

PJM's comments regarding
the 2009 State of the Market Report



4.9.2010

PJM Interconnection

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Executive Summary

Competitive wholesale markets provide substantial benefits to consumers and are essential to reliable large-scale regional grid operation. They also provide an effective means for meeting the challenges of the electricity industry in the years to come, including integrating demand response, renewable energy resources and smart grid technologies; accommodating emissions reduction policies and the prospective turnover in aging generation assets. PJM believes in the importance of the continuing dialogue regarding our competitive markets by our members and other stakeholders. It is in this spirit that this examination of the 2009 PJM State of the Market report is offered.

Energy Market Results are Driven by Competitive Behavior and Market Fundamentals

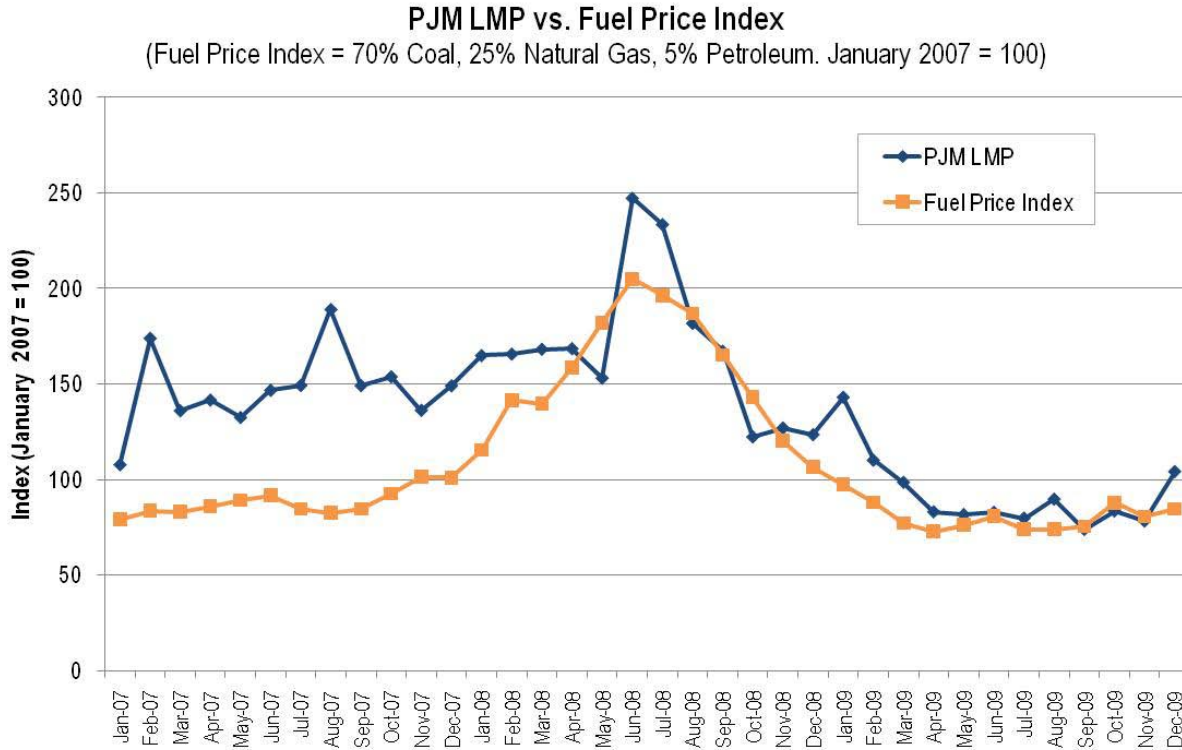
Monitoring Analytics, the Independent Market Monitor for PJM (IMM) has concluded in its 2009 State of the Market (SOM) Report that market results in PJM's Energy, Capacity, Synchronized Reserve, Day-Ahead Scheduling Reserve and FTR Auction Markets are competitive. The economic benchmark for measuring competitiveness of markets is the degree to which suppliers make offers at their marginal cost and the market prices are equal to the marginal cost of delivering one more MW of energy to the market. These marginal costs are represented in formulaic cost-based offers, but some costs are difficult to measure or are not yet included in energy offers, especially opportunity costs related to energy and environmental limits. Consequently, any measure of costs and mark-ups over cost are approximate.

In the Energy Market in 2009 the measure of overall mark-up of price over cost was -6.1 percent according to the IMM. For coal-fired generating units that were on the margin 74 percent of the time in 2009, PJM measured the mark-up of market-based offers over cost in a tight range of -0.01 to -0.04 (-1 to -4 percent) throughout 2009. Natural gas units that were on the margin 22 percent of the time in 2009 exhibited mark-ups of market-based offers over cost in the range of 0.01 and 0.05 (1 to 5 percent) according to PJM analysis. The low (near zero) mark-up of market-based offers relative to marginal cost is very strong evidence of competitive behavior in the PJM Energy Market. Moreover, with uncertainty in cost measurement, rigid cost-based offer requirements in all hours may result in suppliers being unable to reflect their true cost in offers.

The marginal cost of generation is largely driven by the cost of fuel, holding demand constant. Consequently, as fuel prices rise, the marginal cost of generation rises leading to higher locational marginal price (LMP) values in a competitive environment. Conversely, as energy prices decline, the marginal cost of generation declines leading to lower LMP in a competitive environment. The evolution of PJM LMP and fuel prices can be seen in the Figure 1. Throughout 2007 and the first half of 2008, fuel prices were rising and a corresponding increase in LMP is seen. From July 2008 fuel prices have declined and a corresponding decline in LMP is observed.

Demand levels are also a driver of LMP. Given fuel prices, higher levels of demand require high marginal cost generation to be dispatched and result in higher LMP. By the same token, lower levels of demand result in lower marginal cost generation to be dispatched and correspondingly lower LMP. In 2009 average hourly loads were down over 4 percent from 2008 due to milder weather patterns and economic conditions, and further amplifying the LMP effects of declining fuel prices. The combination of these trends has led to a sharp fall in load-weighted average LMP from the 2008 level of \$71.13/MWh to \$39.05/MWh in 2009.

Figure 1: PJM LMP vs. Fuel Price Index



Coal-Fired Generating Units Potentially at Risk for Retirement

The IMM has found approximately 11,000 MW of coal-fired generation were unable to cover their avoidable (going-forward) costs through the combined net revenues from the energy and RPM Capacity Markets in 2009. Most of the coal generation identified by the IMM is older, smaller, and less efficient. Although it would be easy to dismiss the inability of so much coal generation to cover their avoidable costs during a year with low energy prices and demand, the finding highlights the concern market participants have regarding the market and reliability impacts of the potential retirement of so much coal-fired generation.

PJM has evaluated the amount of coal-fired capacity that may be at risk for retirement due to environmental policy considerations. Using criteria related to the environmental attributes of generating units and unit age, PJM estimates the amount of coal-fired generation that may potentially be at risk for retirement to range from 12,000 MW to 19,000 MW. PJM is working with the IMM to identify coal units at risk for retirement. We are sharing our initial findings, which shows a large overlap in the identification of units at risk and planning additional analysis to ensure reliability can be maintained at the lowest possible cost.

RPM is Attracting New Entry and Sending Price Signal for Additional Entry

In a competitive market, the persistent inability of older, smaller, and less efficient coal units to cover their going-forward costs, regardless of the reason, would result in the exit of these units and the eventual entry of newer, more efficient generating technologies or demand-side resources. Since the implementation of RPM, there has been a net gain of more

than 15,000 MW of new capacity, (not including reactivations of existing units, forestalled or cancelled retirements, or increases in capacity imports) that has been made available to the PJM Market through the 2012/2013 delivery year which can help offset the potential retirement of some coal units in the short-term.

With almost three years of experience with the RPM Capacity Market operating in conjunction with the Energy Market, RPM can be seen to provide price signals over a period of years to market participants that incent new entry of generation and demand resources where they are needed most, as is the case for the high penetration of demand resources in the Baltimore-Washington area of the PJM footprint.

Regulation Market Behavior and Results are Competitive

The IMM has concluded the behavior of market participants in the Regulation Market was competitive in 2009, but that the results were not competitive due to FERC-approved changes in the Regulation Market rules related to the calculation of opportunity costs. PJM does not believe the IMM's conclusion is supported by the facts. PJM believes that the outcomes of the Regulation Market were competitive as evidenced by the competitive behavior cited by the IMM and the overwhelming evidence of enhanced competitiveness provided by the IMM analysis. The competitiveness of market results must be based on the FERC-approved definition of costs, including opportunity costs. Given that PJM has followed its FERC-approved tariff, and with competitive behavior already acknowledged, it is difficult to understand the logic of the IMM conclusion regarding the Regulation Market.

The facts cited by the 2009 SOM Report paint a compelling picture of a more structurally competitive market. In 2009, the Regulation Market witnessed a 16 percent increase in the average hourly eligible supply, a 13 percent increase in supply offered by regulation capable units, while the average hourly supply to demand ratio increase from 2.39 in 2008 to 2.98 in 2009, and the percentage of hours in which at least one supplier failed the Three pivotal supplier test fell from 83 percent in 2008 to 52 percent in 2009. In addition, competitive offer behavior drove the load-weighted average marginal offer (not including opportunity costs) to drop 26 percent in 2009 to \$8.79/MWh from \$11.94/MWh in 2008 which PJM estimates reduced regulation costs by \$23.4 million in 2009.

