PJM’s Response to the 2011 State of the Market Report

5.11.2012
PJM Interconnection
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Introduction

The 2011 State of the Market Report issued by PJM’s Independent Market Monitor (IMM) provides an assessment of market performance and recommendations aimed at enhancing PJM’s market design or market performance. The market monitor performs a critical role in providing an independent assessment of market performance and provides valuable insights in its conclusions and recommendations. In the 2011 State of the Market Report, the IMM concludes that the Energy, Capacity, Synchronized Reserve, Day-Ahead Scheduling Reserve and FTR markets were competitive. PJM believes the observed market results support these conclusions.

In the 2011 SoM Report, the data, information, analysis, and recommendations are organized by market type (Energy, Capacity, Ancillary Services and FTRs) and by specific topic area that touches on PJM’s markets (Operating Reserves, Demand Response, Generator Net Revenue, Environmental and Renewable Energy Regulation, Interchange Transactions, Congestion and Marginal Losses, and FTR Markets). PJM notes the IMM does not assign any priority or materiality metric to the various recommendations. PJM believes consideration of materiality and priority would be a helpful enhancement to recommendations provided in future State of the Market Reports.

PJM considers a useful way to view the recommendations provided by the IMM in the 2011 State of the Market Report is in comparison to the impact on PJM Wholesale Market Cost as shown in Figure 1.

**Figure 1: Components of PJM Total Wholesale Power Cost in 2011**

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>$45.94</td>
</tr>
<tr>
<td>Black Start</td>
<td>$0.02</td>
</tr>
<tr>
<td>Trans. Owners Control</td>
<td>$0.09</td>
</tr>
<tr>
<td>Synchronized Reserve</td>
<td>$0.09</td>
</tr>
<tr>
<td>Reliability (Capacity)</td>
<td>$9.49</td>
</tr>
<tr>
<td>Transmission</td>
<td>$4.34</td>
</tr>
<tr>
<td>Regulation</td>
<td>$0.32</td>
</tr>
<tr>
<td>Operating Reserve</td>
<td>$0.74</td>
</tr>
<tr>
<td>PJM Cost</td>
<td>$0.28</td>
</tr>
<tr>
<td>Reactive</td>
<td>$0.35</td>
</tr>
</tbody>
</table>

TOTAL: $61.65/MWh

*Values are PJM averages and do not reflect potential locational cost differences.


- PJM's Energy Market accounted for nearly three-quarters (74.5 percent) of total wholesale market costs in 2011, and the IMM has provided no recommendations related directly to the design or performance of PJM's Energy Market.

- The IMM does provide recommendations related to areas that touch on energy market operations such as operating reserves which account for 1.2 percent of total wholesale power costs, marginal losses which are embedded into energy market costs, demand response operations in the energy market, and interchange transactions.

- PJM's Reliability Pricing Model (RPM) Capacity Market accounted for 15.4 percent of total wholesale power costs in 2011. The IMM recommendations related to the capacity market are generally related to the obligations of capacity resources and the definition of what it means to be a capacity resource with only one major recommendation to the current design of the RPM Capacity Market. Many recommendations related to demand response are also tied directly to the RPM Capacity Market.

- Transmission Charges accounted for seven (7) percent of total wholesale power costs in 2011. PJM staff appreciates the IMM's addition of a section regarding transmission planning and its potential impacts on PJM's markets. The IMM recommendations in this area are relatively few and all of these are already under consideration in the PJM stakeholder process.

- Ancillary services have been emphasized by the IMM as an area for further improvement. Ancillary services, in total, accounted for 1.3 percent of total wholesale power costs in 2011. Market-based services Regulation, Synchronized Reserve, and Day-ahead Scheduling Reserve contributed only 0.5 percent, 0.1 percent, 0.05 percent respectively to wholesale power costs in 2011. Non-market Reactive Power and Voltage Support and Black Start contributed 0.6 percent and 0.03 percent respectively to wholesale power cost in 2011.

Overall, the IMM concludes that the state of PJM's markets is good. Given the areas in which the majority of the IMM's recommendations are concentrated, PJM's markets are entering a period of maturity where any further changes to market design and reliability planning are addressing areas that have lower cost impacts when examined in the context of wholesale power costs. The examination of these areas by PJM and the IMM are critical as they are essential to maintaining operating reliability through ancillary service markets, resource adequacy through the RPM Capacity Market, and transmission reliability through the transmission planning process that is informed by long-term investment decisions made by market participants.

It is critical that any recommendations or changes proposed to PJM’s markets be carefully considered given the emphasis on ensuring reliability through markets. This means conducting an analysis of data and market results that provide evidence of a problem or potential problem, and analyzing recommended solutions to understand their market and reliability impacts.

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3 2011 SoM Report at 17, Table 1-7 for the contribution of Day-ahead Scheduling Reserve to total wholesale power costs.
4 2011 SoM Report at 1.
PJM staff have reviewed and agree with many of the recommendations provided by the IMM. PJM staff review also indicates instances where recommendations and conclusions made by the IMM require further analysis to better define the problem to be solved, and more clearly delineate the market and reliability implications of the recommended solutions. The 2011 State of the Market Report provides a large volume of data and information regarding PJM’s Markets and can be a useful reference for PJM staff and market participants. PJM staff believe it would be useful to tie the data, information, and analysis contained in the 2011 State of the Market Report together into an easy to follow narrative that explains why there is a problem and how the recommendations solve the identified problem and promote more efficient and cost-effective market outcomes that support reliability goals.

There are many recommendations made by the IMM that have been repeated in each of the past three State of the Market Reports. A prioritization of many of these recommendations would provide value to the PJM stakeholders. PJM staff notes the IMM has the right and ability to bring a well-defined problem to the PJM stakeholder process to be assigned to a designated committee or task force if the PJM membership believes it is warranted and the potential solution could provide enhanced value.

