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 Market.** PJM was a monthly net exporter of energy during the period from 2004 through late 2008. PJM was a monthly net importer of energy in the Real-Time Market in January, February, March and May of 2009, and a net exporter of energy in April, June, July, August and September. In the Real-Time Market, monthly net interchange averaged -20 GWh.[1] Gross monthly import volumes averaged 3,738 GWh while gross monthly exports averaged 3,758 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** PJM was a net exporter of energy in the Day-Ahead Market in all months except July. The Day-Ahead monthly net interchange averaged -665 GWh. Gross monthly import volumes averaged 4,106 GWh while gross monthly exports averaged 4,771 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first nine months of 2009, gross imports in the Day-Ahead Energy Market were 110 percent of the Real-Time Market's gross imports (90 percent for the calendar year 2008) while gross exports in the Day-Ahead Market were 127 percent of the Real-Time Market's gross exports (106 percent for the calendar year 2008).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first nine months of 2009, there were net exports at 12 of PJM's 21 interfaces.[2] The top four net exporting interfaces in the Real-Time Market accounted for 72 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 50 percent (PJM/Neptune (NEPT) with 27 percent and PJM/NYIS with 23 percent), PJM/Carolina Power and Light-East (CPLE) with 13 percent and PJM/First Energy (FE) with 9 percent of the net export volume. Nine PJM interfaces had net imports, with two importing interfaces accounting for 88 percent of the net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 66 percent and PJM/Michigan Electric Coordinated System (MECS) with 22 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 13 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 62 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 24 percent, PJM/eastern Alliant Energy Corporation (ALTE) with 19 percent and PJM/NYIS with 17 percent. (While there were net imports at the PJM/NYIS interface in the Day-Ahead, when combined with the net exports at the PJM/NEPTUNE (NEPT) interface, the overall interchange with the NYISO accounts for 17 percent of the Day-Ahead exports). There were net imports in the Day-Ahead Market at eight of PJM's 21 interfaces. The top three importing interfaces accounted for 80 percent of the total net imports, PJM/OVEC with 51 percent, PJM/Michigan Electric Coordinated System (MECS) with 18 percent and PJM/Wisconsin Energy Corporation (WEC) with 11 percent.

- **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 bidirectional, but in the first nine months of 2009, power flows were only from PJM to New York. The average hourly flow during the first nine months of 2009 was -567 MW.

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.

2 In September 2009, the Linden Variable Frequency Transformer (VFT) facility began testing. This facility is treated as a separate interface with PJM, bringing the total interfaces with PJM to 21.

- **Linden Variable Frequency Transformer (VFT) facility.** On November 1, 2009, the Linden VFT facility is expected to be placed in service, providing an additional connection between PJM and the New York Independent System Operator, Inc. A variable frequency transformer is a technology which allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer. The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[3] In September 2009, PJM and the NYISO began scheduling flow across this line for the purposes of testing. The average hourly flow during the initial testing period in September 2009 was -24 MW.

Interactions with Bordering Areas

- **PJM Interface Pricing with Organized Markets.**
  - **PJM and Midwest ISO Interface Pricing.** During the first nine months of 2009, 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 the first nine months of 2009, 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.** During the first nine months of 2009, PJM issued 116 transmission loading relief procedures (TLRs). Of the 116 TLRs issued, the highest levels reached were TLR 3a in 57 instances and TLR 3b in the remaining 59 events. This represents a decrease of 9 percent in TLRs from the 127 TLRs issued during the first nine months of 2008. (47 TLR 3a, 77 TLR 3b, 2 TLR 4 and 1 TLR 5b).

- **Operating Agreements with Bordering Areas.**
  - **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[4] 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 during the first nine months of 2009. The market-based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[5]

    In 2009, the Midwest ISO requested that PJM review the components of the CMP to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect during the time period from April 2005 through June 2009. The resulting inaccuracies in the market flow calculation meant that the Midwest ISO received less compensation than appropriate. While the errors in input data have been corrected for market to market activity moving forward, the Midwest ISO and PJM are currently in the process of calculating the shortfall. PJM reported an estimate of 77.5 million dollars.[6]

3 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed November 4, 2009) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,403 KB).

4 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

5 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (November 1, 2007) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

6 See PJM. "PJM/MISO Market Flow Calculation Error" (September 10, 2009) (Accessed October 14, 2009) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

As of October 1, 2009, PJM and the Midwest ISO had not agreed upon a method to estimate the amount for the entire period. Differences have also emerged over how the parties are administering the Joint Operating Agreement, such as the use by Midwest ISO of proxy flowgates. This practice, if confirmed, measured and determined inconsistent with the Joint Operating Agreement, would mean that the Midwest ISO received more compensation than appropriate. The parties are currently engaged in a confidential FERC mediated settlement process.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[7] 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 the first nine months of 2009.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[8] 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 the first nine months of 2009. As part of this agreement, both parties agreed to develop a formal CMP. During the first nine months of 2009, PEC and PJM continued confidential discussions on more granular interface pricing as well as the development of the CMP.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[9] 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.

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first nine months of 2009, PJM continued to operate under the terms of the operating protocol developed in 2005.[10]

Interchange Transaction Issues

- **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.[11] 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 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.[12] 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 partially address the mismatch 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.

- **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

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

8 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2.98 MB).

9 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed November 4, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

10 111 FERC ¶ 61,228 (2005).

11 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed November 4, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).

12 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed November 4, 2009) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mrc/20080221-minutes.ashx > (61KB).

that the energy takes. Although PJM's total scheduled and actual flows differed by 5 percent in the first nine months of 2009, greater differences existed at individual interfaces. Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2008, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-10,536 GWh during the first nine months of 2009 and -14,014 GWh during the calendar year 2008), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (2,614 GWh during the first nine months of 2009 and 4,065 GWh during the calendar year 2008). 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 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) was significant during the first nine months of 2009.

- **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.[13] 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.

During the third quarter of 2009, the Broader Regional Markets group, consisting of representatives from PJM, NYISO, MISO and IESO, continued to work on a solution to the northeastern loop flow issues. The group developed several recommendations, including the use of Phase Angle Regulators (PARs) to control energy flows, a buy-through congestion methodology and the development of new technology to visualize the loop flows.

The use of PARs to regulate power flows is an engineering solution that can be used to directly affect power flows but the increased use of PARs does not address the underlying market pricing issues which provide an incentive for loop flows and is unlikely to provide a solution to loop flows.

Implementing a buy-through congestion methodology is also unlikely to resolve the underlying pricing issue. PJM offers a similar product, where market participants will be allowed to continue to flow their transactions when they would otherwise be curtailed by a TLR, if they were willing to pay the congestion costs of their parallel flows affecting the PJM system. This product, called "TLR Buy-Through", was implemented in PJM in 2001. In the nearly eight years that PJM has offered this product, it has never been used by market participants. Instead, the transactions were curtailed in the TLR process to alleviate the loop flows. The buy-through congestion methodology also included a recommendation that the NYISO move to a less than hourly dispatch timeframe. This is a positive step as using dispatch on the quarter hour, the NYISO market participants will be able to respond more quickly to NYISO pricing signals.

The development of a visualization tool to help identify loop flows could provide useful information to dispatch personnel, but does not address the underlying pricing problem.

The MMU recommends that a change in the interface pricing methodology be addressed directly. The MMU recommends that the parties consider the uniform adoption of a Generation Control Area (GCA) to Load Control Area (LCA) pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

13 See the *2008 State of the Market Report for PJM*, Volume II, "Interchange Transactions."

- **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 contribute to 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 flow 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.

Additional Interchange Transaction Analysis

- **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 applied under specified conditions. There were 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 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 in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

  In addition to terminating the agreements, PJM worked through the stakeholder process to develop a revision to the tariff that would enhance the method for calculating interface pricing with all neighboring balancing authorities that wish to take advantage of the more granular interface pricing. The new interface pricing methodology includes three options.

  The proposed tariff revisions were filed with FERC on December 2, 2008[14], and approved on May 1, 2009.[15] As a condition of the approval, the Commission required that PJM establish procedures to negotiate, in good faith, a congestion management agreement (which is necessary for eligibility to continue the "high/low" and "marginal cost proxy" pricing beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[16] As of October 1, 2009, each of Duke Energy Carolinas, Progress Energy Carolinas and the North Carolina Municipal Power Agency was in the process of negotiating a congestion management agreement with PJM.

  As of July 2009, Duke Energy Carolinas had submitted the required data, and PJM had completed the required software modifications to support the "marginal cost proxy method." As of October 1, 2009, neither Progress Energy Carolinas nor the North Carolina Municipal Power Agency has elected to supply the additional data necessary to take advantage of the "high/low" or the "marginal cost proxy method" for interface pricing. Figure 4-18 through Figure 4-21 show the real-time and day-ahead prices for imports and exports applicable for the interface pricing under the various agreements. During the period from February 1 through May 3, 2009, the interface pricing is based on the SouthIMP and SouthEXP LMPs as there were no agreements in place.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion (WPC), 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 to require a limitation on cross-border transmission service and energy schedules in order to limit

14 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).
15 PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).
16 127 FERC ¶ 61,101.

the impact of such transactions on selected external flowgates.[17] 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 provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a 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. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and at 5:00 EPT when queued the day prior. On June 23, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage has been over 99 percent, compared to 70 percent prior to the modification. (See Figure 4-22). The MMU will continue to monitor participant use of spot import service.