PJM believes that the IMM analysis of the impact of the FERC-approved opportunity cost change contains substantial errors which resulted in an over-estimation of the impact by the IMM by almost an order of magnitude. While the IMM estimates for 2009 the increase in costs amounts to \$45.9 million, PJM estimates this figure to be at most \$5.3 million and likely even less. In light of the minimal cost impact, greatly enhanced competitiveness, and acceptance by PJM stakeholders and approval by FERC, no changes to the FERC-approved rules are warranted at this time.

Introduction and Purpose

PJM is steadfastly committed to the ongoing development and operation of robust, competitive wholesale electricity markets that are integral to reliable grid operation and provides substantial benefits to customers. Moreover, competitive wholesale markets provide an effective means for meeting the challenges of the electricity industry in the years to come including integrating demand response, renewable energy resources and smart grid technologies; accommodating emissions reduction policies and the prospective turnover in aging generation assets.

On March 11, 2010, Monitoring Analytics, the Independent Market Monitor for PJM (IMM) released the 2009 State of the Market Report (SOM Report).¹ Overall, the IMM concluded the results of PJM's Markets were competitive during 2009 with the exception of the Regulation Market where the behavior of market participants was deemed competitive, but the results not competitive due to recent stakeholder and FERC-approved market rule changes. PJM concurs with the IMM's overall observations as to the competitiveness of the various PJM Markets, but disputes the conclusion regarding the results of the Regulation Market.

The PJM response is not meant to replicate the voluminous information and analysis provided by the IMM, but is designed to highlight, emphasize, and expand upon important issues or conclusions that appear in the SOM Report beyond the high level conclusions. PJM's response has four major points of emphasis:

1. Elaborate on, and reinforce, the conclusions reached by the IMM in the SOM Report that the results of the PJM Energy Market are competitive and LMPs are driven by market fundamentals related to fuel prices and demand;
2. Address in additional detail the implications of the IMM finding of over 11,000 MW of coal-fired generation in 2009 that were unable to recover their avoidable costs as being at-risk of retirement;
3. Emphasize that the combined price signals from all of PJM's Markets, including the RPM Capacity Market, are sending price signals signifying profitable entry for new resources in areas where they may be needed most; and
4. Highlight the competitive results of the Regulation Market as evidenced by the competitive behavior cited by the IMM and the 25 percent reduction in marginal offers, enhanced structural competitiveness, improved supply-demand balance, and over-estimated cost impacts of the FERC-approved market rule changes.

The SOM Report also enumerates multiple recommendations by the IMM regarding PJM's Markets. PJM provides, in an appendix to this document, response to each of the recommendations made by the IMM in the SOM Report.

¹ See *2009 State of the Market Report for PJM: Volume 2 Detailed Analysis*, March 11, 2010 (2009 SOM Report) at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2.pdf.

LMP Tracks with Fuel Prices and Demand

The load-weighted average LMP in 2009 was \$39.05/MWh as reported in the SOM Report.² This is a marked decrease from the 2008 load-weighted average LMP of \$71.13/MWh. The decrease in LMP can be explained by the combination of lower fuel prices in 2009 compared to 2008, and the generally lower load levels in 2009. However, the 2009 load-weighted average LMP fuel-cost adjusted to 2008 fuel prices was only \$63.66/MWh, which is almost \$10/MWh lower than the 2008 load-weighted average LMP of \$73.13/MWh.³ The decrease in load-weighted average LMP expressed in 2008 fuel prices from 2008 to 2009 can be largely explained by the decrease in average load of 79,515 MW in 2008 to 76,035 MW in 2009.⁴ Absent the observed reduction in load, the load-weighted average LMP would have been higher in 2009 than it was.

While the fuel-cost adjusted LMP tells part of the story with regard to the relationship between LMP levels and fuel prices, there were significant changes in fuel prices throughout 2008 and 2009. In 2009, fuel prices were lower than 2008 prices, particularly for natural gas through the summer period. Natural gas prices particularly dipped to levels not seen in several years and in some parts of the year made natural gas generation competitive with some segments of coal-fired generation. The trend of load-weighted monthly average LMP throughout 2009 follows the pattern of fuel prices. This is to be expected in a competitive market as prices will rise when production costs rise (such as fuel prices), all else equal. Prices will likewise fall as fuel prices fall, all else equal. This correlation is clearly seen in the performance of PJM's Energy Market. Monthly load-weighted average LMP began in January at approximately \$60, declined to around \$35 by April and remained at that level through most of the year, including the summer peak period. Figure 1 shows the relationship between a fuel price index based on the percent of hours various fuels are on the margin and load-weighted average LMP from January 2007 to January 2010.⁵ Figure 2 clearly shows how LMP and fuel prices move together.

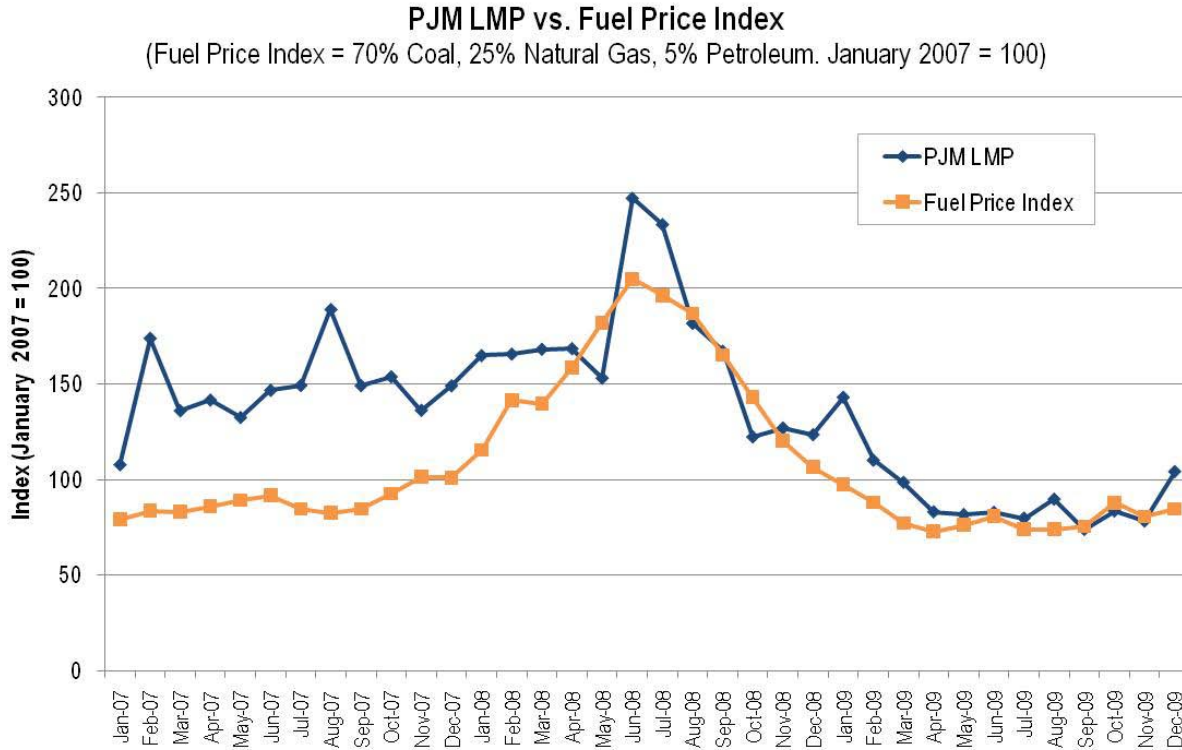
² 2009 SOM Report, Table 2-59 at 68.

³ 2009 SOM Report at 73.

⁴ 2009 SOM Report at 56.

⁵ The fuel index is based on the percent of hours the coal, gas, and oil were reported to be on the margin in the 2007 State of the Market Report, Volume 2: Detailed Analysis (2007 SOM Report) at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2007/2007-som-volume2.pdf, Table 2-32 at 33. Fuel data is from the Energy Information Administration. The natural gas prices are monthly average wellhead price prices found at <http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3m.htm>, the monthly average petroleum prices are West Texas Intermediate crude prices found at <http://tonto.eia.doe.gov/dnav/pet/hist/rwtcM.htm>, and coal prices are monthly NYMEX Future prices for Central Appalachian coal found at <http://www.eia.doe.gov/cneaf/coal/page/nymex/current.xls> and <http://www.eia.doe.gov/cneaf/coal/page/nymex/historical.xls>.

