PJM Interconnection (PJM)

Section 6 – PJM Performance Metrics and Other Information

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

- Acting as a neutral, independent entity, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability for more than 51 million people.
- PJM's long-term regional planning process provides a broad, interstate perspective over a 15-year horizon that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system-wide basis.
- An independent board, representing various knowledge and experience requirements, provides oversight on behalf of PJM's 600+ members. Through effective governance and a collaborative stakeholder process, PJM is guided by its vision: "To be the electric industry leader – today and tomorrow – in reliable operations, efficient wholesale markets and infrastructure planning."

Founded in 1927 as a power pool, PJM opened its first bid-based energy market on April 1, 1997. Later that year, the Federal Energy Regulatory Commission (FERC) approved PJM as an independent system operator (ISO). ISOs operate, but do not own, transmission systems in order to provide open access to the grid for non-utility users.

PJM became a regional transmission organization (RTO) in 2001, as FERC encouraged the formation of RTOs to operate the transmission system in multi-state areas as a means to advance the development of competitive wholesale power markets.

From 2002 through 2005, PJM integrated a number of utility transmission systems into its operations. They included: Allegheny Power in 2002; Commonwealth Edison, American Electric Power and Dayton Power & Light in 2004; and Duquesne Light and Dominion in 2005. These integrations expanded the number and diversity of resources available to meet consumer demand for electricity and increased the benefits of PJM's wholesale electricity market.

Currently, PJM administers a day-ahead energy market, real-time energy market, capacity market, financial transmission right congestion hedging market, day-ahead scheduling reserve market, synchronized reserve market and regulation market. PJM ensures sufficient black start service to supply electricity for system restoration in the unlikely event that the entire grid would lose power. PJM also administers demand response programs that help increase operational efficiency and improve resource diversity which in turn can reduce customer costs and reduce wholesale prices.

A. PJM Bulk Power System Reliability

The table below identifies which NERC Functional Model registrations PJM has submitted effective as of the end of 2009. Additionally, the Regional Entities for PJM are noted at the end of the table with a link to the websites for the specific reliability standards. To date, PJM has had no self-reported or audit-identified violations of NERC or applicable Regional Entities' standards, though certain potential violations are under review based on a first quarter 2010 standards audit. Also, PJM has not shed any load in the PJM region due to violating a NERC or Reliability Entity operating standard.

NERC Functional Model Registration	PJM
Balancing Authority	✓
Interchange Authority	✓
Planning Authority	✓
Reliability Coordinator	✓
Resource Planner	✓
Transmission Operator	✓
Transmission Planner	✓
Transmission Service Provider	✓
Regional Entities	Reliability*First* and SERC

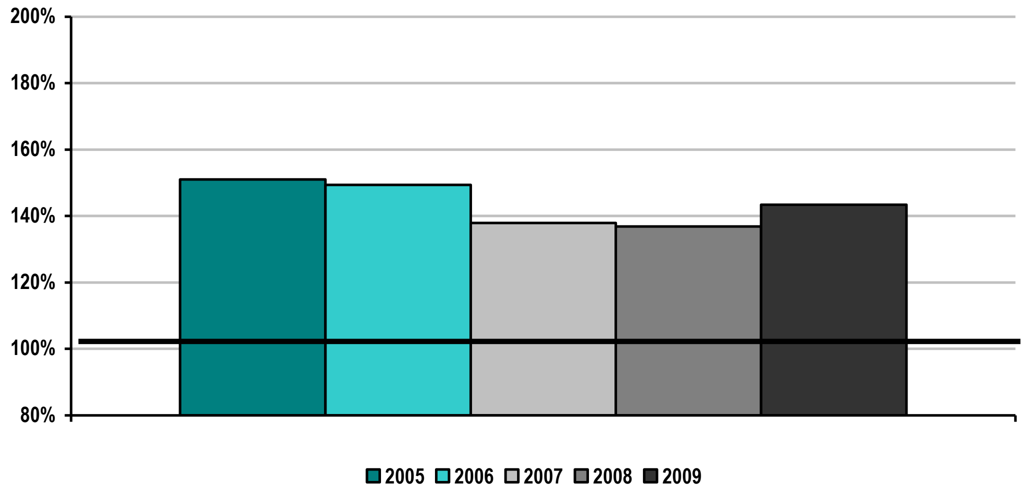
Standards that have been approved by the NERC Board of Trustees are available at:
http://www.nerc.com/page.php?cid=2|20

Additional standards approved by the Reliability*First* Board are available at:
http://www.rfirst.org/Standards/ApprovedStandards.aspx

Additional standards approved by the SERC Board are available at:
http://www.serc1.org/Application/ContentPageView.aspx?ContentId=111

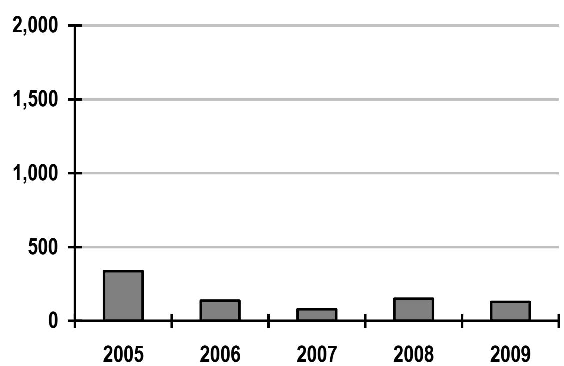
Dispatch Operations

PJM CPS-1 Compliance 2005-2009



Compliance with CPS-1 requires a performance level of at least 100% throughout a 12-month period. PJM was in compliance with CPS-1 for each of the calendar years from 2005 through 2009. PJM began participating in a field trial to replace CPS-2 as a performance measure in August 2005 and was granted a waiver from the CPS-2 measure at that time. This new control performance measure is the Balancing Authority ACE Limit (BAAL). The BAAL performance measure combines the CPS-1 performance measure with a specific limit known as a Frequency Trigger Limit (FTL). In order to be compliant with the BAAL standard, a Balancing Authority must recover from a FTL excursion within a 30-minute period of time. PJM was in compliance with the BAAL performance standard for each calendar year from 2005 to 2009.

Transmission Load Relief or Unscheduled Flow Relief Events 2005-2009

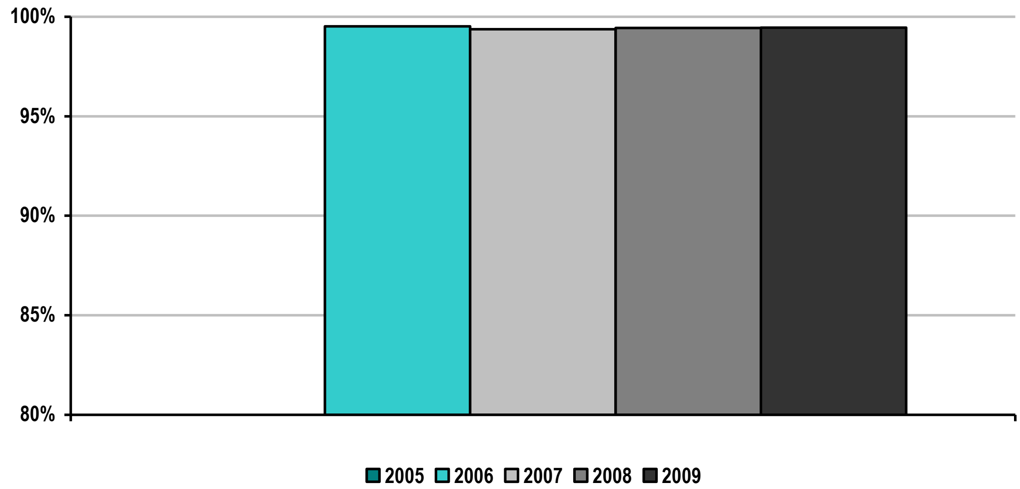


PJM data reflects the number of Transmission Load Relief (TLR) events. PJM's TLRs are almost exclusively level 3 and 4 TLRs with less than 1% of TLRs called from 2005 through 2009 being level 5. The number of TLRs in the PJM region has decreased since the integration of several transmission zones in 2003 – 2005. The levels of TLRs are also impacted by lower overall congestion levels in the past few years.

Transaction curtailments implemented under the TLR process are an extremely costly mechanism for reducing the flow on constrained transmission elements when compared to much more specifically targeted security constrained economic dispatch procedures. The TLR process relies on the administrative curtailment of wide area, control area-to-control area transactions in order to maintain flow within established ratings on transmission system elements. These transaction curtailments do not in any way reflect the economic desires of the market participants by which they are scheduled, but rather are conducted in a priority order determined by the length and firmness of the transmission service on which they are tagged. Because of the nature of this priority order, the curtailed transactions may have a five percent or smaller flow impact on the transmission constraint being controlled, and transmission system operators may therefore be required to implement thousands of MW of curtailments to achieve the necessary relief on constrained facilities. PJM, on the other hand, relies on security constrained unit commitment and economic dispatch in order to maintain transmission system reliability. This mechanism minimizes out-of-merit dispatch by economically redispatching resources that have the greatest impact on a constrained facility first, and has significantly reduced the transaction curtailments PJM has been required to implement in order to maintain transmission facilities within limits. From 2004 to 2007, PJM transaction curtailment requests were reduced in excess of 1,000,000 gigawatt hours. PJM production cost simulation results conservative estimates of the savings realized from the reduction in these inefficient transaction curtailments between $78 million and $98 million per year.

There are additional reliability benefits to the reduced reliance on the TLR procedure that are less quantifiable as a dollar value. Because TLR relies on curtailments of interchange transactions, relief from implementation of that process on a transmission facility cannot begin to be realized until at least 30 minutes after the constraint is recognized. This is because an inherent time delay exists between when a constraint is recognized, applicable transaction curtailments can be determined by the Reliability Coordinator, and those transaction curtailments can actually be implemented via the NERC electronic transaction tagging system. Additionally, because the transactions being curtailed under the TLR process are scheduled from control area to control area, it is impossible for the Reliability Coordinator to know specifically which generation resources will respond to accomplish the curtailments. The relief actually provided can therefore vary from that which was expected based on differences among unit-specific distribution factors on the constraint being controlled. Security constrained economic dispatch, on the other hand, sends electronic dispatch signals to individual generators within minutes of a constraint being identified. Within a few additional minutes, individual generators can respond to those signals and begin to provide relief on the constrained facility. While a monetary quantification is difficult, the reliability benefit of providing much more timely and targeted relief on transmission constraints is undeniable.

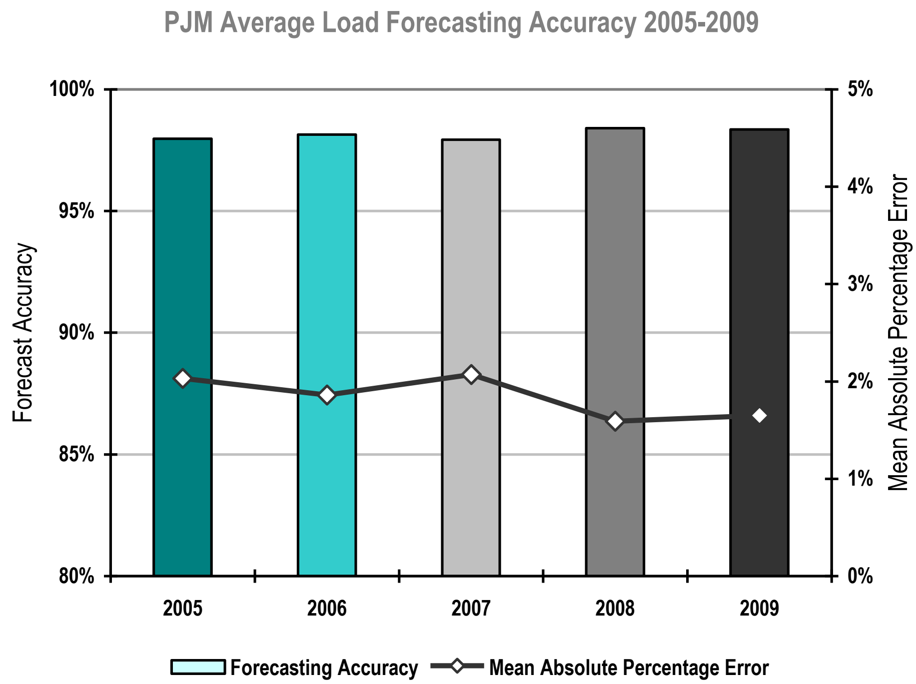
PJM Energy Market System Availability 2005-2009

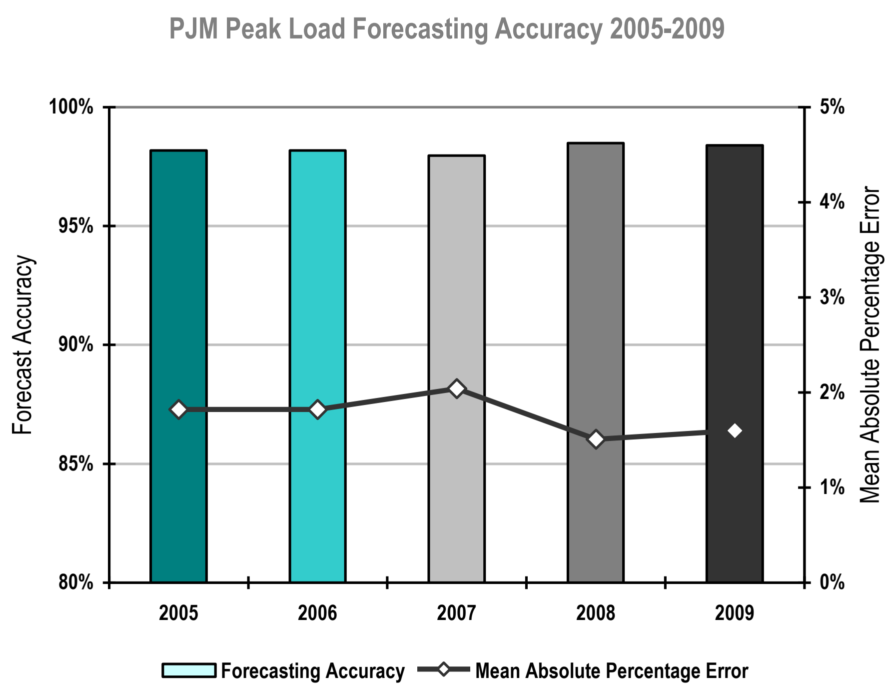


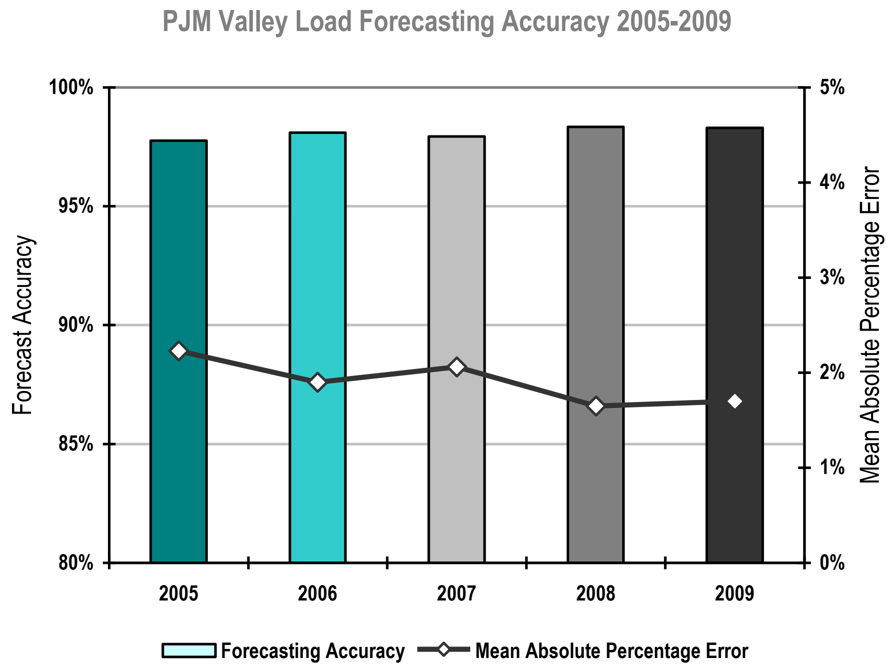
Availability of the Energy Management System (EMS) is key to reliable monitoring of the electric system in the PJM region. For the past four years, PJM's EMS has been unavailable less than 1% of all hours in each year. The majority of the time PJM's EMS system was unavailable to operators reflects challenges with data communications links, not EMS software or hardware issues. With the implementation of PJM's second control center, PJM will have dual, independent data communication links to the EMS systems at each control center to reduce the EMS availability impact of potential data communication link lapses. PJM does not have EMS availability data for 2005.

Load Forecast Accuracy

ISO/RTO	Load Forecasting Accuracy Reference Point
PJM	Noon prior day

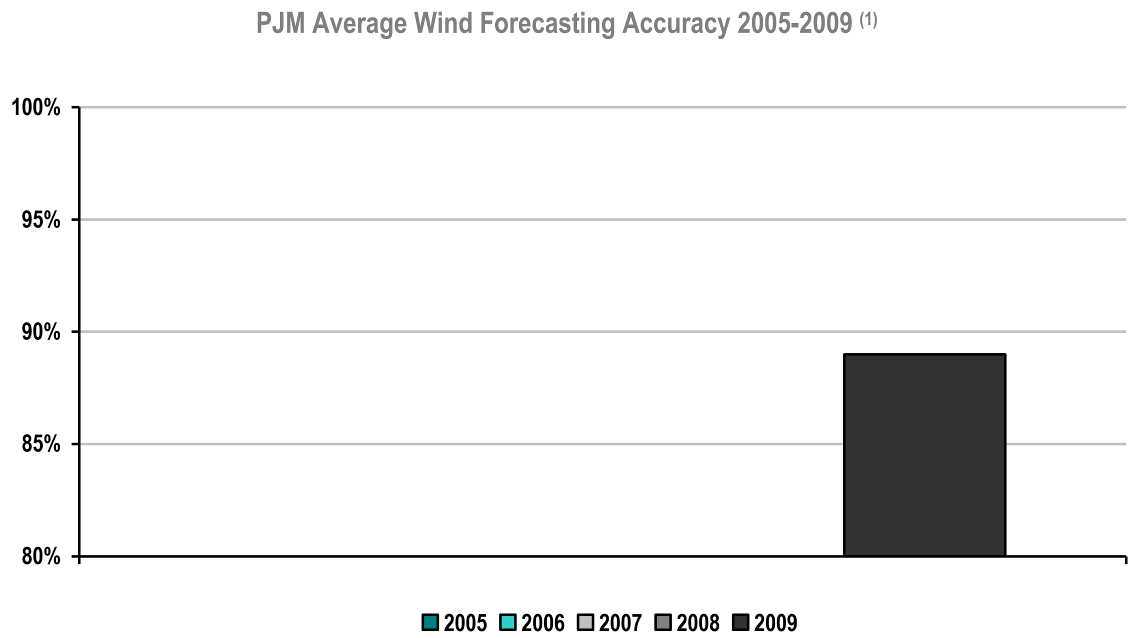






PJM has maintained its approximate 98% load forecasting accuracy for the aggregate PJM region for the years 2005 – 2009. This accuracy level is consistent for the average, peak and valley load forecasting during those years. This means that PJM is forecasting the total generation needs, as well as the daily maximum and minimum generation requirements, for the PJM region within a 2% variance to the actual needs.

Wind Forecasting Accuracy



(1) PJM data represents the month of December 31, 2009 when PJM began tracking this data.

PJM began tracking wind forecasting accuracy during December 2009. The data in this report includes the results of that single month and does not yet support any trend analysis. The potential output from a wind generation resource can be impacted by its geographic location, hub height, turbine type, turbine capacity, manufacturer's power curve, and ambient temperature operating limits.

PJM's approach to wind forecasting focuses on gathering the operating and historical data for each wind generation resource and incorporating that information in a forecast model that forecasts anticipated generation output based on predicted future operational and weather conditions. PJM's objective is to improve its wind forecasting accuracy as it gathers more historical data and experience with the current wind generators in the PJM region.