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 not transparent.

The MMU analyzed the transactions between PJM and neighboring balancing authorities for the first nine months of 2009, including evolving transaction patterns, economics and issues. During the first nine months of 2009, PJM was a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 72 percent of the total real-time net exports and two interfaces accounted for 88 percent of the real-time net import volume. Three interfaces accounted for 62 percent of the total day-ahead net exports and three interfaces accounted for 80 percent of the day-ahead net import volume.

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. 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, accurately reflects actual LMP impacts on PJM, and that all participants have access to the defined pricing when in the same position. The goal of such pricing agreements should be to replicate LMP price signals that reflect the actual loads and the actual dispatch of units.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do

17 See "WPC White Paper" (April 20, 2007) (Accessed November 4, 2009) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

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

Figure 4-1 PJM real-time scheduled imports and exports: January through September 2009 (See 2008 SOM, Figure 4-1)

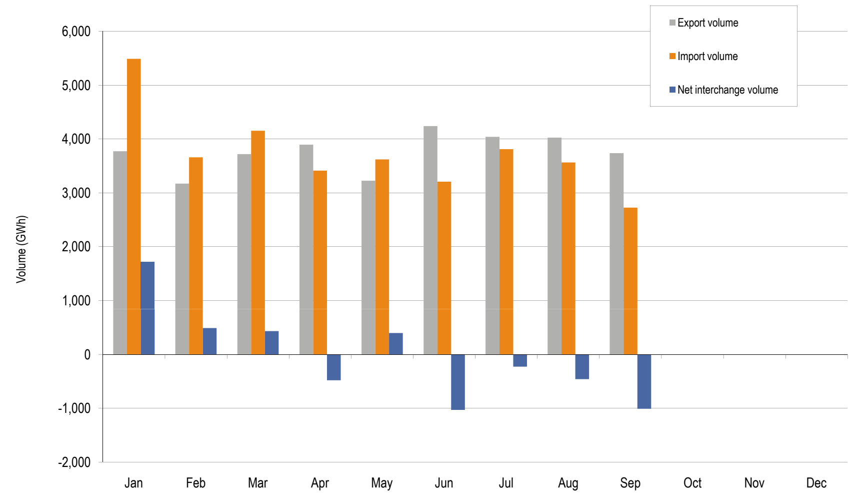


Figure 4-2 PJM day-ahead scheduled imports and exports: January through September 2009 (See 2008 SOM, Figure 4-2)

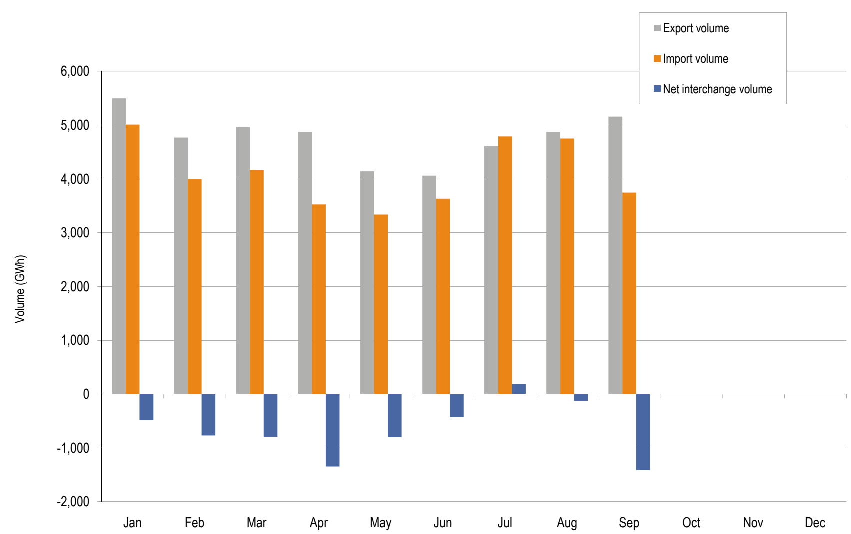
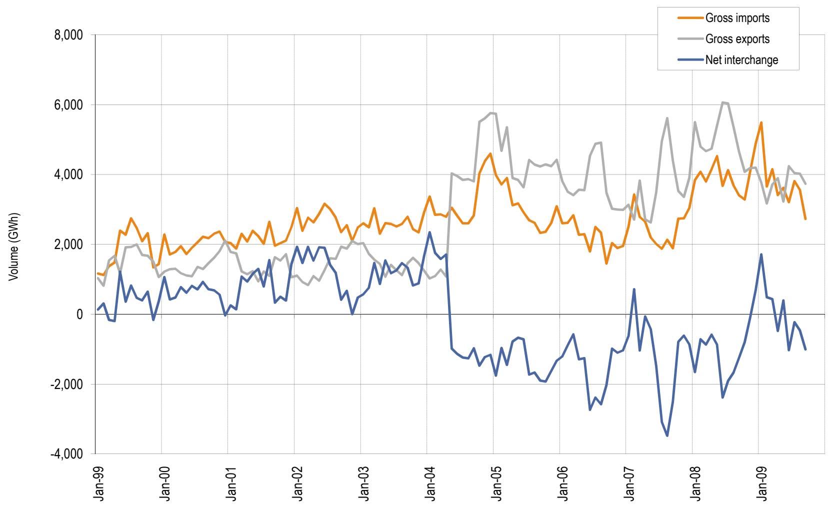


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through September 2009 (See 2008 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	44.4	(41.8)	(86.5)	(147.3)	(117.6)	(143.6)	(136.3)	(94.9)	(39.1)	(762.7)
ALTW	(65.6)	(69.6)	(74.3)	(97.5)	(66.4)	(175.3)	(230.4)	(151.1)	(92.2)	(1,022.4)
AMIL	126.2	23.7	8.7	(14.9)	28.0	(24.0)	(6.8)	(13.6)	24.6	151.9
CIN	102.6	(96.1)	(179.7)	(216.6)	14.7	(91.8)	154.0	133.9	206.5	27.5
CPLE	(62.7)	(161.8)	(208.1)	(281.1)	(113.8)	(293.2)	(317.7)	(242.9)	(241.7)	(1,923.0)
CPLW	(71.4)	(67.4)	(74.3)	(72.0)	(60.3)	(69.8)	(74.6)	(76.7)	(57.6)	(624.1)
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7
DUK	622.7	67.8	89.9	10.6	60.9	(86.0)	(135.9)	(67.5)	(180.9)	381.6
EKPC	(173.5)	(78.8)	(88.6)	(57.4)	67.3	(9.7)	(45.0)	(57.3)	(113.1)	(556.1)
FE	(215.6)	(221.5)	(166.6)	(204.3)	(178.6)	(93.1)	(16.8)	(80.2)	(168.8)	(1,345.5)
IPL	47.1	(17.5)	(88.6)	(79.8)	101.5	(23.9)	173.4	(5.7)	(14.2)	92.3
LGEE	137.4	90.7	176.3	101.4	169.8	32.6	(3.9)	54.6	43.5	802.4
LIND									(8.9)	(8.9)
MEC	150.4	302.1	146.1	155.1	(148.4)	(239.8)	(117.9)	(26.8)	(446.6)	(225.8)
MECS	421.7	361.8	552.3	60.9	341.6	398.7	512.8	258.3	157.3	3,065.4
NEPT	(294.8)	(402.5)	(445.1)	(400.9)	(434.5)	(456.9)	(493.9)	(484.6)	(382.6)	(3,795.8)
NIPS	(8.2)	(51.5)	(35.5)	(60.0)	(3.9)	(38.1)	(13.9)	(71.5)	(28.0)	(310.6)
NYIS	(396.1)	(231.7)	(253.3)	(180.8)	(265.5)	(466.0)	(489.6)	(583.6)	(453.1)	(3,319.7)
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	9,268.3
TVA	244.0	128.7	167.6	35.2	69.3	(160.0)	(73.1)	(23.1)	(42.7)	345.9
WEC	(64.6)	(41.0)	(26.5)	(44.9)	(38.3)	(86.3)	(30.4)	(53.7)	(36.6)	(422.3)
Total	1,715.3	487.8	432.9	(481.8)	396.2	(1,031.0)	(229.7)	(461.4)	(1,009.2)	(180.9)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	170.4	65.4	18.2	1.7	0.1	0.1	1.7	0.0	2.1	259.7
ALTW	45.7	22.2	1.7	0.0	1.9	3.5	5.1	0.3	4.8	85.2
AMIL	147.3	44.9	38.3	26.8	62.2	48.6	65.8	54.0	46.5	534.4
CIN	382.9	265.0	335.2	209.3	256.2	335.3	332.8	402.7	443.7	2,963.1
CPLE	223.9	69.4	66.8	39.9	115.1	16.8	9.3	17.0	5.2	563.4
CPLW	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7
DUK	737.8	277.9	209.5	154.1	239.2	151.2	101.4	98.5	72.6	2,042.2
EKPC	2.7	6.1	12.9	2.5	90.3	33.2	11.6	4.2	0.9	164.4
FE	60.5	32.6	101.6	60.8	73.0	160.0	251.7	180.8	130.3	1,051.3
IPL	107.5	43.8	51.9	63.5	148.6	65.7	199.1	52.0	33.0	765.1
LGEE	187.4	125.2	183.6	125.8	172.0	55.7	48.0	72.1	44.3	1,014.1
LIND									0.0	0.0
MEC	337.6	428.2	371.7	361.2	77.8	26.5	113.5	182.9	4.8	1,904.2
MECS	573.5	500.4	679.7	264.3	458.0	486.8	601.6	368.9	246.7	4,179.9
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	32.5	8.1	0.5	0.0	11.0	0.0	18.2	0.0	0.0	70.3
NYIS	1,004.4	589.8	829.7	982.3	795.2	791.0	862.5	915.8	738.0	7,508.7
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	9,268.3
TVA	292.8	185.1	214.2	107.1	146.2	31.4	65.9	88.9	86.0	1,217.6
WEC	8.7	1.2	17.8	0.6	4.4	5.8	6.9	0.1	2.5	48.0
Total	5,489.0	3,659.5	4,152.4	3,412.4	3,621.6	3,206.8	3,811.4	3,563.2	2,726.4	33,642.7