An IMM prioritization will aid stakeholders in deciding which issues to address immediately, to defer to a later date, or not to address at all so that all recommendations can be brought to resolution. It is during the stakeholder process where the IMM is able to bring its recommended solution to the membership to be considered alongside other potential solutions developed by the wider stakeholder body.

The remainder of this response will discuss in detail the major market highlights and recommendations provided by the IMM followed by responses to specific recommendations by topic area in the order of contribution to wholesale market costs.

**Market Highlights**

**Energy Market**

The 2011 State of the Market Report (2011 SoM Report) illustrates the competitive bidding behavior in the Day-Ahead and Real-Time Energy Markets. In that report, the IMM calculates the cost mark-up component of load weighted average LMP versus the offer price of the marginal unit was $1.28 (or 2.8% of price) in the Real-time Energy Market and negative $0.92 (or -2% of energy price) in the Day-Ahead Energy Market. Moreover, the 2011 SoM Report shows that the mark-up component of Real-time LMP is negative, on average, at LMPs below $50/MWh (which encompass over 82 percent of all hours in 2011). All of this is strong evidence of competitive behavior.5

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5 2011 SoM Report at 33-34.
Figure 2 provides PJM’s analysis of Energy Market offer data showing the capacity weighted average mark-up for coal and natural gas fired units by month. On average coal units make market-based offers slightly below their defined cost-based offers while natural gas units provide market-based offers slightly above their defined cost-based offers. Figure 2 shows that competitive behavior is not just limited to the offers of marginal units in the energy market, but is consistent across the two dominant fossil fuel types in PJM’s Energy Market.

**RPM Capacity Market**

As highlighted in the IMM’s report, in 2011 the transparent, forward price signals that the RPM auctions have been producing for several years began bearing fruit as five large plants (over 500 MW) began generating in PJM in 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, Longview Power in the APS zone, Dresden Energy Facility in the AEP zone, and Fremont Energy Center in the ATSI zone. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011 (excluding the integration of the ATSI zone), the most since 2002. Additionally, the 2014/2015 Base Residual Auction (BRA) conducted in May 2011 was the first under which coal-fired generation had good information on what types of costs they may face with EPA’s Mercury and Air Toxics Rule. In the 2014/2015 BRA there were 6,985 MW less Unforced Capacity (UCAP) being committed than in the previous year. This was largely offset by an addition of 4,836 MW UCAP of Demand Resources committed at a price below the Cost of New Entry (CONE) in the same

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6. *PJM Manual 15: Cost Development Guidelines: Revision 19, Effective June 1, 2012* available at [http://www.pjm.com/~/media/documents/manuals/m15.ashx](http://www.pjm.com/~/media/documents/manuals/m15.ashx). Allowed cost-based offers and their components are defined in Manual 15 and include a 10 percent adder over those costs. So even if units are offering below their defined cost-based offers, they may simply not be including all of the allowed 10 percent adder component of the offer in their market-based offers.


This performance demonstrates the competitiveness and value of the forward capacity market, RPM, and illustrates the effectiveness of market price signals to attract new generation and Capacity Resources when needed.

**Regulation Market**

Similar to the previous few years, in the 2011 report the IMM concluded the Regulation Market performance is not competitive in spite of the IMM’s finding that the offer behavior of market participants is competitive. The IMM bases its determination upon its objection to a few market design elements which were implemented as part of a PJM stakeholder compromise to implement the Three Pivotal Supplier Test (TPST) into the Regulation Market. These market design elements were also approved by FERC. The design elements to which the IMM objects are: the calculation method for lost opportunity costs (LOC), the elimination of the offset of Regulation Market revenues against operating reserve credits and the increase in the regulation offer adder to $12/MWh.

PJM disagrees with the IMM’s assertion that the Regulation Market results are not competitive because the actual market results demonstrate competitive behavior as acknowledged by the IMM in the 2011 SoM Report. The Regulation Market continues to operate in a competitive manner consistent with PJM’s FERC-approved tariff with the changes FERC has already deemed to be just and reasonable. In a market-based environment, just and reasonable rates must be, by default, deemed competitive. Secondly, PJM staff questions the validity of finding that market behavior is competitive, yet the market results are not competitive due to objections to certain design elements. While PJM respects the IMM opinion related to these design elements, given the overwhelming stakeholder support and FERC approval of the design PJM believes the market is operating as intended and the market results are competitive.

Additionally, since the implementation of the changes in the Regulation Market at the end of 2008, the available supply, hourly eligible supply, daily supply offered, and the ratio of supply offered to the requirement have all increased substantially as shown in Table 1. Moreover, Table 1 also shows in spite of the allowed $12/MWh adder, the weighted average marginal offer for regulation is has been lower every year than it was prior to the change and always below $12/MWh.

<table>
<thead>
<tr>
<th>Table 1: Regulation Market Statistics 2007-2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
</tr>
<tr>
<td>Regulation capability (MW)</td>
</tr>
<tr>
<td>Average Daily Offer (MW)</td>
</tr>
<tr>
<td>% capability offered</td>
</tr>
</tbody>
</table>

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9 Id. at 2, and 2014/2015 Base Residual Auction Results at 4, available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx. Table 1 which shows a projected 19.6 percent installed reserve margin in 2014/2015 which is 4.3 percent above the target.

The IMM filed its initial assessment of the changes with FERC at the end of 2009 and petitioned FERC to alter the design. FERC has declined to act upon the filing which provides indication the Commission believes the market results are just and reasonable, and therefore competitive. In any case the current Regulation Market design will likely be replaced with PJM’s proposed design submitted in April 2012 to comply with FERC Order 755 making many of the IMM’s recommendations with respect to the Regulation Market moot. Moreover, the IMM’s objections to the LOC calculation may be resolved as part of a PJM initiative, in cooperation with the IMM, to harmonize the definition opportunity costs across all PJM markets.\footnote{See Consistency of Energy Related Opportunity Cost Calculations available at \url{http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=8BDD3AD9-2832-4E47-A2C0-1B896B6ECA6F}.}

**Up-to Congestion Transactions**

The 2011 SoM Report notes that over the last two years there has been a movement by financial market participants from the use virtual bids in the form of INC offers (virtual supply) and DEC bids (virtual demand) towards what are known as “up-to congestion transactions.”\footnote{2011 SoM Report at 14.} The 2011 SoM Report contains several recommendations related to “up-to congestion transactions”. The IMM recommends eliminating the “up-to congestion” product from the market design or in the alternative to modify the product to ensure it pays appropriate operating reserve charges and has appropriate credit requirements.