Figure 1: PJM LMP vs. Fuel Price Index



LMP is Determined through Competitive Bidding Behavior

In the SOM Report, the IMM concludes that the results of the PJM Energy Markets are competitive and that the offer price versus cost mark-up component of load weighted average LMP of negative six percent is strong evidence of competitive behavior.⁶ Moreover, the SOM Report shows that the mark-up component of LMP is negative on average at LMP below \$75/MWh, encompassing over 97 percent of all hours in 2009.⁷ PJM has examined the mark-up behavior of coal units and gas units regardless of whether they were on the margin or not. The mark-up indices for coal and gas units below were computed for coal- and gas-burning units at their maximum economic output, and weighted by the MW quantity of their offer. Figure 2 shows that coal units, on a consistent basis, were on average offering just below their cost-based offers.⁸ This finding is consistent with the mark-up component of LMP being negative for LMP less than \$75/MWh as in these

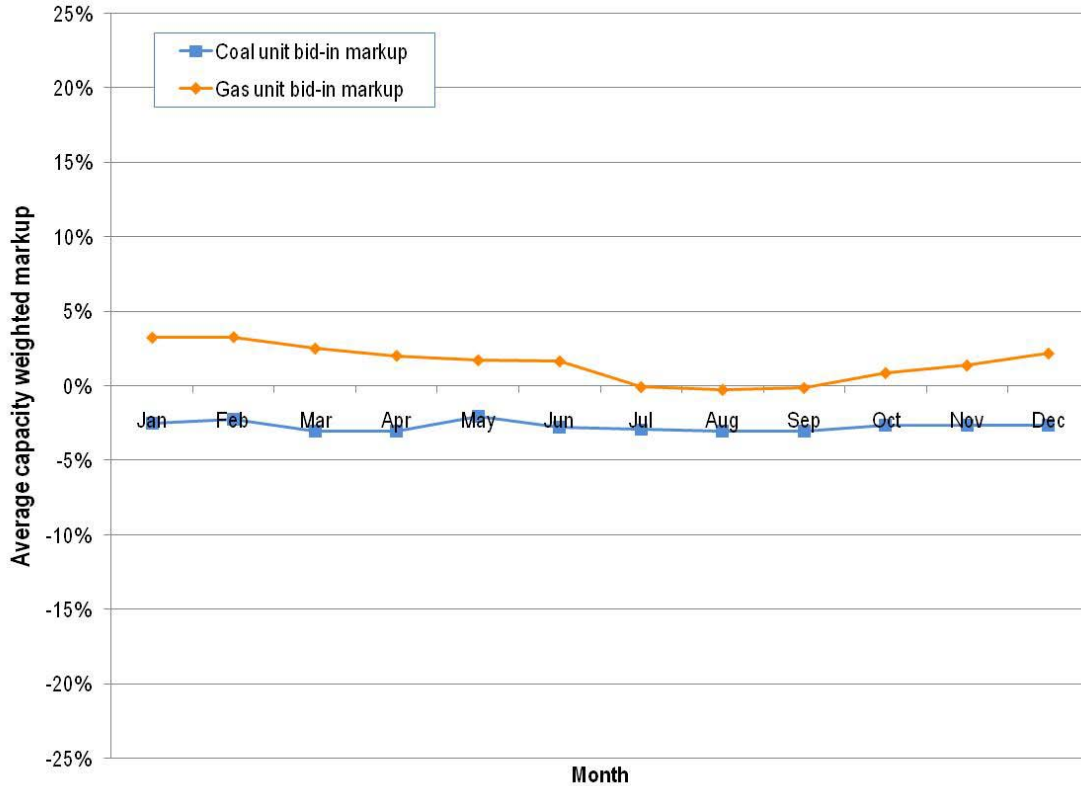
⁶ 2009 SOM Report at 15. PJM has previously noted, and the IMM has previously acknowledged, there are issues with calculating the mark-up component of LMP using only marginal units and not performing a full re-dispatch of the system. See *PJM's Comments Regarding the 2007 State of the Market Report Issued by the PJM Market Monitoring Unit* April 11, 2007 at 12-14.

⁷ 2008 SOM Report Table 2-35 at 44.

⁸ Cost-based offers consist of defined marginal running costs as defined in PJM Manual 15 plus an adder of up to 10 percent that accounts uncertainty in the measurement of costs and has been reiterated by FERC in various orders. For examples, refer to 52 FERC ¶ 61,241 at 61,840 (1990)

hours coal units are most likely to be on the margin and setting price.⁹ Gas units on average are offering at just over their marginal costs as shown in Figure 2. The positive mark-up on average could be attributed to cost-based offers, not including opportunity costs related to run-time restrictions due to hard caps on emissions, starts, or heat input dictated by applicable regulatory rules or restrictions of operating permits.¹⁰ In both cases the overall mark-up bidding behavior of coal and gas units is in a tight band of +/- 0.04, providing strong evidence of marginal cost bidding behavior demonstrating that PJM's Energy Markets are very competitive.

Figure 2: Capacity Weighted Markup Index – Calendar Year 2009



Future Availability of Aging Coal-Fired Generation

In the SOM Report the IMM has determined that 11,250 MW, or 25 percent, of coal coal-fired generation did not receive sufficient revenues from PJM's Energy and Reliability Pricing Model (RPM) Capacity Markets combined to cover their avoidable (going-forward) costs in 2009.¹¹ Many of the generators identified by the IMM analysis are less than 200 MW in size, run less than 3,000 hours, are less efficient, and are likely much older units given these characteristics. The IMM has

⁹ This kind of bidding behavior is not surprising for coal units. They want to ensure they run through off-peak hours because there are opportunity costs for shutting down and starting up again that can be avoided by running a few hours just below cost. See *PJM's Comments Regarding the 2007 State of the Market Report Issued by the PJM Market Monitoring Unit* April 11, 2007 at 11-12.

¹⁰ See *PJM's Comments Regarding the 2007 State of the Market Report Issued by the PJM Market Monitoring Unit* April 11, 2007 at 11-12. Also see Report of PJM Interconnection, L.L.C. pursuant to the FERC May 16, 2008 Order in EL08-47, September 5, 2008 at 24 found at <http://www.pjm.com/Media/documents/ferc/2008-filings/20080905-el08-34.pdf>.

¹¹ 2009 SOM at 134

recommended that "... PJM carefully consider the implications of the potential loss of the relatively small subcritical coal units identified as at risk in the MMU net revenue analysis and whether market design changes are required to address their potential loss."¹²

PJM deeply appreciates the IMM's analysis, and has begun exchanging data with the IMM regarding coal units that may potentially be at risk for retirement to determine how this might affect reliability and market outcomes. Prior to the IMM's analysis, PJM began an examination of coal units that may potentially be at risk given the age, size, and characteristics of environmental controls of many units in the coal fleet. In particular the implications of the recently implemented Clean Air Interstate Rule (CAIR), which has reduced allowable nitrogen oxide (NO_x) and sulfur dioxide (SO₂) emissions, and potential federal climate change policies might be deciding factors in whether these units are driven to retirement. Even with the improved RPM Capacity Market to help cover the going-forward costs for new and existing generating units, there is concern that economic factors highlighted by the IMM, and the costs associated with environmental policy factors being considered by PJM could combine to incent the owners of older, smaller coal-fired generators to retire these units. While the retirement of older, less efficient, generators is expected, it is important that the interaction of the RPM results and the transmission planning process adequately accounts for such retirements in order to ensure regional reliability is maintained as the plants are replaced over time.

Interaction of Energy and RPM Capacity Markets in Covering Avoidable Cost

Avoidable costs do not vary with the output of a generating unit, but must be incurred in order to produce energy. All generators have some kind of avoidable costs, although the level differs by unit, ranging from the costs of investment that implicitly include a rate of return on that investment to fixed operation and maintenance costs to fixed administrative and management costs. Sometimes these avoidable costs are referred to as going-forward costs.

Generators recover some of these avoidable or going-forward costs through participation in the PJM Energy Market through the net revenues they earn from producing energy.¹³ The net revenues from producing energy in any hour in the PJM Energy Market are equal to the LMP in that hour less the running cost of the generating unit. Consequently, lower running cost generating units such as base load nuclear and coal units have larger net revenues from the PJM Energy Market that can go toward covering avoidable or going-forward costs as had been shown by the IMM in its analysis. However, the level of net revenues from the PJM Energy Market for these types of units are affected by the average demand for energy (system loads), the cost of fuel being used by the base load units, and by the costs of other fuels such as natural gas that are used by intermediate and peaking units. To the extent that the demand for power is low on average, as it was in 2009, and the spread between natural gas and coal prices decrease, as they did in 2009, the opportunity for older, smaller, and less efficient coal units to cover their avoidable costs in through net revenues from the PJM Energy Market is diminished.

In addition to the net revenues from the PJM Energy Market, generators also have the opportunity to recover their avoidable costs through the RPM Capacity Market. The RPM Capacity Market is not designed to cover a generating unit's

¹² 2009 SOM at 3

¹³ Generators also can earn net revenues through participation in the Regulation, Synchronized Reserve, and Day-ahead Scheduling Reserve Markets, but these revenues are comparatively small relative to energy market revenues.

avoidable costs in its entirety, but to recover any portion of avoidable costs that are not covered by net revenues from the PJM Energy Market. RPM Capacity prices are determined in auctions in advance of the delivery or calendar years in which generators earn net energy market revenues. However, the RPM Capacity Market does provide a link between net energy market revenues and RPM Capacity prices. For a Base Residual Auction in RPM, offer caps for existing generating units are equal to a generating unit's avoidable cost less its annual average net energy market revenues for the three years preceding the Base Residual Auction. The historic, three-year average of net energy market revenues is used as the expectation of net energy market revenues for the delivery year three years after the Base Residual Auction. Generating units that clear the Base Residual Auction receive an RPM Capacity Price that along with the expected net energy market revenues will cover the avoidable costs in expectation. However, in the case where net energy market revenues are less than expected in a future delivery or calendar year, some generators may be unable to cover their avoidable costs through the combination of revenues from the PJM Energy Market and RPM Capacity Market.

