153 FERC ¶ 61,223
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. and New England Power Pool	Docket Nos. ER14-1050-002 EL14-52-001

ORDER DENYING REHEARING

(Issued November 19, 2015)

1. On January 17, 2014, ISO New England Inc. (ISO-NE) and the New England Power Pool Participants Committee (NEPOOL) submitted, pursuant to section 205 of the Federal Power Act (FPA)[1] and section 11.1.5 of the ISO-NE Participants Agreement,[2] alternative proposals intended to address fleet-wide resource performance problems in New England (January 17 Filing). By order issued May 30, 2014, the Commission *sua sponte* invoked FPA section 206[3] and found, *inter alia*, that: (1) ISO-NE's existing Forward Capacity Market (FCM) payment design was unjust and unreasonable; (2) neither ISO-NE's proposal nor NEPOOL's proposal, standing alone, had been shown to be just and reasonable; and (3) aspects of the two proposals, in combination and as modified by the Commission, constituted a just and reasonable solution to the region's

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[1] 16 U.S.C. § 824d (2012).

[2] 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."

[3] 16 U.S.C. § 824e (2012).

resource performance problems.[4] Therefore, the Commission directed ISO-NE to submit revisions to its Transmission, Markets and Services Tariff (Tariff) to increase the Reserve Constraint Penalty Factors in its real-time markets, as proposed by NEPOOL, and implement a modified version of the two-settlement capacity market design that ISO-NE proposed.[5] Multiple parties submitted requests for rehearing or requests for clarification of the May 30 Order.[6] In this order, we deny rehearing and dismiss as moot the requests for clarification.

I. Background

2. In the January 17 Filing, ISO-NE proposed changes to the 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

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[4] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172, at PP 23-26 (2014) (May 30 Order).

[5] Docket No. EL14-52-000 was assigned to the FPA section 206 proceeding.

[6] The following parties filed requests for rehearing or clarification: Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Co., New Hampshire Electric Cooperative, Inc., Vermont Public Power Supply Authority, and Vermont Electric Cooperative (collectively, Public Systems); Connecticut Public Utilities Regulatory Authority, Connecticut Office of Consumer Counsel, George Jepsen, Attorney General for the State of Connecticut, Connecticut Department of Energy and Environmental Protection, United Illuminating Co., and Rhode Island Public Utilities Commission (collectively, Connecticut and Rhode Island); Dominion Resources Services, Inc. (Dominion); Exelon Corp., Equipower Resources Management, LLC, Essential Power, LLC, Dynegy Marketing and Trade, LLC, and Casco Bay Energy Co., LLC (collectively, Indicated Generators); Potomac Economics, Ltd. (Potomac Economics); New England Power Generators Association, Inc. (NEPGA); New England Power Pool Participants Committee (NEPOOL); NextEra Energy Resources, LLC (NextEra); PSEG Power LLC, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut LLC, NRG Power Marketing, LLC, GenOn Energy Management, LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, NRG Canal LLC, and Energy Curtailment Specialists Inc. (collectively, PSEG and NRG).

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 replace 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 Order, the Commission instituted a section 206 proceeding, finding that the existing Tariff was unjust and unreasonable because it failed to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits. The Commission 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 and to increase the Reserve Constraint Penalty Factors.

5. With regard to the modifications to the two-settlement capacity market design, the Commission 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 the application of Capacity Performance Payments for resources on the export side of an intra-zonal transmission constraint during a Capacity Scarcity Condition, or further

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

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, and on October 2, 2014, the Commission issued an order accepting in part, subject to condition, and rejecting in part ISO-NE's compliance filing, and directing a further compliance filing.[10] In the October 2 Order, the Commission accepted ISO-NE's Tariff revisions regarding the increased Reserve Constraint Penalty Factors, the treatment of energy efficiency resources, and ISO-NE's proposal to retain the Capacity Performance Payment Rate and the dynamic de-list bid threshold at the levels that ISO-NE originally proposed in the January 17 Filing. However, the Commission rejected ISO-NE's proposed Tariff revisions concerning intra-zonal transmission constraints.

7. The rejected Tariff provision contained ISO-NE's proposed solution to the potential improper price signal issue that the Commission identified in the May 30 Order. 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, would create other distortionary incentives. Therefore, ISO-NE argued that a superior solution would be to credit those resources only for the reserves, not for the energy, they provide during Capacity Scarcity Conditions because only reserves have a positive marginal value on the export side of a transmission constraint.

8. In the October 2 Order, the Commission rejected ISO-NE's proposed solution to the intra-zonal transmission constraint issue because, based upon additional information submitted by ISO-NE and other parties, the Commission found that an exemption is not necessary. More specifically, the Commission found that the additional information indicated that the improper price signal problem that the Commission identified in the May 30 Order is of limited geographic scope, and that the incentive for capacity resources to submit energy market offers below their actual costs is weaker than the Commission contemplated.[11]

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[8] *Id.* P 67.

[9] *Id.* P 110.

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

[11] October 2 Order, 149 FERC ¶ 61,009 at PP 56-62.

9. Connecticut and Rhode Island,[12] Dominion Resources Services, Inc. (Dominion), Indicated Generators,[13] NextEra Energy Resources, LLC (NextEra), Potomac Economics, PSEG Companies and NRG Companies (PSEG and NRG), and Public Systems[14] filed requests for rehearing of the May 30 Order. The New England Power Generators Association (NEPGA) and NEPOOL filed requests for clarification of the May 30 Order.

II. Discussion

10. The requests for rehearing and clarification in this proceeding raise issues regarding: (1) rejection of NEPOOL's proposal, (2) adoption of the modified version of ISO-NE's two-settlement capacity market design, (3) adoption of the two-settlement capacity market design and the increased Reserve Constraint Penalty Factors in combination, (4) exemptions for resource non-performance, (5) certain parameters of the two-settlement capacity market design, (6) market power mitigation rules under the two-settlement capacity market design, and (7) the Peak Energy Rent adjustment mechanism. We will address the requests for rehearing and clarification in that sequence.

A. Rejection of NEPOOL's Proposal

1. Requests for Rehearing

11. Connecticut and Rhode Island argue that the Commission erred in rejecting NEPOOL's proposal on the basis that the EFORp metric is flawed. Connecticut and Rhode Island contend that the Commission dismissed the EFORp metric because it would measure performance in terms of "availability," and that, in doing so, the Commission ignored arguments and evidence showing that "retaining an availability-based capacity

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[12] Connecticut and Rhode Island consist of: the Connecticut Public Utilities Regulatory Authority, the Connecticut Office of Consumer Counsel, George Jepsen, Attorney General for the State of Connecticut, the Connecticut Department of Energy and Environmental Protection, the United Illuminating Company, and the Rhode Island Public Utilities Commission.

[13] Indicated Generators consist of: Exelon Corporation; Equipower Resources Management, LLC; Essential Power, LLC; Dynegy Marketing and Trade, LLC; and Casco Bay Energy Company, LLC.

[14] Public Systems consist of: Connecticut Transmission Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Company, New Hampshire Electric Cooperative, Inc., Vermont Public Power Supply Authority, and Vermont Electric Cooperative.

product is just and reasonable."[15] Connecticut and Rhode Island argue that the Commission arbitrarily and capriciously faulted the EFORp metric for maintaining "numerous exemptions for nonperformance," without identifying which exemptions are unacceptable and why.[16] Connecticut and Rhode Island contend that, contrary to the Commission's assertion, the fact that the EFORp metric would measure availability only in certain peak hours of the year is a strength, not a weakness, because those hours are precisely the times when capacity is scarce and an outage created by a capacity deficiency is most likely to occur.[17] Connecticut and Rhode Island assert that the Commission failed to consider Potomac Economics' adjustments to the EFORp metric and failed to consider other proposed improvements to the capacity market rules.[18] Connecticut and Rhode Island argue that the Commission erred by departing from its practice of giving weighted consideration to the stakeholder process and vote.[19]

12. Public Systems argue that the Commission erred in finding that increasing the Reserve Constraint Penalty Factors would not, by itself, provide a sufficient incentive to address the region's resource performance problems.[20] Public Systems contend that the Commission failed to consider that the increased Reserve Constraint Penalty Factors, combined with other existing and future energy market enhancements, could adequately address the region's resource performance problems.[21]

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[15] Connecticut and Rhode Island Request for Rehearing at 8. Connecticut and Rhode Island specifically cite to passages from their protest to the January 17 Filing stating that an "availability-defined capacity product" provides incentives to a broad range of asset types and requires plant managers to run their facilities "consistent with good utility practice, without being distracted by the need to predict dispatch practices and unforeseen transmission outages that may cause capacity scarcity conditions." *Id.* at 8-9.

[16] *Id.* at 9.

[17] *Id.*

[18] *Id.* at 11-12.

[19] *Id.* at 30 (citing *Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1062 (D.C. Cir. 2008); *ISO New England Inc. and New England Power Pool*, 126 FERC ¶ 61,180, at P 15 (2009)).

[20] Public Systems Request for Rehearing at 23-24.

[21] *Id.* at 24.

2. **Commission Determination**

13. We deny rehearing of the Commission's determination that NEPOOL's proposal has not been shown to be just and reasonable.

14. In the May 30 Order, the Commission concluded that NEPOOL's EFORp metric was flawed for several reasons, including that it: (1) only measures a resource's performance against its own historical performance; (2) could provide resources an incentive to lower their performance over the next four years in order to lower the performance score against which their performance would be measured after the EFORp metric is implemented; (3) would measure performance in terms of "availability," and would do so only in certain peak hours of the year; and (4) would maintain numerous exemptions for non-performance.[22] Connecticut and Rhode Island erroneously assert that the Commission ignored evidence or argument concerning the appropriateness of NEPOOL's EFORp metric. As explained below, the Commission did, in fact, consider the evidence and arguments to which Connecticut and Rhode Island cite.

15. Connecticut and Rhode Island argue that, in rejecting the EFORp metric because it is based on resource availability, the Commission ignored testimony indicating that an availability-based metric is just and reasonable.[23] We disagree. The testimony to which Connecticut and Rhode Island cite involves the FCM payment structure that was in place prior to the two-settlement capacity market design, and that testimony is belied by record evidence showing a substantial decline in fleet-wide resource performance under that payment structure.[24] As the Commission explained in the May 30 Order, that payment structure "treats many resources as if they are fully available to operate during Shortage Events, and pays them accordingly, even when those resources are unable to deliver energy or reserves at that time."[25] The Commission found that payment structure to be

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[22] May 30 Order, 147 FERC ¶ 61,172 at P 24, n.22.

[23] Connecticut and Rhode Island Request for Rehearing at 8 (citing Connecticut and Rhode Island Protest at 10-12, Att. C at 6:6-7:5, 8:15-16:4; Connecticut and Rhode Island Answer at 13, 16; Potomac Economics Comments at 15, 25-26).

[24] May 30 Order, 147 FERC ¶ 61,172 at P 26 (explaining that resource performance has declined to a level that has jeopardized ISO-NE's ability to reliably operate the electric system, the overall rate of unplanned outages has doubled since 2007, and the average response rate for generators dispatched following a contingency is only 71 percent).

[25] *Id.*

unjust and unreasonable because it "not only fail[s] to incent resource performance, but also perversely select[s] less reliable resources over more reliable resources."[26] The Commission rejected the EFORp metric because, in addition to its other flaws, it would perpetuate that payment structure by continuing to measure resource performance in terms of "availability," as defined under the existing market rules, and would do so only in certain peak hours of the year.[27] As explained in the May 30 Order and again below, the existing FCM's availability-based compensation structure has contributed to the region's resource performance problems by failing to adequately incent resource performance and by perversely selecting less reliable resources over more reliable resources.[28]

16. We similarly reject Connecticut and Rhode Island's assertion that the measurement of resource availability only in certain peak hours of the year is not a flaw, but rather is one of the EFORp metric's strengths. As the Commission explained, recent resource performance in New England has shown that the region needs resources that provide energy or reserves during reserve deficiencies. We are not persuaded that the EFORp metric would procure that product. Because reserve deficiencies can occur at any time of year, not just in the peak hours included in the EFORp metric, the EFORp metric would not appropriately value resources' contributions during reserve deficiencies that occur outside of EFORp Hours. Further, the EFORp metric measures resource availability in EFORp Hours regardless of whether any reserve deficiencies actually occur in those hours. This could result not only in a resource being paid a premium even if no reserve deficiencies occur, but also in a resource being paid a premium where it performed poorly during a reserve deficiency but made up for that by performing well during the EFORp hours in which there is no deficiency. In short, the EFORp metric would not only perpetuate the payment structure that the Commission found to be problematic in the May 30 Order, it would also exacerbate the flaws in that payment

[26] *Id.*

[27] As to Connecticut and Rhode Island's assertion that the Commission ignored Potomac Economics' arguments concerning availability-based performance measurement and the EFORp metric, *see* Connecticut and Rhode Island Request for Rehearing at 8, n. 11, the Commission did in fact address Potomac Economics' arguments on this issue in the May 30 Order. *See* May 30 Order, 147 FERC ¶ 61,172 at n.22. We note that Potomac Economics' argument is also contradicted by the record evidence of the resource performance problems under the "availability" definition that has been in place in New England, and that the EFORp metric would perpetuate.

