153 FERC ¶ 61,224
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

ISO New England Inc. | Docket Nos. ER14-2419-003
EL14-52-002

ORDER DENYING REHEARING

(Issued November 19, 2015)

1. In a May 30, 2014 order,[1] the Commission acted under section 206 of the Federal Power Act (FPA)[2] to direct ISO New England Inc. (ISO-NE) to revise its Transmission, Markets and Services Tariff (Tariff) to increase the Reserve Constraint Penalty Factors in its real-time markets and implement a two-settlement capacity market design in order to address fleet-wide resource performance issues and help ensure reliability. On October 2, 2014, the Commission accepted in part, subject to condition, and rejected in part ISO-NE's compliance filing to the May 30, 2014 Order.[3] Multiple parties request rehearing of the October 2, 2014 Order.[4] In this order, we deny rehearing.

I. Background

2. On January 17, 2014, ISO-NE and the New England Power Pool Participants Committee (NEPOOL) submitted, pursuant to section 205 of the FPA[5] and section 11.1.5

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[1] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (2014) (May 30, 2014 Order).

[2] 16 U.S.C. § 824e (2012).

[3] *ISO New England Inc.*, 149 FERC ¶ 61,009 (2014) (October 2, 2014 Order).

[4] *See infra* P 8.

[5] 16 U.S.C. § 824d (2012).

of the ISO-NE Participants Agreement,[6] alternative proposals intended to address fleet-wide resource performance problems in New England (January 17 Filing). For its part, ISO-NE proposed changes to the Forward Capacity Market (FCM) which were intended to link resources' capacity revenues to their performance during reserve deficiencies. ISO-NE sought to implement a two-settlement FCM process, whereby a capacity resource's total capacity revenue is comprised of a Capacity Base Payment and a Capacity Performance Payment (two-settlement capacity market design). The Capacity Base Payment would be determined by the associated Forward Capacity Auction (FCA) clearing price, and the Capacity Performance Payment would be determined by the resource's performance – in the form of delivery of energy and/or reserves in real-time – during reserve deficiencies, known as Capacity Scarcity Conditions.

3. NEPOOL agreed that fleet-wide performance problems exist but argued that a major FCM redesign, as ISO-NE proposed, was unnecessary to address them. Instead, NEPOOL proposed to increase the performance incentives in ISO-NE's energy and ancillary services markets and change the metric by which capacity resource "availability" is determined. First, NEPOOL proposed to increase the existing Reserve Constraint Penalty Factors for 30-Minute Operating Reserves, from $500/MWh to $1,000/MWh, and for 10-Minute Non-Spinning Reserves, from $850/MWh to $1,500/MWh. These Reserve Constraint Penalty Factor changes would increase the price that ISO-NE may pay to procure energy and reserves in real-time. Second, NEPOOL proposed to change the FCM rules by replacing the existing Shortage Event mechanism with a new Equivalent Peak Period Forced Outage Rate, or "EFORp," metric that measures a resource's performance based on its availability during all EFORp hours. NEPOOL asserted that these incremental changes to the real-time markets and capacity markets, when combined with other recent market rule changes, would ensure adequate procurement of energy and operating reserves when the New England system is stressed.

4. In the May 30, 2014 Order, the Commission instituted a proceeding under section 206 of the FPA, finding that the existing Tariff was unjust and unreasonable because it failed to provide adequate incentives for resource performance, thereby threatening

[6] Section 11.1.5 of the Participants Agreement, commonly referred to as the "jump ball" provision, provides, in pertinent part, that if a Market Rule proposal that differs from that proposed by ISO-NE is approved by a Participants Committee vote of 60 percent or more, ISO-NE "shall, as part of any required Section 205 filing," describe the alternate Market Rule proposal in sufficient detail to permit reasonable review by the Commission and also explain its reasons for not adopting the alternate proposal and why it believes its own proposal is superior. Section 11.1.5 provides that the Commission may "adopt any or all of ISO[-NE]'s Market Rule proposal or the alternate Market Rule proposal as it finds ...to be just and reasonable and preferable."

reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits. The Commission further found that neither ISO-NE's nor NEPOOL's proposal, standing alone, had been shown to be just and reasonable. However, the Commission also found that a modified version of ISO-NE's proposal combined with the higher Reserve Constraint Penalty Factors in NEPOOL's alternative proposal provided a just and reasonable solution. The Commission therefore directed ISO-NE to submit Tariff revisions in a compliance filing to implement a modified version of ISO-NE's two-settlement capacity market design and to increase the Reserve Constraint Penalty Factors.

