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.** During the first nine months of 2010, PJM was a net exporter of energy in the Real-Time Market in all months. In the Real-Time Market, monthly net interchange averaged -824 GWh.[1] Gross monthly import volumes averaged 3,475 GWh while gross monthly exports averaged 4,299 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** During the first nine months of 2010, PJM was a net exporter of energy in the Day-Ahead Market in all months except August. In the Day-Ahead Market, monthly net interchange averaged -740 GWh. Gross monthly import volumes averaged 7,075 GWh while gross monthly exports averaged 7,815 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first nine months of 2010, gross imports in the Day-Ahead Energy Market were 204 percent of the Real-Time Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Market were 182 percent of the Real-Time Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 90 percent of net interchange in the Real-Time Energy Market (-7,412 GWh in the Real-Time Market and -6,658 GWh in the Day-Ahead Market).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first nine months of 2010, there were net exports at 15 of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 70 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 30 percent, PJM/Neptune (NEPT) with 20 percent and PJM/MidAmerican Energy Company (MEC) with 20 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 55 percent of the total net PJM exports in the Real-Time Market. Five PJM interfaces had net imports, with two importing interfaces accounting for 87 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 75 percent and PJM/Michigan Electric Coordinated System (MECS) with 12 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, during the first nine months of 2010, there were net exports at 12 of PJM's 21 interfaces. The top four net exporting interfaces accounted for 89 percent of the total net exports: PJM/western Alliant Energy Corporation (ALTW) with 33 percent, PJM/NYIS with 32 percent, PJM/NEPT with 14 percent and PJM/MidAmerican Energy Company (MEC) with 10 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 47 percent of the total net PJM exports in the Day-Ahead Market. Nine PJM interfaces had net imports in the Day-Ahead Market, with two interfaces accounting for 71 percent of the total net imports: PJM/OVEC with 40 percent and PJM/Michigan Electric Coordinated System (MECS) with 31 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During the first nine months of 2010, 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

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 the Real-Time Market, one PJM interface had a net interchange of zero.

Midwest ISO. Over the first nine months of 2010, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $34.51 while the Midwest ISO LMP at the border was $34.88, a difference of $0.37. While the average hourly flow reflected imports into PJM from the Midwest ISO, further analysis of hourly interchange showed patterns of expected market participant response that created price convergence at the PJM/MISO Interface.

- **PJM and New York ISO Interface Prices.** During the first nine months of 2010, 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 the NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and the NYISO. Over the first nine months of 2010, the PJM average hourly LMP at the PJM/NYISO border was $48.33 while the NYISO LMP at the border was $45.66, a difference of $2.67. While the average hourly flow reflected exports from PJM into the NYISO, further analysis of hourly interchange showed patterns of expected market participant response that created price convergence at the PJM/NYISO Interface.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[3] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

  The PJM/NYISO JOA does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued during the first nine months of 2010. By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[4] After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment by stakeholders and market monitors, the NYISO filed on January 12, 2010, a *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[5] On July 15, 2010, the Commission conditionally accepted the NYISO Report subject to the parties filing answers to the questions set forth in the order within 30 days of the date of the order.[6] The Commission requested that the parties provide additional evidence regarding the proposed solutions. On August 16, 2010, the NYISO provided their response to the July 15th Order.[7] On September 15, 2010, the Market Monitoring Unit (MMU) responded to the NYISO filing.[8] The MMU commented that the NYISO response lacked detail and focus in implementing solutions that could be implemented quickly, and continued to lack detailed and firm timelines for implementation. Additionally, the MMU questioned the curtailment priority granted to transactions scheduled on non-firm transmission when electing to purchase "buy-through of congestion" as well as the inability to implement a market to market congestion management agreement with PJM. Finally, the MMU provided comments and recommendations on implementing an interface pricing solution in the NYISO to mitigate the incentives to scheduling circuitous paths into and out of the NYISO. The Market Monitor actively participated in the meeting of the Broader Regional Markets Group in Philadelphia on September 27, 2010, and continues to advocate in that process a joint operating agreement between NYISO and PJM that is equivalent to or better than the JOA between the Midwest ISO and PJM.

- **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 2010. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. The MMU believes that this

3 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed October 15, 2010, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (208 KB).

4 128 FERC ¶ 61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶ 61,239.

5 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010) (Accessed October 15, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

6 132 FERC ¶ 61,031.

7 See NYISO. "*Response to Questions and Supplemental Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow*" Docket No. ER08-1281-004 (August 16, 2010) (Accessed October, 14, 2010). <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/08/NYISO_resp_To_FERC_questions_8_13_10.pdf> (135 KB).

8 See "Comments of the Independent Market Monitor for PJM."Docket No. ER08-1281-004 (September 15, 2010) (Accessed October 14, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Comments_ER08-1281-004_20100915.pdf> (203 KB).

approach should be the minimum industry standard. This conceptual achievement, however, has not been matched by adequate attention to the details of its administration.

The market based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[9] 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.[10] On March 8, 2010, after the settlement discussions mediated by the Federal Energy Regulatory Commission (FERC) ended, the Midwest ISO filed complaints with FERC against PJM.[11] On April 12, 2010, PJM answered and filed a counter complaint.[12] These matters are now pending before the Commission in settlement proceedings.[13] The MMU remains concerned that this disagreement over administration of the JOA will unduly detract from its ability to serve as the basis for moving forward industry practice for managing congestion and loop flows at system interfaces, but notes that the *Memorandum of Understanding* signed by PJM and the Midwest ISO on May 27, 2010 "reaffirms the value of the agreement and pledges continued cooperation to develop new practices to improve the interface between the two organizations."[14]

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[15] 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 2010.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[16] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through the first nine months of 2010. As part of this agreement, both parties agreed to develop a formal CMP. On February 2, 2010, PJM and PEC filed a revision to the JOA to include a Congestion Management Protocol.[17] The MMU responded to the filing on February 23, 2010.[18] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors, and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[19] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[20] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the dynamic scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[21] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[22] The MMU moved for a technical conference to explore these issues.[23] As of September 30, 2010, the Commission had not made any additional issuances related to the Compliance Filing or the comments submitted by the MMU.

9 See PJM. "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,294 KB).
10 See PJM. "PJM/MISO Market Flow Calculation Error"(September 10, 2009) (Accessed October 15, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).
11 Complaints of the Midwest Independent Transmission System Operator, Inc., filed Dockets Nos. EL10-45-000 & EL10-46-000 (respectively, MISO Complaint I and MISO Complaint II).
12 Complaint of PJM Interconnection, L.L.C., filed in EL10-60-000 at 19.
13 131 FERC ¶ 61,284 (June 29, 2010).
14 See PJM. "PJM-MISO-MOU-May-2010" (May 27, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pjm-miso-mou-may-2010.ashx> (313 KB).
15 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

16 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (February 2, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (2,983 KB).
17 See PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).
18 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010) (Accessed October 15, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-713-000_20100225.pdf> (225 KB).
19 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.
20 See Docket No. ER10-713-000. Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas.
21 See PJM/PEC compliance filing in Docket No. ER10-713-002.
22 See IMM response to PJM/PEC compliance filing in Docket No. ER10-713-002.
23 *Id*.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[24] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region 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.

Other Agreements with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first nine months of 2010, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[25] This 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 lower 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.

  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 the first nine months of 2010, PSE&G's FTR credits were $335,809 less than the congestion charges because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Con Edison receives credits, on an hourly basis, for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In the first nine months of 2010, Con Edison's congestion credits were less than the associated congestion charges by approximately $1.6 million.

  In effect, Con Edison has been given congestion credits that are equivalent to a special class of FTRs uniquely available to Con Edison covering positive congestion with subordinated rights to revenue. However, Con Edison, unlike standard FTR holders, is not treated as having an FTR when congestion is negative. A standard FTR holder in that position would pay the negative congestion credits, but Con Edison does not. During the first nine months of 2010, Con Edison's negative congestion credits would have been approximately $28,000.

  Under the terms of its 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 five percent of the hours during the first nine months of 2010.

  After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[26] By order issued September 16, 2010, the Commission approved this settlement,[27] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[28] The Commission explained (at PP 49–50):

> We find that the Settlement, the 2008 1000 MW TSAs and the JOA Protocol are a just and reasonable means of continuing service to ConEd and do not create undue harm to pricing in the NYISO or PJM. Both the parties supporting the Settlement and NRG generally agree that the 2008 1,000 MW TSAs are economic in roughly 88 percent of hours. Further, ConEd placed into evidence data that during the hours when prices are lower in NYISO than PJM, the price differential usually is not great, but, when prices in NYISO are higher than PJM, they are substantially higher. [Footnote omitted]

24 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).
25 111 FERC ¶ 61,228 (2005).
26 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.
27 *PJM Interconnection, L.L.C., et al.*, 132 FERC ¶61,221.
28 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010). The MMU questioned whether allowing rollover is appropriate and raised concerns that continuing these agreements could interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. The MMU questioned whether a valid offsetting reliability consideration had been identified and explained. The MMU noted, "the settling parties fail to demonstrate any circumstances that may now exist warranting a non-conforming agreement under the current approach to seams management, nor do they attempt to explain how such circumstances would continue to exist under the reforms to be implemented through the Broader Regional Markets Initiative." Additionally, that MMU argued,"the settling parties have failed to show that continuation of the grandfathered transmission service agreements will neither interfere with the efficient calculation of LMPs in both PJM and the NYISO, and at their interface, nor harm the ability of parties to efficiently transact business."

Moreover, the Commission has established other procedures to address the loop flow issue comprehensively. [fn.79: Pursuant to Commission orders in Docket No. ER08-1281, the scheduling and seams issues are being addressed. On January 12, 2010, NYISO submitted a status report on the progress of the development of (1) the buy-through congestion proposal; (2) the congestion management/market-to-market coordination proposal; (3) interface pricing revisions; and (4) enhanced interregional transaction coordination. On July 15, 2010, the Commission issued an order conditionally accepting the status report and directing the parties to provide additional information on the proposed comprehensive solutions. New York Indep. Sys. Operator, Inc., 132 FERC ¶ 61,031 (2010).] As ConEd notes, neither the 2008 1,000 MW TSAs nor the JOA Protocol would prevent PJM and NYISO from modifying their scheduling arrangements for inter-area transactions, once these seams issues are resolved. Rather, the 2008 1,000 MW TSA will be subject to PJM's OATT and, if PJM and NYISO amend the scheduling practice prescribed by their OATTs, the new practice will govern service under the 2008 1,000 MW TSA.

The Commission further finds that no other entity has been unduly discriminated against by denial of substantially similar service on the same terms and conditions as those requested by ConEd, because no entity has requested such service. Rather, the Commission finds that it would be discriminatory to deny ConEd through-and-out service when all other customers are entitled to the service, simply because ConEd sources and sinks its power in the same control area.

- **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, via undersea and underground cable, was placed in service, providing a direct connection from PJM to the New York Independent System Operator, Inc. (NYISO). This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[29] The basis for this limitation is unclear. Over the first nine months of 2010, the PJM average hourly LMP at the Neptune Interface was $51.98 while the NYISO LMP at the Neptune Bus was $59.68, a difference of $7.69. The average hourly flow during the first nine months of 2010 was -550 MW, which aligned with price differentials in only 56 percent of all hours during the first nine months of 2010.

- **Linden Variable Frequency Transformer (VFT) Facility.** On November 1, 2009, the Linden VFT facility was placed in service, providing an additional direct connection from PJM to the NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer.[30] 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.[31] The basis for this limitation is unclear. Over the first nine months of 2010, the PJM average hourly LMP at the Linden Interface was $51.25 while the NYISO LMP at the Linden Bus was $52.83, a difference of $1.58. The average hourly flow during the first nine months of 2010 was -139 MW, which aligned with price differentials in only 58 percent of all hours during the first nine months of 2010.

Interchange Transaction Issues

- **Loop Flows.** Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows arise from transactions on contract paths that do not correspond to the actual physical paths that the energy takes. During the first nine months of 2010, net scheduled interchange was -5,845 GWh and net actual interchange was -5,566 GWh for a difference of 279 GWh or 4.8 percent (5.5 percent for the first nine months of 2009). The net totals in the first three months of 2010 reflected a large mismatch between scheduled and actual interchange (21.4 percent). As the net scheduled export levels increased in the second and third quarter of 2010, the year to date net difference, as a percentage of the year to date scheduled interchange decreased. A similar pattern was observed in the first quarter of 2007, when the net scheduled interchange changed from net exports to net imports, reducing the net scheduled interchange, and increasing the net difference, resulting in a difference

29 See PJM. "PJM Open Access Transmission Tariff" (September 17, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (14,838 KB).

30 A phase angle regulating transformer (PAR) allows dispatchers to change the flow of MW over a transmission line by changing the impedance of the transmission facility.