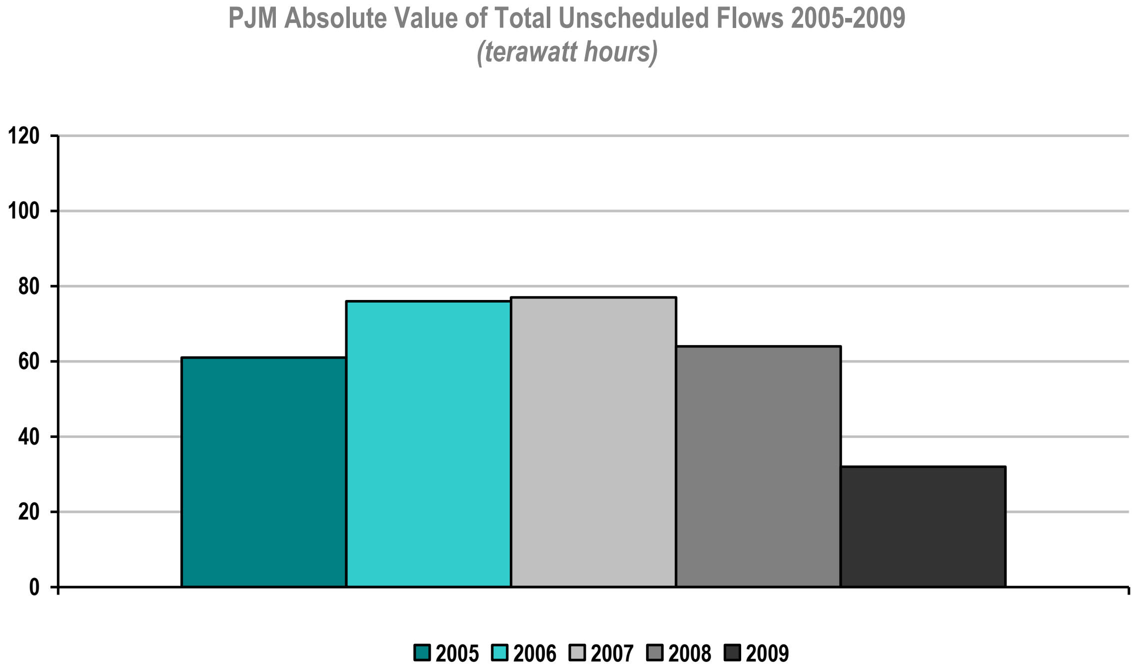
Hydroelectric and pump storage resources are scheduled in PJM's day-ahead energy market and as such do not impact forecast variability. Penetration of variable energy resources aside from wind generation are not significant enough at this time to impact the accuracy of the PJM load forecast.

PJM Wind Forecasting Future Enhancement:

During 2010 and early 2011, PJM plans to continue to focus on wind forecasting accuracy by:

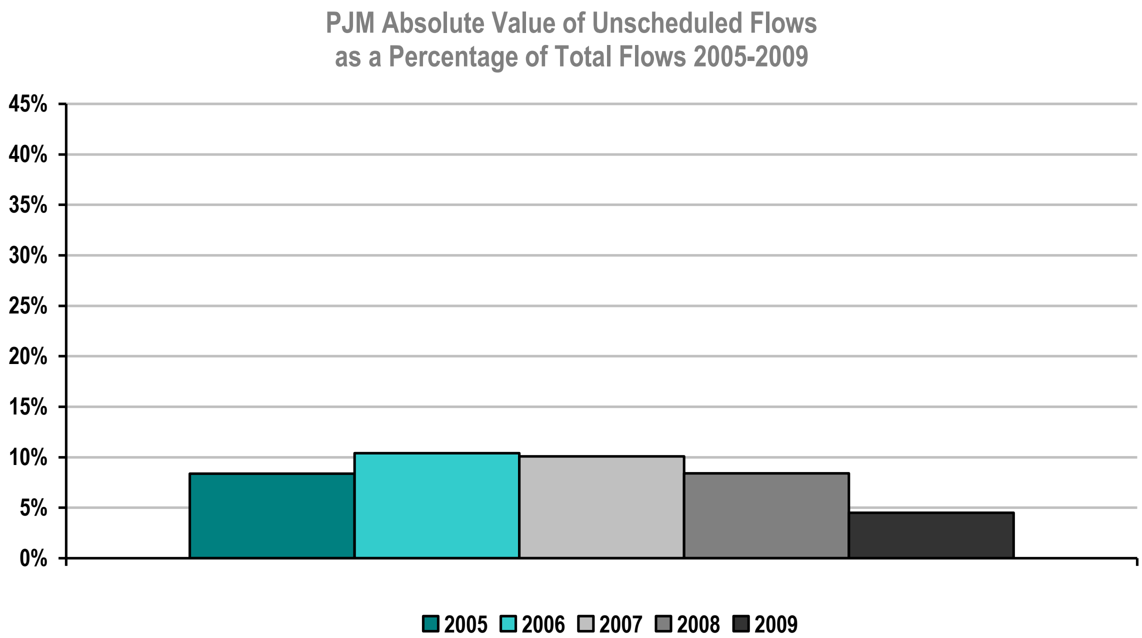
- Working with wind farms to provide more accurate turbine outage data; and
- Integrating PJM's wind power forecast application with PJM's other dispatch tools, such as security constrained economic dispatch.

Unscheduled Flows



For context, the table below notes the number of external interfaces in 2009 over which PJM may have experienced unscheduled flows.

ISO/RTO	Number of External Interfaces
PJM	19



PJM's unscheduled flows in both absolute terms and as a percentage of total flows have decreased over the past few years. This downward trend is primarily a function of a slower economy and milder weather in both 2008 and 2009 that resulted in lower transaction volumes into, out of, and through the PJM transmission system. Also, PJM has been actively engaged in the Broader Regional Markets effort with the NYISO, the Independent Electric System Operator of Ontario, and the Midwest ISO to develop effective solutions to continue to reduce unscheduled flows around Lake Erie.

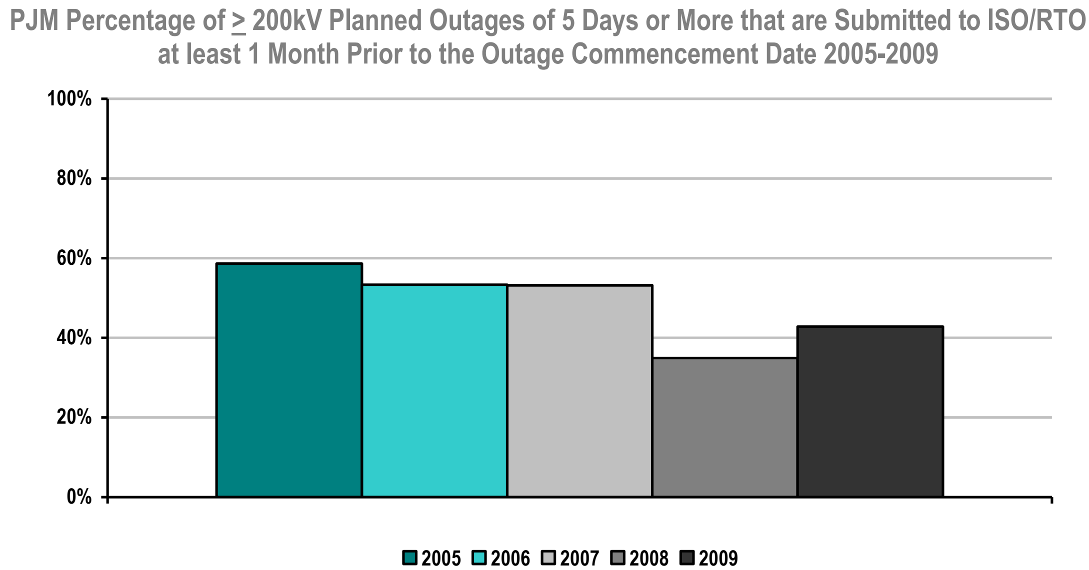
(in terawatt hours)

PJM Unscheduled Flows by Interface	2005	2006	2007	2008	2009
Progress Energy Carolinas	(4)	(3)	(5)	(6)	(7)
Midwest ISO (1)	---	(10)	(14)	(3)	7
Ohio Valley Electric Cooperative	1	(1)	(1)	2	4
Tennessee Valley Authority	(10)	(10)	(6)	(4)	(4)
Duke Energy Carolinas	3	5	6	4	3

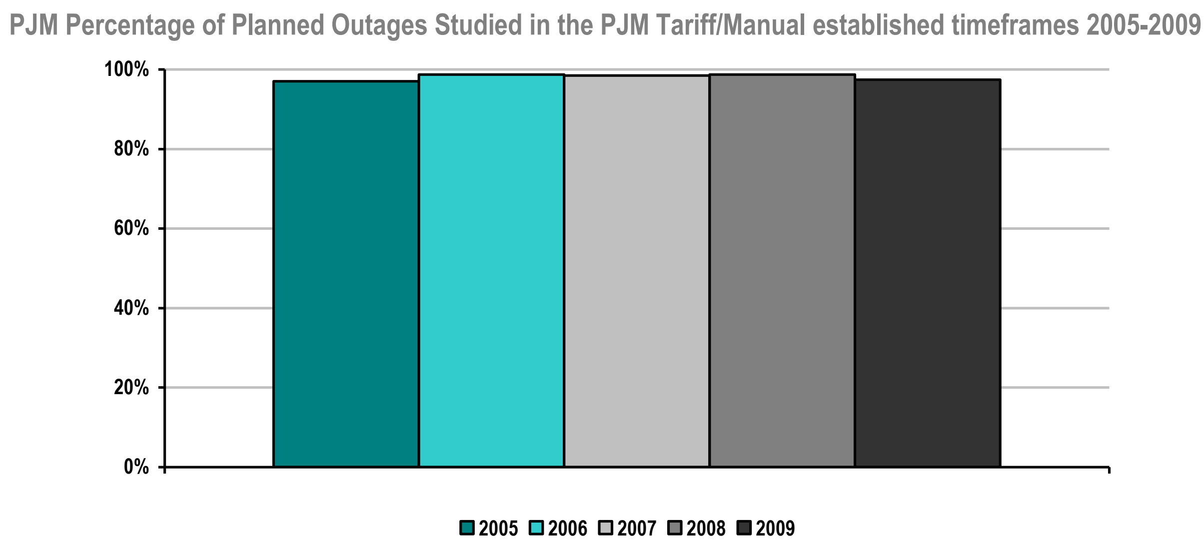
(1) Inadvertent flows with Midwest ISO tracked commencing in 2006.

PJM's list of the highest magnitude unscheduled flows by interface demonstrates the primary unscheduled flow patterns involving the PJM region – flows from west of PJM through PJM and then out to the regions south of PJM. PJM is working on joint operating agreements with its neighboring balancing authorities to identify means to minimize such unscheduled flows. For example, PJM has been working actively with Progress Energy and Duke Energy on enhancements to the current Joint Operating Agreement to provide for enhanced congestion management between the respective organizations.

Transmission Outage Coordination

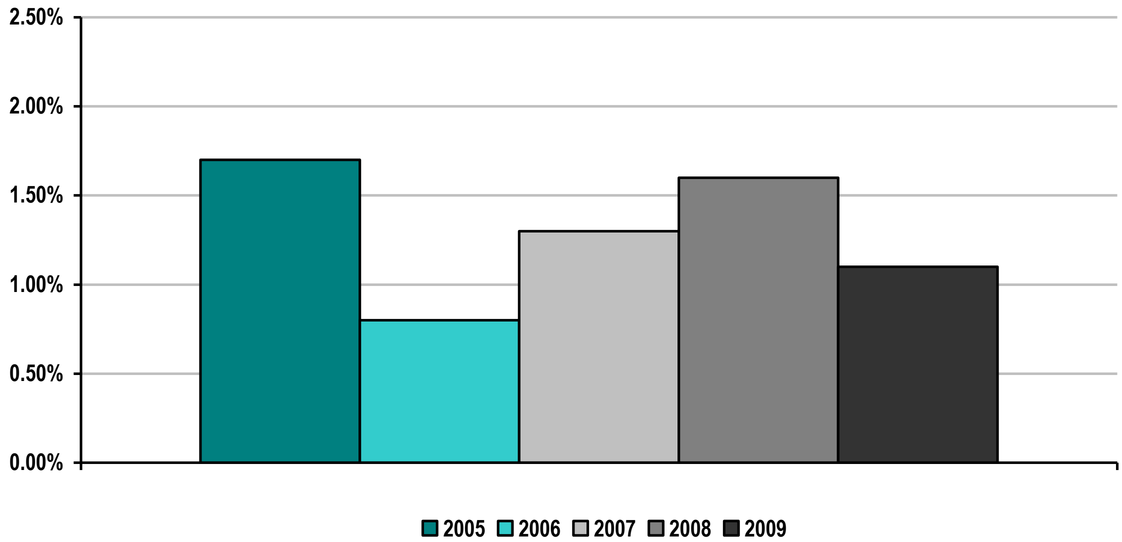


PJM's Tariff requires transmission owners to provide PJM at least five days notice of a planned transmission outage for 200 kV or higher transmission facilities. Longer term outages should be reported to PJM at least one month prior to the target outage commencement date. As noted in the preceding chart, a significant portion of the planned outages in the PJM region have been reported to PJM well before the minimum reporting requirements in the PJM Tariff.



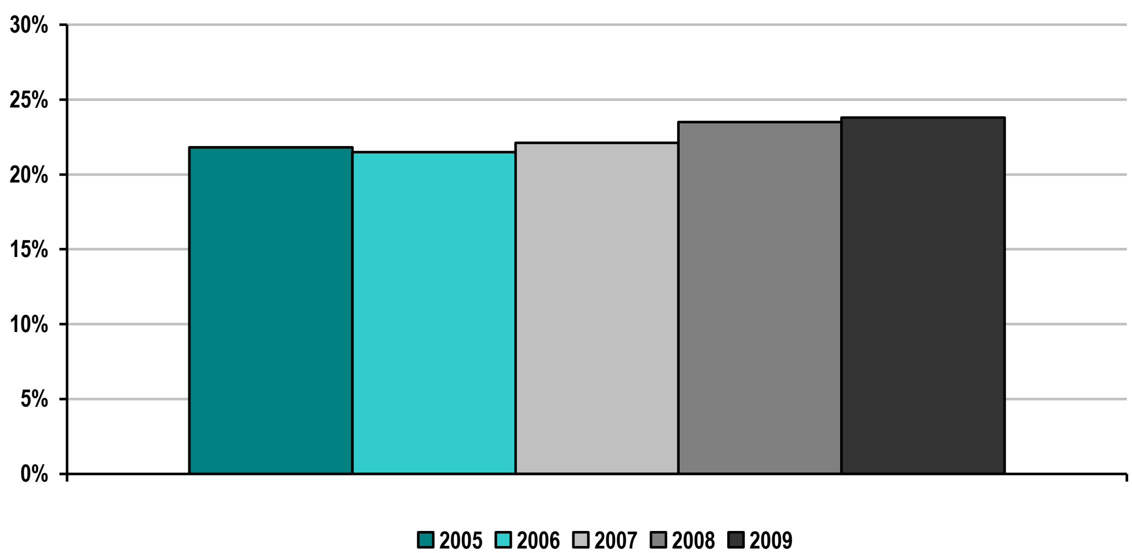
The data in the preceding chart indicates its members' substantial compliance with the PJM Tariff minimum transmission outage 5-day reporting requirement. These five days allow PJM to study the proposed transmission facility outage for potential reliability implications before the transmission outage commences. The very small percentage of outages not reported to PJM at least five days prior to the target outage commencement date will only be approved by PJM if that requested outage does not cause increased congestion or have any adverse reliability impacts.

PJM Percentage of > 200 kV Outages Cancelled by PJM After Having Been Previously Approved 2005-2009



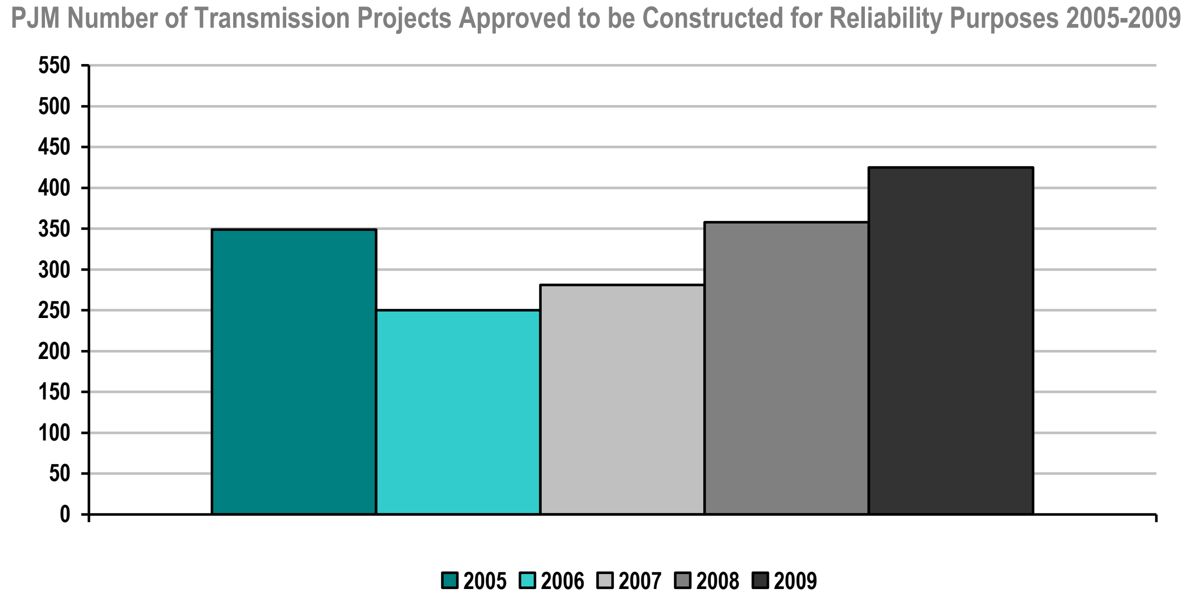
PJM has the authority to cancel or reschedule previously-approved planned transmission outages if such outages would jeopardize system reliability conditions at the time the outage is ready to commence. As such, an outage that would require an emergency procedure will be cancelled and rescheduled. When a transmission outage would impact generation availability, PJM works to schedule the transmission outage at a time where the impact is mitigated (such as when the generation would be on a maintenance outage) where possible. Historically, PJM has only needed to cancel or reschedule a very small percentage of transmission outages that it had previously approved.

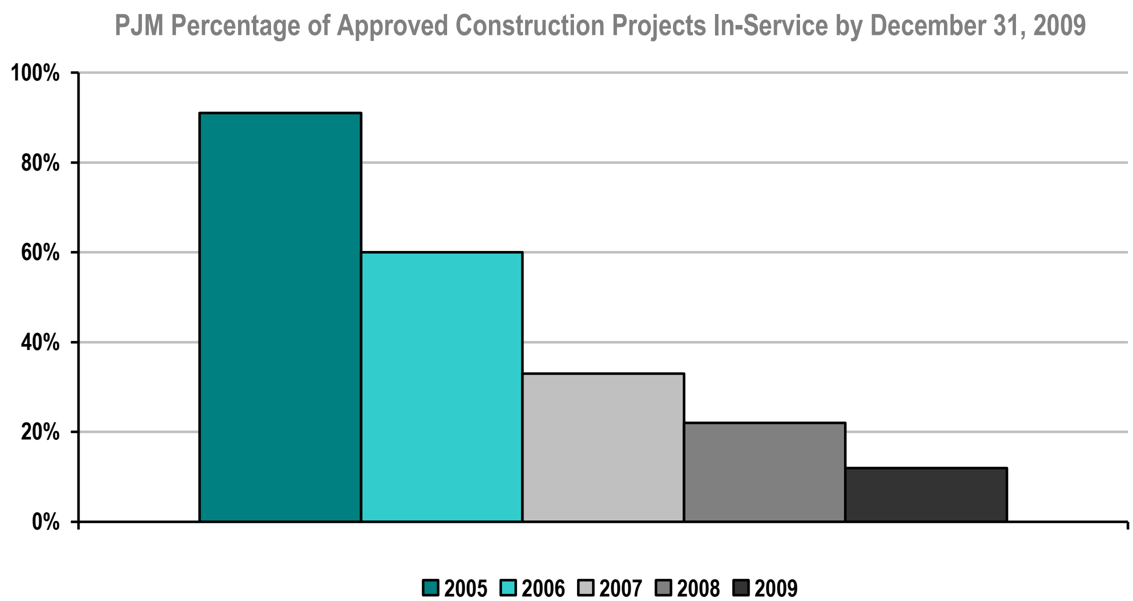
PJM Percentage of Unplanned > 200kV Outages 2005-2009



Unplanned transmission outages may occur due to equipment malfunctions on the transmission line or an adjacent substation. They can also occur due to weather conditions that cause a transmission facility to trip out of service. Historically, 22 – 24% of the outages of transmission assets in the PJM region with 200 kV or higher voltages have been unplanned.

Transmission Planning





PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission system additions and improvements needed to keep electricity flowing to 51 million people throughout 13 states and the District of Columbia. Studies are conducted that test the transmission system against mandatory national standards and PJM regional standards. These studies look 15 years into the future to identify transmission overloads, voltage limitations and other reliability standards violations. PJM then develops transmission plans in collaboration with the stakeholders' Transmission Expansion Advisory Committee (TEAC) which provides advice and recommendations to aid in the development of the RTEP to resolve violations that could otherwise lead to overloads and black-outs. This process culminates in one recommended plan – one RTEP – for the entire PJM region that is subsequently submitted to PJM's independent governing Board for consideration and approval.

