Contingency Plan Addressing the Potential Loss of FERC Jurisdiction Over Demand Resources

ISO New England Inc.
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Henry Yoshimura
Director, Demand Resource Strategy
Market Development

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I. Executive Summary

A. Introduction

To achieve an economically efficient and reliable electricity system, it is vital that consumers be provided with information and opportunities comparable to those provided to producers to actively participate in the electricity market. For this reason, the New England region has made a collective effort—be it through policies, programs, or improved participation incentives—to foster growth in the region's Demand Resource base. While the region's historical efforts created momentum for the development and integration of Demand Resources into the region's wholesale markets, the future state of demand response is on a less clear forward path.

The *EPSA* decision by the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit") to vacate the FERC directive in Order 745 has introduced significant uncertainty about the future participation of demand response resources in wholesale electricity markets. The subsequent appeals of the DC Circuit's decision to the U.S. Supreme Court further complicate these circumstances.

Without direction from the U.S. Supreme Court and the FERC, the region's next steps are uncertain. Possible scenarios range from maintaining an approach that is fairly consistent with the status quo, to allowing demand response participation solely in the capacity and ancillary services markets, or to removing Demand Resources from the supply-side of the wholesale market platform altogether.

Planning for these potential outcomes is difficult given the interdependencies of each scenario. Still, ISO New England has worked to strategize how best to be proactive amid the uncertainties the region now faces, while still exercising prudence. As such, the ISO has developed several contingency planning scenarios for discussion with stakeholders, explained briefly in this Executive Summary and assessed more fully in the detailed sections of this paper.

B. Factors Influencing ISO New England's Contingency Planning

ISO New England's contingency planning is complicated by the interplay between the likely timing of decisions from the U.S. Supreme Court and the array of potential legal interpretations in this case.

At the outset, it is not clear at this time whether the U.S. Supreme Court will take up this matter—that decision is not expected until mid-2015. If the U.S. Supreme Court opts not to take the case, the decision of the DC Circuit will stand, subject to FERC's direction on remand. Should the U.S. Supreme Court decide to hear the appeals of the DC Circuit decision, the U.S. Supreme Court's judgment to either uphold or reverse the DC Circuit's findings would not be known until mid-2016. In the interim, the *vacatur* of Order 745 has been stayed pending the outcome of the appeals process and ISO New England continues to operate under existing, FERC-approved market rules for Demand Resources.

In addition to the potentially protracted legal process in this case, it is also unclear how narrowly or broadly the decision in *EPSA* will be interpreted—primarily by the Commission, but potentially by the U.S. Supreme Court as well. In the narrowest legal interpretation, the mandate to vacate Order 745 would apply only to demand response participation as a supply-side resource in the energy market. However, given the centrality of energy markets in wholesale market design, the participation of Demand Resources as supply-side resources in the capacity and ancillary service markets also becomes questionable if the mandate to vacate Order 745 is upheld and the legal interpretation of its applicability is applied more broadly.

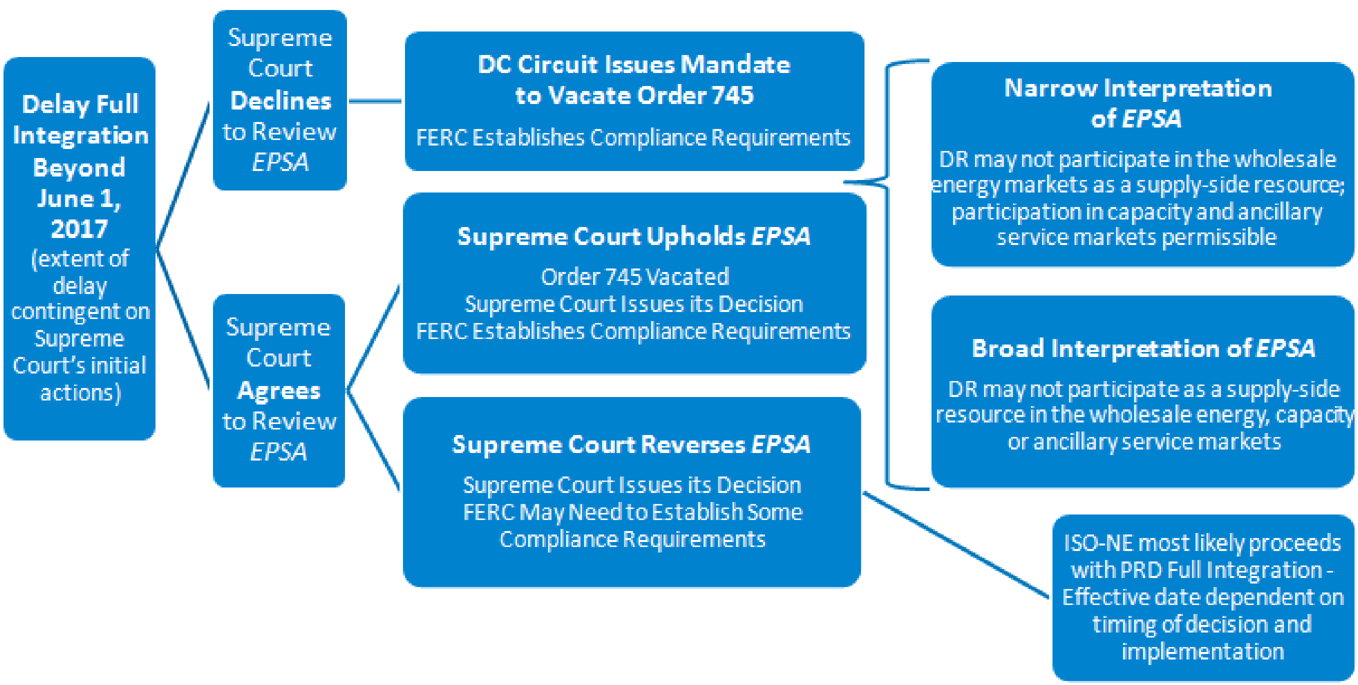
C. ISO New England's Initiative to Fully-Integrate Demand Response Must be Delayed

Amid all other uncertainty, what is clear is that no matter the timing of the legal processes or the range of interpretation, the planned June 1, 2017 implementation for full integration of demand response resources into the energy and reserves market structure should be postponed at least a year to allow for more clarity and direction regarding the future state of demand response.

As fully explained in the detailed sections of this paper, proceeding with the June 1, 2017 implementation date for the full integration of demand response into the energy and reserve markets prior to U.S. Supreme Court deciding its course of action and, if applicable, issuing its final ruling could prove to be an unwise use of the ISO's and Market Participants' resources.

D. Contingency Planning Depends Heavily on Legal Interpretations

In addition to the rationale and requirements for a one-year delay of the full integration of demand response, the ISO's contingency plan additionally outlines possible market design approaches that could be taken depending on the legal interpretation of the mandate to vacate Order 745. If the *EPSA* mandate to vacate Order 745 is eventually issued, the rulings reviewed in *EPSA* would be remanded to the Commission for further action. The Commission would then need to direct the ISO and other affected entities to submit tariff changes to modify their markets as necessary to comply.



1. The Commission Takes a Narrow View of *EPSA*

In its narrowest application, the Commission would interpret a court mandate to vacate Order 745 as limited to the participation of demand response in energy markets only, allowing Demand Resource participation on the supply-side of the other wholesale markets, such as the Forward Capacity Market ("FCM"). This approach would require limited market rule changes to eliminate energy payments to demand response resources for periods prior to June 1, 2018 (presuming the one year delay discussed above is made effective).

After June 1, 2018, the market constructs change fairly significantly to accommodate the planned full integration of demand response resources into the energy and reserve markets and the introduction of the Forward Capacity Market Pay-For-Performance ("FCM PFP") project. The current iteration of the rules expected to be in place for June 1, 2018 will require demand response resources to offer into the energy market—an approach that would be unworkable should demand response participation in the energy markets become impermissible based on Commission direction.

To address this, the ISO could propose that demand response resources be subject to ISO dispatch to reduce demand prior to, or concurrent with, a scarcity condition as defined by FCM PFP. There are several factors that would need to be addressed to more precisely develop this approach, including the price collapse effects that demand response dispatch could create when resources are scarce and prices should be high, applying FCM PFP penalties for demand response resources that do not perform during scarcity conditions, and the potential provision of Operating Reserve by demand response resources that are prohibited from participating in the energy markets. Still, contingent on those modifications, Demand Resources could continue to participate in the capacity and ancillary services markets.

2. The Commission Takes a Broad View of *EPSA*

Should the Commission interpret the ruling in *EPSA* more broadly, Demand Resource participation could be limited beyond just the energy markets and additionally be restricted in the capacity and ancillary service markets. PJM considered this outcome, drafting a whitepaper and filing market rules to account for this possibility by shifting Demand Resource participation to the demand-side of the market.[1] The PJM concept permits load-serving entities ("LSEs") to submit demand reduction bids in the capacity market, effectively decreasing the amount of capacity to be obtained through the auction and, by extension, lowering the capacity clearing price.

Building on the market design concepts put forth by PJM, the ISO's contingency plan for this scenario describes methods by which LSEs would have improved incentives to actively participate on the demand-side of the capacity market. Demand Resources could be integrated into the demand-side of the FCM by allowing load-serving entities to reduce capacity costs by submitting and clearing demand reduction bids.

In addition, the contingency plan proffers an approach basing the allocation of FCM costs on performance. At the present time, the monthly FCM charge billed to an LSE is fixed in that the bill is unaffected by the amount and timing of customer consumption served by the LSE in the month. Under the potential new approach described in greater detail below, the allocation of monthly FCM costs to LSEs could vary based on a "performance charge" reflecting the actual consumption of their customers during scarcity conditions. During a scarcity condition, LSEs consuming less than their allocated share of available capacity would see their performance charge and associated FCM charge go down; the converse is true for those consuming more. This approach gives LSEs the incentive to consider cost-effective Demand Resources to control their customers' energy consumption to a level at or below their allocated share of capacity that is available to meet energy requirements during a scarcity condition.

[1] The FERC, however, found that the filed market rules were premature and rejected the filing.

II. Background and Contingency Planning Stakeholder Process

A. Background

This paper provides a framework outlining potential approaches to integrating Demand Resources into the New England electricity markets given the uncertainty created by the decision of the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit") vacating Order 745.[2]

Order 745 requires regional transmission organizations ("RTOs") to pay the full locational marginal price ("LMP") to providers of demand response resources[3] participating in organized wholesale energy markets subject to certain conditions.[4] Soon after the proceedings concerning Order 745 were concluded, the Electric Power Supply Association petitioned the DC Circuit to review Order 745.

The *EPSA* order was issued by a three-judge panel[5] of the DC Circuit on May 23, 2014. In addition to finding that the Federal Energy Regulatory Commission's ("FERC" or "Commission") decision in Order 745 was arbitrary and capricious, more significantly the DC Circuit found that the Commission lacked jurisdiction to promulgate the rules established by Order 745. The DC Circuit stated: "[b]ecause FERC's rule entails direct regulation of the retail market—a matter exclusively within state control—it exceeds the Commission's authority."[6] At the time of the decision, the DC Circuit simultaneously stayed the mandate to vacate Order 745 to allow for rehearing petitions.