31 See PJM. "PJM Open Access Transmission Tariff" (September 17, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (14,838 KB).

between scheduled and actual interchange of 49.4 percent. 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 2009, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-10,553 GWh during the first nine months of 2010 and -10,536 GWh during the first nine months of 2009). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (2,794 GWh during the first nine months of 2010 and 2,614 GWh during the first nine months of 2009). The net difference between scheduled flows and actual flows at the PJM/MECS Interface was exports while the net difference at the PJM/TVA Interface was imports.

- **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 2010.

  The southern interfaces have historically experienced significant loop flows.[32] A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the Locational Marginal Price (LMP) at the Southeast pricing points and the SouthEXP pricing point was $4.15 during the first nine months of 2010 and the average difference between LMP at the Southwest pricing points and the SouthEXP pricing point was -$2.97 during the first nine months of 2010. In other words, it was more expensive to buy from PJM, for export to the south, using the old Southeast pricing point as opposed to the current SouthEXP pricing point, and less expensive to buy from PJM, for export to the south, using the old Southwest pricing point as opposed to the current SouthEXP pricing point.) These grandfathered agreements remain in place. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first nine months of 2010, PJM issued 96 TLRs. Of the 96 TLRs issued, the highest levels reached were TLR 3a for 56 events and TLR 3b for the remaining 40 events. Figure 4-22 shows that there was an increase in the number of TLRs issued by PJM in June 2010. The increase in TLRs, as well as the increase in the total MWh of curtailed transactions resulting from those TLRs, was primarily the result of increased weather related load. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. There are several factors that affect the number of times a reliability coordinator needs to initiate a TLR and the TLR level, including market design and operating agreements. The fact that PJM has issued only 98 TLRs during the first nine months of 2010, compared to 114 during the first nine months of 2009, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would require the need for higher level TLRs.

- **Up-To Congestion.** In the period following the March 1, 2008 modifications to the up-to congestion bids (March 1, 2008 through September 30, 2010), the monthly average of up-to congestion bids increased from 3,027.1 GWh (for the period from January 1, 2006 through April 30, 2008) to 5,714.6 GWh. In June and July, there was a significant increase in the total up-to congestion bids as shown in Figure 4-23. This increase in activity for up-to congestion transactions was caused by the allocation methodology for the marginal loss surplus.

32 See *2002 State of the Market Report,* Part 2, Section 3, "Interchange Transactions." (March 5, 2003) (Accessed October 15, 2010) <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2002/SOM2002-part2.pdf> (4,068 KB).

The up-to congestion transactions during the first nine months of 2010 were comprised of 47.9 percent imports, 45.2 percent exports and 6.9 percent wheeling transactions. Only 0.1 percent of the up-to congestion transactions had matching Real-Time Market transactions. Of the up-to congestion transactions with matching Real-Time Market transactions, 4.2 percent were imports, 86.9 percent were exports and 8.9 percent were wheel through transactions.

When the up-to congestion product was used as intended, with matching Real-Time Market transactions, 73.3 percent of the total cleared transactions MW were profitable during the first nine months of 2010. The net profit on all these transactions was approximately $396,000. When up-to congestion transactions did not have a matching Real-Time Market transaction, 56.2 percent of the total cleared transactions MW were profitable. The net loss on all these transactions was approximately $38.8 million.

- **Marginal Loss Surplus Allocation.** In an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[33] On May 15, 2010, PJM implemented the modified method of allocating the marginal loss surplus. As modified, Section 5.5 of the PJM OATT provided that a cleared up-to congestion transaction in the Day-Ahead Energy Market qualified for an allocation of the marginal loss surplus for an hour if that transaction required the purchase of transmission service. Prior to the modification, up-to congestion transactions had not been eligible for an allocation of the marginal loss surplus. However, PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus. These transactions included the submission of up-to congestion wheeling transactions at the same interface, submission of equal and opposite up-to congestion transactions to and from the same internal PJM bus and equal and opposite up-to congestion transactions at buses within the PJM Energy Market that are physically close to one another where the LMP between those buses would be negligible. Market participants engaging in these activities received $17.4 million in marginal loss surplus allocations (with a net profit of $9.5 million after the cost of transmission) during the period of May 15, 2010 through August 31, 2010.

As a result of this activity, PJM and the MMU presented and discussed proposed short term revisions to the market rules at the August 5, 2010, meeting of the Markets and Reliability Committee and the August 12, 2010, meeting of the Members Committee.[34] PJM proposed to eliminate the requirement for up-to congestion transactions to obtain transmission service and to discount the marginal loss allocation to non-firm transmission service customers. The MMU short term proposal was to cap the marginal loss distribution to any non-firm transmission customer so that the allocations do not exceed the total charges for transmission service. PJM stakeholders voted in favor of the PJM proposal at the August 12, 2010 PJM Members Committee, subject to an agreement to initiate additional stakeholder discussions on a long term solution to the issues. On August 18, 2010, PJM submitted its proposal to the Commission.[35]

On September 2, 2010, the MMU responded to the PJM filing, explaining that PJM's proposed revisions to the gaming issue were not sufficient to address the underlying problem, the inconsistency between the approved principle and the actual implementation of the method of allocating the marginal loss surplus. [36] The MMU also explained that PJM's proposal would create a spread bidding product, a product type that had been previously proposed and subsequently rejected by PJM participants that would have allowed market participants to take simultaneous positions at two points in the PJM system. The MMU opposed spread bidding because it risked creating opportunities for gaming with no offsetting market benefit. The elimination of the requirement to acquire transmission for up-to congestion transactions creates a spread bidding product that would have either the source or the sink at an interface and the other point anywhere on the PJM system. While limited to either source or sink at an interface, the newly created spread bidding product raises the same issues previously identified with the spread bid product proposals that have previously been rejected by the PJM membership. On September 17, 2010, the Commission approved the PJM revisions as filed on August 18, 2010.[37]

33 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

34 A copy of the presentations can be viewed at http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-monitoring-analytics-presentation.ashx and http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-pjm-presentation.ashx.

35 Docket No. ER10-2280-000.

36 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM." Docket No. ER10-2280-000 (September 2, 2010) (Accessed October 15, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-2280-000_20100902.pdf> (329 KB).

37 *PJM Interconnection, L.L.C.* 132 FERC ¶ 61,244.

The Order deferred consideration of the issues raised by the MMU, stating (at P 49):

> [The MMU's] concerns go beyond the scope of this filing and, in effect, argue that PJM has incorrectly implemented the Commission-approved methodology for allocating line losses. While we do not find that these issues should result in the rejection of this filing, they may be considered in the stakeholder process to analyze possible alternatives to PJM's proposed changes to which PJM are committed, including *inter alia* the various issues raised by Monitoring Analytics.

PJM created the "Transactions Issues Task Force" to address the deferred issues and to evaluate the allocation of the marginal loss surplus.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** 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.

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

  Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. 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.

  The total uncollected congestion charges for the first nine months of 2010 were approximately $2.9 Million ($272,651 for the first nine months of 2009). The increase in uncollected congestion charges has been caused by an increase in market participant use of not willing to pay congestion transmission on their energy transactions in 2010. The MMU recommended modifying the evaluation criteria via a change to PJM's market software, to ensure that a not willing to pay congestion transaction is not permitted to flow in the presence of congestion. On August 16, 2010, PJM modified the EES application to automatically detect and modify not willing to pay congestion transactions, prior to their start, when system LMPs at the transactions' identified source and sink differ. This functionality will prevent not willing to pay congestion transactions from starting in those instances by automatically issuing curtailment requests. The same evaluation is performed on not willing to pay congestion transactions that have already been loaded, and will curtail those transactions at the next applicable 15 minute interval. These changes will reduce the amount of uncollected congestion charges by eliminating the previously utilized manual intervention for curtailments and reducing the potential for not willing to pay congestion transactions to continue to flow, undetected. While the recent EES modifications automate the process for identifying those instances, the timing requirements for curtailing transactions requires that the evaluation be done with 20 minutes notice prior to the start of the transaction. There is still the potential for not willing to pay congestion transactions to begin in cases when congestion exists prior to the transaction start time but after the evaluation. When this occurs, the transaction will be curtailed at the next applicable 15 minute interval.

  The MMU recommends that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service; and restricting the use of not willing to pay congestion transactions to wheeling transactions across the PJM footprint.

  The not willing to pay congestion product was originally offered to market participants in order to limit their exposure to congestion at a time when market participants could only modify their transactions with 60 minutes notice. This is no longer the case. Market participants can now modify their transactions at any 15 minute interval with 20 minutes notice. Thus, the underlying rationale for the product no longer exists. Use of this product eliminates the need for 24 hour monitoring, as PJM automatically curtails not willing to pay congestion transactions as soon as possible when congestion is realized. PJM provides a service to market participants in minimizing the exposure to congestion charges for not willing to pay congestion transactions, and market participants who elect to utilize not willing to pay congestion transmission should be willing to pay the minimized congestion charges. The MMU also recommends limiting the use of not willing to pay congestion transactions to wheeling transactions only. It is not possible to control the flow of energy from an external interface to an internal bus within the PJM footprint. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows.

- **Elimination of Sources and Sinks.** The MMU has recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch.

  The issue of uncollected congestion from not willing to pay congestion transmission reservations would also be mitigated by the elimination of internal sources and sinks from the Real-Time PJM Energy Market. Because only interfaces would be permitted to be specified as a valid source and sink on an external energy transaction, the only opportunity for congestion exposure would be for wheeling transactions, as all external imports and exports would have the source and sink specified as the same bus (i.e. the interface where the transaction enters or leaves the PJM Market) which, by definition, would represent no congestion exposure.

  Until the internal source and sink designations are eliminated from the external energy transactions in the Day-Ahead Energy Market, the MMU continues to recommend that PJM require that all import and export up-to congestion transactions pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserve charges.

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 its neighboring balancing authorities for the first nine months of 2010, including evolving transaction patterns, economics and issues. During the first nine months of 2010, PJM was 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 70 percent of the total real-time net exports and two interfaces accounted for 87 percent of the real-time net import volume. Four interfaces accounted for 89 percent of the total day-ahead net exports and two interfaces accounted for 71 percent of the day-ahead net import volume.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

In the third quarter of 2010, some market participants were observed entering uneconomic up to congestion transactions for the sole purpose of taking advantage of the revised marginal loss surplus allocation methodology. Some market participants took advantage of the fact that up to congestion transactions offered the flexibility to specify any import or export pricing point, regardless of the associated transmission path, and that up to congestion transactions became eligible to receive marginal loss surplus allocations, where they previously were ineligible. The MMU believes that this issue arose due to a flaw in the implemented marginal loss surplus allocation, and that if PJM modifies the methodology to comport with the Commission's directive to allocate marginal losses based on a pro rata share of market participants' contributions to the fixed costs of the transmission system, the incentives to submit uneconomic transactions would be eliminated, and the marginal loss surplus allocations would be distributed in the most equitable manner.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through September 2010 (See 2009 SOM, Figure 4-1)

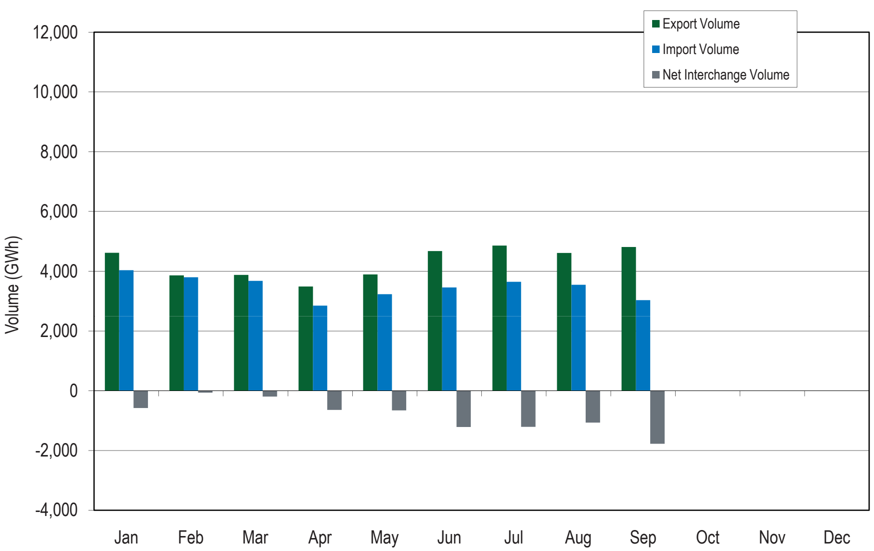


Figure 4-2 PJM day-ahead scheduled imports and exports: January through September 2010 (See 2009 SOM, Figure 4-2)