[28] *See id.* P 26; *infra* Section II.B.2.

structure by measuring resources' availability in fewer hours of the year, and would do so regardless of whether any reserve deficiencies occurred in those hours.

17. Connecticut and Rhode Island argue that the Commission erred by faulting the EFORp metric for maintaining numerous exemptions for nonperformance without identifying which exemptions are unacceptable and why. This argument misses the point. While it is possible that different exemptions have contributed to the region's resource performance problems in different proportions, the record does not indicate how much each individual exemption has contributed to the poor resource performance reflected in the record. Further, it is unnecessary to identify how much each exemption has contributed to the resource performance problems. The salient points are that (1) the combined effect of those exemptions is a flawed market construct that treats resources as if they have fully performed when, in fact, they did not perform, and (2) the EFORp metric would maintain *all* of those exemptions and, in addition to its other flaws, would do so without paying resources based on their provision of energy and reserves during reserve deficiencies. Thus, the Commission appropriately identified this as one of the EFORp metric's shortcomings.

18. Connecticut and Rhode Island further argue that the Commission's criticisms of the EFORp metric are speculative. We disagree. The Commission identified specific flaws in the EFORp metric and explained how those flaws could further erode reliability in the region. It was not necessary for the Commission to prove that the EFORp metric would, in fact, erode reliability.[29]

19. Contrary to Connecticut and Rhode Island's assertions, the Commission did not ignore evidence or argument that the EFORp metric would enhance performance incentives.[30] The evidence and argument to which Connecticut and Rhode Island cite

[29] *See, e.g., Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 531 (D.C. Cir. 2010) ("Neither *Electric Consumers* nor any other case law prevents the Commission from making findings based on 'generic factual predictions' derived from economic research and theory."); *Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239, 260-61 (D.C. Cir. 2007) ("It is well-established that an 'agency's predictive judgments about areas that are within the agency's field of discretion and expertise are entitled to particularly deferential review, as long as they are reasonable.") (quoting *Earthlink, Inc. v. FCC*, 462 F.3d 1, 12 (D.C. Cir. 2006)).

[30] Connecticut and Rhode Island Request for Rehearing at 10 (citing Connecticut and Rhode Island Protest at 12-15).

concerns the EFORp metric's use of EFORp Hours, which, as discussed above, the Commission fully considered and found to be problematic.[31]

20. We disagree with Public Systems' assertion that the Commission erred in finding that the increase in Reserve Constraint Penalty Factors would not, by itself, be sufficient to address the region's resource performance problems. No party in this proceeding, including NEPOOL, which proposed the increased Reserve Constraint Penalty Factors, has provided evidence showing that increasing the Reserve Constraint Penalty Factors for 30-Minute Operating Reserves, from $500/MWh to $1,000/MWh, and 10-Minute Non-Spinning Reserves, from $850/MWh to $1,500/MWh, will adequately address the region's resource performance problems. Further, the evidence to which Public Systems cite does not support such a showing.[32] That evidence either (1) is based on the flawed premise that the Capacity Performance Payment Rate must be based on the value of lost load,[33] or (2) merely supports the notion that the necessary incentive level could be achieved solely through the energy and ancillary services markets if the Reserve Constraint Penalty Factors are increased to levels above those that NEPOOL proposed.[34] In the May 30 Order, the Commission explicitly rejected the former premise.[35]

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[31] *See* May 30 Order, 147 FERC ¶ 61,172 at P 24 n.22; *supra* P 16.

[32] *See* Public Systems Request for Rehearing at 24 n.22 (citing Eastern Massachusetts Consumer-Owned Systems Protest and Comments, Test. of William Bottiggi at 13-14; Connecticut and Rhode Island Comments and Protest, Att. A, Att. C, Att. B; NEPOOL Comments, Att. A at 56-61, Att. B at 10-13).

[33] *See* Connecticut and Rhode Island Comments and Protest, Att. C at 24-25.

[34] *See* Eastern Massachusetts Consumer-Owned Systems Feb. 12, 2014 Protest and Comments, Test. of William Bottiggi at 13-14. Public Systems also attempts to support its argument by citing testimony that NEPOOL submitted. *See* Public Systems Request for Rehearing at 24 (citing NEPOOL Comments, Att. A at 56-61, Att. B at 10-13). However, that testimony does not indicate that increasing the Reserve Constraint Penalty Factors will, by itself, adequately address the region's resource performance problems. Rather, it merely indicates that increasing the Reserve Constraint Penalty Factors will provide a performance incentive, which is consistent with the Commission's findings in the May 30 Order.

[35] May 30 Order, 147 FERC ¶ 61,172 at P 74; *see also infra* PP 84-87 (explaining, *inter alia*, that the record does not support the conclusion that calculating the Capacity Performance Payment Rate based on the value of lost load would satisfy the 1-day-in-10-years reliability standard under current system conditions).

21. As to the evidence indicating that the energy and ancillary services markets could provide the necessary incentive, the Commission acknowledged that possibility in the May 30 Order, but explained that the specific values that NEPOOL proposed were insufficient for that purpose.[36] We further note that the record does not contain evidence showing what Reserve Constraint Penalty Factor levels would be necessary to fully address the region's resource performance problems. Additionally, in directing ISO-NE to implement both NEPOOL's proposed increase to the Reserve Constraint Penalty Factors and the two-settlement capacity market design, the Commission explained that "there is value in providing incentives in both the FCM and the energy and ancillary services markets."[37] Thus, while it may be possible to produce the necessary performance incentive entirely through the energy and ancillary services markets, the record before us is insufficient for developing such an incentive, and there may be disadvantages to such an approach. We, therefore, find that the Commission properly concluded that the increase in Reserve Constraint Penalty Factors that NEPOOL proposed, i.e., the only increase to the Reserve Constraint Penalty Factors that is supported by the record, would not, by itself, be sufficient to address the region's resource performance problems.[38]

22. Similarly, we reject Public Systems' and Connecticut and Rhode Island's contentions that the Commission failed to consider whether the increased Reserve Constraint Penalty Factors, combined with other market enhancements, will improve resources' availability and could adequately address the region's resource performance problems. The actual and potential market rule changes to which these parties cite do not alter our analysis, because they do not address the fundamental flaws in the FCM payment structure. Furthermore, while some of the market rule changes that Public Systems highlight could provide an incremental performance incentive, the record does not support a finding that those changes, when combined with the increased Reserve Constraint Penalty Factors, would provide a performance incentive sufficient to solve the region's resource performance problems. As for the one change that Connecticut and

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[36] May 30 Order, 147 FERC ¶ 61,172 at P 24.

[37] *Id.* P 108.

[38] Furthermore, even assuming *arguendo* that the record could support a specific solution that relied only on the energy and ancillary services markets, that fact does not undermine the justness and reasonableness of the Commission's chosen solution. *See, e.g.*, *Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 470-71 (D.C. Cir. 2008), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010); *City of Winnfield, La. v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984).

Rhode Island specifically identify, i.e., NEPOOL's proposed change to the "Poorly Performing Resources" provision in section III.13.7.1.1.5 of the Tariff,[39] we are not persuaded that that change would provide a sufficient performance incentive. That market rule change would not only maintain the problematic FCM payment structure but would also impact only those resources whose availability scores were less than 40 percent in multiple years.[40]

Lastly, we reject Connecticut and Rhode Island's assertion that the Commission's practice is to assign "weights to each proposal commensurate with the level of stakeholder support each garnered at the Participants Committee vote,"[41] and that the Commission departed from that practice in this case. While the Commission's practice is to give weight to stakeholder voting in its consideration of any proposal, [42] the Commission's consideration of stakeholder voting is not as formalistic as Connecticut and Rhode Island assert. Moreover, as the Commission has stated previously, " "stakeholder support alone cannot ultimately prove that a rate design is just and reasonable."[43]

B. Adoption of a Modified Version of ISO-NE's Proposal

1. Requests for Rehearing

23. Multiple parties request rehearing of the Commission's decision to adopt a modified version of ISO-NE's two-settlement capacity market design.[44]

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[39] *See* Connecticut and Rhode Island Request for Rehearing at 12, n.19.

[40] *See* January 17 Filing, Att. N-1b at 16:22-17:9.

[41] Connecticut and Rhode Island Request for Rehearing at 30.

[42] *See, e.g., Am. Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,083, at P 172 (2008).

[43] *Id.*

[44] Connecticut and Rhode Island, PSEG and NRG, and Public Systems. Dominion, Indicated Generators, NextEra, and Potomac Economics also request rehearing of specific aspects of the two-settlement capacity market design. Those rehearing requests are addressed *infra* sections II.D and II.E.

24. Connecticut and Rhode Island argue that the Commission erred by finding most aspects of the two-settlement capacity market design just and reasonable without considering the impacts on customer charges.[45] Connecticut and Rhode Island assert that they showed that ISO-NE's proposal would increase capacity charges "to levels beyond the bounds of reasonableness" because, they allege, the Capacity Performance Payment Rate is incorrectly based on the 1-day-in-10-years loss of load expectation, rather than on the value of lost load,[46] and because the risks imposed on suppliers will drive them to withdraw their capacity from the New England market, which will produce "fake shortages."[47] Connecticut and Rhode Island also argue that the Commission failed to consider the role that demand response resources play in resolving reserve deficiencies.[48]

25. Multiple parties argue that the Commission erroneously determined that the two-settlement capacity market design does not unduly discriminate against mid-range resources that lack quick start capability.[49] PSEG and NRG assert that, although the two settlement capacity market design does not facially distinguish among technology types, it will have very different, predictable impacts on different types of units.[50]

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[45] Connecticut and Rhode Island Request for Rehearing at 13.

[46] More specifically, Connecticut and Rhode Island argue that using the value of lost load is "the only reasonable economic method to assess whether the charges customers pay are commensurate with the benefits they receive," *id.* at 14, and that the Commission erred in using the loss of load expectation approach because it ties the performance payment rate to the cost of new entry for a generator, "which has no bearing on the value of the reliability benefit for customers," *id.* at 15. Connecticut and Rhode Island further argue that the Commission's approach is unprecedented, *id.* (citing *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071 (2008); 119 FERC ¶ 61,306, at P 75 (2007)), and disregards the value that customers place on new capacity, instead focusing exclusively on the cost of producing more supply. *Id.* Connecticut and Rhode Island contend that such an approach is likely to create signals for increased capacity resources when customers would not be willing to pay for that supply based on the cost of a new generator. *Id.* These arguments, and other arguments concerning the value of lost load, are addressed *infra* section II.E.

[47] Connecticut and Rhode Island Request for Rehearing at 15-17.

[48] *Id.* at 15.

[49] PSEG and NRG Request for Rehearing at 19; Public Systems Request for Rehearing at 18.

[50] PSEG and NRG Request for Rehearing at 19.

PSEG and NRG contend that, "to show undue discrimination, the petitioner must demonstrate that the two classes of customers are similarly situated *for purposes of the rate*."[51] PSEG and NRG claim that the "purpose of the rate," in this case, is to incentivize resource performance, not to penalize mid-range units without quick start capability.[52]

26. PSEG and NRG argue that the Commission erred in addressing the performance issues through the two-settlement capacity market design when the same goal potentially could have been achieved through the energy and ancillary services markets with less disruption and less discrimination.[53] Pointing to the Commission's acknowledgement that the energy and ancillary services markets could potentially be used to achieve the same performance incentive as the two-settlement capacity market design, PSEG and NRG assert that the Commission should have taken that approach because doing so "would be expected to have much less discriminatory impact because it would not severely *penalize* an entire class of units for lacking particular operational capabilities."[54] PSEG and NRG argue that the two-settlement capacity market design would only be justified by "showing that discriminatory pricing was the *only way* to achieve the alleged benefits it sought."[55]

27. Multiple parties argue that the Commission's standard for determining when resources are similarly situated in this context is unduly narrow because it ignores the reliability contributions of resources that do not have quick start capability, and ignores other reliability characteristics such as fuel diversity.[56] PSEG and NRG argue that the owners of mid-merit resources have made investments in those resources in reliance on existing market rules, and the Commission's adoption of the two-settlement capacity

[51] PSEG and NRG Request for Rehearing at 21 (quoting *"Complex" Consol. Edison Co. of NY v. FERC*, 165 F.3d 992, 1013 (D.C. Cir. 1999)) (emphasis added by PSEG and NRG).

[52] PSEG and NRG Request for Rehearing at 21.

[53] *Id.* at 21-22.

[54] *Id.* at 21 (emphasis in original).