PJM's RTEP process includes both five-year and 15-year dimensions. Five-year-out planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. PJM's 15-year planning horizon permits consideration of many long-lead-time transmission options. These options often comprise larger magnitude transmission facilities that more efficiently and globally address reliability issues. Typically, these are higher voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels. A 15-year horizon also allows PJM to consider the aggregate effects of many system trends including long-term load growth, impacts of generation deactivation, and broader generation development patterns, including renewable resources and storage technologies that may be under development across PJM.

PJM's RTEP process throughout 2009 culminated in a series of upgrades approved by the PJM Board. PJM identified and recommended these upgrades to resolve reliability criteria violations identified through 2024. Now part of PJM's RTEP, 2009 upgrade plans have been integrated with those RTEP upgrades which were approved by PJM's Board between 1999 and December 31, 2008. Consistent with findings in prior years, 2009 RTEP transmission upgrades and enhancements cover a range of power system elements: circuit breaker replacements to accommodate increased current interrupting duty cycles, new capacitors to increase reactive power support, new lines, line reconductoring, new transformers to accommodate increased power flows and other circuit reconfigurations and upgrades to accommodate power system changes.

Load growth remains a fundamental driver of transmission expansion plans. Over time, experience has demonstrated that load growth in eastern PJM load centers, if not coupled with increases in new generation and demand response, leads to increased west-to-east flows on transmission facilities in the PJM region, potentially aggravating an already heavily-loaded system. Incorporating the impacts of the economic downturn in the US since the fall of 2008 has resulted in revised dates when certain extra high-voltage (EHV) transmission lines are projected to be needed to avoid reliability standard violations.

Various state renewable portfolio standard initiatives promote demand response and energy efficiency programs. Such programs can have the effect of moderating peak demand and energy growth. PJM supports these programs and is closely monitoring developments. Currently, PJM includes demand response and energy efficiency values into its RTEP process based on the degree to which such programs clear in Reliability Pricing Model capacity auctions and are factored into reliability analyses based on the circumstances under which the programs are expected to be implemented in actual operations.

Within PJM, demand response participation may be price responsive, contractually obligated, or directly controlled. As more experience with these programs is gained, PJM will be better able to assess their impact on energy usage and peak load. PJM sensitivity studies in 2010 will attempt to provide as assessment bracketing the potential effect of states' demand response and energy efficiency programs on reliability criteria violations which drive the need for new transmission.

Through the end of 2009, the PJM RTEP process has resulted in about $15 billion of actual and planned transmission infrastructure development in the PJM footprint. In addition to their reliability benefits, the transmission upgrades planned under the PJM RTEP process have resulted in significant economic efficiencies. As of 2007, PJM incorporates economic efficiency analysis into the regional planning process in order to supplement the reliability criteria on which transmission infrastructure development decisions are based. PJM's analysis indicates that for the year 2012 alone, the transmission upgrades in the current RTEP will result in over $390 million of increased economic efficiency for the footprint. This single-year value provides a conservative estimate of the annual economic value of the PJM reliability planning process, because this value can be expected to accrue year over year into the future, and will increase with every transmission project constructed and implemented in future years as well.

The 2009 RTEP reaffirmed the need for several major transmission line projects that the PJM Board of Managers previously had authorized to address power supply problems. These transmission backbone projects are:

- Trans-Allegheny Interstate Line (TrAIL), 502 Junction to Loudon: Construction is well under way on TrAIL, and it will be in service in 2011. This 500-kV transmission line will run from near the border of Pennsylvania and West Virginia to northern Virginia. .
- Potomac-Appalachian Transmission Highline, (PATH), Amos to Kemptown: This 765-kV transmission line will extend about 300 miles from the Amos Substation in West Virginia to the Kemptown Substation in Maryland.
- Susquehanna to Roseland: This 500-kV line will run approximately 130 miles from northern Pennsylvania to northern New Jersey.
- Mid-Atlantic Power Pathway Project (MAPP): This 500-kV line will connect the Possum Point Substation in Virginia to Indian River Substation on the Delmarva Peninsula.

Market efficiency simulation results have indicated that approved RTEP upgrades will significantly reduce PJM constrained operations. These simulations project that PJM annual system congestion costs will decrease 90% (or approximately $1.7 billion) compared with the congestion costs expected absent the upgrades. The majority of the congestion cost reduction can be attributed to the addition of the new 765-kV and 500-kV RTEP backbone projects listed above.

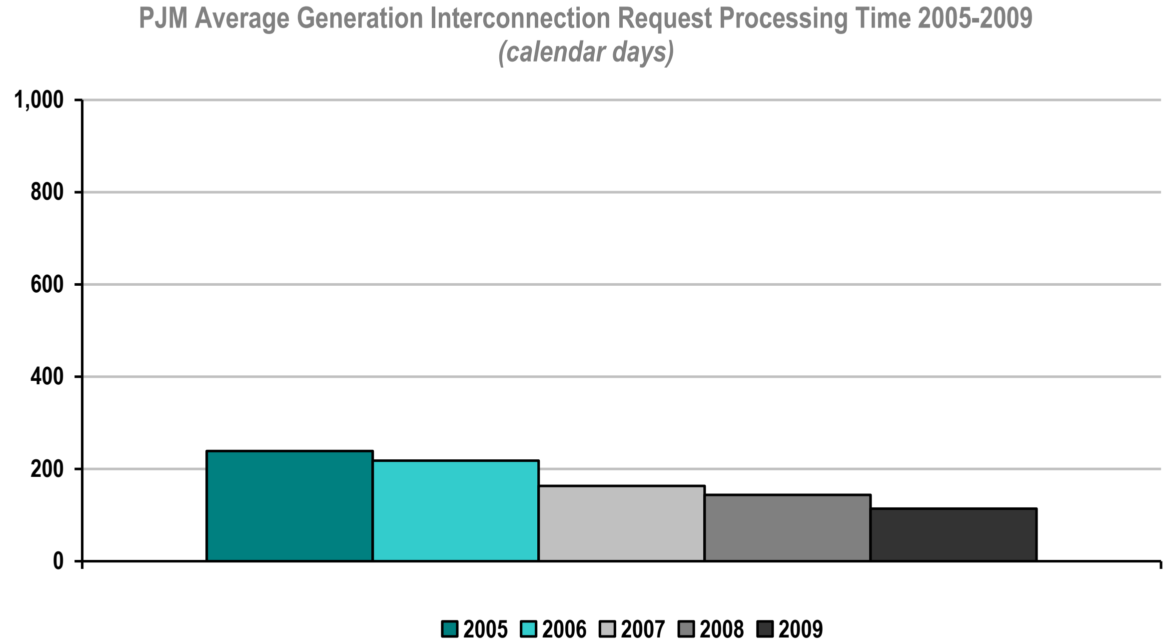
In compliance with FERC's Order 890, PJM expanded its stakeholder process in 2008 to enhance coordinated, open and transparent planning at both the regional and local level. PJM and stakeholders already conduct a compliant planning process filed with the Commission and incorporated in Schedule 6 of the PJM Operating Agreement. Valuable stakeholder discussions culminated in the establishment of three Sub-Regional RTEP Committees – Mid-Atlantic, Western and Southern – commissioned to review proposed upgrades of more local concern. Each Sub-Regional RTEP Committee increases the opportunity for direct stakeholder participation in the planning process from initial assumption setting stages through review of the planning analyses, violations and alternative transmission expansions. The Subregional RTEP Committee provides a more local forum for gathering and considering planning issues.

Recent developments in such areas as renewable energy resources are greatly expanding the scope of interregional planning efforts. Not least among these are the following:

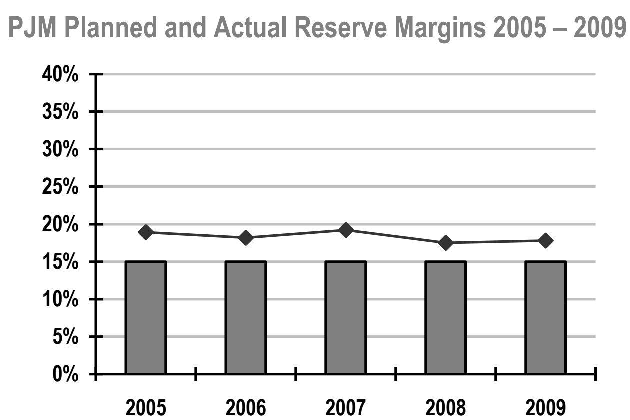
- Eastern Interconnection Planning Collaborative (EIPC)
- Joint Coordinated System Planning Study (JCSP)
- Eastern Wind Integration Transmission Study (EWITS)
- PJM / MISO Joint Operating Agreement studies
- PJM / NYISO / ISO-NE Northeast Coordinated System Plan
- PJM / NYISO Focused Study
- North Carolina Planning Collaborative Coordination

In particular, the PJM-NYISO study is based on a more expansive scope than similar studies in prior years. The current study includes extensive reliability analysis of the northern New Jersey / southeast New York interface.

Generation Interconnection



PJM has made timely processing of generation interconnection study requests a high priority for the past few years with additional engineering staff and contractors engaged to complete these studies and the implementation of clustering of geographically similar studies to expedite study completion.



Bars Represent Planned Reserve Margins	Lines Represent Actual Reserves Procured

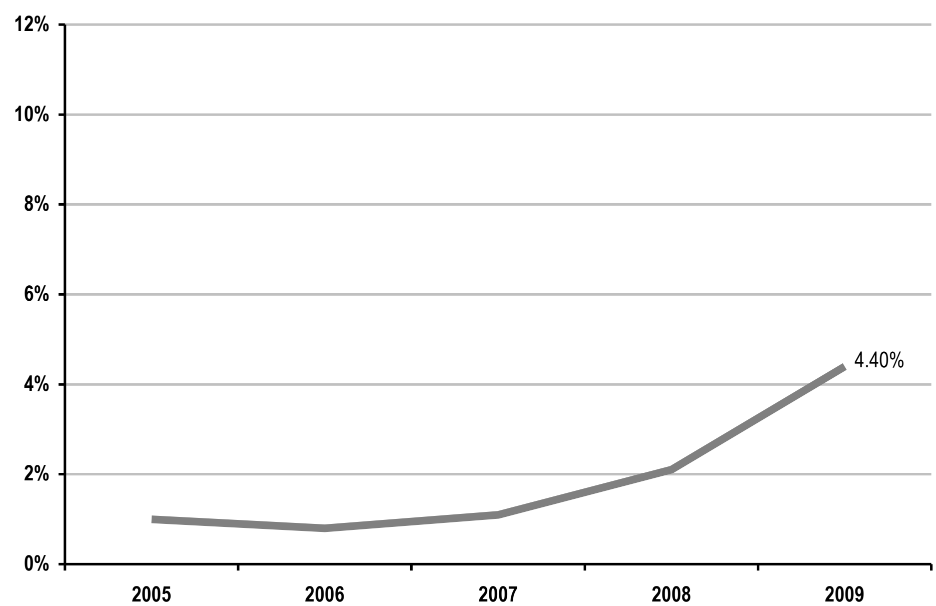
In 2007, PJM implemented a forward capacity market, the Reliability Pricing Model (RPM), which provides incentive for forward investment in generation and demand response by requiring capacity contracts to be procured three years prior to the delivery year. The RPM utilizes variable resource requirement curves to optimize the amount of installed capacity procured to minimize costs while satisfying the capacity requirements of the region. Assuming sufficient capacity resources are available, the variable resource requirement curve will allow the market to clear at quantities between the regional planned installed reserve margin (IRM) and the IRM plus five percent. Quantities above the IRM will only clear if the total procurement cost is reduced when compared to clearing at the reserve margin. Therefore, in PJM, the actual reserve margins resulting from RPM are expected to be and have been between the IRM and the IRM plus 5%.

One of the parameters of each RPM auction is the annual load forecast for the planning year for which the RPM auction is procuring capacity resources. Given RPM auctions occur three years prior to the planning year for which capacity is being procured, the planning year load forecasts will vary from the date of the initial RPM base residual auction and the actual planning year. To be able to adapt to future load fluctuations, PJM's RPM auction incorporates two features – short-term resource procurement targets and incremental auctions. In each RPM auction, the capacity that clears will reflect 2.5% less than the forecasted resource requirement to avoid over-procurement of capacity due to potential variability in the short-term resource procurement target and the uncertainty of the economic recovery. To address the risk of under-procurement, PJM also has the ability to hold incremental RPM auctions to procure additional capacity if forecasts project greater capacity needs than procured in the RPM base residual auction.

Since the implementation of the RPM auctions in 2007, approximately 11,600 MWs of incremental capacity resources have offered into PJM's RPM auctions. This incremental capacity includes 6,400 MWs of new capacity, 4,700 MWs of uprates to existing capacity resources, and 500 MWs of capacity from reactivated units.

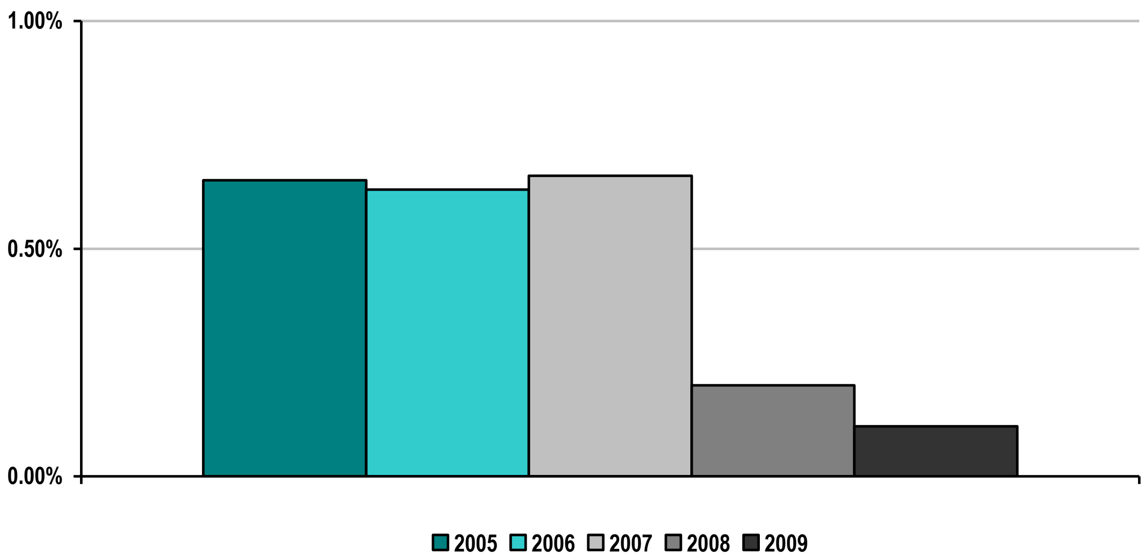
With the 2007 implementation of PJM's forward capacity market, demand resources can offer demand response as a forward capacity resource. Under this model, demand response providers can submit offers to provide a demand reduction as a capacity resource in the forward RPM auctions. If these demand response offers are cleared in the RPM auction, the demand response provider will be committed to provide the cleared demand response amount as capacity during the delivery year and will receive the capacity resource clearing price for this service.

PJM Demand Response Capacity as Percentage of Total Installed Capacity 2005-2009



Additional generation infrastructure investment savings is realized through the commitment of demand response resources to provide reliability assurance. If reliability can be maintained through the commitment of demand resources to reduce load during times of system peaks, the cost of building generation facilities to provide the additional required capacity is avoided. The PJM RPM provides a mechanism by which generation, demand response and transmission can compete on equal footing, thereby providing a transparent mechanism by which demand response can participate in the capacity market. Through this mechanism, the quantity of demand response that is providing capacity in the PJM footprint has increased by over 1,800 MW. The resulting avoidance of infrastructure development represents savings to the region of approximately $275 million per year.

Percentage of Generation Outages Cancelled by PJM 2005-2009

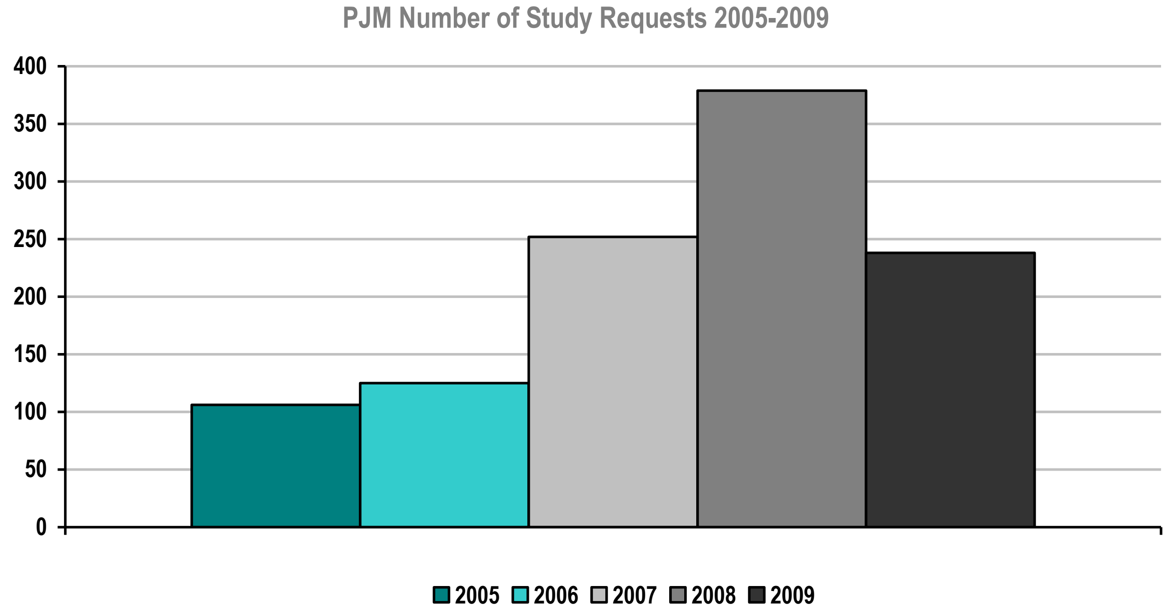


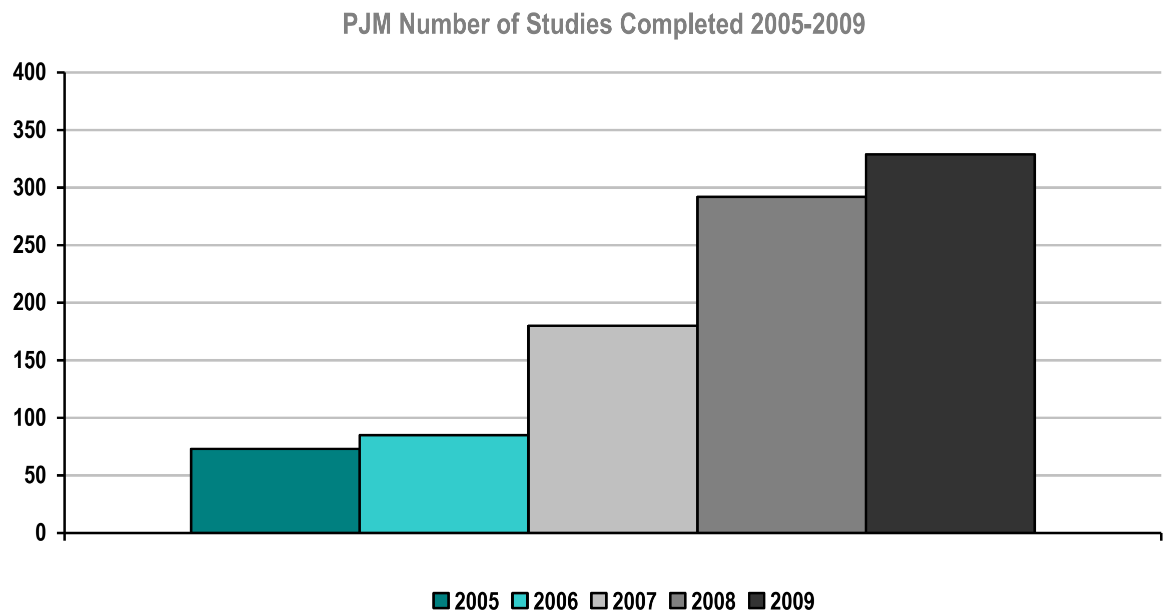
Less than 1% of planned generation outages were cancelled by PJM from 2005 through 2009. This low cancellation rate allows generation owners to complete maintenance as they have planned without incurring rescheduling costs or delays due to PJM cancellation.