As the IMM alludes in the SOM Report, the potential for retirement of coal units unable to cover their avoidable costs is only a real concern if this were to persist over multiple years, or as new environmental policies become effective and increase potential costs for coal units to continue operating. These conditions would make retirement the rational economic decision for such units.

Impacts of Environmental Policy

Environmental policies such as CAIR, which will reduce the amount of permitted sulfur dioxide (SO₂) and nitrogen oxide (NO_x) emissions across the eastern half of the United States, state environmental mandates such as NO_x reductions on high electricity demand days (HEDDs) and potential federal climate change policy targeting carbon dioxide (CO₂) emissions have the potential to change the economics of the many coal-fired units within the PJM footprint. These types of policies have two distinct effects on the future financial viability of coal-fired generation: 1) The increase in running costs caused by the pricing of emissions through cap-and-trade programs such as CAIR and proposed climate change policy; and 2) The need to make capital investments required to reducing emissions under state mandates, CAIR, or potential climate change policy.

An increase in coal unit running costs related to the need to buy emissions allowances or variable costs of emissions abatement related to fuel switching or operating pollution control equipment, all else equal, has the effect of reducing net energy market revenues for coal units since the difference between LMP and the running cost is reduced and the number of hours a coal unit runs may also be reduced. For any future year, if the realized net energy market revenues are less than the expected net energy market revenues at the time of the Base Residual Auction, then it is possible that combined net energy market and RPM revenues may not cover avoidable costs.

The need to undertake capital investments to reduce emissions will show up in coal unit offers in future RPM Base Residual Auctions through an increase in the avoidable cost and may affect whether or not existing coal units will clear in future Base Residual Auctions. Given the large capital expense for older, smaller coal units to retrofit their units with post combustion emissions controls for SO₂ and NO_x it may be highly likely that these units, when faced with retrofit or retire decision, will find it economically rational to retire if they do not clear in an RPM Base Residual Auction with offers that include pollution control retrofit costs.

Prior to the IMM's analysis in the SOM Report, PJM commenced examining what believed to be coal units at risk of retirement based on the risks faced by many older, smaller coal units without up-to-date post combustion emissions controls for SO₂ or NO_x installed. Examining coal-fired units with capacities of 300 MW or less, more than 40 years old, without limestone based flue gas desulfurization to reduce SO₂ emissions, and without selective catalytic reduction technology for NO_x reductions reveals just over 12,000 MW of capacity potentially at risk for retirement. This represents 90 percent of all capacity more than 40 years old and less than 300 MW. Changing the criteria to include all coal units of any size more than 40 years old, without limestone based flue gas desulfurization to reduce SO₂ emissions, and without selective catalytic reduction technology for NO_x reductions shows approximately 19,000 MW of capacity potentially at risk.

Combining this with the work of the IMM, there is a large overlap in units identified by the IMM as not covering avoidable costs in 2009 and units identified by PJM using age, size, and emissions control criteria, but the units identified are not completely identical. There are units identified by PJM as potentially at risk that are covering their avoidable costs according to the IMM, and conversely there are units in 2009 that did not cover avoidable costs according to the IMM that PJM has not identified as potentially being at risk. Given this information, PJM will continue to work with the IMM to examine more closely what coal units may be potentially at risk for retirement in the near to medium term to ensure that reliability will be maintained at the lowest possible cost.

Reliability Implications, New Entry and Planning

To the extent that there is new entry of capacity resources, regardless of technology, to replace units that retire, there will be little impact on resource adequacy although there will be effects observed in PJM's Energy Markets that depend upon the differences between the new entry resources and the retiring resources. Following the 2012/2013 RPM Base Residual Auction, PJM has calculated a net increase in capacity resources made available to PJM of just over 15,000 MW since the inception of RPM in 2007 which is net of generation capacity reductions. More than two-thirds of the capacity additions are attributable to demand response and energy efficiency resources. Of the generating capacity additions, they are roughly split evenly between new resources and capacity uprates at existing resources. In the short-term (through the 2012/2013 delivery year), there appears to have been sufficient entry of additional capacity to offset potential coal unit retirements.

From a long-term planning perspective, understanding the potential for generation retirements and entry by location will help develop long-term transmission plans that will be more reflective of expected future operating conditions than would otherwise be the case. With future reliability and market outcomes in the balance, PJM will continue to closely work with the IMM to monitor the potential for coal unit retirements to ensure reliability (resource adequacy and transmission reliability) is maintained at the lowest cost and that PJM's Markets result in efficient, competitive outcomes as the resource configuration evolves in the future. To the extent changes to the PJM market design are necessitated by the changing resource mix in the future, PJM will work with stakeholders to develop the necessary mechanisms to ensure reliability goals are met at the lowest cost.

RPM Prices and Energy Market Outcomes Provide Signals for New Entry Where Needed

In the 2009 SOM Report the IMM provides an analysis on the ability of net revenues in a year from the PJM's Markets, primarily from the Energy Market and RPM Capacity Market, to cover the 20-year levelized fixed cost of new entry for

natural gas combustion turbines, natural gas combined cycle plants, and coal plants. The IMM has noted in 2009 no new entry unit of any technology type at any location would have been able to cover its levelized fixed cost in 2009.

However, the ability of net revenues from PJM's markets to cover 20-year levelized fixed costs of new entry generation is something that must be evaluated, not over a single year, but over a number of consecutive years in order to determine whether or not it is in expectation economically rational for new entry to take place and at what location it should take place. With almost three calendar years of experience with the PJM Energy Market operating alongside the RPM Capacity Market, some preliminary conclusions regarding the effectiveness of the RPM Capacity Market to provide additional signals for new entry where it is needed can be drawn.

According to the analysis provided by the IMM, it appears economically rational for natural gas combined cycle units to enter in SWMAAC, which encompasses the BGE and Pepco zones in the Baltimore-Washington area of PJM. While in 2009 alone, revenues would not have been sufficient to cover the 20-year levelized fixed cost, revenues well above the 20-year levelized fixed cost in 2007 and 2008 would have been enough to offset the shortfall.¹⁴ This is important as SWMAAC is the most congestion prone region of PJM so intuitively it would be expected that the combined energy and RPM prices should signal the need for new entry in this region.

Table 1 shows the net market revenues from all PJM Markets for a new entry natural gas combined cycle facility in SWMAAC to range from \$173,000/MW-year to \$183,000/MW-year. Table 2 shows the 20-year levelized fixed costs at two different internal rates of return to be no more than \$173,174/MW-year, which is the levelized fixed cost used by the IMM in its analysis of new entry net revenue sufficiency. Tables 1 and 2 show that the combined RPM Capacity and Energy Markets are providing signals over a sustained period of time that new entry into the PJM Market in the SWMAAC region is needed.

Table 1: Net Revenues from All PJM Markets for New Entry Natural Gas Combined Cycle (\$/MW-year)¹⁵

Year	BGE	Pepco
2007	\$173,198	\$175,698
2008	\$207,969	\$219,105
2009	\$138,066	\$154,109
Average	\$173,078	\$182,971

Table 2: 20-Year Levelized Fixed Cost for New Entry Natural Gas Combined Cycle in 2009¹⁶

Rate of Return	Levelized Fixed Cost
12.0% Internal Rate of Return	\$173,174
10.4% Internal Rate of Return	\$163,174

¹⁴ SOM Report, Figure 3-6, at 165.

¹⁵ SOM Report, Table 3-28 at 170.

¹⁶ SOM Report, Table 3-28 at 170.

The Results of the Regulation Market are Consistent with Competitive Outcomes

Regulation is a reliability service that allows PJM to maintain system frequency and match supply and demand at all times. PJM has operated, and continues to operate the Regulation Market within the FERC-approved rules set forth in the PJM Tariff and Operating Agreement. While the Regulation Market provides a service essential to maintain reliability, Regulation as a percentage of the total cost of wholesale power amounted to only 0.6% or \$0.34/MWh in 2009.¹⁷

In the 2009 SOM Report, the IMM notes that the behavior of market participants in the Regulation Market was competitive, but concludes the Regulation Market results were not competitive due to the market rule changes, particularly in the calculation of opportunity cost that leads to prices greater than the competitive cost.¹⁸ PJM agrees with the IMM regarding the competitive behavior of market participants. However, PJM does not agree that the results Regulation Market were not competitive as will be outlined below. Moreover, PJM analysis of the Regulation Market rule changes regarding opportunity costs indicates errors in the IMM's analysis resulting in an over-estimation of the "additional cost" to customers.