5. With regard to the modifications to the two-settlement capacity market design, the Commission, in the May 30, 2014 Order, directed ISO-NE to submit Tariff revisions (1) to ensure that energy efficiency resources' Capacity Performance Payments are calculated only for Capacity Scarcity Conditions during hours in which demand reduction values are calculated under the Tariff for that particular type of resource;[7] and (2) to create an exemption from application of Capacity Performance Payments for resources on the export side of an intra-zonal transmission constraint during a Capacity Scarcity Condition, or further explain why such an exemption is not necessary.[8] The Commission also directed ISO-NE to submit Tariff revisions reflecting any adjustments that it believes are necessary in light of the Commission's decision to implement Reserve Constraint Penalty Factor changes, or an explanation as to why no such adjustments are necessary.[9]

6. On July 14, 2014, ISO-NE submitted its compliance filing. In the October 2, 2014 Order, the Commission accepted, in part, subject to condition, and rejected, in part, and directed a further compliance filing.[10] The Commission accepted ISO-NE's proposed Tariff revisions regarding increases to the Reserve Constraint Penalty Factors, the treatment of energy efficiency resources under the two-settlement capacity market design, and ISO-NE's proposal to retain the Capacity Performance Payment Rate and the dynamic de-list bid threshold at the levels that it originally proposed in the January 17 filing. The Commission rejected the proposed Tariff revisions to section III.13.7 concerning intra-zonal transmission constraints, and directed a further compliance filing to revise Tariff section III.13.7.

[7] May 30, 2014 Order, 147 FERC ¶ 61,172 at P 89.

[8] *Id.* P 67.

[9] *Id.* P 110.

[10] October 2, 2014 Order, 149 FERC ¶ 61,009.

7. The rejected Tariff provision, section III.13.7, contained ISO-NE's proposed solution to the potential improper price signal issue that the Commission identified in the May 30, 2014 Order. In support of its proposal, ISO-NE asserted that exempting resources on the export side of an intra-zonal transmission constraint from application of Capacity Performance Payments, as the Commission suggested in the May 30, 2014 Order, would create other distortionary incentives. Instead of creating such an exemption, ISO-NE sought to credit those resources only for the reserves, and not for the energy, that they provide during Capacity Scarcity Conditions, asserting that only reserves have a positive marginal value on the export side of a transmission constraint.

8. In the October 2, 2014 Order, the Commission determined, based upon additional information submitted by ISO-NE and other parties, that the disputed exemption is not necessary. The Commission found that the additional information indicated that the improper price signal problem identified in the May 30, 2014 Order is of limited geographic scope and the incentive for capacity resources to submit energy market offers below their actual costs is weaker than contemplated. In addition, the Commission found that the additional information provided at the compliance stage of the proceeding indicated that, during the 24-month period from June 1, 2012 through May 31, 2014, nearly 80 percent of generation nodes were never on the export-side of a constraint during Reserve Constraint Penalty Factor activations. The October 2, 2014 Order also found that the incentive for resources to offer below their actual marginal costs is offset by the risks associated with responding to that incentive. Furthermore, the October 2, 2014 Order found that ISO-NE's Tariff, including the FCM rules and transmission planning procedures, provides mechanisms that help prevent and address recurring intra-zonal transmission constraints and makes it difficult for a resource to anticipate, three years in advance, whether it will be on the export side of an intra-zonal transmission constraint.[11]

9. On November 3, 2014, two groups of parties filed requests for rehearing of the October 2, 2014 Order: (1) Connecticut Municipal Electric Energy Cooperative; Massachusetts Municipal Wholesale Electric Company; New Hampshire Electric Cooperative, Inc.; and Vermont Electric Cooperative (collectively, Public Systems); and (2) Rhode Island Public Utilities Commission; Connecticut Public Utilities Regulatory Authority; George Jepsen, Attorney General for the State of Connecticut; Connecticut Office of Consumer Counsel; and Connecticut Department of Energy and Environmental Protection (collectively, Connecticut and Rhode Island).[12]

[11] May 30, 2014 Order, 147 FERC ¶ 61,172 at PP 56-62.

