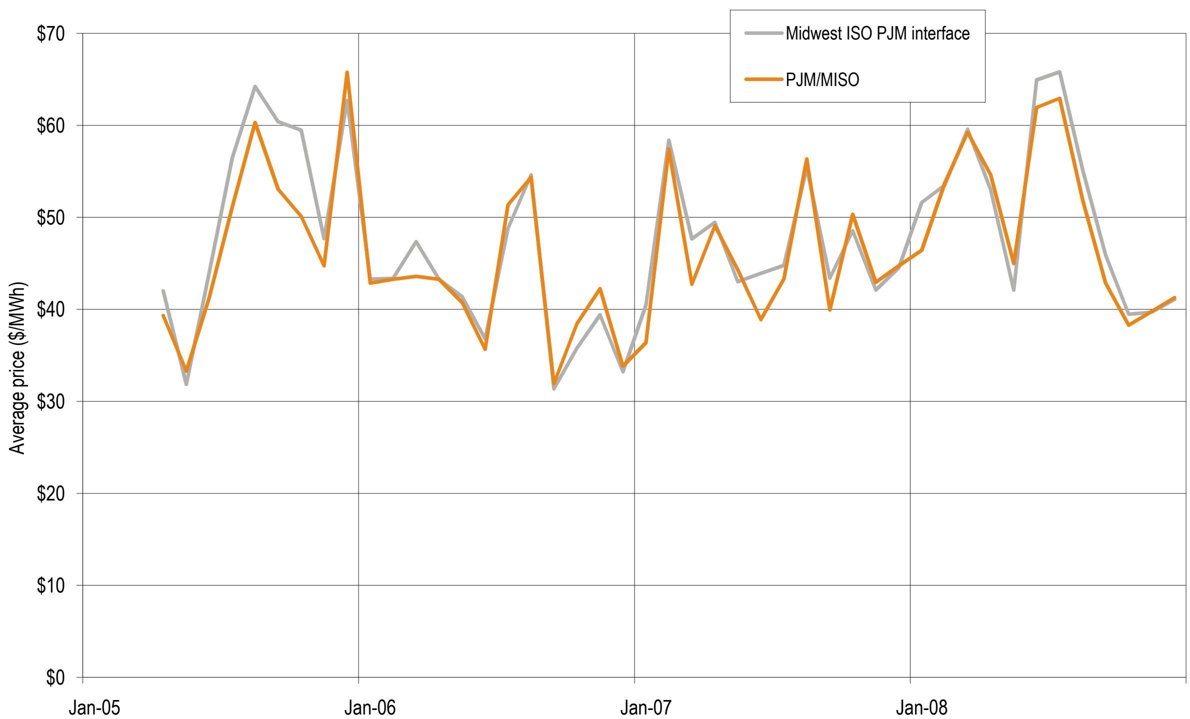
18 Based on information obtained from the Midwest ISO Extranet (January 13, 2009) <http://extranet.midwestiso.org>.

PJM Interface price. The standard deviation of the difference in interface prices was $26.53. The average of the absolute value of the hourly price difference was $16.95. Absolute values reflect price differences regardless of whether they are positive or negative.

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 2008 period. Figure 4-6 shows this correlation between hourly PJM and Midwest ISO interface prices.

***Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 to 2008***




The difference in real-time 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 four time periods: calendar year 2006, January through May 2007 (i.e., the pre-marginal loss implementation period), June through December 2007 (i.e., the post-marginal loss implementation period) and calendar year 2008.

Table 4-9 shows that in 2006 all of the unit pairs and jointly owned units had real-time LMP differences larger than the difference at the PJM/MISO Interface. After the implementation of marginal losses in PJM, most units showed decreases in their real-time 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. Price differences at Kincaid reflect actual operational issues that make the price adjustment process less continuous.

*Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 1, 2006, through December 31, 2008*

| | 2006 | 2007 (Pre-Marginal Losses) | 2007 (Post-Marginal Losses) | 2008 |
|---|---|---|---|---|
| Kincaid (PJM) & Coffeen (MISO) | $5.87 | $4.31 | $5.76 | $8.26 |
| Beaver Valley (PJM) & Mansfield (MISO) | $2.28 | ($2.64) | $0.55 | $0.89 |
| Miami Fort (PJM) & (MISO) | $1.95 | ($1.30) | ($0.95) | $1.25 |
| Stuart (PJM) & (MISO) | $2.09 | ($0.81) | ($0.64) | $0.85 |
| PJM/MISO Interface | ($0.23) | ($1.83) | ($0.85) | ($0.76) |

### 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.[19]

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the NYISO, all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The MIS evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the MIS. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the

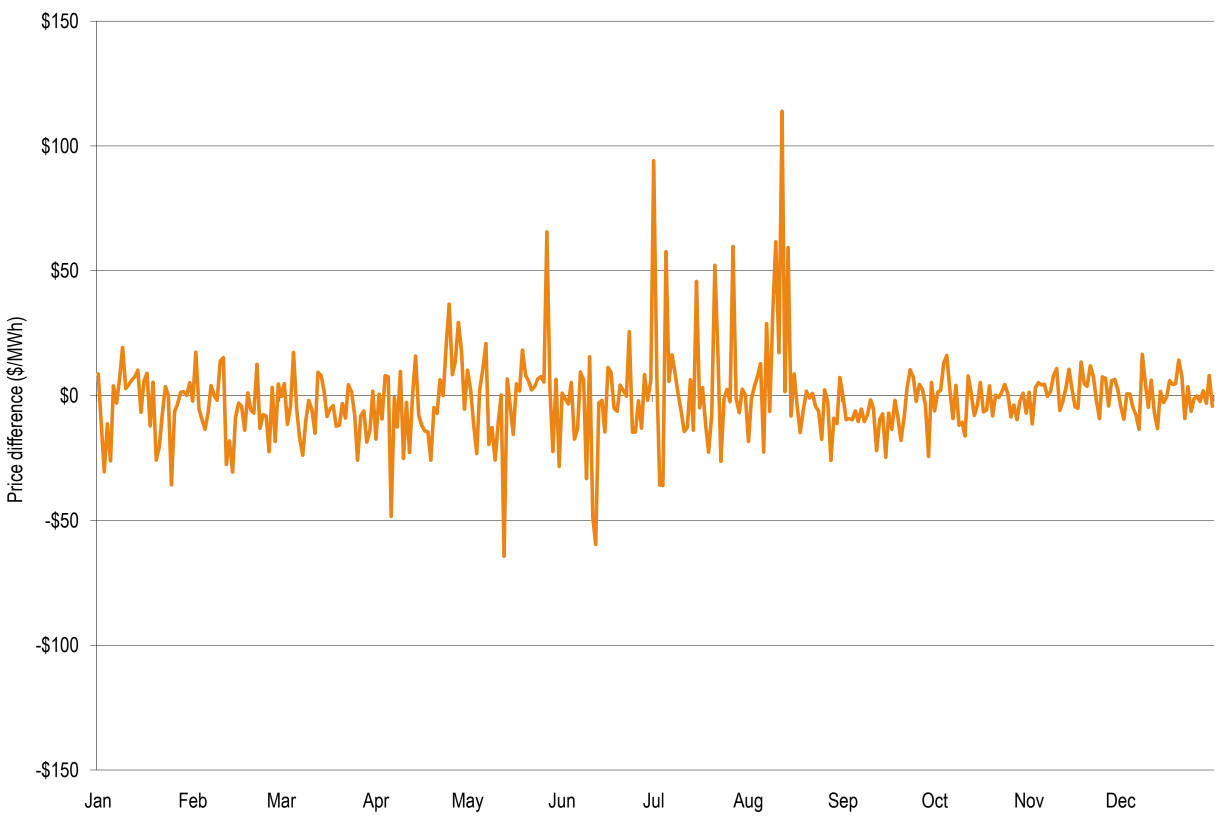
19 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

adjustments often cause large swings in expected ramp for the next hour (as discussed in the “Ramp” section).

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.[20] 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 2008 real-time hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $71.99 and $72.86, respectively. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price decreased from -$4.07 per MWh in 2007 to $0.86 per MWh in 2008, and the variability of the difference also decreased. (See Figure 4-7.) PJM’s net export volume to New York for 2008 was significantly higher than in 2007. This is consistent with the fact that the PJM/NYIS price was, on average, lower than the NYISO/PJM price in 2008.

*Figure 4-7 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2008*




20 See PJM. “LMP Aggregate Definitions” (December 18, 2008) (Accessed January 13, 2009) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1MB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

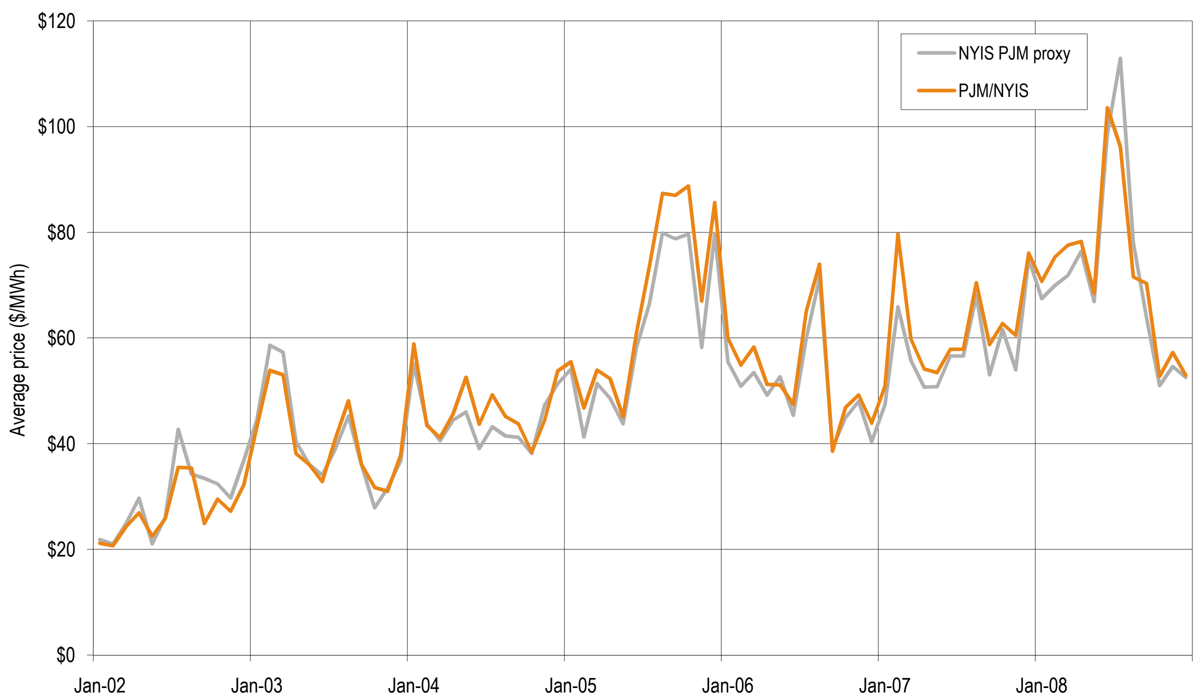
The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices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

The difference between the real-time PJM/NYIS interface price and the real-time NYISO/PJM price continued to fluctuate between positive and negative about eight times per day during 2008 as it has since 2003. The standard deviation of hourly price was $39.97 in 2008 for the PJM/NYIS price and $33.14 in 2008 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $48.53 in 2008. The average of the absolute value of the hourly price difference was $23.74 in 2008. 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.[21]

There has been a significant correlation between real-time monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2008. Figure 4-8 shows this correlation between hourly PJM and NYISO interface prices.