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	126.0	107.2	104.7	149.0	117.7	143.7	138.0	94.9	41.2	1,022.4
ALTW	111.3	91.8	76.0	97.5	68.3	178.8	235.5	151.4	97.0	1,107.6
AMIL	21.1	21.2	29.6	41.7	34.2	72.6	72.6	67.6	21.9	382.5
CIN	280.3	361.1	514.9	425.9	241.5	427.1	178.8	268.8	237.2	2,935.6
CPLE	286.6	231.2	274.9	321.0	228.9	310.0	327.0	259.9	246.9	2,486.4
CPLW	73.5	67.4	74.3	72.0	60.3	69.8	74.6	76.7	57.6	626.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	115.1	210.1	119.6	143.5	178.3	237.2	237.3	166.0	253.5	1,660.6
EKPC	176.2	84.9	101.5	59.9	23.0	42.9	56.6	61.5	114.0	720.5
FE	276.1	254.1	268.2	265.1	251.6	253.1	268.5	261.0	299.1	2,396.8
IPL	60.4	61.3	140.5	143.3	47.1	89.6	25.7	57.7	47.2	672.8
LGEE	50.0	34.5	7.3	24.4	2.2	23.1	51.9	17.5	0.8	211.7
LIND									8.9	8.9
MEC	187.2	126.1	225.6	206.1	226.2	266.3	231.4	209.7	451.4	2,130.0
MECS	151.8	138.6	127.4	203.4	116.4	88.1	88.8	110.6	89.4	1,114.5
NEPT	294.8	402.5	445.1	400.9	434.5	456.9	493.9	484.6	382.6	3,795.8
NIPS	40.7	59.6	36.0	60.0	14.9	38.1	32.1	71.5	28.0	380.9
NYIS	1,400.5	821.5	1,083.0	1,163.1	1,060.7	1,257.0	1,352.1	1,499.4	1,191.1	10,828.4
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	48.8	56.4	46.6	71.9	76.9	191.4	139.0	112.0	128.7	871.7
WEC	73.3	42.2	44.3	45.5	42.7	92.1	37.3	53.8	39.1	470.3
Total	3,773.7	3,171.7	3,719.5	3,894.2	3,225.4	4,237.8	4,041.1	4,024.6	3,735.6	33,823.6

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	(142.2)	(61.4)	(518.5)	(673.0)	(779.1)	(521.6)	(340.1)	(409.7)	(542.5)	(3,988.1)
ALTW	(722.6)	(756.0)	(604.5)	(746.7)	(389.5)	(497.7)	(392.8)	(552.0)	(417.7)	(5,079.5)
AMIL	52.8	72.3	42.2	86.6	102.4	261.6	153.3	32.6	6.3	810.1
CIN	(225.4)	(96.3)	(47.8)	57.5	(36.7)	55.7	(8.5)	85.2	80.3	(136.0)
CPLE	49.1	(23.0)	(86.0)	(81.0)	(88.1)	(157.1)	(158.8)	(109.9)	(91.0)	(745.8)
CPLW	(176.6)	(166.0)	(184.5)	(180.0)	(155.9)	(176.2)	(184.7)	(184.0)	(147.8)	(1,555.7)
CWLP	(0.7)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.8)
DUK	255.9	26.4	1.1	22.3	120.9	58.7	88.5	45.5	(30.9)	588.5
EKPC	(31.1)	(22.8)	(1.1)	0.0	0.0	0.0	0.0	(1.4)	(0.3)	(56.7)
FE	(206.7)	(233.8)	(241.4)	(197.3)	(206.0)	(116.4)	(119.4)	(76.8)	(115.4)	(1,513.2)
IPL	(316.7)	(191.0)	(157.2)	(67.1)	85.2	143.0	254.3	165.3	(34.8)	(119.0)
LGEE	(16.5)	(8.9)	23.5	6.9	9.7	39.9	38.0	2.7	46.4	141.7
LIND									(2.7)	(2.7)
MEC	27.3	(90.0)	(173.4)	(185.3)	(209.3)	(252.9)	(216.0)	(207.8)	(448.7)	(1,756.1)
MECS	101.9	172.9	250.4	261.1	370.6	433.8	548.7	356.0	257.0	2,752.4
NEPT	(326.4)	(403.8)	(446.4)	(402.1)	(436.6)	(472.3)	(496.9)	(491.7)	(408.7)	(3,884.9)
NIPS	(233.7)	(320.9)	(71.3)	(194.6)	(286.2)	(62.2)	(81.7)	(287.8)	(591.0)	(2,129.4)
NYIS	158.7	146.5	130.8	7.5	(1.8)	(8.2)	7.9	(42.1)	(153.3)	245.9
OVEC	835.6	743.5	786.0	738.6	824.2	857.3	1,028.8	1,038.7	795.4	7,648.1
TVA	482.5	384.6	151.7	81.8	5.4	(42.8)	18.0	79.6	(22.7)	1,138.1
WEC	(52.5)	57.0	352.4	117.2	269.0	28.7	43.4	434.7	409.8	1,659.7
Total	(487.2)	(770.8)	(794.0)	(1,347.6)	(801.8)	(428.7)	182.0	(122.9)	(1,412.3)	(5,983.3)

Table 4-5 Day-ahead gross import volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	675.2	674.4	470.1	173.7	52.2	106.5	367.9	191.1	171.6	2,882.7
ALTW	190.8	183.6	33.2	2.3	0.0	12.5	29.9	40.4	15.8	508.5
AMIL	59.4	75.0	44.5	91.5	105.0	261.6	155.7	76.1	17.7	886.5
CIN	103.2	159.2	178.5	247.6	190.5	320.2	273.2	328.9	391.8	2,193.1
CPLE	187.6	75.8	14.4	21.0	24.0	7.8	7.4	19.8	12.4	370.2
CPLW	9.5	2.1	0.6	0.0	2.8	0.0	2.2	2.0	0.0	19.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	291.9	102.7	55.9	71.4	138.8	90.0	123.6	66.8	83.6	1,024.7
EKPC	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
FE	15.2	44.9	60.0	23.0	10.3	100.7	206.1	227.7	242.0	929.9
IPL	246.5	159.9	153.2	254.2	258.7	250.0	389.3	374.6	77.6	2,164.0
LGEE	2.9	0.2	24.9	8.1	11.4	41.0	40.1	5.2	46.4	180.2
LIND									0.0	0.0
MEC	173.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	174.9
MECS	504.9	400.1	488.5	606.8	631.9	626.5	769.8	595.9	390.9	5,015.3
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	284.5	248.4	490.5	208.0	135.6	151.4	338.2	231.6	152.0	2,240.2
NYIS	890.3	584.5	776.0	776.4	612.0	675.0	840.6	958.6	710.3	6,823.7
OVEC	866.7	766.6	810.5	763.1	828.4	858.2	1,032.0	1,043.8	840.5	7,809.8
TVA	496.4	407.2	172.8	104.0	20.2	12.0	40.4	96.3	46.0	1,395.3
WEC	11.2	113.8	393.7	172.7	316.2	118.3	174.5	492.0	546.0	2,338.4
Total	5,010.2	3,998.4	4,167.3	3,524.0	3,338.0	3,631.7	4,790.9	4,750.8	3,746.3	36,957.6