[12] In this order, we will refer to Connecticut and Rhode Island and Public Systems, collectively, as Rehearing Parties.

II. Discussion

A. Combining the Capacity Performance Payment Rate with the Increased Reserve Constraint Penalty Factors

1. Requests for Rehearing

10. Rehearing Parties argue that the October 2, 2014 Order erred in adopting both the full Capacity Performance Payment Rate and the phase-in Capacity Performance Payment Rates without adjusting them to account for the increased Reserve Constraint Penalty Factors. Rehearing Parties assert that the October 2, 2014 Order erroneously rests on the Commission's finding that the record lacks evidence showing the combined replacement rate is unjust and unreasonable. Rehearing Parties contend that such reasoning erroneously shifts the burden to protestors to show that the replacement rate is unjust and unreasonable, where instead the Commission carries the burden under section 206 to show that the replacement rate is just and reasonable. Moreover, Connecticut and Rhode Island state the parties in this proceeding were not given adequate notice or a meaningful opportunity to present evidence regarding the combined effect that the Commission-directed rules will have on the New England markets and customers. They argue that by failing to provide the parties with a reasonable opportunity to address the combined effect of the rule changes and then establishing a narrow compliance proceeding for the purpose of determining whether ISO-NE complied with the Commission's directives, the Commission effectively ensured that its ruling would never be subject to scrutiny.[13]

11. Rehearing Parties further contend that the Commission ignored record evidence showing that the combined Capacity Performance Rates and increased Reserve Constraint Penalty Factors will produce rates that are excessive for electric customers. Public Systems contend that there is no dispute that the future Capacity Performance Payment Rate has an immediate impact on current investment decisions and, thus, capacity-market offers and prices. Public Systems argue that, because the future Capacity Performance Payment Rate has a near term impact on capacity investment and prices, the Commission cannot accept it without any immediate scrutiny.[14]

12. Connecticut and Rhode Island contend that the combined pricing incentives exceed the cost of new entry and provide excessive compensation to generators, to the detriment of ratepayers and market efficiency. Connecticut and Rhode Island contend that the Commission ignored the testimony of Jonathan Falk explaining that the

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[13] Connecticut and Rhode Island Request for Rehearing at 20-21.

[14] Public System Request for Rehearing at 5.

combination of the higher Reserve Constraint Penalty Factors and the full Capacity Performance Payment Rate produces "excessive shortage pricing compensation," and encourages generators to take costly actions with "little corresponding social benefit."[15] Connecticut and Rhode Island argue that the Commission failed to meaningfully address Mr. Falk's testimony, as well as the External Market Monitor's concerns, and objections to the ISO-NE compliance proposal, and that therefore the October 2, 2014 Order is arbitrary and capricious.

13. Connecticut and Rhode Island further contend that by allowing ISO-NE to determine in the future whether the Capacity Performance Payment Rate will need to be reduced, rather than reducing the disputed rate immediately, the Commission erred by approving a "placeholder" rate.[16] Connecticut and Rhode Island contend that the October 2, 2014 Order is inconsistent with the Commission's statutory obligation to determine just and reasonable rates at the time of the decision.[17]

14. Connecticut and Rhode Island contend that even if the Commission's decision was supported by substantial evidence, the Commission's technical analysis of the combined rates is erroneous. Connecticut and Rhode Island state that the Capacity Performance Payment Rate phase-in levels, which were selected arbitrarily at roughly proportional fractions of the full rate, were determined well before the Commission ordered ISO-NE to implement higher operating reserve prices during scarcity events.[18] In addition, Public Systems argue that the total shortage price should not exceed the economic value of lost load, which they assert is $2,000/MWh for 30-minute reserves.[19]

2. Commission Determination

15. We deny rehearing on the Commission's decision to increase the Reserve Constraint Penalty Factors without modifying the Capacity Performance Payment Rate. Contrary to Rehearing Parties' assertions, the Commission fully considered the potential

[15] Connecticut and Rhode Island Request for Rehearing at 15.

[16] *Id*. at 20-21.

[17] *Id.* (citing *Missouri Pub. Serv. Comm'n v. FERC*, 601 F.3d 581, 587-588 (D.C. Cir. 2010) (*Missouri PSC*)).