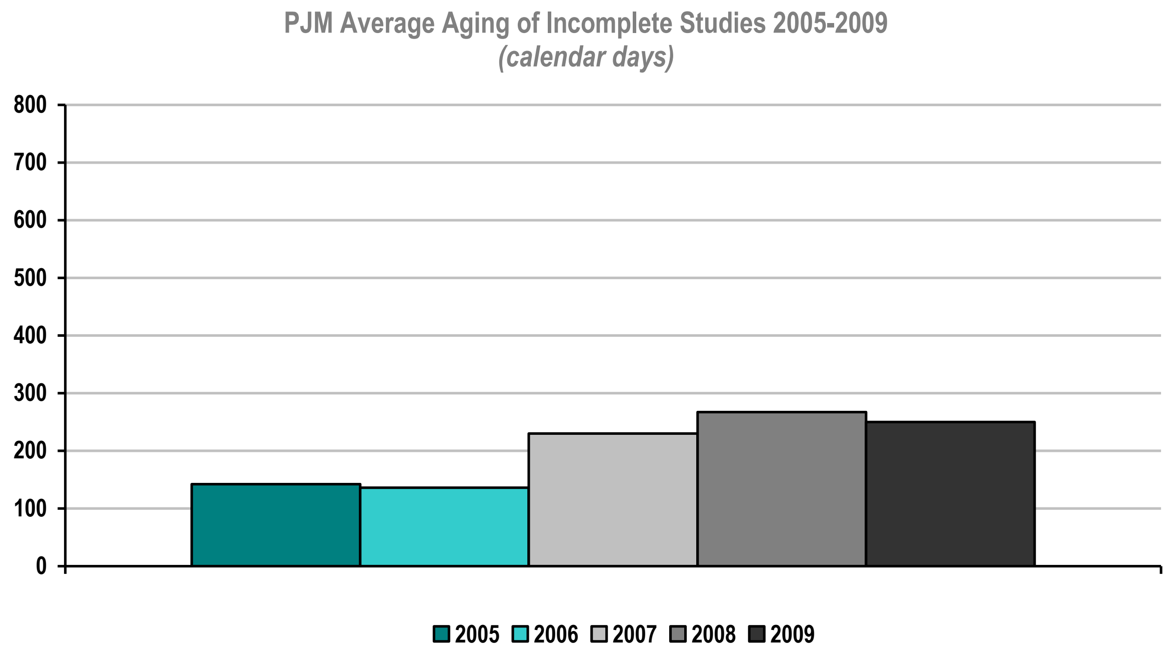
PJM Generation Reliability Must Run Contracts 2005-2009

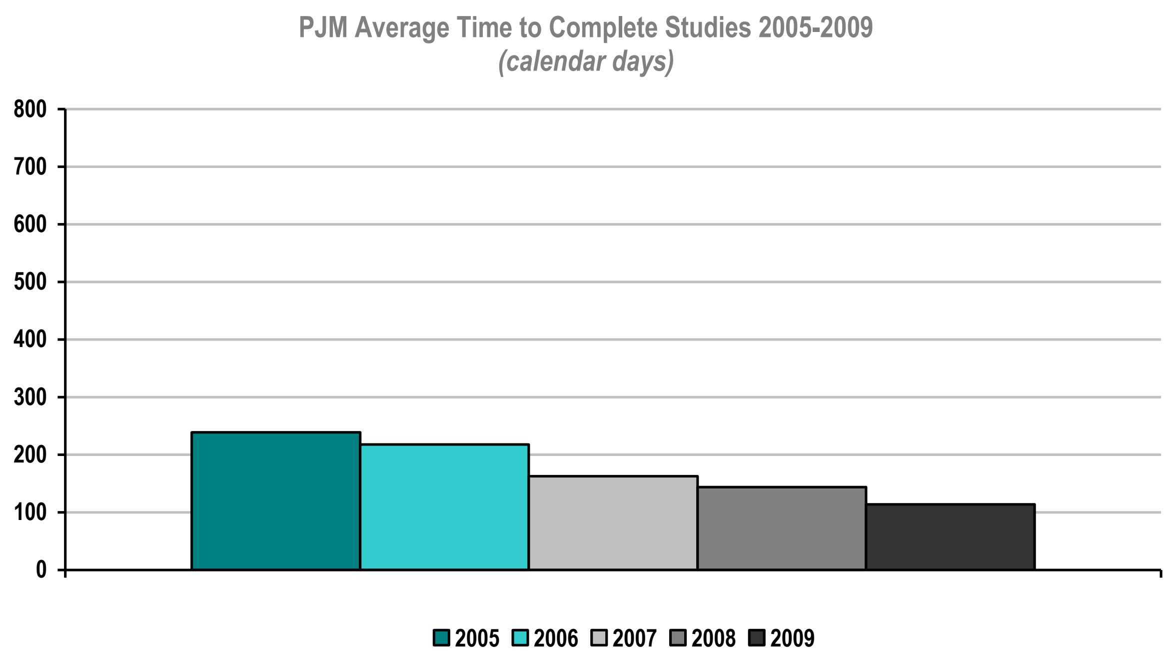
PJM did not have any generating units under Reliability Must Run (RMR) contracts from 2005 through 2008. During 2009, PJM placed one 383 MW nameplate capacity generation station under an RMR that is scheduled to expire during 2010.

Interconnection / Transmission Service Requests









From 2005 through 2009, PJM received approximately 1,100 study requests from companies interested in adding new generation or upgrading current generation output in the PJM region. On average, approximately 12% – 15% of megawatts of potential generating capacity in interconnection study requests progress to the execution of an interconnection service agreement to commence construction of the new generating capacity. So, over 80% of the studies completed by PJM relate to potential projects that withdraw from the generation interconnection queue.

A large number of those study requests were geographically concentrated in the western part of the PJM region with an increasing number of the potential developers investigating the use of storage technologies such as batteries, flywheels and compressed air, as well as wind and solar fuel sources. In terms of megawatts of potential new generating capacity, more than 50% of PJM's year-end 2009 interconnection queues relates to potential wind or solar plants. It is significant to note that the total potential new generating capacity in PJM's year-end 2009 interconnection queues represent 46% of the year-end 2009 generating capacity installed in the PJM region.

PJM completed study requests faster each year from 2005 through 2009, as represented by the more than 50% reduction in average time to complete studies during that period. At the same time, the average age of incomplete studies has actually increased. The decreasing number of incomplete studies represents older study requests that are concentrated in areas of the PJM region where transmission system complexity and study data availability have delayed completion of the feasibility portion of the study process. PJM has reduced the number of incomplete studies significantly in the past few years. For example, PJM reduced the number of open studies by more than 35% during 2009.

PJM's generation interconnection process includes three potential types of studies – feasibility studies, system impact studies and facility studies. Feasibility studies assess the practicality and cost of transmission system additions or upgrades required to accommodate the interconnection of the generating unit or increased generating capacity with the transmission system. System impact studies provide refined and comprehensive estimates of cost responsibility and construction lead times for new transmission facilities and system upgrades that would be required to allow the new or increased generating capacity to be connected to the transmission system in the PJM region. Facility studies develop the transmission facilities designs for any required transmission system additions or upgrades due to the interconnection of the generating unit or increased generating capacity. PJM has had no formal complaints regarding the interconnection processes in recent years.

The table below reflects the average costs incurred by PJM for each type of generation interconnection study. These costs are billed to and collected from the entities requesting each type of study, not from PJM's administrative costs charged to its members.

Average Cost of Each Type of Study

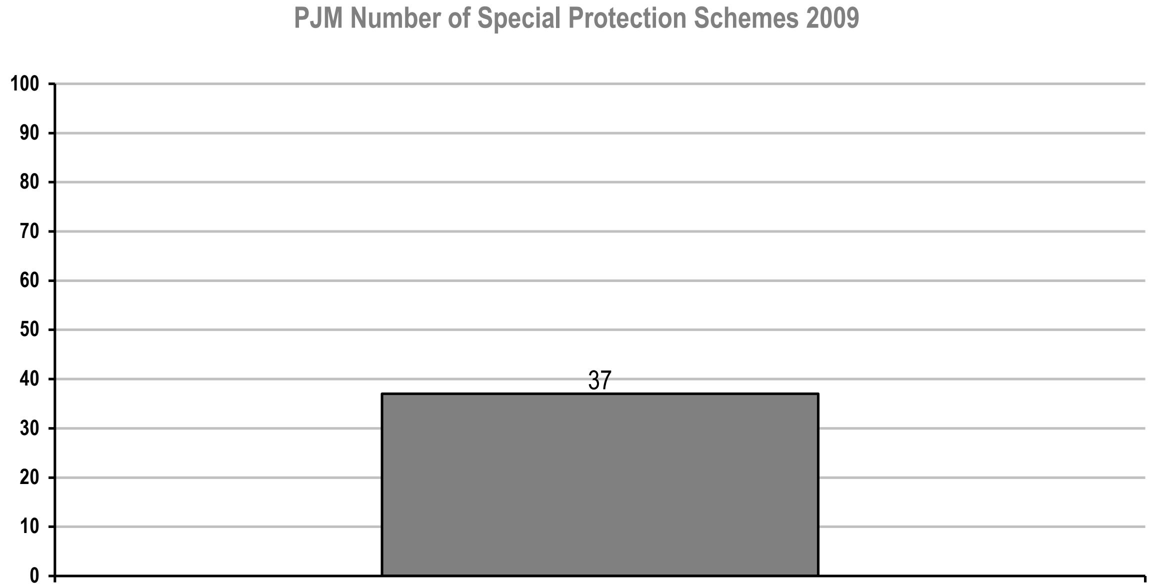
	2005	2006	2007	2008	2009
Feasibility Studies	$5,474	$4,121	$4,538	$3,514	$4,057
System Impact Studies	$12,015	$10,537	$11,224	$10,263	$14,406
Facility Studies	$30,137	$29,458	$28,635	$66,648	$54,380

PJM's average costs incurred for feasibility and system impact studies have not varied materially in the past five years. The complexity of each proposed generation project impacts primarily the costs of completing facility studies, the average cost of which has varied accordingly in the past five years.

PJM Interconnection / Transmission Service Request Future Enhancement:

- During 2010 and 2011, PJM plans to focus on process improvements to reduce both the number of incomplete generation interconnection studies and the average aging of such incomplete studies.

Special Protection Schemes



There are 37 Special Protection Schemes (SPSs) in place in the PJM region. These SPSs are automatic protection systems designed to maintain system reliability by detecting abnormal or predetermined system conditions and isolating selected equipment. All SPSs in the PJM region must be reviewed and approved by PJM to ensure they support all applicable reliability standards. Those SPSs are established throughout the PJM region as a source of automatic system protection that is in addition to the manual system adjustments available to PJM system operators.

In PJM, there were no misoperations of SPSs during 2009. There were no intended or unintended activations of SPSs during 2009.

B. PJM Coordinated Wholesale Power Markets

For context, the table below represents the split of the $26.6 billion dollars billed by PJM in 2009 into the primary types of charges its members incurred for their transactions.

(dollars in millions)	2009 Dollars Billed	Percentage of 2009 Dollars Billed
Energy Markets	$ 11,163.1	42.0%
Capacity	8,752.4	33.0%
FTR Auction Revenues	1,902.2	7.2%
Transmission Service	1,352.5	5.1%
Transmission Losses	1,267.6	4.8%
Transmission Congestion	784.6	3.0%
Operating Reserves	323.5	1.2%
Reactive Supply	239.5	0.9%
Regulation Market	228.3	0.9%
Transmission Enhancement	164.2	0.6%
PJM Administrative Expenses	155.6	0.6%
Other	217.8	0.8%
Total	**$ 26,551.3**	**100.0%**

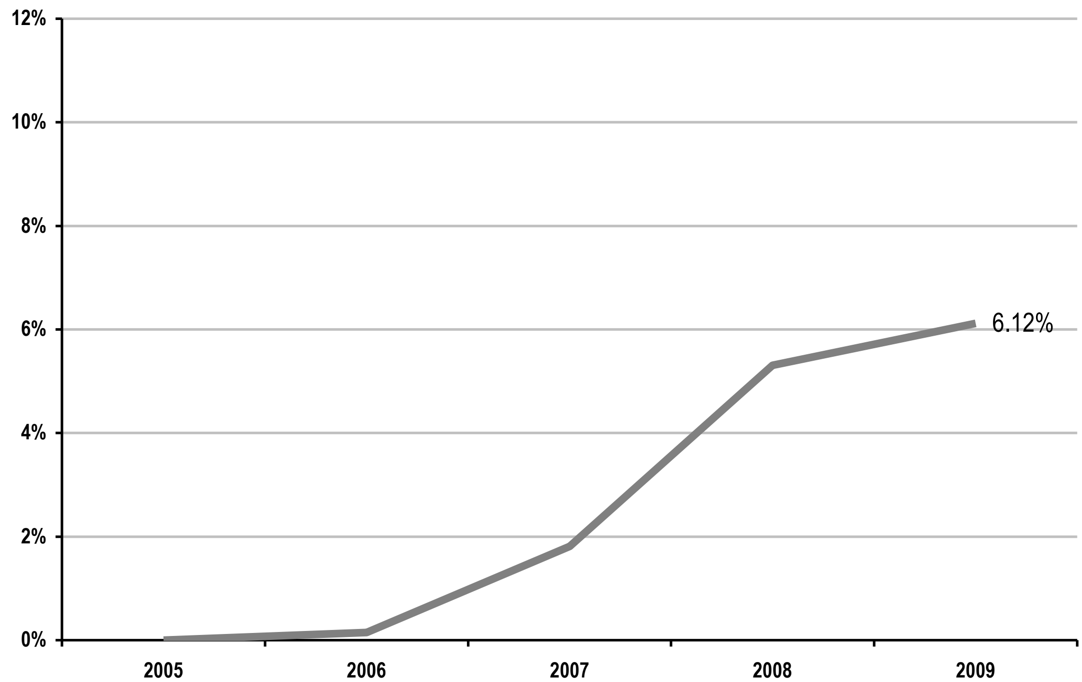
PJM has conducted an annualized, production cost analysis of the savings attributable to operating a single footprint compared to operation of the previously independently operated control areas. As is typical in such analyses, hurdle rates were utilized to simulate the ability of these independent control areas to transact with the remainder of the footprint without the benefit of a centrally operated dispatch. Based on this analysis, the energy production cost impact of the expanded PJM RTO operation is between $240 million and $345 million per year. PJM also has enhanced the efficiency of its dispatch since these integrations. The benefits of this enhanced efficiency are realized in reduced make-whole payments to generators known as Balancing Operating Reserve costs. Reduction in these costs has resulted in additional savings exceeding $100 million per year.

In addition to the production cost benefit of operating the larger footprint, the transparent price signals produced by the operation of the LMP energy market enable demand response to actively participate and compete directly with generation. Because the value of energy is made transparent in real time, demand responders that otherwise would have no incentive to reduce demand can do so in response to real time prices, thereby competing directly with generation resources. This ability, although difficult to quantify as an annual average value, has the effect of reducing the cost to all load by reducing real-time prices, most particularly during times of high system demand.

PJM maintains synchronized reserve in the amount of the largest single contingency in the entire RTO footprint and procures regulation from the most cost-efficient resources across the entire footprint. The savings attributable to the procurement of these services utilizing a market mechanism that spans the RTO footprint is between $80 million and $105 million per year.

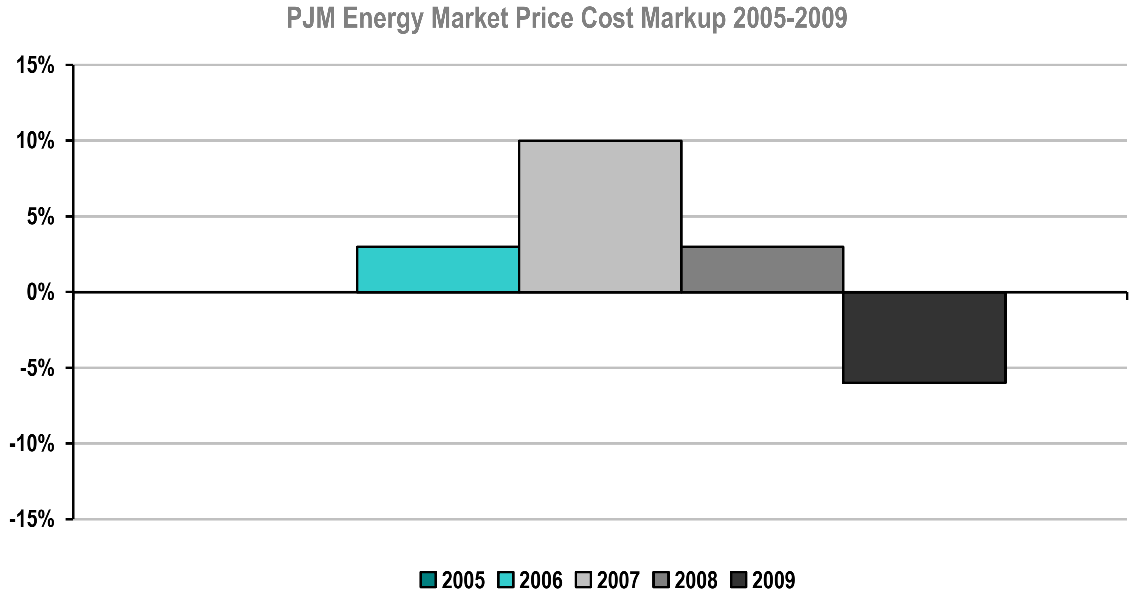
Demand response resources are eligible to participate in PJM's Regulation and Synchronized Reserve Markets. Through the end of 2009, demand response resources have not yet participated in the PJM regulation market. During 2009, demand side responders earned over $300 million through PJM energy, capacity and ancillary services markets.

PJM Demand Response as a Percentage of Synchronized Reserve Market 2005-2009



Market Competitiveness

Note: The data in this Market Competitiveness section was obtained from the 2005 – 2009 State of the Market Reports issued by PJM's independent market monitor.

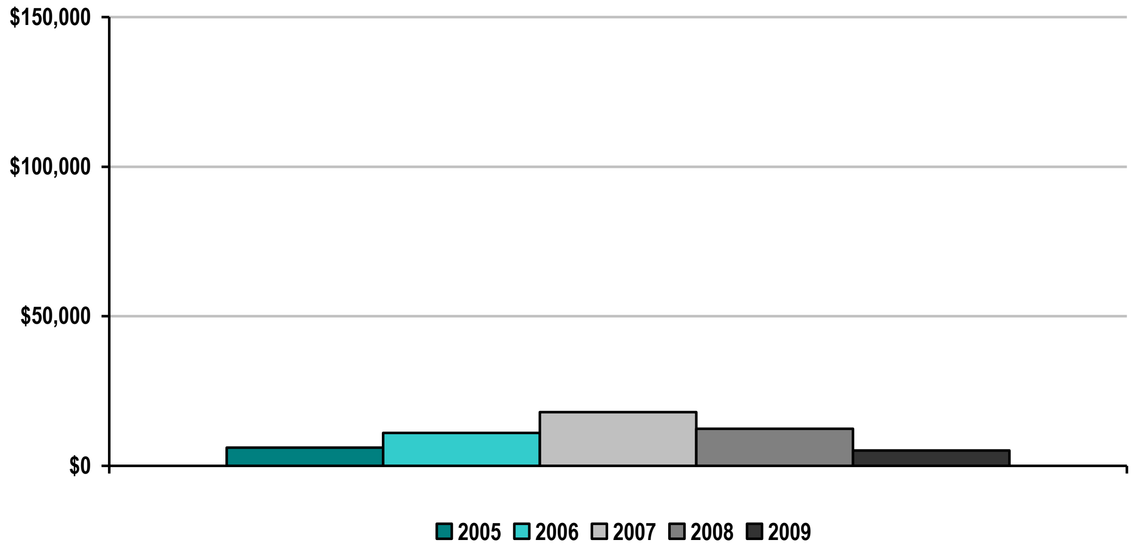


The overall price cost markup percentages for the past four years support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. PJM does not have data for this metric for 2005.