[55] *Id.* at 22 (quoting *Transcontinental Gas Pipe Line v. FERC*, 998 F.2d 1313, 1321, 1322 (5th Cir. 1993)) (internal quotations omitted) (emphasis added by PSEG and NRG).

[56] *Id.* at 22-23; Public Systems Request for Rehearing at 18.

market design impermissibly devalues those sunken investments in long-lived assets.[57] Public Systems argue that the Commission has already adopted other market mechanisms to ensure that flexible resources receive additional revenues reflecting the benefits they provide, and that the two-settlement capacity market design risks double-compensating resources for those benefits.[58] Public Systems contend that, the two-settlement capacity market design ignores the difference between resource adequacy and resource performance—a distinction that the Commission has acknowledged in the past.[59] PSEG and NRG argue that the Commission's treatment of energy efficiency resources undermines the Commission's rationale for denying the claims of undue discrimination.[60]

28. PSEG and NRG argue that the shift from compensating resources based on their availability to compensating them based on their performance represents a fundamental shift in the New England capacity market, and the Commission cannot lawfully rationalize its decision by downplaying the significance of this shift. PSEG and NRG assert that the Commission erred by comparing the two-settlement capacity market design to an energy-only market, because this line of reasoning "appears to conflate lost opportunity costs with penalties."[61] PSEG and NRG contend that, in an energy-only market, units are "only penalized for failure to deliver energy in real-time *if they fail to follow dispatch instructions*."[62]

29. Connecticut and Rhode Island argue that the Commission erred by misapprehending the differences between availability-defined capacity and performance-defined capacity.[63] They argue that ISO-NE's proposal radically changes the capacity product, and the Commission's attempt to minimize the difference demonstrates a

[57] PSEG and NRG Request for Rehearing at 23.

[58] Public Systems Request for Rehearing at 17 (citing *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012)).

[59] Public Systems Request for Rehearing at 17 (citing *ISO New England Inc.*, 144 FERC ¶ 61,204, AT P 30 (2013), *reh'g denied*, 147 FERC ¶ 61,026 (2014)).

[60] PSEG and NRG Request for Rehearing at 24.

[61] *Id.* at 9.

[62] *Id.* (emphasis in original).

[63] Connecticut and Rhode Island Request for Rehearing at 20.

fundamental misunderstanding of availability and performance. They argue that, contrary to the Commission's assertion, a resource's must-offer obligation is not an obligation to perform, but rather an obligation to be available to perform subject to the resource's operational characteristics.[64] They contend that an availability metric considers a resource's operational characteristics and other relevant considerations, whereas a performance metric is "strictly indifferent to a resource's ability to perform."[65] They assert that, because the Commission misapprehended the difference between availability and performance, it erroneously ignored evidence and dismissed concerns that a performance-based capacity product cannot be hedged.[66] They contend that their expert witness concluded that, because these risks cannot be hedged, "suppliers will simply 'hedge their risks by submitting higher delist bids in the auction[,]'" which is unfair to customers.[67]

30. Public Systems argue that, by pointing to methods by which a capacity resource can hedge its performance risks, the Commission fails to identify the statutory authority allowing it to require utilities to become "wholesalers of insurance" as well as electric capacity.[68] They further state that the new performance rules will unreasonably favor market participants with large portfolios.[69] Lastly, Public Systems state that the new rules overpay for flexibility and unreasonably and discriminatorily pay capacity resources more to respond to scarcity than to prevent it.[70]

2. <u>Commission Determination</u>

31. We deny rehearing of the Commission's decision to adopt a modified version of ISO-NE's proposal.

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[64] *Id.* at 21.

[65] *Id.*

[66] *Id.* at 23 (citing Connecticut and Rhode Island Protest at 25, n.3; Dykes Test. at 5:11-17; Connecticut and Rhode Island Answer at 20-21; Falk Supp. Test. at 14:11-18:18).

[67] *Id.* (quoting Falk Test. at 80:10-15)

[68] Public Systems Request for Rehearing at 15.

[69] *Id.* at 15-16.

[70] *Id.* at 16-18.

32. Multiple parties[71] assert that the two-settlement capacity market design is fundamentally at odds with the existing FCM construct because the two-settlement capacity market design emphasizes resource performance rather than resource availability. Whether the two market designs are similar or different ultimately does not determine whether the two-settlement capacity market design is just and reasonable. Nonetheless, we disagree that the two market designs are fundamentally at odds with each other. The two designs have similarities, i.e., they serve the same fundamental purpose and share an important design principle, and they have differences, e.g., the treatment of a resource's operational characteristics. This fact does not undermine the justness and reasonableness of the two-settlement capacity market design.

33. The fundamental purpose of the FCM is to procure sufficient resources to meet the reliability objective, and encouraging better performance from capacity resources helps to achieve this purpose. As the Commission explained in the May 30 Order, under both the existing FCM construct and the two-settlement capacity market design, a resource's capacity revenues are intended to be linked to the resource's real-time performance. In this way, the two constructs are similar, but the previous mechanism to link capacity revenue and real-time performance was flawed, as evidenced by the documented deterioration of resource performance. The mechanics of the new Capacity Performance Payment significantly strengthen the linkage and thus provide the strong incentives for resource performance that were previously missing.[72] This is, in part, because a resource's operational characteristics are valued differently under the two constructs.

34. Under the existing FCM design, a resource's operational characteristics do not impact its capacity revenues—i.e., the market design does not consider a resource's operational characteristics in determining that resource's value. Under the two-settlement capacity market design, a resource's operational characteristics can impact the resource's capacity revenues (positively or negatively) during Capacity Scarcity Conditions because operational characteristics impact the resource's ability to provide the capacity product desired—i.e., the market design does consider a resource's operational

[71] Connecticut, Rhode Island, Public Systems, PSEG and NRG.

[72] The degree of difference between these two market designs is attributable to both the payment structure and the available exemptions, or lack thereof, under each design. Therefore, we note that the rationale set forth in the instant section also supports the Commission's decision to not allow exemptions from Capacity Performance Payments. Similarly, the Commission's rationale for not allowing exemptions also supports the Commission's determination that the two-settlement payment structure is just and reasonable. We address the arguments specifically challenging the lack of exemptions under the two-settlement capacity market design *infra* section II.D.

characteristics in determining a resource's value during times of system stress.[73] Notwithstanding parties' assertions to the contrary, this aspect of the two-settlement capacity market design is consistent with the FCM's fundamental purpose to help ensure reliability through resource adequacy. Resources' provision of energy and reserves, during Capacity Scarcity Conditions is critical to maintaining reliability, so compensating resources in part based on their ability to provide that service ensures that they are properly compensated for their contributions to system reliability. As the Commission explained when it originally accepted ISO-NE's FCM, the FCM represents an "appropriate market structure to ensure that generating resources are appropriately compensated based on their location and contribution to system reliability and provides incentives to attract new infrastructure where needed."[74]

35. PSEG and NRG assert that the Commission "artificially downplay[ed] the significance of the change."[75] The level of significance, however, is beside the point. The relevant point is that the change is consistent with the FCM's fundamental purpose, to help ensure reliability through resource adequacy, and one of the FCM's design principles, i.e., that a resource's capacity revenues should be adjusted based on its performance. Furthermore, as the Commission explained in the May 30 Order, the fact that the existing FCM has largely compensated resources based on their availability, with little regard to their performance, has contributed to the region's resource performance problems by failing to adequately incent resource performance and by perversely selecting less reliable resources over more reliable resources.[76] To address this

[73] Contrary to Public Systems' assertion, the two-settlement capacity market design does not ignore the fact that capacity resources provide reliability year-round. Under the two-settlement capacity market design, capacity resources receive capacity revenues year-round. At times when there is no Capacity Scarcity Condition, the capacity revenues are based solely on each resource's Capacity Base Payment. When there is a Capacity Scarcity Condition, the capacity revenues are based on both the Capacity Base Payment and the Capacity Performance Payment. The fact that the two-settlement capacity market design compensates resources differently depending on how stressed the system is does not mean that the market design ignores resources' contributions to the system when it is less stressed. Rather, it means that the market design appropriately values resources' based on their ability to help ensure reliability during both stressed and unstressed system conditions.

[74] *Devon Power LLC*, 115 FERC ¶ 61,340, at P 71 (2006).

[75] PSEG and NRG Request for Rehearing at 9.

[76] May 30 Order, 147 FERC ¶ 61,172 at P 26.

shortcoming, the Commission found the two-settlement capacity market design to be just and reasonable exactly because it strengthens the tie between a resource's compensation and its performance and, in so doing, encourages better performance and reliability. While it is possible that a properly designed availability-based capacity market can provide the necessary performance incentives, the availability-based payment design under the existing FCM rules has not done so. Thus, contrary to parties' assertions, it is the existing FCM payment design, not the two-settlement capacity market design, that has operated in a manner that is inconsistent with the fundamental purpose of the FCM.

36. Connecticut and Rhode Island argue that the Commission misapprehended the differences between "availability-defined capacity" and "performance-defined capacity" and, as a result, erroneously dismissed concerns that the latter cannot be hedged.[77] We disagree. The Commission did not misapprehend the differences between the two-settlement capacity market design and the existing FCM design. While Connecticut and Rhode Island interpret the differences and similarities between the two market designs differently than we do, we are not persuaded by their interpretation. Connecticut and Rhode Island list ways in which the two market designs are different, and assert that those differences undermine the Commission's statement that the market designs are similar.[78] However, as explained above, the difference that Connecticut and Rhode Island highlights—i.e., that the two approaches treat a resource's operational characteristics differently—does not render the two market designs fundamentally at odds.[79]

37. We disagree with Public Systems' and PSEG and NRG's arguments that the Commission's comparison of the two-settlement capacity market design to an uncapped energy market is flawed. In the May 30 Order, the Commission explained that the two-settlement capacity market design was consistent with certain economic principles underlying an uncapped energy market—i.e., that (1) linking a resource's revenues to its performance during scarcity conditions provides a performance incentive, and (2) "resources only earn scarcity revenue if they can actually deliver energy during periods of scarcity."[80] Regardless of any comparison, the relevant question is whether

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[77] Connecticut and Rhode Island Request for Rehearing at 20-22.

[78] *Id.* at 21.

[79] *See supra* PP 32-35.

[80] May 30 Order, 147 FERC ¶ 61,172 at P 63.

the principles the Commission cited are economically sound.[81] As explained here and in the May 30 order, we believe those principles to be sound, and the fact that the two-settlement capacity market design replicates performance incentives consistent with those principles gives us confidence that the two-settlement capacity market design will produce just and reasonable rates.[82]

38. Public Systems contend that the two-settlement capacity market design impermissibly requires resources to be "wholesalers of insurance."[83] To the extent Public Systems contends that resources must hedge against risk, we note that resource owners may choose to hedge against various risks, through insurance or other means. The May 30 Order does not require them to do so.

39. We also disagree with Public Systems' assertion that the two-settlement capacity market design is unreasonably biased in favor of entities with large resource portfolios. It is plausible that an entity with a large portfolio of poorly performing resources could have more difficulty hedging its performance risks than could an entity with a small portfolio of high-performing resources. In other words, regardless of the size of an entity resource portfolio, its ability to hedge its performance risk largely depends on the expected performance of its resources.

40. Connecticut and Rhode Island assert that the Commission did not consider the impacts that the two-settlement capacity market design would have on customers. We disagree. The Commission found that the risk premiums reflected in ISO-NE's two-settlement capacity market design may increase costs to consumers, but that, given the nature of the fleet-wide resource performance problems facing the New England region, the two-settlement capacity market design appropriately balances the increased costs to consumers against the added reliability benefits consumers will receive from a resource

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[81] The latter of these two principles is relevant to the issue of whether it is appropriate to allow exemptions from Capacity Performance Payments. We address the arguments on that issue *infra* section II.D.

[82] *See Cent. Hudson Gas & Elec. Corp. v. FERC*, 783 F.3d 92, 109 (2nd Cir. 2015) ("FERC may permissibly rely on economic theory alone to support its conclusions so long as it has applied the relevant economic principles in a reasonable manner and adequately explained its reasoning") (citing *Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 531 (D.C. Cir. 2010); *Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239, 260-61 (D.C. Cir. 2007); *Associated Gas Distribs. v. FERC*, 824 F.2d 981, 1008 (D.C. Cir. 1987)).

[83] Public Systems Request for Rehearing at 15-16.

fleet with more appropriate incentives and capability to reliably perform when needed.[84] In reaching this conclusion the Commission indeed considered the specific factors raised by Connecticut and Rhode Island.[85]

41. We also disagree with Connecticut and Rhode Island's assertion that the Commission failed to consider the role that demand response plays in resolving reserve deficiencies. Regardless of how the Capacity Performance Payment Rate is calculated, demand response resources are allowed to participate in the two-settlement capacity market design and are subject to the same Capacity Performance Payment Rate as all other resources.[86] Thus, the two-settlement capacity market design equally values the reliability contributions of demand response resources and generation resources.