[18] *Id*. at 18-19.

[19] Public Systems Request for Rehearing at 6-7.

impact that the increased Reserve Constraint Penalty Factors could have on the Capacity Performance Payment Rate.

16. As the Commission explained in the May 30, 2014 Order, the increased Reserve Constraint Penalty Factors are an incremental solution to help improve resource performance in the near-term, until the two-settlement capacity market design begins impacting real-time performance to provide a long-term solution to the region's resource performance problems.[20] These two market rule changes provide incentives over different time periods and, therefore, they each independently improve resource performance. To the extent the Reserve Constraint Penalty Factors and the two-settlement capacity market design might produce a combined performance incentive, such a combination would not occur until 2018. Prior to 2018, the Reserve Constraint Penalty Factors and the two-settlement capacity market design only "combine" in the sense that, together, they ensure that resources in the New England region have a continuous performance incentive. As the Commission has acknowledged, it is possible that, in the future, the Reserve Constraint Penalty Factors could impact resource performance in a way that could warrant adjusting the Capacity Performance Payment Rate. However, in order to determine whether a different Capacity Performance Payment Rate would produce a more appropriate performance incentive, the Commission directed ISO-NE to submit Tariff provisions reflecting any such adjustment, if necessary, and provided all parties the opportunity to present evidence and argument on that question. Upon reviewing the arguments and evidence submitted in response to that directive, the Commission, in the October 2, 2014 Order, agreed with ISO-NE that no adjustment was warranted because the Reserve Constraint Penalty Factors have only an indirect and uncertain impact on the Capacity Performance Payment Rate.[21] Thus, the Commission concluded that it would be premature and speculative to make any such adjustments based on record evidence at this time, and that it would instead be more appropriate to make any necessary adjustments based on observations of the Reserve Constraint Penalty Factors' actual impact on system parameters.[22]

17. Public Systems assert that the Capacity Performance Payment Rate will "likely" need to be reduced because the higher Reserve Constraint Penalty Factors will increase energy and ancillary services market revenues and, therefore, will improve resource performance. These assertions are speculative and unsupported. As the Commission explained in the October 2, 2014 Order, while the increased Reserve Constraint Penalty Factors *could* impact resource performance in a way that warrants a change in the

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[20] May 30, 2014 Order, 147 FERC ¶ 61,172 at P 108.

[21] October 2, 2014 Order, 149 FERC ¶ 61,009 at P 24.

[22] *Id.*

Capacity Performance Payment Rate, that impact is far from certain. Furthermore, there are many other variables—including, *inter alia*, changes in demand, fuel availability, environmental regulations, and the region's resource portfolio—that directly and indirectly impact resource performance.[23] It is difficult to predict the impact, if any, that a change in one of those variables will have on resource performance, and even more difficult to predict the combined impact of changes in all of those variables. As a result, changing the Capacity Performance Payment Rate based on the increased Reserve Constraint Penalty Factors, prior to observing their impact on resource performance, would require speculation and could produce inaccurate results. The Commission, therefore, found that it would be premature to change the $5,455/MWh Capacity Performance Payment Rate at this time, and that it is more appropriate for any such changes to be made based on observations of whether and how the increased Reserve Constraint Penalty Factors actually affect resource performance.

18. We disagree with Connecticut and Rhode Island's assertion that the increased Reserve Constraint Penalty Factors and the Capacity Performance Payment Rate, in combination, are excessive. Connecticut and Rhode Island's assertion is based on the argument, which they reiterate on rehearing, that the Capacity Performance Payment Rate should be based on the value of lost load. The Commission has repeatedly rejected that argument in this proceeding and we do so here for the same reasons.[24] Connecticut and Rhode Island further argue that, even when the combined rates are based on the cost of new entry, rather than the value of lost load, the resulting rate is, by definition, excessive because the Capacity Performance Payment Rate itself is based on the cost of new entry. This argument oversimplifies the calculation of the Capacity Performance Payment Rate by assuming that a particular increase in energy market revenues is certain to produce a proportional increase in resource performance. There are many variables that impact resource performance and, depending on how those variables change, an increase in energy market revenues will not necessarily produce a net increase in resource performance. For example, the performance incentive associated with the increased Reserve Constraint Penalty Factors could be mitigated, or even negated, by the adverse performance impacts of some other variable, such as fuel availability.