PJM believes the “up-to congestion” product provides a valuable hedging and arbitrage alternative for market participants in the Day-ahead Energy Market. The “up-to congestion” product acts as an hourly transmission position which provides the ability to participants to specify price differentials between two locations for which they would reserve transfer capability in the Day-ahead Market. This product provides a unique alternative that cannot be provided by paired increment offers and decrement bids that cannot be guaranteed to clear the Day-Ahead Energy Market together or not at all. Therefore, PJM disagrees with the IMM recommendation that the product should be eliminated. PJM does not believe the 2011 SoM Report contains sufficient analysis to justify the recommendation that the product should be eliminated and believes the elimination of the product would reduce hedging alternatives and price convergence between the Day-Ahead and Real-Time Energy Markets.
In the discussion and description of the “up-to-congestion” product, the 2011 SoM Report states the following:

"an up-to-congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids". \(^{13}\)

The report also states:

"the DEC portion of the up-to-congestion transaction contributes to the PJM day-ahead load, and the INC portion contributes to the PJM day-ahead generation". \(^{14}\)

This second characterization is not correct because the “up-to-congestion” transaction is modeled as a transfer of power from one location to another and cannot impact power balance as INC and DEC bids would. Since this misunderstanding of the nature of the “up-to-congestion” transaction may be the basis for the IMM recommendation to modify the market rules to assess operating reserves charges to “up-to-congestion” transactions, PJM believes it is helpful to quantify the impact of “up-to-congestion transactions” as compared to increment offers/decrement bids on the unit commitment and production cost results in the Day-Ahead Market. In order to quantify the impact, PJM utilized the production Day-Ahead Market software to re-run two actual day-ahead market cases from the recent past without the “up-to-congestion” transactions and without virtual bids (INCs/DECs) to determine the relative impact of these products on unit comment and production cost. The analysis results are shown below in Table 2:

**Table 2: Analysis of Relative Impact of Up-to Congestion Transactions**

<table>
<thead>
<tr>
<th></th>
<th>Base Case</th>
<th>Without “Up To” Transactions</th>
<th>Without INCs / DECs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Production Cost</td>
<td># Units Committed</td>
<td>Change in Production Cost</td>
</tr>
<tr>
<td>Case 1</td>
<td>$35,561,781</td>
<td>487</td>
<td>$337,631 (0.9%)</td>
</tr>
<tr>
<td>Case 2</td>
<td>$33,121,913</td>
<td>396</td>
<td>$15,332 (0.05%)</td>
</tr>
</tbody>
</table>

Based on this analysis, it appears that the “up to congestion” product does not have a significant impact on unit commitment or on production cost in the Day-Ahead Market. Therefore, the relative impact of “up to congestion” transactions on unit scheduling in the Day-Ahead Market is very small compared to the impact of increment offers and decrement bids. While further analysis may be required to attempt to assess impact on operating reserve costs, the relatively small impact of “up to congestion” transactions on Day-Ahead Market unit commitment and production cost

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\(^{13}\) 2011 SoM Report at 39.

\(^{14}\) Id.
appear to indicate these transactions have a much smaller impact on such operating reserve costs. PJM notes that a stakeholder task force is already considering this issue and PJM will work with the IMM and all stakeholders to determine if further analysis will be instructive and feasible given stakeholder priorities.

The shifting of market activity from virtual bids (INCS and DECS) toward the up-to congestion product provides hedging and arbitrage opportunities at a much lower overall cost to the PJM Market. As Table 2 clearly shows, because “up-to congestion” transactions have a much smaller impact on production cost and unit commitment and it appears that deviations from day-ahead schedules are minimized relative to the use of virtual bids providing a more cost-effective means on a market-wide basis to manage price risk between the Day-Ahead and Real-Time Energy Markets.

PJM agrees with the IMM recommendation that appropriate credit requirements be implemented for the “up to congestion” product. The PJM Credit Department is addressing this issue through the stakeholder process. However, PJM notes it is important to establish reasonable credit requirements to strike the appropriate balance between protecting members from default risk while not creating undue barriers to the continued viability of the “up to congestion” product.

**Capacity Market**

The IMM has offered multiple recommendations regarding the RPM Capacity Market and the majority of these are addressed below.

**Elimination of the Short-Term Resource Procurement Target (2.5 percent demand holdback in the Base Residual Auction (BRA)):** PJM disagrees with this recommendation. PJM staff does not believe the IMM has provided sufficient evidence or analysis that supports this recommendation. PJM staff recommends the IMM conduct a more comprehensive analysis which considers the original drivers for this design feature, review of load forecast methods and recent changes to load forecasts closer to the Delivery Year, performance of the incremental auctions and other relevant information. Moreover, PJM staff analysis has shown that for the 2014/2015 BRA elimination of the 2.5 percent holdback would have increased capacity prices by $16.80/MW-day in the RTO and $23.50/MW-day in all constrained areas except for PS-North.15 While this procures the entire forecasted reliability requirement in the BRA, given recent trends in downward updates to load forecasts, this could result not only in a higher price but in purchasing more capacity than is necessary for the delivery year should load continue to grow more slowly than initially forecast.