On July 7, 2014, the Commission petitioned the DC Circuit for rehearing *en banc*—a request for the full 11-member DC Circuit to rehear the case. On September 17, 2014, the petitions for rehearing en banc were denied without comment. On September 22, 2014, the Commission petitioned the DC Circuit for a stay of issuance of the mandate to vacate Order 745, pending the federal government's consideration and possible future filing of a petition for a writ of certiorari with the U.S. Supreme Court – i.e., an appeal to the Supreme Court to review *EPSA*. On October 20, 2014, the DC Circuit granted the Commission's motion to stay the issuance of the mandate through December 16, 2014, the due date for writ of certiorari.

On December 5, 2014, the Solicitor General of the United States on behalf of the FERC filed with the Supreme Court a request for an extension to January 15, 2015 to file a petition to review the DC Circuit's decision in *EPSA*. The Supreme Court granted that request on December 8, 2014. Also on December 8, 2014, the FERC petitioned the DC Circuit for an extension of the original stay of the mandate to vacate Order 745. On December 15, 2014, the DC Circuit extended the stay and will continue to withhold

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[2] *Electric Power Supply Association v. FERC*, 753 F.2d 216. (D.C. Cir. 2014) ("*EPSA*").

[3] Broadly, a demand response resource is an aggregation of one or more end-use customers in the same Dispatch Zone that reduces its electricity consumption from the electric grid in response to a Dispatch Instruction from the ISO, which is triggered by high LMPs and/or by a real-time system condition threatening system reliability such as a capacity deficiency.

[4] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 15, 2011), FERC Stats. & Regs. ¶ 31,322, *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011) ("Order 745").

[5] One judge dissented and found that Order 745 was not arbitrary or capricious, and did not exceed the Commission's jurisdiction.

[6] *EPSA* at p. 14.

issuance of the mandate pending the outcome of Supreme Court proceedings.[7] On January 15, 2015, the Solicitor General filed a petition for writ of certiorari with the Supreme Court appealing the decision in *EPSA*.[8] At the time of this writing, the Supreme Court has yet to decide whether to review *EPSA*. It is likely that the Supreme Court will decide whether to review *EPSA* by the end of June 2015. If *EPSA* is reviewed, the Supreme Court's final decision will likely be issued by the end of June 2016.

If the *EPSA* mandate to vacate Order 745 is eventually issued, the rulings reviewed in *EPSA* would be remanded to the Commission for further action.[9] The Commission would then direct the ISO and other affected entities to submit tariff changes to modify their markets as necessary to comply with *EPSA*. Direction from the Commission concerning future demand response participation is unlikely until the Supreme Court process has been completed.

B. Contingency Planning Stakeholder Process

The ISO's going forward plans rely on future decisions by the courts and the FERC, where the content and timing of each future decision is uncertain and interdependent. This is a complex situation with many unknowns and permutations, which make it impractical to craft a plan that addresses every conceivable outcome. Therefore, the approach taken herein is to outline the timeline and process that the ISO would follow as the legal/regulatory process unfolds. The recommended plan is as follows:

April 2015	Distribute this paper to stakeholders and the states.
May 2015	Discuss contingency plan with stakeholders and the states.
June 2015	Introduce a proposal to delay the full integration of demand response into the energy and reserve markets by at least one year. Decision by the Supreme Court on whether it will review *EPSA* is expected by the end of this month.
July-September 2015	Market rule changes to delay the full integration of demand response into the energy and reserve markets are introduced for stakeholder review and consideration.[10] If the Supreme Court decides not to review *EPSA*, meaning that the DC Circuit will shortly thereafter issue the *EPSA* mandate, the ISO will thereafter begin the process of revising its market rules as directed by the Commission and will attempt to complete that process before FCA 10 is conducted. The contingency plan discussions will help provide a head start should this happen.
September 2015	NEPOOL Markets Committee vote on market rule changes related to delaying the full integration of demand response into the energy and reserve markets.

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[7] *Electric Power Supply Association v. FERC*, D.C. Cir. Nos. 11-1486 (D.C. Cir. December 15, 2014) (per curiam) (order granting government's motion to extend stay of the mandate through January 15, 2015 pending filing and disposition of petition for a writ of certiorari).

[8] *Federal Energy Regulatory Commission v. Electric Power Supply Association et al.*, U.S. Supreme Court No. 14-840 (US, January 15, 2015) (petition for a writ of certiorari). A petition for a writ of certiorari of *EPSA* was also filed separately by a group of other entities. See *EnerNOC, Inc. et al. v. Electric Power Supply Association et al.*, U.S. Supreme Court No. 14-841 (US, January 15, 2015).

[9] *EPSA* at p. 16.

[10] Other market rule changes related to the current administration of Demand Resources – which are unrelated to this contingency plan – will likely be proposed by the ISO during this period. These changes will be discussed with stakeholders pursuant to the normal stakeholder process.

October 2015	NEPOOL Participants Committee vote on market rule changes related to delaying the full integration of demand response into the energy and reserve markets; filing with the FERC.
January 2016 (prior to FCA 10)	Order from the Commission on market rule changes.
June 2016	If the Supreme Court decides to review *EPSA* in 2015, but ends up affirming *EPSA* in or around June 2016, the ISO will thereafter begin the process of revising its market rules as directed by the Commission and will attempt to complete that process before FCA 11 is conducted. If *EPSA* is reversed, the ISO would execute its plan to integrate demand response resources into the capacity, energy, and reserves markets by June 1, 2018.

III. Major Uncertainties – Timing and Legal Interpretations

A. Timing of the Legal and Regulatory Process

If the Supreme Court decides not to review *EPSA*, the DC Circuit will issue a mandate to vacate Order 745 soon thereafter. Then, the Commission must direct the wholesale market operators to change their market rules to comply with the mandate. However, the process and substance of the Commission's direction is unknown. In particular, it is not clear whether the Commission will interpret *EPSA* narrowly or broadly, as discussed more below. Obviously, the Commission's interpretation will influence the market rule changes the RTOs will be directed to make.

If, on the other hand, the Supreme Court decides to review *EPSA*, the ultimate outcome of the Supreme Court's decision would be unknown until as late as mid-2016. If the Supreme Court reverses the DC Circuit's decision in *EPSA*, the ISO would continue to execute its current plan for integrating demand response resources in the capacity, energy, and reserves markets, albeit on a slightly different timeline as described in this paper. If the Supreme Court upholds the DC Circuit's decision in *EPSA*, the findings upon which the Supreme Court's final decision is based could limit or expand the applicability of *EPSA* and ultimately influence what the Commission directs the wholesale market operators to do to comply. The approach that the Commission might take is uncertain at this time, and the selected approach may lead to further litigation.

If a mandate to vacate Order 745 is issued and it is found that *EPSA* also applies to demand response resources participating in wholesale capacity markets, another uncertainty involves the potential retrospective application of these findings to demand response resources that cleared in past FCAs for upcoming Capacity Commitment Periods. This possibility further complicates and increases the number of possible future outcomes. To simplify this contingency plan, the ISO will address this issue at the appropriate time – i.e., if and when a mandate to vacate Order 745 is issued and the Commission finds that the mandate applies to Demand Resources participating in wholesale capacity markets. This may involve potentially revising the obligations, and/or providing opportunities to release the obligations, of demand response resources that previously cleared in FCA 8, 9 and/or 10 as specified by the Commission.

B. Legal Interpretation: *EPSA* Could Be Interpreted Broadly or Narrowly

The approach taken by the region to continue to integrate Demand Resources into the electricity market is dependent upon how expansively the Commission (and possibly the Supreme Court) interprets *EPSA*.

Order 745 requires RTOs to pay the full LMP to demand response providers participating in organized wholesale energy markets when (1) the demand response has the capability to balance supply and demand, and (2) the benefit to consumers exceeds the cost of dispatching and paying the LMP to demand response resources.[11] The *vacatur* of Order 745 immediately affects demand response participating in wholesale energy markets as a supply-side resource given that Order 745 was a ruling that affected the rates, terms and conditions of those wholesale market operators that allow demand response to participate in and derive payments from their energy markets.

EPSA is premised on a finding that Order 745 constitutes an attempt by the Commission to directly regulate the "retail [energy] market" (the jurisdiction over which is reserved to the states).[12] If, as the *EPSA* decision found, the Commission lacks jurisdiction to order payment of wholesale energy market prices to demand response providers, this raises the question as to whether that jurisdiction is similarly lacking in the wholesale capacity and reserve markets. Given the linkage between the energy, capacity and reserve markets, it is likely that continued participation of demand response resources in the FCM and other wholesale markets will be protested on the basis of the jurisdictional analysis put forth in *EPSA* should the court issue the *EPSA* mandate.

Unfortunately, we do not know how expansively the Commission and future courts will interpret *EPSA*. Given this uncertainty, the ISO's contingency plan must identify a range of potential likely outcomes and develop a plan for those outcomes. The next section addresses how the ISO could comply with either a narrow or a broad interpretation of *EPSA*. Developing potential compliance approaches in these two relatively extreme cases would assist the ISO in quickly developing the actual compliance approach as the legal process unfolds and the Commission directs the ISO to comply with a mandate that might be issued by the courts.

IV. Approach to Major Uncertainties and Scenario Analysis

A. No Matter the Timing of the Legal Process or the Interpretation of *EPSA*, a Delay in the Full Integration of Demand Response is Needed

Under any conceivable scenario, the ISO believes that full integration of demand response into the energy and reserves market (presently scheduled for June 1, 2017[13]) must be delayed. Fully integrating demand response into the energy and reserves markets is a complex undertaking, which will take at least two years to implement.[14] Given the possibility that the Supreme Court may uphold the DC Circuit's decision

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[11] Order 745 also required RTOs to make any necessary changes to maintain accurate baselines from which to measure the amount of demand response provided, and to allocate energy costs associated with demand response proportionally to all entities that purchase from the relevant energy market where the demand response reduces LMPs.

[12] *EPSA* at p. 16.

[13] *ISO New England Inc. and New England Power Pool*, Docket No. ER15-257-000, Market Rule 1 Changes to Integrate Price-Responsive Demand into Reserve Markets (October 31, 2014); *ISO New England Inc. and New England Power Pool Participants Committee*, 150 FERC ¶ 61,007 (January 9, 2015).

[14] From the time the Commission accepted the integration of demand response into the reserve markets in January 2015, the ISO would have had almost 30 months to implement its plan to fully integrate demand response into the wholesale markets

in *EPSA*, the most prudent course of action at this time is to delay by at least one year the full integration of demand response into the energy and reserves market—i.e., from June 1, 2017 to June 1, 2018.

If the Supreme Court declines to review *EPSA* in June 2015, then the mandate to vacate Order 745 goes into effect immediately and the full integration of demand response into the energy and reserves markets must be permanently suspended and replaced with a new approach pursuant to Commission guidance.

If the Supreme Court agrees to review *EPSA*, the outcome of the Supreme Court's review would not be known until around June 2016. Since it will take the ISO at least two years to modify its software and system infrastructure to integrate demand response into the energy and reserves markets, the ISO would be at least one-year into the project to meet the June 1, 2017 implementation date before knowing the Supreme Court's ultimate decision. And for all of the time, money, and effort expended up to that point, the Supreme Court may nevertheless uphold the DC Circuit's previous ruling. Substantial resources will be wasted if the ISO moves forward to fully integrate demand response into the energy and reserves market by June 1, 2017 and the Supreme Court ultimately upholds *EPSA*.

