POSITION OF INDEPENDENT MARKET MONITOR FOR PJM ON RPM MARKET DESIGN ISSUES.
CMEC Meeting. September 29, 2008

Market Design Issues

1. Definition of capacity. The definition of the product is central to refining the market rules governing the sale and purchase of the product. The definition of capacity includes several components: the obligation to offer the energy of the unit into the day ahead market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM. The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the day ahead market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are.
2. There is a straightforward economic theory underlying the wholesale power markets. The theory should be stated clearly and the theory should inform efforts to refine the market rules governing the sale and purchase of capacity. The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity.
3. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power.
4. The local market power mitigation rules reflect a recognition of the fact that local market power will exist in energy markets in a transmission network and needs to be addressed in order to ensure competitive outcomes.
5. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.
6. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues.
7. Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets.
8. The development of the RPM design was based on the recognition that this incentive/revenue goal needed to be explicitly included in the capacity market design. The original daily capacity credit market design evolved from the need to have a transparent market mechanism where new retail competitors could obtain capacity in

order to meet the requirements of all load serving entities under PJM rules and did not consider revenue issues.

9. The revenues in the capacity market are scarcity revenues.
10. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues.
11. The energy market can and should be competitive. A competitive market clears based on the marginal cost of the highest cost unit that is producing energy, accounting for the possibility of multiple marginal units in the presence of transmission constraints. There is no reason to build market power into the design of the energy markets. A complete market design will provide adequate revenues via scarcity revenues in an energy only market or via scarcity revenues provided in the form of capacity payments in a hybrid market design.
12. It is the obligation of every unit that is a capacity resource to make an offer into the day ahead energy market. The offer into the day energy market should be required to be a competitive offer. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the day ahead energy market are 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.
13. An offer that exceeds short run marginal cost is not a competitive offer in the day ahead energy market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the day ahead energy market. Such a unit should reflect an appropriate outage rather than its availability to compete in the energy market.
14. Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the hours defined as critical, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy during any of the hours defined as critical, it should receive no capacity revenues.

15. This approach to performance is also consistent with the reduction of administrative penalties associated with failure to meet capacity tests, for example.
16. A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit mechanism to remove those revenues from capacity market revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not.

Must Offer Rules

1. The must offer rules could be modified in several areas to ensure that all relevant capacity is offered into the RPM auctions. In particular, the rules governing the participation of FRR resources should be modified to require that all available FRR resources are offered into the RPM auctions, without any cap on the total amount. The current rules provide for a cap on the excess FRR resources that may be offered into the RPM auctions and do not provide a must offer requirement. In order to be consistent and to ensure that FRR participants cannot exercise market power by increasing or decreasing auction prices, both modifications are required.
2. While it has not been a significant level of MW, another source of capacity not offered into the RPM auctions is associated with units for which ownership ends during a delivery year. An owner faces disincentives to offer into an auction if the owner is taking on a delivery obligation for part of a delivery year when there is no longer ownership. Most of such issues have been resolved bilaterally. A requirement to resolve such issues bilaterally could be created to ensure that all such capacity is offered into the auctions. Although it has not occurred to date, leaving this issue unaddressed could create a mechanism for physical withholding.

APIR Rules

3. The APIR provisions of the tariff permit owners to add to offer caps an amount based on investments required to maintain units as capacity resources and a capital recovery factor which translates the total investment into an annual recoverable amount. This is equivalent to the treatment of the costs of new entry for a new unit and provides the ability for older units to make required investments and reflect the associated costs in RPM offers. The APIR provisions of the tariff permit this recovery over relatively short periods of time when the investment is at units above specific age thresholds and when other specific criteria are met. The shorter the time period, the higher the adder to the offer caps.
4. If the treatment of APIR investments were identical to the general treatment of new entry, the ability to add the associated investment recovery would be limited to one

year. The tariff reflects the explicit decision to permit such recovery over a defined number of years in order to reduce the uncertainty associated with such recovery and to increase the incentives to make such investments. The tariff reflects policy decisions regarding the appropriate way to provide incentives to investments in existing generation and in new entry.

5. The tariff treatment for APIR investments is consistent with the tariff provisions that permit such treatment for new investments under defined circumstances. Such treatment should be considered for all new investments. The creation of a mechanism to create multi-year price certainty for new entry should be considered.

Calculation of Net CONE

6. The net CONE consists of a gross CONE level and an offset based on the net revenues from energy and ancillary services markets. The net CONE level represents the revenues that would have to be earned from the capacity market if the full amount of gross CONE is to be covered from all markets, including energy, ancillary and capacity markets. The energy and ancillary services revenue offset is currently based on a three year historical average of revenues for the CONE technology, determined prior to the relevant Base Residual Auction, which is itself three years prior to the actual delivery year. The results of the historical offset calculation bear no clearly defined relationship to the level of actual energy and ancillary services revenues that will be achieved in the delivery year.
7. While the most accurate way to set capacity prices would be to link them to actual net revenues in the delivery year, it is not possible to set CONE for a BRA three years prior to the auction using actual net revenues. The demand curve must be established using data available at the time. However, a true up provision could be used to adjust the historical average after the fact. While there is no single right way to calculate the offset using actual data, the use of a three year historical average is a reasonable compromise between using one or two years which could be affected more significantly by unusual results in a single year and using a longer period which would include increasingly stale data reflecting irrelevant market conditions.
8. A reasonable way to calculate the offset would be to set it based on the three year average for the BRA, with or without scaling based on forward prices, and then to do a true up after the delivery year based on actual results in the delivery year. Such a true up approach would have the advantage of ensuring an accurate link to the energy and ancillary services markets results for the delivery year, while minimizing the associated uncertainty experienced by market participants. The true up could be limited to scarcity revenues in order to bound uncertainty while retaining the critical link between scarcity revenues from the energy market and revenues from the capacity market, another form of scarcity revenues.
9. The advantages of a pure forward looking calculation of energy and ancillary services revenues are overstated. The forward market is not liquid three years forward, the forward market will represent a single pricing point on the PJM system and the forward market will not reflect hourly variation in energy market prices. Historical

data will have to be used to estimate the locational differentials between the single pricing point and the relevant locations for CONE. Historical data will have to be used to develop the hourly shape of energy prices. These two adjustments will need to be related as the basis differentials also have an hourly dimension. The forward looking approach, while appealing conceptually, is not likely to add to the accuracy of the energy and ancillary services revenue offset. In addition, the approach is extremely complex, will be relatively non transparent and could require the exercise of significant judgment by PJM.

10. The advantages of an empirical approach to net CONE are overstated. An empirical net CONE approach is not likely to be more accurate than an approach based on market research (the current approach) and it is quite possible that the result could be substantially too low or too high. The result could be too low if based on market clearing prices when those prices reflect historical market conditions of excess supply that no longer exist. The result could be too high if based on uncleared offers which are subject to gaming as high offers could be submitted for the purpose of affecting the empirical CONE result.

CETO/CETL Rule

11. The analysis of the 2011/2012 base residual auction results by the IMM shows the significant impact of the rule that directs PJM, as a general matter, to ignore underlying locational RPM price differentials when the ratio of CETL to CETO exceeds 1.05. That rule should be removed from the tariff as it inappropriately prevents locational price differences based on the economic fundamentals of the capacity market from being revealed in the auction. The result is to suppress appropriate locational price signals that reflect the relative shortage of capacity in specific locations. Getting those locational price signals right was one of the key elements of the RPM design.