42. Connecticut and Rhode Island also assert that the Commission failed to respond to their argument that the two-settlement capacity market design will impose unreasonable risks on suppliers, which will drive them from the market and produce "fake shortages" of capacity as those resources leave the FCM but continue to participate in the energy and ancillary services markets. This argument is speculative and unsupported by the record. Further, the FCM is designed to reflect such shortages through a clearing price that represents the demand for resources that are willing to take on a three-year forward commitment. In this way, the FCM clearing price reflects the value that consumers, through the load serving entities from which they purchase electric service, place on ensuring reliability three years hence. If resources leave the FCM, the auction clearing price will signal the need for additional capacity, and other resources—that more reliably or affordably provide the product that the region needs—can be expected to respond to that price signal and replace the withdrawn resources. The record does not support a finding that the two-settlement capacity market design will "drive" resources from the FCM or that any withdrawals that do occur will create a persistent, problematic shortage.

43. Multiple parties argue that the Commission incorrectly found that the two-settlement capacity market design does not unduly discriminate against mid-range

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[84] May 30 Order, 147 FERC ¶ 61,172 at P 75.

[85] *See, e.g., id.* PP 62-75 (addressing the financial risks associated with the two-settlement capacity market design, including the Capacity Performance Payment rate).

[86] The Commission takes note of a pending U.S. Supreme Court decision in *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *cert. granted*, Nos. 14-840, 14-841. The Commission continues to consider both the scope and possible next steps with respect to the Court's upcoming decision.

resources that lack quick-start capability.[87] We disagree. We acknowledge that, although the two-settlement capacity market design is facially neutral with respect to different types of resources, it could impact different types of resources differently. Rather than overlook this fact, the Commission in the May 30 Order explained that it is an important aspect of the two-settlement capacity market design.[88] Furthermore, we note that the non-baseload, non-fast-start resources that the parties claim will be unduly discriminated against under the new performance rules can still expect to receive capacity revenues unless they *completely* fail to perform during all Capacity Scarcity Conditions. In fact, the impact analysis that ISO-NE submitted as part of its initial filing in this proceeding indicates that a greater number of combined-cycle gas units – the resource type that most closely fits the non-baseload, non-fast-start description – are expected to remain more profitable under the new performance rules than under the previous rules.[89]

44. We are also unpersuaded by PSEG and NRG's assertion that the Commission could have achieved the same goal through the energy and ancillary services markets with less discriminatory impact than the two-settlement capacity market design, because using the energy and ancillary service markets "would not severely *penalize* an entire class of units for lacking particular operational attributes."[90] Regardless of whether one characterizes the Capacity Performance Payments as a "penalty" or an *ex post* settlement, resources will be compensated differently based on the level of service they provide, regardless of which market or markets provide the requisite performance incentive.[91]

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[87] PSEG, NRG, and Public Systems.

[88] May 30 Order, 147 FERC ¶ 61,172 at P 86 ("To the extent resources have different capabilities to provide energy and reserves during Capacity Scarcity Conditions, those resources are not similarly situated, and therefore it is not unduly discriminatory to compensate those resources differently based on their respective capabilities.").

[89] ISO-NE, Tariff Filing, at Attachment I-1g (Jan. 17, 2014) (Affidavit of Todd Schatzki); *id.* at Appendix B (Impact Assessment by Analysis Group, Inc.). The analysis results show that under all three equilibrium scenarios, fewer megawatts of combined-cycle gas units become uneconomic under the two-settlement capacity market rules than under the status quo FCM rules.

[90] PSEG and NRG Request for Rehearing at 21 (PSEG and NRG's emphasis).

[91] We note that, under the two-settlement capacity market design, a resource does not receive its Capacity Base Payments and Capacity Performance Payments separately. Rather, for each month of a Capacity Commitment Period, a resource receives one payment for that month—after the month has passed and ISO-NE has determined the

(continued ...)

Just as the operational characteristics of a mid-range resource without quick-start capability can limit the amount of revenue it receives under the two-settlement capacity market design, those operational characteristics would similarly limit the amount of revenue the resource would receive in the energy and ancillary services markets.[92]

45. We disagree with PSEG and NRG's assertion that the Commission's standard for determining whether resources are similarly situated in the context of this proceeding is unduly narrow because it only considers whether resources will be on-line during unpredictable Capacity Scarcity Conditions. The two-settlement capacity market design compensates resources for their overall contribution to reliability in *all* hours, not only during Capacity Scarcity Conditions. When a Capacity Scarcity Condition does not apply to a resource, which is the case in the vast majority of hours,[93] all resources are treated the same because all resources are contributing equally to overall system reliability. The fact that performance is valued more highly during Capacity Scarcity Conditions, and that a resource can receive net negative Capacity Performance Payments if its performance during times of system stress is poor, does not mean that the two-settlement capacity market design ignores reliability contributions outside Capacity Scarcity Conditions. Rather, it means that a resource's overall capacity revenues are based on that resource's contribution to reliability under different system conditions. We also disagree with PSEG and NRG's argument concerning fuel diversity. While fuel diversity can contribute to reliability, a diverse fuel mix will not ensure reliability if the resource fleet does not provide the level of performance that the region needs. The two-settlement capacity market design is tailored to provide the level of performance that the region needs, and to do so in a way that is fuel- and technology-neutral.

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resource's performance during that month—which represents both the Capacity Base Payment and the Capacity Performance Payment.

[92] We also note that providing the necessary performance incentive solely through the energy and ancillary services markets, as multiple parties prefer, could potentially discriminate in ways that providing the incentive through a combination of the ISO-NE markets does not. *See* May 30 Order, 147 FERC ¶ 61,172 at P 108 (explaining that there is value in providing incentives in both the FCM and the energy and ancillary services markets, because different combinations of revenue streams make sense for different resources).

[93] ISO-NE calculated that, when the system needs new entry, it expects that there will be 21.2 hours of Capacity Scarcity Conditions per year. *See* ISO-NE Tariff Filing, Att. I-1c at 107.

46. We are not persuaded by PSEG and NRG's argument that the Commission's adoption of the two-settlement capacity market design impermissibly devalues the investments that entities have already made in mid-merit resources. As an initial matter, we note that the record does not support a finding that those resources will, in fact, experience a drop in value under the two-settlement capacity market design. ISO-NE estimated that resources with performance rates as low as 40 percent will be better off financially under the two-settlement capacity market design than under the previous FCM rules.[94] As a result, it is reasonable to expect that many mid-merit resources will actually increase in value under the two-settlement capacity market design. Furthermore, to the extent that investments in existing resources are devalued, that change in value is a result of the changing capacity needs in the New England region, to which the two-settlement capacity market design is a response, not the cause.

47. We also disagree with PSEG and NRG's argument that the Commission's findings regarding energy efficiency resources undermine the Commission's rationale for determining that the two-settlement capacity market design does not unduly discriminate against mid-range resources that lack quick start capability. PSEG and NRG assert that the Commission acknowledged that "energy efficiency resources provide zero performance in off-peak hours," but then ignored that fact by stating that energy efficiency resources "represent a pre-determined level of load reduction that is constant as a percentage of that resource's load."[95] Contrary to PSEG and NRG's assertion, energy efficiency resources can perform in off-peak hours, and the Commission explicitly acknowledged that fact.

48. As the Commission explained in the May 30 Order, ISO-NE's original proposal in this proceeding "*assumes* that energy efficiency resources provide zero performance in off-peak hours."[96] The Commission found that aspect of ISO-NE's proposal to be unduly discriminatory, explaining that such an assumption is inappropriate because it would require energy efficiency resources—which can, and often do, perform in off-peak hours—to incur significant costs to monitor and verify their load reductions around-the-clock. As the Commission explained, it is unnecessary to track the performance of energy efficiency resources around-the-clock because, unlike all other types of resources, energy efficiency resources by design do not *actively* perform in real-time and, therefore,

[94] ISO-NE Feb. 12, 2014 Answer at 25 (citing Test. of Paul Hibbard and Todd Schatzki at 23).

[95] PSEG and NRG Request for Rehearing at 24 (quoting May 30 Order, 147 FERC ¶ 61,172 at P 89) (internal quotations omitted).

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

are not able to respond to real-time performance incentives.[97] The Commission's acknowledgement that this fundamental difference warrants an exemption for energy efficiency resources does not undermine the Commission's findings that the other types of resources are similarly situated to one another.

49. Public Systems argue that the two-settlement capacity market design risks double-compensating resources that receive compensation for providing ancillary services, such as frequency regulation service. We disagree. The two-settlement capacity market design compensates resources for providing the capacity product the region needs, whereas the ancillary services market compensates resources for certain additional benefits they provide to the system beyond their ability to operate consistent with their Capacity Supply Obligations. The fact that a resource's real-time performance can impact the revenue it receives from both the capacity market and the energy and ancillary services markets does not mean the resource is overcompensated. Rather, it means that the resource's attributes are providing multiple system benefits and the resource is being compensated accordingly.[98]

C. Adopting Aspects of ISO-NE's and NEPOOL's Proposals in Combination

1. Requests for Rehearing

50. Connecticut and Rhode Island argue that the Commission erred by predetermining that the combined incentive scheme represented by the increased Reserve Constraint Penalty Factors and the two-settlement capacity market design is just and reasonable. They argue that the record contains no evidence showing that the combination of these two changes will produce a just and reasonable result.[99] Connecticut and Rhode Island further argue that the Commission erred in establishing a narrow section 206 proceeding and failed to provide the parties with adequate notice of its intention to adopt a combined

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[97] *Id.*

[98] For example, if a resource provides frequency regulation service during a reserve deficiency, that resource is supporting system reliability in two separate, but related, ways: (1) by satisfying its share-of-system obligation, consistent with its Capacity Supply Obligation, and (2) by helping to regulate the frequency of the transmission grid. As long as the compensation for each service is commensurate with the benefits the resource is providing, compensating that resource for those two services does not constitute overcompensation.

[99] Connecticut and Rhode Island Request for Rehearing at 31.

incentive scheme consisting of aspects of ISO-NE's and NEPOOL's proposals. They assert that, by failing to provide an opportunity to meaningfully consider and respond to the combined scheme, the Commission has violated the Due Process Clause and the Administrative Procedures Act.[100]

51. PSEG and NRG argue that the Commission erred by instituting an FPA section 206 proceeding and thereby "injecting substantial uncertainty and further disruption into the market."[101] PSEG and NRG contend that, under the "jump ball" provision in the Tariff, the Commission did not need to establish an FPA section 206 proceeding to implement a rate that consists of aspects of both ISO-NE's proposal and NEPOOL's proposal.[102] PSEG and NRG request that the Commission either "clarify its reasons for establishing a separate proceeding and the specifics of the rates that would apply as of the refund effective date in the event that refund is deemed necessary[,]" or "grant rehearing and find that the FPA section 206 proceeding is either constrained in scope, or was unnecessary."[103] PSEG and NRG further assert that the Commission heightened this uncertainty by establishing a refund effective date of one day after publication in the Federal Register, rather than suspending the rate for the 5-month maximum period allowed under the FPA.[104]

52. Public Systems argue that the Commission should treat ISO-NE's compliance filing as a supplement to its section 205 filing, and should clarify that interveners may protest it as such. Public Systems specifically request that the Commission clarify "that its review of the compliance filing will include substantive concerns, and not merely the procedural question whether ISO-NE complied with the obligation to make a filing addressing certain topics."[105]

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[100] *Id.* at 32 (citing *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004, 1012 (D.C. Cir. 2005) (*PSC of Kentucky*)).

[101] PSEG and NRG Request for Rehearing at 25.

[102] *Id.*

[103] *Id.*

[104] *Id.* at 26.

[105] *Id.* at 25-26.

2. **Commission Determination**

53. We deny rehearing of the Commission's decision simultaneously to adopt NEPOOL's proposed Reserve Constraint Penalty Factors and a modified version of ISO-NE's two-settlement capacity market design. Contrary to multiple parties' assertions, the record contains sufficient evidence that simultaneously adopting the increased Reserve Constraint Penalty Factors and the two-settlement capacity market design constitutes a just and reasonable solution to the region's resource performance problems.

54. As the Commission explained in the May 30 Order, the two-settlement capacity market design together with the increased Reserve Constraint Penalty Factors provide a just and reasonable incentive structure that will help ensure reliability.[106] Increasing the Reserve Constraint Penalty Factors is a change to the real-time energy and reserves markets that will provide an immediate, incremental incentive for improved resource performance.[107] The two-settlement capacity market design is a change to the capacity market that will provide a more significant performance incentive but will not produce revenues reflecting that incentive until 2018.[108] The Commission continues to find that an effective combination of increased Reserve Constraint Penalty Factors and the two-settlement capacity market design will provide the requisite incentive structure need to help ensure reliability in New England. 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, the Commission has also explained why no such adjustment is appropriate at this time.[109]

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[106] May 30 Order, 147 FERC ¶ 61,172 at P 25.

[107] *Id.* P 108.