Prudent resource management, therefore, requires that ISO New England delay this resource-intensive project until the Supreme Court decides its course of action and, if applicable, issues its final ruling. If the Supreme Court reverses the DC Circuit's decision in *EPSA*, that decision would likely be issued by June 2016, which should be sufficient time to implement the full integration of demand response resources into the energy and reserves markets by June 2018. Should the Supreme Court uphold *EPSA*—by declining to review the case in 2015 or by affirming the DC Circuit's decision in 2016— the delay would give the region a better opportunity to develop and implement an alternative approach by June 2018.

Delaying the full integration implementation date from June 1, 2017 to June 1, 2018 will require market rule changes for demand response participation in the 8th Capacity Commitment Period, which runs from June 1, 2017 to May 31, 2018. To do so, the currently effective market rules for Real-Time Demand Response Resources—already found by the Commission to be just and reasonable—would need to be extended to apply to the 8th Capacity Commitment Period. This approach is the most expeditious and efficient proposal the ISO can implement under the current circumstances.

B. Scenario Analysis: Potential Approaches to a Narrow or a Broad Interpretation of *EPSA*

1. Scenario 1: The Commission Prohibits Demand Response Participation in the Energy Markets, but Allows Demand Response to Participate in Other Wholesale Markets

a. Demand Response as a Supply Resource in Capacity and Operating Reserve Markets

Under Scenario 1, the Commission orders that the participation of demand response as a supply resource in the energy markets be prohibited in response to the *EPSA* mandate that Order 745 be vacated. Here, the Commission interprets a court mandate to vacate Order 745 as limited to the participation of demand response in energy markets only. This scenario is the least disruptive to the current approach under which Demand Resources participate in the wholesale markets as a supply resource.

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by June 2017 were it not for the uncertainties caused by *EPSA*. So even a 24-month implementation schedule is aggressive relative to the schedule with which the ISO was previously working.

i. Capacity Commitment Periods prior to June 1, 2018

Presuming a one-year delay in the full integration implementation date, for Capacity Commitment Periods prior to June 1, 2018, Real-Time Demand Response ("RTDR") and Real-Time Emergency Generation ("RTEG") Resources are not integrated into and are not required to participate in the energy markets. Rather, RTDR and RTEG Resources with a Capacity Supply Obligation ("CSO") in the FCM are required to reduce demand in Real-Time when the ISO experiences a capacity deficiency and implements certain actions of ISO New England Operating Procedure No. 4.[15] Additionally, market participants with RTDR Resources are eligible, but are not required, to participate in a transitional price-responsive demand ("TPRD") program which pays participants the full LMP for reduced energy consumption when the participant's Demand Reduction Offer[16] is in economic-merit order.

Apart from cancelling this optional TPRD program and discontinuing energy payments to RTDR and RTEG Resources when dispatched by the ISO,[17] it appears that the current approach to active Demand Resources in the FCM rules could continue until June 1, 2018, even if the Court vacates Order 745 under this scenario. Likewise, passive Demand Resources, like On-Peak and Seasonal Peak Demand Resources consisting mostly of Energy Efficiency and some Distributed Generation measures, could continue participating in the FCM. By definition, passive Demand Resources cannot be dispatched to balance supply and demand, which makes them ineligible for full LMP payment under Order 745, so vacating Order 745 itself has no direct impact on passive Demand Resources.

ii. Capacity Commitment Periods starting on and after June 1, 2018

Beginning with the FCM rules in place for the 2018-2019 Capacity Commitment Period (again, presuming a one-year delay in the full integration implementation date), a demand response resource[18] must submit Demand Reduction Offers into the energy markets in an amount equal to or greater than its CSO whenever the resource is physically available for dispatch.[19] Under Scenario 1, a demand response resource cannot participate in the energy market, causing it to be incapable of meeting its CSO under the current FCM rules starting June 1, 2018.

To allow demand response resources to continue participating in the FCM on and after June 1, 2018 and yet comply with the *EPSA* mandate, the market rules must be modified. Rather than dispatching a

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[15] *See* http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

[16] The Demand Reduction Offer is an energy offer that includes a $/MWh price and a MW quantity of consumption that the participant is willing to reduce if LMPs are at or above the $/MWh price offer. Once demand response resources are fully integrated into the energy and reserve markets, a demand response provider could submit inter-temporal parameters, similar to those of generators, as part of a demand response resource's Demand Reduction Offer.

[17] According to the current FCM rules, RTDR and RTEG Resources are paid the full LMP for reduced energy consumption when these resources are dispatched by the ISO in accordance with ISO New England Operating Procedure No. 4 and in accordance with Section III.13.6.1.5.4 during a Seasonal DR Audit. Given the small number of hours in a year that these resources are typically dispatched, energy payments constitute a relatively insignificant amount of revenue to RTDR and RTEG Resources even at the full LMP.

[18] Starting with the 2018-2019 Capacity Commitment Period, RTDR Resources are replaced by "Demand Response Capacity Resources" and "Demand Response Resources." A Demand Response Capacity Resource participates in the FCM, acquires a CSO if cleared, and consists of an aggregation of one or more Demand Response Resources. A Demand Response Resource participates in the Day-Ahead and Real-Time Energy Markets, and could be designated to provide Operating Reserve, through the submission of a Demand Reduction Offer. For simplicity, the general term "demand response resource" will be used to refer to both Demand Response Capacity Resources and Demand Response Resources.

[19] Market Rule 1, Section III.13.6.1.5.1.

demand response resource in accordance with a Demand Reduction Offer submitted into the energy markets, a simple approach could be to require demand response resources be subject to ISO dispatch to reduce demand prior to, or concurrent with, a scarcity condition[20] as defined by FCM PFP.[21] Because the market rules for FCM PFP go into effect on June 1, 2018, this approach would bring demand response resources into the FCM PFP structure at the same time as all other capacity resources, thus preserving comparable performance incentives for all capacity resources.

To consider such an approach, however, several issues need to be addressed. The first issue is the adverse impact on energy prices, particularly during scarcity conditions, from dispatching demand response resources that are not integrated into the energy market. In contrast to generating capacity resources, a demand response resource would be unable to participate in the energy markets under Scenario 1.

One of the primary reasons the ISO proposed to fully integrate demand response resources into the energy markets was to eliminate the energy price collapse these resources may cause when dispatched just prior to or concurrent with a scarcity condition, when prices should be high. During a scarcity condition, the demand curve intersects the very steep portion near the top end of the supply curve, so a small reduction in demand could produce a substantial decrease in the energy clearing price. To avoid the adverse impact of demand response on energy price formation, the ISO proposed to integrate demand reduction offers into the energy market supply function and to dispatch demand response in economic merit based upon these demand reduction offers. Under that design, a significant amount of demand response is likely to be offered into the energy market at prices higher than those of generators given that the opportunity cost of deferring consumption is likely to be higher than the marginal cost of generating energy. LMPs are based on the cost of the marginal resource so the offers from demand response resources would likely set the LMP at high levels as generation capacity becomes scarce and demand response becomes the marginal resource. This original approach eliminated the adverse impact that the dispatch of demand response previously had on energy prices. Therefore, if demand response resources are not integrated into the energy market, an alternative technique must be implemented to avoid the adverse impact of demand response dispatch on energy price formation.

The second issue that must be addressed is the potential application of non-performance penalties under FCM PFP to a demand response resource that is not dispatched by the ISO during a scarcity condition. A scarcity condition may occur unexpectedly and for a short period of time. A resource that is not dispatched during this period may incur performance penalties under the current FCM PFP rules even though the resource was otherwise available to help bring supply and demand into balance. Consistent with the treatment of generating capacity resources under FCM PFP, the ISO is considering an approach where Market Participants would be responsible for monitoring system conditions and dispatching their demand response resources whenever scarcity conditions arise.

An approach that would allow available demand response resources to perform under FCM PFP, even if these resources were not dispatched to reduce demand during a scarcity condition, would be to allow demand response resources to provide Operating Reserve. Under FCM PFP, a resource providing Operating Reserve (and not providing energy) during a scarcity condition is considered to be performing for the amount of Operating Reserve provided. However, the manner in which a resource is designated

[20] A scarcity condition occurs any time the ISO is unable to meet the combined energy and operating reserve requirement needed for reliable operations.

[21] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (May 30, 2014); *ISO New England Inc.*, 149 FERC ¶ 61,009 (October 2, 2014).

to provide Operating Reserve under the present market design is contingent upon its participation in the energy market; offers submitted into the energy market are used to determine which resources ought to be dispatched to provide energy or designated to provide reserves as part of the co-optimization process. Therefore, changes to the current market rules and system infrastructure would be needed to enable demand response resources to provide Operating Reserve or to participate in the Forward Reserve Market ("FRM") if these resources are not able to participate in the energy market.

The current market rules could be revised so that a demand response resource with demonstrated physical characteristics consistent with that of a Fast Start Demand Response Resource[22] could be designated to provide Operating Reserve and participate in the FRM. And rather than demand response resources submitting energy offer prices, which would have been used to establish Real-Time Reserve Clearing Prices, an administratively-determined (and relatively high) energy price could be assigned to demand response resources, which would be used in the reserve designation process (and the energy dispatch and LMP-setting process for that matter).[23] However, given the prohibition on demand response participation in the energy/reserve market structure in this scenario, these resources could not be paid the LMP or the Real-Time Reserve Clearing Price.

In summary, rather than using energy market offer parameters to attach a price to the dispatch of demand response resources (and avoid energy price collapse during a scarcity condition) and to determine their eligibility to provide Operating Reserve, the rules could specify the dispatch price and the eligibility requirements that a demand response resource must meet to be designated to provide Operating Reserve and to participate in the FRM. Under this approach, a demand response resource participating in the FCM would receive a capacity payment (and a FRM payment rate if participating as a Forward Reserve Resource), but would not receive energy or Real-Time Reserve revenues. Such an approach would not only require market rule changes, but would also require implementing other, major infrastructure changes similar to those the ISO was considering under the full integration of demand response into the energy and Operating Reserve market structure.

b. Summary of Changes Needed to Implement Scenario 1

To allow demand response resources to participate in the FCM and/or Operating Reserve structure under Scenario 1, the following changes to the market rules and system infrastructure are needed:

- Extend the current FCM rules governing Real-Time Demand Response Resources until June 1, 2018;
- Eliminate the transitional price-responsive demand program – codified in Section III.E1 of the Tariff – and discontinue energy payments to Real-Time Demand Response Resources and Real-Time Emergency Generation Resources;
- Require demand response resources with a CSO be subject to ISO dispatch to reduce demand prior to, or concurrent with, a scarcity condition (and not in response to dispatch based on an energy market offer) as defined by FCM PFP starting June 1, 2018;

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[22] Under the market rules for the full integration of demand response resources into the energy and Operating Reserve market structure, the ISO proposed and the Commission accepted that an undispatched Demand Response Resource must meet the definition of a "Fast Start Demand Response Resource," which had physical characteristics comparable to that of a Fast Start Generator, to provide Operating Reserve.

