UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Capacity Markets in Regions with Organized Electric Markets	Docket No. AD08-4-000
ISO New England, Inc.	Docket No. ER08-633-000

STATEMENT OF RANDALL L. SPECK ON BEHALF OF THE CONNECTICUT DEPARTMENT OF PUBLIC UTILITY CONTROL AND THE MARYLAND PUBLIC SERVICE COMMISSION

I am Randall L. Speck, an attorney at Kaye Scholer LLP, and I have represented the Connecticut Department of Public Utility Control and the Maryland Public Service Commission in a number of matters relating to development and implementation of capacity mechanisms for New England and PJM, respectively. While these capacity constructs are sometimes erroneously lumped together, they offer substantial contrasts both in terms of their structure and their performance.

The states – and my clients in particular – have had significant concerns about RTOs' development of capacity mechanisms and have expressed those concerns in many Commission proceedings. Of course, all of the states have a paramount interest in assuring resource adequacy as one of their core responsibilities, and both Connecticut and Maryland have taken steps to ensure that customers continue to have reliable electric service. The states have at least comparable interests, however, in furthering other important objectives – *e.g.*, developing renewable energy resources, energy efficiency, and demand response. Most importantly, given huge retail rate increases in recent years, the states are more cognizant than ever of the impact that wholesale prices have on individual customers and on economic development. States simply cannot tolerate

further accelerating costs that are not fully justified by concrete benefits, and they bring this sensitivity to their analysis of structures to compensate capacity.

In examining the Forward Capacity Market ("FCM") and the Reliability Pricing Model ("RPM"), I will focus on their differences in three key areas: (1) the transition period before the mechanisms are fully operational; (2) the extent to which the mechanisms support the states' reliability, environmental, and cost-effectiveness objectives; and (3) the ability of the capacity mechanisms to mesh with energy and ancillary services markets. While the FCM has performed well thus far, RPM has not produced the intended benefits at reasonable costs.

1. Transition Period

Because both mechanisms use a three-year forward auction to procure capacity, they both require a transition period before PJM or ISO-NE can conduct an auction with the requisite lead time that will permit new capacity resources to compete with existing capacity to provide supply. The FCM and the RPM adopted sharply divergent approaches, however, for their respective transition periods.

Recognizing that there could be no effective competition to provide capacity without sufficient lead time for entry by new resources, New England simply fixed the amount of the transition payments from December 1, 2006, through June 1, 2010, in gradually escalating amounts that would end at a level close to the projected floor for the first Forward Capacity Auction ("FCA"). All capacity resources receive these transition payments, and there are no locational differences throughout the region. RMR agreements may continue during the transition, but parties can challenge the continuing need for them in light of higher capacity payments.

FERC accepted this transition approach as just and reasonable based on the extensively litigated record in the *Devon* case that showed the agreed upon transition payments were lower than the projected payments would have been under the proposed demand curve that had been adopted in the Initial Decision and were comparable to the rates under alternative demand curves proposed at the hearing.[1] The DC Circuit recently affirmed these transition payments.[2]

In PJM, the transition period was handled by conducting Base Residual Auctions ("BRAs") with truncated planning periods that were much shorter than the planned three years – ranging from only two months to 29 months between the auction and the beginning of the commitment period. These shortened lead times made if difficult for new generation resources to compete, and PJM had not fully developed procedures that would permit full participation by potential demand response resources. Indeed, PJM did not expect new capacity resources to participate fully in the auctions until the upcoming May 2008 BRA for the commitment period that begins in June 2011.[3] The BRAs could and did include locational price differentials, but there was insufficient time for supply or load to respond to those distinctions. Consequently, the first four auctions have taken place with the potential for price separation of constrained zones but without the discipline of full-fledged competition from new entrants that could provide a market-based restraint on market power. For each of these first four auctions, PJM's Market Monitoring Unit concluded that there was a high potential for the exercise of market

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1 *Devon Power LLC*, 115 FERC ¶ 61,340 (2006) at P 72.