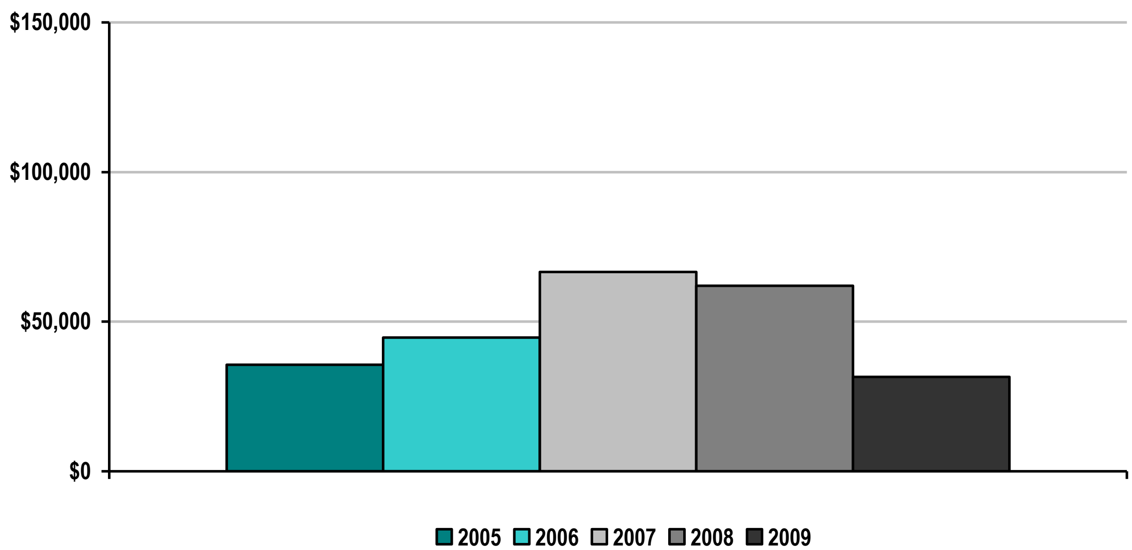
A substantial portion of the 2007 markup occurred on high-load days during the summer of 2007. Markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power. For reference, PJM's annual 2007 load was 763 terawatt hours, which is the highest annual load ever served in the PJM region. These high usage volumes drove higher locational marginal prices (LMPs) and contributed to the higher 2007 energy market price cost markup percentage.

During 2009, both coal steam units and combined cycle units that use gas as their primary fuel source had negative price cost markup percentages due to the low usage volumes that resulted in lower 2009 LMPs that were insufficient to cover those units' costs.

PJM New Entrant Gas-Fired Combustion Turbine (CT) Net Generation Revenues 2005-2009
(dollars per installed megawatt year)



PJM New Entrant Gas-Fired Combined Cycle (CC) Net Generation Revenues 2005-2009
(dollars per installed megawatt year)



For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue.

In 2009, total net revenues were not adequate to cover annualized total fixed costs for a new entrant CT or CC in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues. Energy net revenues are generally lower for each technology in most zones compared to 2008, while capacity market revenues are higher in every zone compared to 2008. For the CT and CC technologies, the increase in capacity revenue offset the reduction in energy market revenue.

There is a set of sub-critical coal units in 2008 and 2009 and a set of super-critical coal units in 2009 that did not recover avoidable costs even with capacity revenues. The total installed capacity associated with coal units that did not cover avoidable costs in 2009 was 11,250 MW. There were 122 coal units in PJM in 2009 with capacity less than or equal to 200 MW. Of those units, 35 did not cover avoidable costs and 52 were close to not covering avoidable costs.

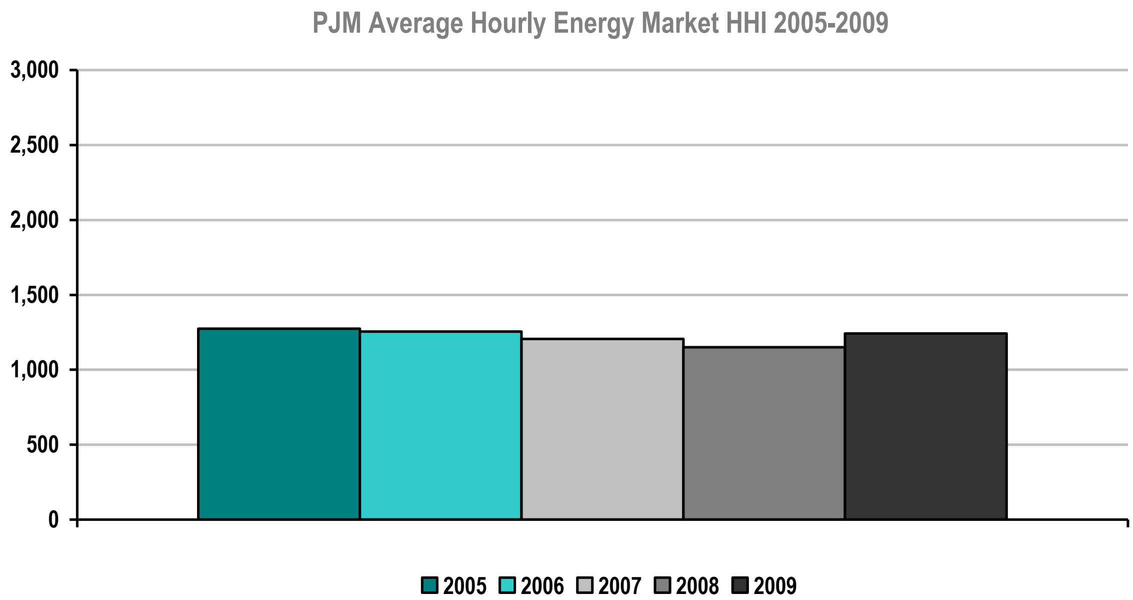
The coal plant technologies have higher avoidable costs and are more dependent on net revenues received in the energy market. In 2009, with lower load levels and, generally, lower price levels relative to operating costs, some coal-fired units in PJM did not fully recover avoidable costs even with capacity revenues. If this result is expected to continue, the retirement of these plants would be an economically rational decision.

Market Concentration

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner.

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports. Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

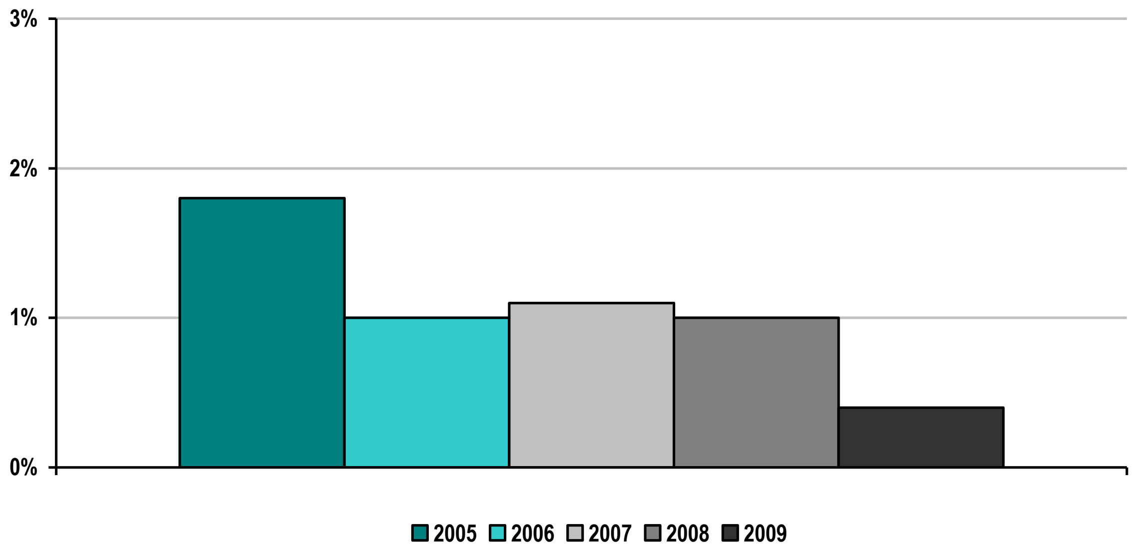


The “Merger Policy Statement” of the Federal Energy Regulatory Commission states that a market can be broadly characterized as:

- Unconcentrated. Market HHI below 1000, equivalent to 10 firms with equal market shares;
- Moderately Concentrated. Market HHI between 1000 and 1800; and
- Highly Concentrated. Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market was moderately concentrated each of the years 2005 through 2009. For the same time period, an examination of the supply curve on a segment basis, including base, intermediate and peaking plants, the hourly HHI measure indicated that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

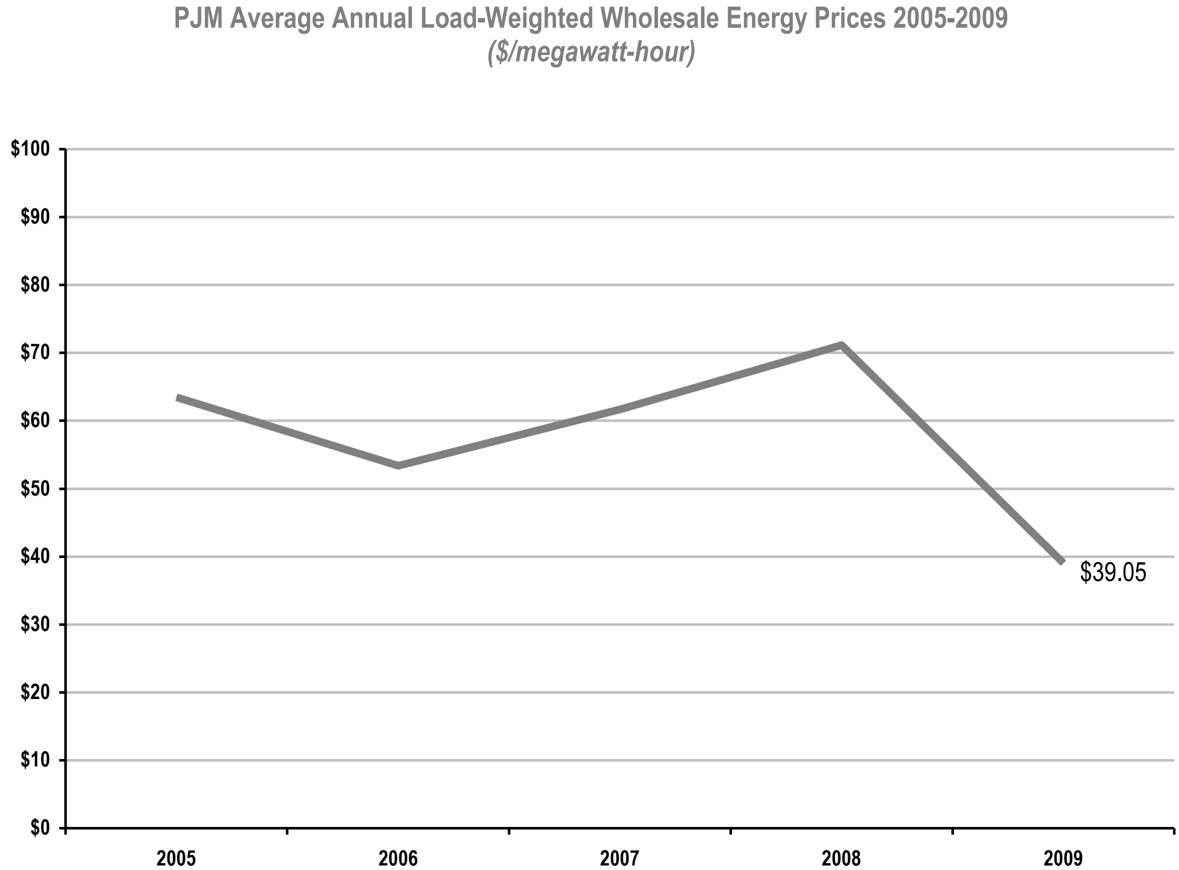
PJM Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation 2005-2009



Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2009. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Real-Time Energy Market offer-capped unit hours fell from 1.0 percent in 2008 to 0.4 percent in 2009.

The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Pricing

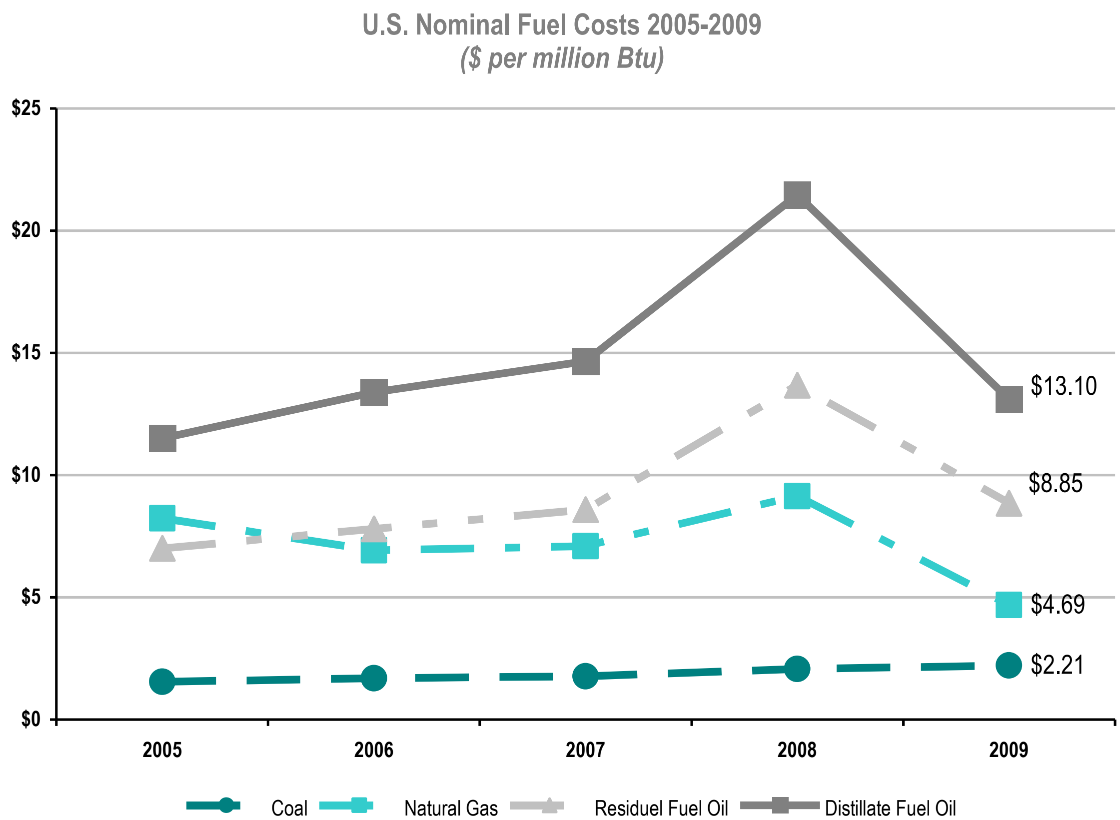


The PJM average load-weighted wholesale energy prices varied during the 2005 – 2009 period due in part to variances in underlying fuel costs and also due to 4.6% lower customer demand in 2009. For example, approximately 72% of the 2008 to 2009 reduction in wholesale electricity prices in the PJM region was due to fuel cost decreases, while the remaining 28% of the reduction was due to lower customer demand. In nominal terms, that means the fuel cost reductions from 2008 to 2009 led to a 32% decrease in wholesale electricity prices in the PJM region, while lower demand contributed an additional 13% reduction in wholesale electricity prices in the PJM region.

Conservation during heat waves not only stretches power supplies, it saves money. Reductions in electricity use during the early August 2006 heat wave produced price reductions estimated to be equivalent to more than $650 million in payments for energy for the week. Customers in the 13-state PJM region set a new record for power consumption of 144,796 megawatts on August 2, 2006. On that day alone, voluntary reductions in electricity use through demand response resulted in price reductions estimated to be equivalent to more than $230 million in payments for energy.

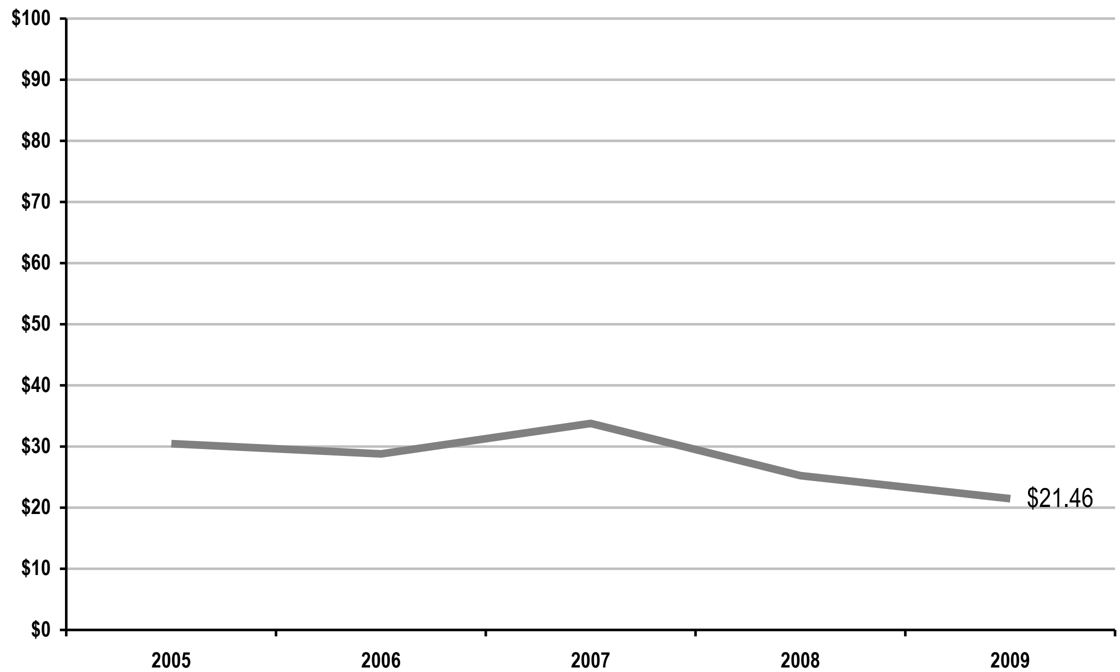
These voluntary curtailments through PJM's Demand Response program reduced wholesale energy prices by more than $300 per megawatt hour during the highest usage hours in early August 2006. While many wholesale customers, such as utilities, were hedged against high real-time spot-market prices, all customers benefit from the dramatic price reductions because future longer-term electricity sales are based on prices set in the real-time market, where prices were lower as a result of demand response.

The chart below from the U.S. Energy Information Administration is a visual representation of the fuel cost inputs from 2005 – 2009 that influenced the energy prices in the PJM region. The consistency in the trends between the preceding chart and several of the fuel cost trends on the chart on the following page are significant, because they illustrate the high correlation between wholesale energy prices and underlying fuel costs.



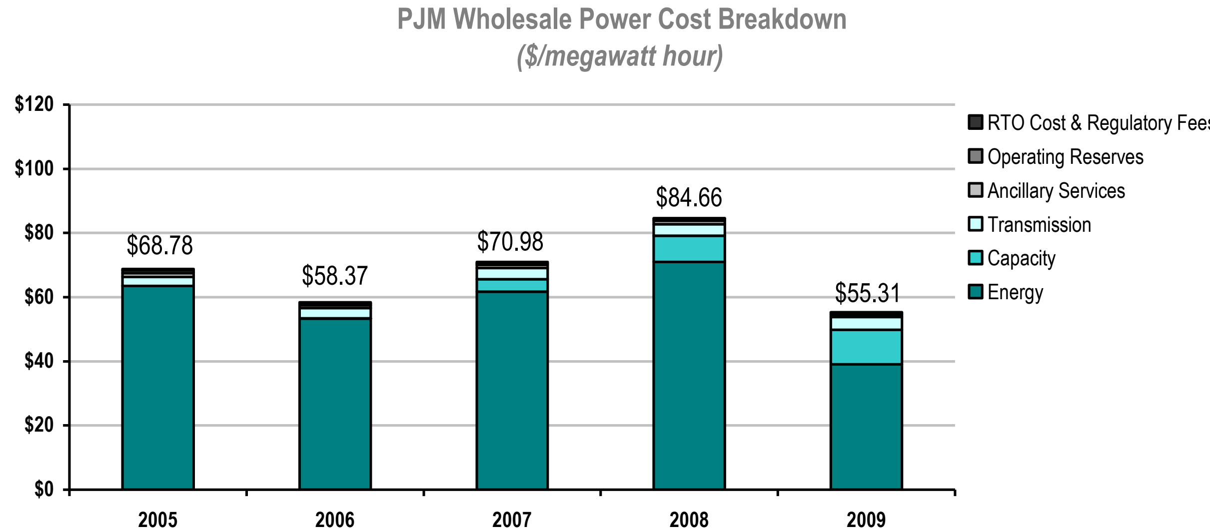
Source: U.S. Energy Information Administration, Independent Statistics and Analysis

PJM Average Annual Load-Weighted
Fuel-Adjusted Wholesale Spot Energy Prices 2005-2009
($/megawatt-hour)



For the five-year period ended December 31, 2009, the load-weighted fuel-adjusted wholesale spot energy prices in the PJM region have decreased 30% from $30.45 to $21.46. The trend in these fuel-adjusted prices reflects the lower demand particularly in 2008 and 2009 that resulted from both the economic downturn and mild weather patterns. With the lower demand, the prices of electricity decreased in the past few years in the PJM region.