Table 4-6 Day-ahead gross export volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
ALTE	817.4	735.8	988.6	846.7	831.3	628.1	708.0	600.8	714.1	6,870.8
ALTW	913.4	939.6	637.7	749.0	389.5	510.2	422.7	592.4	433.5	5,588.0
AMIL	6.6	2.7	2.3	4.9	2.6	0.0	2.4	43.5	11.4	76.4
CIN	328.6	255.5	226.3	190.1	227.2	264.5	281.7	243.7	311.5	2,329.1
CPLE	138.5	98.8	100.4	102.0	112.1	164.9	166.2	129.7	103.4	1,116.0
CPLW	186.1	168.1	185.1	180.0	158.7	176.2	186.9	186.0	147.8	1,574.9
CWLP	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
DUK	36.0	76.3	54.8	49.1	17.9	31.3	35.1	21.3	114.5	436.2
EKPC	31.9	22.8	1.1	0.0	0.0	0.0	0.0	1.4	0.3	57.5
FE	221.9	278.7	301.4	220.3	216.3	217.1	325.5	304.5	357.4	2,443.2
IPL	563.2	350.9	310.4	321.3	173.5	107.0	135.0	209.3	112.4	2,283.0
LGEE	19.4	9.1	1.4	1.2	1.7	1.1	2.1	2.5	0.0	38.5
LIND									2.7	2.7
MEC	145.9	90.0	173.4	185.3	209.3	252.9	216.0	207.8	450.4	1,931.0
MECS	403.0	227.2	238.1	345.8	261.3	192.7	221.1	239.9	133.9	2,262.9
NEPT	326.4	403.8	446.4	402.1	436.6	472.3	496.9	491.7	408.7	3,884.9
NIPS	518.2	569.3	561.8	402.6	421.8	213.6	419.9	519.4	743.0	4,369.6
NYIS	731.6	438.0	645.2	768.9	613.8	683.2	832.7	1,000.7	863.6	6,577.8
OVEC	31.1	23.1	24.5	24.5	4.2	0.9	3.2	5.1	45.1	161.7
TVA	13.9	22.6	21.1	22.2	14.8	54.8	22.4	16.7	68.7	257.2
WEC	63.7	56.8	41.3	55.5	47.2	89.6	131.1	57.3	136.2	678.7
Total	5,497.4	4,769.2	4,961.3	4,871.6	4,139.8	4,060.4	4,608.9	4,873.7	5,158.6	42,940.9

Interface Pricing

Table 4-7 Active interfaces: January through September 2009 (See 2008 SOM, Table 4-7)

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

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Figure 4-4 PJM's footprint and its external interfaces (See 2008 SOM, Figure 4-4)

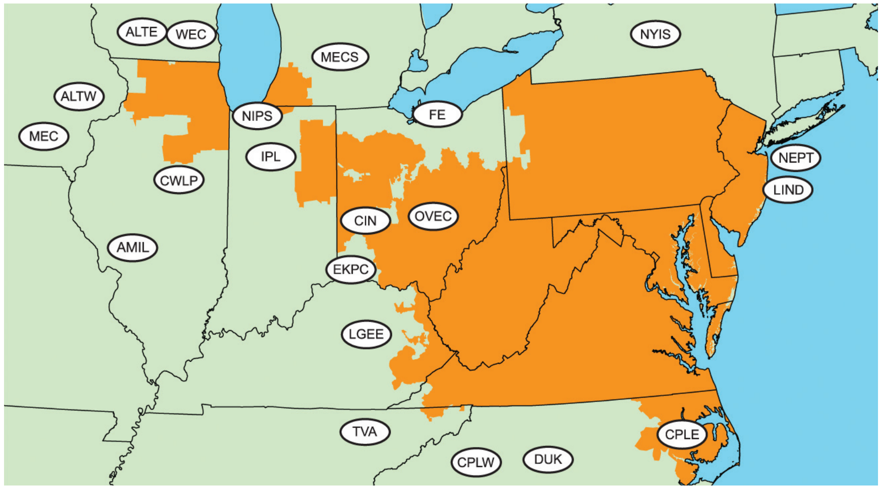


Table 4-8 Active pricing points: January through September 2009 (See 2008 SOM, Table 4-8)

PJM 2009 Pricing Points			
LIND	MICHFE	MISO	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO
OVEC	SOUTHEXP	SOUTHIMP	

Interactions with Bordering Areas

PJM and Midwest ISO Interface Prices

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through September 2009 (See 2008 SOM, Figure 4-5)

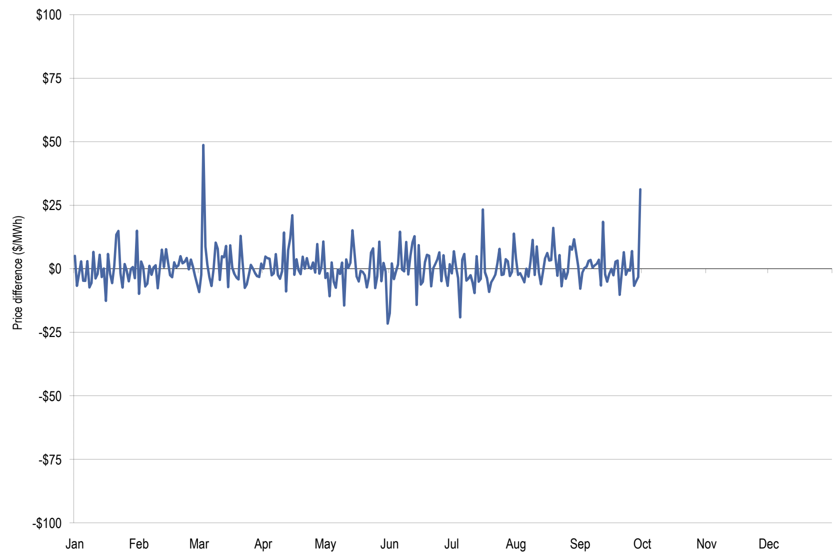


Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2009 (See 2008 SOM, Figure 4-6)

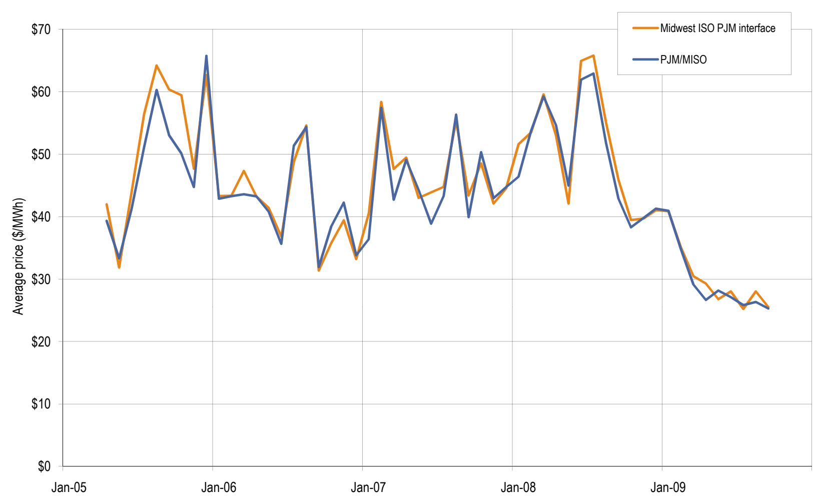


Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): Calendar year 2008 and January through September 2009 (See 2008 SOM, Table 4-9)

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$8.26	($6.56)	($2.86)	$5.18	($3.06)	($2.12)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$1.81	($5.39)	($3.16)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.11	($5.50)	($2.78)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($5.39)	($3.16)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	($0.56)	($8.28)	($2.64)
LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component						

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through September 2009 (New Figure)

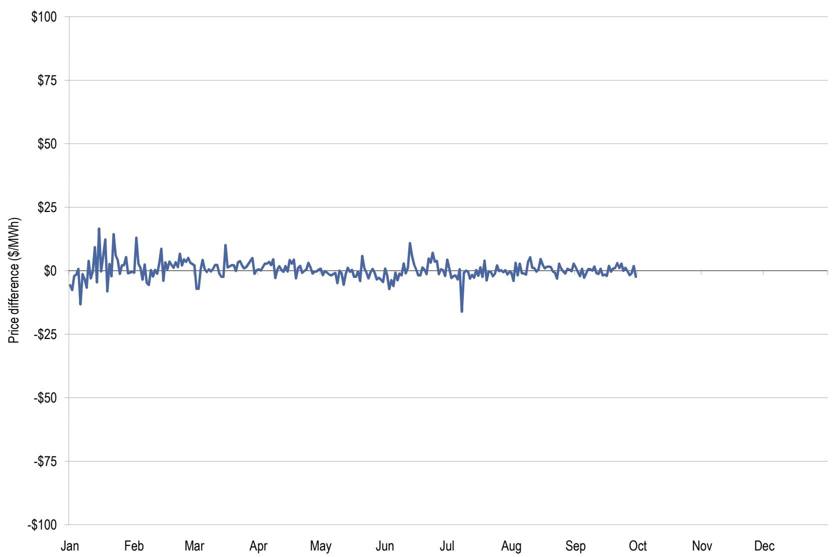


Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2009 (New Figure)