Determination of Competitive Markets Results Must Use FERC-Approved Definition of Costs

The economic benchmark for determining whether market results are competitive is measuring price versus the marginal cost of providing a service in any market. The IMM's conclusion that the Regulation Market results were not competitive rests upon the IMM's disagreement with the FERC-approved definition of opportunity costs to be used in the calculation of market-clearing prices in the Regulation Market.¹⁹ This stands in sharp contrast to the conclusions reached by the IMM that the Regulation Market results were competitive under the same definition of opportunity costs in its previous two Quarterly State of the Market Reports from the second and third quarter of 2009 under the same rules and definition of opportunity costs.²⁰

The IMM has not made any assertions or presented any evidence that the FERC-approved definition of opportunity cost for the Regulation Market has created any incentive to not reveal a resource's cost of providing Regulation, and has noted, "The Regulation Market results are a result of the market design changes and are not a result of the behavior of market participants...".²¹ Finally, PJM has followed its FERC-approved Tariff in applying opportunity costs, and the IMM has confirmed PJM is following the FERC-approved Tariff in stating, "...PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules."²² Consequently, given market participant behavior is competitive, and PJM has followed the FERC-approved definition of opportunity cost, it must be the case that the results of the Regulation Market are equal to the defined, FERC-approved marginal cost of providing Regulation so that the results of the Regulation Market cannot be anything but competitive.

¹⁷ SOM Report at 11.

¹⁸ 2009 SOM Report at 2, see footnote 4.

¹⁹ SOM Report at 2, footnote 4. See also SOM Report at 360-361.

²⁰ Refer to http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009q2-som-pjm.pdf at 2, and http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009q3-som-pjm.pdf at 2.

²¹ SOM Report at 361

²² *Id.*

Structural and Behavioral Competitiveness of the Regulation Market is Improved Since the Rule Changes were Implemented

The amount of available supply, the overall supply-demand balance, and by extension the structural competitiveness of the Regulation Market has markedly improved since the FERC-approved rules changes were implemented on December 1, 2008. Key statistics provided by the IMM in the SOM Report bear witness to the enhanced structural competitiveness:

- The Regulation supply eligible in each hour increased by 354 MW or 16.2 percent in 2009 compared to 2008;²³
- The percentage of Regulation capable units offering into the Regulation Market increased from 68 percent in 2008 to 81 percent in 2009;²⁴
- The ratio of supply to demand improved 20 percent from 2.39 in 2008 to 2.98 in 2009;²⁵
- The percentage of hours in which at least one supplier failed the Three Pivotal Supplier Test declined from 83 percent of hours in 2008 to 52 percent of hours in 2009.²⁶

The behavior of market participants in the Regulation Market has become even more competitive from 2008 to 2009 in light of the load-weighted average marginal offers (prior to the application of opportunity costs). Under the FERC-approved market rule changes, cost-based offers into the Regulation Market can include an adder to account for uncertainties in the measurement of costs of up to \$12.00/MWh, which is an increase over the \$7.50/MWh adder allowed previously. However, the load-weighted average marginal offer decreased 26 percent from \$11.94/MWh in 2008 to \$8.79/MWh in 2009 in spite of the increase in the allowed adder for cost-based offers providing a very strong signal regarding the competitiveness of behavior.²⁷ An estimate of the impact on costs to customers would indicate the reduction in load-weighted average marginal offers alone results in approximately \$23.4 million in savings during 2009.²⁸ Overall, Regulation Market prices (inclusive of opportunity costs) fell 44 percent in 2009.²⁹

The IMM's Assertion of Increased Costs Due to Market Rules Changes are Over-estimated by an Order of Magnitude

The IMM states that the changes related to the calculation of opportunity costs resulted in increased payments of \$45.9 million or 20 percent in calendar year 2009.³⁰ PJM's analysis indicates the IMM calculations contain substantial errors and shows that this amount is overstated. A more detailed examination of the impacts shows the increase to be approximately \$5.3 million dollars or two percent for 2009. Additionally, PJM believes its own figure is likely still an over-estimation of the actual impact of the opportunity cost changes as discussed below.

²³ SOM Report, Table 6-2 at 364 and 2008 SOM Report, Table 6-2 at 308.

²⁴ *Id.*

²⁵ SOM Report, Table 6-1 at 363 and 2008 SOM Report, Table 6-1 at 307.

²⁶ SOM Report at 366 and 2008 SOM Report at 310.

²⁷ SOM Report at 369.

²⁸ This estimate is derived by multiplying the difference in load-weighted average marginal offers (\$11.94/MWh - \$8.79/MWh = \$3.15/MWh) by the hourly average MW of regulation required in each hour from Table 6-1 (849 MW) multiplied by 8760 hours.

²⁹ SOM Report at 355.

³⁰ 2009 SOM, Table 6-13 at 379

The discussion below develops the analysis first by explaining how settlements work in the Regulation Market followed by a discussion regarding the calculation of opportunity costs in the Regulation Market. The analysis further explains how the change in opportunity cost rules affected the opportunity cost calculation and subsequently on the Regulation Market Clearing Price (RMCP) and opportunity costs paid out of market. Finally, the results of the PJM analysis are presented decomposing the two ways in which the opportunity cost change can affect costs in the Regulation Market.

Regulation Settlement

There are two potential components to the compensation received by resources committed to provide Regulation in PJM, the Regulation Market Clearing Price (RMCP) and after-the-fact opportunity cost credits (OCC). Every resource that provides regulation during an hour, whether they are self-scheduled or committed by PJM, is paid the product of the hourly RMCP and the hourly integrated MWs of regulation they provided. This value, the RMCP Credits, makes up over 70 percent of annual regulation billing in 2009.³¹

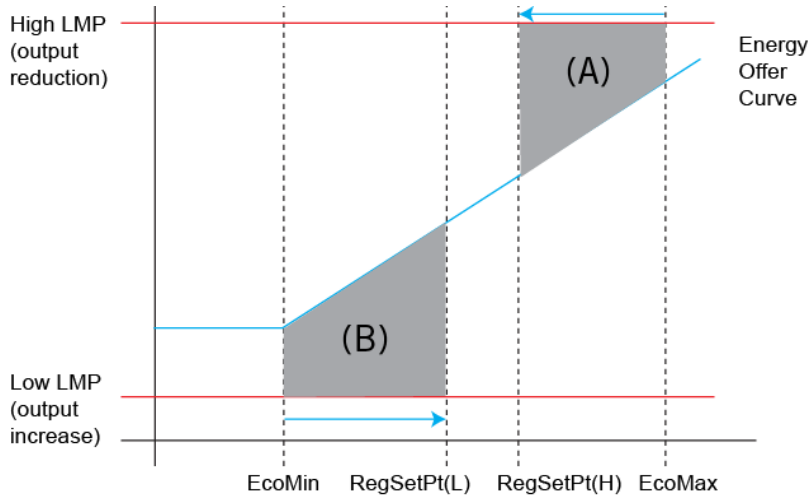
Under many circumstances the RMCP credits received by regulation resources in PJM do not completely cover their total cost of providing the regulation service. This most commonly occurs when the anticipated system conditions used to clear the hour-ahead Regulation Market differ from those that occur in real-time. If a resource that is committed for regulation by PJM does not recover its cost to provide the service, it will receive an OCC payment. This unit specific payment is calculated as the difference between the cost to provide the service, defined as the sum of the offer and actual opportunity costs calculated using real-time LMPs, and the RMCP Credits.

Calculating Opportunity Costs in the Regulation Market

Opportunity cost in the Regulation Market is calculated when a resource must operate uneconomically with respect to its energy dispatch point to comply with its regulation commitment. In general it is calculated as the integrated area between the LMP and the energy offer curve for the amount of MWs the resource had to deviate from its economic dispatch set point for energy. The opportunity costs for an example resource are shaded in grey and labeled (A) and (B) in the Figure 3 below. For the shaded region labeled (A), the LMP dictates that the resource should operate at full output for energy, however, the resource's output must be reduced to Regulation Set Point (RegSetPt)(H) so that it may provide regulation. In this example, the opportunity cost shown in shaded area (A) takes the form of foregone revenue in the energy market due to the regulation assignment. The shaded region labeled (B) illustrates the converse case; the low LMP indicates that the resource should operate for energy at its minimum but it must operate at RegSetPt(L) to provide regulation. The opportunity costs shown by shaded area (B) take the form of increased operating costs.

³¹ SOM Report at 372-373.

Figure 3: Opportunity Costs in the Regulation Market

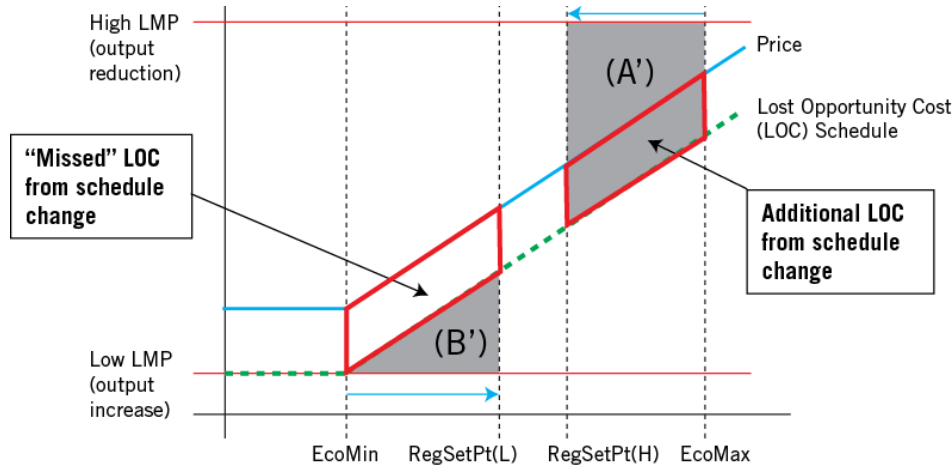


The change in the opportunity cost calculation rule highlighted by the IMM allows opportunity cost to be computed from the lower of the cost-based energy schedule, or market-based energy schedule. For example, if a unit providing regulation has been committed for energy on its market-based schedule and its cost-based schedule is lower, opportunity costs in the Regulation Market are computed based on the lower cost-based schedule. However, if a unit is committed on its market-based schedule for energy, and it is lower than its cost-based energy schedule, then there is no change in schedules to compute opportunity costs.