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[23] In fact, the increase to the Reserve Constraint Penalty Factors can itself impact other variables relevant to resource performance, in addition to directly providing an increased performance incentive. For example, increasing the Reserve Constraint Penalty Factors increases the number of resources that ISO-NE is able to call during Capacity Scarcity Conditions.

[24] *ISO New England, Inc. and New England Power Pool*, 153 FERC ¶ 61,223, at PP 84-87 (2015).

19. Due to the three year forward commitment timeline of ISO-NE's FCM, it is not possible for resource owners to simultaneously receive revenues from both increased Reserve Constraint Penalty Factors and the full Capacity Performance Payment Rate until the 2024-2025 Capacity Commitment Period. Therefore, we find that the concerns about excessive shortage pricing are premature and do not at this time warrant preempting ISO-NE's ability to propose revisions based on observed changes in resource performance. Allowing for the possibility of an adjustment to the Capacity Performance Payment Rate is not tantamount to accepting a "placeholder" rate as the Rehearing Parties allege. In adopting a current rate as just and reasonable, the Commission may fairly recognize, as it did in the October 2, 2014 Order, that as markets evolve, so too may market mechanisms.[25]

20. Public Systems argue that the Commission ignored the fact that the Capacity Performance Payment Rate has an immediate impact on current investment decisions. However, whether the Capacity Performance Payment Rate impacts resource owners' investment decisions is irrelevant to the issue here, which is whether the increased Reserve Constraint Penalty Factors impact the Capacity Performance Payment Rate. While it is possible that the Capacity Performance Payment Rate might impact a resource owner's investment decisions in the near term, i.e., before resources begin receiving capacity market revenues through the two-settlement forward capacity market design, the same is true of all market rule changes that might impact a resource owner's market revenues. Resource owners routinely make business and investment decisions based on their own forecasts of future market revenues, and those decisions are made without certainty as to what those market revenues will actually be. While it is possible that a resource owner's actions in anticipation of future market revenues could improve resource performance prior to receiving those revenues, that does not mean the resource owner is *now* receiving excessive shortage pricing as a result. As noted, the Capacity Performance Payment Rate will not be effective until 2024.

21. Rehearing Parties also assert that the Commission did not make an affirmative finding that the phase-in Capacity Performance Rates are just and reasonable, but instead found only that the record lacks evidence showing that those rates are unjust and unreasonable. We disagree. The language to which Rehearing Parties cite merely reflects the Commission's acknowledgement that no party has presented valid evidence or argument that undermines the Commission's rationale for adopting the phase-in rates.

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[25] We note that this case is distinguishable from *Missouri PSC*, 601 F.3d 581, because in the instant case the Commission neither attempted to defer its statutory obligation to a future proceeding, nor failed to explain its rationale for finding the Capacity Performance Payment Rate to be just and reasonable based on the record before it.

22. Connecticut and Rhode Island argue that the Commission failed to provide the parties with adequate notice and a meaningful opportunity to be heard and ignored arguments that they were able to submit. The parties here had multiple opportunities to submit arguments and evidence.[26] Connecticut and Rhode Island had notice that the Commission might adopt both the increased Reserve Constraint Penalty Factors and the Capacity Performance Payment Rate, and they had the opportunity to submit—and did, in fact, submit—evidence on the relevant factual issue, i.e., whether the increased Reserve Constraint Penalty Factors warrant a change to the Capacity Performance Payment Rate. They have also had the opportunity to raise their arguments concerning this issue on rehearing.[27]

B. Reserve Constraint Penalty Factors and the Dynamic De-List Bid Threshold

1. Requests for Rehearing

23. Connecticut and Rhode Island argue that the October 2, 2014 Order fails to ensure that the dynamic de-list bid threshold is reasonably calibrated in light of the increased Reserve Constraint Penalty Factors. Connecticut and Rhode Island assert that, as with the Capacity Performance Payment Rate, the Commission erroneously applied FPA section 205 legal standards, rather than FPA section 206 legal standards, to the compliance filing, thereby shifting the burden of proof to Connecticut and Rhode Island. Connecticut and Rhode Island reiterate their argument that the Commission erred by disregarding record evidence showing that the dynamic de-list bid threshold must be modified to account for the increased Reserve Constraint Penalty Factors.[28]

2. Commission Determination

24. We deny rehearing on the issue of the dynamic de-list bid threshold. As an initial matter, we disagree with Connecticut and Rhode Island's assertion that the Commission erroneously applied FPA section 205 legal standards, rather than FPA section 206 legal

[26] *See supra* P 4.