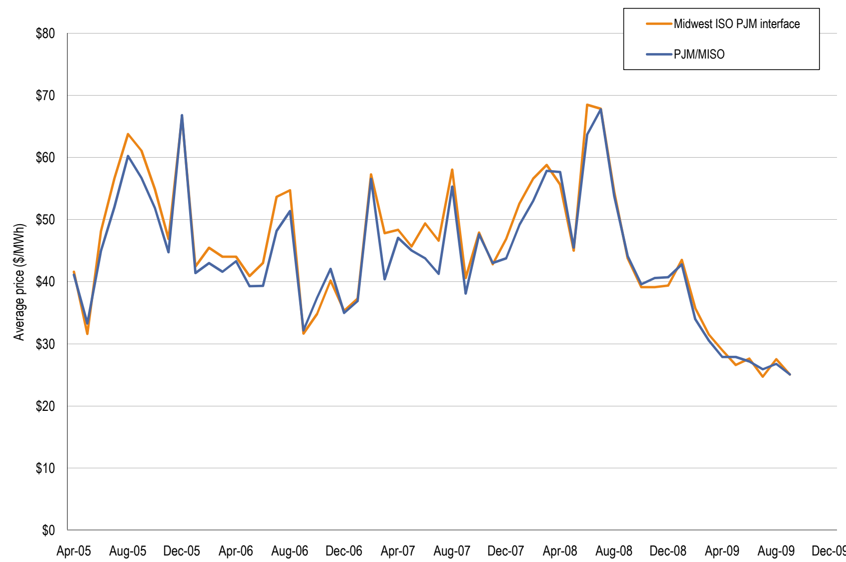


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): Calendar year 2008 and January through September 2009 (New Table)

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$9.19	($3.00)	($4.25)	$4.61	($2.20)	($2.89)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.59	($5.33)	($1.79)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$2.01	($4.45)	($3.23)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.60	($4.40)	($3.70)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.35)	($6.78)	($3.28)
LMP: Locational Marginal Price, MCC: Marginal Congestion Component MLC: Marginal Loss Component						

PJM and NYISO Interface Prices

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through September 2009 (See 2008 SOM, Figure 4-7)

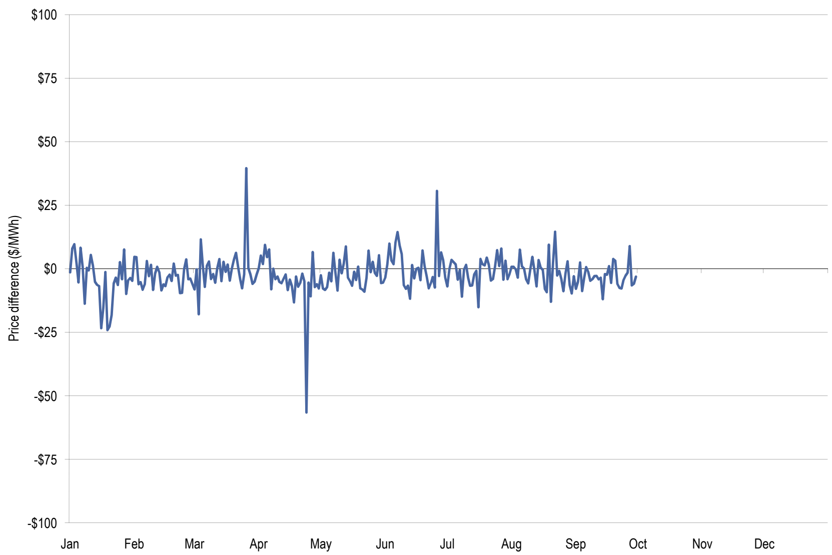


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through September 2009 (See 2008 SOM, Figure 4-8)

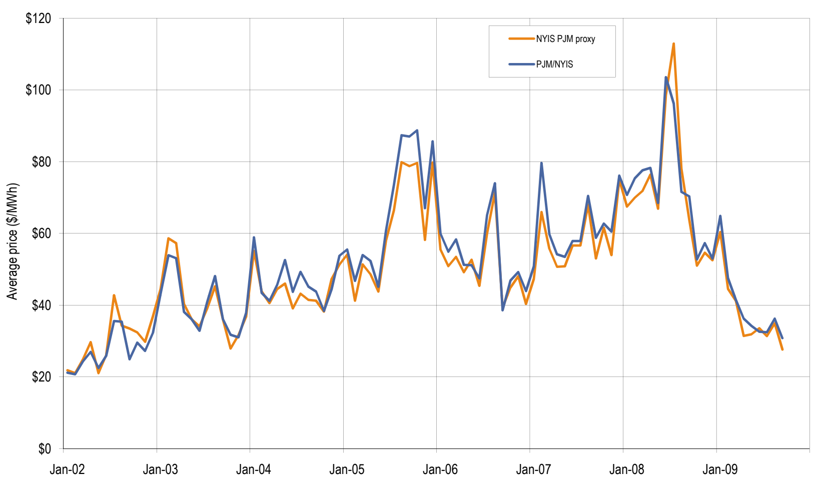
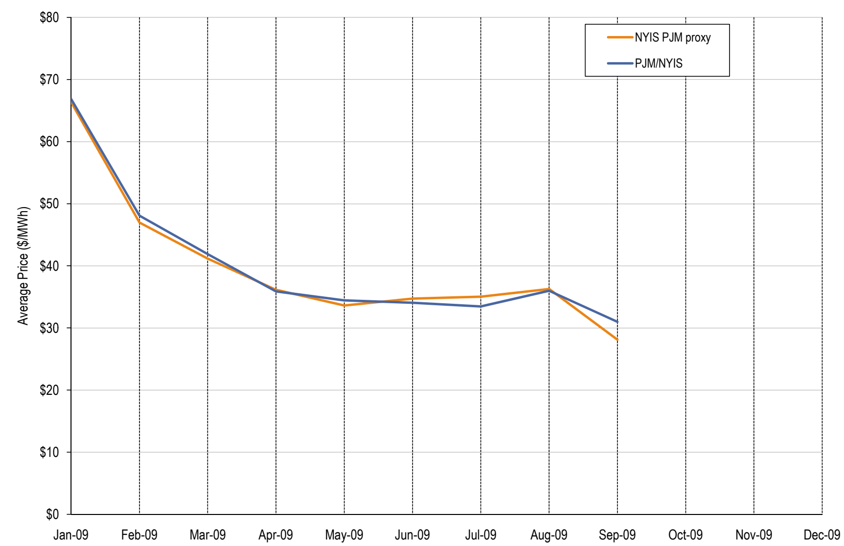


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September 2009 (New Figure)

Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January through September 2009 (New Figure)



Summary of Interface Prices between PJM and Organized Markets

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through September 2009 (See 2008 SOM, Figure 4-9)

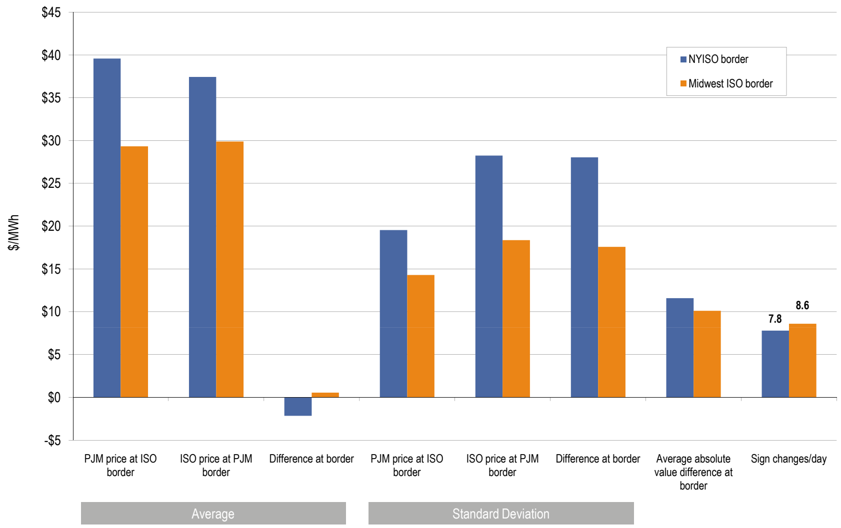
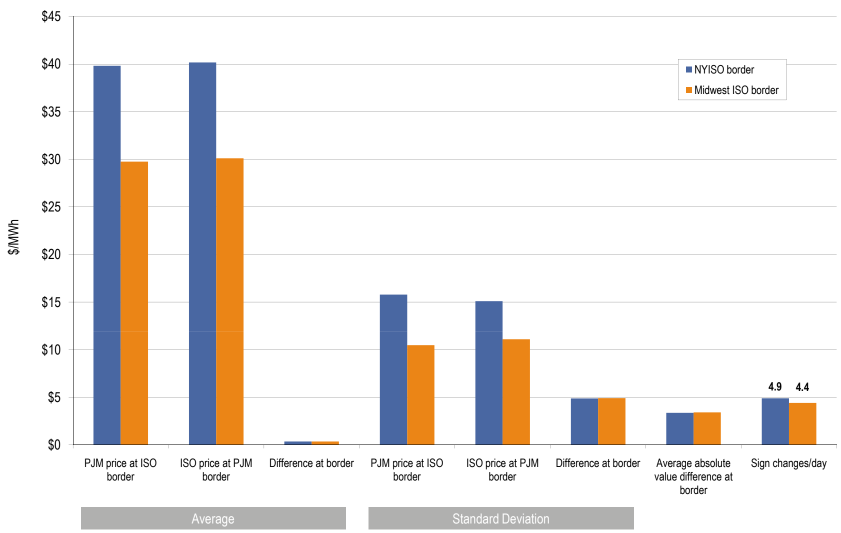