**The definition of Demand Response resources should be made comparable to generation capacity resources to ensure that all resources provide the same value in the capacity market such as providing unlimited interruptions:** PJM disagrees with this recommendation. The IMM has not provided sufficient analysis to support this recommendation such as an imminent resource adequacy or real-time operating reliability threat from permitting limited response from Demand Resources. Moreover, PJM has recognized that there is a reliability-based limit to the dependence on more limited forms of Demand Resources16 and has implemented FERC-approved changes to the RPM Capacity Market to

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reflect the limited nature of some Demand Resources while still permitting cost effective participation that maintains reliability.\textsuperscript{17}

Address barriers to entry in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM: PJM agrees that barriers to entry of new generation resources should be eliminated to the extent possible. PJM staff understands this recommendation is tied to a similar recommendation in the Transmission Planning section of the \textit{2011 SoM Report} regarding potential barriers related to the interconnection queue process.\textsuperscript{18} The IMM states PJM is addressing some of these barriers to entry, and we confirm we are addressing issues related to the transmission planning process and the generator interconnection process through the stakeholder process and these are addressed further below. PJM is committed to working with the IMM and the PJM membership to reduce these potential barriers to new generation entry.

\textbf{Redefining the test for determining modeled Locational Deliverability Areas in RPM to include a detailed reliability analysis of all at-risk units:} PJM staff believes this recommendation is driven by the recent EPA rulemakings and the situation surrounding the upcoming BRA and believes this is a high priority issue. PJM staff commits to work with the IMM to better define the problem and bring the issue to the stakeholder process for resolution with an eye toward the 2016/2017 BRA to be held in May 2013.

\textbf{Elimination of modifications to existing resources being considered as new resources for purposes of market power related offer caps or MOPR offer floors:} PJM staff disagrees with this recommendation and believes that it would be discriminatory to treat capacity differently based on the source and believes that the value of new capacity is the same regardless of whether it is new “iron in the ground” or an increase of the capacity of an existing facility. Additionally, the IMM has not provided sufficient analysis of the consequences of such a change or an explanation of how such a change would not open a loophole for new resources to use to avoid application of the MOPR. One example of such a loophole could be an existing steam unit that wishes to repower to combined cycle natural gas and significantly expand capacity. PJM believes the IMM recommendation would inappropriately exempt such a major capacity addition from MOPR as below cost offers from this “uprated” capacity has the same effect as the effect of below cost offers from new generating units.

\textbf{Explicit requirement that capacity unit offers into the Day-Ahead Energy Market be competitive where competitive is defined to be the short run marginal cost of the units:} PJM disagrees with this recommendation. PJM staff does not believe that capacity resources should be required offer in the energy market at short-run marginal cost as currently defined in PJM Manual 15 and used for market power mitigation.\textsuperscript{19} First, PJM believes this would circumvent the FERC’s clear authority to grant market-based rates. Second, PJM notes that short-run marginal costs are difficult to define and this

\begin{footnotesize}
\begin{itemize}
  \item \textsuperscript{17} PJM Interconnection, L.L.C filing in ER12-513, December 1, 2011 available at \url{http://www.pjm.com/~/media/documents/ferc/2011-filings/20111201-er12-513-000.ashx}, and PJM Interconnection, L.L.C. 138 FERC ¶ 61,062 January 30, 2012 for the most recent design changes incorporating different Demand Resource categories into RPM.\textsuperscript{13}
  \item \textsuperscript{18} \textit{2011 SoM Report} at 11. PJM will more directly respond to this recommendation in the section on Transmission Planning below.
  \item \textsuperscript{19} \textit{PJM Manual 15: Cost Development Guidelines: Revision 19, Effective June 1, 2012} available at \url{http://www.pjm.com/~/media/documents/manuals/m15.ashx}.
\end{itemize}
\end{footnotesize}
has been recognized by the FERC many times over.\textsuperscript{20} Third, there is no indication that there is an incentive or market power problem as offer behavior in the energy market clearly shows offers at or near the PJM Manual 15 defined short-run marginal cost based on the IMM's own analysis and confirmed by PJM analysis as shown above Figure 2. Moreover, natural gas units, which are likely to contribute an ever increasing share of energy in PJM, face the differences in timing between the gas market day and electric market day, and the ability to make market based offers to manage the associated risk is essential for their operation and financial viability going forward.

Protocols should be defined for recalling the energy output of capacity resources when PJM is in an emergency condition: PJM agrees and has developed these protocols and they have been added to the PJM Manuals and the IMM has acknowledged PJM's development of the requested protocols.\textsuperscript{21}

A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis: PJM staff agrees to the extent that if a unit is not capable of supplying energy at all, it should be reflected as an outage. However if the unit is capable of supplying the energy in an emergency, then it is appropriate to designate the energy as available. To deem energy from such a resource as unavailable when it is available under emergency conditions would remove a potentially valuable tool PJM has available to manage operating reliability under conditions when those tools are most needed. Moreover, the IMM has not provided an analysis of impacts to operating reliability in real-time if such a recommendation were implemented.

The MMU recommends PJM review all requests for Out of Management Control (OMC) outages carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM propose eliminating lack of fuel as an acceptable basis for an OMC outage: PJM agrees that development of transparent rules governing OMC outages is appropriate, but disagrees that lack of fuel be categorically eliminated as an OMC outage. PJM staff already reviews all requests for OMC outages carefully and many OMC codes have strict documentation requirements. PJM staff is in the process of codifying these processes in the PJM manuals. With respect to lack of fuel OMC outages, PJM staff notes that if fuel supply was reasonably within the control of the resources, an OMC outage is not granted. The IMM analysis of OMC outages shows that one firm is responsible for over 95 percent of such outages, but the IMM has not provided sufficient analysis as to the consequences for RPM Capacity Market outcomes or any reliability issues associated with the current practice since the Installed Reserve Margin (IRM) determination already takes into account all outages including OMC outages.