[108] *Id.*; *see also ISO New England Inc. and New England Power Pool Participants Committee*, 152 FERC ¶ 61,190, at P 45 (accepting ISO-NE tariff provisions that implement a program to help ensure reliability during the winter seasons prior to the two-settlement capacity market design being implemented in 2018).

[109] As the Commission explained in the October 2 Order, due to the speculative nature of the relationship between the values used for the Reserve Constraint Penalty Factors and the value used for the Capacity Performance Payment Rate, it is appropriate for any necessary adjustments to the $5,455/MWh Capacity Performance Payment Rate to be based on the increased Reserve Constraint Penalty Factors' actual impacts on system parameters. October 2 Order, 149 FERC ¶ 61,009 at P 24, *reh'g*, 153 FERC ¶ 61,224 at PP 16-17.

55. Connecticut and Rhode Island argue that the Commission violated the Due Process Clause and the Administrative Procedures Act by failing to provide the parties with adequate notice that it would adopt a solution comprised of elements of ISO-NE's proposal and NEPOOL's proposal.[110] We disagree. The parties in this proceeding did, in fact, have notice and opportunity to present evidence and argument on the issue of whether the combined solution is just and reasonable. From the outset of this proceeding, the proposed solutions to the region's resource performance problems involved changes to the FCM and the energy and ancillary services markets, including simultaneous changes to both. Thus, Connecticut and Rhode Island had notice that the Commission might adopt either of the proposed solutions, or individual aspects of those solutions. At the initial stage of the proceeding, Connecticut and Rhode Island had the opportunity to submit—and did, in fact, submit—evidence and argument concerning the increased Reserve Constraint Penalty Factors, the two-settlement capacity market design, and the merits of adopting a performance incentive structure involving both the FCM and the energy and ancillary services markets. At the compliance stage of the proceeding, they also had the opportunity to submit—and did, in fact, submit—evidence and argument on whether the increased Reserve Constraint Penalty Factors might impact specific elements of the two-settlement capacity market design.[111] Further, the parties have also had the opportunity to raise their arguments concerning this issue on rehearing.[112]

56. We are also unpersuaded by PSEG and NRG's argument that by instituting a section 206 proceeding rather than acting under the "jump-ball provision," the Commission in the May 30 Order caused substantial uncertainty and disrupted the market. Aside from their vague and unsupported allegations, no other ensuing pleadings and filings, nor ISO-NE's compliance filing, revealed any such confusion. In any case, the Commission properly invoked its section 206 authority to find that ISO-NE's existing tariff was unjust and unreasonable "because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing

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[110] Connecticut and Rhode Island Request for Rehearing at 32 (citing *PSC of Kentucky*, 397 F.3d at 1012).

[111] *See* May 30 Order, 147 FERC ¶ 61,172 at P 110; October 2 Order, 149 FERC ¶ 61,009 at PP 14-30.

[112] *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 (2011).

consumers to pay for capacity without receiving commensurate reliability benefits,"[113] a finding supported by overwhelming record evidence and not within the scope of the "jump-ball provision." Further, the Commission did not merely adopt ISO-NE's and NEPOOL's proposals outright; the Commission provided for further processes under its section 206 authority by directing ISO-NE to submit as part of its compliance filing either 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.[114] Thus, regardless of whether the "jump-ball provision" allows the Commission to adopt any or all aspects of *both* proposals, as PSEG and NRG allege,[115] the Commission in the May 30 Order took action and made findings beyond those contemplated in the "jump-ball provision," and which required the Commission to invoke section 206. Having instituted a section 206 proceeding, the Commission was statutorily required to establish a refund effective date.[116]

57. Lastly, we dismiss as moot Public Systems' request to clarify the scope of the compliance proceeding that the Commission instituted in the May 30 Order. Public Systems request that the Commission treat ISO-NE's compliance filing as a supplement to its section 205 filing and clarify that interveners can protest the substance of ISO-NE's compliance filing. ISO-NE submitted its compliance filing on July 14, 2014, and

[113] May 30 Order, 147 FERC ¶ 61,172 at P 23; *see also id.* P 26.

[114] *Id.* P 110.

[115] We make no finding as to whether PSEG and NRG correctly interpret the "jump-ball provision" in that regard.

[116] 16 U.S.C. § 824e(b) (2012) ("Whenever the Commission institutes a proceeding under this section, the Commission *shall* establish a refund effective date.") (emphasis added). We dismiss as moot PSEG and NRG's request that we "clarify the specifics of the rates that would apply as of the refund effective date in the event that refund is deemed necessary." PSEG and NRG Request for Rehearing at 25. Section 206(b) of the FPA provides that the Commission may order refunds "of any amounts *paid*, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, *in excess of those which would have been paid under the just and reasonable rate* . . . *which the Commission orders to be thereafter observed and in force.*" 16 U.S.C. § 824e(b) (2012) (emphasis added). Because the Commission has established the just and reasonable rate in this proceeding prior to any payments being made under that rate, there is now no basis on which to calculate refunds in this proceeding.

multiple parties, including Public Systems, filed protests raising numerous substantive issues. In the October 2 Order, the Commission rejected in part and accepted in part ISO-NE's compliance filing, subject to a further compliance filing.[117] In doing so, the Commission addressed the merits of the various protests to the compliance filing, including Public Systems' protest.[118] Because the Commission has already addressed the substantive issues that Public Systems raised in the compliance proceeding, we dismiss as moot Public Systems' request to clarify the scope of that proceeding.

D. Exemptions for Resource Non-Performance

1. Requests for Rehearing and Clarification

58. Dominion, Indicated Generators, NextEra, PSEG and NRG, and Public Systems request rehearing of the Commission's determination that a capacity market design that includes no exemptions for resource non-performance is just and reasonable.

59. Dominion argues that the Commission erred in accepting ISO-NE's two-settlement capacity market design without allowing an exemption from penalties in situations where electric transmission outages make it impossible for capacity resources to supply energy or operating reserves during a scarcity event. Accordingly, Dominion requests that the Commission grant rehearing and direct ISO-NE to exempt capacity resources from penalties when a planned or unplanned transmission outage prevents or limits resources from supplying their share of energy or operating reserves during a scarcity event.[119]

60. Dominion contends that the Commission's rejection of an exemption for transmission outages is inconsistent with the very rationale it employed in accepting ISO-NE's proposal. Dominion explains that if a resource is not available during a scarcity event because of a planned or unplanned transmission outage, no amount of incentives or penalties will result in the resource being available. Therefore, Dominion argues that if a resource is willing and able to perform but cannot do so because of a transmission outage that is beyond its control, it is neither just nor reasonable to penalize the resource through a reduction in the capacity payments it receives for being available to ISO-NE.[120]

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[117] The Commission accepted ISO-NE's second compliance filing in *ISO New England Inc.*, Docket No. ER14-2419-002 (Jan. 15, 2015) (delegated letter order).

[118] October 2 Order, 149 FERC ¶ 61,009 at P 1.

[119] Dominion Request for Rehearing at 1-2.

[120] *Id.* at 8.

Dominion also argues that the Commission's decision to accept ISO-NE's no-exemptions policy is contrary to the Commission's recent decision in *New England Power Generators Association, Inc. v. ISO New England, Inc.*, 144 FERC ¶ 61,157 (2013) (*NEPGA*), where the Commission found "that a demonstrated inability to procure fuel or transportation, as opposed to an economic determination not to procure fuel or transportation, may legitimately affect whether a capacity resource is physically available under the Tariff, and therefore may excuse non-performance."[121]

61. Dominion also argues that the Commission does not explain how a resource could factor in the risk of planned or unplanned transmission outages in its offers three years before the applicable Capacity Commitment Period. Dominion asserts that the Commission does not explain how these resources "with better performance characteristics" could incorporate a lower risk premium in their offer when transmission outages have nothing to do with the performance characteristics of generation resources.[122]

62. Dominion argues that reliance on what may be just and reasonable in a hypothetical fully-functioning uncapped energy market is not a valid justification for rejecting an exemption from penalties based on transmission outages or constraints.[123] Dominion states that the notion that ISO-NE operates a fully-functioning uncapped energy market is a fiction, which cannot serve as a legitimate basis for the Commission's acceptance of ISO-NE's proposal.[124]

63. Indicated Generators contend that the Commission has not given proper consideration to the comments from numerous market participants regarding exemptions for transmission outages, force majeure events, maintenance outages, and when a resource is following an ISO-NE dispatch instruction. Therefore, Indicated Generators argue that the Commission incorrectly concluded that capacity suppliers are uniquely situated to control for non-performance.[125] Indicated Generators assert that the Commission did not address their arguments demonstrating that excusing non-performance caused by circumstances not reasonably anticipated or under the control of

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[121] *Id.*

[122] *Id.* at 10.

[123] *Id.* at 7.

[124] *Id.* at 8.

[125] Indicated Generators Request for Rehearing at 5-6.

the supplier is both established industry practice and consistent with rational economic theory. Indicated Generators state that virtually all transactions within the Commission's jurisdiction excuse non-performance in circumstances beyond a contracting party's reasonable control.[126] In addition, Indicated Generators argue that the Commission failed to address arguments that, contrary to ISO-NE's assertions, ISO-NE is most often the best-positioned party to manage non-performance risk.

64. Indicated Generators argue that the May 30 Order results in an unjust and unreasonable redistribution of non-performance risk to entities that have no control over such risk and no viable means to abate it. For example, Indicated Generators state that the Capacity Performance Bilateral market that the Commission accepted in the May 30 Order does not exist at present. In addition, Indicated Generators state that the results of FCA 8 strongly suggest that there will not be adequate uncommitted capacity to support a robust Capacity Performance Bilateral market.[127] Indicated Generators argue that this could have significant deleterious effects on the marketplace and reliability overall if suppliers depart from the marketplace to avoid the onerous burdens associated with unexcused non-performance. Therefore, Indicated Generators state that the Commission should grant rehearing and order ISO-NE to recognize non-performance exemptions in those limited instances in which suppliers truly have no ability to control for the risk of non-performance – transmission outages, maintenance outages, force majeure events, and when following dispatch instructions from ISO-NE.[128]

65. NextEra contends that by rejecting all exemptions to the two-settlement capacity market design the Commission acted in an arbitrary and capricious manner.[129] NextEra states that transmission outages and the timing for transmission owners to fix problems on the transmission system are completely out of the control of capacity resources. NextEra further asserts that the Commission failed to address how the May 30 Order could assume a "fully-functioning" market, while on the same day the Commission granted an exemption for renewables that will depress capacity prices paid to capacity

[126] *Id.* at 6-7.

[127] *Id.* at 9-11.

[128] *Id.* at 11.

[129] NextEra Request for Rehearing at 2.

resources.[130] NextEra contends that it is arbitrary and unreasonable for the Commission to make conflicting policy decisions without an explanation.[131]

66. PSEG and NRG argue that the May 30 Order's failure to recognize appropriate exemptions from non-performance penalties is unreasonable because events beyond a resource's control that prevent it from delivering energy during a Capacity Scarcity Condition are precisely the kind of events that are best addressed through shared risk management.[132] PSEG and NRG contend that allocation of these risks to consumers, spread broadly over the entire system, makes economic sense. PSEG and NRG further argue that many dispatch decisions are not based on a security-constrained economic dispatch, and that holding generators financially responsible for decisions by system operators that are opaque to the generators is both unfair and inefficient and represents a significant transfer of risk.[133]

67. Public Systems argue that the Commission erred by defining capacity resource performance as producing energy or reserves during a Capacity Scarcity Condition regardless of whether ISO-NE has asked a resource to provide such energy or reserves.[134] Public Systems assert that ISO-NE may not dispatch capacity resources for energy or reserves during scarcity conditions in many situations, including when (i) transmission outages or constraints prevent ISO-NE from delivering the resource's energy or reserves where they are needed; (ii) the resource is offline due to an ISO-NE-approved, scheduled maintenance outage; or (iii) ISO-NE previously scheduled or dispatched the resource in such a way that its operational characteristics now prevent it from being available during the scarcity condition. Public Systems argue that these situations do not represent failures by the resource to provide capacity, but rather represent situations beyond the resource's control that render it temporarily inaccessible or undeliverable where it is needed. Public Systems state that the rules approved in the May 30 Order fail to

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[130] Specifically, NextEra states that the Commission issued an order in which an annual exemption for up to 200 MW (capacity rating) of renewables would be permitted to enter the market without mitigation at $0/kW-month, which the Commission acknowledged would put downward pressure on capacity clearing prices. *Id.* at 9 (citing *ISO New England, Inc.*, 147 FERC ¶ 61,173 (2014)).

[131] *Id.* at 10.

[132] PSEG and NRG Request for Rehearing at 11-13.

[133] *Id.* at 13-18.