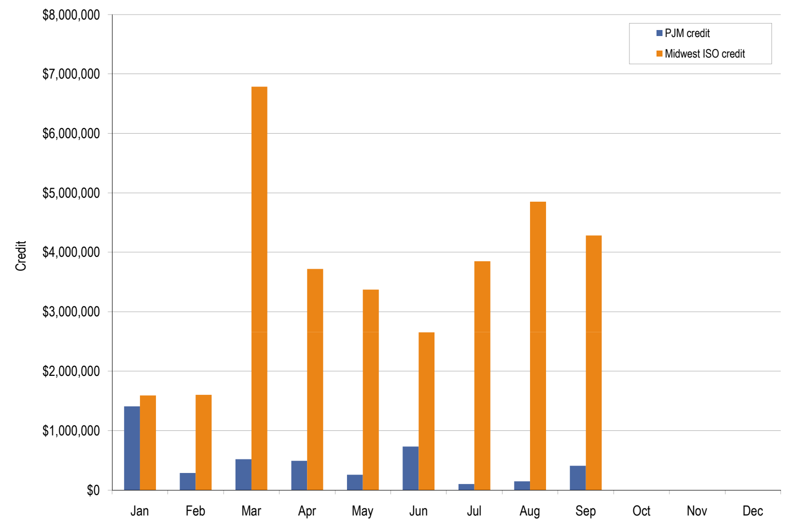
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through September 2009 (New Figure)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement (JOA)

Figure 4-15 Credits for coordinated congestion management: January through September 2009 (See 2008 SOM, Figure 4-10)



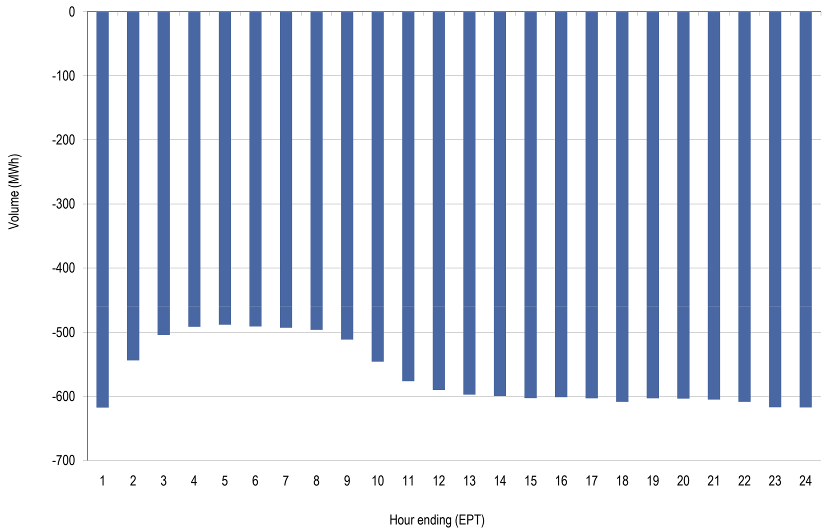
Con Edison and PSE&G Wheeling Contracts

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through September 2009 (See 2008 SOM, Table 4-10)

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$1,302,867	$1,832	$1,304,700	$3,676,287	$0	$3,676,287
Congestion Credit			$1,114,647			$3,651,446
Adjustments			$484,174			$14,563
Net Charge			($294,122)			$10,278

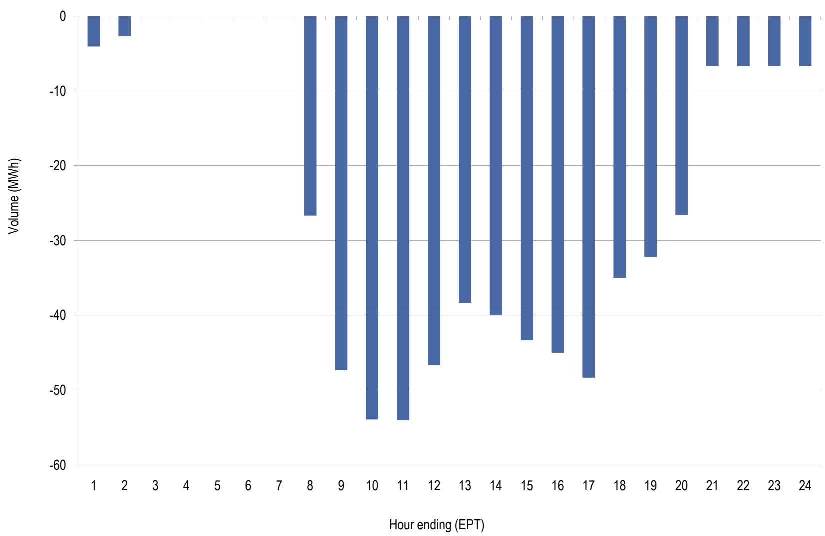
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-16 Neptune hourly average flow: January through September 2009 (See 2008 SOM, Figure 4-11)



Linden Variable Frequency Transformer (VFT) facility

Figure 4-17 Linden hourly average flow: September 2009 (New Figure)



Interface Pricing Agreements with Individual Companies

Table 4-12 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (See 2008 SOM, Table 4-11)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$50.58	$47.29	$47.29	$3.29	$3.29
PEC	$52.21	$47.29	$47.29	$4.93	$4.93
NCMPA	$50.66	$47.29	$47.29	$3.37	$3.37

Table 4-13 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009 (See 2008 SOM, Table 4-11)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.59	$31.00	$29.56	$29.56	$1.03	$1.44
PEC	$31.01	$32.44	$29.56	$29.56	$1.45	$2.89
NCMPA	$30.78	$30.85	$29.56	$29.56	$1.23	$1.30

Figure 4-18 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2009 (New Figure)

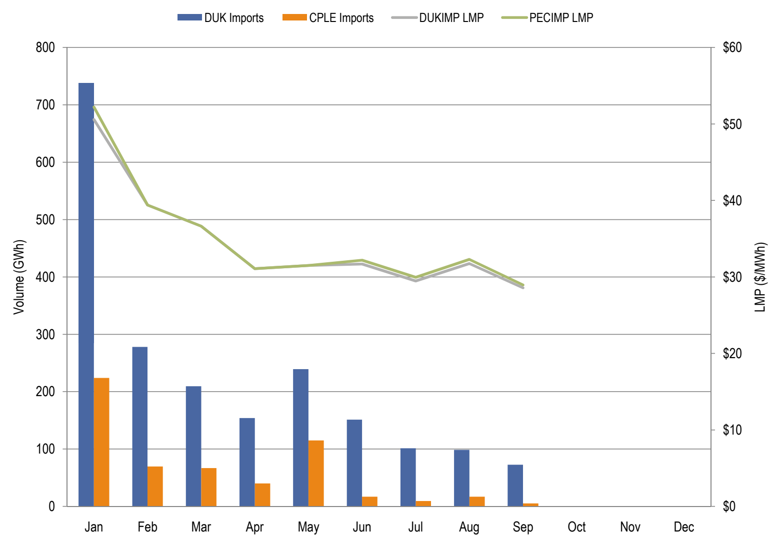


Figure 4-19 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2009 (New Figure)

Table 4-14 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (New Table)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$52.01	$48.59	$48.59	$3.42	$3.42
PEC	$54.41	$48.59	$48.59	$5.82	$5.82
NCMPA	$52.10	$48.59	$48.59	$3.51	$3.51

Table 4-15 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009 (New Table)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.57	$31.28	$29.92	$29.92	$0.65	$1.35
PEC	$31.13	$32.62	$29.92	$29.92	$1.21	$2.70
NCMPA	$30.91	$30.98	$29.92	$29.92	$0.99	$1.05

Figure 4-20 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2009 (New Figure)