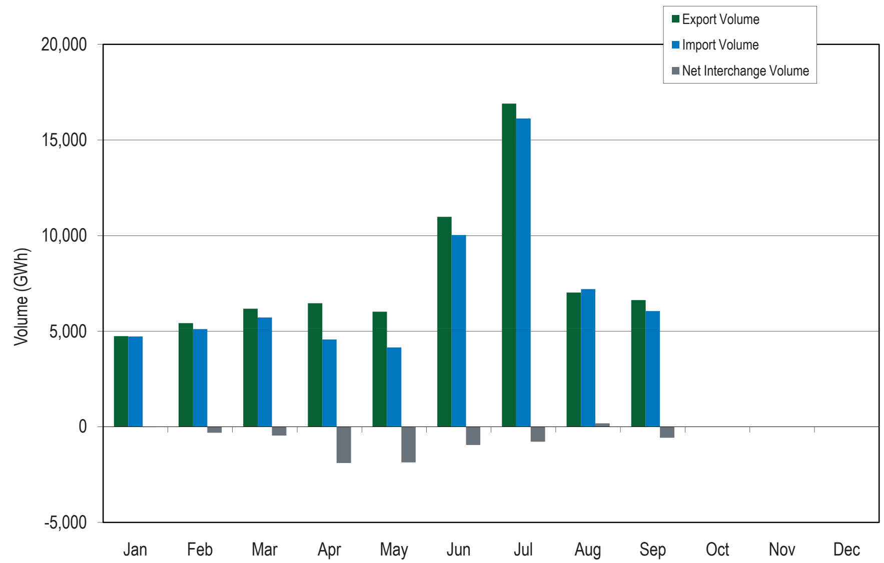
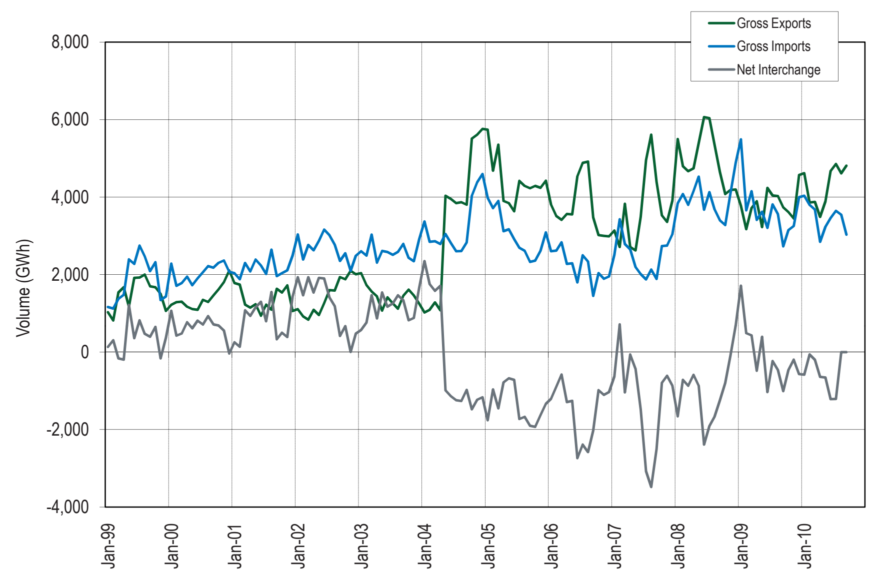


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through September 2010 (See 2009 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through September 2010 (See 2009 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(70.4)	(72.8)	(40.8)	(141.2)	(114.0)	(154.2)	(150.1)	(162.4)	(154.8)	(1,060.7)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	219.7	92.2	(32.8)	(22.9)	123.6	(116.4)	(50.8)	(21.0)	(113.3)	78.3
EKPC	(65.5)	(99.2)	14.1	39.3	(0.2)	(19.5)	81.2	88.4	(43.5)	(4.9)
LGEE	31.9	144.5	29.7	44.1	116.8	130.0	160.3	103.4	185.4	946.1
MEC	(454.2)	(422.0)	(458.1)	(383.0)	(436.0)	(429.4)	(440.7)	(402.4)	(420.2)	(3,846.0)
MISO	(74.1)	512.4	510.7	8.1	188.5	(327.7)	(658.1)	(550.5)	(945.7)	(1,336.4)
ALTE	3.6	(9.5)	13.7	(7.1)	(0.7)	(66.2)	(90.3)	(46.3)	(116.0)	(318.8)
ALTW	(32.1)	(8.4)	1.4	(16.1)	(27.7)	(148.3)	(80.2)	(54.7)	(106.3)	(472.4)
AMIL	(141.6)	(85.5)	(63.5)	(25.6)	37.1	18.8	22.1	77.6	(7.4)	(168.0)
CIN	78.4	323.4	233.5	(112.2)	189.0	155.8	(37.8)	(52.3)	(333.5)	444.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(13.8)	(13.8)
FE	(117.4)	(60.2)	(70.6)	(114.3)	(142.5)	(173.5)	(182.1)	(211.3)	(86.1)	(1,158.0)
IPL	(28.4)	48.4	(4.6)	112.6	61.3	(61.2)	(177.9)	(121.3)	(170.1)	(341.2)
MECS	195.1	312.7	387.5	199.7	95.9	103.2	34.9	0.5	20.1	1,349.6
NIPS	(24.0)	(10.8)	(4.9)	(0.6)	(1.9)	(111.1)	(98.2)	(49.9)	(56.7)	(358.1)
WEC	(7.7)	2.3	18.2	(28.3)	(22.0)	(45.2)	(48.6)	(92.8)	(75.9)	(300.0)
NYISO	(1,307.0)	(1,039.9)	(1,109.6)	(950.3)	(1,334.9)	(1,257.1)	(1,003.0)	(1,029.6)	(1,219.8)	(10,251.2)
LIND	(146.0)	(125.5)	(115.7)	(75.8)	(89.8)	(100.4)	(99.2)	(63.6)	(113.0)	(929.0)
NEPT	(496.7)	(423.6)	(449.9)	(280.9)	(464.8)	(466.6)	(411.5)	(292.7)	(375.7)	(3,662.4)
NYIS	(664.3)	(490.8)	(544.0)	(593.6)	(780.3)	(690.1)	(492.3)	(673.3)	(731.1)	(5,659.8)
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	8,517.9
TVA	(39.0)	(121.5)	(129.3)	(88.3)	(7.8)	(43.4)	69.0	(97.4)	2.7	(455.0)
Total	(581.7)	(63.3)	(197.3)	(640.2)	(658.1)	(1,215.8)	(1,210.5)	(1,066.9)	(1,778.1)	(7,411.9)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through September 2010 (See 2009 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	128.3	113.4	99.8	0.6	22.7	9.9	28.2	26.5	6.4	435.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	408.5	235.2	135.1	142.6	258.6	174.8	229.5	243.7	104.5	1,932.5
EKPC	15.8	3.0	53.9	58.1	34.8	36.6	88.9	104.2	22.6	417.9
LGEE	48.9	150.5	73.5	58.7	135.6	161.8	187.6	171.8	218.2	1,206.6
MEC	44.1	28.1	35.7	52.3	61.5	34.7	41.7	46.5	43.7	388.3
MISO	1,142.9	1,388.4	1,292.1	852.6	907.3	1,055.0	866.6	748.7	656.4	8,910.0
ALTE	30.0	8.0	28.9	2.4	9.4	1.0	1.3	6.7	3.3	91.0
ALTW	0.0	5.4	7.6	1.1	2.8	6.3	7.6	17.6	14.5	62.9
AMIL	23.5	49.2	39.2	45.6	55.0	37.1	33.3	88.8	17.3	389.0
CIN	500.9	555.4	454.8	227.2	364.7	551.6	366.0	314.9	216.4	3,551.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	181.6	207.6	205.4	156.0	147.5	162.3	176.9	150.8	218.3	1,606.4
IPL	47.1	116.7	16.2	115.9	113.5	71.8	16.0	1.5	4.3	503.0
MECS	304.3	385.9	475.1	283.7	181.5	185.2	215.2	150.5	170.9	2,352.3
NIPS	0.0	0.0	0.0	0.2	13.4	6.4	2.9	14.7	10.8	48.4
WEC	55.5	60.2	64.9	20.5	19.5	33.3	47.4	3.2	0.6	305.1
NYISO	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	8,516.6
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	8,516.6
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	8,517.9
TVA	134.6	35.7	47.7	63.0	115.6	67.9	237.4	116.4	131.8	950.1
Total	4,034.4	3,798.5	3,679.1	2,847.6	3,232.8	3,458.7	3,646.3	3,547.0	3,031.3	31,275.7

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through September 2010 (See 2009 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	198.7	186.2	140.6	141.8	136.7	164.1	178.3	188.9	161.2	1,496.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	188.8	143.0	167.9	165.5	135.0	291.2	280.3	264.7	217.8	1,854.2
EKPC	81.3	102.2	39.8	18.8	35.0	56.1	7.7	15.8	66.1	422.8
LGEE	17.0	6.0	43.8	14.6	18.8	31.8	27.3	68.4	32.8	260.5
MEC	498.3	450.1	493.8	435.3	497.5	464.1	482.4	448.9	463.9	4,234.3
MISO	1,217.0	876.0	781.4	844.5	718.8	1,382.7	1,524.7	1,299.2	1,602.1	10,246.4
ALTE	26.4	17.5	15.2	9.5	10.1	67.2	91.6	53.0	119.3	409.8
ALTW	32.1	13.8	6.2	17.2	30.5	154.6	87.8	72.3	120.8	535.3
AMIL	165.1	134.7	102.7	71.2	17.9	18.3	11.2	11.2	24.7	557.0
CIN	422.5	232.0	221.3	339.4	175.7	395.8	403.8	367.2	549.9	3,107.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.8	13.8
FE	299.0	267.8	276.0	270.3	290.0	335.8	359.0	362.1	304.4	2,764.4
IPL	75.5	68.3	20.8	3.3	52.2	133.0	193.9	122.8	174.4	844.2
MECS	109.2	73.2	87.6	84.0	85.6	82.0	180.3	150.0	150.8	1,002.7
NIPS	24.0	10.8	4.9	0.8	15.3	117.5	101.1	64.6	67.5	406.5
WEC	63.2	57.9	46.7	48.8	41.5	78.5	96.0	96.0	76.5	605.1
NYISO	2,241.4	1,941.1	2,032.1	1,716.0	2,225.7	2,173.2	2,187.7	2,114.2	2,136.4	18,767.8
LIND	146.0	125.5	115.7	75.8	89.8	100.4	99.2	63.6	113.0	929.0
NEPT	496.7	423.6	449.9	280.9	464.8	466.6	411.5	292.7	375.7	3,662.4
NYIS	1,598.7	1,392.0	1,466.5	1,359.3	1,671.1	1,606.2	1,677.0	1,757.9	1,647.7	14,176.4
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	173.6	157.2	177.0	151.3	123.4	111.3	168.4	213.8	129.1	1,405.1
Total	4,616.1	3,861.8	3,876.4	3,487.8	3,890.9	4,674.5	4,856.8	4,613.9	4,809.4	38,687.6

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through September 2010 (See 2009 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(89.3)	(111.3)	(114.7)	(122.2)	(108.3)	(134.2)	372.0	(119.5)	(70.8)	(498.3)
CPLW	10.2	(1.0)	1.0	(0.9)	(1.0)	(1.5)	6.7	2.0	5.6	21.1
DUK	161.4	38.4	8.6	12.6	72.5	23.2	(222.7)	(100.4)	29.2	372.2
EKPC	(1.5)	(5.9)	(3.4)	(0.2)	(1.4)	(3.0)	(4.5)	(3.5)	(0.1)	(59.9)
LGEE	1.0	5.3	0.0	(0.1)	1.4	(8.0)	(13.7)	(51.5)	(3.7)	(20.8)
MEC	(479.4)	(444.1)	(482.8)	(433.0)	(464.1)	(789.0)	(374.3)	(457.0)	(448.1)	(2,824.3)
MISO	282.3	(160.5)	(312.1)	(1,450.5)	(1,018.5)	550.4	3,478.1	820.5	79.0	2,268.7
ALTE	227.6	(257.5)	(136.2)	(302.4)	(711.0)	(168.0)	73.0	145.9	(9.0)	(1,137.6)
ALTW	(282.2)	(414.3)	(1,220.9)	(1,761.3)	(766.8)	(2,195.9)	(1,908.2)	(567.7)	68.1	(9,049.2)
AMIL	14.4	97.5	6.7	12.4	44.5	114.6	1.7	9.0	(1.3)	299.5
CIN	182.9	(60.8)	43.1	(70.3)	41.8	310.0	1,376.9	161.3	4.2	1,989.1
CWLP	0.0	0.0	0.0	0.0	(0.3)	0.0	(19.5)	0.0	(11.8)	(31.6)
FE	(70.5)	(20.7)	118.8	(72.4)	(79.3)	390.4	1,007.5	20.4	(218.3)	1,075.9
IPL	(53.4)	(18.4)	(44.7)	(8.5)	(42.0)	68.9	131.8	41.7	(41.0)	34.4
MECS	387.8	654.4	885.6	732.9	546.6	1,223.9	1,484.6	767.5	379.5	7,062.8
NIPS	(204.5)	(217.0)	(143.3)	(87.6)	(120.2)	(103.9)	394.9	(34.3)	(67.1)	(583.0)
WEC	80.2	76.3	178.8	106.7	68.2	910.4	935.4	276.7	(24.3)	2,608.4
NYISO	(969.0)	(912.0)	(825.4)	(752.7)	(1,017.9)	(1,657.9)	(4,727.8)	(904.8)	(894.0)	(12,661.5)
LIND	(21.1)	(18.3)	(53.2)	(11.4)	(15.3)	(12.0)	(24.7)	(9.9)	(53.2)	(219.1)
NEPT	(502.6)	(445.2)	(456.7)	(301.3)	(473.4)	(472.7)	(420.9)	(317.7)	(374.8)	(3,765.3)
NYIS	(445.3)	(448.5)	(315.5)	(440.0)	(529.2)	(1,173.2)	(4,282.2)	(577.2)	(466.0)	(8,677.1)
OVEC	1,074.0	1,243.3	1,300.5	917.1	679.0	1,058.2	1,045.7	978.5	711.5	9,007.8
TVA	(5.3)	37.8	(27.0)	(60.9)	(5.4)	7.7	(335.1)	16.4	18.0	(353.8)
Total	(15.6)	(310.0)	(455.3)	(1,890.8)	(1,863.7)	(954.1)	(775.6)	180.7	(573.4)	(6,657.8)