[23] The administrative price used for this purpose should be slightly less than the RCPF for TMOR – e.g., RCPF for TMOR is presently $1,000/MWh, so the administrative price could be $999/MWh. At this price, the ISO's existing software would be able to determine a dispatch solution inclusive of demand response resources, and would most likely utilize demand response resources to provide Operating Reserve instead of other, lower-priced generating resources.

- Implement a technique (e.g., an administratively-determined dispatch price) to avoid the adverse impact of demand response dispatch on energy prices;
- Consistent with the treatment of generating capacity resources under FCM PFP, develop market rules making Market Participants responsible for dispatching their demand response resources during scarcity conditions; and
- Investigate the possibility of demand response resources providing Operating Reserve and participating in the FRM, which can potentially be accomplished by requiring that all demand response resources have demonstrated physical characteristics consistent with that of a Fast Start Demand Response Resource and assigning a relatively high, administratively-determined energy offer price that would be used in the reserve designation process.

2. Scenario 2: The Commission Prohibits Participation of All Demand Resources on the Supply-Side of Jurisdictional Wholesale Electricity Markets

a. Introduction

Arguably, the decision vacating Order 745 is confined to the payment of demand response resources participating in the wholesale energy market. However, the jurisdictional analysis used by the appellate court to vacate Order 745 is likely to be used as precedent in litigation addressing Demand Resource participation in the wholesale markets generally, including the FCM and possibly the ancillary service markets. Given this risk, this paper addresses the scenario in which the Commission orders all Demand Resources operating as supply resources to be removed from all wholesale electricity markets generally.

This issue is already in play within PJM, due to the FirstEnergy Complaint.[24] That complaint seeks to remove demand resources from PJM's 2014 Base Residual Auction – the equivalent to the ISO's FCA. PJM released a white paper on October 6, 2014 outlining an approach that would allow demand resources to participate on the demand-side of the capacity market through load-serving entities ("LSEs"). The PJM white paper noted the strong linkage between the energy and capacity markets, which it argues places demand resource participation in the capacity markets at risk:

> Moreover, the linkage between the capacity and energy markets is undeniably strong. After all, the theory underlying the purpose of capacity markets is the recognition that energy markets alone are impeded in providing sufficient compensation to supply – due in part to the suppressing effect of offer caps, reserve margins and other features giving rise to a "missing money" problem that capacity markets are designed to solve. PJM's unfolding capacity performance initiative more explicitly defines capacity in reference to a resource's performance in the energy markets, further suggesting that capacity is simply a form of inchoate energy or a call on energy. The derivative and interdependent nature of the capacity market vis-a-vis the energy market raises the question under *EPSA* whether a commitment to curtail in the capacity market (a demand resource) is functionally any different than a commitment to curtail in the energy market.[25]

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[24] *See FirstEnergy Service Company*, Complaint of FirstEnergy Service Company, Docket No. EL14-55-000 (May 23, 2014, amended September 22, 2014) ("FirstEnergy Complaint"). A similar protest was filed by the New England Power Generators Association. *See New England Power Generators Association, Inc.*, Complaint Requesting Fast Track Processing of the New England Power Generators Association, Inc., Docket No. EL14-102-000 (November 14, 2014) ("NEPGA Complaint").

[25] *PJM Interconnection*, "The Evolution of Demand Response in the PJM Wholesale Market," October 6, 2014, p. 4.

If the Commission applies this rationale, it could produce Scenario 2, in which all Demand Resources – demand response resources, Real-Time Emergency Generation Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources would no longer be eligible to participate in the FCM as supply resources.

b. Option 1: Reducing the Installed Capacity Requirement ("ICR") by Expected Additional Demand Resources

i. Description of the Approach

The calculation of the ICR relies heavily on load forecasts, which are based on historical load data. Any past Demand Resource performance would be reflected in these data. Therefore, the load-reducing impact of existing Demand Resources can be readily integrated into the FCM through the computation of the ICR,[26] effectively lowering the ICR and prompting both a lower capacity purchase amount and a lower Capacity Clearing Price.

However, if any additional Demand Resources are implemented after the load forecast and associated ICR has been determined, the FCM could end up acquiring capacity resources in excess of what is needed to meet the region's reliability criterion, which would tend to create a more reliable system, but at a higher cost. This issue is addressed under the current market design by allowing Market Participants to offer additional Demand Resources to meet the ICR as a supply resource along with generation resources. However, if the vacatur of Order 745 is interpreted broadly, Demand Resources would be prohibited from participating in the FCM as a supply resource to meet the ICR. Given this constraint, another option to address this issue would be to reduce the ICR before conducting the FCA by the projected impact of additional Demand Resources that will likely be installed for the relevant Capacity Commitment Period, but after the load forecast was estimated.

To some extent, this approach is already being utilized by the ISO for energy efficiency and is planned for photovoltaic-based distributed generation that does not participate as a supply resource in the FCM. This approach appears to be most appropriate for energy efficiency and passive distributed generation since these measures consist primarily of long-lived hardware that produces a predictable amount of energy savings the moment it is installed. Future demand reductions can be forecasted from energy efficiency and distributed generation program budgets provided by the states. Should these budgets change, the forecasted demand reductions are revised.

Estimating future demand reductions from demand response resources is a somewhat different matter. Demand response constitutes real-time changes to normal consumption behavior in response to real-time prices or real-time system conditions. The temporal and behavioral nature of demand response makes forecasting the amount of demand response that may occur in a future period complex. The actual performance of a demand response resource would depend upon specific program parameters (e.g., whether the load is under the direct control of the Market Participant, the level of the price signal/incentive, whether technology assisting the customer in responding to a price signal/dispatch instruction has been installed, the type of customers in the program and their price elasticities, the penalty imposed (if any) for not responding to or opting out of a dispatch event, etc.).

Assuming that a reliable load reduction estimate for each new Demand Resource of different types (e.g., energy efficiency, distributed generation, demand response, and perhaps new technologies such as

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[26] This is accomplished by eliminating the practice of adding back into the load forecast, which is used to determine the ICR, the load reductions produced by Demand Resources that participate in the FCM as a supply resource.

storage) can be developed, the primary problem becomes the risk that the additional Demand Resources may not be installed by the relevant Capacity Commitment Period, resulting in a less reliable electric system. For generating resources with a CSO, this risk is addressed through the application of financial assurance requirements and performance penalties under FCM PFP. However, no such construct would be in place for Demand Resources if these resources are not allowed to take on a CSO. Additionally, those installing Demand Resources do not get an immediate and proportional reduction in capacity charges, which reduce the incentive to install them. While a reduced ICR accrues to the benefit of all consumers, those installing Demand Resources to achieve that benefit incur immediate costs but do not obtain a reduced capacity charge until the historical data upon which FCM cost allocation is based includes actual load reductions produced by the Demand Resource.

To address this risk to system reliability, the ISO could subject Demand Resources to a stringent qualification and critical path schedule monitoring process, perhaps similar to the process currently applied to Demand Resources participating as a supply resource in the FCM, and would only reduce the ICR if that process indicates a high likelihood that the additional Demand Resources will be installed.

While such an approach may be adequate for resources that produce demand reductions the moment they are installed (e.g., energy efficiency and passive distributed generation), it is not clear that such an approach is adequate for demand response resources. While monitoring the progress of a Market Participant installing infrastructure to facilitate demand response (e.g., more sophisticated metering, communication, load control and/or dispatchable distributed generation technology) is relatively straightforward, the load reductions facilitated by this technology also depend upon the active response of customers during scarcity conditions. This implies that a FCM PFP-like incentive structure is needed to better ensure that the anticipated amount of demand response that was integrated into the ICR computation is produced during scarcity conditions.

ii. Summary of Changes Needed to Implement Option 1

Under Option 1 of Scenario 2, all Demand Resources—demand response resources, Real-Time Emergency Generation Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources—would no longer be eligible to participate in the wholesale markets as supply resources. Since the load-reducing impact of existing Demand Resources can be readily integrated into the FCM through the computation of the ICR as described above, the approach under Option 1 would be to reduce the ICR by a projection of additional Demand Resources. Implementation activities under Option 1 include:

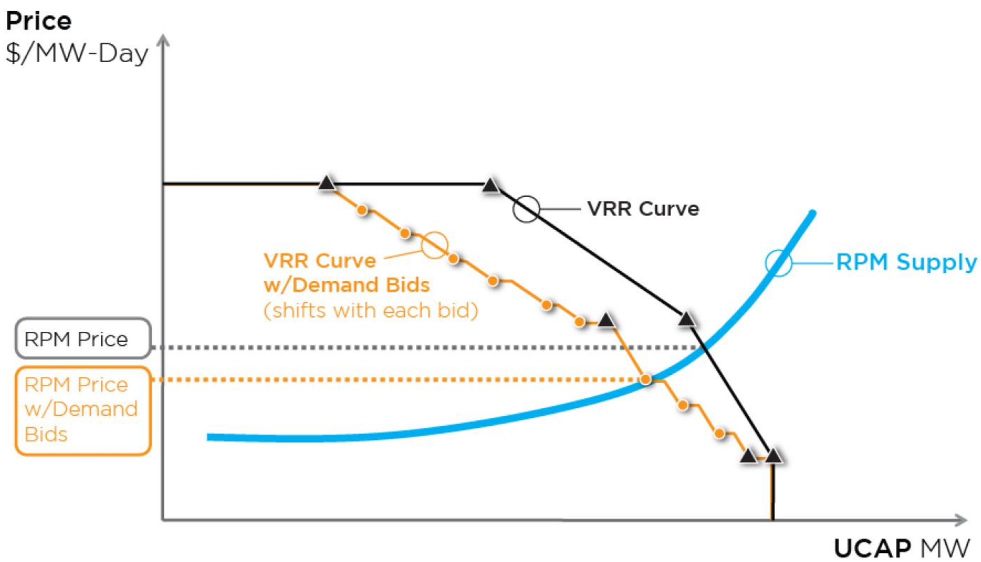
- Extend the current FCM rules governing Real-Time Demand Response Resources until June 1, 2018;
- For the 2018-2019 Capacity Commitment Period and beyond, eliminate all Tariff provisions related to demand response resources, Real-Time Emergency Generation Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources;
- Modify the FCM rules so as to subject incremental Demand Resources to a qualification and critical path schedule monitoring process similar to the process currently applied to Demand Resources participating in the FCM, and reduce the ICR if that process indicates a high likelihood that the additional Demand Resources will be installed; and
- Investigate the need for a FCM PFP-like incentive structure to better ensure that the anticipated amount of demand response that was integrated into the ICR computation is produced during scarcity conditions.

c. PJM Demand-Side Proposal

To address the potential loss of Demand Resource capacity should these resources be prohibited from participating on the supply-side of capacity market, PJM outlined a "demand-side" approach in its October 6th whitepaper (cited above), for which detailed market rules were filed with the Commission on January 14, 2015.[27]

The PJM proposal allows LSEs to submit load reduction bids into the capacity market, which would be integrated into the demand curve (not the supply curve) of the capacity market. To participate in this market structure, demand response providers must either take on load obligations, in which case they become an LSE, or participate indirectly by assisting an LSE in meeting any cleared load reduction obligation. These load reduction bids would shift the administrative demand curve in the capacity market to the left (see Figure 1 below).[28] If any of these load reduction bids clear, the amount of capacity purchased in the market and the resulting capacity clearing price would be lower. A detailed example of how load reduction bids can be integrated into a forward capacity market structure and the impact of such bids on the market-clearing solution is presented in Appendix A.