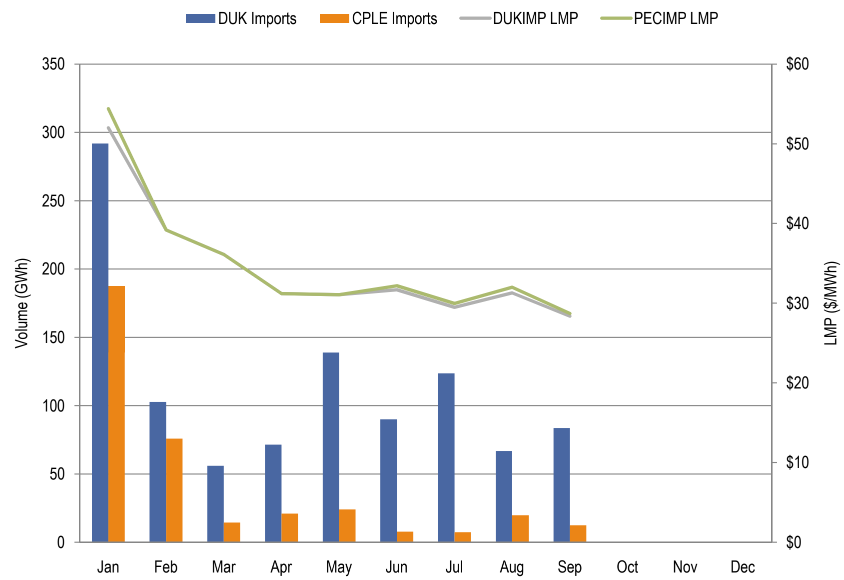
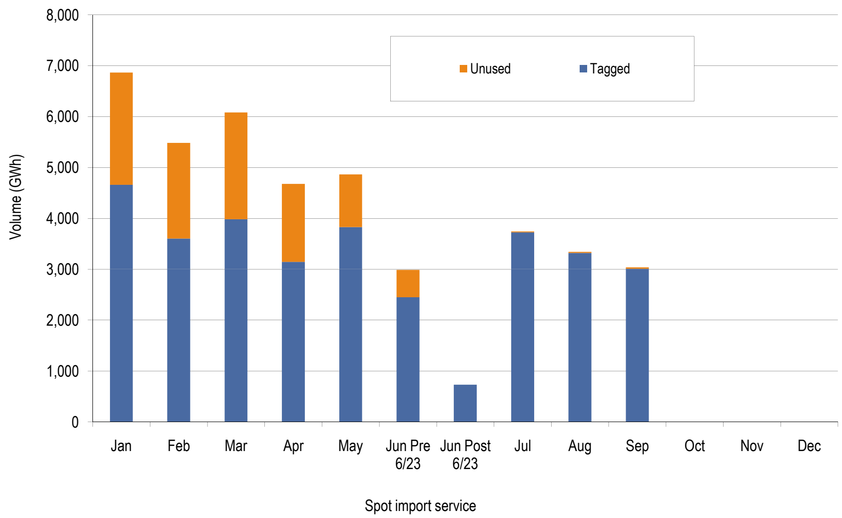


Figure 4-21 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2009 (New Figure)

Interchange Transaction Issues

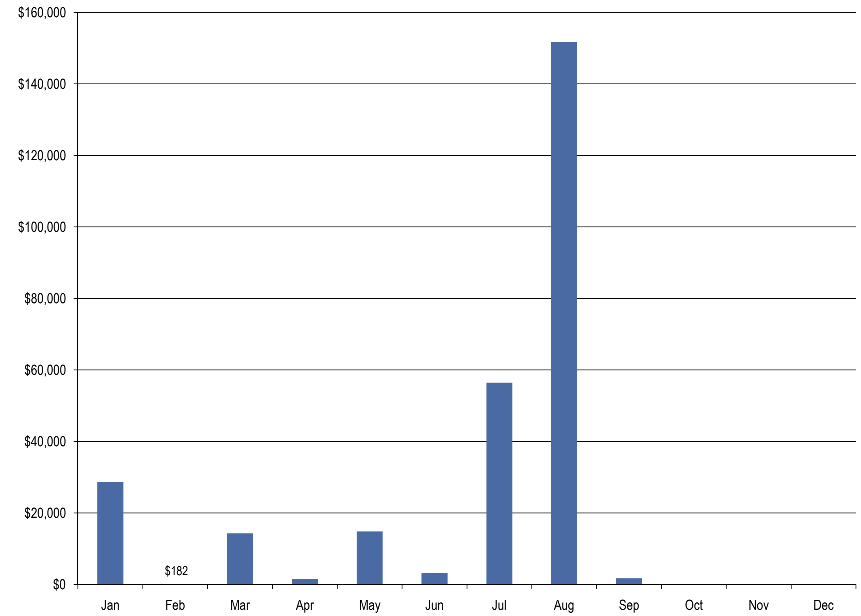
Spot Import

Figure 4-22 Spot import service utilization: January through September 2009 (See 2008 SOM, Figure 4-12)



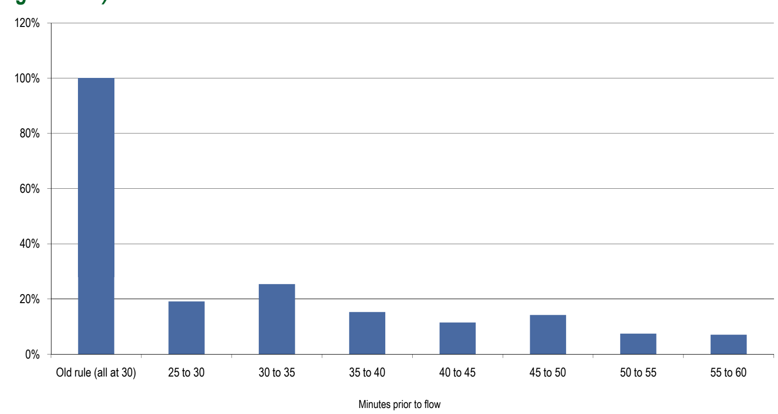
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-23 Monthly uncollected congestion charges: January through September 2009 (See 2008 SOM, Figure 4-13)



Ramp Availability

Figure 4-24 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through September 2009 (See 2008 SOM, Figure 4-14)



Curtailment of Transactions

TLRs

Figure 4-25 PJM and Midwest ISO TLR procedures: Calendar year 2008 and January through September 2009 (See 2008 SOM, Figure 4-15)

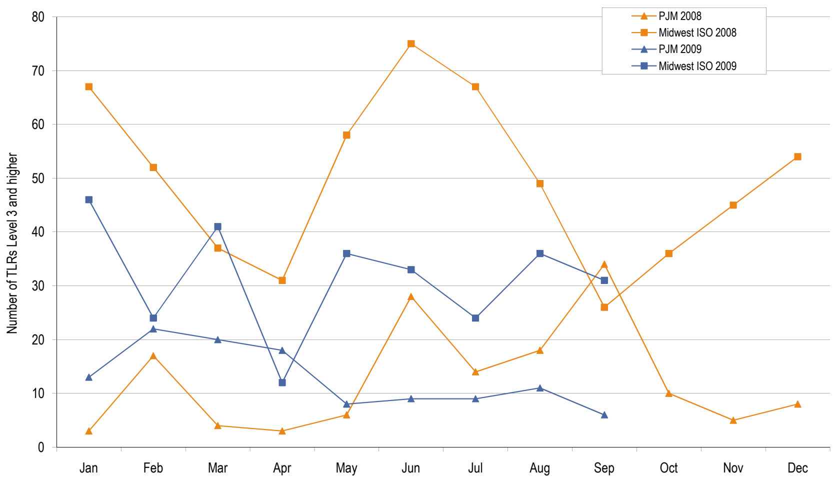


Figure 4-26 Number of different PJM flowgates that experienced TLRs: Calendar year 2008 and January through September 2009 (See 2008 SOM, Figure 4-16)

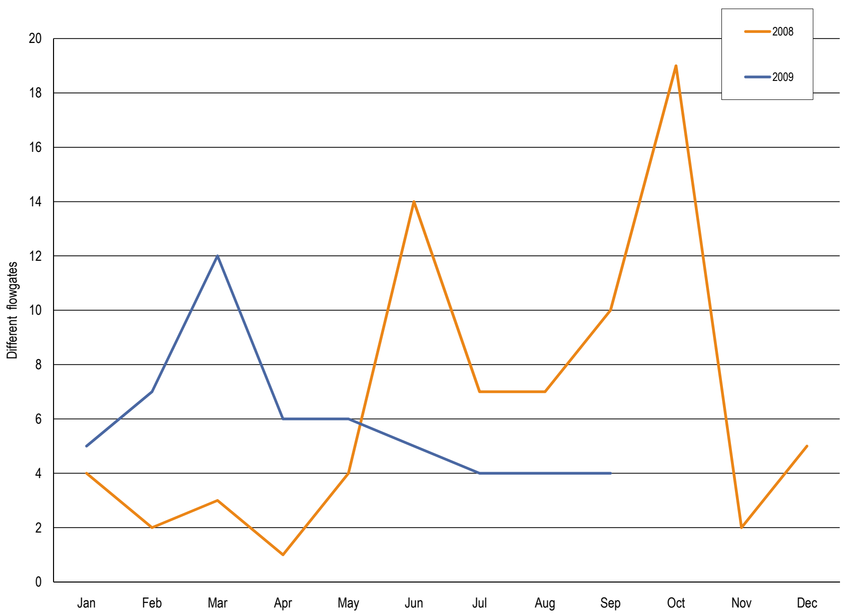
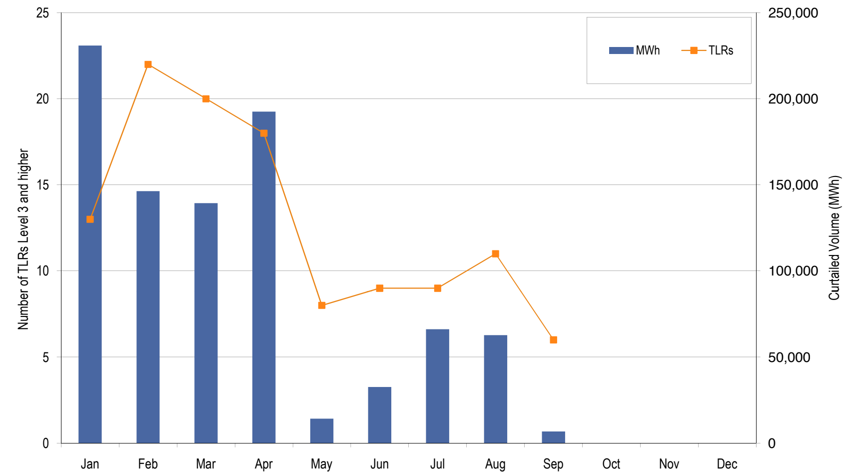
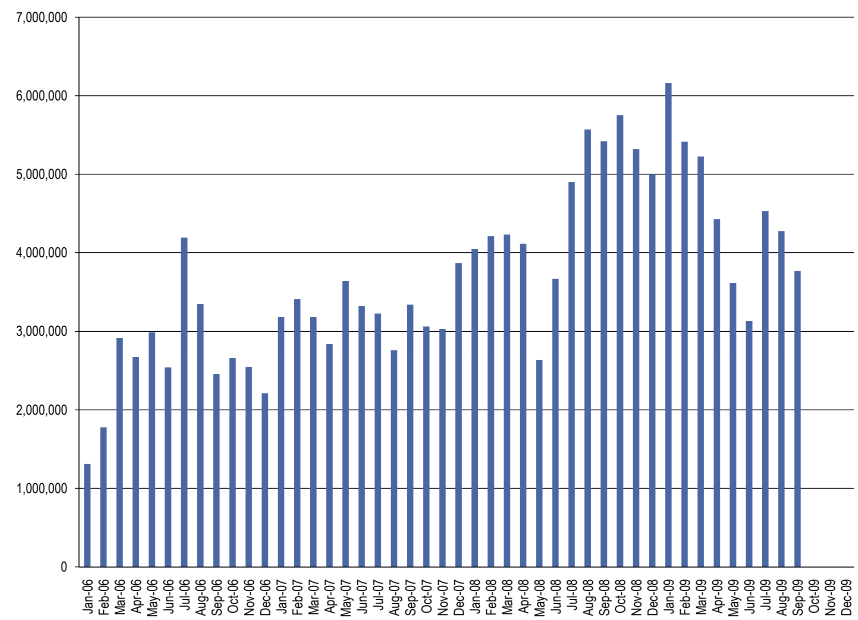