2 *Me. Pub. Utils. Comm'n v. FERC*, No. 06-1403, slip op. at 9-17 (D.C. Cir. Mar. 28, 2008).

3 *See, e.g.*, Reply Testimony of Michael J. Kormos, PJM Interconnection, L.L.C., on Behalf of the Staff of the Maryland Public Service Commission, Maryland PSC Case No. CN-9117, October 30, 2007, p. 4-5.

power,[4] and, consequently, all offers were mitigated to administratively determined marginal costs.

Both PJM's and New England's approaches to the transition period were intended to provide revenues that would maintain existing capacity resources until the full planning period would permit new entry. Certainly capacity has remained adequate during the transition period in both RTOs, but it is not clear that the substantially enhanced capacity payments had a significant causal effect on retaining existing generation resources.

The two mechanisms for addressing the transition period have had starkly different price impacts, however. New England's prices were known in advance and were not subject to administrative determinations or any market participant's actions, *i.e.*, there was no opportunity for existing suppliers to exercise market power. In contrast, PJM's transition prices were subject to multiple administrative determinations, including the estimated cost of new entry ("CONE"), energy and ancillary services ("E&AS") offsets, and the offer cap mitigation that was applied to every offer. Because RPM uses an administrative Variable Resource Requirement ("VRR") demand curve and because the capacity market is structurally non-competitive, suppliers had strong incentives to adjust their mitigated offers whenever possible within the rules in order to set the clearing prices in some locational zones. As a consequence, capacity prices in PJM were significantly above CONE in constrained zones, significantly higher than most load parties anticipated, and even higher than the forward market for bilateral contracts immediately before the first BRA. Although there were substantial locational premiums

[4] *See* 2007 State of the Market Report, PJM Market Monitoring Unit (Mar. 11, 2008), Vol. 1 at 29.

in the first three auctions, they disappeared entirely by the fourth auction (and the upcoming fifth auction). In essence, RPM set prices well above CONE in constrained zones through the first three auctions but produced little, if any, tangible benefit for load.

2. Support for States' Objectives

States evaluate the success of a capacity mechanism based on its ability to support their objectives in three areas: reliability, development of renewable resources (including energy efficiency), and cost effectiveness.

A. Reliability

State regulators are certainly cognizant of the need to assure reliable power when it is needed, and they would not hold their jobs long if there were chronic threats of power interruptions. Of course, there may be disputes about how much reliability is necessary or provides a real benefit. RTOs have an understandable institutional bias in favor of more reliability, with less concern for load's costs.[5] The methods that PJM and ISO-NE have used to set reliability requirements in transmission constrained zones like Maryland and Connecticut, however, would require load to pay for more capacity than the states believe is necessary.

State regulators emphasize the balance that has to be struck between a belt-and-suspenders approach to reliability and the costs of each increment of additional reliability assurance. States believe they should decide how much reliability their customers want and need consistent with the state's overall land use, environmental, and resource

[5] *See NSTAR v. FERC*, 481 F.3d 794, 803 (D.C. Cir. 2007) (finding that an RTO has an incentive to ensure that system-critical power is available to ensure grid stability and reliability, but does not have incentives to bargain for low prices).

utilization policies. Each of these capacity mechanisms begins with a capacity requirement, and the DC Circuit will soon decide whether states or FERC has responsibility to set that requirement.[6]

Once the resource adequacy requirement is set, the capacity mechanism must provide clear, unequivocal assurance that the necessary capacity will be there when it is required to meet expected demand. Theoretical "price signals" are not enough if they do not produce actual capacity resources that can be relied on to provide energy or demand reductions to satisfy peak loads. The real test will come when new capacity resources are called on to perform, and in that sense, neither RPM nor FCM have yet proved that they will assure the reliability that they promise.

The results from New England's first FCA are encouraging because of the substantial participation from new generation and new demand response. The fact that these new resources cleared in abundance for the first auction is substantial evidence that the FCM provides adequate incentives to attract new capacity resources.