Figure 1: Integration of Demand Response Bids with RPM Demand Curve



Shown based on existing PJM Variable Resource Requirement Curve.
PJM has proposed an alternative demand curve as part of the triennial review process.

Under the PJM demand-side proposal, LSEs with cleared load reduction bids do not receive any capacity payments. Rather, the LSE would receive a reduced capacity obligation for the load reduction that cleared the market, which in turn lowers its capacity charge. If load is curtailed in real time, the LSE does not receive energy payment, but instead avoids paying the LMP for the curtailed load. On the other hand, PJM

[27] *PJM Interconnection, L.L.C.*, Revisions to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA"), Docket No. ER15-852-000 (January 14, 2015). Note that the Commission rejected the filing on March 31, 2015, based on the finding that it was premature. *See PJM Interconnection, L.L.C.*, 150 FERC ¶ 61,251 (March 31, 2015).

[28] Figure 1 from *PJM Interconnection*, "The Evolution of Demand Response in the PJM Wholesale Market," October 6, 2014, p. 7.

argues that loads providing ancillary services (i.e., regulation and operating reserve) could continue receiving payment for providing those services.[29]

To facilitate implementation of this approach, PJM initially would apply all of the existing "supply-side" demand resource rules to LSE load reduction bids. For example, an LSE could submit a Wholesale Load Reduction ("WLR") bid, reflecting a commitment to reduce demand in real time when needed by the system operator, and/or a Wholesale Energy Efficiency Load ("WEEL") bid, reflecting a commitment to reduce demand during all on-peak hours by installing energy efficiency measures, into the Base Residual Auction (PJM's version of the ISO's FCA). If the bid clears, the LSE with the cleared bid is now obligated to produce the demand reduction. The specific rules regarding how an LSE meets its demand reduction obligation, including availability, notification and start-up requirements, qualification, financial assurance, asset registration, auditing, measurement and verification, penalties for non-performance penalties, etc., are almost identical to the current supply-side rules applied to demand resources. In exchange, the LSE receives a lower capacity obligation from PJM.

It is also important to note that PJM has recently proposed to implement its Capacity Performance market design, similar to ISO New England's FCM PFP, in its capacity market.[30] To provide performance incentives to LSEs with WLR and WEEL resources once this market design goes into effect, PJM proposes that revenue collected from all non-performing capacity resources, including WLR and WEEL resources,

> [B]e distributed to all energy resources (of any type, even if they are not Capacity Resources), all WLR Loads, and all WEELs that performed above expectations. A WLR Load (or WEEL) with an Actual Performance above its Expected Performance is considered to have provided "Bonus" Performance, and will be assigned a share of the pooled Non-Performance Charge revenues based on the ratio of its Bonus Performance to the total Bonus Performance (from all resources, WLR Loads, and WEELs) for the same Performance Assessment Hour."[31]

d. Building on the PJM Approach

Building on the PJM approach, LSEs need strong economic incentives to encourage more of its customers (and not just customers presently with load control capability) to use electricity more efficiently. After all, it is the aggregate consumption of all customers that contribute to peak load and scarcity conditions. If

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[29] PJM asserts that loads providing ancillary services (i.e., regulation and operating reserve) could continue to receive payment for providing those services. PJM argues that:

> Ancillary services are well-defined wholesale products and services closely tied to the FERC's federal authority over interstate transmission service. They were defined as required elements of open access transmission service in FERC Orders Nos. 888 and 889. Ancillary services are not directly bought or sold at retail by, or from, end users. As such, they are not matters historically under state purview. While ancillary services support the consumption and delivery of electric energy, they are discretely recognized and not, by PJM's way of thinking, so closely linked as capacity might be to energy. *Id.*, p. 8.

[30] On December 12, 2014, in Docket Nos. ER15-623-000 and EL15-29-000, PJM filed proposed revisions to the RPM rules to be effective April 1, 2015, that implement ISO New England's FCM Performance Incentives approach to the PJM RPM. *PJM Interconnection, L.L.C.*, Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA"), Docket No. ER15-623-000 (December 12, 2014) ("Capacity Performance Filing").

[31] *PJM Interconnection, L.L.C.*, Revisions to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA"), Docket No. ER15-852-000 (January 14, 2015) at 70.

wholesale prices are not allowed to reflect the true value of electricity at every moment in real time (particularly during times of scarcity), wholesale price volatility is inaccurately muted—leaving LSEs with little motivation to encourage more retail customers to become more price-responsive, which in turn reduces the economic incentive for additional energy efficiency, distributed generation, and/or demand response capability.

One simple approach that would provide LSEs with an incentive to pursue demand reductions is to allow energy prices to increase during scarcity conditions to a level more reflective of the value of lost load. In addition to financial hedging instruments, LSEs could also use retail Demand Resource products to address the resulting price volatility. Energy efficiency measures and non-dispatchable distributed generation could be used to reduce total power requirements (i.e., the amount of power purchased from the wholesale power grid) across a broad set of hours, and a combination of dynamic retail pricing, load control, and dispatchable distributed generation (perhaps combined with storage) could be used to encourage price-responsiveness for the remaining power requirement.

e. Option 2A: Encouraging LSE Pursuit of Demand Resources Through Revised FCM Cost Allocation

Another way to encourage LSEs to consider cost-effective Demand Resources is to modify the manner in which capacity costs are allocated among LSEs. The basic idea is that LSEs whose customers consume less than the proportional share of capacity purchased on their behalf through the FCM when capacity is in short supply should have their FCM cost allocation decreased; those that consume more should have their FCM cost allocation increased. To control and/or reduce FCM costs, therefore, LSEs would be encouraged to work with their retail customers to control consumption with Demand Resources, but only to the extent where the cost of the Demand Resource is less than the avoided energy and FCM costs.

The recommended approach would parallel the ISO's FCM PFP proposal, which was accepted by the Commission with modifications.[32] The objective of FCM PFP was to align supplier production incentives with the value that customers place on reliable service during scarcity conditions. Whereas the FCM PFP project focused on enhancing the incentives for the supply-side of the market to perform during scarcity conditions, a similar approach can be taken to enhance the incentives for the demand-side of the market. Such an approach recognizes that it is the collective action of the Market Participants on both the supply- and demand-sides of the market that create and/or alleviate scarcity conditions.

Similar to the manner in which FCM PFP allocates monthly capacity revenues among capacity suppliers, the ISO could allocate monthly FCM costs by charging each LSE a Base Charge and a Performance Charge. See Appendix B for a detailed set of formulas and examples, which reflect the FCM cost allocation approach described here. As in FCM PFP, the Performance Charge is the critical change in FCM cost allocation that would encourage cost-effective demand response, as well as other Demand Resources.

Like the approach used to incentivize capacity suppliers to perform during a scarcity condition, the Performance Charge would be designed to incentivize LSEs (who in turn could incentivize their retail customers) to control their consumption during a scarcity condition. The Performance Charge would be the product of the Performance Payment Rate, which should be the same Performance Payment Rate used to provide capacity suppliers with economic incentives to perform during scarcity conditions, and a Demand Score. The Demand Score is like the performance score established for a capacity supplier under FCM PFP and would be based on the difference between an LSE's actual consumption during a scarcity

[32] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (May 30, 2014) (May 30, 2014 Order); *ISO New England Inc.*, 149 FERC ¶ 61,009 (October 2, 2014).

condition (or more accurately, the actual consumption of the retail customers served by the LSE during a scarcity condition) and the capacity allocated to the LSE to serve that consumption. If the LSE's customers consume more than their allocated share of capacity during the scarcity condition, the Demand Score should be positive, resulting in a positive Performance Charge and thus a higher FCM Charge for the month. Conversely, if the LSE's customers consume less than their allocated share of capacity during the scarcity condition, the Demand Score should be negative, resulting in a negative Performance Charge, and thus a lower FCM Charge for the month.

Under FCM PFP, a balancing ratio was also applied to account for the actual energy and reserve requirement at the time of a scarcity condition so as to prevent non-performance penalties under conditions when not all of a resource's CSO is needed. Similarly, a Demand Balancing Ratio must be applied to ensure that LSEs receive lower FCM Charges for decreasing consumption below, and receive higher FCM Charges for increasing consumption above, their proportionate share of capacity available to serve system energy requirements at the time of a scarcity condition.

If the customers of one LSE consumes more than their proportional share of capacity during a particular scarcity condition, the customers of another LSE must be consuming less than their proportional share of capacity during that same scarcity condition (assuming that load is still being served). Accordingly, any increase in FCM Charges billed to over-consuming LSEs would be used to decrease the FCM Charges of under-consuming LSEs. This approach, which is in contrast to the PJM approach, allows the transfer of performance penalties and payments among capacity suppliers to be kept separate from those transferred among LSEs.

Ultimately, LSEs whose customers reduce consumption below their share of the capacity purchased on their behalf through the FCM during scarcity conditions will have a lower FCM Charge. On the other hand, LSEs whose customers increase consumption above their proportionate share of capacity will have a higher FCM Charge. This gives LSEs the incentive to control the physical energy consumption of their customers to a level at or below the proportionate share of capacity procured through the FCM to serve their customer's energy requirements so as to control monthly FCM Charges.

LSEs could control the physical energy consumption of their customers through a variety of means such as installing additional energy efficiency, distributed generation, and/or demand response capability. LSEs that do not attempt to control the physical energy consumption of their customers are at risk of higher than expected monthly FCM Charges that could diminish their profits.

f. Option 2B: Accounting for Incremental Demand Reduction Commitments in the FCM

i. Introduction

If implemented, the above-mentioned FCM cost allocation approach could be further modified to incorporate the idea from PJM's whitepaper to integrate demand response into the demand-side of the capacity market by allowing LSEs to submit load reduction bids. Modifications to FCM cost allocation as explained in the previous section will encourage Demand Resources. However, this approach alone would not allow an LSE to reduce the ICR at the time the FCA is conducted by committing to additional, future Demand Resource capability.

The primary advantage of allowing Demand Resources to participate in the FCM as a supply resource was to allow additional Demand Resources to clear in the FCA, affect the Capacity Clearing Price and displace unneeded generation capacity—unneeded by virtue of the electricity demand that the Demand

Resource would eliminate. Importantly, a new Demand Resource provider clearing in the FCA would have a financial obligation and incentive to deliver the Demand Resource and realize the demand reductions that displaced generation capacity from clearing the FCA. These beneficial aspects of Demand Resource participation in the FCM as a supply resource could potentially be lost, if other compensating measures are not undertaken. As mentioned previously, PJM's solution to this challenge is to integrate demand response into the demand-side of the market by allowing LSEs to bid load reduction commitments into the capacity market.

ii. Integrating Demand Reduction Bids Into FCM Cost Allocation

If the PJM solution were considered in New England, LSEs would need to submit demand reduction bids into the FCM consisting of any number of price/quantity pairs with prices specified in $/kW-month and a demand reduction quantity in kW (with a minimum reduction amount of, say, 100 kW per block). These bids would be incorporated into the appropriate zonal demand curves for capacity as illustrated in Figure 1 above and Appendix A. The intersection of the supply and demand curves constitutes the market clearing solution, which establishes the Capacity Clearing Price, the Capacity Supply Obligations of capacity suppliers, and the "Demand Reduction Obligations" of LSE's whose demand reduction bids clear the auction. As seen in Figure 1 and Appendix A, the clearing of Demand Reduction Obligations lowers the amount of capacity supply purchased in the FCA and lowers the clearing price.