Table 4-5 Day-ahead gross import volume by interface (GWh): January through September 2010 (See 2009 SOM, Table 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	64.2	39.5	29.3	10.7	15.8	49.1	595.7	124.6	89.2	1,018.1
CPLW	15.6	0.6	1.8	0.0	1.4	0.8	6.7	2.0	7.1	36.0
DUK	176.3	96.2	48.1	40.2	107.2	77.8	139.9	112.9	108.6	907.2
EKPC	0.0	0.0	0.4	0.0	0.0	0.0	0.2	0.0	0.0	0.6
LGEE	1.0	5.4	0.0	0.0	1.8	0.5	1.4	6.5	2.2	18.8
MEC	18.8	5.6	12.2	18.6	70.2	158.8	247.8	33.6	20.7	586.3
MISO	2,400.5	2,738.3	3,112.5	2,678.8	2,251.6	7,455.1	12,488.8	4,596.2	3,905.6	41,627.4
ALTE	866.4	762.4	662.8	382.9	263.8	721.2	2,191.6	1,241.3	1,728.4	8,820.8
ALTW	72.0	67.2	72.4	53.6	40.2	345.7	896.3	257.6	542.7	2,347.7
AMIL	68.1	157.9	50.5	32.1	44.8	114.6	1.7	10.5	4.5	484.7
CIN	436.8	592.0	555.1	590.4	430.6	969.6	1,988.3	701.1	238.3	6,502.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	156.2	176.9	364.9	203.7	179.3	752.7	1,536.1	519.1	204.8	4,093.7
IPL	26.9	29.4	30.7	102.8	97.0	1,045.3	1,004.8	124.0	16.8	2,477.7
MECS	606.2	801.7	1,125.2	1,118.7	1,035.2	2,223.8	2,629.9	1,246.7	1,060.7	11,848.1
NIPS	28.6	19.5	24.3	33.1	26.9	292.1	1,115.1	84.5	19.3	1,643.4
WEC	139.3	131.3	226.6	161.5	133.8	990.1	1,125.0	411.4	90.1	3,409.1
NYISO	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	9,193.0
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	9,193.0
OVEC	1,133.2	1,259.7	1,379.9	922.0	802.1	1,063.8	1,086.8	985.3	793.4	9,426.2
TVA	75.9	77.8	36.7	15.2	44.4	55.3	357.2	120.3	79.1	861.9
Total	4,720.8	5,108.2	5,716.6	4,569.2	4,152.6	10,026.2	16,127.4	7,201.2	6,053.3	63,675.5

Table 4-6 Day-ahead gross export volume by interface (GWh): January through September 2010 (See 2009 SOM, Table 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	153.5	150.8	144.0	132.9	124.1	183.3	223.7	244.1	160.0	1,516.4
CPLW	5.4	1.6	0.8	0.9	2.4	2.3	0.0	0.0	1.5	14.9
DUK	14.9	57.8	39.5	27.6	34.7	54.6	362.6	213.3	79.4	535.0
EKPC	1.5	5.9	3.8	0.2	1.4	3.0	4.7	3.5	0.1	60.5
LGEE	0.0	0.1	0.0	0.1	0.4	8.5	15.1	58.0	5.9	39.6
MEC	498.2	449.7	495.0	451.6	534.3	947.8	622.1	490.6	468.8	3,410.6
MISO	2,118.2	2,898.8	3,424.6	4,129.3	3,270.1	6,904.7	9,010.7	3,775.7	3,826.6	39,358.7
ALTE	638.8	1,019.9	799.0	685.3	974.8	889.2	2,118.6	1,095.4	1,737.4	9,958.4
ALTW	354.2	481.5	1,293.3	1,814.9	807.0	2,541.6	2,804.5	825.3	474.6	11,396.9
AMIL	53.7	60.4	43.8	19.7	0.3	0.0	0.0	1.5	5.8	185.2
CIN	253.9	652.8	512.0	660.7	388.8	659.6	611.4	539.8	234.1	4,513.1
CWLP	0.0	0.0	0.0	0.0	0.3	0.0	19.5	0.0	11.8	31.6
FE	226.7	197.6	246.1	276.1	258.6	362.3	528.6	498.7	423.1	3,017.8
IPL	80.3	47.8	75.4	111.3	139.0	976.4	873.0	82.3	57.8	2,443.3
MECS	218.4	147.3	239.6	385.8	488.6	999.9	1,145.3	479.2	681.2	4,785.3
NIPS	233.1	236.5	167.6	120.7	147.1	396.0	720.2	118.8	86.4	2,226.4
WEC	59.1	55.0	47.8	54.8	65.6	79.7	189.6	134.7	114.4	800.7
NYISO	1,804.3	1,797.1	1,921.1	1,636.4	1,876.0	2,822.9	5,930.7	2,124.6	1,941.4	21,854.5
LIND	21.1	18.3	53.2	11.4	15.3	12.0	24.7	9.9	53.2	219.1
NEPT	502.6	445.2	456.7	301.3	473.4	472.7	420.9	317.7	374.8	3,765.3
NYIS	1,280.6	1,333.6	1,411.2	1,323.7	1,387.3	2,338.2	5,485.1	1,797.0	1,513.4	17,870.1
OVEC	59.2	16.4	79.4	4.9	123.1	5.6	41.1	6.8	81.9	418.4
TVA	81.2	40.0	63.7	76.1	49.8	47.6	692.3	103.9	61.1	1,215.7
Total	4,736.4	5,418.2	6,171.9	6,460.0	6,016.3	10,980.3	16,903.0	7,020.5	6,626.7	70,333.3

Interface Pricing

Table 4-7 Active interfaces: January through September 2010 (See 2009 SOM, Table 4-7)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
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	Active	Active	Active	Active	Active	Active	Active	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

Figure 4-4 PJM's footprint and its external interfaces (See 2009 SOM, Figure 4-4)

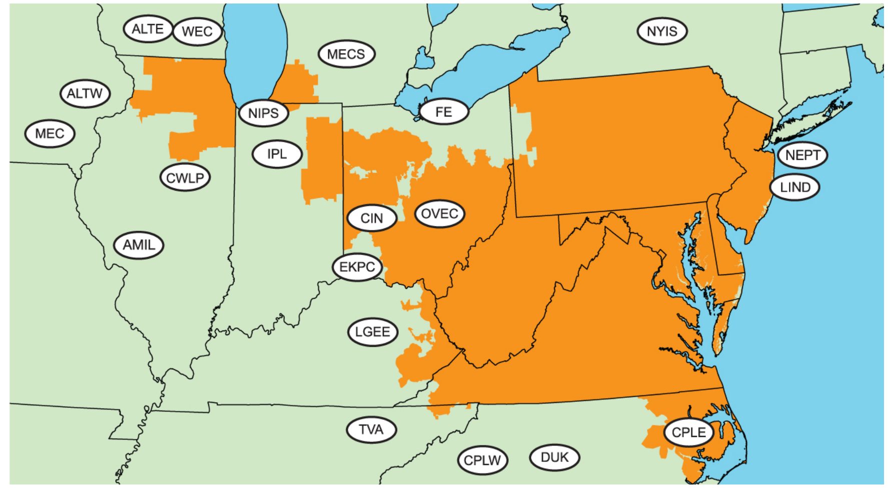


Table 4-8 Active pricing points: January through September 2010 (See 2009 SOM, Table 4-8)

PJM 2010 Pricing Points (January through September)			
LIND	MICHFE	MISO	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO
OVEC	SOUTHEXP	SOUTHIMP	

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

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 2010 (See 2009 SOM, Figure 4-5)

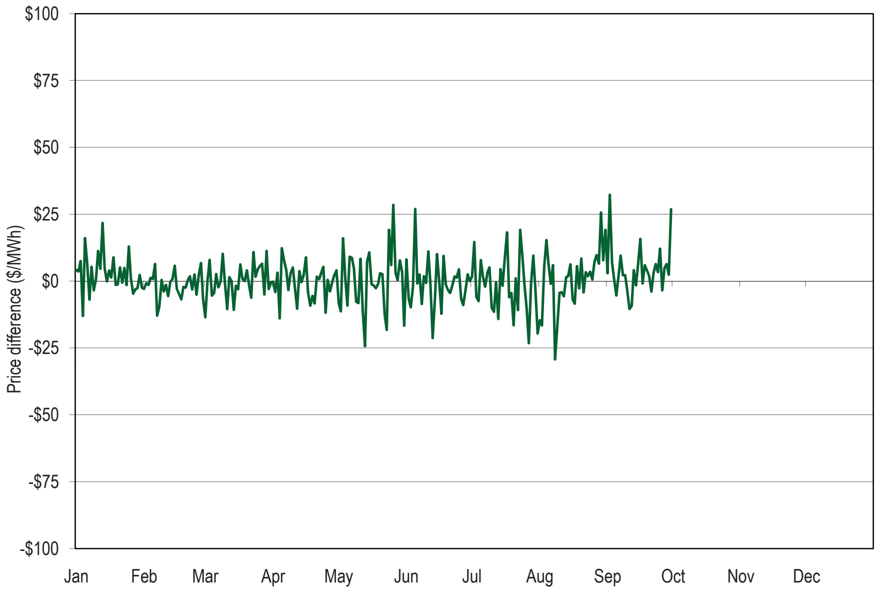


Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2010 (See 2009 SOM, Figure 4-6)

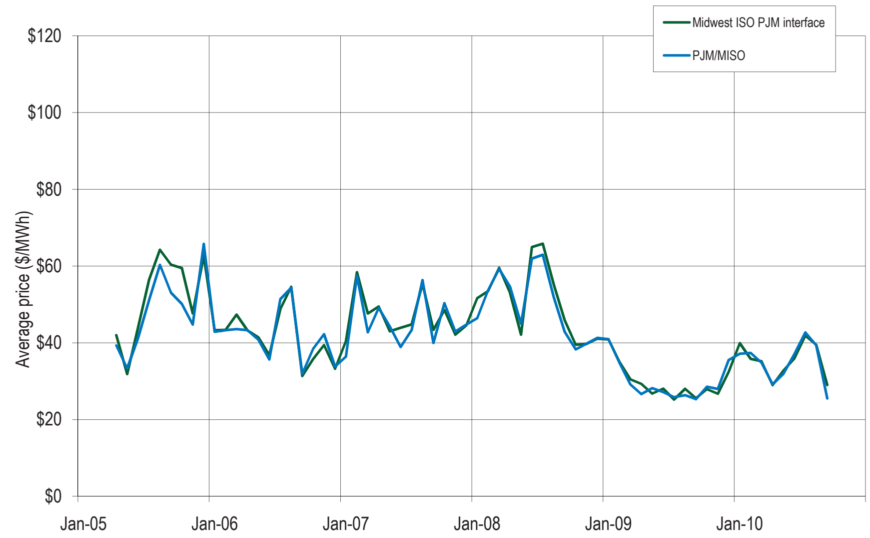


Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 2008 through September 2010 (See 2009 SOM, Table 4-9)

	2008			2009			2010		
	LMP	MCC	MLC	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$8.26	($6.56)	($2.86)	$4.81	($2.65)	($2.06)	$3.18	($6.66)	($2.70)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$3.22	($4.92)	($1.38)	$2.41	($8.23)	($1.90)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.20	($4.64)	($2.70)	$1.87	($4.82)	($3.41)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($4.63)	($3.07)	$1.77	($6.97)	($3.80)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	$0.01	($6.94)	($2.58)	($0.37)	($9.70)	($3.21)
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 2010 (See 2009 SOM, Figure 4-7)