The jury is still out, however, on RPM because the May 6 BRA is the first auction with a full three-year planning period. PJM's interconnection queue includes more than 15,000 MW of potentially eligible capacity, but it remains to be seen whether that potential will become a reality. Demand response to RPM has not been nearly as vigorous as in New England, and that difference undoubtedly reflects barriers to entry that need to be removed.

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[6] *Connecticut Dept. of Pub. Util. Control v. FERC*, No. 07-1375 (D.C. Cir.), filed Sept. 19, 2007 (consolidated with No. 07-1460).

The real proof will come in the performance of capacity resources at peak load. Both FCM and RPM include substantial penalty provisions for non-performance, but we will have to wait to see whether they are sufficient to assure supply when needed. Because states have continuing doubts about the performance of these mechanisms, they have adopted hedging strategies in the form of long-term contracts. For instance, because Connecticut is transmission constrained and could be segregated as a separate capacity zone with higher prices, it contracted for more than 800 MW of capacity resources to assure its own reliability, independent of FCM, which expressly provides for such self-help to assure reliability. This state ability to contract for reliability resources is an essential component of FCM. The Maryland PSC is currently evaluating the need for long-term contracts and will make its decision about how to proceed based on results from the May 6 BRA.

B. Renewable Energy

States in both New England and PJM have established ambitious goals for reducing emissions and overall energy consumption. Many of the New England and PJM states have committed to Regional Greenhouse Gas Initiative ("RGGI") goals that will require reduced dependence on coal and natural gas generation. In addition, the EmPower Maryland initiative seeks to reduce per capita energy consumption by 15 percent by 2015, and Maryland has Renewable Portfolio Standards calling for 9.5 percent of energy consumption from renewables by 2022. Connecticut has objectives of 27 percent renewable generation by 2020 and a 20 percent reduction in peak consumption.

Both FCM and RPM present challenges for development of renewable generation resources because wind and solar resources receive relatively little credit for capacity.

Renewable generation resources are also often hampered by interconnection procedures that are not suited to the new capacity mechanisms or to the volume of new capacity that those payments are intended to attract. Stakeholder processes are addressing some of these concerns, but there are not yet procedures that facilitate integration of renewable generation.

FCM has been much more successful than RPM in attracting demand response and energy efficiency in its capacity auction. In New England, 2,500 MW of demand response cleared in the first FCA, and another 850 MW have expressed interest in the next FCA. FCM includes provisions that facilitate participation by energy efficiency. Demand response is what drove the FCA clearing price to the floor – as it should when load has an opportunity to respond to price signals in the same way as supply. In contrast, in PJM, aside from PSC-mandated utility programs in Maryland, demand response participation in the January 2008 BRA actually declined for the rest of the RTO. RPM as currently constituted has not shown that it will support the states' environmental objectives, particularly with regard to demand response.

C. Cost Effectiveness

The political firestorms in many states over increasing electricity costs are well documented, and the increase in capacity charges has become one lightening rod that has drawn substantial attention. In Maryland, for instance, capacity charges are estimated to be about 20 percent of the default service charges for residential customers. Policy makers will not be able to tolerate such substantial charges without clear evidence that customers are getting their money's worth. There can be no regulatory certainty without a broad acceptance of capacity charges as reasonable, and states will take actions on their

own to subvert or overturn federal capacity mechanisms if they do not demonstrably pass the cost-effectiveness test.

Load representatives overwhelmingly perceive that RPM has not produced cost-effective results. Capacity prices in the first four auctions have been much higher than load expected – well above CONE in the constrained area. The "price signals" – now set through May 31, 2011 – have not yet attracted any significant new capacity in constrained areas, and there is no assurance that new capacity will appear where and when it is needed. In fact, the states believe that RPM creates incentives to promote scarcity that actually discourage existing generation owners from building new capacity that would lower the price for their entire fleet. Now, locational "price signals" have disappeared entirely due to expected transmission upgrades, eliminating any price incentives from the capacity mechanism to build new generation in constrained zones. At least to date, RPM has not been a reasonable, cost-effective capacity mechanism.