It is important to understand that the change in the energy schedule for the purpose of calculating regulation opportunity costs does not always result in higher opportunity costs and consequently higher regulation prices, nor does it impact all regulation resources. For example, a resource that is self-scheduled for regulation is not eligible to receive opportunity cost credits and therefore is not impacted by this change. In addition, opportunity cost for hydro resources that have a \$0/MWh energy offer are calculated through an entirely different mechanism and are therefore similarly not impacted by this change.

For units where the rule change does impact the calculation of opportunity cost, the change can result in either higher or lower opportunity costs depending on system conditions. Figure 4 below shows how the change functions under different operating conditions. Regions (A') and (B') are shaded to show the calculated opportunity costs of reducing or increasing a resource's output to provide regulation, respectively.

Figure 4: Illustration of opportunity cost changes



As stated previously, the implementation of the opportunity cost calculation rule highlighted by the IMM does not always result in increased opportunity costs when compared to the previous rule. The result can be higher or lower depending on the scenario. When a resource has its schedule changed and it is being reduced to provide regulation, it will incur a higher opportunity cost (A'). However, if the resource is being raised from its minimum output to provide regulation, it actually incurs a smaller opportunity cost (B'). This off-setting interaction is crucial to analyzing the impacts of this change. It means that **the only time this change increased regulation market costs is when resources had their schedules changed for the opportunity cost calculation and were committed and reduced from their otherwise economic energy set point to provide regulation and either set the RMCP or were made whole via OCC calculated based on the lower cost energy schedule.** Detailed calculations for each are described in the following sections.

Impacts on the Regulation Market Clearing Price

The change in the energy schedule used to calculate regulation opportunity costs can impact the Regulation Market in two ways:

1. It can impact the RMCP if the resource setting the price has had its energy schedule changed for the purpose of calculating opportunity costs.
2. It can impact the OCC paid to resources if the cost to provide regulation is calculated using a different schedule than that which the resource was following for economic dispatch

As described above, the only time the opportunity cost schedule change would have increased the RMCP causing increased payments by load customers is when the resource setting it incurred a schedule switch and it was being reduced to provide regulation. This occurred in 567 hours, or less than 6% of the time, during the 13 month period from December 1, 2008 through December 31, 2009. To quantify the impacts of this PJM made a conservative estimate as to what the RMCP would have been absent this change and then multiplied the difference between the actual and estimated RMCPs by the amount of regulation MWs in each corresponding hour that did not receive any OCC payment. The reason units that received an OCC payment were excluded from this calculation is because they were compensated at a total value that exceeded the RMCP credit and therefore their compensation would not have changed as a result of the reduction in RMCP.

For each of the 567 hours PJM performed the calculation below,

$$RMCP \text{ Exposure} = (\text{Original RMCP} - \text{Hypothetical RMCP}) * \text{Total Hourly MWs Not Receiving OCC}$$

To estimate what the RMCP would have been absent the opportunity cost change, PJM assumed that the clearing price would have been set by the highest priced regulation resource that was committed and did not have its schedule changed. So if the RMCP was originally set by a resource whose schedule was switched and whose offer plus opportunity cost was \$50/MWh and the most expensive infra-marginal resource who did not have a schedule switch had an offer plus opportunity cost of \$45/MWh, PJM would assume that \$45/MWh would have been the RMCP for the purpose of this analysis. This is a relatively conservative estimate because if the originally committed \$50/MWh resource were not committed the MWs of regulation it was providing would have been assigned elsewhere at a price above \$45/MWh to clear the market. Selecting the \$45/MWh resource as the hypothetical marginal resource absent the opportunity cost change overstates the impact of the change itself but provides a reasonable estimate.

The difference between the RMCPs is then multiplied by the total number of regulation MWs that did not receive an after-the-fact OCC payment. The reason this subset of regulation MWs is used as opposed to the total number of MWs is because if the resource was made-whole after-the-fact the cost paid by consumers for this resource to regulate is not impacted by a potentially higher clearing price. The higher clearing price would shift credits paid to the resource from OCC to RMCP Credits but it would not impact the total compensation to the resource and would therefore not impact total payments by load for regulation. The only increase in costs through the higher RMCP as a result of the opportunity cost change is those credits paid to resources that were not made-whole after-the-fact. Table 3 provides a monthly summary for these calculations.

Table 3: Monthly Summary of RMCP Exposure

2009 Month	Total Regulation MWs	MWs Not Receiving OCC in 567 Hours	Average RMCP Difference During the 567 Hours	RMCP Exposure
Jan	719,972	23,450	\$3.56	\$102,572
Feb	606,112	42,963	\$14.04	\$917,237
Mar	609,426	52,583	\$2.80	\$186,216
Apr	547,446	7,950	\$2.20	\$21,637
May	547,941	6,161	\$3.82	\$29,241
Jun	633,938	27,058	\$5.79	\$192,656
July	673,708	9,366	\$3.06	\$30,391
Aug	739,915	30,102	\$2.95	\$101,182
Sep	574,820	11,684	\$4.24	\$57,881
Oct	550,255	3,300	\$6.14	\$30,087
Nov	557,139	8,350	\$6.20	\$54,414
Dec	679,575	76,637	\$4.81	\$402,171
2009 Total	7,440,247	299,606	\$4.97	\$2,125,686

As stated, the previous table only estimates the increase in RMCP Credits as a result of the opportunity cost change. However, because the change actually decreases regulation opportunity costs when resources are raised from their minimum provide regulation **there is no doubt an off-setting reduction in RMCP Credits during some hours where the RMCP was set lower than it otherwise would have been.** Quantifying this is more complicated as it would require a hypothetical re-clearing of the market as opposed to an ex-post analysis but would likely result in a cost savings on the same order of magnitude as the increase.

Impacts on the Opportunity Cost Credits

Because the previous calculation only quantifies the impact on increased payments through the RMCP as a result of the opportunity cost change, a separate calculation must be done to determine the impact on OCC payments made to generators whose schedule was switched and therefore received a higher after-the-fact OCC payment than they would have under the old rule. To quantify this effect, PJM calculated the total OCC payments made to regulating resources whose opportunity cost schedule was switched. As in the market clearing, the only scenario that results increased costs due to the opportunity cost change is when a resource was reduced to provide regulation and received an OCC payment. Table 4 summarizes the regulation OCC payments for 2009.

Table 4: Monthly Summary of Regulation OCC Payments for 2009

2009 Month	Total Regulation OCC to all Resources	Regulation OCC to Reduced, Schedule Switched Resources
Jan	\$10,276,038	\$1,291,966
Feb	\$5,028,318	\$316,972
Mar	\$5,282,308	\$428,334
Apr	\$2,538,214	\$141,023
May	\$2,717,932	\$59,754
Jun	\$2,164,185	\$238,560
July	\$1,923,834	\$129,410
Aug	\$3,412,195	\$146,448
Sep	\$2,365,179	\$79,760
Oct	\$2,589,323	\$180,920
Nov	\$2,123,861	\$35,854
Dec	\$6,851,279	\$127,873
2009 Total	\$47,272,666	\$3,176,874

As a percentage, the OCC payments made to resources whose schedule was switched and were reduced for regulation represent about 6.7% of the total after-market payments. There are two reasons why the actual impact of the rule change on OCC payments was in all likelihood less than this value. First, any regulation OCC payments that would have been made to the resources absent the schedule switch are included in the \$3.176 million total. That is, if the calculation of OCC payment would have been non-zero under the old rules PJM did not subtract that non-zero value from the total.

Secondly, similar to the previous RMCP Exposure calculation, there is an off-setting impact of the opportunity cost change when applying it to OCC as well. Any resource that was raised to provide regulation and had a schedule switch for the purpose of determining opportunity costs would have received a lower OCC payment than it otherwise would have absent the change. Determining the cost savings is again more complex than determining the additional costs but is likely on the same order of magnitude.

Total Impacts and Conclusion

Combining the two components of the calculation yields a maximum of \$5.3 million in increased regulation charges in 2009 as a result of the opportunity cost changes implemented in December, 2008. This value represents an upper bound of the possible impact as it is calculated given the following caveats:

- The estimate of the RMCP difference used to calculate RMCP Exposure likely overstates the difference between the actual and hypothetical RMCPs as it does not consider the cost of replacing the regulation MWs provided by the original marginal resource whose schedule was switched.
- The estimate of the RMCP Exposure does not consider any hours where the RMCP was set lower than it otherwise would have been because the marginal resource was raised from its minimum to provide regulation and had a lower opportunity cost as a result of the schedule switch.