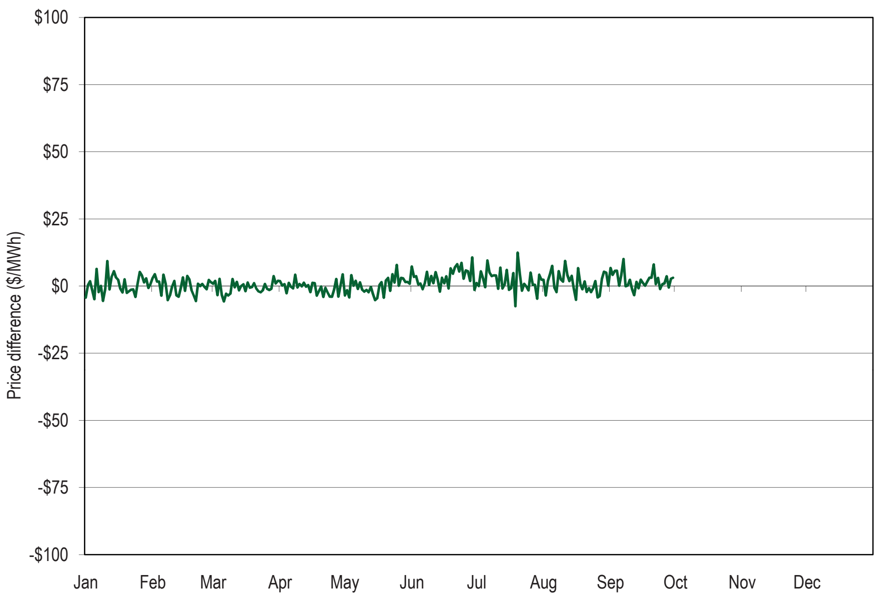


Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2010 (See 2009 SOM, Figure 4-8)

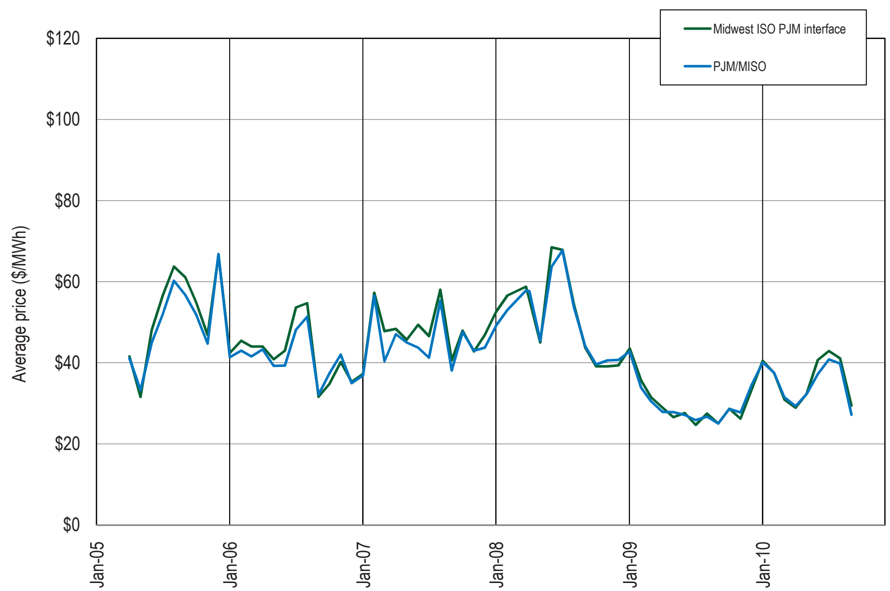


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): January 2008 through September 2010 (See 2009 SOM, Table 4-10)

	2008			2009			2010		
	LMP	MCC	MLC	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$9.19	($3.00)	($4.25)	$4.02	($2.06)	($2.80)	$1.86	($5.87)	($3.31)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.48	($4.72)	($1.67)	$1.84	($6.82)	($2.38)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$1.87	($3.85)	($3.16)	$0.68	($6.09)	($4.26)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.40	($3.87)	($3.61)	$0.35	($5.95)	($4.74)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.03)	($5.75)	($3.16)	($0.95)	($7.84)	($4.15)
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 2010 (See 2009 SOM, Figure 4-9)

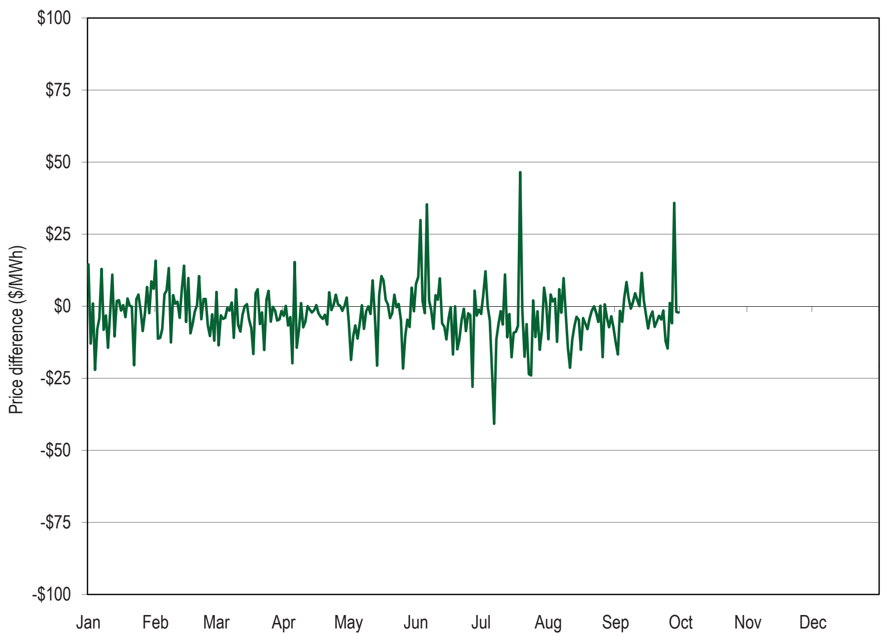


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through September 2010 (See 2009 SOM, Figure 4-10)

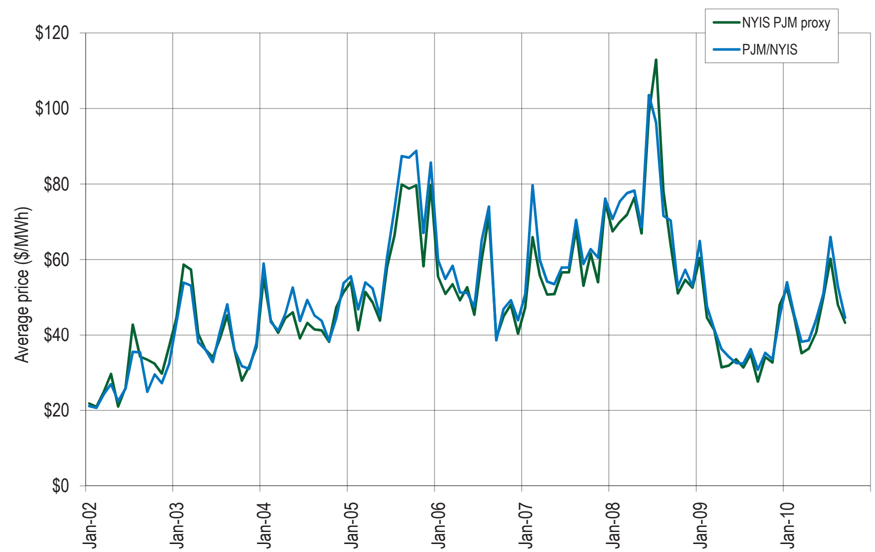


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September 2010 (See 2009 SOM, Figure 4-11)

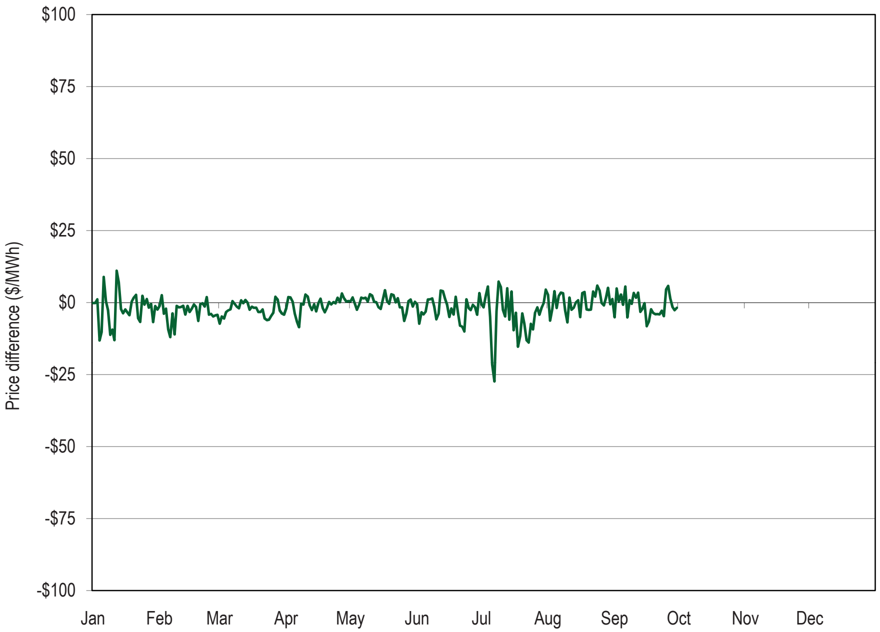
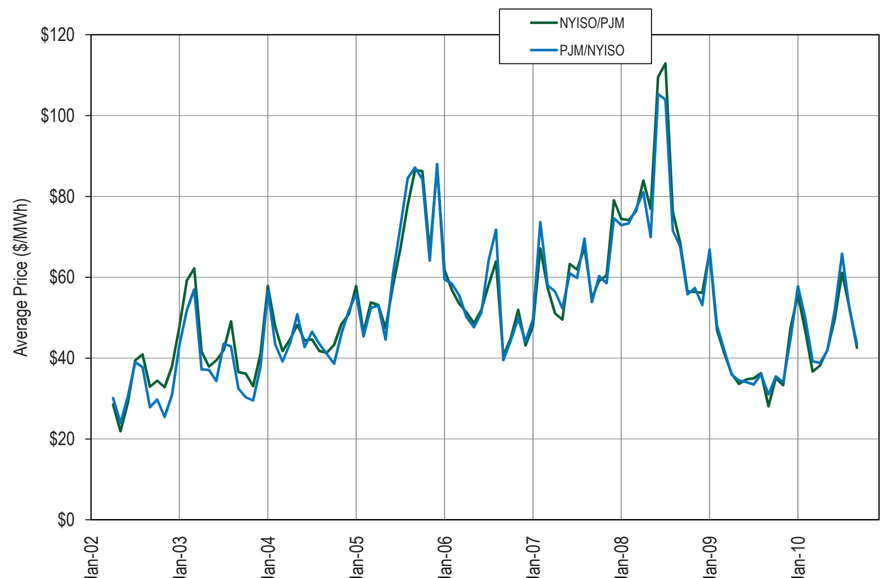


Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through September 2010 (See 2009 SOM, Figure 4-12)



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 2010 (See 2009 SOM, Figure 4-13)

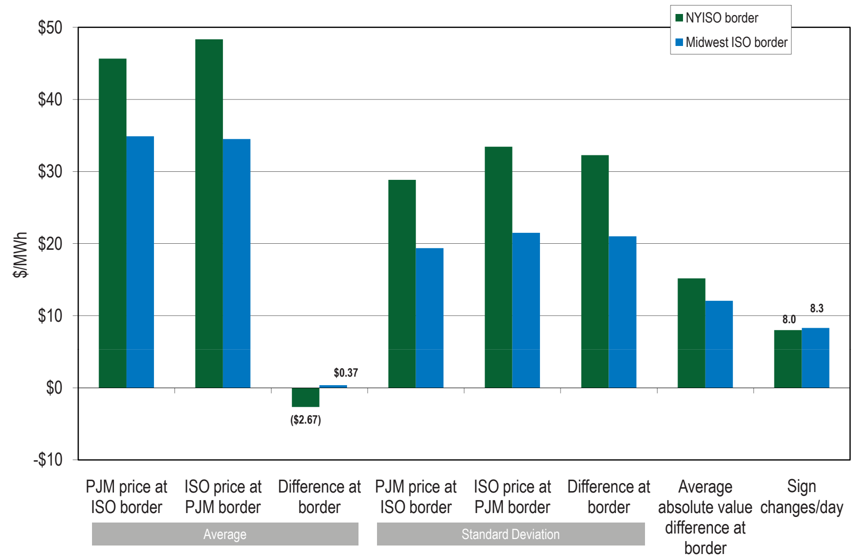
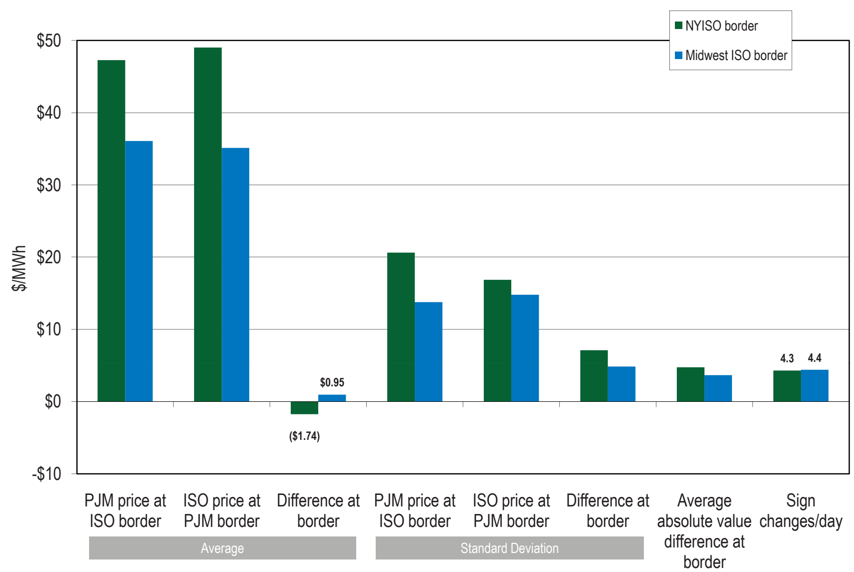