PJM's base year for fuel cost references is 1999 as this is the first full year that PJM administered both spot and day-ahead energy prices.



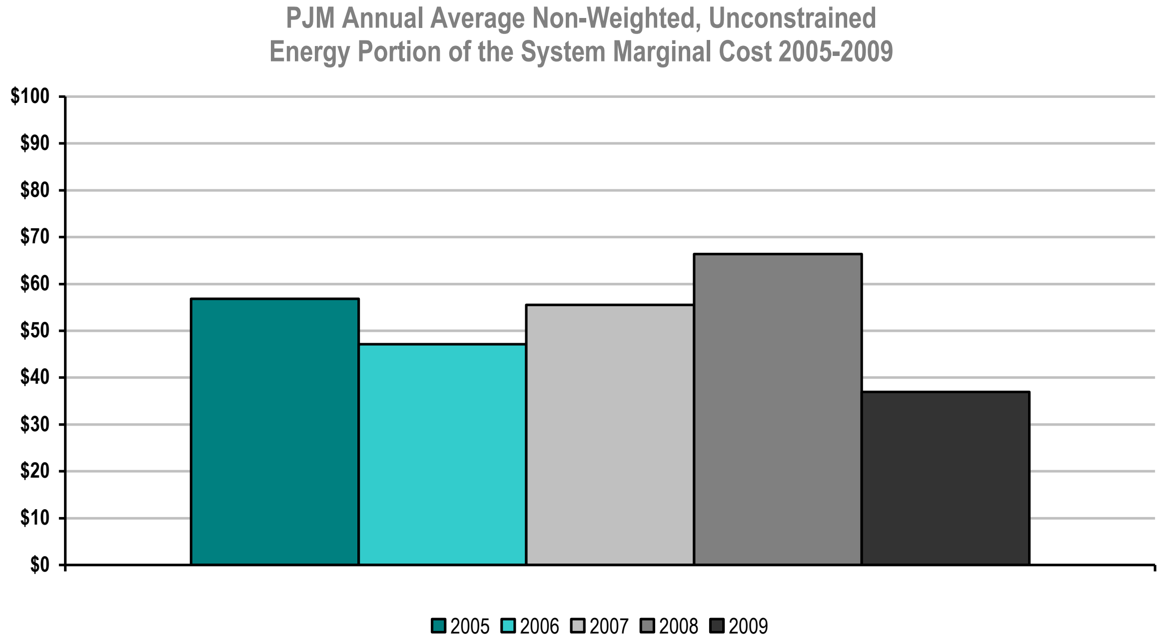
On an annual basis, energy costs have comprised 70 – 90% of PJM's total wholesale power costs for the past five years. PJM implemented its three-year forward capacity market, the Reliability Pricing Model (RPM), in 2007. Capacity revenues earned through RPM are netted against the energy cost component of total power costs per megawatt hour. If combined, the energy plus capacity components represent more than 90% of total power costs per megawatt hour for each of the five years in the period 2005 – 2009.

Recent sensitivity analyses indicate that the completion of all transmission backbone projects in PJM's Regional Transmission Expansion Plan (RTEP) would reduce total RPM capacity costs by about $3 billion (or more than 30%) annually.

And, as noted previously, fuel costs drive approximately 70% of wholesale electricity price changes in the PJM region. So, it is again logical that the trends in total wholesale power costs in the PJM region have moved consistently with fuel cost trends.

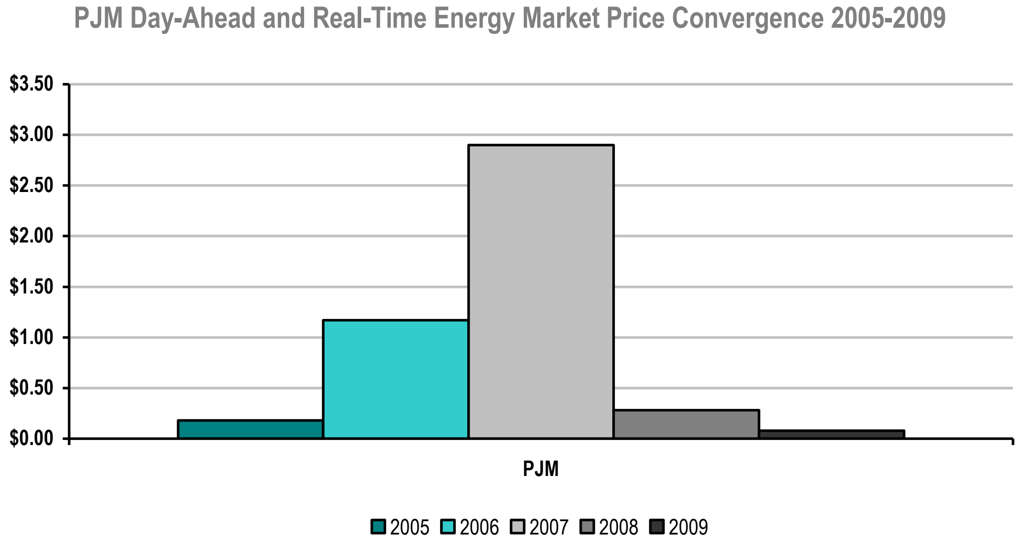
All other components of PJM's wholesale power cost per megawatt hour, exclusive energy and capacity, account for less than 10% of the total costs per megawatt hour. In particular, the operating reserve costs (sometimes referred to as uplift) have been less than $1.00 per megawatt hour of the total wholesale power cost in the PJM region. In 2005 through 2009, such uplift costs represented 1.4% or less of the total wholesale power cost per megawatt hour during that five-year period.

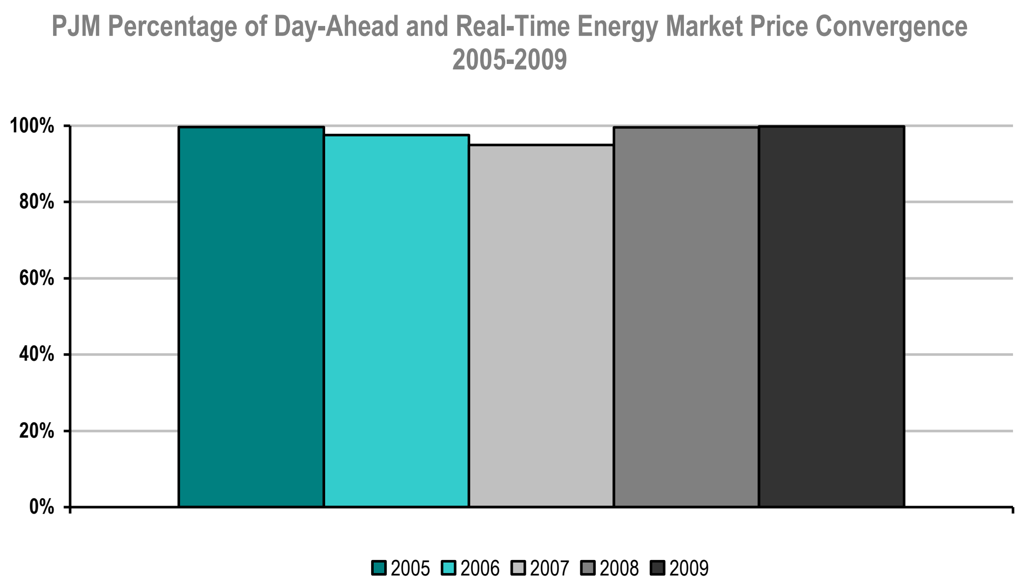
Unconstrained Energy Portion of System Marginal Cost



The unconstrained energy portion of system marginal cost is the marginal price of maintaining power balance in the economic dispatch in the PJM region ignoring transmission limitations. This trend chart reflects the annual average marginal price of energy across the PJM region over all hours. The trend closely follows the trend of aggregate fuel prices from 2005 through 2009, which illustrates the fact that marginal energy price fluctuations are primarily driven by fuel prices.

Energy Market Price Convergence





PJM's nominal difference between day-ahead and real-time prices was highest in 2007 when there was greater volatility in real-time prices, reflecting high constraint levels in fall 2007 when weather remained hot in the PJM region as the fall transmission maintenance season commenced. However, the percentage of day-ahead and real-time price convergence in the PJM electricity markets averaged over 98% from 2005 through 2009.

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO and an implemented operating agreement with the Midwest ISO. One objective of such interregional coordination agreements is the harmonization of border prices. Price convergence between PJM’s and bordering region’s wholesale competitive market prices is one data point to assess the effectiveness of these agreements.

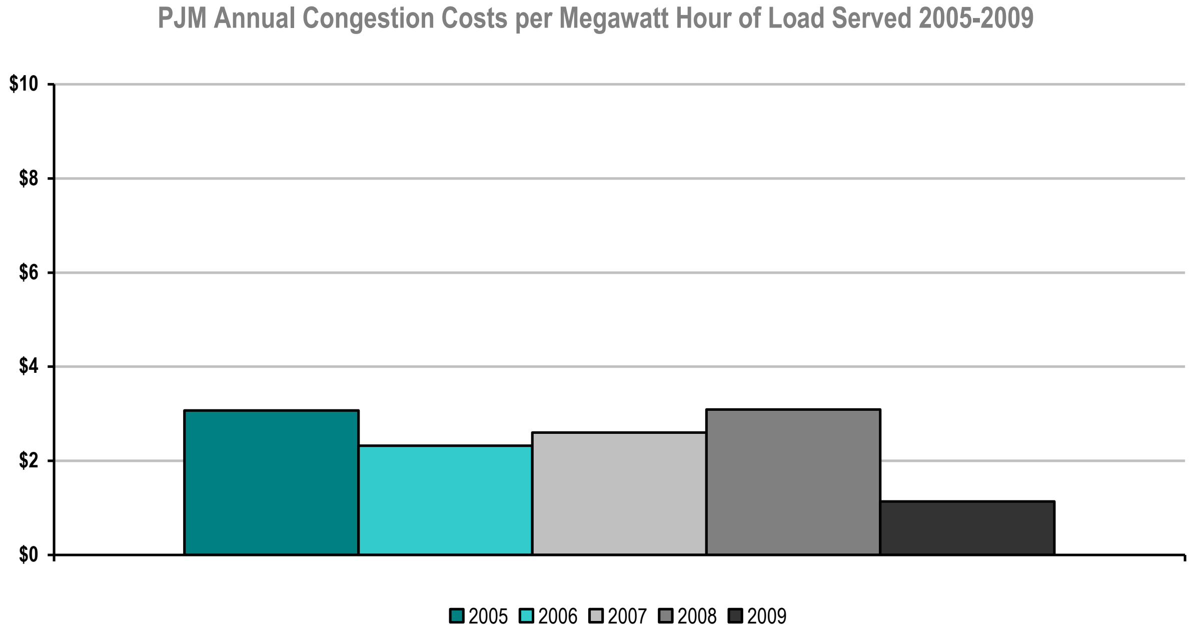
The 2009 real-time hourly average interface prices for PJM/Midwest ISO and Midwest ISO/PJM were $29.67 and $29.68, respectively. The simple average difference between the real-time Midwest ISO/PJM Interface price and the PJM/Midwest ISO Interface price decreased from $1.17 per megawatt hour in 2008 to $0.01 per megawatt hour in 2009. These differences represent 97.68% and 99.97% price convergence, respectively, for 2008 and 2009. This is consistent with the fact that PJM’s net exports in 2009 were significantly lower than in 2008, as the price convergence in 2009 did not provide the incentives to purchase power from PJM and export to or through the Midwest ISO.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative. In addition, there is a significant correlation between the real-time monthly average hourly PJM/Midwest ISO and Midwest ISO/PJM Interface prices during the 2009 period.

PJM’s price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses. Similarly, the NYISO’s price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO/PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2009 real-time hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $37.37 and $39.16. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price increased from $0.86 per megawatt hour in 2008 to $1.79 per megawatt hour in 2009. These differences represent 98.81% and 95.32% price convergence, respectively, for 2008 and 2009. PJM’s net export volume to the NYIS Interface for 2009 was significantly higher than in 2008. This is consistent with the fact that the PJM/NYIS price was, on average, lower than the NYISO/PJM price in 2009.

Congestion Management

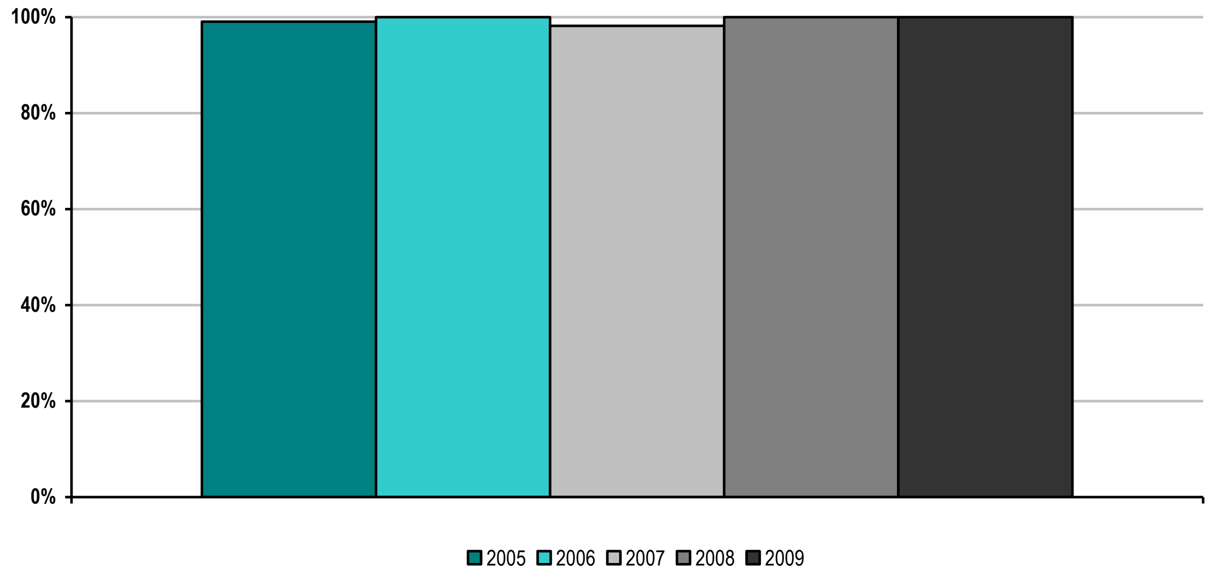


Congestion costs in the PJM region are influenced by weather, energy prices and available transmission system capacity. For example, the higher wholesale energy prices in 2008 resulted in a higher congestion cost per megawatt hour of load served that year, while lower wholesale energy prices and lower demand in 2009 caused per megawatt hour congestion to fall over 60%.

PJM's Regional Transmission Expansion Plan (RTEP) includes several extra high voltage transmission lines that will increase the available transmission system capacity in the PJM region. In the aggregate, those transmission lines are expected to alleviate 90% of the current congestion costs in the PJM region.

In order to address the need for long-term transmission rights, PJM added a stage to its FTR market. In stage 1A of the allocation process, each network service user may request auction revenue rights (ARRs) for a term covering 10 consecutive PJM planning periods. ARRs allocated in stage 1A will be modeled in a 10-year analysis in which a zonal growth rate will be applied and anticipated ARR allocation increases will be determined. If during any year of this 10-year analysis it is determined that the anticipated ARRs will not be feasible, then PJM will recommend transmission upgrades into the PJM RTEP to ensure the 10-year feasibility of stage 1A ARRs.

PJM Percentage of Congestion Dollars Hedged Through PJM's Congestion Management Markets 2005-2009



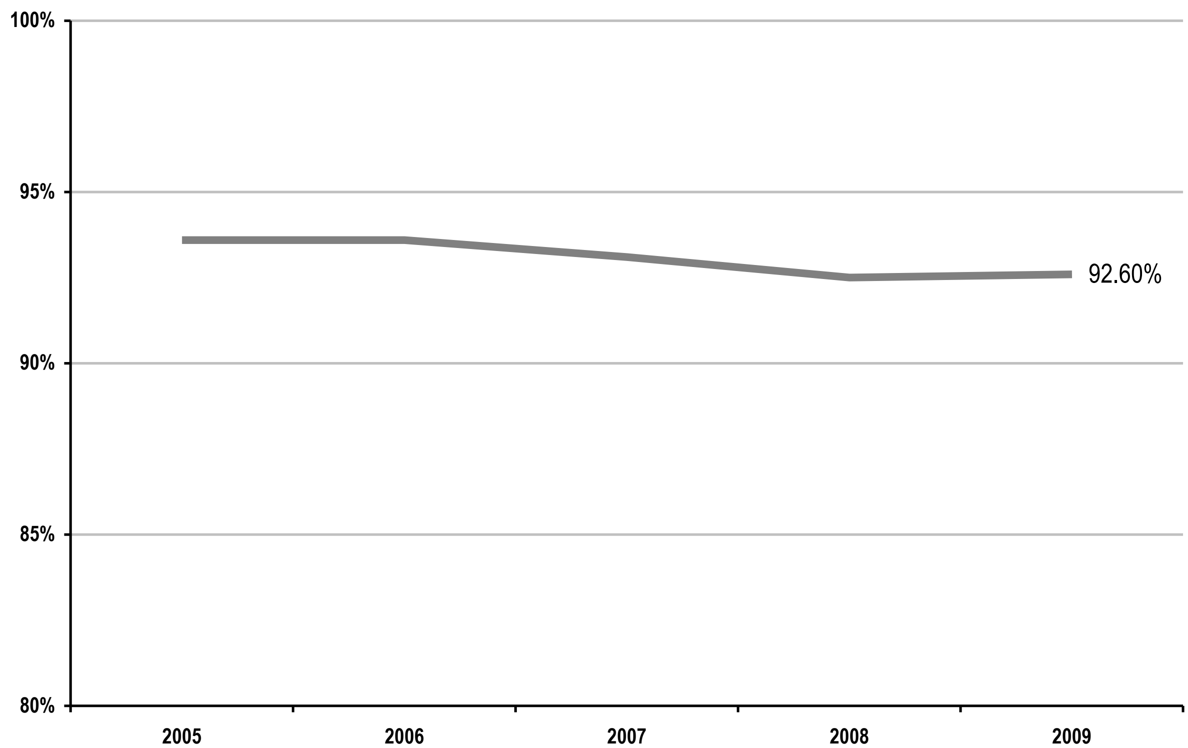
PJM's financial transmission rights (FTR) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path in the Day-Ahead Energy Market. FTRs provide a hedging mechanism that can be traded separately from transmission service. Market participants are able to hedge against their congestion costs by acquiring FTRs that are consistent with their energy deliveries. Participants use PJM's FTR market tool to post their FTRs for bilateral trading as well as to participate in the scheduled monthly, annual and long-term (three-year) FTR auctions.

For the past five years, PJM's FTR market has had sufficient liquidity and capacity to allow the overwhelming majority (98 – 100%) of congestion to be hedged. PJM's FTR market was 93% and 96% revenue adequate in 2005 and 2006, respectively, and 100% revenue adequate from 2007 through 2009. FTR market revenue adequacy reflects the relationship of actual FTR revenues to the target allocations for all FTR holders in the aggregate.

Resources

Balancing customer demand and available resources can be achieved by a combination of changing generation output and/or reducing the total customer demand. The charts and discussion below reflect PJM's history with generation and demand response resources being available when called upon by PJM to revise output or usage levels.