\textsuperscript{20} The use of the 10 percent adder goes back decades. For example, see Terra Comfort Corporation, et al., 52 FERC ¶ 61,241 at 61,840 (1990), “With respect to the Applicants’ argument that the ten percent adder is a contribution to fixed costs, we have always viewed percentage adders as mechanisms to recover only incremental energy costs. 28/ Such adders are traditionally supported by utilities - and approved by the Commission - on the grounds that the ten percent adders recover incidental, miscellaneous expenses that are expensive or difficult to quantify. 29/ It continues to be the industry's consistent practice to justify ten percent adders to incremental costs as allowing recovery of incremental energy costs, not as providing a contribution to fixed costs. 30/”

\textsuperscript{21} 2/10/12 OC Meeting Item 7c found at http://www.pjm.com/~media/committees-groups/committees/oc/20120214/20120214-item-07c-draft-pjm-manual-13-emergency-operations.ashx and the 2/23/12 MRC meeting First Read Item 1C found at http://www.pjm.com/~media/committees-groups/committees/mrc/20120223/20120223-first-read-item-01c-draft-manual-13-revisions.ashx on pages 22-23 of the proposed revision to PJM Manual 13.
Performance incentives in the RPM Capacity Market design should be strengthened. The MMU recommends that the generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical: PJM disagrees with this recommendation. The IMM has not provided PJM staff or stakeholders with sufficient analysis that shows there is an imminent or potential problem that threatens resource adequacy reliability under the current set of performance incentives in RPM, or what the consequences would be of implementing this recommendation. PJM believes that Capacity Resources have strong incentives to perform during the most critical hours as these are, in general, the highest priced hours during the year. Foregoing such energy market revenues places a Capacity Resource in a position where it may be unable to cover its avoidable costs for the year. Moreover, Capacity Resources taking forced outages during peak periods are also subject to penalties for failing to be available as expected which effectively reduces their capacity revenues for the year. Finally, if Capacity Resources are taking outages outside of peak periods they may increase their overall forced outage rate which may lead to lower Unforced Capacity (UCAP) available to be offered in subsequent auctions to cover the avoidable costs of the entire Capacity Resource.

The terms of Reliability Must Run (RMR) service should be reviewed, refined and standardized and that RMR units only recover costs they would not have incurred absent the RMR: PJM disagrees with this recommendation for two main reasons. First, standardized compensation already exists in the tariff governing RMR service if the necessary capital investment for the unit in question is less than $2 million. The standardized compensation allows for the recovery of avoidable costs which are, by definition, costs the RMR unit would not have incurred but for the RMR arrangement. Second, some RMR units may require more significant investments requiring the matter go to FERC as a rate case proceeding to determine the justness and reasonableness of the RMR contract submitted for approval. To the extent the IMM believes RMR contracts are recovering costs they should not, PJM believes the PJM Tariff explicitly contemplates that the IMM should petition the FERC for an order regarding the appropriateness of the avoidable costs in question. Moreover, PJM staff notes the conditions leading to a generator retirement and the need for an RMR contract are unit specific and practically limit the ability for comprehensive standardization to be effective.

RMR service should be mandatory and retirement notices should be extended from 90 days to one year: PJM disagrees with these recommendations. First, neither PJM, nor FERC has the authority to order a generating unit to operate or remain in service. Only the Secretary of Energy through section 202(c) has the authority to compel a generator to remain in service and only in certain circumstances. Second, the rationale for the 90 day notice for retirements has historically been related to unit failures where it has been clear the unit will be unable to return to service. Unit owners may also be in some financial distress that may lead them to provide retirement notice of less than one year. However, in most instances, generation owners generally provide much longer notice of retirement to allow for the possibility that the unit may need to be retained to ensure reliability until appropriate transmission reinforcements can be placed into service. Additionally, the three-year forward capacity market and the must offer requirement for existing resources provide strong

23 PJM Tariff, Part V Section 119.
24 Id.
25 For an overview of Section 202(c) authority and actions, see DOE’s Use of Federal Power Act Emergency Authority available at http://energy.gov/oe/does-use-federal-power-act-emergency-authority.
financial incentives for resources to declare their intent to retire well in advance which makes the 90 day notice requirement much less relevant from a practical perspective.

**Demand Response**

The IMM recommendations with respect to Demand Response and Demand Resources touch on aspects of PJM’s Energy and Capacity Markets.

Elimination of the Limited and Extended Summer Demand Response products from the capacity market. All products competing in the capacity market should be required to be available to perform when called for every hour of the year: PJM disagrees with this recommendation and does not believe the IMM has supported the recommendation with sufficient analysis, nor sufficient analysis of potential market impacts. The purpose of the different types of Demand Response to serve as capacity was borne from the reliability concern of depending too heavily on Demand Resources that were too operationally limited, but this did not imply an elimination of more limited demand resources was required.\(^\text{26}\) PJM implemented reliability-based limitations in the RPM auction to constrain the auction clearing based on reliability requirements. PJM notes that the recent implementation of the expanded categories has been successful in attracting more diverse demand response resources offered into the market. In fact most Demand Resource offering into the 2014/2015 BRA made coupled offers that would have allowed most Demand Response to be Annual if necessary.\(^\text{27}\)

**PJM should continue to implement sub-zonal dispatch for Demand Response products and develop a plan to implement nodal dispatch for all demand resources:** PJM agrees with the sub-zonal dispatch recommendation and continues its efforts to implement sub-zonal dispatch and notes that sub-zonal dispatch has been called for on at least two occasions last year. As to the question of nodal dispatch, PJM must recognize the FERC requirements for the aggregation of Demand Resources, and these requirements limit the likelihood of nodal dispatch of Demand Resources.