[134] Public Systems Request for Rehearing at 6-9.

acknowledge that in some of these situations even an ideal capacity resource—i.e., one that is well-maintained and operated, with instantaneous starting and ramping ability—would produce no energy. Public Systems argue that the approved rules will, therefore, deprive even such an ideal resource of substantial portions of its capacity revenues. Public Systems further contend that potentially penalizing capacity resources for conditions beyond their control violates the FPA's requirement that there be some meaningful relationship between an entity's actions and the costs or revenues it is assigned.[135]

68. PSEG, NRG, and Public Systems request rehearing on several related issues, including the basis on which the Commission adopted the no-exemptions design and the impacts of the design on different market participants. Public Systems argue that the Commission failed to adequately explain its reasoning for why the absence of exemptions from non-performance charges is just and reasonable.[136] Public Systems, PSEG and NRG assert that the Commission erroneously denied that the two-settlement capacity market design represents a fundamental change,[137] and found the new performance definition reasonable because it mimics what would happen in an uncapped energy market. However, Public Systems contend that there is no reason to assume that an uncapped energy market is inherently reasonable. Public Systems aver that, in order to be reasonable, an uncapped energy market might give resources more autonomy in scheduling outages and in determining the timing and level of their operation, and that capacity resources in the FCM do not have such autonomy. Similarly, PSEG and NRG assert that the Commission's comparison of the new rules to outcomes in an uncapped energy market are inappropriate because foregone energy market revenues are not analogous to penalties for failing to deliver energy. Public Systems also argue that the new performance rules fail to properly value the reliability benefits that capacity resources provide during non-scarcity conditions, when those resources may be helping prevent a reserve deficiency.[138]

69. Lastly, NEPGA and NEPOOL each request clarification of the Commission's finding that an exemption is appropriate in instances where an intra-zonal transmission constraint may lead to improper price signals. NEPGA asserts that, at a June 20, 2014 NEPOOL Markets Committee meeting, ISO-NE appeared to interpret the Commission's

[135] *Id.* at 9-11.

[136] *Id.* at 13-14.

[137] *Id.*; PSEG and NRG Request for Rehearing at 8-11.

[138] Public Systems Request for Rehearing at 18.

directive as allowing ISO-NE to base the exemption on nodal pricing in the energy markets.[139] NEPGA argues that such an approach does not identify every situation where an intra-zonal constraint would limit the ability of a resource to provide energy or reserves across the constraint.[140] Therefore, NEPGA requests that the Commission clarify that it intended for ISO-NE to exempt resources not only when the dispatch software indicates a constraint exists, but also when generators follow dispatch instructions that limit their output.[141] Similarly, NEPOOL requests that the Commission clarify that the exemption should apply not only to resources whose performance is limited by intra-zonal congestion, but also to resources whose performance is limited by un-modeled transmission constraints.[142]

2. <u>Commission Determination</u>

70. We deny rehearing on the issue of exemptions from Capacity Performance Payments when a capacity resource fails to deliver energy or reserves due to a transmission outage or some other factor beyond the resource's control. In addition, we dismiss as moot NEPGA's and NEPOOL's requests for clarification.

71. Dominion, Indicated Generators, PSEG, and NRG assert that the Commission erred by failing to recognize exemptions from Capacity Performance Payments when a resource's non-performance is the result of factors beyond the resource owner's control—specifically, non-performance caused by a transmission outage, force majeure event, following ISO-NE's dispatch instructions, or being on a maintenance outage. These parties argue that the risk of non-performance in those situations is properly borne by, and spread across, transmission customers. We disagree. Exemptions within the two-settlement capacity market design represent a reallocation of performance risk from capacity suppliers to consumers. We are not persuaded by the requesting parties' arguments that such a reallocation is appropriate here.

72. NextEra and Public Systems argue that the Commission erred in justifying the lack of exemptions by assuming the existence of an uncapped energy market, which they assert does not exist in New England. However, by agreeing with ISO-NE that it is appropriate for a capacity market construct to mimic, to the extent practicable, the

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[139] NEPGA Request for Clarification at 3.

[140] *Id.*

[141] *Id.* at 4.

[142] NEPOOL Request for Clarification at 7.

performance incentives of an uncapped energy market, the Commission did not assume or suggest that an uncapped energy market exists in New England. Rather, as explained above, the Commission merely referenced certain economic principles underlying an uncapped energy market, and found it appropriate for the two-settlement capacity market design to adhere to those principles.[143] The specific principle that the Commission cited in relation to the lack of exemptions—i.e., that "resources only earn scarcity revenue if they can actually deliver energy during periods of scarcity"[144]—supports the notion that the risk of non-performance under the two-settlement capacity market design, including risk that may be beyond a resource owner's control, is most appropriately borne by capacity suppliers, rather than consumers.

73. Dominion argues that resources will not be capable of accurately pricing the risk of transmission outages into their offers three years in advance of the delivery year because such outages are unpredictable. However, as the Commission noted in the May 30 Order, evaluating the risk of factors beyond one's control is neither impossible nor uncommon in numerous market contexts.[145] Capacity suppliers have knowledge of their resources' locations on the transmission system, as well as knowledge of the types and probabilities of transmission outages, or dispatch constraints, that might affect their ability to provide energy and reserves to load. Based on that knowledge, resource owners can calculate the likelihood that a particular resource's performance will be affected by such constraints. Using that information, resource owners can then calculate a risk premium, which they are permitted to include in their capacity supply offers.

74. While it is true that there is uncertainty in these types of risk premium calculations, as the Commission acknowledged in the May 30 Order,[146] that uncertainty does not render the market design unjust and unreasonable.[147] Indeed, uncertainty is, to some extent, unavoidable in a market. For example, when a resource owner submits an offer into any forward capacity market, it does so based on its expectations regarding numerous uncertain variables, including construction costs, maintenance costs, the

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[143] *See supra* P 37.

[144] May 30 Order, 147 FERC ¶ 61,172 at P 63.

[145] *Id.* P 98.

[146] *Id.*

[147] *See, e.g.*, *New England Power Generators Ass'n, Inc. v. FERC*, 707 F.3d 364, 369 (2013) (rejecting argument that uncertainty regarding rate stability constitutes legal injury).

regulatory environment, and what the energy market price is likely to be in the delivery year. The fact that a resource owner must make its bid based on uncertain, and sometimes unknowable, variables does not necessarily render the market design unjust and unreasonable. As with those risks, capacity suppliers, not consumers, are in the best position to assess and price the performance risk associated with their resources. Thus, the Commission correctly found that it is appropriate to adjust resources' Capacity Performance Payments when they fail to perform, regardless of the reason for their non-performance.

75. Furthermore, while it is possible that the lack of exemptions will produce higher capacity prices, we reiterate that consumers will receive commensurate benefits for any such rate increase. This is because the lack of exemptions will produce a stronger performance incentive for resources, which will increase the probability that consumers will receive the capacity product that they paid for, through their load serving entities, during the most critical hours of the year. With the lack of exemptions under the two-settlement capacity market design, consumers are not as reliant upon specific capacity resources. That is, if a resource that assumed a Capacity Supply Obligation cannot perform during a Capacity Scarcity Condition, load serving entities' payment for that capacity will instead be redirected to those resources that can deliver the required product. Similarly, the increased performance incentive can be expected to reduce price spikes in the real-time markets, and therefore reduce the rates that load serving entities, and ultimately consumers, pay. Therefore, we continue to find that the benefits of using such a market design in the New England region are commensurate with, and may in fact outweigh, the associated costs.

76. We reject Dominion's assertion that the Commission's decision to not allow exemptions is at odds with *NEPGA*. As relevant here, *NEPGA* addressed the question of whether, under the Tariff rules in place at that time, a demonstrated inability to procure fuel, or transportation of that fuel, could excuse a capacity resource's failure to satisfy its performance obligations.[148] The Commission found that, under the then-existing Tariff rules, an inability to procure fuel or transportation "may legitimately affect whether a capacity resource is physically available under the Tariff, and therefore may excuse nonperformance."[149]

77. *NEPGA* does not bear on the issue of non-performance exemptions under the two-settlement capacity market design, because that case involved Tariff provisions that differ from those adopted in the May 30 Order. *NEPGA* concerned FCM rules under

[148] *See id.* P 47.

[149] *Id*.

which a resource could be excused for non-performance in certain circumstances.[150] The May 30 Order changed those FCM rules by, among other things, removing non-performance exemptions. This difference alone renders *NEPGA* inapposite to the issue of exemptions under the two-settlement capacity market design. However, *NEPGA* is also distinguishable because the performance obligations at issue in *NEPGA* were different from those at issue in the instant case.[151]

78. Public Systems also argue that failing to include an exemption from Capacity Performance Payments for resources that fail to deliver energy or reserves due to a factor beyond the resource owner's control violates cost causation principles.[152] We disagree. Under the two-settlement capacity market design, a capacity resource is paid for taking on a forward obligation to, *inter alia*, provide energy or reserves up to its share of the system's needs during Capacity Scarcity Conditions. As in many other forward-contract structures, the seller of the contract is not relieved of its obligation to deliver the product at the delivery time if circumstances beyond its control prevent it from doing so. In the event of such a failure to deliver, the seller must settle for the deviation from its obligation at the spot price.

79. In the two-settlement capacity market design, the Capacity Performance Payment Rate, rather than the real-time energy price, serves as the spot price for settling

[150] *See, e.g.*, *id.* P 55 ("Although the Tariff imposes strict performance obligations on capacity resources, it also recognizes that certain events may cause a capacity resource to be unable to follow dispatch instructions. In particular, Forced Outages, Force Majeure events and other events that result in a capacity resource not being physically available may excuse a capacity resource from following dispatch instructions.") (internal citations omitted); *id.* P 56 ("If a capacity resource cannot procure fuel or transportation in real time in order to run at dispatch levels beyond its day-ahead commitment (or when not scheduled in the day-ahead market), then the resource is not physically available to perform for a reason beyond the resource's control for those additional hours and/or incremental MWs; thus the resource may be excused for non-performance.").

[151] The performance obligations at issue in *NEPGA* were, *inter alia*, the submission of a day-ahead offer and the response to dispatch instructions. In contrast, the performance obligation at issue in the instant proceeding is the provision of a particular resource's share of the system's needs during a Capacity Scarcity Condition.

[152] Public Systems Request for Rehearing at 9.

deviations.[153] Thus, for a resource that fails to deliver energy or reserves due to a factor beyond its control, the Capacity Performance Payment does not represent the assessment of an unassociated cost; rather, it represents the resource's settlement for deviating from its forward obligation. While we acknowledge that a resource may occasionally be unable to deliver energy or reserves due to factors such as a transmission outage or a dispatch decision by ISO-NE, the resource is permitted to include a reasonable estimate of the frequency of such occurrences in the risk premium component of its capacity supply offer. Thus, the resource has the opportunity to recover the costs associated with such non-performance risks. Additionally, a resource that undertakes the investment and maintenance actions necessary to maximize the probability that it can perform during Capacity Scarcity Conditions can reasonably expect that it will have opportunities to perform in excess of its share of the system's needs during some Capacity Scarcity Conditions, thereby partially or fully offsetting any negative Capacity Performance Payments it might be assessed during other Capacity Scarcity Conditions.

80. We dismiss as moot NEPGA's and NEPOOL's requests for clarification. NEPGA and NEPOOL request, in effect, that the Commission clarify the scope of the exemption it expects ISO-NE to adopt in addressing the intra-zonal transmission constraint issue that the Commission identified in the May 30 Order. However, in the October 2 Order, the Commission found that, based on the additional evidence submitted at the compliance stage of the proceeding, such an exemption is not necessary.[154] Because the Commission has found such an exemption to be unnecessary, we find NEPGA's and NEPOOL's requests to clarify the scope of that exemption to be moot.[155] For the same reason, we

[153] We note that using the Capacity Performance Payment Rate as the basis for settling deviations provides market participants with certainty as to what the spot price for such settlements will be.

[154] October 2 Order, 149 FERC ¶ 61,009 at PP 56-62. The Commission directed ISO-NE to submit an additional compliance filing to reflect the Commission's finding that such an exemption was unnecessary. *Id.* at 56. ISO-NE submitted the additional compliance filing on November 3, 2014, and the Commission accepted that compliance filing on January 15, 2015. *ISO New England Inc.*, Docket No. ER14-2419-002, at 1-2 (Jan. 15, 2015) (delegated letter order).