***Figure 4-8 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2008***

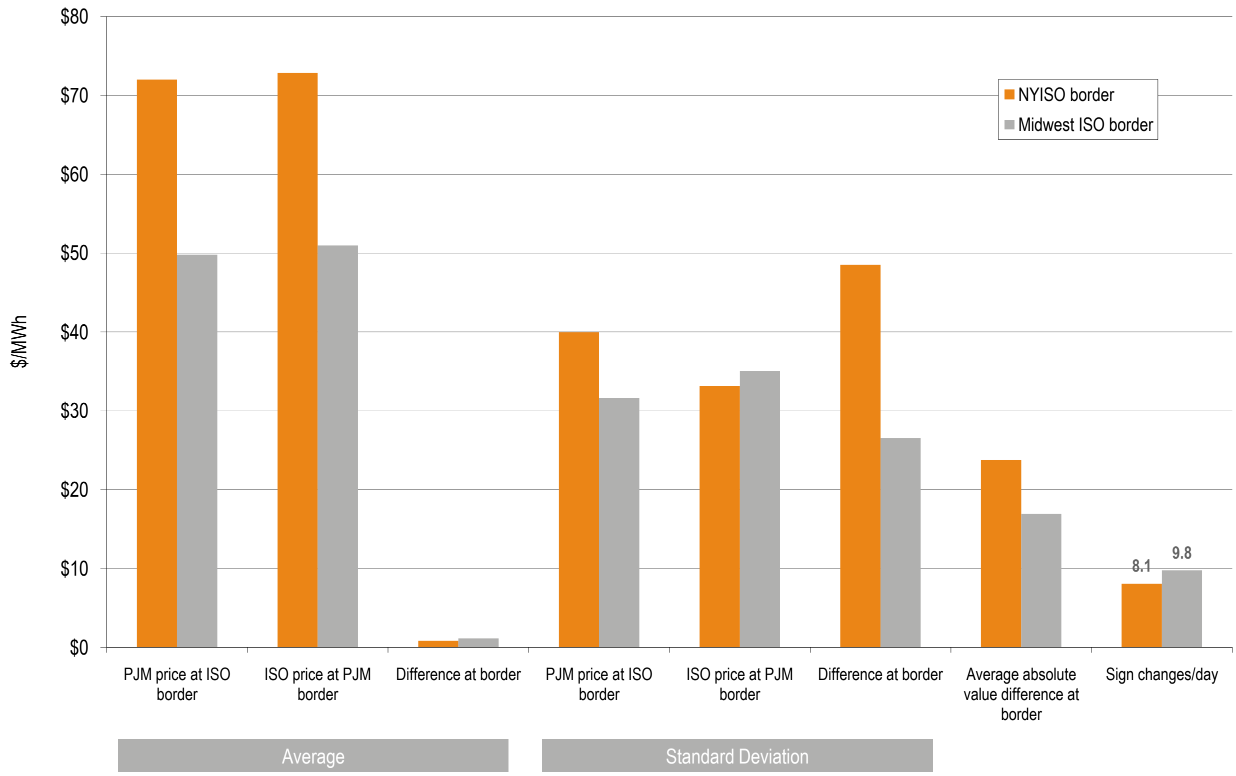



21 As previously noted, institutional difference between PJM and NYISO markets partially explains observed differences in border prices. For a description of those differences, see the *2005 State of the Market Report,* Appendix D, "Interchange Transactions" (March 8, 2006), pp. 195-198.

### 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 real-time border price averages: Calendar year 2008*




## Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with 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)

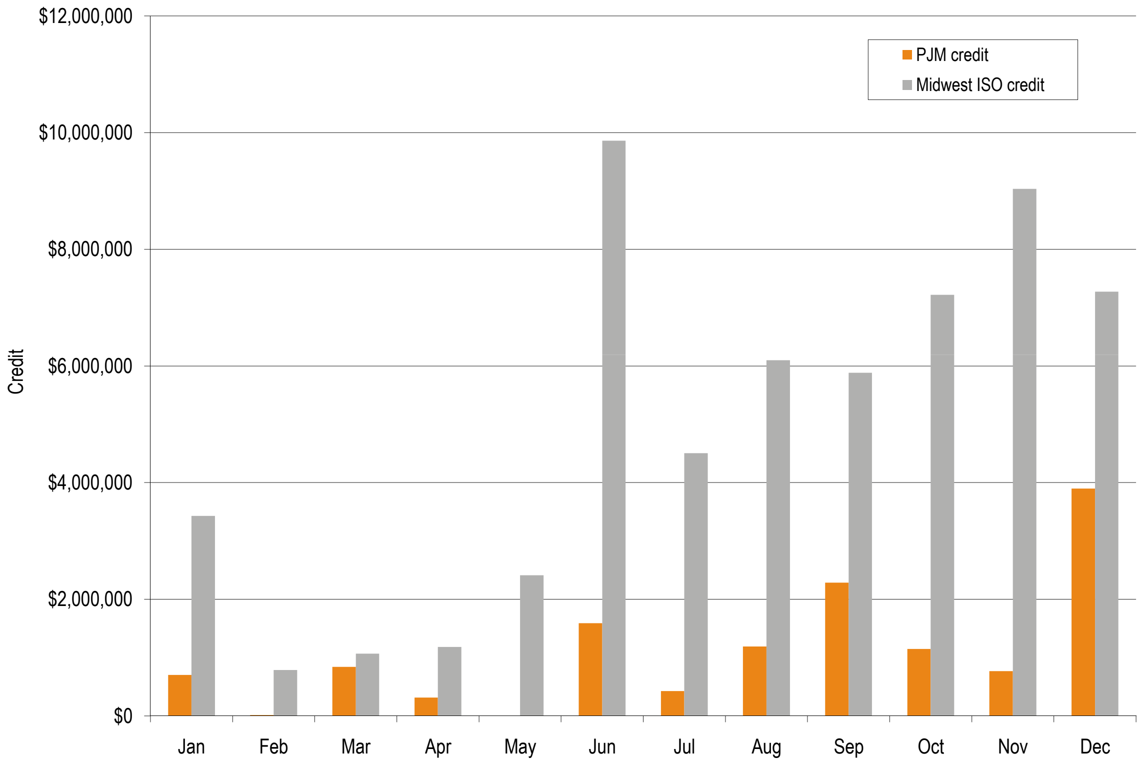
On May 22, 2007, the JOA between PJM and NYISO became effective. This agreement was developed to improve reliability, and includes obligations concerning: maintaining interconnected operations, voltage control and reactive power; coordinating scheduled outages and transmission planning; and providing emergency assistance. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for 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. The MMU recommends that PJM and NYISO develop market-based congestion management protocols as soon as practicable.

### *PJM and Midwest ISO Joint Operating Agreement (JOA)*

The market-to-market coordination between PJM and MISO continued in 2008. Under the market-to-market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate a 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 2008, 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 4-10 presents the monthly credits each organization received from redispatching for the other. A PJM credit is a payment by the Midwest ISO to PJM and a Midwest ISO credit is a payment by PJM to the Midwest ISO. The largest payments from PJM to Midwest ISO during the year were the result of redispatch by Midwest ISO to relieve congestion on the East Frankfort – Crete 345 kV for loss of Dumont – Wilton Center 765 kV line. Market-to-market activity on this line in 2008 was primarily due to line outages caused by tornados in May and June. Total PJM payments to Midwest ISO were $54.2 million, a 107 percent increase from the 2007 level. The largest payments from Midwest ISO to PJM during the year were the result of redispatch by PJM to relieve congestion on the Rising 345/138 XFMR 1 for the loss of Clinton – Brokaw 345 kV line. Total Midwest ISO payments to PJM were $8.6 million, a 64 percent decrease from the 2007 level.

*Figure 4-10 Credits for coordinated congestion management: Calendar year 2008*




## 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 during 2008. 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 remains in effect. Since Progress Energy Carolinas is not a market system, the coordination agreement between PEC and PJM is similar to the agreement that existed between the Midwest ISO and PJM during the first phase of their JOA. The ATC coordination that had been expected to be completed during the first half of 2006 remained under development during 2008. PJM and Progress continued to develop the congestion management process as required by the agreement. A phased approach to development of congestion management is being discussed.

### PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), Progress Energy Carolinas, Inc. (PEC), South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems.

## Other Agreements with Bordering Areas

### 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 2008 while continuing to pursue work on the 19 items identified in the work plan to improve protocol performance. In August, 2007 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 2008, PSE&G's FTR revenues were less than its congestion charges by $26,250 after adjustments (Revenues were approximately $14,250 less than charges in 2007.) Under the FERC order, Con Edison receives credits on an hourly basis for

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).

its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2008, Con Edison's congestion credits were $268,368 less than its day-ahead congestion charges. Con Edison also had negative day-ahead congestion charges, with the result that Con Edison's total credits exceeded its congestion charges by $213,535. (Credits had been approximately $1.7 million less than charges in 2007.) (See Table 4-10.)