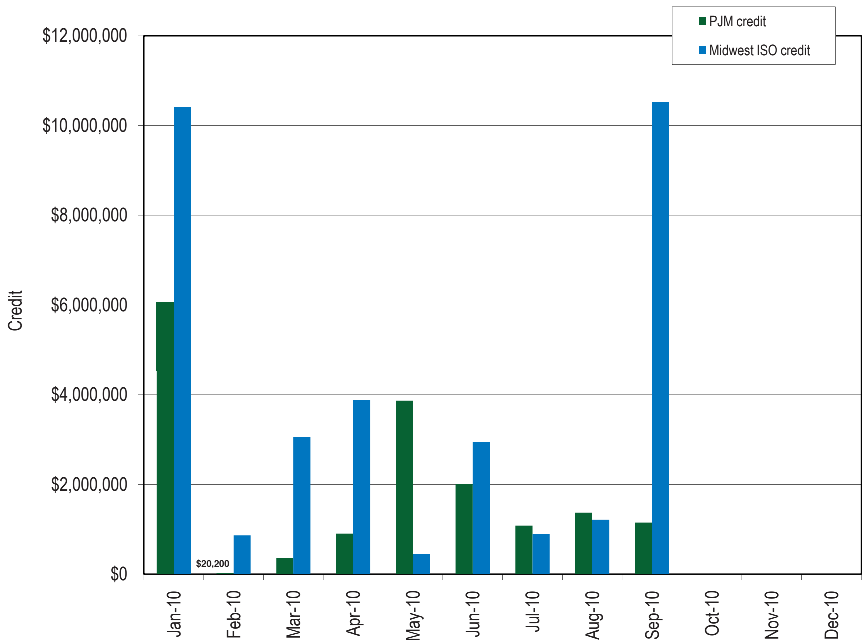
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through September 2010 (See 2009 SOM, Figure 4-14)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement

Figure 4-15 Credits for coordinated congestion management: January through September 2010 (See 2009 SOM, Figure 4-15)



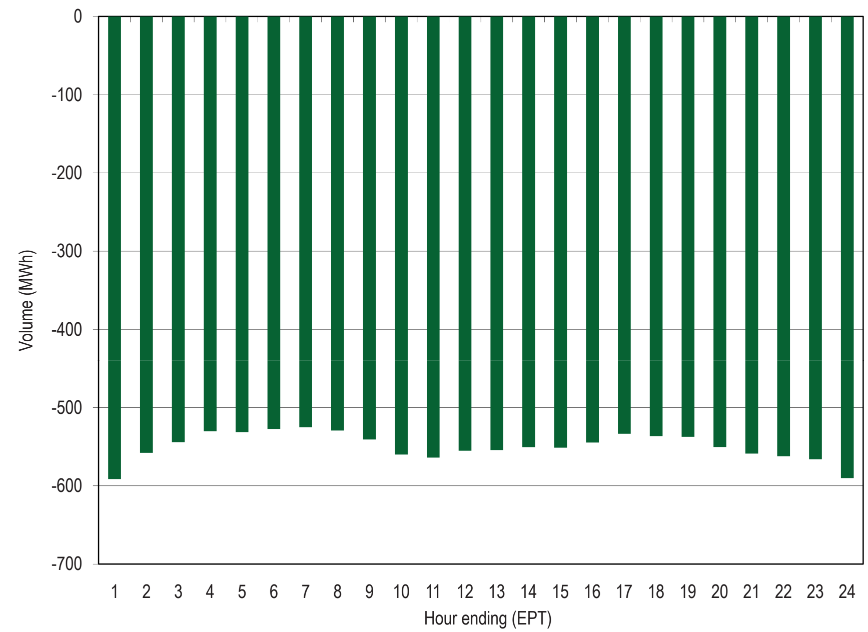
Con Edison and PSE&G Wheeling Contracts

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through September 2010 (See 2009 SOM, Table 4-11)

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total	Congestion Charge	$3,721,574	($26,966)	$3,694,608	$6,031,780	$0	$6,031,780
	Congestion Credit			$2,042,635			$5,344,584
	Adjustments			$16,175			$351,387
	Net Charge			$1,635,798			$335,809

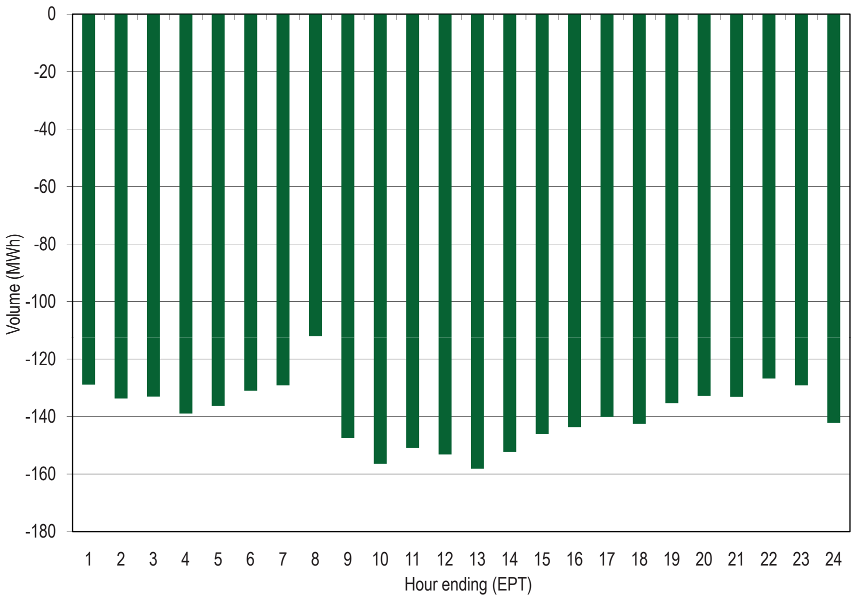
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-16 Neptune hourly average flow: January through September 2010 (See 2009 SOM, Figure 4-16)



Linden Variable Frequency Transformer (VFT) facility

Figure 4-17 Linden hourly average flow: January through September 2010 (See 2009 SOM, Figure 4-17)



Interchange Transaction Issues

Loop Flows

Table 4-12 Net scheduled and actual PJM interface flows (GWh): January through September 2010 (See 2009 SOM, Table 4-12)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	5,910	(182)	6,092	(3,347%)
CPLW	(1,434)	-	(1,434)	0%
DUK	(2,325)	80	(2,405)	(3,006%)
EKPC	675	-	675	0%
LGEE	917	949	(32)	(3%)
MEC	(1,963)	(3,856)	1,893	(49%)
MISO	(5,784)	(399)	(5,385)	1,350%
ALTE	(4,304)	(319)	(3,985)	1,249%
ALTW	(1,562)	(473)	(1,089)	230%
AMIL	4,568	(236)	4,804	(2,036%)
CIN	1,126	2,293	(1,167)	(51%)
CWLP	(194)	(14)	(180)	1,286%
FE	(610)	(1,954)	1,344	(69%)
IPL	2,120	(397)	2,517	(634%)
MECS	(9,193)	1,360	(10,553)	(776%)
NIPS	(1,698)	(358)	(1,340)	374%
WEC	3,963	(301)	4,264	(1,417%)
NYISO	(8,871)	(10,325)	1,454	(14%)
LIND	(910)	(910)	-	0%
NEPT	(3,601)	(3,601)	-	0%
NYIS	(4,360)	(5,814)	1,454	(25%)
OVEC	5,178	8,551	(3,373)	(39%)
TVA	2,131	(663)	2,794	(421%)
Total	(5,566)	(5,845)	279	(4.8%)

Loop Flows at PJM's Southern Interfaces

Figure 4-18 Southwest actual and scheduled flows: January 2006 through September 2010 (See 2009 SOM, Figure 4-18)

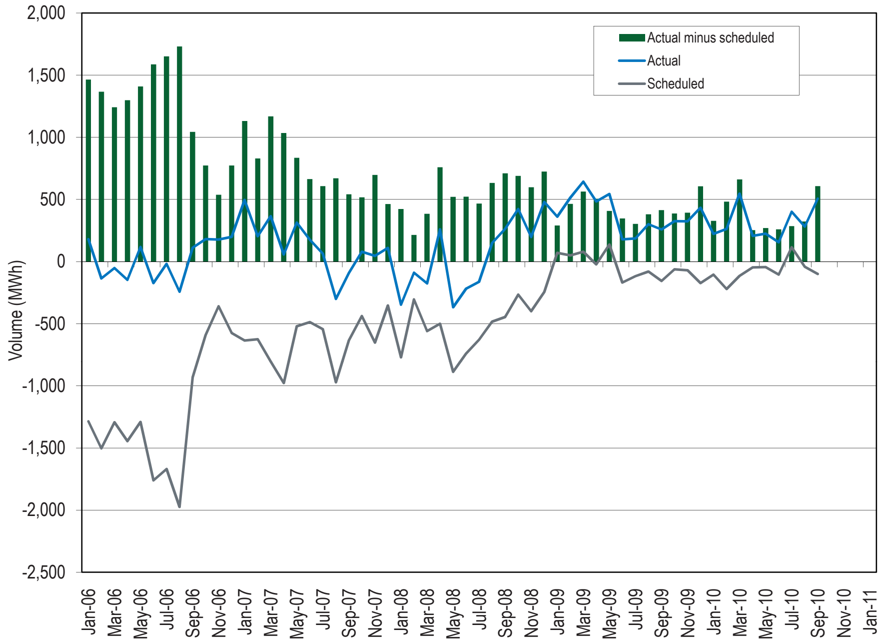
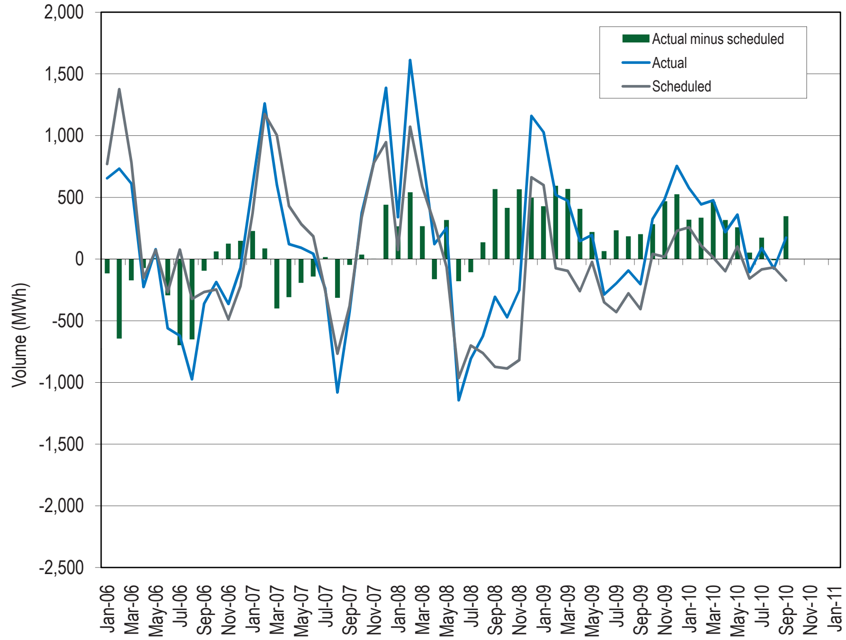


Figure 4-19 Southeast actual and scheduled flows: January 2006 through September 2010 (See 2009 SOM, Figure 4-19)



TLRs

Figure 4-20 PJM and Midwest ISO TLR procedures: Calendar year 2009 and January through September 2010 (See 2009 SOM, Figure 4-20)