The option to specify a minimum dispatch price under the Emergency Program Full option should be eliminated and that participating resources should receive the hourly real-time LMP less any generation component of their retail rate: PJM disagrees with this recommendation and believes that Demand Resources should have the opportunity to express their economic dispatch capabilities in a manner similar to that available to other resources such as generation resources. However, PJM agrees that a stakeholder process should examine and potentially modify the rules for emergency resources that are also economic resources and have a higher price as an emergency resource but provide no more reduction in an emergency than in economic conditions. Moreover, in PJM’s shortage pricing filing recently approved by the FERC, PJM will use the minimum dispatch price to facilitate emergency demand response to set price in the energy market when called during emergencies.\(^\text{28}\) As FERC recognized in its order, this will help eliminate the pricing discontinuity


that currently exists during emergencies where a call for emergency demand response results in lower prices during the emergency than prior to emergency conditions.

The Emergency Program Energy Only option should be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program: PJM staff is in agreement with the IMM’s observation leading to the recommendation. The Emergency Program Energy Only option is a program has historically generated very little interest among participants. PJM is not opposed to the removal of this option in principle, but believes this is a low priority issue given that this provision is currently not used by market participants and retaining it would have no practical impact on current operations. Consequently, PJM does not believe it is worth the time and resources necessary to bring this recommendation to resolution at this time. If the IMM believes this issue is a high priority, the IMM has the option of presenting the issue to the PJM membership for consideration.

Improvement in measurement and verification (M&V) methods should be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities: PJM agrees with this recommendation. The IMM acknowledges within the 2011 SoM Report that PJM has implemented or plans to implement changes to the CBL calculation that should improve M&V for many customers. PJM will implement several improvements in the CBL calculation and methodologies on June 1, 2012. PJM staff further notes the increased importance of enhanced M&V with the implementation of FERC Order 745 that mandates “full LMP” compensation for economic demand response.

Modify the testing program to require verification of test methods and results and that all available metered load data should be submitted to PJM and the MMU in order to verify accurate testing and measurement of customer loads: PJM staff agrees with the IMM recommendation and believes this is consistent with the M&V enhancements PJM plans to implement on June 1, 2012. However, PJM staff notes consideration should be given the costs of incrementally improved M&V relative to the benefits of improved baselines that can be determined. The costly nature of improved M&V is one aspect that makes Price Responsive Demand an attractive alternative in that it eliminates the need for M&V in the PJM Energy Market.

Any baseline approach that attempts to estimate unrestricted load consumption should be based on a comparable day or a comparable set of days be adjusted for ambient conditions and other variables impacting load for all participants, and be limited to the days closest to the event: PJM staff believes these issues will be addressed by the CBL and M&V improvements referenced above.

Any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a 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: PJM does not agree with this recommendation as it may be redundant with processes already in place or soon to be implemented. PJM staff notes that such an occurrence already triggers a settlement review by Demand Response Operations. Adding a CBL review on top of the settlement review may be unnecessary given the CBL and M&V improvements that are soon to be implemented.
Transmission Planning

With regard to transmission planning, the IMM has offered three substantial recommendations regarding transmission planning. Many of the issues surrounding the recommendations are being considered by PJM stakeholders at the Regional Planning Process Task Force (RPPTF) and the Interconnection Process Senior Task Force (IPSTF). It is important to recognize that transmission investments are primarily driven by reliability needs, although any reliability driven projects will also have economic efficiency consequences.

PJM should continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty and improve the efficiency of the process so as to eliminate any inappropriate barriers to the entry of new generation: PJM agrees that the interconnection process should not create inappropriate barriers to entry of new generation. PJM staff recognizes that uncertainty regarding the costs of interconnection can cause potential new entrants to wait for better information before committing to enter into the PJM Market through the RPM Base Residual Auction. PJM recently received FERC approval, subject to a compliance filing, on a package of interconnection queue reforms that are intended to increase the timeliness, transparency, and certainty of the interconnection queue.29 PJM also received approval, subject to a compliance filing, on revisions to its transmission planning process that will enable PJM to identify and evaluate potential transmission system needs through sensitivity studies, modeling assumption variations, and scenario planning analyses that will consider public policies.30 PJM will continue to work with the IMM and through the RPPTF and the IPSTF in an effort to come arrive at a stakeholder driven consensus on additional interconnection queue and transmission planning reforms to address these issues.

PJM should continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible: PJM agrees with this recommendation. The PJM market design and rules already incorporate direct consideration of market driven decisions for new transmission investment in several different ways. First, transmission developers may propose and submit a Qualifying Transmission Upgrade in the RPM Capacity Market as a Capacity Resource that allows greater transfer capability into a constrained Locational Deliverability Area. Second, PJM may consider economic upgrades based on the satisfaction of cost-benefit thresholds. Also, to the extent that new generation entry into constrained locations can avoid the need for new transmission designed to maintain reliability, the Regional Transmission Expansion Plan can be revised to reflect these market driven investments.

PJM should propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables: PJM staff understands the need for increased certainty on the status of transmission upgrades as these can significantly alter the financial viability of new generation entrants. However, should macroeconomic conditions change leading to lower load forecasts as they have in recent years, and/or underlying power market fundamentals such as the EPA MATS rule, the shift in natural gas supply and prices, and increasing economies of scale in gas-fired generation, the underlying reasons and need for the transmission investment may have disappeared. In such cases to continue to build transmission

29 PJM Interconnection, L.L.C., 139 FERC ¶ 61,079 (2012)
30 PJM Interconnection, L.L.C., 139 FERC ¶ 61,080 (2012)
would impose costs on load that are not necessary. Moreover, continuing with transmission investments that may have been reliability and not market driven may actually run counter to the IMM’s recommendation, with which PJM agrees, that transmission investments be incorporated within market driven processes. Definitively delaying or cancelling projects also provides certainty to potential new generation entrants into the PJM Market allowing clear market-based solutions to take precedence. PJM will continue to work with stakeholders to consider this issue.