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 $213,535 in 2008. The parties should address this issue.

*Table 4-10 Con Edison and PSE&G wheeling settlement data: Calendar year 2008*

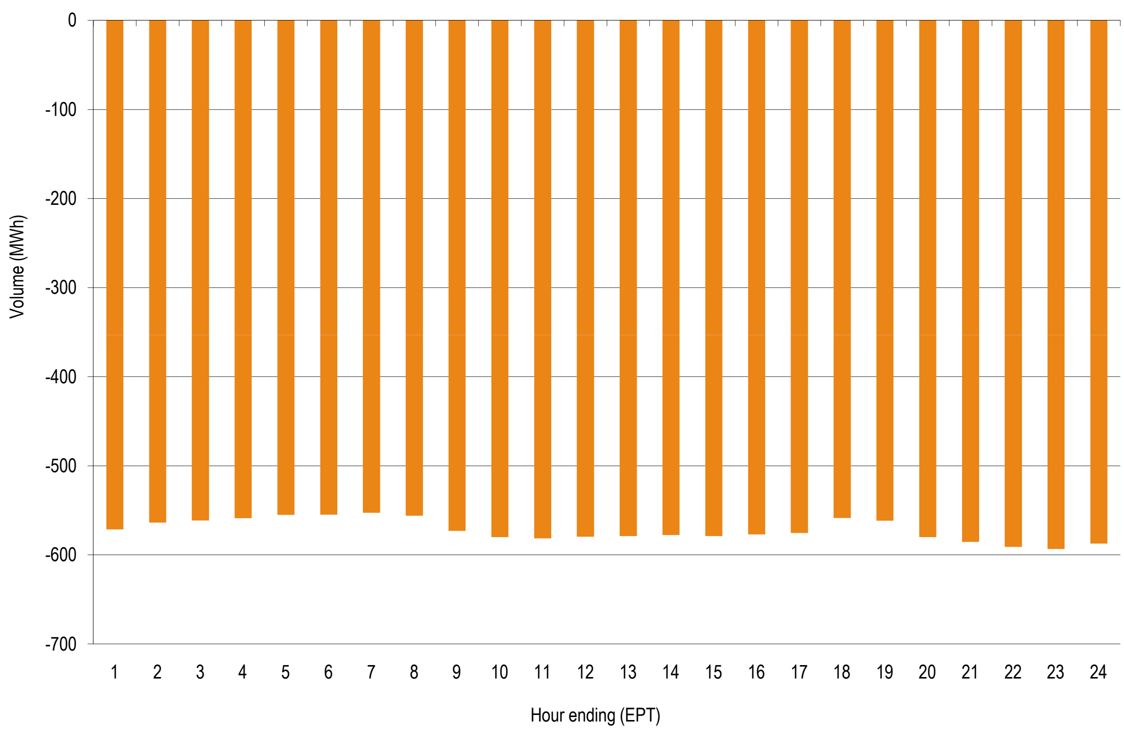
| | Con Edison | | | PSE&G | | |
|---|---|---|---|---|---|---|
| | Day Ahead | Balancing | Total | Day Ahead | Balancing | Total |
| Total Congestion Credit | $4,061,370 | ($71,943) | $3,989,426 | $6,425,449 | ($40,018) | $6,385,431 |
| Congestion Credit | | | $3,793,002 | | | $6,405,281 |
| Adjustments | | | ($17,110) | | | ($6,082) |
| Net Charge | | | $213,535 | | | ($13,768) |

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 5 percent of the hours in 2008.

### 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 2008, power flows were only from PJM to New York. Power is exported directly from New Jersey to Long Island. For 2008, the total real-time scheduled net exports on the Neptune line were 5,133 GWh while the day-ahead scheduled net exports were 5,169 GWh. Figure 4-11 shows the hourly average flow, by hour of the day, on the Neptune line for calendar year 2008. The average hourly flow during 2008 was -572 MWh. For the calendar year 2008, the average hourly PJM/NEPT Interface price was $84.74 per MWh, while in NYISO the Long Island zone's average price was $99.07 per MWh.

*Figure 4-11 Neptune hourly average flow: Calendar Year 2008*




### Interface Pricing Agreements with Individual Companies

PJM consolidated the southeast and southwest interface pricing points to a single interface (SOUTHIMP and SOUTHEXP) on October 31, 2006.[25] The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

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

25 PJM posted a copy of its notice, dated August 31, 2006, on its Website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx>
26 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) (Accessed January 13, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx> (171 KB).
27 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) (Accessed January 13, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx> (210 KB).

March 19, 2007.[28] Each of these agreements established a locational price for power purchases and sales between PJM and the individual company that applies under specified conditions. For example, when the company desires to sell into PJM (a PJM import), the rules require that the company cannot have simultaneous scheduled imports from other areas. Similarly, when a company wants to purchase from PJM (a PJM export), the rules require that the company cannot simultaneously have scheduled exports to other areas.

There are a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing did not reflect actual power flows, that the pricing did not reflect security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate and notified the counterparties that PJM would be terminating the agreements effective January 31, 2009.[29]

Table 4-11 shows the LMP calculated per the bilateral agreements and, for comparison, the SOUTHIMP and SOUTHEXP LMP for calendar year 2008. The difference between the LMP under the agreements and PJM's SOUTHIMP LMP ranged from $4.18 with Duke to $6.98 with PEC while the difference between the LMP under the agreements and PJM's SOUTHEXP LMP ranged from $4.20 with Duke to $7.01 with PEC.

***Table 4-11 Average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2008.***

| | LMP | SOUTHIMP | SOUTHEXP | Difference LMP - SOUTHIMP | Difference LMP - SOUTHEXP |
|---|---|---|---|---|---|
| Duke | $59.65 | $55.47 | $55.45 | $4.18 | $4.20 |
| PEC | $62.46 | $55.47 | $55.45 | $6.98 | $7.01 |
| NCMPA | $59.72 | $55.47 | $55.45 | $4.25 | $4.28 |

In response to requests for broader applicability, PJM proposed a new pricing methodology. PJM filed tariff revisions with FERC that allowed for a three phase approach, with a sunset date of January 2010, and provided for the parallel development of an interregional congestion management agreement.[30]

The broader issue is how best to provide price signals to external areas, including both market and non market areas. The goal of interface pricing is to match actual, physical flows into and out of PJM with appropriate locational marginal price signals. An appropriate locational marginal price signal for an external generating unit is a price signal identical to that which would result from an LMP system, which reflects the actual incremental dispatch of units to meet incremental load, in the presence of transmission constraints. Prices which ignore the actual dispatch of generation in external areas and its impacts on locational prices, including PJM locational prices, will result in inefficient pricing, the potential for increased loop flows and the potential for gaming at the expense of PJM members. Comprehensive interregional congestion management agreements that

28 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) (Accessed January 13, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx> (279 KB).

29 See "Interface Pricing Discussion" (September 11, 2008) (Accessed February 25, 2009) <http://www.pjm.com/Media/committees-groups/committees/mic/20080911-item-05a-interface-pricing-presentation.pdf> (44 KB).

30 *PJM Interconnection LLC.*, Tariff Filing, Docket No. ER09-369-000 (December 2, 2008).

provide for joint redispatch to relieve congestion are an essential starting point for establishing the basis for accurate pricing. Such agreements would provide for redispatch and LMP modeling on both sides of existing seams in order to ensure that all participants receive the correct price signals, consistent with their impact on the underlying electrical network. The goal is to establish locational marginal price signals that accurately reflect all loads, generation and power flows based on security constrained economic dispatch, in all areas where entities want to sell to and buy from PJM markets. This does not mean that any external entity or area would have to use locational marginal pricing for its own internal purposes.

## *Interchange Transaction Issues*

Interchange transactions may occur in the Real-Time Energy Market or in the Day-Ahead Energy Market. Issues arise in both the Real-Time and Day-Ahead Markets.

### Interchange Transactions – Real-Time Energy Market

There are three steps required for market participants to enter external interchange transactions in PJM's Real-Time Energy Market. The steps are: acquisition of valid transmission via the Open Access Same Time Information System (OASIS); acquisition of available ramp via PJM's Enhanced Energy Scheduler system (EES); and the creation of a valid NERC Tag. In addition, the interchange request must pass the neighboring balancing authority checkout process in order for the request to be implemented. After a successful implementation of an external energy schedule, the energy will flow between balancing authorities. Such a transaction will continue to flow at its designated energy profile as long as the system can support it, it is deemed economic based on options set at the time of scheduling, or until the market participant chooses to curtail the transaction.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction.

### Interchange Transactions – Day-Ahead Energy Market

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

There are three types of day-ahead external energy transactions: Fixed; Up-to congestion; and Dispatchable.

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

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay. If, in the Day-Ahead Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations.

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

## Transactions Issues in the Real-Time Energy Market

### *Spot Import*

Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability. Price and PJM system conditions, rather than ATC, effectively limited imports.

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with Midwest ISO (MISO) to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[31] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

31 See "WPC White Paper" (April 20, 2007) (Accessed December 29, 2008) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>(97 KB).

In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[32] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

Some market participants responded to the new rules by reserving spot import service but tagging only 1 MW against the reservation. This prevented the transmission reservation from expiring and allowed them to hold it for future use. This approach does not prevent other participants from obtaining transmission capability, as the ATC for the next hour is calculated based on the level of transmission with a NERC Tag and not reservations. Any transmission not scheduled on the NERC Tag would become available in the next hour.