If the ISO adopts this approach, the resulting Demand Reduction Obligation must be integrated into FCM cost allocation. Appendix B shows the detailed formulas by which this is accomplished. In summation, if an LSE takes on a Demand Reduction Obligation by clearing a demand reduction bid in the FCA, the LSE's Base Charge should be reduced. Further, the Performance Charge should consider consumption levels of the LSE's customers during a scarcity condition relative to the LSE's prorated share of total capacity net of its Demand Reduction Obligation – consumption higher than this level should result in a positive Performance Charge and a higher total FCM Charge; consumption lower than this level should result in a negative Performance Charge and a lower total FCM Charge. This provides the financial motivation for an LSE to produce the requisite demand reduction during a scarcity condition so as to prevent system reliability from degrading.

Of course, the amount of demand reduction produced does not have to equal the full Demand Reduction Obligation for every scarcity condition. Just as a balancing ratio is used to adjust the notional obligation of a capacity supplier when total system requirements in real time are not equal to the ICR, the Demand Reduction Obligation should also be adjusted to account for real-time system requirements at the time of a scarcity condition. To provide this incentive, Demand Reduction Obligations must be incorporated into the LSE's Demand Score. Outside of scarcity conditions, the LSE should receive no additional capacity charges even if its customers consume at levels exceeding the LSE's prorated share of total capacity net of its Demand Reduction Obligation.

By taking on a Demand Reduction Obligation through Demand Resource implementation, an LSE reduces its Base Charge each and every month. Additionally, Demand Resources could enable an LSE to further reduce its overall monthly FCM Charge through the Performance Charge component by reducing demand in real time in response to a scarcity condition to a level lower than its proportionate share of Available Capacity acquired through the FCM to serve the LSE's energy requirements. Finally, by taking on Demand Reduction Obligations, both the Capacity Clearing Price and the amount of capacity procured through the FCM is lowered – and on a sound, unbiased, economic basis – which accrues to the benefit of society in general.

g. Ancillary Benefits and Other Considerations From Changes to FCM Cost Allocation

The inclusion of demand reduction bids into the above-mentioned FCM cost allocation structure has the added benefit of simplicity. In contrast to the current supply-side approach to demand response, the settlement process in the approach outlined above requires no baseline computation.[33] This is because the Demand Score compares Actual MW Consumption—a quantity that can be directly measured—to the LSE's proportionate share of Available Capacity less any Demand Reduction Obligation that the LSE bids and clears in the FCA, adjusted by the Demand Balancing Ratio. Available Capacity is a fixed quantity based on the amount of capacity acquired through the FCA that is expected to be available to serve system energy requirements at the time of the annual system coincident peak, and the components making up the Demand Balancing Ratio are also directly measurable quantities.

To facilitate demand response when needed in real time, the ISO could modify its current demand response infrastructure to provide real-time information and Dispatch Instructions by location to LSEs with Demand Reduction Obligations. These Dispatch Instructions could indicate when demand must be reduced (and by how much based on the real-time information used to determine Demand Balancing Ratios), which would assist LSEs in meeting any Demand Reduction Obligation. To allow the ISO to better maintain system reliability, the available MW amount and Dispatch Zone location of specific customer sites used by LSEs to satisfy Demand Reduction Obligations should be registered with the ISO. However, other than LSEs providing ancillary services using controllable loads and distributed generation (described in the next section below), tracking the demand-reduction performance of individual customer sites providing demand response appears to be unnecessary since FCM cost allocation is based on the actual consumption of all customers served by the LSE.[34]

Finally, given the forward nature of the FCM, LSE's with Demand Reduction Obligations would likely be required to post financial assurance similar to that posted by capacity resources. However, the need to qualify LSE demand reduction bids needs more careful consideration since these requirements are a function of the strength of the price signals, performance penalty structure, and Financial Assurance requirements, and how these compare to the requirements applied to supply-side capacity resources. If it is ultimately found that qualification requirements are needed, perhaps these could be in the form of the requirements currently applied to Demand Resources.

h. Provision of Ancillary Services

The above approach to FCM cost allocation does not allow LSEs to provide regulation service or Operating Reserve. However, market rules and system infrastructure have already been implemented to allow demand technologies to provide regulation service in response to Order 755. Controllable loads (treated on the demand-side of the market) are able to provide regulation by managing consumption in

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[33] Should reconstitution be necessary, a baseline computation may be needed to determine the amount of load to be added to actual metered load so as to determine Coincident Peak Contribution percentages for the following year. The method used to compute baselines for reconstitution purposes could be similar to the method used to compute Demand Response Baselines as described in Section III.8B of the Tariff. However, the baseline would be determined after-the-fact using revenue-quality meter data (and not using telemetry data) since the baseline is not needed in real time for operational purposes, which greatly simplifies the approach and reduces costs.

[34] If responsive demands and distributed energy resources become more ubiquitous in the future, reliable system operations and efficient market operations may require registering, monitoring, *and* forecasting the real-time performance of such assets. While this is an important issue requiring further research, these operational issues are beyond the scope of this paper.

response to 4-second AGC dispatch instructions. Individual small loads may be aggregated into a single regulation resource across the system. The aggregated resource would be dispatched by the ISO, and the aggregator then dispatches the individual loads to produce the required aggregate response. Further, aggregators can modify their regulation capacity, performance characteristics, and offer prices of regulation resources on an hourly basis to reflect consumption patterns that change throughout the day. The ISO would propose no changes to this approach.

Additionally, the current market rules and system infrastructure for Dispatchable Asset Related Demand ("DARD") provide a platform that allows an LSE to purchase energy on behalf of specific end-use customers directly from the wholesale market at the Nodal LMP. DARDs can provide Operating Reserve, participate in the Forward Reserve Market, and are charged for capacity only up to its minimum consumption limit. While the DARD rules and infrastructure will need to be enhanced to allow for greater participation of demand in the provision of Operating Reserves, these could be proposed and developed at a later time.

i. Summary of Changes Needed to Implement Options 2A and 2B

Under Options 2A and 2B of Scenario 2, all Demand Resources—demand response resources, Real-Time Emergency Generation Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources—would no longer be eligible to participate in the wholesale markets as supply resources. The approach under Options 2A and 2B, therefore, would be to modify FCM cost allocation, which would give LSEs the incentive to pursue economic Demand Resources. Implementation activities under Options 2A or 2B include:

- Extend the current FCM rules governing Real-Time Demand Response Resources until June 1, 2018;
- For the 2018-2019 Capacity Commitment Period and beyond, eliminate all Tariff provisions related to demand response resources, Real-Time Emergency Generation Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources;
- Modify the FCM cost allocation rules and implement the new FCM cost allocation infrastructure as explained above, to become effective on June 1, 2018;
- If Option 2B is pursued, modify the FCA to allow LSEs to submit demand reduction bids and to take on Demand Reduction Obligations as explained above, and potentially modify the demand response system infrastructure to assist LSEs in meeting any Demand Reduction Obligations; and
- Evaluate changes to the DARD rules and infrastructure to allow for greater participation of demand in the provision of Operating Reserves and in the Forward Reserve Market.

V. Conclusion

The region's, and indeed the country's, going forward plans with respect to Demand Resources rely on future decisions by the courts and the FERC in which the content and timing of each future decision is uncertain and interdependent. Given the many unknowns and permutations, it is difficult and most likely not useful to craft a plan that addresses every conceivable outcome. Given that, the approach taken herein is to outline the timeline and process that the ISO would follow as the legal/regulatory process unfolds. Further, what the region eventually implements to integrate Demand Resources into the wholesale electricity markets should *EPSA* be upheld depends on how expansively the Commission and future courts will interpret *EPSA*. Given this uncertainty, the ISO identified a range of potential likely outcomes and developed an approach to Demand Resources under each outcome. The approaches outlined herein are not meant to represent a firm proposal by the ISO at this time, but rather were offered as potential considerations for discussion purposes. These discussions will provide valuable information to the ISO in developing its actual compliance approach, if and when directed by the Commission.

APPENDIX A: Integration and Impact of Wholesale Load Reduction ("WLR") Bids into the Forward Capacity Market[35]

Figure 1 below illustrates how WLR Bids will move the RPM[36] demand curve and reduce the capacity clearing price. The black line is the administratively determined VRR Curve[37] prescribed by PJM's Tariff. The light blue line is a typical RPM supply curve, with a greater overall quantity of supply offered as capacity prices increase. With no Wholesale Load Reductions, the demand and supply curves intersect at a point where quantity equals 167,185 MWs and price equals $400/MW-day.

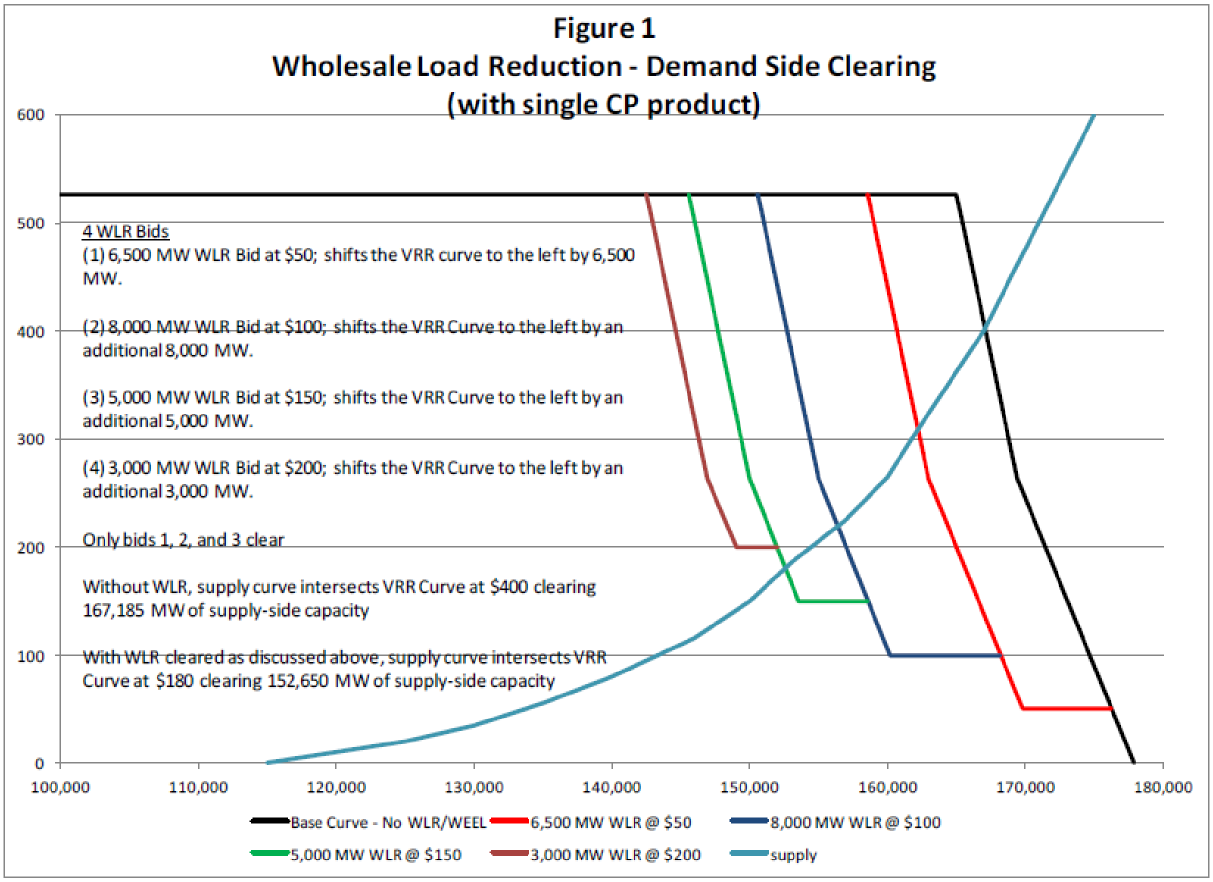

Figure 1
Wholesale Load Reduction - Demand Side Clearing
(with single CP product)