Ancillary Services

The single clearing price for Regulation and Synchronized Reserves should be determined based on the actual LMP: PJM agrees with the recommendation. This recommendation will be implemented in October 2012 given the recent FERC order approving PJM’s shortage pricing proposal that implements co-optimization of energy and ancillary services. PJM staff agrees with the IMM’s conclusions that this change will increase prices, but also reduce uplift and increase transparency so that all the costs associated with providing Regulation and Synchronized Reserves will be reflected in the posted prices.

To the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected: PJM staff believes this recommendation is mooted by PJM’s compliance filing in response to FERC Order 755.

PJM should document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market: PJM agrees with this recommendation. The Order 755 compliance filing proposal as well as the recent FERC order approving PJM’s shortage pricing filing and subsequent compliance filing to implement five-minute co-optimization of energy, regulation, and synchronized reserves will resolve this issue.

PJM should modify its penalty rules for non-compliance in the Synchronized Reserve Market to correct the situation of gross noncompliance (less than 30% compliance in every spinning event) operating profitably because the total SRMCP credits can exceed total penalties: PJM agrees with this recommendation and supports appropriate incentives for both performance and non-performance. PJM believe this is a high priority issue given the recent FERC order approving PJM’s shortage pricing filing that changes pricing and commitment of Synchronized Reserves through co-optimization with Energy and Regulation. PJM staff commits to work with the IMM to bring the issue to the stakeholder process so as to gain stakeholder approval for such changes to be filed at FERC in conjunction with PJM’s expected October 2012 shortage pricing implementation.

A full list of potential reasons for unit de-selection from Tier 1, Tier 2, and Regulation should be published in PJM’s M-11 Scheduling Operations Manual along with mandatory documentation of reasons for Tier 1, Tier 2, and Regulation de-selection as a way to improve transparency: PJM agrees with this recommendation. PJM staff acknowledges dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 Synchronized Reserve, or unit dispatch prior to running the market solution which effectively imposes additional constraints on the market solution. PJM is

31 PJM Interconnection L.L.C. 139 FERC ¶ 61,057 April 19, 2012
32 http://www.pjm.com/~/media/documents/ferc/2012-filings/20120402-er12-1430-000.ashx
implementing improvements in the de-selection process and expects to have revised manual language in place by the end of 2012 to promote transparency regarding this process. PJM expects such de-selections to decline in the future with implementation of co-optimization of Energy and Ancillary Services and Regulation Market changes proposed in PJM’s Order 755 compliance filing.

The DASR Market rules should be modified to incorporate the application of the TPS test in order to address potential market power issues: PJM is not opposed to the use of the TPST and marginal cost offer capping in the DASR Market with appropriate adjustments to fit the DASR Market context. PJM notes that the average market clearing price in the DASR market was $0.05/MWh in 2011 or 0.1 percent of total wholesale costs and as such the impact on the market as a whole is minimal.\(^{33}\) Given the small market impact and the scope of other higher priority issues, PJM does not view implementation of the TPST as a high priority because the costs in terms of time and resources to work through the stakeholder process to full implementation can be better utilized to address open issues related to the RPM Capacity Market and transmission planning as well as implementations of shortage pricing and a new Regulation Market.

PJM, FERC, reliability authorities, and state regulators should re-evaluate 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 should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process: PJM agrees with this recommendation. PJM and the membership have established the System Restoration Senior Task Force to address the issues currently associated with the provision of Black Start service. These discussions are still at their initial stages.

### Operating Reserves

The IMM has recommended multiple changes to reporting, logging, and categorization processes so as to ensure the appropriate allocation of costs associated with operating reserve credits paid to resources. PJM staff is either in agreement with the IMM on these recommendations or is not opposed to them but notes that a prioritization should be established to ensure efforts to change market rules are justified based on value added. While PJM agrees that improved logging, reporting, and categorization improves transparency, operating reserve charges only accounted for 1.2 percent of wholesale costs in 2011 and therefore from a cost-benefit perspective, this is a lower priority item in PJM’s estimation with some exceptions as described below.

PJM staff agrees with the IMM recommendation regarding the logging of reasons generation resources are committed for reliability for providing Reactive Power and Voltage Support or Black Start Service through Automatic Load Rejection (ALR). This will allocate costs appropriately to Reactive Power and Voltage Support or Black Start Service rather than through operating reserves. PJM commits to bring this issue to the stakeholder process. PJM staff has noted a large increase in operating reserve charges related to reliability commitments in the western portion of PJM as natural gas prices

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\(^{33}\) 2011 SoM Report at 17.
have declined.\textsuperscript{34} This is an indication of coal units being committed for voltage support or Black Start and these costs may be inappropriately allocated.

The recommendation regarding the categorization of lost opportunity costs paid to wind resources that are requested to reduce output to maintain system reliability in real-time operations is scheduled to be implemented by PJM by June 1, 2012.

To the extent the IMM believes other areas of logging, reporting, and categorization are higher priority, the IMM is free to bring such recommendations forward to the PJM membership in the stakeholder process along with appropriate supporting analysis for further consideration.

**Interchange Transactions**

The IMM has made numerous recommendations which PJM has combined below:

**The MMU recommends that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets:** PJM agrees with this recommendation and once up-to congestion transactions can be submitted through eMarket (June 1, 2012) PJM will be in a position to make this change. PJM will work with the system operations staff to analyze the system changes required and to establish priority based on value.

**The MMU recommends that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool:** PJM has already implemented dispatchable transactions in the ITSCED tool. PJM disagrees with the recommendation to eliminate BOR payments to dispatchable import transactions because these transactions are supply resources similar to generation and therefore should be entitled to the same production cost guarantee as is afforded to a generator that follows PJM dispatch instructions.