[27] *See, e.g.*, *State of Cal. ex rel. Lockyer v. FERC*, 329 F.3d 700, 711 (9th Cir. 2003) ("the Commission provided all the procedural protections required by the Fifth Amendment and FPA when it carefully considered all the evidence and arguments that the petitioners offered in their petitions for rehearing and motions to intervene."); *see also ANR Pipeline Co. and TC Offshore LLC*, 143 FERC ¶ 61,225, at PP 57, 60 (2013).

[28] Connecticut and Rhode Island Request for Rehearing at 21-24 (citing Connecticut and Rhode Island August 4, 2014 Protest, Att. A at Q28-Q29).

standards, to the compliance filing. The Commission did not place the burden on Connecticut and Rhode Island to prove that the dynamic de-list bid threshold was unreasonable. Rather, the Commission affirmatively found the dynamic de-list bid threshold to be just and reasonable.[29] Connecticut and Rhode Island's argument to the contrary ignores the ample record evidence supporting the $3.94 per kW-month figure[30] and, as discussed below, places undue weight on a small amount of speculative and unsupported witness testimony.

25. We disagree with Connecticut and Rhode Island's assertion that the Commission ignored evidence concerning the appropriateness of the $3.94 per kW-month dynamic de-list bid threshold, and whether it should be adjusted to reflect the increased Reserve Constraint Penalty Factors. The evidence to which Connecticut and Rhode Island cite consists of witness testimony asserting that the dynamic de-list bid threshold must be adjusted to reflect the increased Reserve Constraint Penalty Factors because the increased Reserve Constraint Penalty Factors will impact the inputs into the formula for the dynamic de-list bid threshold. The Commission directly addressed this evidence and argument in the October 2, 2014 Order, explaining that Connecticut and Rhode Island's assertions regarding the formula inputs were speculative and unsupported.[31] We continue to find that to be the case.

26. The evidence at issue, and Connecticut and Rhode Island's arguments in reliance on it, incorrectly assumes that the increased Reserve Constraint Penalty Factors are *certain* to change the Capacity Performance Payment Rate and the expected Capacity Balancing Ratio, and that the expected hours of Capacity Scarcity Conditions "can reasonably be expected to fall."[32] However, these assumptions are based on an oversimplification of the relationship between the Reserve Constraint Penalty Factors, resource performance, and the inputs into the dynamic de-list bid threshold formula.

27. The linkage between the Reserve Constraint Penalty Factors and the dynamic de-list bid threshold is as follows: the Reserve Constraint Penalty Factors can impact resource performance, and changes in resource performance can impact the inputs into the dynamic de-list bid threshold formula—specifically, the Capacity Performance Payment Rate, the expected Capacity Balancing Ratio, and the expected hours of

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[29] May 30, 2014 Order, 147 FERC ¶ 61,172 at P 96.

[30] *See, e.g.*, ISO-NE, Tariff Filing, Docket No. ER14-1050-000, at Att. I-1c, Att. I-1e (Jan. 17, 2014).

[31] *See* October 2, 2014 Order, 149 FERC ¶ 61,009 at PP 26-27.

[32] Connecticut and Rhode Island August 4, 2014 Protest, Att. A at Q29.

Capacity Scarcity Conditions. However, it is difficult to predict in advance the extent of such impacts since there has not yet been any experience under these changes. The same is true of the expected Capacity Balancing Ratio and the expected hours of Capacity Scarcity Conditions. Accordingly, the record does not support Connecticut and Rhode Island's assertions that the dynamic de-list bid threshold must be changed at this time.