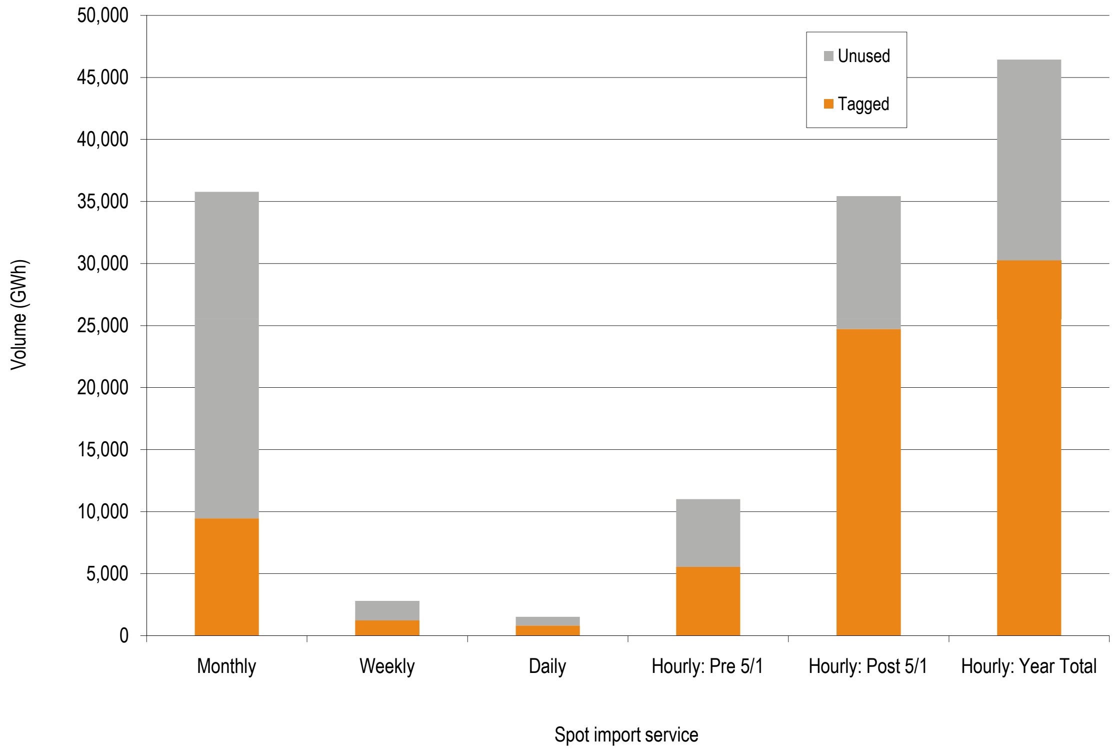
The new rules governing spot import service could have an unanticipated effect. For example, if there were 1,000 MW of ATC posted for a particular hour, a market participant could reserve the 1,000 MW of transmission service and schedule 1 MW against it. In the next hour, 999 MW of ATC would be posted for the same hour. A second market participant could reserve the 999 MW of service and schedule 1 MW against it. In this example, there are 1,999 MW of transmission reserved on a path that has a reliable limit of 1,000 MW. If both market participants chose to utilize their full allocation of spot import service, the potential exists for creating a transmission system limit to be exceeded.

The MMU recommends that PJM reconsider whether the new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable.

Figure 4-12 shows the utilization of spot import service for calendar year 2008. As of May 1, 2008, only hourly spot import service is available. The spot reservations for the monthly, weekly and daily options represent those reservations that existed prior to the modifications.

32 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) (Accessed December 29, 2008) <http://www.pjm.com/~/media/etools/oasis/20090131-regional-practices-redline.ashx> (450 KB).

*Figure 4-12 Spot import service utilization: Calendar year 2008*




## Willing to Pay Congestion and Not Willing to Pay Congestion

The source and sink of an OASIS reservation designate the buses on the PJM system for which settlement LMPs are calculated. For import external energy transactions, the source defaults to the external interface as determined by the selected Point of Receipt (POR) and Point of Delivery (POD). For export external energy transactions, the sink defaults to the external interface as determined by the selected POR and POD. For wheel through transactions, both the source and sink default to the external interfaces as determined by the selected POR and POD (the source defaults to the POR interface and the sink defaults to the POD interface). The market participant can then select the source or sink that is not pre-determined by the selected path. This selection determines the explicit congestion charge that the market participant is exposed to, as congestion is calculated as the difference in LMP from the sink to the source.

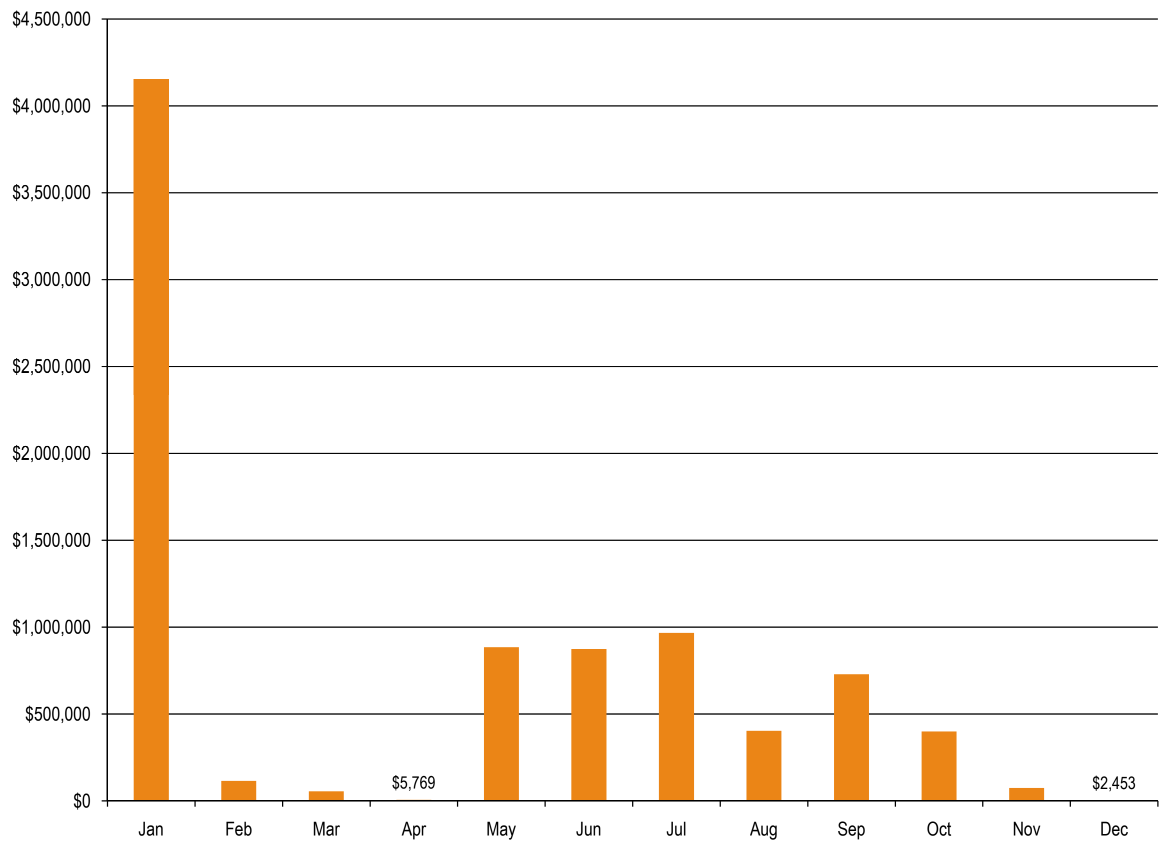
When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow and congestion results.

If a market participant is not willing to pay congestion, the market participant expects the PJM operators to curtail their transaction as soon as there is a difference in LMPs between their selected source and sink.

Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. In January 2008, approximately four million dollars in uncollected congestion charges were realized by PJM related to not willing to pay congestion transmission reservations. Many of the transactions that contributed to the uncollected congestion charges were only 15 minutes in duration. The method that PJM uses to curtail not willing to pay congestion requires the transaction to be loaded. While loaded, if congestion occurs for a not willing to pay congestion transaction, a message is sent to the PJM operators requesting the transaction be curtailed at the next 15 minute interval. When transactions are scheduled for only 15 minutes, market participants are able to complete a transaction in the presence of congestion without paying congestion charges.

The market participants whose activities resulted in uncollected congestion charges were contacted by the MMU and the uncollected congestion charges were significantly reduced over the next few months. The issue reappeared in May, although to a lesser extent. (See Figure 4-13). The MMU recommends modifying the evaluation criteria via a modification to PJM's market software, to ensure that not willing to pay congestions transactions are not permitted to flow in the presence of congestion.

*Figure 4-13 Monthly uncollected congestion charges: Calendar year 2008*



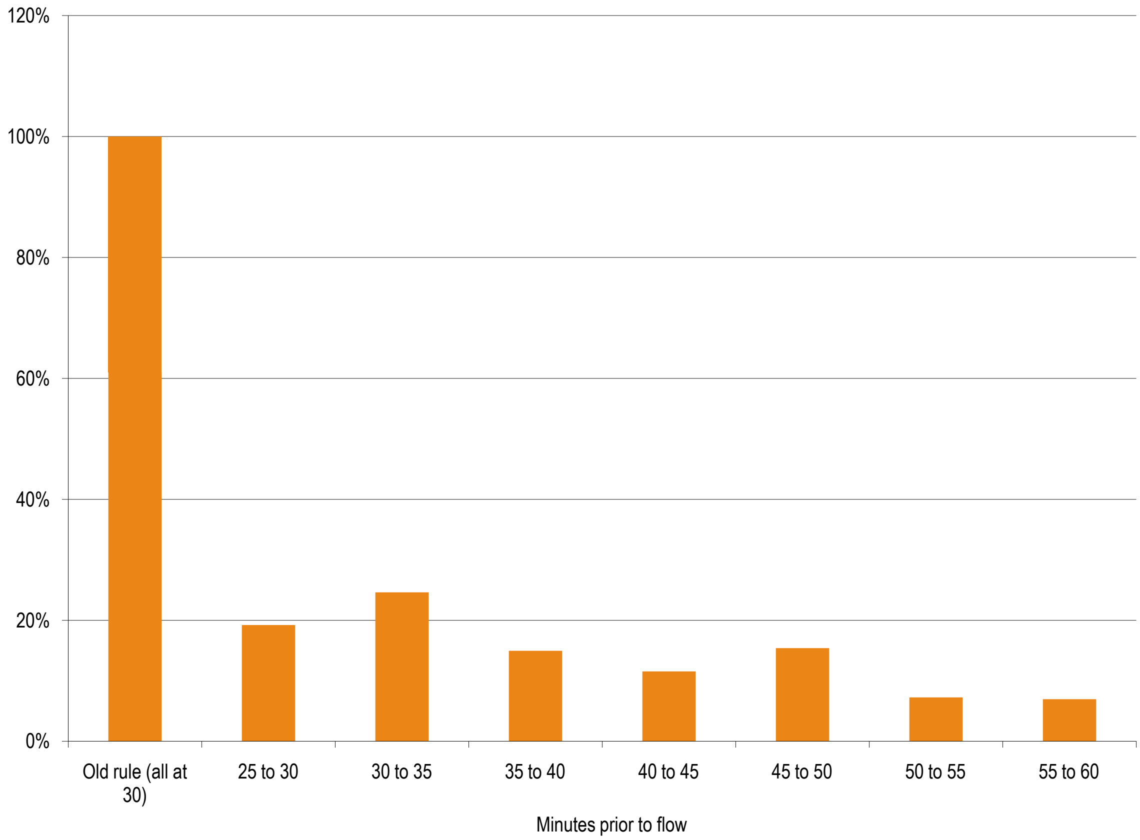
### Ramp Availability

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 default limit is ± 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 4-14 shows the ongoing results of the ramp rule change that became effective on August 7, 2006. 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 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 4-14. 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).