Figure 4-27 Number of PJM TLRs and curtailed volume: January through September 2009 (See 2008 SOM, Figure 4-17)



Up-To Congestion

Figure 4-28 Monthly up-to congestion bids in MWh: January 2006 through September 2009 (See 2008 SOM, Figure 4-18)



Loop Flows

Table 4-16 Net scheduled and actual PJM interface flows (GWh): January through September 2009 (See 2008 SOM, Table 4-12)

	Net scheduled and actual PJM interface flows: JAN - SEP 2009			Difference (percent of net scheduled)
	Actual	Net Scheduled	Difference (GMh)	
ALTE	(4,591)	(763)	(3,828)	502%
ALTW	(1,595)	(1,023)	(572)	56%
AMIL	6,622	89	6,533	7340%
CIN	1,931	1,301	630	48%
CPLE	5,096	(1,079)	6,175	(572%)
CPLW	(1,319)	(623)	(696)	112%
CWLP	(471)	-	(471)	0%
DUK	(2,196)	382	(2,578)	(675%)
EKPC	508	(556)	1,064	(191%)
FE	(831)	(1,963)	1,132	(58%)
IPL	1,621	92	1,529	1662%
LGEE	1,035	803	232	29%
LIND	(9)	(9)	-	0%
MEC	(1,596)	(222)	(1,374)	619%
MECS	(7,471)	3,065	(10,536)	(344%)
NEPT	(3,718)	(3,718)	-	0%
NIPS	(1,851)	(310)	(1,541)	497%
NYIS	(1,499)	(3,470)	1,971	(57%)
OVEC	6,097	9,268	(3,171)	(34%)
TVA	2,960	346	2,614	755%
WEC	2,404	(422)	2,826	(670%)
YTD Total	1,127	1,188	(61)	(5%)

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

Figure 4-29 PJM/MECS Interface average actual minus scheduled volume: January through September 2009 (See 2008 SOM, Figure 4-19)

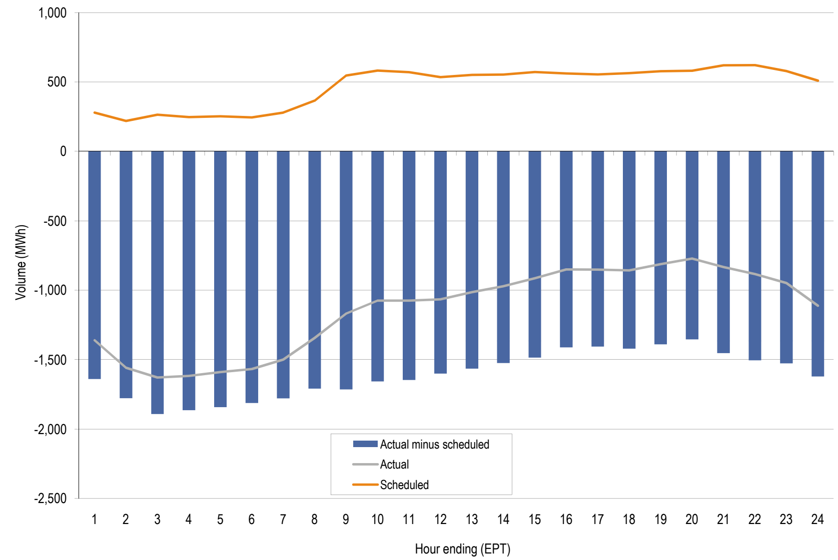
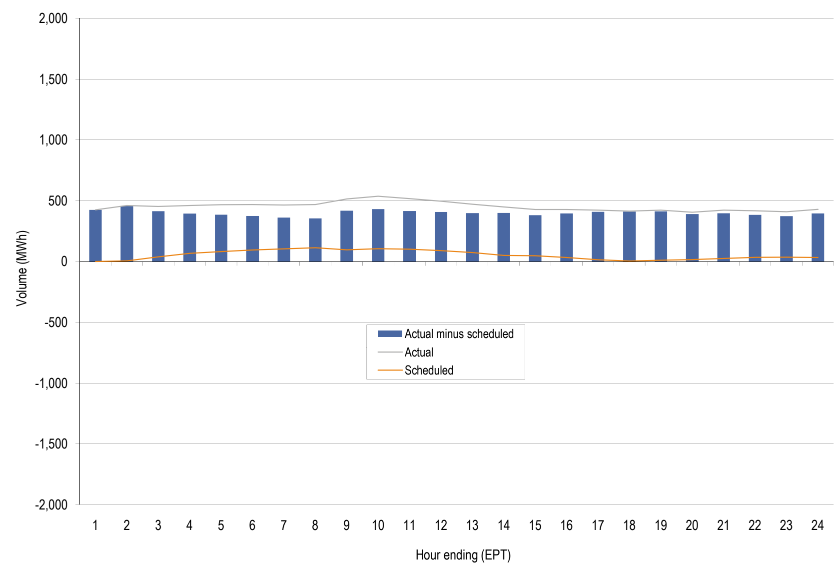


Figure 4-30 PJM/TVA average flows: January through September 2009 (See 2008 SOM, Figure 4-21)



Loop Flows at PJM's Southern Interfaces

Figure 4-31 Southwest actual and scheduled flows: January 2006 through September 2009 (See 2008 SOM, Figure 4-22)

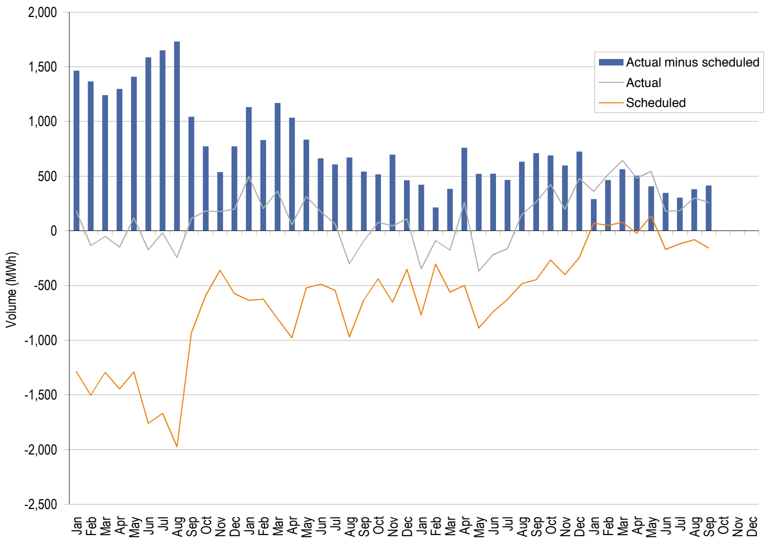


Figure 4-32 Southeast actual and scheduled flows: January 2006 through September 2009 (See 2008 SOM, Figure 4-23)