- The estimate of the increased OCC payments is the sum of all OCC payments to resources who were reduced to provide regulation and whose schedule was switched. This assumes that these resources included would not have received make whole payment absent the opportunity cost change. This is likely not the case. Affected resources likely received an incrementally higher OCC payment as a result of these changes which means that the \$3.2 million dollars by definition overstates the true impacts.
- The estimate of the increased OCC payments not consider any hours where the OCC payments were lower than they otherwise would have been because resources whose output was increased to provide regulation were paid less because of the opportunity cost change.

PJM's analysis shows that the financial impact calculated by the IMM is overstated by an order of magnitude. A more detailed examination of the impacts shows the maximum possible increase to be approximately \$5.3 million dollars or 2 percent, and the actual impact is likely to be significantly lower. As a result, PJM disagrees with the IMM's conclusions regarding the potential magnitude of cost increases in the Regulation Market as a result of the rule changes. The package of rule changes when viewed in their entirety, including the incentives created to increase regulation supply offers likely reduced costs of regulation to consumers rather than increased it.

Appendix: PJM Response to the 2009 State of the Market Report Recommendations

The Independent Market Monitor (IMM) makes a number of recommendations in the 2009 State of the Market Report. PJM generally either supports the recommendations or supports the recommendation with some modifications.

Recommendations for new action:

1. **IMM Recommendation** — The IMM recommends that the option to specify a minimum dispatch price under the Demand Side Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.

PJM Response — PJM believes that demand response resources should have the opportunity to express their economic dispatch desires in a manner similar to that available to other resources such as generation resources, and does not believe that the elimination of this option is appropriate at this time.

2. **IMM Recommendation** — The IMM recommends that the Demand Side Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. There is no economic reason to compensate load reductions up to \$1,000/MWh during an emergency event regardless of the hourly LMP.

PJM Response — This program has historically generated very little interest among participants. PJM is not opposed to the removal of this option in principal and invites the IMM to bring a proposal to the PJM stakeholders.

3. **IMM Recommendation** — The IMM recommends that PJM carefully consider the implications of the potential loss of the relatively small subcritical coal units identified as at risk in the IMM net revenue analysis and whether market design changes are required to address that potential loss.

PJM Response — PJM has carefully monitored the characteristics and economic incentives of the generation fleet. In particular PJM has monitored the coal generation fleet as many of these generators are approaching or past their expected operational lifetime. The disincentives facing these generators include economic factors (which market incentives could address) as well as regulatory uncertainties such as environmental limits, which are not as easily addressed by the market construct. PJM appreciates the IMM providing increased awareness of this issue and will continue to monitor the incentives of the entire generation fleet and continue to find methods of providing appropriate incentives to maintain grid reliability.

4. **IMM Recommendation** — The IMM recommends that any proposal to modify scarcity pricing include the following essential components: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; a maximum price of \$1,000 per MWh; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective offset mechanism for RPM revenues; maintaining local market power mitigation mechanisms; and an

explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur

PJM Response — PJM agrees with some of the IMM's recommendations and disagrees with others. However at this time, the development of an appropriate shortage pricing mechanism is underway in the stakeholder process. PJM remains committed to the stakeholder process, and encourages the IMM to continue to bring these types of recommendations through the stakeholder process for consideration by all stakeholders.

5. **IMM Recommendation** — The IMM recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

PJM Response — PJM agrees with this recommendation and notes that it is generally consistent with the changes implemented in December, 2008 to operating reserve charges.

6. **IMM Recommendation** — The IMM recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

PJM Response — PJM supports this recommendation and invites the IMM to bring a detailed proposal to the PJM stakeholders.

7. **IMM Recommendation** — The IMM recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make the data necessary for loop flow analysis available to the RTOs and market monitors to make a full market analysis possible. PJM continues to face significant loop flows for reasons that continue not to be fully understood because PJM, other balancing authority operators and market monitors have inadequate access to the data required for a complete analysis of loop flow in the Eastern Interconnection.

PJM Response — PJM agrees with the IMM that additional information is required on an hourly basis to provide greater transparency with respect to the sources of flows on the power grid. PJM is committed to working with other ISOs /RTOs and neighboring control areas to seek sharing of real-time transaction tag information and hourly flow information regarding power flows on key flowgates that result from hourly generation dispatch to meet control area. Currently, such hourly flow information is not available on an interregional basis.

8. **IMM Recommendation** The IMM recommends that the obligation of capacity resources to offer energy in the Day- Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price.

PJM Response — PJM does not believe it is appropriate to require all capacity resources to offer at marginal cost. PJM does not believe it is feasible to determine the marginal cost of a demand resource. For generation

resources, marginal costs can be difficult to fully quantify, and while a method is in place at this time, it is only used during mitigation and therefore requires less accuracy than would be needed if all resources were required to bid at marginal cost at all times. The IMM offers no evidence or analysis to support this recommendation. Instead, it has stated that the Energy Market results are competitive, and that markups have been consistently negative in 2009, and this is confirmed by PJM's own analysis. Lastly, PJM does not believe it is either within the authority of PJM nor the IMM to grant or remove market-based rate authority from market participants.

9. **IMM Recommendation** — The IMM recommends that the rules making capacity auctions mandatory for both load and generation be clarified.

PJM Response — PJM supports this recommendation and invites the IMM to bring a proposal to the PJM stakeholders to be incorporated with other proposals being discussed regarding price responsive demand.

10. **IMM Recommendations** — The IMM recommends that the must offer requirement for capacity should also apply generally to out of market transactions.

PJM Response — PJM generally supports the must offer requirement. However PJM does not understand the specific recommendation and will request clarification from the IMM.

11. **IMM Recommendation** — The IMM recommends that PJM take the required steps to ensure that capacity prices reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETO/CETL analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. PJM should perform a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions, units that do not cover avoidable costs, and units that face significant investment requirements due, for example, to environmental requirements.

PJM Response — PJM generally agrees that capacity prices should be an appropriate reflection of local supply and demand conditions. Discussion about these topics is currently underway in the stakeholder process exploring to what locational level capacity prices should be modeled.

12. **IMM Recommendation** — The IMM recommends that the recently implemented modification to the definition of opportunity cost in the Regulation Market be reversed and that the correct definition of opportunity cost be reinstated. The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years.

PJM Response — PJM believes that the outcomes of the Regulation Market were competitive in 2009. PJM believes the IMM contains substantial errors and therefore overstates the impact of these changes and that the actual impact is nominal. The IMM is encouraged to bring this proposal to the stakeholder process if it believes a market rule change is required.

13. **IMM Recommendation** — The IMM recommends that the recently implemented modification to the treatment of net revenues from the Regulation Market be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

PJM Response — PJM believes that the outcomes of the Regulation Market were competitive in 2009. PJM believes the IMM analysis is in error and overstates the impact of these changes and that the actual impact is nominal. The IMM is encouraged to bring this proposal to the stakeholder process if it believes a market rule change is required.

Detailed recommendations:

1. **IMM Recommendation** — Load Management (LM) test results are submitted by Curtailment Service Providers (CSPs) directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification. This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The IMM recommends that the testing program be modified to require verification of test methods and results.

PJM Response — PJM is committed to robust measurement and verification practices and has established the Load Management Task Force specifically to look into issues of this type. PJM encourages the IMM to bring specific proposals for improvement to that stakeholder group. PJM notes that the results provided by CSPs are subject to audit under current practices. PJM also notes that the submittal and verification process is not dissimilar to the test results and practices used for generation resources.

2. **IMM Recommendation** — The IMM recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a Customer Baseline (CBL) review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the IMM to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

PJM Response — PJM is committed to robust measurement and verification practices and encourages the IMM to bring specific proposals for improvement to the appropriate stakeholder group.

3. **IMM Recommendation** — While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, the IMM recommends that LSE/EDCs should be able to initiate PJM settlement reviews.

PJM Response — Currently, if an LSE/EDC questions the validity of a settlement, PJM will investigate accordingly. PJM plans to continue this practice in the future.

4. **IMM Recommendation** — The IMM recommends that regression analysis capturing the effect of ambient temperature be incorporated in any GLD testing that estimates unrestricted load consumption based on a comparable day or a comparable set of days.

PJM Response — PJM is committed to robust measurement and verification practices and has established the Load Management Task Force specifically to look into issues of this type. PJM encourages the IMM to bring specific proposals for improvement to that stakeholder group.

5. **IMM Recommendation** — While the introduction of Load Management testing for any delivery year without an emergency event is an improvement to the Program, the current state of testing does not constitute an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The IMM recommends that the testing program be modified to require verification of test methods and results. In addition, the IMM recommends that when used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include statistical analysis that captures the effect of ambient conditions.

PJM Response — PJM is committed to robust measurement and verification practices and has established the Load Management Task Force specifically to look into issues of this type. PJM encourages the IMM to bring specific proposals for improvement to that stakeholder group.

6. **IMM Recommendation** — The IMM recommends two ways to further improve the Economic Program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen. The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation.

PJM Response — PJM is committed to insuring that payments are only made for appropriate reasons within the Demand Response programs, but this must be done in a responsible manner and in a way that provides material benefits consistent with the corresponding costs of doing reviews. The FERC has recently accepted PJM's review process as detailed in PJM's Order 719 compliance filings and the FERC has found the current PJM process for reviews to be prudent and appropriate. PJM encourages the IMM to monitor the payments made and investigate any market participants it feels are requesting payments inappropriately, and report their findings to the appropriate authorities.