[155] NEPOOL additionally seeks clarification as to whether an exemption is appropriate when, during a Capacity Scarcity Condition, the output of a resource on the export side of a capacity zone interface is limited due to a reduction in transfer capability between capacity zones resulting from a transmission outage or de-rate. However, if we assume that the capacity zone on the export side of the interface is not experiencing a Capacity Scarcity Condition, then the resource in question will not be subject to Capacity

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also deny Public Systems' request for rehearing concerning whether the Commission failed "to fully define the problem of applying PI to resources on the export side of an intra-zonal transmission constraint, and err[ed] in failing to direct [ISO-NE] to fix the problem properly."[156]

E. Capacity Market Design Parameters

1. Performance Payment Rate

a. Requests for Rehearing

81. Connecticut, Rhode Island, and Potomac Economics argue that the Commission erred in accepting ISO-NE's Capacity Performance Payment Rate because it creates an energy market shortage price based on planning requirements rather than a reasonable estimate of the value of energy during shortage conditions.[157] Potomac Economics also argues that the Commission erred in failing to base the Capacity Performance Payment Rate on economic principles that would indicate the value of energy in the operating horizon. In addition, Potomac Economics argues that the Commission erred in failing to recognize that the Capacity Performance Payment Rate and the Reserve Constraint Penalty Factors are additive, and that the Commission thereby adopted an aggregate rate that exceeds the level supported by evidence in the record. Potomac Economics argues that the Commission erred in failing to recognize that the Capacity Performance Payment

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Performance Payments. If, instead, we assume that both capacity zones are in Capacity Scarcity Conditions, the reduced transfer capability across the zonal interface is not distinguishable from any other inter-zonal transmission congestion that might limit a capacity resource's output, and the Commission rejected calls for an exemption in such a situation in the May 30 Order, 147 FERC ¶ 61,172 at PP 63, 68, for the same reasons articulated above: Exemptions from Capacity Performance Payments within the two-settlement market design merely represent a reallocation of performance risk from capacity suppliers to consumers, and we find that suppliers, not consumers, are in the best position to assess and price the performance risk associated with their resources. *See supra* PP 71-75.

[156] Public Systems Request for Rehearing at 5.

[157] Potomac Economics Request for Rehearing at 3-4; Connecticut and Rhode Island Request for Rehearing at 14-16.

Rate should increase as shortages become deeper in order to reasonably and efficiently reflect system conditions.[158]

82. Potomac Economics argues that there is no reason the Capacity Performance Payment Rate alone needs to provide the revenue necessary to incent new investment, as it is well understood that the marginal incentive to invest in new resources is provided by a combination of capacity and energy revenues.[159] Potomac Economics states that ISO-NE's sloped demand curve, which the Commission approved on April 1, 2014, is based on the net cost of new entry. Potomac Economics asserts that basing the demand curve on the net cost of new entry ensures that capacity market revenues, together with energy and ancillary services market revenues, are sufficient to cover the cost of new entry up to at least the planning requirement that meets the 1-day-in-10-years reliability criterion. Potomac Economics contends that if the Capacity Performance Payment Rate were lowered, ISO-NE's sloped demand curve would still establish capacity prices that will ensure the 1-day-in-10-years standard is satisfied.[160]

83. Potomac Economics contends that the Commission erred by not addressing its proposal to adopt a Capacity Performance Payment Rate that would increase as a reserve shortage deepens. Potomac Economics states that it is indisputable that energy and operating reserves become more valuable as operating reserve shortages deepen because the probability of having to shed load increases exponentially. Potomac Economics notes that a single, flat Capacity Performance Payment Rate will not provide as substantial a signal during the deepest shortages to incent suppliers within and outside of New England to provide all available energy under these conditions to avoid involuntary load loss.

b. **Commission Determination**

84. We deny rehearing on the issue of whether the $5,455/MWh Capacity Performance Payment Rate and the phase-in Capacity Performance Payment Rates are just and reasonable.[161] Multiple parties contend that the two-settlement capacity market

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[158] Potomac Economics Request for Rehearing at 3-4.

[159] *Id.* at 5-6.

[160] *Id.* at 7.

[161] We note that, concurrently with this order, the Commission is issuing an order on rehearing in the compliance proceeding that the Commission initiated in the May 30 Order. *See ISO New England Inc.*, 153 FERC ¶ 61,224. In that compliance proceeding, the Commission explicitly directed ISO-NE to address whether it is appropriate to adjust

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design will produce unjust and unreasonable rates for consumers because the Capacity Performance Payment Rate is based on the 1-day-in-10-years reliability standard, rather than on the real-time value that consumers place on additional supply when supply is not meeting demand in real-time—which is commonly referred to as the value of lost load.[162] We disagree.

85. The Capacity Performance Payment Rate is based on the number of expected annual scarcity hours for the New England power system. Using the 1-day-in-10-years resource adequacy criterion, which is established by the Northeast Power Coordinating Council and is the basis for the Installed Capacity Requirement in the New England region, ISO-NE calculated an expected 21.2 hours of scarcity per year.[163] In the May 30 Order, the Commission explained that it was "not persuaded that setting the Capacity Performance Payment Rate at the value of lost load would provide adequate incentive for new entry, when required, and would therefore meet [the 1-day-in-10-years] reliability standard."[164] We remain unpersuaded on this issue, as the record does not support the conclusion that calculating the Capacity Performance Payment Rate based on the value of lost load would satisfy the 1-day-in-10-years reliability standard under current system conditions, where consumers do not see wholesale prices in real-time and, therefore, are unable to assign value to lost load in real-time.

86. Potomac Economics argues that basing the Capacity Performance Payment Rate on a planning criterion does not reflect the value of energy in the operating horizon.[165] Similarly, Connecticut and Rhode Island assert that this approach "disregards customers' value of reliability and, consequently, far outstrips the reasonable range of values that

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the Capacity Performance Payment Rate to reflect the increased Reserve Constraint Penalty Factors. While Potomac Economics has raised arguments concerning that issue in its request for rehearing of the May 30 Order, we find that the arguments on that issue are more appropriately raised in the compliance proceeding. Accordingly, we dismiss Potomac Economics' request for rehearing on that issue here as beyond the scope of the instant proceeding. However, we note that the Commission is addressing nearly identical arguments from other entities in the companion order. *See id.* PP 15-22.

[162] *See* Connecticut and Rhode Island Request for Rehearing at 14; Potomac Economics Request for Rehearing at 5.

[163] January 17 Filing, Att. I-1c at 107.

[164] May 30 Order, 147 FERC ¶ 61,172 at P 74.

[165] Potomac Economics Request for Rehearing at 5.

customers place on avoiding an electric power outage,"[166] and "ties the cost of reliability (i.e., the performance rate) to the cost of new entry for a new generator, which has no bearing on the value of the reliability benefit for customers."[167] We disagree with these assertions.

87. Consumers receive reliability benefits by, *inter alia*, procuring—through the capacity, energy, and ancillary services markets—a resource fleet that provides energy and reserves during reserve deficiencies. As the Commission has explained, the incentive for resources to provide that product can be provided through the capacity market, the energy and ancillary services markets, or a combination of those markets. The combined price that load serving entities pay in those markets reflects the value that consumers place on reliability. An important difference between the current FCM rules and the two-settlement capacity market design is that the level of reliability benefits that consumers are purchasing through their load serving entities' capacity payments will be more transparent. Thus, rather than disregard the value of reliability to consumers, the two-settlement capacity market design should more accurately reflect that value than the existing FCM does. While it is possible that basing the Capacity Performance Payment Rate on the value that consumers place on lost load in real-time could accurately reflect the value that consumers place on reliability, this would require that consumers see, and have the ability to respond to, lost load in real-time. We are not persuaded that demand-side price transparency in New England is sufficient to allow consumers to see and respond to wholesale prices in this way.

88. As to Connecticut and Rhode Island's assertion that the cost of new entry has no bearing on consumers' reliability benefits, this assertion ignores the FCM's purpose, which is, in part, to ensure reliability by procuring capacity that is sufficient to meet demand.[168] Because load serving entities, and ultimately consumers, must pay the cost of new entry when new generation resources are required, the cost of new entry is inextricably linked to the value of the reliability benefit that consumers receive for their capacity market payments.

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[166] Connecticut and Rhode Island Request for Rehearing at 14.

[167] *Id.* at 15.

[168] *See, e.g.*, *Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 260 (D.C. Cir. 2008), *rev'd in part on other grounds*, *NRG Power Marketing, LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 168-170 (2010); *Conn. Dept. of Pub. Util. Control v. FERC*, 569 F.3d 477, 480 (D.C. Cir. 2009).

89. While Potomac Economics argues that the demand curve that ISO-NE uses in the FCA will ensure that the region procures enough resources to satisfy the 1-day-in-10-years reliability standard, we are not persuaded that it will do so reliably and efficiently in the absence of adequate performance incentives. Potomac Economics is correct that ISO-NE's demand curve is based on the cost of new entry. However, it is also the product of a simulation analysis that accounts for the expected performance of the New England fleet. While the demand curve will procure an amount of capacity necessary to satisfy the 1-day-in-10-years reliability standard, a demand curve accompanied by strong performance incentives will be farther to the left, and thus need to procure fewer megawatts to meet the reliability standard, than a demand curve without strong performance incentives. A low Capacity Performance Payment Rate—i.e., one that does not satisfy the principle that a resource that does not perform at all should receive zero revenue—will result in poor performing resources remaining in the market despite providing unreliable service, and ISO-NE will have to procure a greater quantity of installed capacity in an attempt to ensure reliability, thereby increasing consumer costs.[169] Furthermore, if resource performance in a delivery year deteriorates to a level that is lower than that which the demand curve assumes, such performance can threaten reliability. Thus, as the Commission explained in the May 30 Order, merely procuring an amount of nameplate capacity that meets the region's net Installed Capacity Requirement does not necessarily produce, and recently has not produced, the level of resource performance necessary to ensure reliability.[170] It is the demand curve and the Installed Capacity Requirement *plus* the incentive to perform that ensures the 1-day-in-10-years reliability standard is satisfied.

90. Lastly, concerning Potomac Economics' argument that, at a minimum, the Capacity Performance Payment Rate should be altered so that it increases as shortages become deeper, we acknowledge that such an approach might be sound. However, assuming *arguendo* that Potomac Economics' alternative would be just and reasonable, it is well-established that there can be more than one just and reasonable rate.[171] Thus, the existence of another potentially just and reasonable approach does not render unjust and

[169] January 17 Filing, Att. I-1c at 102.

[170] *See* May 30 Order, 147 FERC ¶ 61,172 at P 36.

[171] *See, e.g.*, *Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 470-71 (D.C. Cir. 2008), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010); *City of Winnfield, La. v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984).

unreasonable the Capacity Performance Payment Rate that the Commission adopted in the May 30 Order.[172]

2. Monthly Stop-Loss

a. Request for Rehearing

91. Connecticut, Rhode Island, and NextEra argue that the Commission erred by holding that ISO-NE's monthly stop-loss mechanism was just and reasonable, even though it creates a skewed risk profile. NextEra argues that the Commission ignored the fact that the auction starting price is arbitrary, apparently finding that the "auction starting price is known in advance, and therefore allows a resource to calculate its maximum risk exposure for a Capacity Commitment Period based on its offer price."[173] NextEra argues that it is not the auction starting price, but rather the projected auction clearing price (and the associated monthly and annual stop-loss limits), that sets the risk profile for a market participant.

92. Connecticut, Rhode Island, and NextEra contend that the monthly stop-loss mechanism places the greatest risks on capacity resources when the FCA clearing price is low and places potentially insignificant risks on capacity resources when FCA clearing prices are high. Connecticut, Rhode Island, and NextEra assert that this leads to excess non-performance risk when clearing prices are low, and little or no non-performance risk when clearing prices are at or near the starting price.[174] NextEra contends that the skewed risk profile associated with the Commission-approved monthly stop-loss limits shifts to consumers the costs associated with the higher non-performance risks that occur when FCA prices are projected to be low.[175]

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[172] We also note that the approach the Commission adopted is, in fact, similar to Potomac Economics' recommended alternative because less severe Capacity Scarcity Conditions are likely to be shorter in duration, and therefore have less financial impact, than more severe events, which are likely to be longer in duration and have a larger financial impact.

[173] NextEra Request for Rehearing at 6 (citing May 30 Order, 147 FERC ¶ 61,172 at P 71).

[174] *Id.* at 1-2; Connecticut and Rhode Island Request for Rehearing at 24-26.

[175] NextEra Request for Rehearing at 6-7.

93. NextEra contends that the Commission should grant rehearing to find ISO-NE's monthly stop-loss limit unjust and unreasonable and direct ISO-NE to implement NextEra's monthly stop-loss methodology, which is based directly on the existing monthly stop-loss limit. NextEra states that, if the Commission does not grant rehearing and direct the adoption of its stop-loss proposal, the Commission should set the issue for hearing or direct stakeholders to develop monthly stop-loss limits that do not result in a skewed risk profile.

b. Commission Determination

94. We deny rehearing on the monthly stop-loss mechanism that the Commission adopted in the May 30 Order. We acknowledge that there are trade-offs to basing the stop-loss limits on either the auction starting price or the auction clearing price, and it is possible that both approaches could be just and reasonable. As the Commission explained in the May 30 Order, a key benefit of using the auction starting price is that it is known in advance, which allows resource owners to calculate, prior to participating in an FCA, its maximum net loss exposure. The resource owners can communicate this maximum risk exposure to third parties, which may help the resource owners secure financing that will enable them to participate in the FCA.[176] Given the necessary uncertainty associated with a new market design, such as the two-settlement capacity market design, it is important to provide resource owners a degree of certainty with respect to their maximum financial exposure. Thus, because it provides that certainty, we continue to find it appropriate to base the monthly stop-loss limit on the auction starting price.