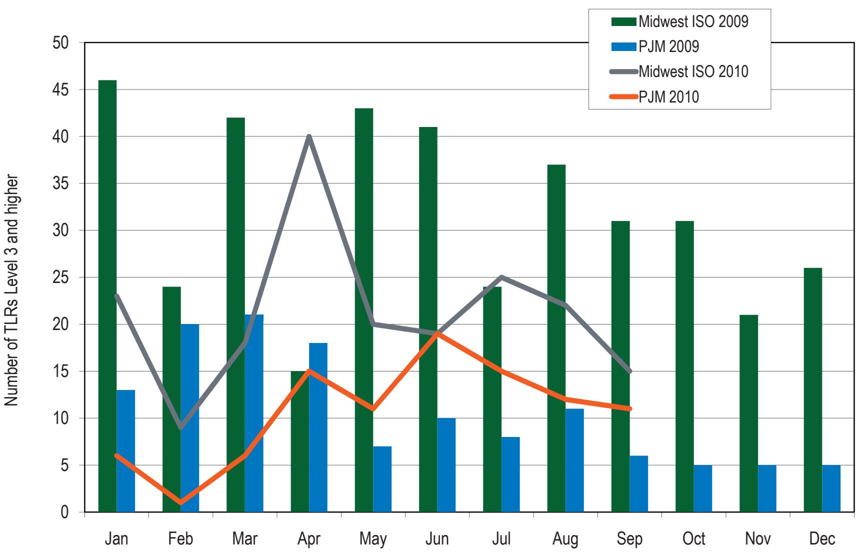


Figure 4-21 Number of different PJM flowgates that experienced TLRs: Calendar year 2009 and January through September 2010 (See 2009 SOM, Figure 4-21)

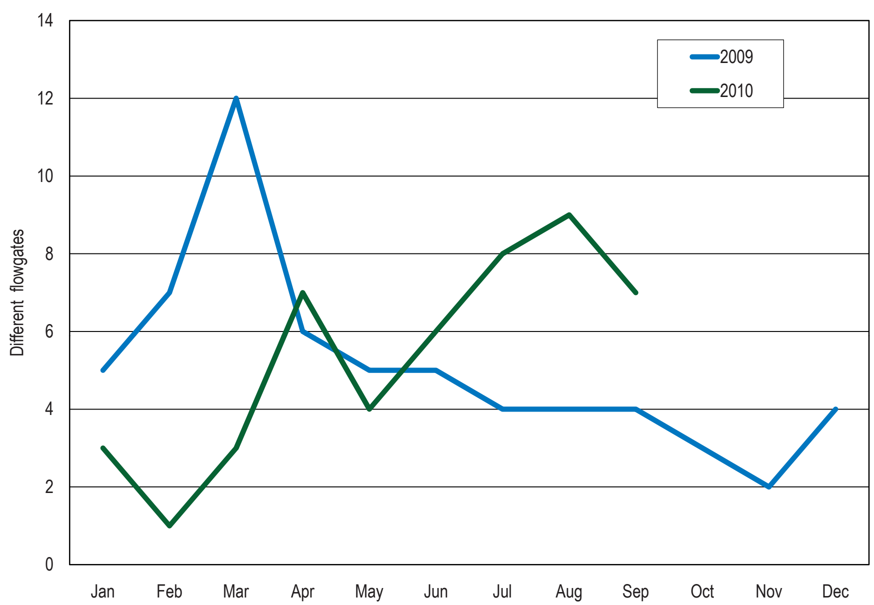


Figure 4-22 Number of PJM TLRs and curtailed volume: January through September 2010 (See 2009, Figure 4-22)

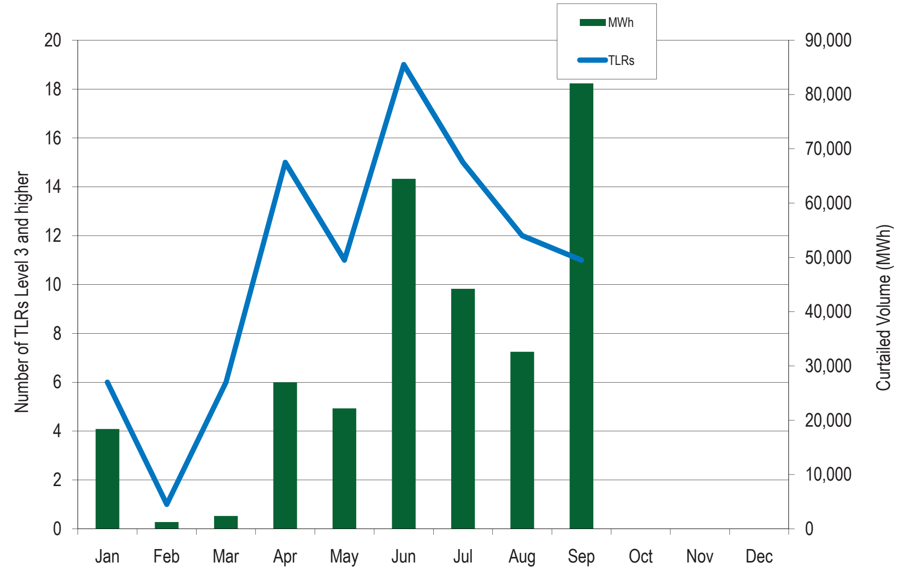


Table 4-13 Number of TLRs by TLR level by reliability coordinator: January through September 2010 (See 2009 SOM, Table 4-13)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2010	ICTE	67	23	141	43	30	0	304
	MISO	102	59	0	14	16	0	191
	NYIS	99	0	0	0	0	0	99
	ONT	62	5	0	1	0	0	68
	PJM	56	40	0	0	0	0	96
	SWPP	183	950	19	51	26	0	1,229
	TVA	13	27	7	0	1	0	48
	VACS	1	1	0	0	0	0	2
Total		583	1,105	167	109	73	0	2,037

Up-To Congestion

Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through September 2010 (See 2009 SOM, Figure 4-23)

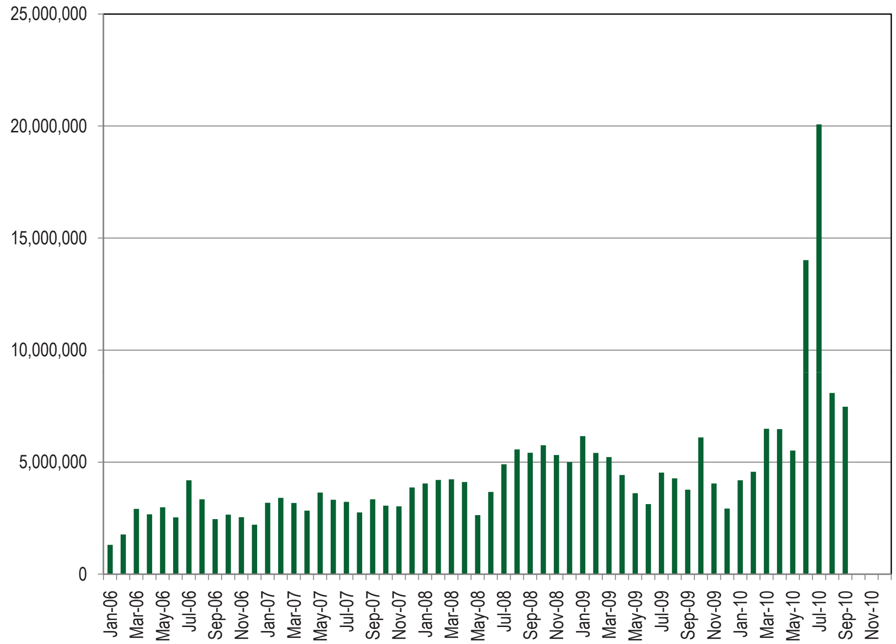


Table 4-14 Up-to congestion MW by Import, Export and Wheels: January 2006 through September 2010 (See 2009 SOM, Table 4-14)

	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	10,730,659	20,398,833	468,648	31,598,141	34.0%	64.6%	1.5%
2007	13,950,514	24,080,803	817,237	38,848,554	35.9%	62.0%	2.1%
2008	20,889,972	32,351,960	1,632,874	54,874,806	38.1%	59.0%	3.0%
2009	24,455,358	27,722,740	1,453,553	53,631,651	45.6%	51.7%	2.7%
2010	36,897,250	34,715,643	5,291,729	76,904,622	48.0%	45.1%	6.9%
TOTAL	106,923,753	139,269,979	9,664,040	255,857,773	41.8%	54.4%	3.8%

Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: January through September 2010 (See 2009 SOM, Figure 4-24)

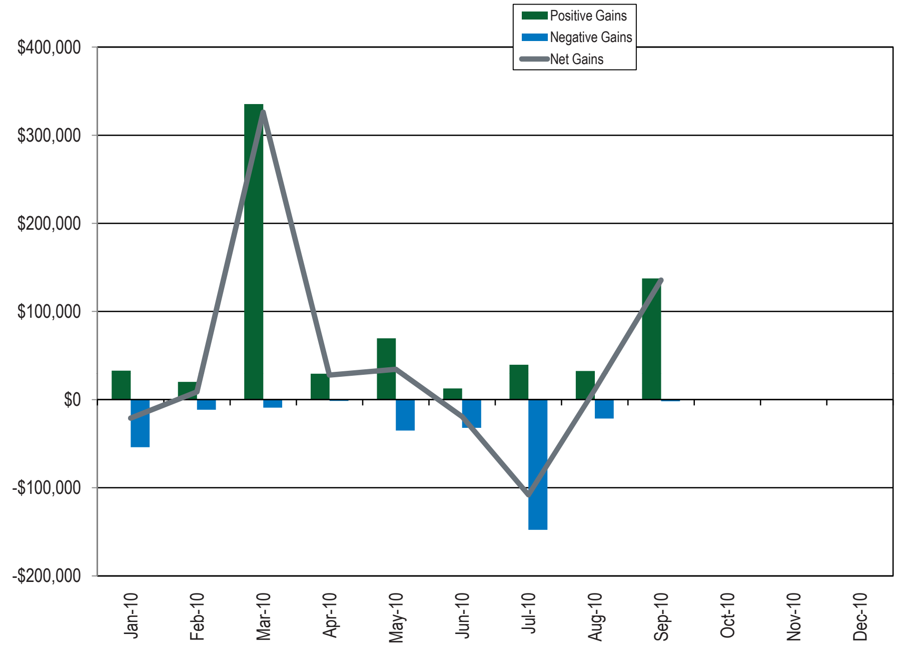


Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: January through September 2010 (See 2009 SOM, Figure 4-25)

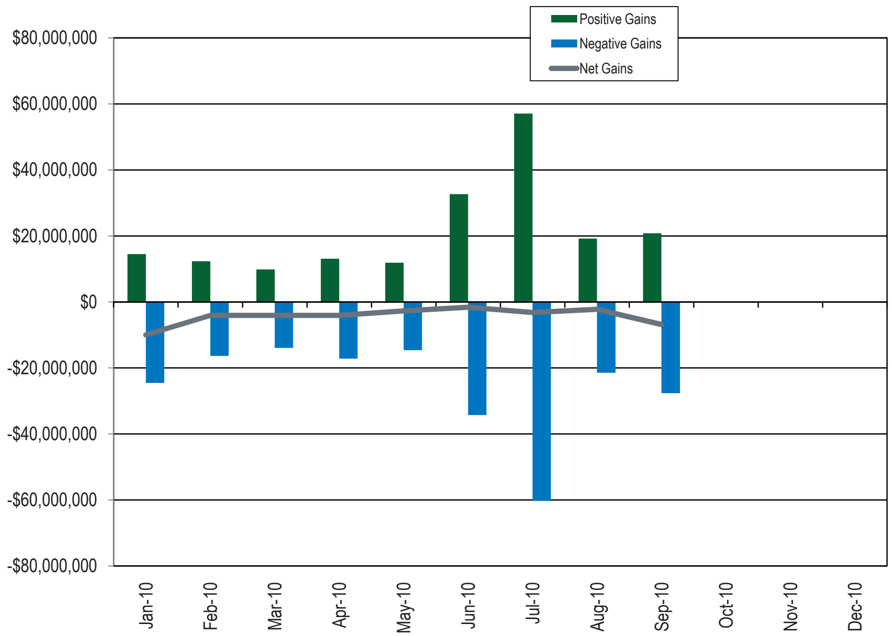


Table 4-16 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2010 (See 2009 SOM, Table 4-17)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$42.03	$43.10	$40.15	$40.15	$1.88	$2.94
PEC	$42.84	$46.07	$40.15	$40.15	$2.69	$5.91
NCMPA	$42.53	$42.69	$40.15	$40.15	$2.38	$2.54

Interface Pricing Agreements with Individual Companies

Table 4-15 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through September 2010 (See 2009 SOM, Table 4-15)