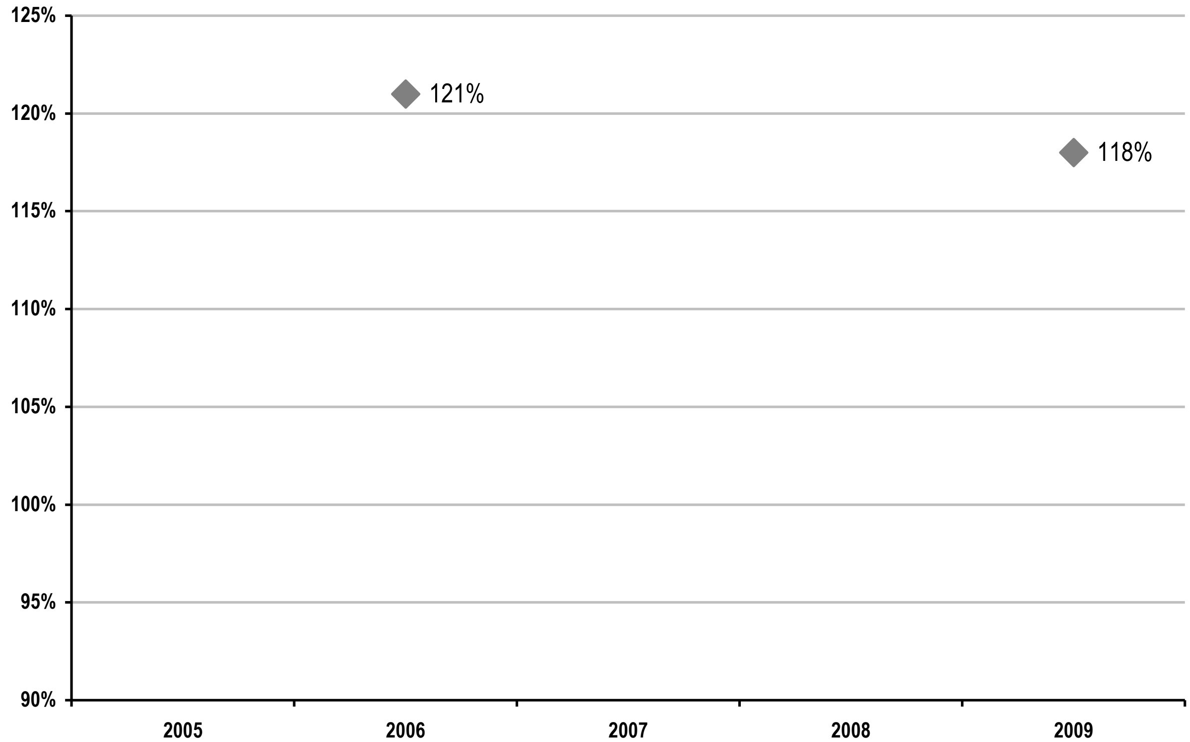
PJM Annual Generator Availability 2005 – 2009



Generator availability in the PJM region has been strong during the last five years. Older coal-fired generating units in the PJM region have had decreased availability approximately 1% in the past few years. These units have run less frequently based on their costs, and investments in upgrades to those units have become challenging financial decisions for their owners in light of the uncertainty over the impact on those units of potential future state and federal environmental legislation.

The incentives provided by PJM's transparent, single clearing price energy market have directly resulted in improved generator performance and reduced outage rates, further decreasing the required reserve margin. The PJM average forced outage rate has decreased over 2% since the initiation of the PJM locational marginal pricing (LMP) energy market in 1998. Multiplying the megawatts of reduced reserve margin times the cost of installing the additional capacity that would be required absent centralized dispatch and the improved generator availability yields a savings of between $366 million and $900 million each year.

PJM Annual Demand Response Availability 2005 – 2009



Historically, load serving entities in PJM have had the ability to meet their capacity requirements through the commitment of demand side resources. With the advent of the Reliability Pricing Model, demand side resources are able to participate in the capacity procurement process as either demand resources or interruptible load for reliability.

The 2006 Demand Response Availability represents the actual response PJM received when PJM called on demand resources in August 2006.

The 2009/2010 delivery year marks the first time PJM has required demand side resources to test their capability to deliver the reductions committed to meet capacity requirements. The test results for the 2009/2010 deliver year demonstrate that in aggregate, committed demand side resources performed at 118% of their committed capacity values.

Demand resources in 16 of the 17 transmission zones in the PJM region tested at more than 100% of their respective commitment levels. These commitments were made by 80 Curtailment Service Providers (CSPs) in 17 transmission zones with a total of 336 CSP/zone combinations.

PJM Demand Response Future Enhancements:

In 2007 and 2008, PJM worked collaboratively with its members and regulators to identify a Demand Response (DR) Roadmap of the opportunities for the evolution of DR resource participation in PJM. The DR Roadmap for the PJM region includes potential improvements in the following areas: dispatch of demand resources, data management, settlement of DR activity, DR in the planning process, and forward price signals for DR.

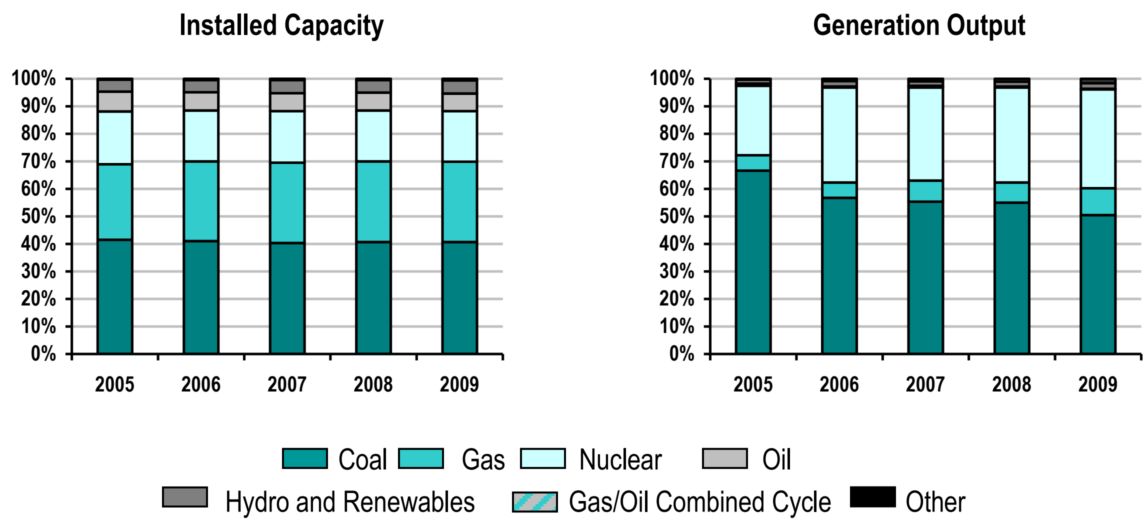
The suggestions in PJM's DR Roadmap were assembled from a variety of sources. These include Mid-Atlantic Demand Resources Initiative (MADRI) activities, recommendations from PJM Symposium on Demand Response, state commission demand response working groups, PJM's Demand Side Response Working Group, and the NARUC/FERC demand response collaborative. The next steps in PJM DR Roadmap include:

- Shortage Pricing implementation in 2011 – Shortage pricing allows for the joint optimization of energy and ancillary services in the real-time dispatch algorithm together, as well as incorporates demand curves to set energy and reserve prices during periods of operating reserve shortage. Managing ancillary service requirements simultaneously with energy in real time and calculating prices every five minutes together with locational marginal pricing (LMP) promotes more efficient commitment of resources for energy or ancillary services and clearing prices that are reflective of actual operating conditions. The joint optimization of energy and ancillary services provides benefit to the system by lowering overall production costs and the resulting five-minute pricing for reserves will enhance opportunities for innovative resources, such as storage devices, to provide ancillary services. Developing a shortage pricing mechanism will adapt market design to more readily provide shortage price signals to take advantage of innovations in demand response and smart grid technologies.

- Price Responsive Demand (PRD) implementation in 2011 – PRD is the predictable reduction in consumption in response to changing wholesale prices. In the PJM region, Smart Grid investment is under development for many market participants and this evolving Advance Metering Infrastructure will enable the enhanced measurement and control required for the implementation of PRD. As a new PJM market option, to the extent retail rates are directly linked to varying wholesale prices, PRD can enable end-use sites with load reduction capability to reduce energy bills by reducing usage during times of high wholesale prices. PRD implementation will enhance market efficiency by increasing the direct participation by demand in the wholesale market.

Fuel Diversity

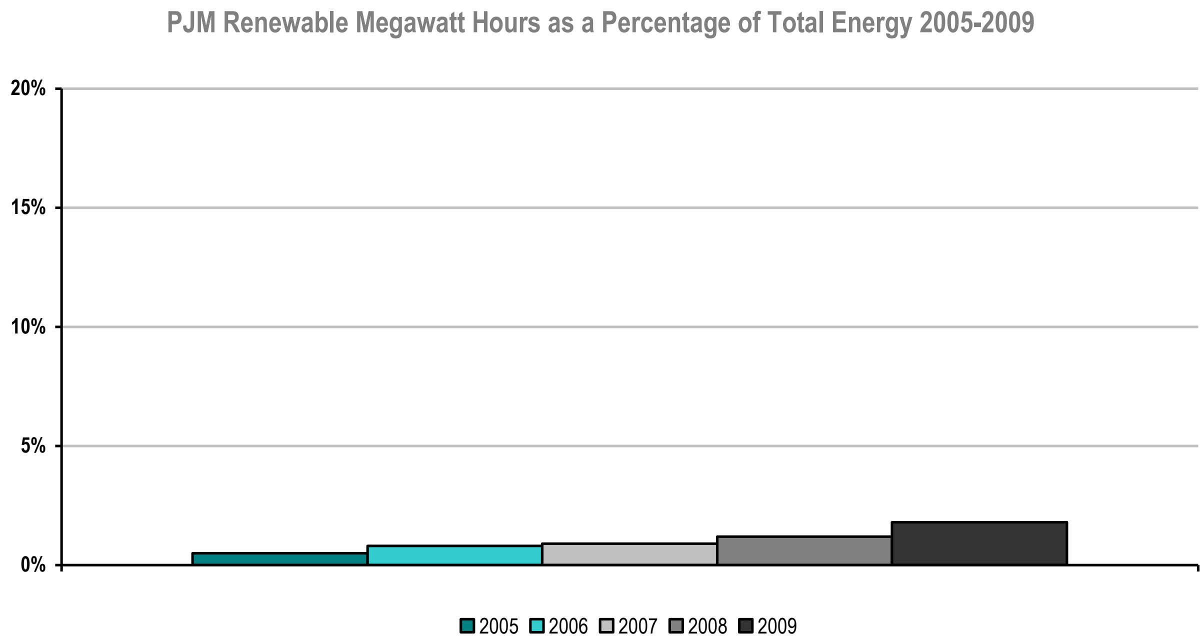
PJM Fuel Diversity 2005-2009

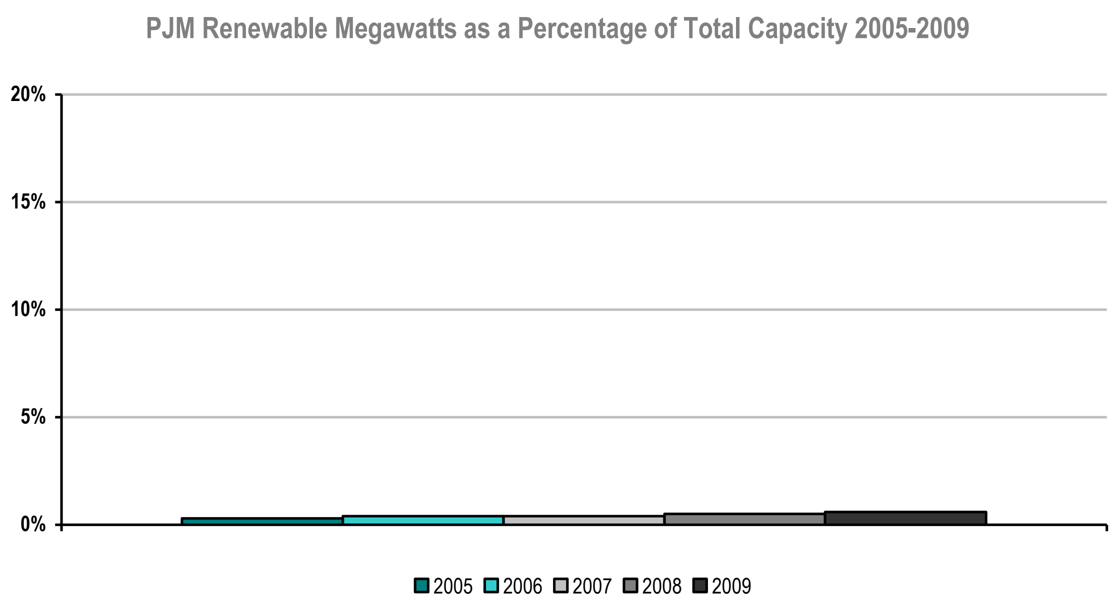


The installed generating capacity in the PJM region is roughly 40% coal, 30% gas and 20% nuclear. However, based on the costs of running the generators in the PJM region, security-constrained economic dispatch actually results in the energy for the PJM region being comprised of 55 – 65% coal, 25 – 35% nuclear and less than 10% from all other fuel sources.

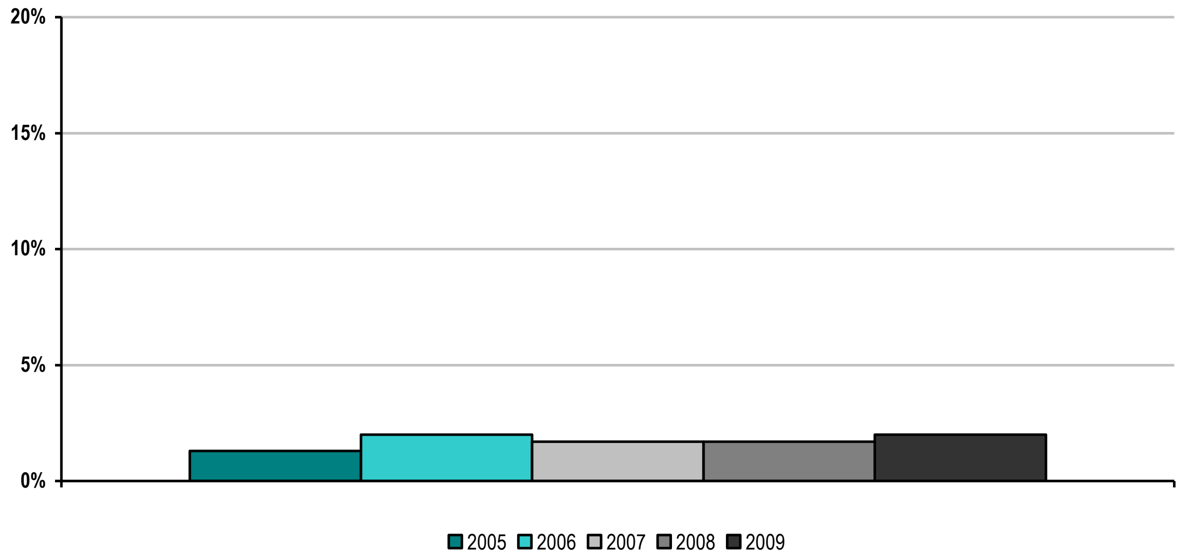
Generation in the PJM footprint does not typically encounter issues around fuel availability or deliverability. PJM has identified approximately 12,000 to 19,000 MW of coal-fired generation that may be at risk of retirement due to potential environmental policy considerations. This range of potential generation at risk represents 7 – 12% of the installed generation capacity in the PJM region. PJM is examining the issue so that reliability may continue to be maintained at the lowest possible cost.

Renewable Resources

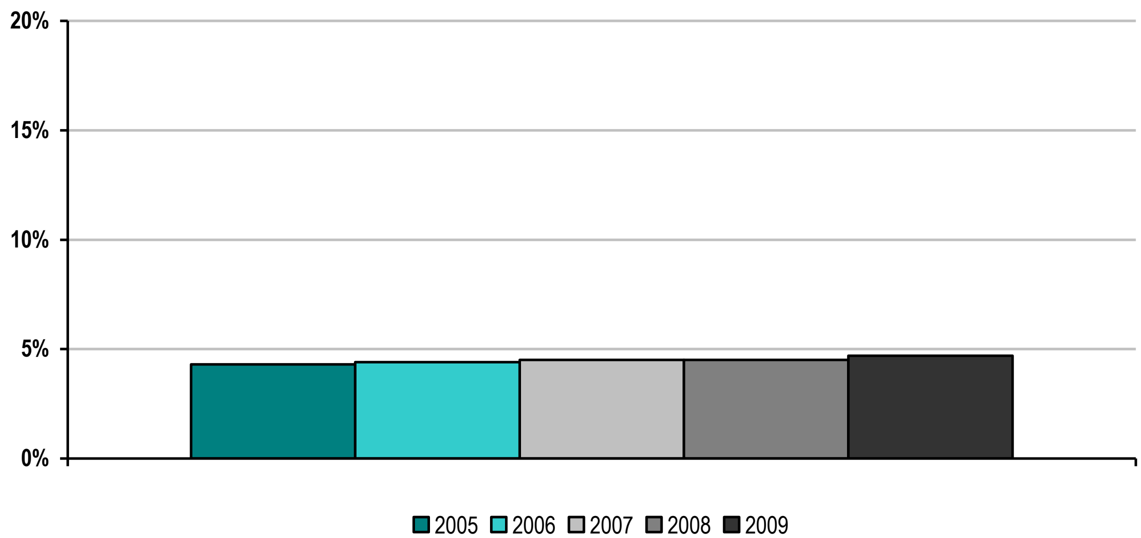




PJM Hydroelectric Megawatt Hours as a Percentage of Total Energy 2005-2009



PJM Hydroelectric Megawatts as a Percentage of Total Capacity 2005-2009



Energy and installed capacity contributions from renewable fuel has been growing in the PJM region in the past few years, with tens of thousands of megawatts of potential renewable capacity currently being studied for potential future construction. Installed hydroelectric capacity in the PJM region has not changed materially in the past few years and there are few hydroelectric plants under consideration by generation developers.

PJM's operating, planning and market rules enable the incorporation of renewable resources into the electric system in the PJM region and into the markets administered by PJM. As of March 31, 2010, PJM had over 75,000 MWs of proposed new generation under consideration in its interconnection queues, including nearly 42,000 MWs of wind generation. At the same time, there were 3,648 MWs of nameplate wind generation in operation at 46 facilities, and 2,752 MWs under construction. In addition, there are 5.5 MW of solar on line at two facilities in the PJM region.

Renewable resources offer into the PJM markets and are subject to security constrained economic dispatch, just as any other generating resource. Renewable resources like wind tend to bid in at zero cost or a negative cost, and this value is considered when economically dispatching units for reliability reasons. In the aggregate, wind resources in the PJM region have a 13% capacity factor, and solar resources in the PJM region have a 38% capacity factor.

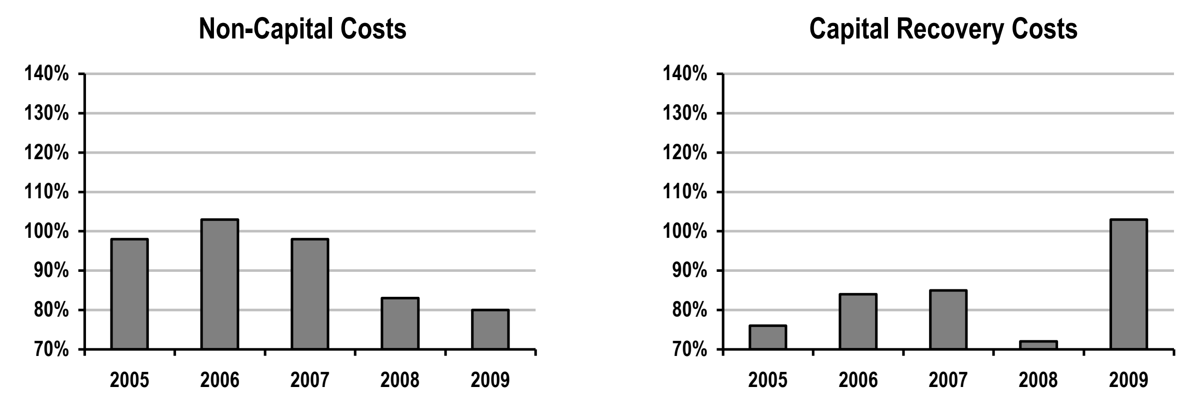
The Renewable Energy Dashboard at www.green.pjm.com illustrates a user-friendly snapshot of the amount and type of generation that currently provides power to the 51 million people in the PJM region. The dashboard also features a map indicating where proposed renewable energy projects are planned and a summary of how much electricity has been produced by renewable sources since 2005.

The amount of renewable energy proposed changes throughout the year as new projects are added and some are withdrawn from the process. The dashboard reflects PJM's on-going commitment to examine energy-related issues and provide information as it relates to the power grid and wholesale power market to help inform public policy discussions.