*Figure 4-14 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 to December 2008*




The artificial creation of ramp room is an ongoing issue. 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. The import transaction flows and the export reservation expires 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.[33] 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.

Large swings in PJM's ramp availability have continued to be regularly observed at the NYISO 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

33 PJM. "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 9.

market clearing. When the NYISO market results are posted, the ramp reservations for any unsuccessful bids are returned to the PJM system. The result is a large swing in ramp observed at approximately 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 by submitting out-of-market bids and offers for import or export transactions to the NYISO, thus limiting ramp availability to competitors. Additionally, market participants can extend their NYISO market bids to cover multiple hours to acquire ramp by submitting out-of-merit bids and offers. For example, if ramp is not available at the end time of the desired hour, the market participant can submit a NYISO schedule to cover two hours, thus having no effect at the time when ramp is not available. When the NYISO evaluates the second hour, it will not pass their market (as it is out-of-merit) and they will deny the transaction. PJM will have no choice but to remove the transaction from the second hour, thus causing a ramp violation at the end of the first hour where ramp was initially not available.

The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit was based on the availability of ramping capability by generators on the PJM system. The available generation on the PJM system can only move 1,000 MW over any given 15 minute period. PJM must limit the amount of imports or exports at each 15 minute interval to account for the physical characteristics of the generation to meet the imports and exports. In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. As a result, a new business rule was proposed and approved to require all transactions to be at least 45 minutes in duration.[34] The EES system was to be modified to require that transactions be 45 minutes in duration. As of the end of 2008, the modification to the EES application had not been completed. Market participants have been scheduling 1 MW for the first 30 minutes, and increasing to a larger MW value for the last 15 minutes, thus continuing to create significant swings in imports and exports. The MMU recommends that the EES application be modified to account for the constant MW rule over the entire 45 minutes as soon as possible.

### *Curtailment of Transactions*

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations.

There are three types of economic curtailments: curtailments of dispatchable schedules; OASIS designation curtailments; and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as “real-time with price”) is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface from which the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP they are willing to sell at). An export dispatchable schedule specifies the maximum LMP at the interface from which the market participant wishes to purchase the power from PJM.

34 PJM. “Manual 41: Managing Interchange,” Revision 03 (November 24, 2008), p. 5.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If at any time the system operator does not feel that the transaction will be economic, they will elect to curtail the dispatchable transaction. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. If prices are such that the transaction should not have been loaded, it will be made whole in the settlement process.

Not willing to pay congestion transactions can be curtailed if there is realized congestion between the designated source and sink.

Spot import service is dispatchable at a price of zero, by definition. If the interface price reaches zero, PJM system operators will curtail all transactions using spot import service flowing over that interface.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

### *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 balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM called more TLRs in 2008 than in 2007. The primary reason for the increase in TLR activity in 2008 was the result of transmission line outages caused by storms and tornados. The transmission line outages reduced the ability to control power flows via redispatch, creating the need to utilize TLRs. PJM TLRs increased by 87.5 percent, from 80 during 2007 to 150 in 2008. (See Figure 4-15.) In addition, the number of different flowgates for which PJM declared TLRs increased from 27 during 2007 to 37 in 2008. (See Figure 4-16.) The total MWh of transaction curtailments increased by 76 percent, from 288,616 MWh in 2007 to 506,617 MWh in 2008. (See Figure 4-17.) Of the 150 TLRs called by PJM in 2008, three facilities comprised 47 percent of the total. The three facilities were:

- **East Frankfort – Crete 345 kV Line for Loss of Dumont – Wilton Center 765 kV Line.** These lines are located in northern Illinois, close to the border of Indiana. TLRs on this flowgate were generally utilized to control flows across the Illinois-Indiana border through the Northern Indiana Public Service system. While PJM and MISO work together to control these flows using the mechanisms prescribed in the JOA, the actions were not always sufficient. TLRs on this flowgate were used to control the constraints (35 TLRs in 2008; 0 TLRs in 2007);

- **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 (23 TLRs in 2008; 8 TLRs in 2007); and

- **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 (15 TLRs in 2008; 9 TLRs in 2007).

Midwest ISO called significantly fewer TLRs in 2008 than in 2007. Midwest ISO TLRs decreased by about 27 percent, from 819 during 2007 to 597 in 2008. (See Figure 4-15.)

***Figure 4-15 PJM and Midwest ISO TLR procedures: Calendar years 2007 and 2008***

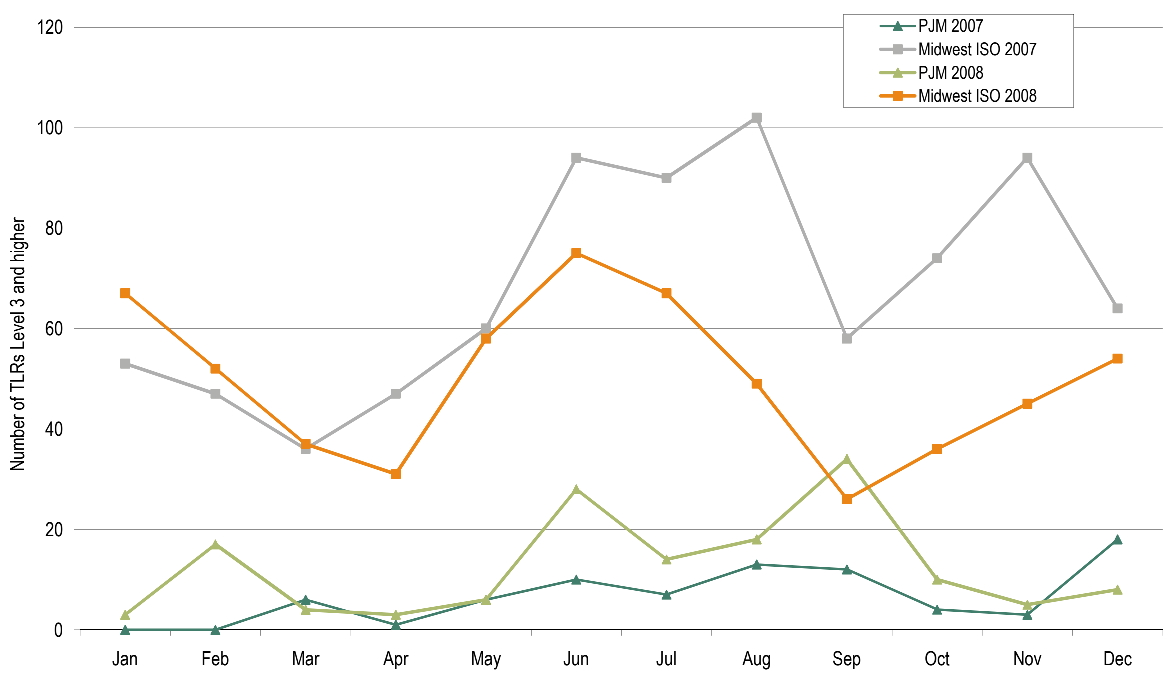


*Figure 4-16 Number of different PJM flowgates that experienced TLRs: Calendar years 2007 to 2008*