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$42.55	$37.89	$38.36	$42.02	$4.20	($0.47)	$0.53	($4.13)
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.01)
2008	$62.97	$51.43	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.01)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)
2010	$44.30	$37.18	$40.15	$40.15	$4.15	($2.97)	$4.15	($2.97)

Figure 4-26 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2010 (See 2009 SOM, Figure 4-26)

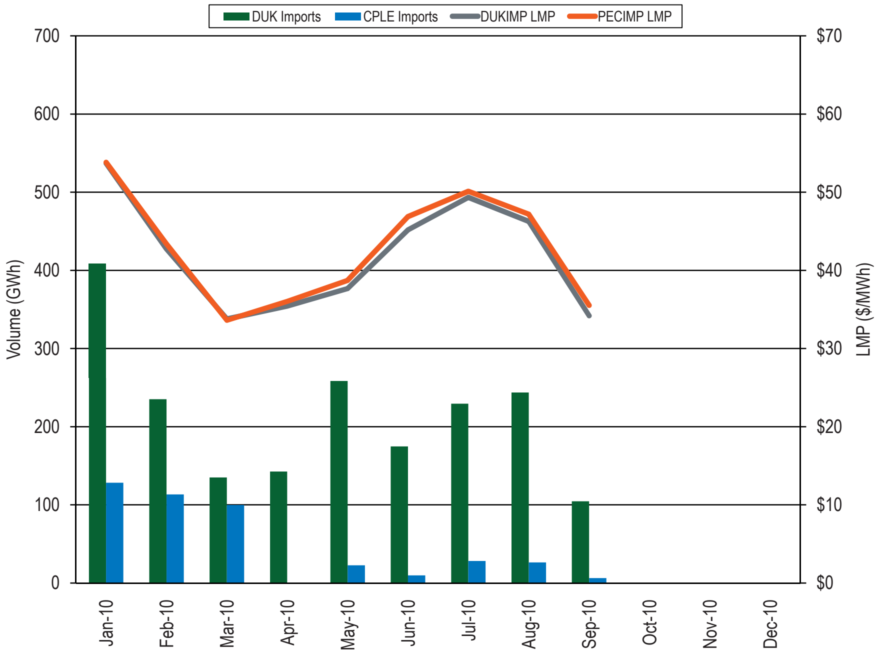


Figure 4-27 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2010 (See 2009 SOM, Figure 4-27)

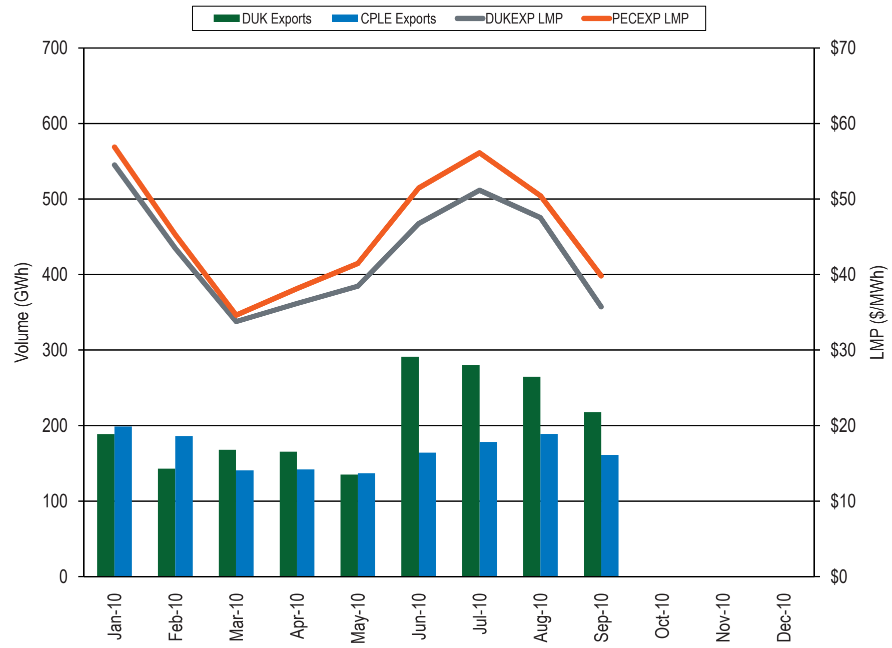


Table 4-17 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through September 2010 (New Table)

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$41.53	$38.10	$38.32	$41.23	$3.21	($0.22)	$0.31	($3.13)
2007	$53.50	$45.01	$48.45	$47.76	$5.06	($3.44)	$5.75	($2.75)
2008	$63.44	$52.27	$56.26	$56.26	$7.17	($3.99)	$7.17	($3.99)
2009	$36.42	$32.05	$33.59	$33.59	$2.83	($1.54)	$2.83	($1.54)
2010	$45.33	$37.57	$40.24	$40.24	$5.23	($2.73)	$5.23	($2.73)

Table 4-18 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September 2010 (See 2009 SOM, Table 4-19)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$42.37	$43.85	$40.24	$40.24	$2.14	$3.61
PEC	$43.57	$46.61	$40.24	$40.24	$3.33	$6.37
NCMPA	$43.17	$43.31	$40.24	$40.24	$2.93	$3.07

Figure 4-28 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2010 (See 2009 SOM, Figure 4-28)

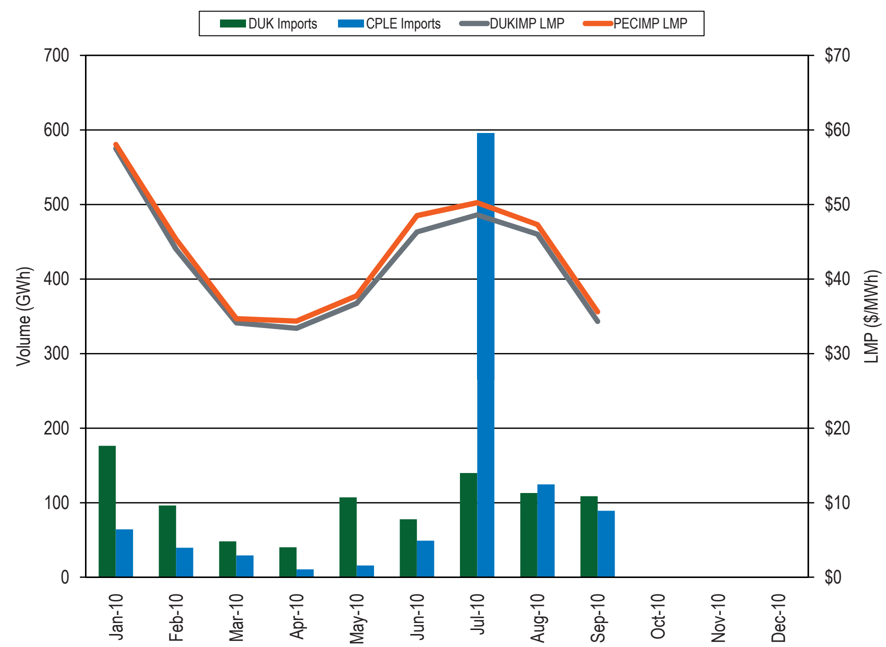
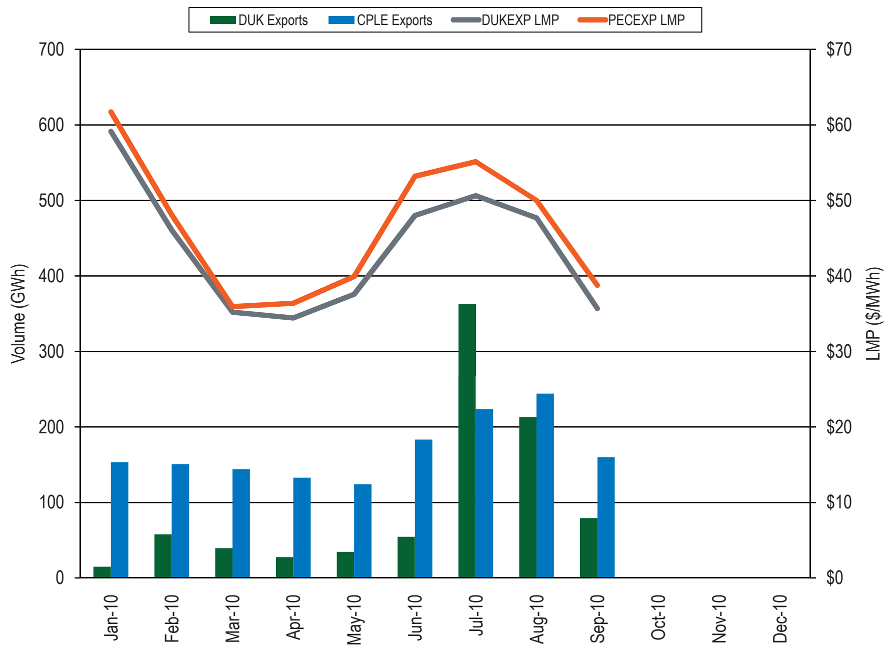
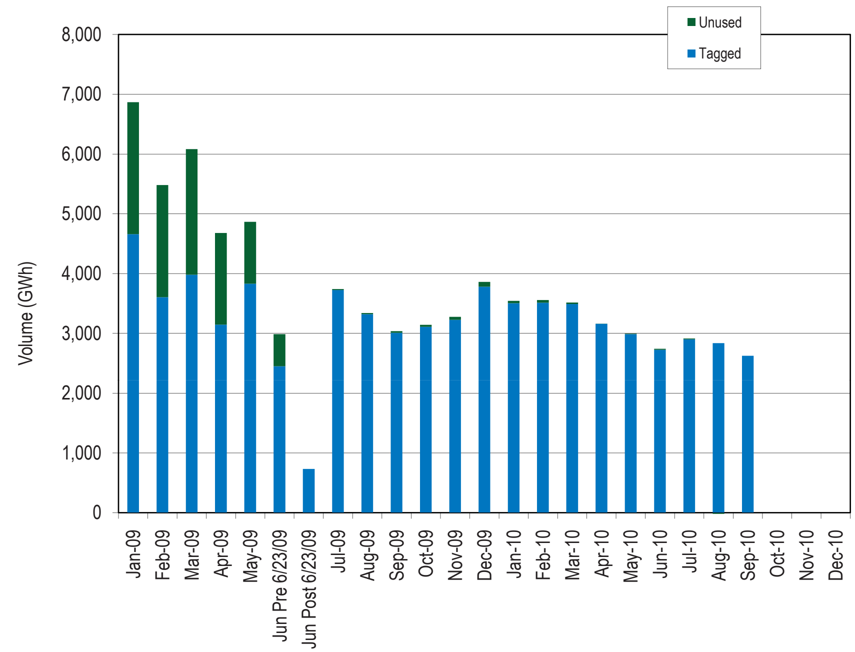


Figure 4-29 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2010 (See 2009 SOM, Figure 4-29)



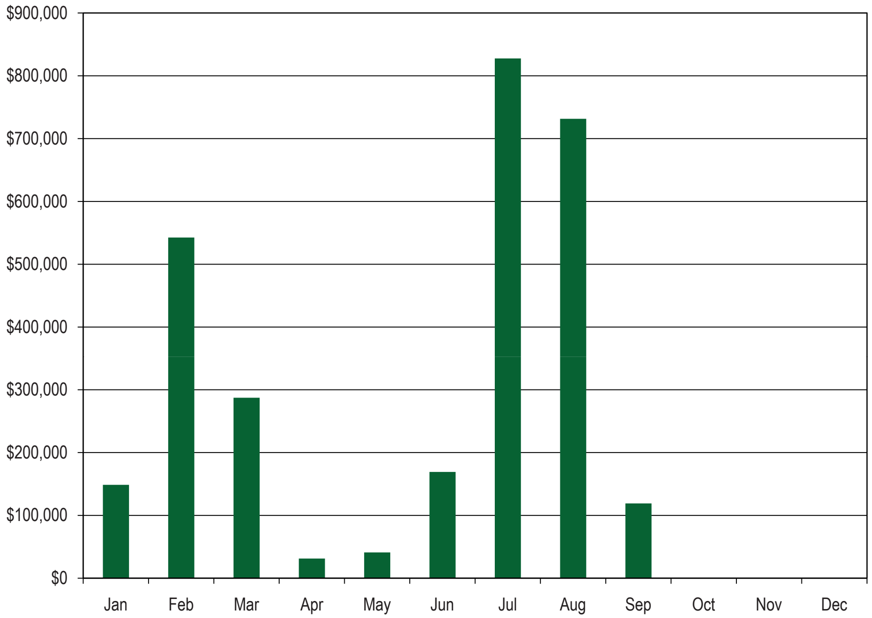
Spot Import

Figure 4-30 Spot import service utilization: January 2009 through September 2010 (See 2009 SOM, Figure 4-30)



Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-31 Monthly uncollected congestion charges: January through September 2010 (See 2009 SOM, Figure 4-31)



Ramp Availability

Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through September 2010 (See 2009 SOM, Figure 4-32)