On the other hand, load representatives in New England perceive that FCM has produced value. The first FCA attracted a wide range of new generation and new demand response. The clearing price was driven by competition among all the available resources that can supply capacity, including less costly demand response. The FCA's descending clock auction produced a surplus of capacity at an objectively competitive price – the optimal result of a functioning market. Based on evidence from the first auction, FCM appears to have performed as intended.

3. <u>Integration with Energy Markets</u>

The theory of capacity mechanisms like RPM and FCM is that they supply the "missing money" that generators may not be able to recover from energy or ancillary

services markets. Of course, if capacity mechanisms are going to supply the missing money, load wants to make sure that generators are not able to recover that same money in the energy market when prices spike due to shortages.

RPM and FCM handle this issue very differently. In the FCM, the Peak Energy Rent ("PER") adjustment reduces capacity payments by the amount of the average monthly energy revenue for the previous twelve months above a specified strike price. The deduction is based on actual energy revenue above that strike price and during a relatively contemporaneous time. This deduction acts as an additional penalty if a generator does not perform during those shortage period when energy prices spike because they will lose that portion of the capacity payment without being able to recoup those revenues in the energy market.[7] Generators' offers in the FCA will increase or decrease based on their expectation of energy revenues up to the amount of the strike price plus any ancillary services revenues (which may be significant for a peaking unit that participates in ISO-NE's Locational Forward Reserves Market).

The RPM relies much more heavily on administrative determinations to adjust capacity payments based on offsets for energy and ancillary services ("E&AS") revenues. Under the RPM, the demand curve sets capacity prices, and the net cost of new capacity is a key parameter to set the demand curve. The net cost of new capacity is CONE minus a three-year historical average for all the energy and ancillary services revenues that a proxy unit would have earned as much as six years earlier. The E&AS offset may be – and has been – wildly out of date and may not reflect actual revenues during the

[7] Ideally, the deduction would be exactly contemporaneous with no lag and would act exactly as an option for energy whenever the energy market price exceeds the strike price.

performance period at all. This E&AS offset does not serve as an effective penalty mechanism for failure to perform during shortage periods. Moreover, because it is set administratively, the E&AS revenue offset is – like CONE – subject to great dispute, as illustrated most recently in PJM's rejected proposal to increase CONE without taking into account the countervailing impact of increased E&AS revenues.[8]

A well-designed capacity mechanism must link those revenues seamlessly to energy revenues. Not only will the deduction of energy revenues above a strike price provide incentives to perform when needed most, it will pave the way for the substantially diminished importance of capacity markets. Generators would be expected to submit offers in the capacity market at prices sufficient to supply the "missing money" based on a known strike price. As technological improvements permit demand to respond to price, price spikes will become less extreme and the potential for market power abuse will diminish. The RTO can then raise the strike price, thus reducing the market price of capacity – testing to make sure that the changes benefit consumers – until the capacity price falls to near zero. In this way, a properly constructed capacity mechanism will become an bridge to the future and will be an anachronism once technology permits demand to respond accurately and contemporaneously to price, thereby establishing an empirical value for reliability.

Conclusion

FCM has proved to be a viable method for providing capacity resources because it (1) fixed capacity payments during the transition period, when new entry would not be able to restrain existing resources' market power, (2) at least partially addressed the

[8] *See PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,015 (Apr. 4, 2008).

states' reliability, environmental, and cost-effectiveness objectives, and (3) meshed capacity payments with energy market revenues. In contrast, RPM has thus far failed to perform as the states intended because it (1) attempted to set capacity prices based on auctions that did not include sufficient new entry to discipline prices, (2) did not produce cost-effective reliability, and (3) does not effectively offset energy and ancillary services revenues against capacity payments.