28. Furthermore, we reiterate that the $3.94 per kW-month dynamic de-list bid threshold was calculated using the initial, phase-in value of $2,000/MWh for the Capacity Performance Payment Rate. As explained above, the Commission properly concluded that it was not necessary to change that phase-in value. Accordingly, the Commission correctly concluded that it was not necessary to change the $3.94 per kW-month dynamic de-list bid threshold based on the Capacity Performance Payment Rate. To the extent resource performance changes in the future warrant a change to the dynamic de-list bid threshold, we again note that the Tariff explicitly provides for such changes.[33]

C. Exempting Resources due to Intra-Zonal Transmission Constraints

1. Requests for Rehearing

29. Public Systems contend that the October 2, 2014 Order errs in failing to exempt resources that are not dispatched due to intra-zonal transmission constraints. Public Systems argue that the intra-zonal constraint issue is just one manifestation of a larger problem at the core of the two-settlement capacity market design: that it redefines performance of a Capacity Supply Obligation to mean actually producing energy or supplying reserves during a scarcity condition regardless of whether ISO-NE has asked the resource to do so, rather than standing ready to provide energy or reserves if asked. Public Systems assert that a capacity resource cannot fail to "perform" unless ISO-NE has dispatched it for energy or reserves.[34]

30. Public Systems argue that it violates cost-causation principles to deprive resources of capacity revenue when transmission constraints prevent ISO-NE from being able to

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[33] Pursuant to the Tariff, the dynamic de-list bid threshold is recalculated no less often than once every three years and the recalculation results must be filed with the Commission after the Internal Market Monitor reviews the results with stakeholders. *See* Tariff § III.13.1, III.13.1 Forward Capacity Auction Qualification (26.0.0) at III.13.1.2.3.1.A. On June 30, 2015, the Commission approved ISO-NE and NEPOOL's Tariff revisions to change the dynamic de-list bid threshold from $3.94/kW-month to $5.50/kW-month. *ISO New England Inc.*, 151 FERC ¶ 61,270, at PP 39-41 (2015).

[34] Public Systems Request for Rehearing at 11-12.

use the energy the resources stand ready to provide.[35] Additionally, Public Systems state that making capacity resources responsible for the consequences of those constraints inappropriately turns them into insurers of other entities' actions, and diminishes the other entities' incentives to take steps to avoid or resolve the constraints.[36]

31. Public Systems argue that the October 2, 2014 Order wrongly minimizes the scope of the concerns identified by the May 30, 2014 Order. Public Systems state that the October 2, 2014 Order implicitly acknowledged that between July 2012 and May 2014 more than one-fifth of all generation nodes in New England were on the export side of an intra-zonal transmission constraint during a reserve shortage. Public Systems assert that even if the occurrence of intra-zonal constraints during scarcity conditions is geographically limited, the issue matters greatly to those who are affected.[37] Public Systems also state that given the major changes already occurring in New England, historical data is not likely to be a reliable guide in predicting the coincidence of scarcity conditions and intra-zonal transmission constraints more than three years in the future.

32. Public Systems further argue that the October 2, 2014 Order underestimates how frequently transmission-constrained resources may try to maximize their energy dispatch in response to Capacity Performance Payments by offering energy below marginal cost. Public Systems contend that offering energy below marginal cost yields operating losses only if the locational marginal prices drop below the offeror's marginal cost. Public Systems argue that resources will know, based on recent history, when and how often that normally occurs. Public Systems also contend that resources attempting to respond to Capacity Performance Payments do not need to predict when a scarcity condition will coincide with a transmission constraint, because they are incentivized to maximize their dispatch during any scarcity condition.[38]

2. <u>Commission Determination</u>

33. We deny rehearing on the issue of whether it is necessary to exempt resources that are on the export-side of an intra-zonal transmission constraint during a Capacity Scarcity Condition. Public Systems argue that the intra-zonal constraint problem is just one manifestation of a larger problem with the two-settlement capacity market design, i.e., that it redefines performance of a Capacity Supply Obligation to mean actually producing

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[35] *Id.* at 12-13.

[36] *Id.*

[37] *Id.* at 14-15.