95. Connecticut, Rhode Island, and NextEra argue that the stop-loss protections are strongest when capacity is scarce and the market clears at a high price, and weakest when there is a capacity surplus and the market clears at a low price. Connecticut and Rhode Island assert that a capacity resource will face no risk if an auction clears at the auction starting price. As an initial matter, we note that Connecticut and Rhode Island are incorrect that a resource faces no risk if an auction clears at the auction starting price. Connecticut and Rhode Island's argument focuses only on the *net* financial risk associated with a resource. Even assuming *arguendo* that, due to the auction clearing at the auction starting price, a resource owner faces no risk of receiving net-negative capacity market revenues for a particular resource, the fact remains that, regardless of the auction clearing price, a resource owner would still face the risk that it might lose a significant portion of its Capacity Base Payment if the resource performs poorly. Further, even if such a resource hits its stop-loss limit, that resource still has an incentive to perform well in the remaining months of the Capacity Commitment Period, because it

[176] January 17 Filing, Att. I-1c at 174.

has a financial incentive to earn back some of the capacity revenues that it lost in earlier months.[177] We also reiterate that, even if an auction clears at the auction starting price, in order for a resource owner to reach the annual stop-loss limit for a resource, the number of hours of Capacity Scarcity Conditions would have to significantly exceed the amount of such scarcity conditions the region has experienced in recent years.[178]

96. We acknowledge, as did the May 30 Order, that as the auction clearing price increases above a resource's offer price, the resource owner's financial risk associated with that resource decreases, because the resource owner can bear more negative Capacity Performance Payments before its capacity revenues reach zero or become net-negative.[179] However, this is true regardless of which price is used to calculate the stop-loss limit. Furthermore, this aspect of the stop-loss mechanism does not change the fact that the resource owner has an incentive to perform in order to avoid losing capacity revenues. To the extent this aspect of the stop-loss mechanism is worse if the mechanism is based on the auction starting price rather than the auction clearing price, we continue to find that, given our interest in providing certainty to resources seeking to participate in a Forward Capacity Auction, the certainty provided by basing the stop-loss limit on the auction starting price outweighs this potential downside of doing so.[180]

97. We also note that, as ISO-NE explained, setting the stop-loss limit at the auction starting price is beneficial because if a stop-loss limit is frequently reached it will weaken the incentives for poorly-performing resources to make investments that improve their performance, thereby adversely affecting the capacity market's ability to ensure reliability.[181]

F. Market Power Mitigation Rules

1. Requests for Rehearing

98. Public Systems assert that the market monitoring regimen ISO-NE has devised to address the risks associated with the two-settlement capacity market design is inadequate,

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[177] *Id.* Att. I-1c at 195.

[178] *Id.* Att. I-1c at 188-191; May 30 Order, 147 FERC ¶ 61,172 at P 70.

[179] May 30 Order, 147 FERC ¶ 61,172 at P 71.

[180] *See id.*

[181] January 17 Filing, Att. I-1c at 176.

because key components of the market monitoring rules remain vague and are contrary to provisions the Commission has approved in other regional transmission organizations.[182] Public Systems argue that the determination to not require more specificity in the market power mitigation regimen is inconsistent with *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,224, at PP 296-98, 321 (2013) (*Southwest Power Pool*), because the rules are "subject to bias," cannot be "independently verified," and employ the use of "unspecified methods" for the calculation of costs.[183]

99. Connecticut and Rhode Island assert that the market monitoring provisions create an overly vague standard of review that will not allow the market monitor to identify an exercise of market power.[184] Connecticut and Rhode Island assert that the adoption of the \$3.94 per kW-month dynamic de-list bid threshold will permit suppliers with market power to set the market clearing price with no market monitor review.[185] Connecticut and Rhode Island argue that exempting pivotal suppliers from mitigation below the dynamic de-list bid threshold of \$3.94 per kW-month inappropriately prejudges the appropriateness of that threshold and fails to consider how the combined ISO-NE and NEPOOL proposals that the Commission adopted could change the assumptions and values underlying the calculation.[186]

2. Commission Determination

100. We deny rehearing of the Commission's adoption of the market monitoring and mitigation provisions. Public Systems argue that allowing risk premiums to be included in dynamic de-list bids ignores Commission precedent and is illogical.[187] We disagree. Allowing resource owners to include appropriate risk premiums in their dynamic de-list bids is logical because such risk premiums, as with the other components of a dynamic de-list bid, represent legitimate costs. Further, the precedent to which Public Systems cite, *Southwest Power Pool*, does not support their argument.

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[182] Public Systems Request for Rehearing at 18-19.

[183] *Id.* at 21-22.

[184] Connecticut and Rhode Island Request for Rehearing at 27.

[185] *Id.* at 29.

[186] *Id.*

[187] Public Systems Request for Rehearing at 18-19.

101. In *Southwest Power Pool* the risk premiums at issue were common elements of offers submitted in Commission-jurisdictional markets, for which there are standardized calculation methodologies that are easily applied to different market participants. In contrast, as the Commission explained in the May 30 Order, the risk premiums associated with non-performance risks under the two-settlement capacity market design require a more complex calculation that depends on the company-specific nature of valuing performance risk. In any case, the Commission's adoption of the market monitoring provisions here is consistent with the Commission's rationale for rejecting the market monitoring provisions at issue in *Southwest Power Pool*. In both cases the Commission was motivated by ensuring that the relevant market monitoring provisions ensure that risk premiums are verifiable and calculated consistently.

102. We also disagree with Connecticut, Rhode Island, and Public Systems' arguments that the Commission erred by adopting a dynamic de-list bid threshold of $3.94 per kW-month.[188] As ISO-NE explained in the underlying filing, the Internal Market Monitor attempts to set the dynamic de-list bid threshold at the estimated offer of the marginal resource in the FCA under the two-settlement capacity market design.[189] The $3.94 per kW-month value that the Commission adopted in the May 30 Order is based on a formula, the inputs into which—the Capacity Performance Payment Rate, the expected Capacity Balancing Ratio, and the expected hours of Capacity Scarcity Conditions—were all supported by substantial evidence.[190] Furthermore, we note that the two-settlement capacity market design changes the level of risk associated with a Capacity Supply Obligation and, therefore, changes the level of the competitive offer into the auction relative to the offers under the existing FCM rules.[191] The record does not support a

[188] With regard to Connecticut and Rhode Island's argument that the Commission erred in adopting the $3.94 per kW-month dynamic de-list bid threshold without considering the impact that the increased Reserve Constraint Penalty Factors might have on that value, we dismiss that argument as beyond the scope of this proceeding. The Commission provided parties the opportunity to present evidence and argument on that issue in the compliance proceeding that the Commission instituted in the May 30 Order. We note that Connecticut and Rhode Island also raised this argument on rehearing in the compliance proceeding, and the Commission is addressing that argument in an order issued concurrently with the instant order. *See* ISO New England Inc., 153 FERC ¶ 61,224 at PP 24-28.

[189] January 17 Filing, Att. I-1e at 55.

[190] *See, e.g.*, January 17 Filing, Att. I-1c at 72-74, 88-111.

[191] January 17 Filing, Att. I-1e at 55.

determination that retaining the $1.00 per kW-month dynamic de-list bid threshold associated with the existing FCM rules would be appropriate under the two-settlement capacity market design.[192]

103. Connecticut, Rhode Island, and Public Systems argue that the Commission erred by limiting market power mitigation to pivotal suppliers.[193] We disagree. While it is possible that a non-pivotal supplier could offer at a level above its net going-forward costs, thereby raising the auction clearing price if that supplier's resource is the marginal unit, this is true regardless of whether the dynamic de-list bid threshold is set at $3.94 per kW-month, $1.00 per kW-month, or some lesser value. The important point is that, due to the competitive nature of a FCA, a non-pivotal supplier has an incentive not to engage in such behavior, i.e., it has an incentive to bid at the level representing its net going-forward cost. This is because, if a resource is not pivotal, overstating its net going-forward costs puts it at greater risk of not clearing in the auction and, as a result, not receiving capacity revenues. Therefore, as ISO-NE explains it, "a non-pivotal supplier cannot exercise unilateral market power and profitably raise price to a non-competitive level."[194] Pivotal suppliers, on the other hand, have an opportunity to exercise market power in a way that will profitably raise the auction clearing price to non-competitive levels, because such suppliers know that they are guaranteed to clear the auction. Given the difference in market power held by pivotal versus non-pivotal suppliers, we continue to find it appropriate for the Internal Market Monitor to mitigate the dynamic de-list bids only of pivotal suppliers.

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[192] We note that, 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. 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).

[193] Public Systems Request for Rehearing at 22-23.

[194] January 17 Filing, Att. I-1e at 20-21.

3. Peak Energy Rent Deduction

a. Request for Rehearing

104. Indicated Generators contend that the Commission incorrectly dismissed, as beyond the scope of the proceeding, arguments that the Peak Energy Rent mechanism should be adjusted. Indicated Generators assert that any benefits from increasing the Reserve Constraint Penalty Factors will be negated by the existing Peak Energy Rent provisions, placing those provisions squarely within the scope of this proceeding. Indicated Generators assert that the increased Reserve Constraint Penalty Factors coupled with Peak Energy Rent deduction will incent generators to clear in the real-time market, rather than the day-ahead market, in order to benefit from the increased Reserve Constraint Penalty Factor. Indicated Generators argue that the two-settlement capacity market design obviates the need for the Peak Energy Rent deduction and the Commission should, therefore, direct ISO-NE to eliminate the Peak Energy Rent deduction in its entirety by FCA 9.[195]

b. Commission Determination

105. We deny Indicated Generators' request for rehearing regarding the Peak Energy Rent deduction. While we acknowledge that the Peak Energy Rent deduction might incent resources to clear in the real-time market rather than the day-ahead market, we reiterate that this potential inefficiency exists independent of the increase in Reserve Constraint Penalty Factors that the Commission directed in this proceeding. In fact, this potential inefficiency has existed since ISO-NE designed the Peak Energy Rent adjustment.[196] The Commission approved the Peak Energy Rent deduction, notwithstanding the potential inefficiency, because the Peak Energy Rent adjustment served an important function, i.e., it acted as a hedge against price spikes.[197] Although a change in the Reserve Constraint Penalty Factors could impact that potential inefficiency,

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[195] Indicated Generators Request for Rehearing at 12-14.

[196] *See, e.g*, *Devon Power LLC*, 111 FERC ¶ 63,063, at PP 397-399 (2005) (noting ISO-NE's acknowledgement of potential inefficiencies caused by using real-time prices to calculate the peak energy rent deduction in ISO-NE's Locational Installed Capacity (LICAP) market, and ISO-NE's arguments as to why those inefficiencies do not warrant altering the peak energy rent mechanism).

[197] *Devon Power LLC*, 115 FERC ¶ 61,340, at PP 24, 29 (2006) (approving the FCM with the same peak energy rent adjustment that was developed for the LICAP market).

we are not persuaded that it is necessary to alter the Peak Energy Rent adjustment in this proceeding.[198] Thus, we continue to find that changes to the Peak Energy Rent deduction are beyond the scope of this proceeding.

106. Further, we note that, on March 6, 2015, ISO-NE and NEPOOL filed Tariff revisions to eliminate the Peak Energy Rent adjustment starting with the Capacity Commitment Period that begins on June 1, 2019 (FCA 10). On May 5, 2015, the Commission approved those revisions, effective May 6, 2015.[199] As the Commission noted in the May 2015 Order, to the extent entities believe further changes to the Peak Energy Rent adjustment are necessary, we encourage stakeholders to utilize the stakeholder process to consider such Tariff revisions. [200]

<u>The Commission orders</u>:

(A) The requests for rehearing of the May 30 Order are hereby denied, as discussed in the body of this order.

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[198] We note that it is risky for a resource to not commit in the day-ahead market, with the hope that real-time demand will exceed ISO-NE's forecast and the resource will be taken in the real-time market. As a result, we are not persuaded that generators will be more inclined to clear in the real-time market versus the day-ahead market. Thus, the potential inefficiency associated with the Peak Energy Rent adjustment is not necessarily problematic.

[199] *ISO New England Inc.*, 151 FERC ¶ 61,096 (2015) (May 2015 Order). We also note that, on January 30, 2015, the Commission denied a complaint seeking modification or elimination of ISO-NE's Peak Energy Rent adjustment mechanism. *See New England Power Generators Ass'n, Inc. v. ISO New England Inc.*, 150 FERC ¶ 61,053 (2015).

[200] May 2015 Order, 151 FERC ¶ 096 at P11.

(B) The requests for clarification of the May 30 Order are hereby dismissed as moot, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.