Figure 1 then shows the effect of four Wholesale Load Reduction bids. Each of these is best seen as equivalent to multiple WLR Bids with a common bid price; for simplicity, each as shown here as a single bid.[38] The first WLR Bid, represented by the red line, is 6,500 MWs, with a bid price of $50/MW-day. As

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[35] *Excerpted from: PJM Interconnection, L.L.C.*, Revisions to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA"), Docket No. ER15-852-000 (January 14, 2015) at 20-22. The explanatory footnotes in Appendix A are the author's.

[36] The term "RPM" refers to the Reliability Pricing Market, which is PJM's version of the Forward Capacity Market.

[37] The term "VRR Curve" refers to the Variable Resource Requirement Curve, which is the administratively-determined demand curve for the PJM capacity market.

[38] The term "CP product" in Figure 1 refers to the Capacity Performance product, which is a demand response resource that must be available year-round to reduce load. PJM allows other types of demand response resources (which PJM calls

with all the WLR Bids, the bid price reflects the maximum price the wholesale purchaser is willing to pay for that increment of capacity to serve its wholesale loads. Below that price, that part of the wholesale load remains in the VRR Curve; above that price, it is removed from the VRR Curve. At the $50/MW-day price point on the VRR Curve, the curve shifts to the left by 6,500 MWs. Because that load is removed from the VRR Curve at all prices above $50/MW-day, the red line runs parallel to the black line—every point on the VRR Curve above $50/MW-day is equally shifted to the left by exactly 6,500 MWs.

The second WLR Bid—represented by the dark blue line—is for 8,000 MWs of load reduction at any price at or above $100/MW-day. Because this LSE is willing to tolerate a higher capacity price, its bid is "stacked" after the first WLR Bid, which proposed to remove an increment of wholesale peak demand at a lower capacity price. This second WLR Bid shifts the demand curve to the left beginning at the $100 price point, and from that point up through every higher price point, it moves the curve exactly 8,000 MWs to the left.

The third WLR Bid—represented by the green line—is for 5,000 MWs of load reduction at any price at or above $150/MW-day. This third WLR Bid shifts the demand curve to the left beginning at the $150 price point, and from that point up through every higher price point, it moves the curve exactly 5,000 MWs to the left. The light blue supply curve now intersects this green shifted VRR Curve, and sets the revised clearing results as 152,000 MWs at $175/MW-day.

The fourth and final WLR Bid—represented by the purple line—is for 3,000 MWs of load reduction at any price at or above $200/MW-day. This fourth WLR Bid shifts the demand curve to the left beginning at the $200 price point, and from that point up through every higher price point, it moves the curve exactly 3,000 MWs to the left. Of the four bidders, this wholesale purchaser places the highest value on capacity. Unless it can forego paying at least $200/MW-day, this wholesale purchaser wants, and is willing to pay for, the capacity needed to serve this part of its peak wholesale demand during emergencies. Given that higher price tolerance, this WLR Bid shifts the VRR Curve to the left at relatively high price points, but does not affect the auction clearing results. As a result of the other three, lower-priced, WLR Bids, the supply curve already intersects the left-shifted VRR Curve at a price below $200/MW-day.

"products") with limited availability to participate in the RPM (e.g., summer-only demand response). However, PJM also restricts the total amount of limited-availability demand response products that can clear the capacity market to avoid diminishing expected system reliability to unacceptable levels. Clearing the capacity market with limited-availability demand response products is more complicated. However, these more complicated examples are not presented here given that the example from PJM's filing quoted above most closely resembles the availability requirement of Demand Response Capacity Resources in the ISO New England Tariff.

APPENDIX B: Mathematical Formulation of FCM Cost Allocation under FCM Pay-For-Performance, Which Will Encourage Price-Responsive Demand

Similar to the manner in which FCM PFP allocates monthly capacity revenues among capacity suppliers, the ISO could allocate monthly FCM costs by charging each LSE a base and performance charge as shown in equation (1) below:

FCM Charge = Base Charge + Performance Charge (1)

Generally, the Base Charge would be the product of the Net Regional Clearing Price as described in Section III.13.7.3 of the Tariff, which is based on the Capacity Clearing Price for a Capacity Zone, and the LSE's Share of Total CSO as shown in equation (2).[39]

Base Charge = (NRC Price × Share of Total CSO) (2)

The LSE's Share of Total CSO could be based on the method currently used. Generally, an LSE's Share of Total CSO is equal to the sum of the Coincident Peak Contribution percentages[40] of the Load Assets served by that LSE in the month of the Capacity Commitment Period – i.e., the LSE's "SCPC %" as shown in equation (3) – multiplied by the sum of all supplier CSOs. The sum of all supplier CSOs – i.e., "Total CSO MW" as shown in equation (3) – reflects the total amount of capacity acquired in the FCM to meet the Installed Capacity Requirement ("ICR") as adjusted by the demand curve.

Share of Total CSO = SCPC % × Total CSO MW (3)

The total of Base Charges billed to all LSEs in a month would be equal to the total of Base Payments made to suppliers in the same month. Essentially, equations (2) and (3) reflect the way in which FCM costs are allocated to LSEs under the present market rules – i.e., currently, LSEs receive only a monthly base charge with no performance adjustment during scarcity conditions. Charging FCM costs on a fixed basis (with no adjustment for performance) as under the current rules gives LSEs a poor incentive to pursue demand response and other Demand Resources.

As in FCM PFP, the critical change in FCM cost allocation in equation (1) that would encourage Demand Resources is the Performance Charge. Like the approach used to incentivize suppliers to perform during a scarcity condition, the Performance Charge would be designed to incentivize LSEs (who in turn could incentivize their retail customers) to control their consumption during a scarcity condition. The Performance Charge of an LSE would be the product of the Performance Payment Rate, which should be the same Performance Payment Rate used to provide capacity suppliers with economic incentives to perform during scarcity conditions, and a Demand Score. See equation (4):

Performance Charge = Performance Payment Rate × Demand Score (4)

The Demand Score, like the performance score established for a capacity supplier under FCM PFP, would be based on the difference between an LSE's actual consumption during a scarcity condition (or more

[39] For simplicity, the equations presented herein are for a capacity market with a single Capacity Zone. The actual ISO settlement process, however, differentiates capacity requirements, Coincident Peak Contribution percentages, and clearing prices by Capacity Zone. Also for simplicity, Customer HQICCs, Customer Capacity Load Obligation Bilaterals, and Self-Supplied MW have been excluded from these formulas.

[40] A Coincident Peak Contribution percentage is a Load Asset's (i.e., an individual customer or group of customers) energy consumption as a percentage of total New England energy consumption during the hour of the annual system coincident peak in the year prior to the Capacity Commitment Period.

accurately, the actual consumption of the retail customers served by the LSE during a scarcity condition) and the capacity allocated to the LSE to serve that consumption. Here the equation to determine the Demand Score of an LSE is somewhat different from the equation used to determine the performance score of a capacity supplier. This is because Total CSO MW includes capacity that is expected to be unavailable to generate energy to serve coincident peak demand in the Capacity Commitment Period. Therefore, we expect that the sum of actual MW consumption of all electricity consumers served by all LSEs at the time of the annual system coincident peak to be less than the total amount of capacity acquired in the FCM. Because of this, an LSE's Demand Score must reflect the Actual MW Consumption of its customers during a scarcity condition in relationship to the amount of "Available Capacity" procured in the FCM to serve LSE energy requirements (where Available Capacity is equal to Total CSO MW minus the amount of capacity expected to be unavailable to serve coincident peak demand), and not to the total amount of capacity procured through the FCM. The Demand Score of an LSE is expressed in equation (5):

Demand Score[41] *= Actual MW Consumption – (SCPC % × Available Capacity × Demand Balancing Ratio)* (5)

The last term in equation (5) – i.e., the Demand Balancing Ratio – is similar to (but not identical to) the "balancing ratio" applied to capacity suppliers in FCM PFP. Under FCM PFP, the balancing ratio accounts for the total energy and reserve requirement at the time of a scarcity condition. Without the balancing ratio, a capacity resource would be penalized for not delivering its full CSO MW if scarcity conditions occur when the system's total energy and reserves requirements are substantially less than the ICR. Similarly, the Demand Balancing Ratio is a proportionate adjustment to the amount of capacity procured through the FCM to serve energy requirements at the time of the annual system coincident peak. The Demand Balancing Ratio ensures that LSEs receive lower FCM Charges for decreasing consumption below, and receive higher FCM Charges for increasing consumption above, its proportionate share of capacity available to serve system energy requirements at the time of a scarcity condition. Equation (6) shows the derivation of the Demand Balancing Ratio:

Demand Balancing Ratio = Total System Load / Available Capacity (6)

The Demand Balancing Ratio is a proportionate adjustment to the product of the SCPC % and Available Capacity. Essentially, the product of an LSE's SCPC % and Available Capacity is the amount of capacity procured through the FCM that is allocated to the LSE to serve its customers' energy requirements. If Total System Load was equal to Available Capacity at the time of a scarcity condition, the Demand Balancing Ratio would equal 1.0. If Available Capacity was 30 GW, the notional amount of capacity procured through the FCM to serve the energy requirement of an LSE with an SCPC % of 0.1 would be 3.0 GW. If the LSE's customers consume more than 3.0 GW during the scarcity condition, the Demand Score in equation (5) would be positive, resulting in a positive Performance Charge in equation (4), and thus a higher FCM Charge (see equation (1)) for the month. Conversely, if the LSE's customers consume less than 3.0 GW during the scarcity condition, the Demand Score in equation (5) would be negative, resulting in a negative Performance Charge in equation (4), and thus a lower FCM Charge (see equation (1)) for the month.

Because a scarcity condition could occur when total system energy requirements are substantially less than Available Capacity, the Demand Balancing Ratio ensures that LSEs do not receive a reduced FCM Charge for consuming above its proportionate share of capacity available to serve system energy requirements at the time of a scarcity condition. For example, assume that the total system energy requirement during a scarcity condition is 21 GW and Available Capacity is 30 GW. The Demand

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[41] Equation (5) shows the Demand Score of an LSE for a single scarcity condition event in a month; if there is more than one scarcity condition in the month, the Demand Score for the month would be the sum of all the Demand Scores for each scarcity condition event in the month.