7. **IMM Recommendation** — The IMM recommends that a change in the interface pricing methodology be addressed directly by the Broader Regional Markets group. The IMM recommends that the parties consider the uniform adoption of a generation control area (GCA) to load control area (LCA) pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

PJM Response — PJM is generally committed to market-based congestion management protocols and is working diligently with surrounding RTOs/ISOs to address this issue.

8. **IMM Recommendation** — The IMM recommends that PJM monitor, and adjust as necessary, the buses and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

PJM Response — PJM does monitor and adjust the buses and weightings applied to the interfaces. PJM has not seen a need or benefit to making more frequent adjustments than those already undertaken, but welcomes any data or analysis the IMM wishes to provide supporting such a need or benefit.

9. **IMM Recommendation** — The IMM supports congestion management agreements but recommends that such agreements be implemented on a regional basis rather than between RTOs and individual external utility companies. In addition, there are a number of issues in the PJM/PEC agreement that need to be addressed. Most fundamentally, any congestion management agreement must ensure that the interface price established reflects the economic fundamentals of an LMP market.

PJM Response — PJM is aware that the proposed JOA and congestion management process will require refinement as experience dictates and have committed to working together to continually identify areas that require improvement or could benefit from further enhancement. To this end, PJM's experience with the dynamic schedule approach will be continuously evaluated to ensure that it continues to represent a reasonable, and practical, approach to address congestion management which meets the particular operational characteristics of PJM and neighboring entities. It has already been recognized by the IMM that it represents a just and reasonable methodology to address congestion on the PJM and neighboring systems.

10. **IMM Recommendation** — The IMM recommends modifying the evaluation criteria for not willing to pay congestion transactions via a change to PJM's market software, to ensure that a not willing to pay congestion transactions is not permitted to flow in the presence of congestion.

PJM Response — PJM is currently implementing a change to the Enhanced Energy Scheduling (EES) application to accomplish this. PJM invites the IMM to report any suspected abuse of this practice to the appropriate authorities.

11. **IMM Recommendation** — The IMM recommends that the EES application be modified further to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.

PJM Response — Current business rules require that transactions be scheduled for a constant MW level over the entire 45 minutes. PJM is currently in the process of implementing software changes to EES to enforce this business rule.

12. **IMM Recommendation** — Generating units that do not respond to RTO dispatch signals may contribute to the need for PJM and the Midwest ISO to implement market to market re-dispatch and result in payments under the

JOA. The IMM recommends that the JOA be modified so as to eliminate payments between RTOs in the event that payments result from the failure of generating units to respond to appropriate pricing signals.

PJM Response — PJM agrees generally with the IMM on this issue, but notes that there are many complex issues that must be discussed and evaluated. PJM is actively pursuing this issue with the Midwest ISO.

13. **IMM Recommendation** — At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. The IMM recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

PJM Response — PJM notes that the interface pricing agreements are based on the underlying physical transmission system and actual flows of power and disagrees that these prices do not reflect appropriate fundamentals.

14. **IMM Recommendation** — The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

PJM Response — PJM does not believe it is appropriate to require all capacity resources to offer at marginal cost. PJM does not believe it is feasible to determine the marginal cost of a demand resource. For generators, marginal costs can be difficult to fully quantify, and while a method is in place at this time, it is only used during mitigation and therefore requires less accuracy than would be needed if all resources were required to bid at marginal cost at all times. The IMM offers no evidence or analysis to support this recommendation. Instead, it has stated that the Energy Market results are competitive, and that markups have been consistently negative in 2009, and this is confirmed by PJM's own analysis. Lastly, PJM does not believe it is either within the authority of PJM nor the IMM to grant or remove market-based rate authority from market participants.

15. **IMM Recommendation** — The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. PJM does not have clear protocols for recalling the energy output of capacity resources and has not recalled such energy since 1999, despite the fact that PJM has experienced emergency conditions since that time.

PJM Response — PJM has maintained a consistent practice of recalling the energy of capacity resources when it would be beneficial to system reliability to do so under emergency conditions. PJM is committed to continuous improvement in documenting and implementing procedures to maintain system reliability and PJM staff has initiated a review of the external transaction recall procedures to ensure that they are adequate for reliability and to meet the rules and intent of PJM's RPM Capacity Market.

16. **IMM Recommendation** — The IMM recommends that PJM review all requests for outside management control (OMC) outages carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines.

PJM Response — PJM supports improvements in OMC outage definition, and invites the IMM to bring any specific proposals it has regarding improvements in this area to the PJM stakeholder process.

17. **IMM Recommendation** — The IMM recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

PJM Response — PJM is committed to the provision of key reliability services at the appropriate pricing levels and we believe the current mechanism is working as intended. As noted by the IMM, this issue reaches broadly across a number of regulatory and stakeholder bodies and PJM notes that changes in this area may be challenging as a result.

18. **IMM Recommendation** — The IMM recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test (TPST). The IMM concludes that the DASR Market results were competitive in 2009.

PJM Response — PJM supports the use of the TPST and marginal cost offer capping in the DASR Market with appropriate adjustments to fit the DASR Market context. PJM suggests the IMM bring this issue through the appropriate stakeholder process.

19. **IMM Recommendation** — The IMM recommends that a full list of potential reasons for unit de-selection be published in PJM's M-11 Scheduling Operations Manual. The IMM recommends that dispatchers classify the reasons for unit de-selection and document all unit de-selections.

PJM Response — PJM is supportive of improvements to logging and is evaluating improvements the logging functions in concert with other related software improvements.

20. **IMM Recommendation** — The IMM recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARR's do. This would include both FTRs that are directly self scheduled and FTRs on paths identical to the ARR, which are financially equivalent to self scheduled FTRs. ARR's are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. The underlying FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARR's when load switches.

PJM Response — The ARR functions as the allocated right, and should therefore move in conjunction with load switches. The use of FTRs however is a business decision left to the market participant and it is therefore inappropriate for this to be reallocated along with load switches. To do so would create discriminatory treatment between FTRs that were self scheduled versus those that were just executed at a high clearing price.

21. **IMM Recommendation** — The IMM supports PJM's actions to reduce unsecured credit including the elimination of unsecured credit in PJM's FTR markets. The IMM continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the IMM's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

PJM Response — PJM believes that credit policies must strike a prudent balance between risks and high transaction costs and barriers to entry. The nature of the FTR markets, with their long forward commitments and the potential for changes both in the transmission system and to market participants in the market, represented a strong candidate for the elimination of unsecured credit. With the introduction of weekly settlements for shorter-term products, PJM feels that there can still be a place for unsecured credit, reducing barriers to entry and keeping transaction costs low, while still providing mitigation for the risks associated with it.

Recommendations for continued action:

PJM supports and agrees with the IMM regarding the recommendations for continued action. PJM appreciates the confirmation of these continuing actions by the IMM in order to ensure competitive market results.

22. **IMM Recommendation** — Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required.

PJM Response — PJM remains committed to retaining robust local market power mitigation rules and procedures.

23. **IMM Recommendation** — Retention, application and improvement of the RPM rules included in PJM's Tariff to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to limit market power by the application of clear and explicit market power mitigation rules.

PJM Response — PJM remains committed to retaining robust market power mitigation procedures in the capacity market. PJM agrees with the IMM that the RPM design include incentives for performance when needed. The RPM Capacity Market explicitly allows competitive prices to reflect local scarcity without relying on the exercise of market power to achieve the objectives of the Capacity Market design and explicitly limits the exercise of market power.

24. **IMM Recommendation** — Retention of the \$1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power.

PJM Response — PJM remains committed to retaining rules that limit incentives to exercise market power including the overall existing energy market offer cap for capacity resources.

25. **IMM Recommendation** — Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism.

PJM Response — PJM is committed to market power mitigation in the Regulation Market to provide assurances of competitive outcomes.

26. **IMM Recommendation** — Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants that were implemented on December 1, 2008.

PJM Response — PJM believes the changes that were implemented to the allocation of balancing operating reserve charges have been performing as intended and plans to retain them.

27. **IMM Recommendation** — Implementation of rules governing the definition of final prices to ensure certainty for market participants.

PJM Response — In response to the IMM's recommendation in the 2008 SOM Report, PJM initiated a stakeholder discussion to form business rules to govern the reposting of prices. PJM expects to receive stakeholder approval and file the required tariff modifications with the FERC by the time this report is issued.

28. **IMM Recommendation** — Modification of rules governing demand-side programs to ensure appropriate levels of payment and to ensure appropriate measurement and verification of demand-side response.

PJM Response — PJM implemented a new CBL methodology on June 13, 2008 to make more the CBL, upon which reductions are measured, more representative of more recent levels of consumption absent demand reductions. Additionally PJM has implemented a Normal Operations Review of demand response settlements to ensure that all settled demand response are a result of actions taken in response to price and not business as usual under an inaccurate CBL. PJM has also been working within the stakeholder process to develop compensation for demand response that helps overcome possible barriers to entry that may remain for demand response.

29. **IMM Recommendation** — Continued improvement of pricing between PJM and surrounding areas, both market and non market.

PJM Response — PJM is committed to working with other ISOs and RTOs and with neighboring control areas to improve interregional congestion management and to explore ways to implement real-time congestion management agreements.