**The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges and charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions).** PJM believes that the issue of uncollected congestion costs has been addressed through process improvements that result in the efficient curtailment of such transactions when congestion occurs. Through active monitoring by PJM, these charges were reduced from $23.0 million in 2010 to $1.3 million in 2011.\textsuperscript{35}

**PJM should perform a regular assessment of the mappings of external balancing authorities associated with the interface pricing points, and modify as necessary to reflect current system topology in order to ensure that transactions are priced based on the actual flows that they create on the transmission system:** PJM staff agrees

\textsuperscript{34} See Member’s Committee Markets Report, April 23, 2012 slide 8 at http://www.pjm.com/~/media/committees-groups/committees/mc/20120423/20120423-reports-item-03a-markets-report.ashx

\textsuperscript{35} 2011 SoM Report at 182
with this recommendation and does regularly perform assessments of these mappings. For example, after the integration of the ATSI zone, PJM altered the interface pricing point definitions to remove busses that were now internal.

PJM should monitor, and adjust as necessary, the weights applied to the components of 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 staff agrees with this recommendation, and is addressing improvements in this area in the ongoing efforts to address loop flows.

The Enhanced Energy Scheduler (EES) application should be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced: PJM staff is aware of this issue and agrees with this recommendation, and PJM will implement the modification according to the priority associated with that change compared to all the other required software changes on the priority list. PJM has not experienced any operational control issues that are related to this rule. PJM is enforcing the business rule as it observes schedules not maintaining the constant schedule through direct contact with the market participants involved.

In order to permit a complete analysis of loop flow, FERC and NERC should ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC: PJM agrees with this recommendation, but notes this recommendation requires FERC and NERC action and as such there are limits to what PJM can do to facilitate such additional information flows. PJM staff recognizes 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.

PJM should ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles: PJM staff acknowledges that arrangements between neighboring balancing authorities will require refinement as experience dictates, and has committed to working together with neighboring control areas to continually identify areas that require improvement or could benefit from further enhancement. For example, PJM and MISO recently commissioned a third party study of the JOA to evaluate its effectiveness and areas for improvement. Moreover, 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 FERC that it represents a just and reasonable methodology to address congestion on the PJM and neighboring systems despite the IMM’s objections.

PJM should work with both MISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to a single LMP market: The IMM acknowledges that PJM is engaged in discussions with both MISO and NYISO on interface pricing based on orders from the FERC. However, PJM staff does not

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believe the IMM has presented adequate evidence that current interface prices are not at efficient levels. For example, differing uplift payments across the RTOs, flows based on existing contractual arrangements, and other transaction costs may lead to flows between RTOs that do not appear consistent with the posted interface prices. Until such issues are addressed, no definitive conclusion can be reached regarding the efficiency of interface prices between RTOs.

The PJM and MISO JOA should be modified to eliminate payments between RTOs when such payments would result from the failure of generating units to respond to appropriate pricing signals: While PJM supports this recommendation, PJM staff notes the situation occurs very infrequently and has not occurred in recent years. As such PJM considers this a very low priority item and therefore it does not require immediate attention.

The grandfathered Southeast and Southwest Interface pricing agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. These agreements expired on January 31, 2012 and have not been renewed. The MMU recommends that PJM not enter into any such special pricing agreements: PJM disagrees with this recommendation. The PJM Tariff requires pricing of transactions consistent with a distribution factor analysis according to their impacts on the transmission system and PJM prices transactions in accordance with the Tariff.

Congestion and Marginal Losses

The IMM offers a single recommendation that “PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results.” PJM staff has conducted a review of market results and market software that has shown marginal and total losses to be unusually low on a few days and PJM believes the issues have been analyzed and explained in detail.

FTRs and ARRrs

The IMM has offered two recommendations regarding ARRrs and FTRs. First the IMM recommends “a detailed review of the ARR/FTR allocation and market clearing [should] be conducted in order to better understand and address the reasons for FTR underfunding. This review should include the assumptions made in the modeling of auctions and their basis in market developments. An explicit statement in the rules explaining the purpose and objectives of ARRrs, FTRs and the appropriate level of funding of FTRs is recommended. The MMU recommends that no action to substantially modify the market design, e.g. removal of balancing congestion from the calculation of FTR revenues, be taken until the review is complete.”

In 2011 the PJM membership established the FTR Task Force to examine issues in the ARR/FTR market and FTR underfunding. The FTR Task Force made recommendations to senior committees. Monthly PJM analysis of FTR underfunding seems to show a trend where loop flows from outside the PJM system are correlated with greater levels of underfunding. PJM is committed to ongoing improvements both report on and where appropriate reduce FTR underfunding.

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The second recommendation offers, “when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs, derived from the ARR allocation to that load, follow the load in the same manner as ARRs.”

PJM disagrees with the second recommendation. PJM believes the IMM has not provided sufficient analysis to support this second recommendation. 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.

**Environmental and Renewable Resources**

The IMM has offered a single recommendation that “renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market.”

PJM disagrees with this recommendation. Renewable energy credits (RECs) and the associated markets are created by state laws or regulations mandating a specified percentage of energy come from renewable resources. And while the presence of renewable resources does influence energy and capacity market outcomes, the market for RECs, whose influence will be seen on retail electricity bills, is a state regulatory matter and beyond PJM’s FERC-assigned role at the wholesale level. In an order issued recently, the FERC re-confirmed that the Commission does not have jurisdiction over RECs that are not bundled with renewable energy. Moreover, to the extent that RECs affect renewable resource energy and capacity market offers and results, these are negligible. As the 2011 SoM Report shows wind resources which is the most prevalent renewable resource on the PJM system was only marginal in 2 percent of hours in the Real-Time Energy Market and effectively not marginal at all in the Day-Ahead Energy Market. The effect of RECs is dwarfed by the effect of emissions allowances and primary fuels on market outcomes, yet there is no recommendation to bring these markets into PJM. Given the data in the 2011 SoM Report, PJM concludes the evidence does not support this recommendation.

38 See 139 FERC ¶ 61,061 at ¶ 18
39 2011 SoM Report at 47. See Table 2-39 that shows no defined effect of RECs and shows wind contributes -0.065 percent to load-weighted average LMP.