[38] *Id.* n.19.

energy or supplying reserves during a scarcity condition regardless of whether ISO-NE has asked the resource to do so, rather than standing ready to provide energy or reserves if asked. This argument is simply another version of the argument that it is inappropriate to reduce a resource's capacity revenues when the resource fails to perform for reasons beyond its control. That issue is beyond the scope of this compliance proceeding, and is more appropriately raised on rehearing of the Commission's May 30, 2014 Order.[39]

34. Public Systems argue that, in determining that no exemption was necessary, the Commission erroneously down-played the geographic scope of the inefficient price signals related to intra-zonal transmission constraints. We disagree. Contrary to Public Systems' assertion, the Commission did not ignore the fact that some resources have been on the export-side of an intra-zonal transmission constraint during past Reserve Constraint Penalty Factor activations. Rather, the Commission acknowledged this fact, but found that, due to the infrequency and location of those occurrences in New England, the problem was not significant enough to warrant an exemption, particularly when weighed against the inefficiencies that such an exemption would create.[40] We continue to find that to be the case.

35. Public Systems argue that the Commission erred in relying on historical data to predict the coincidence of Capacity Scarcity Conditions and intra-zonal transmission constraints, because that data is "not likely to be a reliable guide" in predicting those conditions in the future.[41] As Public Systems correctly note, the coincidence of Capacity Scarcity Conditions and intra-zonal transmission constraints in the future might differ from the historical data in the record. However, the record contains no evidence showing how those conditions will change or, more importantly, showing that those conditions

[39] We note that Public Systems did, in fact, raise this argument in its request for rehearing of the May 30, 2014 Order, and the Commission is addressing that request for rehearing in an order issued concurrently with the instant order. *See ISO New England Inc. and New England Power Pool*, 153 FERC ¶ 61,223, at PP 70-80.

[40] For example, as the Commission noted in the October 2, 2014 Order, the resources that recently have been on the export side of binding intra-zonal transmission constraints are concentrated at the periphery of the New England power system, primarily in Maine. *See* October 2, 2014 Order, 149 FERC ¶ 61,009 at PP 53, 59. Therefore, an exemption would inefficiently reward these peripheral resources more than other resources despite the fact that the peripheral resources contribute less to maintaining reliability during Capacity Scarcity Conditions. *See id.* This could also provide resource owners an incentive to site new resources at the periphery of the New England power system, which will not allow them to efficiently serve the region's needs.

[41] Public Systems Request for Rehearing at 14.

will coincide more frequently in the future. We note that the intent behind many of the changes that Public Systems mention—e.g., changes in transmission system topology, gas pipeline infrastructure, and ISO-NE market rules, including the two-settlement capacity market design—is to improve system efficiency and minimize Capacity Scarcity Conditions. Thus, to the extent the historical data in the record differs from future conditions, we expect the future conditions to lessen the probability of the improper price signals identified in the May 30, 2014 Order.

36. We also disagree with Public Systems' argument that the October 2, 2014 Order underestimates how frequently resources may try to maximize their energy dispatch by offering below their marginal cost.[42] While Public Systems assert that a resource owner will know when and how often the locational marginal price normally drops below a particular resource's marginal cost, we note that a resource owner that offers below its marginal cost based on such a prediction about the locational marginal price will face the same downside risk that the Commission highlighted in the October 2, 2014 Order.[43] As a result, contrary to Public Systems' assertion, a resource owner that is considering offering below its marginal cost will still need to predict the likelihood of concurrent Capacity Scarcity Conditions and binding intra-zonal transmission constraints, in order to understand the risk that the resource owner faces by submitting such an offer. That downside risk acts as a disincentive for such offering behavior, even for resource owners that are confident in their predictions about locational marginal prices.[44]

[42] *Id.* n.19.

[43] *See* May 30, 2014 Order, 147 FERC ¶ 61,172 at P 60.

[44] We also note that Public Systems confuse the incentive for a resource to maximize its dispatch with the incentive for a resource to offer below its marginal cost. *See* Public Systems Request for Rehearing at n.19 ("resources are incentivized (regardless of whether they can *act* on those incentives) to maximize their dispatch during *any* scarcity condition") (Public Systems' emphasis). As the Commission explained in the May 30, 2014 Order, the incentive for a resource to maximize its dispatch, which theoretically exists during any Capacity Scarcity Condition, is adequately addressed by section III.13.7 of the Tariff. *See* May 30, 2014 Order, 147 FERC ¶ 61,172 at P 67 n.71 (quoting Tariff, § III.13.7, Performance, Payments and Charges in the FCM (31.0.0)).

The Commission orders:

Requests for rehearing of the October 2, 2014 Order are hereby denied, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.