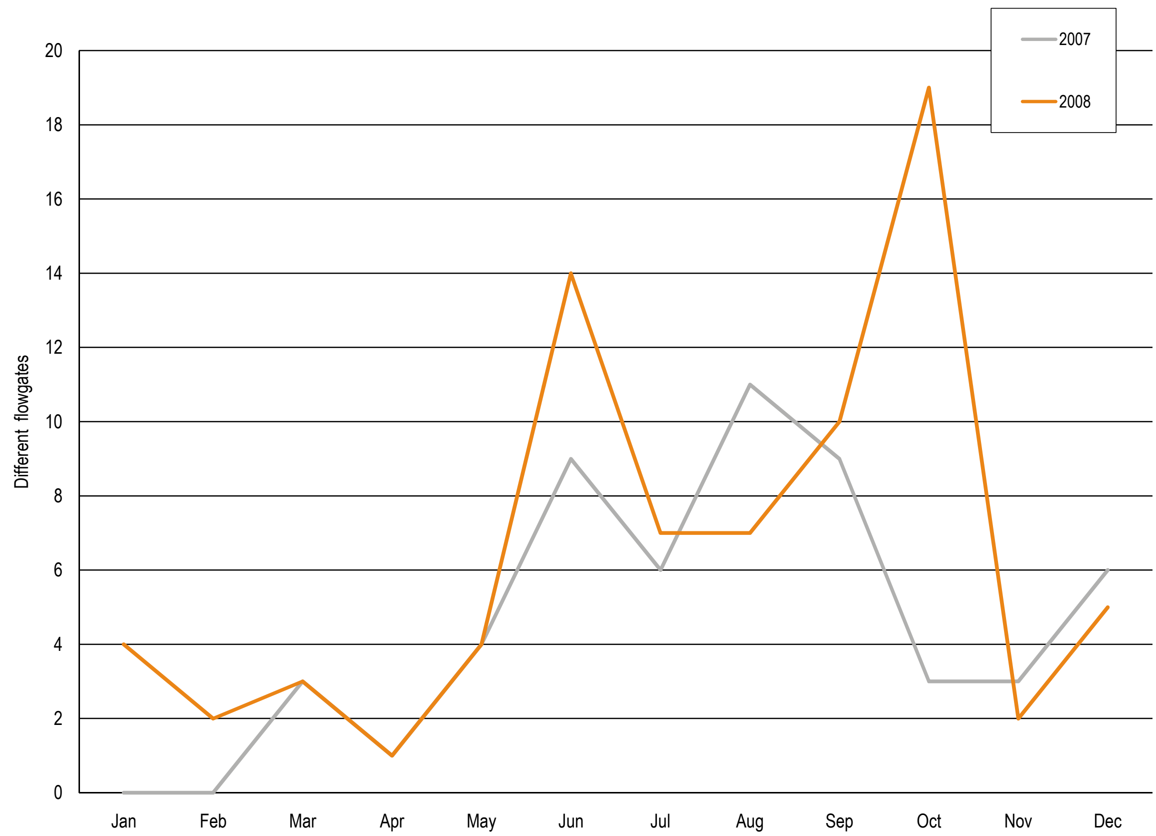
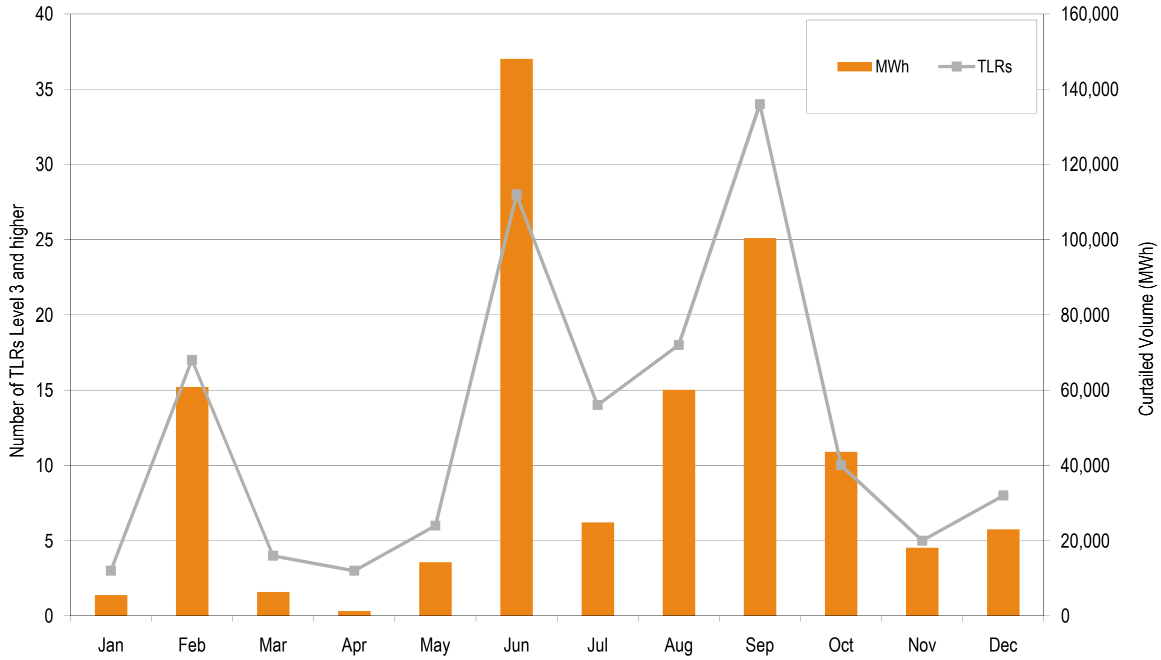


*Figure 4-17 Number of PJM TLRs and curtailed volume: Calendar year 2008*




## Up-To Congestion

In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[35] 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. Increasing the offer cap, and allowing negative offers, could potentially increase the cleared volume of up-to congestion transactions, and aggravate the issue.

On February 21, 2008, the MRC approved PJM's proposed resolution to the request for implementation on March 1, 2008.[36] The proposal allowed for an increased offer cap from $25 to ± $50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to address the mismatches between the Day-Ahead and Real-Time Markets. As part of the agreement, PJM will maintain an up-to date list of sources and sinks that will be unavailable for up-to congestion bids. This list will be posted on the PJM OASIS.[37] In the months following the modifications to the up-to congestion bids, the total MWh of up-to congestion bidding has significantly increased from previous years. (See Figure 4-18.)

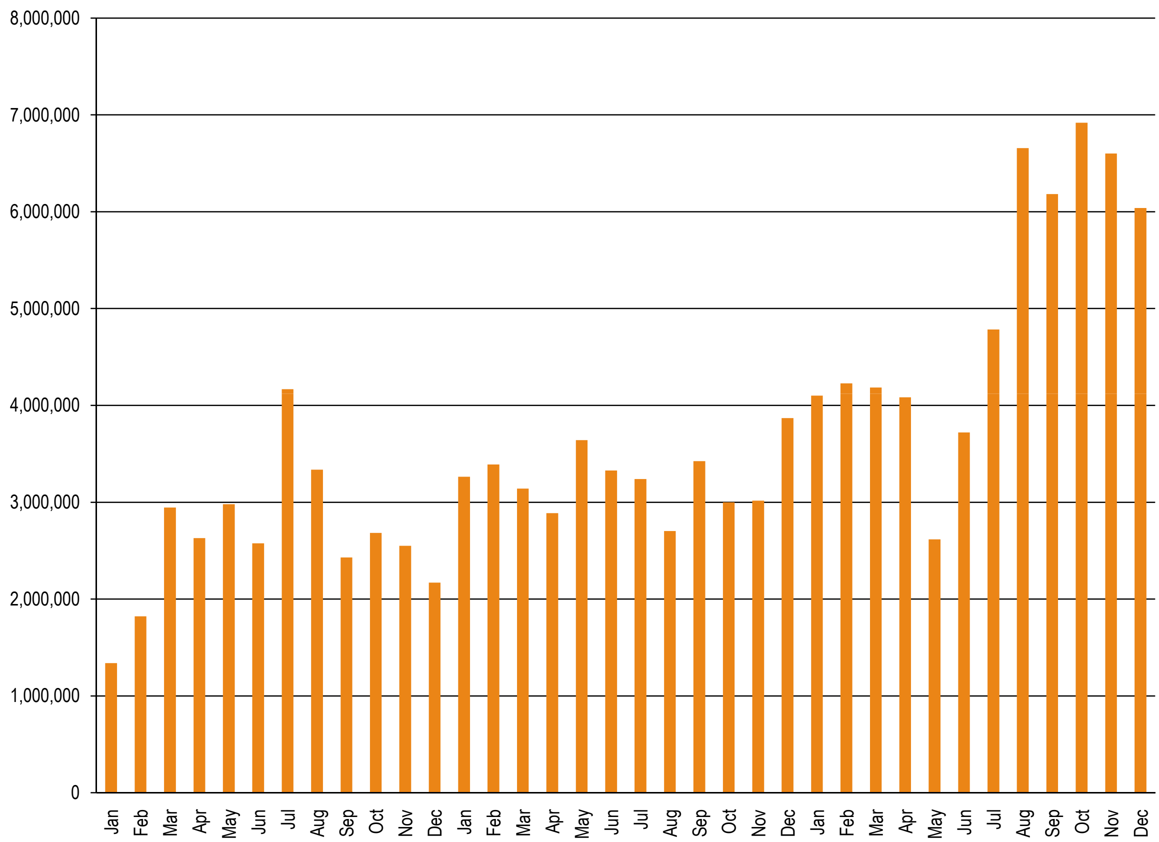
35 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed February 18, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).

36 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2009) <http://www.pjm.com/Media/committees-groups/committees/mrc/20080221-minutes.pdf > (61KB).

37 See PJM. "20080303-oasis-sources-and-sinks.ashx" (March 3, 2008) (Accessed January 15, 2009) <http://www.pjm.com/markets-and-operations/etools/oasis/~/media/etools/oasis/20080303-oasis-sources-and-sinks.ashx > (61KB).

The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

*Figure 4-18 Monthly up-to congestion bids in MWh: Calendar years 2006 to 2008*




## 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 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 close to net scheduled interface flows, on average for 2008 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 balancing authorities.

During 2008, for PJM as a whole, net scheduled and actual interchange differed by 1.7 percent.[38] (See Table 4-12.) Actual system net exports were 9,859 GWh, 174 GWh less than the scheduled total net exports of 10,032 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 11,001 GWh exceeding scheduled imports of 3,013 GWh by 14,014 GWh or 465 percent, for an average of 1,595 MW during each hour of the year. The case also existed at interfaces where there was a net scheduled export, but the actual flows were into PJM. This occurred at the PJM/AMIL, PJM/CPLE, PJM/FE, PJM/IPL, PJM/TVA and the PJM/WEC Interfaces. The largest difference occurred at the PJM/FE Interface, where scheduled exports were 2,450 GWh and actual flows were 6,761 GWh in the import direction, creating an imbalance of 9,211 GWh or 376 percent, for an average of 1,049 MW during each hour of the year.

38 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 2,092 GWh is the net dynamic schedule.