C. PJM Organizational Effectiveness

Administrative Costs

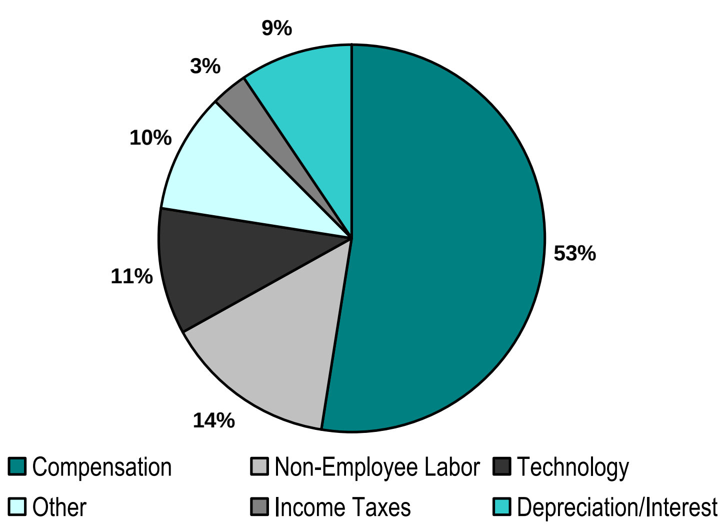
PJM Annual Actual ISO/RTO Costs as a Percentage of Budgeted Costs 2005-2009



Budget	$168	$175	$178	$177	$172
Budget	$90	$55	$34	$17	$19

Bars Represent % of Actual Costs to Approved Budgets; Dollar Amounts Represent Approved Budgets (in millions)

PJM's actual total costs for 2005 through 2009 averaged 90% of the approved budgets, without exceeding the total approved budget in any of those years. As represented in the chart below, PJM's 2005 through 2009 costs were primarily comprised of compensation, non-employee labor and technology expenses. These cost components are consistent with a service organization that utilizes significant people, hardware, software and telecommunications resources to serve its customers.



PJM develops its annual expense and capital budget in consultation with the PJM Finance Committee. The PJM Finance Committee is comprised of two member representatives elected by each of the five member voting sectors plus two members of the PJM Board of Managers. PJM's Chief Financial Officer acts as the non-voting chair of the PJM Finance Committee. PJM's Finance Committee reviews and provides feedback on PJM's preliminary expense and capital budgets during August each year. Then, after PJM management incorporates feedback, the sector-elected representatives to PJM's Finance Committee issue a written recommendation letter to the PJM Board of Managers on the subsequent year's proposed expense and capital budgets. The PJM Board of Managers includes these recommendations in their consideration of the proposed expense and capital budgets no later than October 31st of the year prior to which the proposed budgets apply.

PJM's annual expense and capital resource allocations are based on its service obligations to its members and new initiatives, regulatory directives, industry standards and market rules to be implemented. Prior to the PJM Board of Managers considering the proposed expense and capital budgets, the proposed initiatives and projects are reviewed with several stakeholder committees to ensure the alignment of priorities between the proposed budget resource allocations and the annual plans for those stakeholder committees.

In addition to the recurring review and recommendations on the annual proposed expense and capital budgets, the PJM Finance Committee meets at least quarterly to discuss actual costs compared with approved budgets and the most recent forecast of expenses and capital expenditures for the current year. The PJM Finance Committee is also consulted and asked to provide recommendations regarding (a) proposed multi-year capital projects estimated to cost $25 million or more, and (b) any potential changes to PJM's administrative cost recovery and rates in its Tariff.

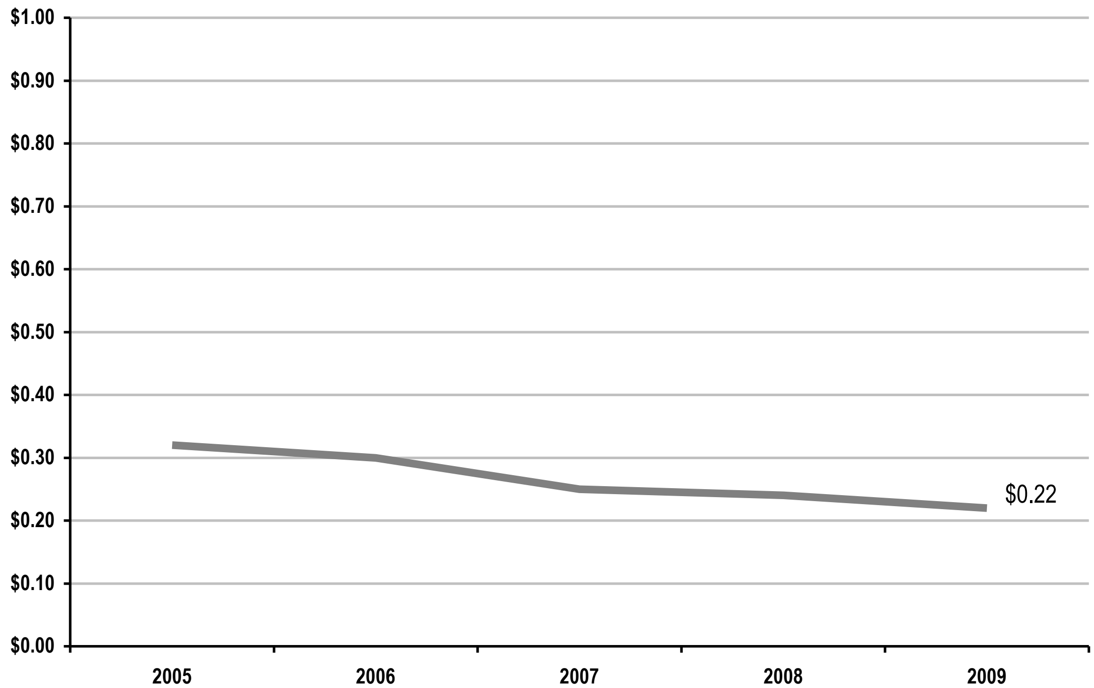
PJM recovers its administrative expenses through stated rates applicable to market participants' transaction volumes, such as megawatt hours of load served, generation sold, and FTRs held. PJM is not authorized to charge its members rates higher than these stated rates without a FERC-approved rate filing. So, the stated rates act has long-term ceilings to how much PJM can charge members for the administrative costs of their transactions. If PJM's actual costs are less than the revenues resulting from the application of the stated rates, then PJM refunds the difference to members on a quarterly basis.

PJM's 2005 through 2007 actual non-capital expenses did not vary materially from the approved non-capital budget for those years. PJM's 2008 actual non-capital expenses were 17% lower than budget primarily due to lower consulting and contracting costs required during the development of PJM's second control center and lower income tax expenses. In June 2009, PJM's Board of Managers approved revisions to PJM's postretirement medical plan resulting in a non-recurring $26 million income tax benefit which was the primary driver of the 20% variance in PJM's actual and budgeted non-capital expenses. The variances in 2008 and 2009 lowered PJM's administrative rate per MWhr of load served by about $0.04 compared with each year's forecasted rates.

PJM's capital recovery costs in the previous chart reflect depreciation and interest expense in each year, as PJM's Tariff stipulates that capital investments are recovered from PJM's members after the related assets are placed in service. PJM's 2005 actual capital recovery costs were approximately 24% lower than its approved budget primarily due to lower than budgeted technology investment related to the integration of additional transmission zones into the PJM region. PJM's 2006 actual capital recovery costs were lower than budgeted for a few reasons – the lower 2005 actual capital spending, lower interest expense on lower than budgeted borrowing levels, and the shift of a few capital projects from 2006 to 2007. PJM's 2007 actual capital recovery costs were lower than budgeted due to lower interest expense due to lower borrowings required to fund PJM's capital expenditures.

PJM's 2008 actual capital recovery costs were 28% lower than budget due to the impact on depreciation and interest expense of the revised completion dates of certain projects such as the market settlement system replacement and lower interest expense from lower borrowings than budgeted. PJM's 2009 actual capital recovery costs did not vary significantly from its budgeted capital recovery costs. With the planned completion of PJM's second control center in 2011, PJM's capital recovery costs are projected to increase from 2011 forward to reflect the depreciation and interest expenses associated with that approximate $140 million capital investment.

PJM Annual Administrative Charges per Megawatt Hour of Load Served 2005-2009
($/megawatt-hour)

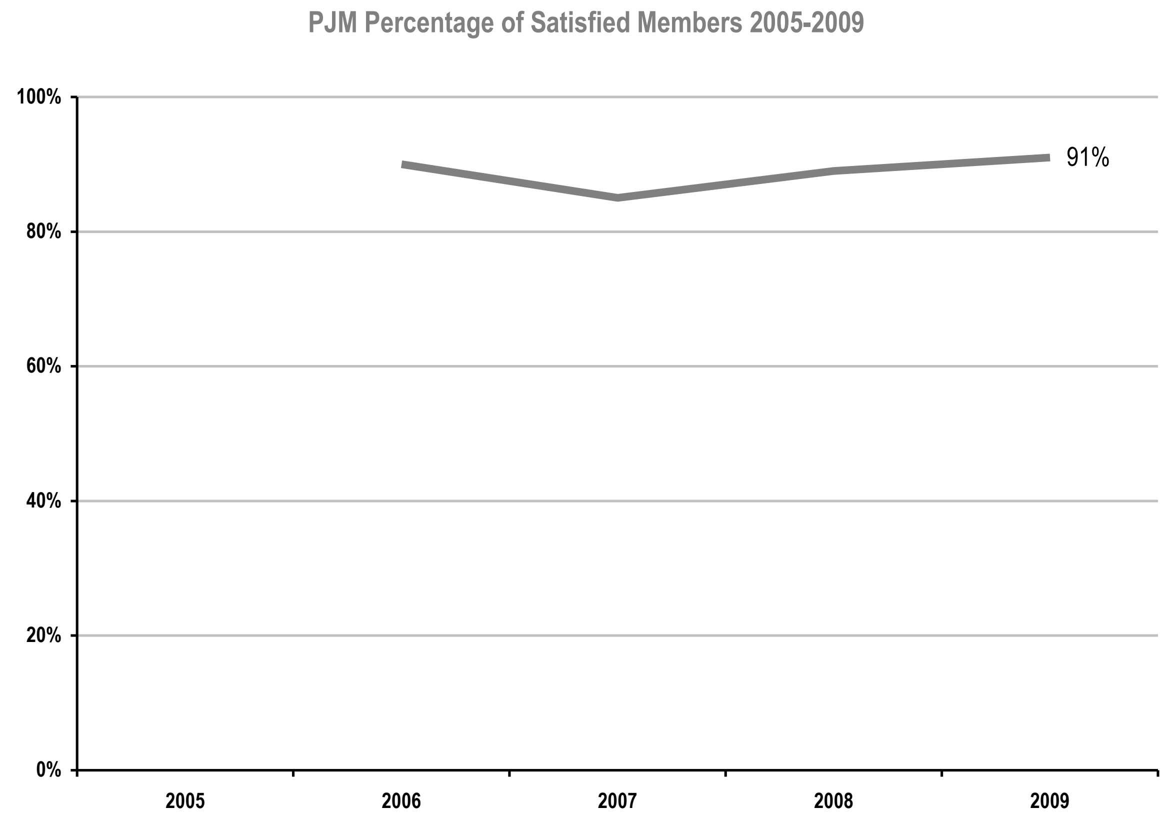


The administrative costs per MWh of load served data in the chart above should be reviewed in the context of the PJM annual load served noted in the table below.

ISO/RTO	2009 Annual Load Served *(in terawatt hours)*
PJM	710

PJM's actual to budget variances in 2008 and 2009 lowered PJM's administrative rate per MWh of load served by about $0.04 compared with each year's forecasted rates. Prospectively, PJM forecasts its annual administrative rates will be approximately $0.31 per MWh of load served as recovery of the investments in (1) a second control center and (2) new reliability and markets software and hardware commence in 2011.

Customer Satisfaction



PJM's 2005 stakeholder survey did not ask the same satisfaction questions as were asked in 2006 through 2009; hence, there is no comparable 2005 satisfaction statistic for PJM. PJM's stakeholder survey requests anonymous feedback to an independent firm on levels of satisfaction and stakeholder value derived from numerous PJM functions. Based on survey takers' self-selected description, PJM's 2006 through 2009 satisfaction percentages have not differed significantly among member sectors, e.g. electric distributors, end-use customers, generation owners, other suppliers and transmission owners. In the 2009 survey, the reliability management and training functions received the highest satisfaction ratings with the system planning and communications areas demonstrating opportunities for improvement.

PJM implements action plans to address areas for which there are opportunities for improvement. In the past few years, PJM has focused on feedback to improve stakeholder access to PJM information and stakeholder communications with the PJM Board of Managers. For example, PJM and its members established the Liaison Committee in 2007 to provide greater opportunities for direct communications between stakeholders and the PJM Board of Managers. Also, in 2008, PJM redesigned its website to facilitate stakeholder access to information on operations, markets and stakeholder committee activity. In 2009, PJM's members responded with the highest value rating in PJM's ten-year history of surveying its members.

PJM Customer Satisfaction Future Enhancements:

Based on feedback received during PJM's 2009 customer satisfaction survey, PJM will implement the following improvements during 2010:

Long-Term System Planning:

- Augment staffing levels
- Re-establish the Regional Planning Process Working Group as a member forum to address transmission planning concerns

PJM Web-site:

- Improve web-site speed
- Improve web-site, generation interconnection and planning queue searches
- Implement Issues Tracking
- Increase frequency of communications to members on web-site changes

Billing Controls

ISO/RTO	2005	2006	2007	2008	2009
PJM	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion

In 2009, PJM's market settlement billing controls passed the stringent SAS (Statement on Auditing Standards) 70 Type 2 audit for the ninth consecutive year, even with the significant 2009 change from a monthly to a weekly billing cycle. In keeping with governance rules, such as those in the Sarbanes-Oxley Act of 2002, PJM's SAS 70 report is designed to provide an understanding of its internal controls to the auditors of the companies that use the organization's services, i.e. PJM's members. PJM's internal controls and processes related to all billing line items are included in the scope of testing completed during each twelve-month SAS 70 audit period.

PJM focuses on the accuracy of both prices posted and amounts billed to ensure members can rely on prices for transacting and have confidence in the amounts included in their PJM invoices.

- In the five years ended December 31, 2009, PJM reposted hourly energy prices once in 2006, twice in 2007 and five times in 2008. There were no energy price corrections in 2005 or 2009. The energy price corrections applied to either one pricing point or one hour's prices for each of the affected days and prices were revised from 0.06% to 6.43% for these hours. For the five-year period ended December 31, 2009, PJM achieved 99.99996% energy price posting accuracy.
- For the five-year period 2005 through 2009, PJM's billing accuracy based on dollars of billing adjustments divided by total dollars billed averaged 99.8%.

D. PJM Interconnection Specific Initiatives

Perfect Dispatch: PJM's Perfect Dispatch metric provides a measure of PJM's performance in dispatching the system in the most efficient manner possible and optimizing locational pricing as a reflection of the dispatch solution. The objective of the Perfect Dispatch measure is to compare PJM's actual dispatch solution against the ideal case if all system conditions, including actual electricity usage, had been known before the dispatch signals were sent to the generators in the PJM region. During 2009, PJM improved its generation dispatch sufficiently to reduce annual generation production costs by $122 million.

PJM Perfect Dispatch Future Enhancement:

During 2010, PJM will expand its Perfect Dispatch initiative to evaluate and optimize steam generating unit commitment actions outside of the Day-Ahead Market schedule to allow PJM to identify areas for further operational improvement in dispatch that result in dollar savings in generation production costs to members.

Credit Risk Management: PJM implemented more than a dozen improvements to its billing and credit practices during 2009 to reduce the risk of socialized default charges to its members. In particular, PJM replaced its previous monthly billing cycle with weekly billing and settlement on June 1, 2009. This change resulted in a $2.9 billion (70%) reduction in the total credit risk exposure to PJM's members. Further, PJM returned $1.0 billion of financial security to its members due to lower credit requirements under accelerated settlements.

PJM Credit Risk Management Future Enhancement:

During 2010, PJM asked its members and the Federal Energy Regulatory Commission to support revisions to PJM's Operating Agreement and Tariff to clarify PJM's legal capacity as the central counterparty for members' non-bilateral transactions billed by PJM effective January 1, 2011.

Demand Response and Energy Efficiency Capacity Market Participation: During 2009, PJM implemented capacity market rule changes that increased the opportunities for demand response and energy efficiency to participate in PJM's capacity market auction for the 2012/2013 planning year. The 5,682 megawatt increase in demand resources over the last Reliability Pricing Model auction in 2008 is enough capacity that would be equivalent to the power needs of about five million households. A total of 67% of the demand resources cleared in constrained regions, reflecting its value in helping to reduce congestion. For the first time, energy efficiency participated in the sixth RPM auction bringing 569 megawatts of new energy efficiency resources to PJM. Total revenues earned by demand response resources in 2009 from energy, capacity and ancillary service market participation exceeded $300 million, nearly a 60% increase from 2008.

Market Liquidity: Another measure of the efficiency and effectiveness of wholesale power markets is the ability for financial derivative products to be developed and utilized by physical market participants to mitigate price risk, such as swap futures. The development of such products that are settled against wholesale market outcomes also signals confidence in the accuracy and relevance of the prices determined in the wholesale market. Currently, the New York Mercantile Exchange (NYMEX) trades 52 PJM-based contracts that are differentiated by location, peak or off-peak, and day-ahead or real-time markets. Open interest in day-ahead and real-time contracts traded at locations within

PJM reflects the total megawatt hours (MWhs) of energy hedged by these Swap Futures, which is 9 – 12.5% of total load in the reference PJM transmission zones. The percentage of load hedged through financial contracts is even more significant if one considers that 17% of the real-time load was served out of the real-time market, with the remainder self-supplied or served by bilateral contracts. Such statistics indicate that the combination of wholesale power markets with financial instruments facilitates less than 10% of total load served in the PJM region likely being exposed to the potential volatility of real-time prices. Further, during 2009, PJM began hosting a long-term contracting bulletin board for all the ISOs/RTOs to enable buyers and sellers interested in longer-term contracts to contact each other.

Industry Innovation / Collaboration: PJM's ability to deliver value also involves leveraging its intellectual resources and vast stores of data to assess the impact of potential public policy initiatives on the grid and markets. An example is the widely referenced study of the potential impact of climate-control legislation that PJM published early 2009. PJM also sponsored symposiums on plug-in hybrid electric vehicles and demand response and Price Responsive Demand in order to provide members and policy-makers with knowledge on the issues and how their development might affect the grid and the PJM region.

Grant Collaboration: To further broader transmission planning, the Eastern Interconnection Planning Collaborative was formed in 2009. The collaborative and the states received a total of $30 million in federal grants to address the need for wide-area planning to deal with the massive growth of wind energy and other renewable sources resulting from new energy policies in Washington. Also, the combined efforts of PJM and 12 transmission-owning members gained $14 million in matching federal stimulus funds to support a massive expansion of the number of synchrophasors throughout 91 substations in 10 states. This will vastly expand our ability to see and quickly react to abnormal conditions, thereby strengthening both the reliability and digital intelligence of the bulk electric system.

PJM Value Proposition: The following summarizes the impact of specific elements of PJM's role that produce benefits and economic value for the region it serves. **Annual savings: as much as $2.2 billion**

Reliability –
resolving constraints and economic efficiency – **from $470 million to $490 million in annual savings**

Generation investment –
decreased need for infrastructure investment – **from $640 million to $1.2 billion in annual savings**

Energy production cost –
efficiency of centralized dispatch over a large region – **from $340 million to $445 million in annual savings**

Grid services –
cost-effective procurement of synchronized reserve, regulation – **from $80 million to $105 million in annual savings**

A. Reliability Savings

PJM's ability to direct changes in the output of generating resources (redispatch) rather than curtail power-sales transactions to deal with transmission congestion enables it to deal with transmission constraints more effectively. By reducing the need for curtailments over a wide area – transmission loading relief procedures, or TLRs – PJM's narrowly targeted redispatch procedures resolve transmission constraints more quickly. This approach has significantly reduced the need for transaction curtailments to maintain transmission system reliability.

Annual savings: $78 million to $98 million

By planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis, PJM's Regional Transmission Expansion Planning (RTEP) process helps focus on transmission upgrades that meet reliability criteria and increase economic efficiency.

Annual savings: $390 million

B. Generation Investment Savings

The large size of the PJM market area, combined with its diversity of demand and resources, reduces the overall level of capacity needed to ensure adequate reserves of electricity to meet peak demand or emergency situations. This capacity buffer, known as the reserve margin, would need to be higher without PJM. Consumers avoid the costs of additional generation to meet higher levels of reserves.

Annual savings: $366 million to $900 million

The commitment of demand-response resources to reduce load during system peaks also forestalls the cost of building additional generating facilities. Through the Reliability Pricing Model (RPM), demand response competes on an equal footing with generation and transmission in the capacity market. Through RPM, the quantity of demand response that is providing capacity in the PJM footprint has increased by more than 1,800 megawatts.

Annual savings: $275 million

C. Energy Production Cost Savings

PJM's centralized dispatch of the numerous resources over its expanded territory produces significant efficiencies and cost savings compared with the previous operation of independent control areas across the region. The increasing effectiveness of PJM's dispatch operations also has reduced operating reserve costs.

Annual savings: $340 million to $445 million

D. Grid Services Savings

By operating markets for grid services, also known as ancillary services, across its footprint, PJM achieves economies in providing services that are essential to the reliability of the electric system. Synchronized reserve service supplies electricity if the grid has an unexpected need for more power on short notice, while regulation helps match generation and load by correcting for short-term changes in electricity use that might affect system stability.

Annual savings: $80 million to $105 million