Balancing Ratio for this event would be 21 GW/30 GW or 0.70. If the LSE had an SCPC % of 0.1, the notional amount of capacity procured through the FCM to serve the LSE's energy requirement at the time of the scarcity condition is 0.1 x 30 GW x 0.70, or 2.1 GW. So, if the LSE's customers consume more than 2.1 GW during the scarcity condition, the monthly FCM Charge would increase; if the LSE's customers consume less than 2.1 GW during the scarcity condition, the monthly FCM Charge would decrease.

If the customers of one LSE consumes more than their proportional share of capacity during a particular scarcity condition, the customers of another LSE must be consuming less than their proportional share of capacity during that same scarcity condition (assuming that load is still being served).[42] Accordingly, any increase in FCM Charges (which is based on the Performance Penalty Rate multiplied by the Demand Score) billed to over-consuming LSEs would be used to decrease the FCM Charges of under-consuming LSEs. This approach, which is in contrast to the PJM approach, allows the transfer of performance penalties and payments among capacity suppliers to be kept separate from those transferred among LSEs.

As a result of this approach to FCM cost allocation, LSEs whose customers reduce consumption below their proportionate share of Available Capacity during scarcity conditions will have a lower FCM Charge whereas LSEs whose customers increase consumption above their proportionate share of Available Capacity will have a higher FCM Charge. This gives LSEs the incentive to control the physical energy consumption of their customers to a level at or below the proportionate share of capacity procured through the FCM to serve their customer's energy requirements so as to control monthly FCM Charges. LSEs could control the physical energy consumption of their customers through a variety of means such as installing additional energy efficiency, distributed generation, and/or demand response capability. LSEs that do not attempt to control the physical energy consumption of their customers are at risk of higher than expected monthly FCM Charges that could diminish their profits.

Integrating Demand Reduction Bids Into FCM Cost Allocation

The FCM cost allocation approach could be further modified to incorporate the idea from PJM's October 6 whitepaper, which is to integrate demand response into the demand-side of the capacity market by allowing LSEs to submit load reduction bids into the capacity market. Modifications to FCM cost allocation as formulated in the previous section above will encourage Demand Resources. However, this approach alone would not allow an LSE to reduce the ICR at the time the FCA is conducted by committing to additional, future Demand Resource capability. If incremental Demand Resources are no longer permitted to participate in the FCM as a supply resource, the ISO may over-procure generation capacity in the FCA if the ICR is not reduced by the additional reduction in demand from incremental Demand Resources installed after the ICR was determined.

If the PJM solution were adopted in New England, LSEs would submit demand reduction bids into the FCM consisting of any number of price/quantity pairs with prices specified in $/kW-month and a demand reduction quantity in kW (with a minimum reduction amount of, say, 100 kW per block). These

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[42] For example, assume a system with three LSEs. In the hour of the annual coincident peak (from the previous year), total consumption was 30 GW and the Load Assets served by each LSE contributed to that peak as follows: LSE_A=12 GW, LSE_B=12 GW, and LSE_C=6 GW. Therefore, the SCPC % of each LSE would be: LSE_A=40%, LSE_B=40%, and LSE_C=20%.

Then on a particular day during the Capacity Commitment Period, the system is able to meet energy requirements but becomes unable to meet Operating Reserve requirements, so a scarcity condition occurs. During this scarcity condition, total load is 27 GW. If the Load Assets served by LSE_A consume 12 GW during this scarcity condition, LSE_A would be serving 44.444% of total consumption (i.e., 12 GW ÷ 27 GW), which is *greater than* its SCPC % of 40%. On the other hand, LSE_B and LSE_C in combination must be serving 15 MW of consumption during this scarcity condition, or 55.556% of total consumption, which is *less than* their combined SCPC % of 60%.

bids would be incorporated into the appropriate zonal demand curves for capacity as illustrated in Figure 1 and Appendix A. The intersection of the supply and demand curves constitutes the market clearing solution, which establishes the Capacity Clearing Price, the Capacity Supply Obligations of capacity suppliers, and the "Demand Reduction Obligations" of LSE's whose demand reduction bids clear the auction. As seen in Figure 1 and Appendix A, the clearing of Demand Reduction Obligations lowers the amount of capacity supply purchased in the FCA and lowers the clearing price.

If the ISO adopts this approach, the resulting Demand Reduction Obligation must be integrated into FCM cost allocation. In a market without demand reduction bids, the amount of capacity acquired by the FCM on behalf of an LSE to serve the energy needs of its customers during a scarcity condition is equal to (SCPC % × Available Capacity × Demand Balancing Ratio), which is a prorated share of total capacity. If an LSE takes on a Demand Reduction Obligation, the LSE's Base Charge should be reduced. For example, if the sum of the Coincident Peak Contribution percentages of the customers served by an LSE was 0.1, and the Total CSO MW procured through the FCM was 33 GW, the LSE's monthly Base Charge would be based on 3.3 GW assuming that the LSE had no Demand Reduction Obligations. If the LSE had a 300 MW Demand Reduction Obligation, its monthly Base Charge should instead be based on 3.0 GW. So each MW of Demand Reduction Obligation should reduce the LSE's monthly Base Charge by the same amount.

Further, the Performance Charge should consider consumption levels of the LSE's customers during a scarcity condition relative to the LSE's prorated share of total capacity net of its Demand Reduction Obligation – consumption higher than this level should result in a positive Performance Charge and a higher total FCM Charge; consumption lower than this level should result in a negative Performance Charge and a lower total FCM Charge. Outside of scarcity conditions, the LSE should receive no additional capacity charges even if its customers consume at levels exceeding the LSE's prorated share of total capacity net of its Demand Reduction Obligation. The integration of Demand Reduction Obligations into FCM cost allocation is accomplished by modifying equations (3) and (5). Recall that equations (3) and (5) are as follows:

$$\textit{Share of Total CSO} = \textit{SCPC \%} \times \textit{Total CSO MW} \tag{3}$$

$$\textit{Demand Score} = \textit{Actual MW Consumption} - (\textit{SCPC \%} \times \textit{Available Capacity} \times \textit{Demand Balancing Ratio}) \tag{5}$$

First, the monthly Base Charge billed to an LSE should be reduced by any Demand Reduction Obligation it cleared in the FCA. This is accomplished by reducing the LSE's Share of Total CSO by the LSE's Demand Reduction Obligation as reflected in equation (3a):

Share of Total CSO = (SCPC %[43] *× Total CSO MW*[44]*) – Demand Reduction Obligation*[45] (3a)

Obviously, the LSE must have a performance incentive to reduce demand during a scarcity condition potentially up to its full Demand Reduction Obligation – the performance incentive provides the financial motivation for an LSE to produce the requisite demand reduction during a scarcity condition so as to prevent system reliability from degrading. Of course, the amount of demand reduction produced does

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[43] Under this approach, further consideration must be given to the need for "reconstituting" the load of those customers served by an LSE with a Demand Reduction Obligation in the development of future Coincident Peak Contribution percentages should a scarcity condition coincide with the hour of the annual system coincident peak.

[44] It should be noted that the Total CSO MW would be lower as a result of the FCA clearing any demand reduction bids – *see* Figure 1.

[45] Self-Supply can be integrated into this cost allocation scheme by including Self-Supply in the Demand Reduction Obligation term.

not have to equal the full Demand Reduction Obligation for every scarcity condition. Just as a balancing ratio is used to adjust the notional obligation of a capacity supplier when total system requirements in real time are not equal to the ICR, the Demand Reduction Obligation should also be adjusted to account for real-time system requirements at the time of a scarcity condition.

To provide a performance incentive to LSEs with a Demand Reduction Obligation adjusted for real-time system requirements at the time of scarcity condition, the Demand Reduction Obligation must be subtracted from the product of the LSE's SCPC % and Available Capacity, and then multiplying the resulting difference by the Demand Balancing Ratio. Subtracting the Demand Reduction Obligation from the product of an LSE's SCPC % and the Available Capacity represents the net amount of capacity procured through the FCM to serve the LSE's peak energy requirement. This net amount, adjusted by the Demand Balancing Ratio, is then compared to Actual MW Consumption to determine the LSE's Demand Score. See equation (5a):

Demand Score = Actual MW Consumption[46] *– {[(SCPC % × Available Capacity) – Demand Reduction Obligation] × Demand Balancing Ratio}* (5a)

The Demand Balancing Ratio in equation (6) remains the same. However, both the denominator and numerator of the equation are influenced by Demand Reduction Obligations. The denominator – Available Capacity – is lower as a result of cleared demand reduction bids. Further the numerator – Total System Load – would be expected to change as a result of LSEs responding to scarcity conditions to meet their Demand Reduction Obligations.

For example, if Total System Load was equal to Available Capacity at the time of a scarcity condition, the Demand Balancing Ratio would equal 1.0. If Available Capacity was 30 GW, the sum of the Coincident Peak Contribution percentages of the customers served by an LSE was 0.1, and the LSE had a 300 MW Demand Reduction Obligation, the notional amount of capacity procured through the FCM to serve the peak energy requirement of this LSE would be 2.7 GW. If the LSE's customers consume more than 2.7 GW during the scarcity condition, the Demand Score would be positive, resulting in a positive Performance Charge and thus a higher FCM Charge for the month. Conversely, if the LSE's customers consume less than 2.7 GW during the scarcity condition, the Demand Score would be negative, resulting in a negative Performance Charge, and thus a lower FCM Charge for the month.

Of course, Total System Load may be lower than Available Capacity at the time of a scarcity condition. Expanding from the example above, assume that the total system energy requirement during a scarcity condition is 21 GW and Available Capacity is 30 GW. The Demand Balancing Ratio for this event would be 21 GW/30 GW or 0.70. If the sum of the Coincident Peak Contribution percentages of the customers served by an LSE was 0.1, and the LSE had a 300 MW Demand Reduction Obligation, the notional amount of capacity procured through the FCM to serve the LSE's energy requirement at the time of the scarcity condition is [(0.1 x 30 GW) – 300 MW] x 0.70, or 1.89 GW. So, if the LSE's customers consume more than 1.89 GW during the scarcity condition, the monthly FCM Charge would increase; if the LSE's customers consume less than 1.89 GW during the scarcity condition, the monthly FCM Charge would decrease.

By taking on a Demand Reduction Obligation through Demand Resource implementation, an LSE reduces its Base Charge each and every month. Additionally, Demand Resources could enable an LSE to further reduce its overall monthly FCM Charge through the Performance Charge component by reducing demand in real time in response to a scarcity condition to a level lower than its proportionate share of Available Capacity acquired through the FCM to serve the LSE's energy requirements. Finally, by taking on Demand Reduction Obligations, both the Capacity Clearing Price and the amount of capacity procured

[46] If Self-Supply is included in the Demand Reduction Obligation term, then Actual MW Consumption must be reduced by the amount of actual Self-Supply generated during the scarcity condition.

through the FCM is lowered – and on a sound, unbiased, economic basis – which accrues to the benefit of society in general.