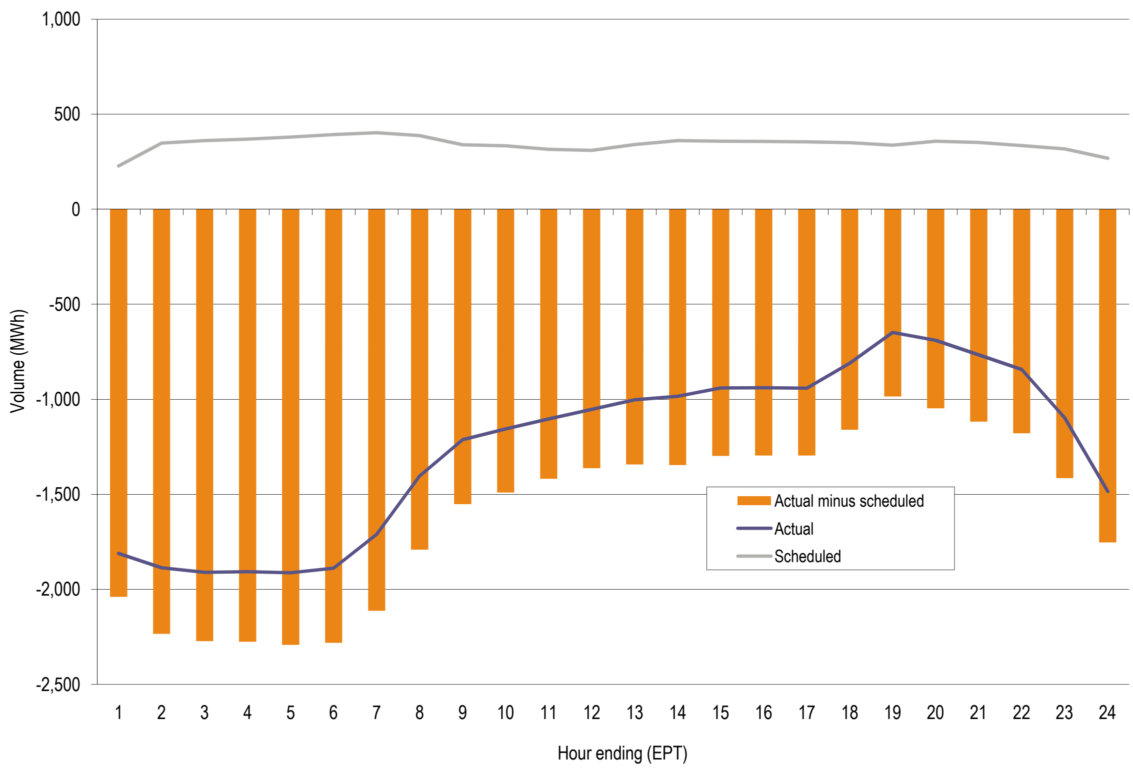
*Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2008*

| | Actual | Net Scheduled | Difference | Difference (percent of net scheduled) |
|---|---|---|---|---|
| ALTE | (6,441) | (1,486) | (4,955) | 333% |
| ALTW | (2,992) | (1,339) | (1,653) | 123% |
| AMIL | 5,060 | (249) | 5,309 | (2132%) |
| CIN | 2,301 | 3,950 | (1,649) | (42%) |
| CPLE | 6,804 | (949) | 7,753 | (817%) |
| CPLW | (2,064) | (809) | (1,254) | 155% |
| CWLP | (744) | (13) | (731) | 5611% |
| DUK | (4,130) | (8) | (4,122) | 50283% |
| EKPC | (586) | (1,447) | 861 | (59%) |
| FE | 6,761 | (2,450) | 9,211 | (376%) |
| IPL | 2,736 | (788) | 3,524 | (447%) |
| LGEE | 1,325 | 1,680 | (355) | (21%) |
| MEC | (3,699) | (1,742) | (1,957) | 112% |
| MECS | (11,001) | 3,013 | (14,014) | (465%) |
| NEPT | (5,027) | (5,027) | - | 0% |
| NIPS | (2,415) | (734) | (1,681) | 229% |
| NYIS | (5,663) | (7,123) | 1,460 | (20%) |
| OVEC | 7,591 | 9,553 | (1,962) | (21%) |
| TVA | 941 | (3,124) | 4,065 | (130%) |
| WEC | 1,385 | (939) | 2,324 | (248%) |
| Total | (9,859) | (10,032) | 174 | (1.7%) |

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

As in 2007, 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 4-19.) 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 2,164 MW per hour for those overnight hours. The daytime hours (hour ending 0800 through hour ending 2300) difference between actual and scheduled exports averaged 1,365 MW.

*Figure 4-19 PJM/MECS Interface average actual minus scheduled volume: Calendar year 2008*




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 4-19 and Figure 4-21.) The consolidation of the former southeast and southwest pricing points in October 2006 has had an ongoing impact at the PJM/TVA Interface.[39] Figure 4-20 shows the average hourly actual flows, 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 2008, this difference decreased by 64 percent to 480 MW (on average) each hour. (See Figure 4-21.)

39 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 4-20 PJM/TVA average flows: January 1, to September 30, 2006, pre-consolidation*

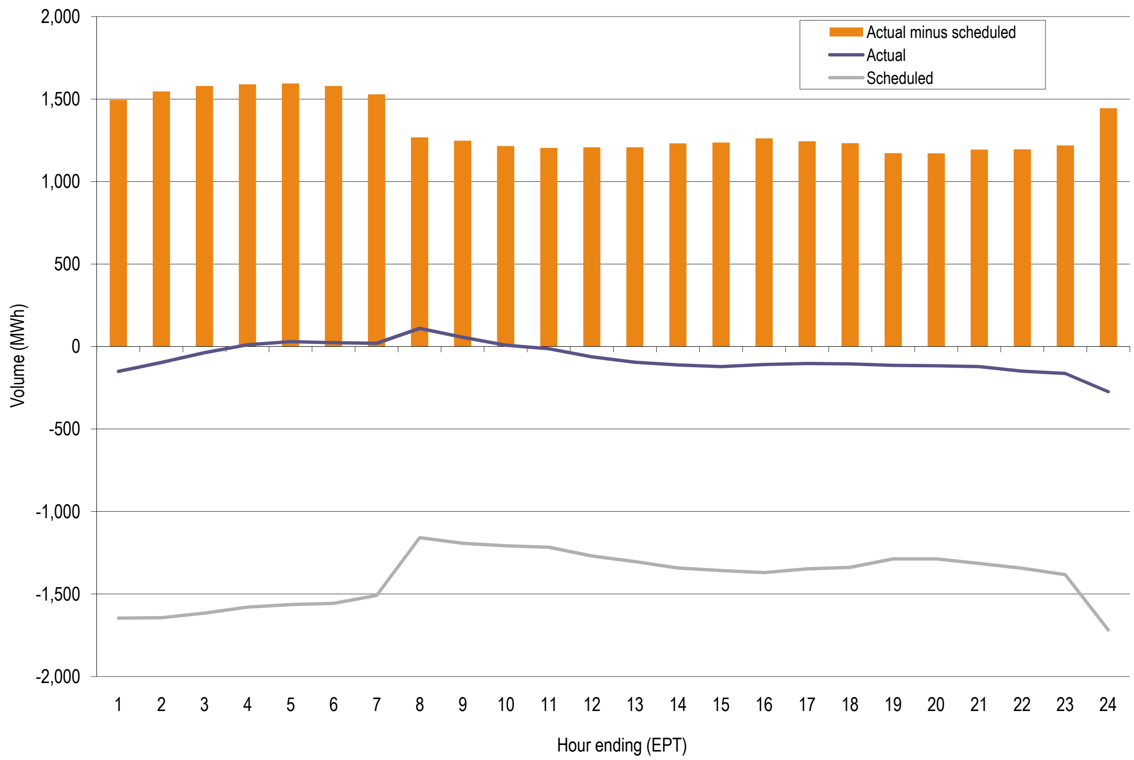
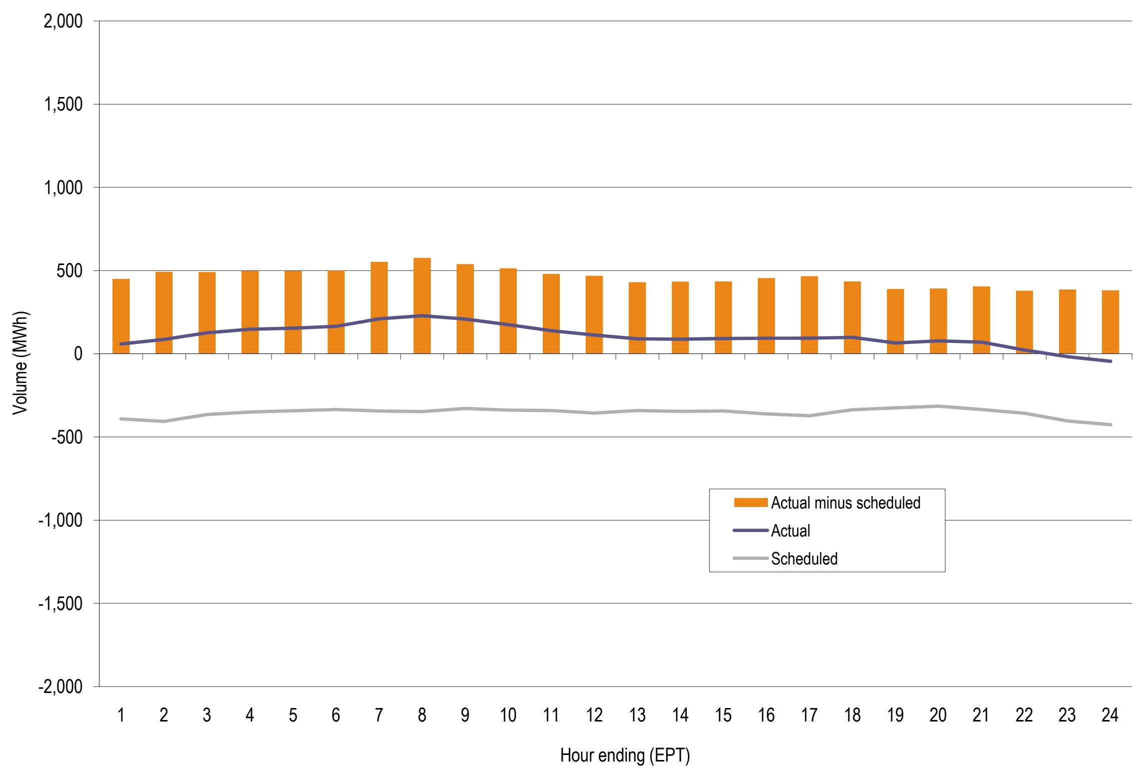



*Figure 4-21 PJM/TVA average flows: Calendar year 2008*



### Loop Flows at PJM's Southern Interfaces

Figure 4-22 and Figure 4-23 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 balancing authorities, at the SOUTHEXP interface pricing point. Similarly, PJM began to price all transactions that sink in PJM and source in one of the defined balancing authorities, 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. While the SOUTHIMP and SOUTHEXP pricing points have replaced the Southeast and Southwest pricing points, Figure 4-22 and Figure 4-23 are included for comparison.

***Figure 4-22 Southwest actual and scheduled flows: Calendar years 2006 to 2008***

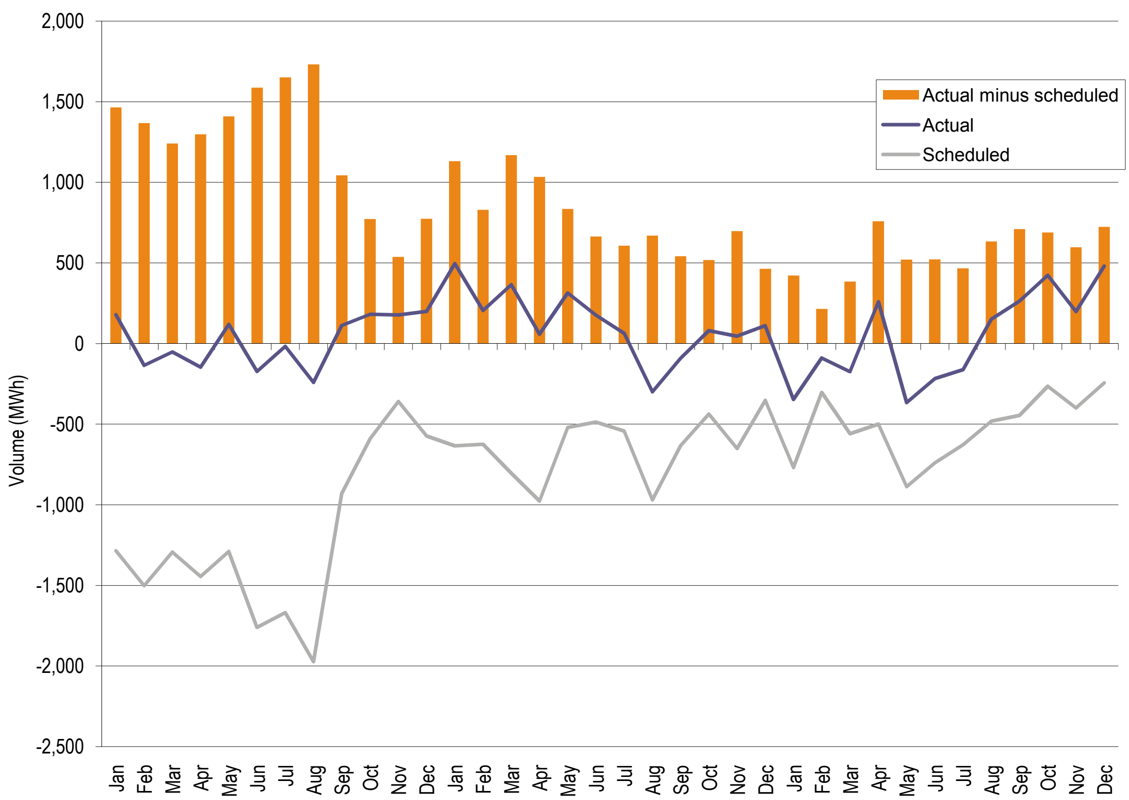
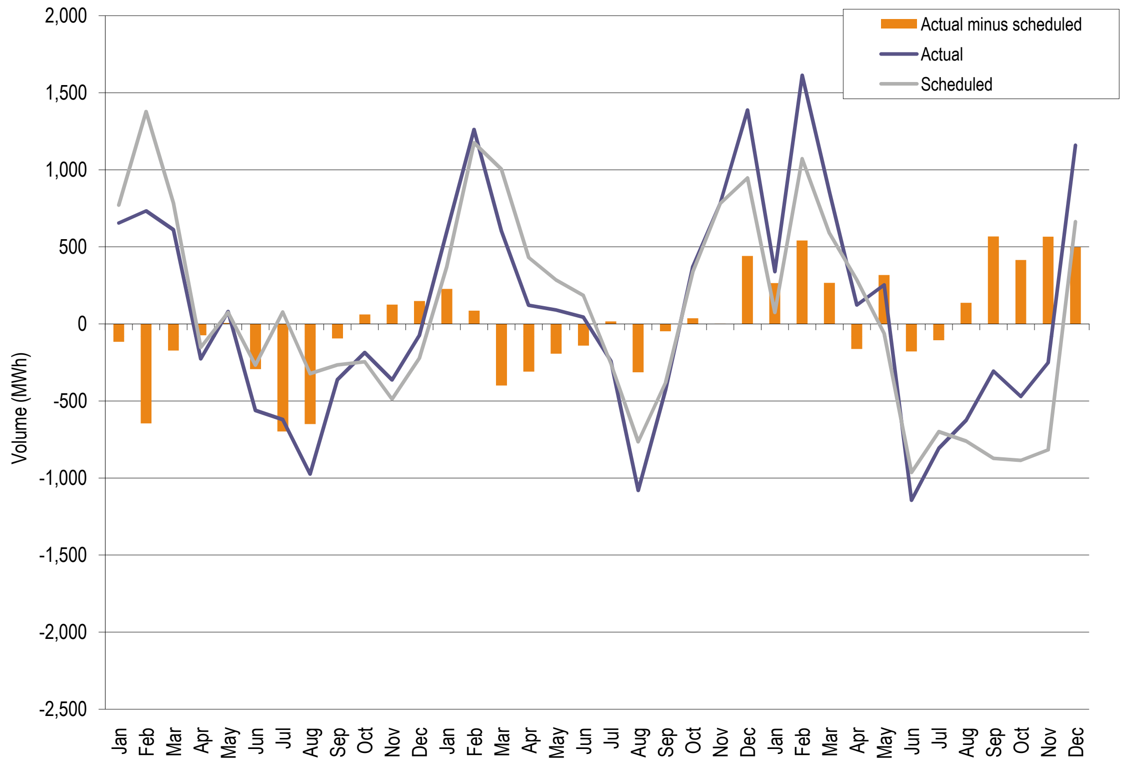


*Figure 4-23 Southeast actual and scheduled flows: Calendar years 2006 to 2008*




## Loop Flows at PJM's Northern Interfaces

In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows. In 2008, market participants scheduled transactions on a path from the NYISO to PJM through Ontario's Independent Electricity System Operator (IESO) and Midwest ISOsystems, rather than reflecting the actual power flows which were primarily directly from NYISO to PJM. The participants faced a price incentive to engage in this behavior. When export transactions were scheduled from NYISO to Ontario, participants paid the lower export price at NYISO's Ontario interface rather than the higher export price at NYISO's PJM interface. The export price differences were more than enough to cover the cost of transmission through Ontario and MISO into PJM. When the export transactions were approved in the NYISO hourly market, the NYISO committed additional generation to support the transactions. The actual flow of energy that resulted was primarily directly from NYISO to PJM across the PJM/NYISO Interface. PJM's interface pricing calculations correctly reflected the actual power flows but NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

On July 21, 2008, the NYISO submitted to FERC an Exigent Circumstances Filing to address this issue.[40] The purpose of the filing was to provide the NYISO the authority to prevent market participants from submitting bids on a set of specific paths associated with the identified scheduling issue. The MMU submitted comments in that proceeding on November 10, 2008, noting that the NYISO's approach to interface pricing is based on the identified fictional scheduled contract paths and do not recognize the actual power flows. The MMU also requested that the Commission condition its approval on a requirement that NYISO work with PJM to develop a more complete solution for interface pricing, congestion management and transmission planning at the NYISO-PJM Interface, within a defined time frame.[41] PJM filed similar comments.[42] By order issued November 17, 2008, the Commission approved NYISO's filing, but required NYISO "to file a status report on its progress in developing solutions to the loop flow problem, including an inter-RTO congestion management process."[43] The NYISO recently filed a report to comply on February 17, 2009.[44] The MMU plans to work with NYISO and PJM to seek a comprehensive solution to this issue.

### *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.[45] 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. The second phase of the joint loop flow study was completed in 2008.[46] In the second phase study, the development of the archive was abandoned due to issues in acquiring IDC data. Instead, the Transmission Adequacy and Reliability Assessment (TARA), an analysis tool that can calculate generation to load impacts, was developed. This tool, while effective in further understanding the sources of loop flows, does not permit a complete analysis of interconnect wide loop flows due to the limited granularity of data.

40 *New York Independent System Operator, Inc.*, Tariff Filing, Docket No. ER08-1281-000 (July 21, 2008).
41 Motion to Intervene and Comments of the Independent Market Monitor for PJM, filed in Docket No. ER09-198, et al. at 2–3. A complete copy of this pleading is posted on Monitoring Analytics' Website at: http://www.monitoringanalytics.com/reports/Reports/2008/filing-motion-to-intervene-comments-er09-198-as-filed.pdf
42 A copy of this filing is posted on PJM's Website at: http://www.pjm.com/Media/documents/ferc/2008-filings/20081110-er09-198-001.pdf
43 *New York Independent System Operator, Inc.*, 125 FERC ¶ 61,184 at P 20.
44 A copy of the report is posted on the NYISO Website at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2009/02/NYISOreport2_17_09FNL.pdf.
45 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).
46 See "Loop Flow Phase II Study Report – Final" (November 14,2008) (Accessed February 4, 2009) http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20081114-loop-flow-phase-ii-study-report-final-20081112.pdf (3,022 KB).

PJM and Midwest ISO also submitted a memorandum to a NAESB committee reiterating and elaborating the recommendation suggesting a process for determining the allocation of responsibility for congestion relief.[47] The NAESB committee included in their annual plan a commitment to work with NERC on the congestion management issue.[48] As the annual plan states, this is an action item scheduled for completion in 2009.

The MMU recommends that PJM and Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impacts data, actual flowgate flows data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

47 See "Annual Plan Item: Determine Future Path for TLR in Concert with NERC" (October 24, 2007) (Accessed February 23, 2009) <http://www.naesb.org/pdf3/weq_aplan102907w1.pdf> (26 KB).

48 See "North American Energy Standards Board, 2008 WEQ Annual Plan Adopted by the Board of Directors on December 13, 2007" (December 13, 2007) (Accessed February 23, 2009) <http://www.naesb.org/pdf3/weq_2008_annual_plan.doc> (281 KB).